Appendix E – Worksheets for Major Sources of PM10, NOx and SO2

Regulation No. 1

Particulates, Smokes, Carbon Monoxide and Sulfur Oxides

Colorado Air Quality Control Commission



- Fort Carson shall maintain records of each fog oil smoke generation exercise which shall include:
 - a. observations from the designated observer(s) regarding the drift of the fog oil smoke only when said smoke approaches the Installation or Site boundary to the extent that all generation must cease to prevent visible emissions from crossing the boundary;
 - b. the amount of fog oil used in gal/day;
 - c. the general location at which the fog oil smoke was generated; and
 - d. the date and duration of the fog oil smoke generation; and
- For purposes of this section, fog oil is defined as highly refined (hydrotreated) virgin oil.

The Commanding General in charge of Fort Carson shall be responsible for ensuring that no drift of smoke from fog oil generation or other obscurant use occurs across the boundary of the military reservations, even if generated in accordance with this section.

III. PARTICULATES

- A. Fuel Burning Equipment
 - No owner or operator shall cause or permit to be emitted into the atmosphere from any fuel-burning equipment, particulate matter in the flue gases which exceeds the following:
 - a. 0.5 lbs. per 10⁶ BTU heat input for fuel burning equipment of less than or equal to 1x10⁶ BTU/hr. total heat input design capacity.
 - b. For fuel burning equipment with designed heat inputs greater than Ix10⁶ BTU per hour, but less than or equal to 500x10⁶ BTU per hour, the following equation will be used to determine the allowable particulate emission limitation.

PE=0.5(FI)-0.26

Where:

PE = Particulate Emission in Pounds per million BTU heat input.

FI = Fuel Input in Million BTU per hour.

 0.1 lbs. per 10⁶ BTU heat input for fuel burning equipment of greater than 500x10⁶ BTU per hour or more.

d. If two or more fuel burning units connect to any opening, the maximum allowable emission rate shall be calculated by summing the allowable emissions from the units being operated.

2. Exceptions

Sources and emissions subject to the emission limitation of Section $\,{\rm V.}\,$ of this regulation.

3. Performance Tests

Prior to granting of a final approval permit or amending a permit, when an emission source or control equipment is altered, or at any time when there is reason to believe that emission standards are being violated, the Division may require the owner or operator of any fuel burning equipment to conduct performance tests, as measured by EPA Methods 1-4 and the front half of EPA Method 5 (40 CFR 60.275, Appendix A, Part 60) to determine compliance with this subsection of this regulation.

B. Incinerators

- No owner or operator of an incinerator shall operate any incinerator without a permit from the Division.
- Standard of Performance for all incinerators other than biomedical waste incinerators.
 - In areas designated as nonattainment for particulate matter, no owner or operator of an incinerator shall cause or permit emissions of more than 0.10 grain of particulate matter per standard cubic foot. (Dry flue gas corrected to 12 percent carbon dioxide.)
 - In areas designated as attainment for particulate matter, no owner or operator of an incinerator shall cause or permit emissions of more than 0.15 grain of particulate matter per standard cubic foot. (Dry Flue gas corrected to 12 percent carbon dioxide.)

3. Performance Tests

Prior to granting a final approval permit or amending a permit, when an emission source or control equipment is altered, or at any time when there is reason to believe that emission standards are being violated, the Division may require the owner or operator of an incinerator to conduct performance tests(s) in accordance with Appendix A of Air Quality Control Commission Regulation Number 6.

4. Standard of Performance for Biomedical Waste Incinerators.

The owner or operator of an existing incinerator used for the disposal of biomedical waste shall comply with Regulation No. 6, Part B. V. Standard of Performance For New Biomedical Waste Incinerators as follows:

- All incinerators, existing as of the effective date of Regulation 6 Part B, V., with a design capacity of 400 pounds per hour and greater must comply with the requirements of this regulation by January 1, 1990.
- b. All incinerators, existing as of the effective date of Regulation 6, Part B, V., with a design capacity of less than 400 pounds per hour must comply with the requirements of this regulation as applicable by December 31, 1994; except incinerators with a design capacity of less than 200 pounds per hour shall be permitted and allowed to operate only so long as the units continue to meet the particulate and visible emission standards existing prior to the effective date of Regulation 6, Part B.V., the manufacturer's design specifications and any other applicable safety standards. (The standards existing prior to the effective date of this regulation are: a) For sources existing prior to January 30, 1979: 20% opacity and 0.10 grains of particulate matter (PM) for particulate matter non-attainment areas and 0.15 grains of PM for PM attainment areas; b) 20% opacity and 0.10 grains of PM for sources constructed after January 30, 1979.)

C. Manufacturing Processes

- Except as provided in paragraphs 2 and 3 of this subsection C., no owner or operator of a manufacturing process unit shall cause or permit emission of any particulate matter into the atmosphere during any consecutive sixty (60) minute period which is in excess of the following.
 - a. For process equipment having process weight rates of 30 tons per hour or less, the allowable emission rate shall be determined by the use of the equation:

 $PE = 3.59(P)^{0.62}$

Where:

PE = Particulate Emission in lbs. per hour

P = Process weight rate in tons per hour

b. For process equipment having process weight rates of greater than 30 tons per hour, the allowable emission rate shall be determined by use of the equation:

 $PE = 17.31(P)^{0.16}$

Where:

PE = Particulate Emission rate in lbs. per hour

P = Process weight rate in tons per hour

- c. If two or more process units are connected to the same opening, the maximum allowable emission rate shall be computed by summing the allowable emissions for the units being operated.
- 2. Alfalfa Dehydration Plant Drum Dryers

New alfalfa dehydration plants shall be subject to the provisions of III.C. of this regulation for process weight rates.

- 3. Exceptions
 - Sources and emissions subject to the emission limitations of Section
 V. of this regulation.
 - Fugitive dust and fugitive particulate emissions as defined in Section II.A.8 of this Regulation.
- 4. Performance Tests: prior to granting of a final approval permit or amending a permit, when an emission source or control equipment is altered, or at any time when there is reason to believe that emission standards are being violated, the Division may require the owner or operator of any manufacturing process to conduct performance tests, as measured by EPA Methods 1-4 and the front half of EPA Method 5 (40 CFR 60.275, Appendix A, Part 60) to determine compliance with this subsection of this regulation.
- D. Fugitive Particulate Emissions
 - General Requirements
 - a. Existing Sources
 - (i) Every owner or operator of a source or activity which is subject to this Section III.D. shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions into the atmosphere through the use of all available practical methods which are technologically feasible and economically reasonable and which reduce, prevent and control emissions so as to facilitate the achievement of the maximum practical degree of air purity in every portion of the State.
 - (ii) In determining what control methods are available, practical, economically reasonable and technologically feasible, the following factors shall be considered: effects on the health, welfare (as defined in Section I.G. of the Common Provisions regulation), convenience, and comfort of the inhabitants of the

(A) For process equipment having process weight rates of up to thirty (30) tons per hour, the allowable emission rate shall be determined by the use of the equation:

 $PE = 3.59(P)^{0.62}$

Where:

PE = Particulate emission in lbs. per hour

P = Process weight rate in ton per hour

(B) For process equipment having process weight rates of greater than thirty (30) tons per hour, the allowable emission rate shall be determined by use of the equation:

 $PE = 17.31(P)^{0.16}$

Where:

PE = Particulate emission rate in lbs. per hour

P = Process weight rate in tons per hour

- (C) If two or more process units are connected to the same opening, the maximum allowable emission rate shall be computed by summing the individual emissions rates.
- (ii) Performance Tests

Prior to granting or amending a permit, when an emission source or control equipment is altered, or at any time when there is reason to believe that emission standards are being violated, the Division may require the owner or operator of an existing manufacturing process to conduct performance test(s) as measured by EPA Methods (1-4) and the front half of EPA Method 5 (40 CFR 60.275, Appendix A, Part 60) as may be amended to determine compliance with this subsection of this regulation.

- G. A statement of the basis and purpose for the revisions to this Section V., adopted March 11, 1982 is hereby incorporated by reference, and a copy of the statement is available from the Air Quality Control Commission office.
- VI. SULFUR DIOXIDE EMISSION REGULATIONS

- A. Sources constructed or modified prior to August 11, 1977 shall be considered an existing source. All existing sources of sulfur dioxide emissions, except for sources listed in Section VII, shall comply with the following:
 - Averaging time Unless otherwise specified in other sections of this
 regulation, the averaging time for all sulfur dioxide emissions standards for
 sources which utilize a CEM shall be a three hour rolling average and the
 frequency of fuel sampling for sources which utilize a fuel sampling plan
 approved pursuant to Section IV.B.2. shall be as specified in such plan.
 - If the sum of sulfur dioxide emission rates for all sources located on a contiguous site is less than three (3) tons per day potential uncontrolled SO₂ emissions, and if all Federal and State Ambient Air Quality Standards are met no process based SO₂ emission standard shall apply.
 - Existing sources of sulfur dioxide shall not emit sulfur dioxide in excess of the following process-specific limitations. (Heat input rates shall be the manufacturer's guaranteed maximum heat input rates).
 - a. Coal-fired operations including coal-fired steam generation:

(These standards are also applicable to the use of coal-based by-product fuels.)

- (i) Units with a heat input from coal or coal-based by-product fuels of less than 300 million BTU per hour:
 - 1.8 pounds of sulfur dioxide per million BTU of heat input.
- (ii) Units with a heat input from coal or coal-based by-product fuels equal to or greater than 300 million BTU per hour:
 - 1.2 pounds of sulfur dioxide per million BTU of heat input.
- b. Oil-fired Operations Including Oil-Fired Steam Generation
 - (i) Units with a heat input from oil of less than 300 million BTU per hour:
 - 1.5 pounds of sulfur dioxide per million BTU of heating input.
 - (ii) Units with a heat input from oil equal to or greater than 300 million BTU per hour:

0.8 pounds of sulfur dioxide per million BTU of heating input.

c. Combustion Turbines

(i) Combustion Turbines with a heat input of less than 300 million BTU per hour:

1.2 pounds of sulfur dioxide per million BTU of heating input.

(ii) Combustion Turbines with a heat input equal to or greater than 300 million BTU per hour:

0.8 pounds of sulfur dioxide per million BTU of heating input.

d. Natural Gas Desulfurization

Desulfurization Plants emitting more than five (5) tons of sulfur dioxide per day:

2 pounds of sulfur dioxide per 1,000 cubic feet of (Actual) delivered gas.

e. Petroleum Refining

0.7 pounds sulfur dioxide for the sum of all SO2 emissions from a given Refinery, per barrel of oil processed, per day. This emission limit shall be calculated over each 24 hour period which commences at midnight. If the refinery does not operate for the entire 24 hour period, the actual hours of operation shall be used as the averaging time. At no time shall the averaging time be greater than 24 hours. Refineries in operation on or before August 1, 1995, which are covered by this regulation, shall submit a plan for Division approval no later than February 1, 1996. Sources constructed after August 1, 1995 shall submit a plan for Division approval along with construction permit applications. The plan shall define how compliance with this limitation will be demonstrated. This plan shall address both how the SO₂ value is calculated, i.e. mass balance, monitors, and how the barrels of oil processed value is derived, taking into account intermediate storage. The Division shall not limit the determination of barrels processed per day to a 24 hour period.

All data used to show compliance with this emission standard shall be maintained by the owner or operator of the affected source for a period of two (2) years for sources that are not subject to the operating permit program, and five (5) years for sources that are subject to the operating permit program. This data shall be available for inspection by the Division upon request.

f. Cement Manufacture

abrogate the Commission's or Division's authority to require testing under Article 7 of Title 25, Colorado Revised Statute 1973, and regulations of the Commission promulgated thereunder.

- 3. The owner or operator of an affected facility shall provide the Division thirty (30) days prior notice of the performance test to afford the Division the opportunity to have an observer present.
- E. Related Compounds Containing Sulfur in Oxidized States:
 - For the purposes of this regulation, all oxidized forms of sulfur (including, but not restricted to sulfur trioxide (SO₃), trionyl chloride (SOCl₂), and sulfuric acid mist (H₂SO₄)) shall be considered as sulfur dioxide.
 - Quantities of such oxidized sulfur compounds shall be converted on a molar basis to an equivalent quantity of sulfur dioxide. The total of all such quantities, (expressed in parts per million by volume sulfur-dioxide-equivalents of other oxidized forms) shall be interpreted as "parts per million by volume sulfur dioxide" as used in Section B. above.
- F. Alternative Compliance Procedures
 - 1. Any person may apply to the Division Director for approval of an alternative:
 - a. Test method.
 - b. Method of control,
 - c. Compliance period,
 - d. Emission limit, or
 - e. Monitoring schedule.
 - The application shall include a demonstration that the proposed alternative produces:
 - An equal or greater air quality benefit than that required in this subsection VI, or
 - b. The alternative test method is equivalent to that required by these regulations.
 - The Division Director shall obtain concurrence from EPA prior to approving an alternative.
- VII. EMISSION REGULATIONS FOR CERTAIN ELECTRIC GENERATING STATIONS OWNED AND OPERATED BY THE PUBLIC SERVICE COMPANY OF COLORADO

- A. The electric generating stations owned and operated by the Public Service Company of Colorado listed below shall not emit or cause to be emitted nitrogen oxides (NO_x) or sulfur dioxide (SO_2) in excess of the following limits. The emission rates for NO_x and SO_2 are measure in terms of pounds of pollutant per million British Thermal Units of fuel fired in the unit (Ib/mmBTU).
 - Cherokee Electric Generating Station, 6198 North Franklin Street, Denver,
 CO

	NO _x (lb/mmBTU)	SO₂ (lb/mmBTU)
Unit 1	-	1.1
Unit 2	•	1.1
Unit 3	0.60	1.1
Unit 4	0.45	1.1

- The NO_x limit will be calculated based on a 30-day rolling average, and is effective November 1, 1994.
- The SO₂ limit will be calculated as a three-hour rolling average, and is effective November 1, 1994.
- Public Service Company of Colorado shall install, certify and operate continuous emission monitoring equipment for measuring opacity, SO_2 , NO_X , and either O_2 or CO_2 on Units 1, 2, 3 and 4 no later than January 1, 1995.
- Arapahoe Electric Generating Station, 2601 South Platte River Drive, Denver, CO

	NO _x (lb/mmBTU)	SO₂ (lb/mmBTU)
Unit 1	-	1.1
Unit 2		1.1
Unit 3	-	1.1
Unit 4	.60	1.1 +20% annual tonnage reduction

- The ${\rm NO}_{\rm X}$ limit will be calculated based on a 30-day rolling average, and is effective November 1, 1994.
- The SO₂ limit will be calculated as a three-hour rolling average, and is effective January 1, 1995.

- The 20% SO₂ limit from Unit 4 shall be calculated on a calendar year, total annual tonnage basis. SO₂ removal Equipment shall be continuously operated from November 1 to March 1 of each year, except during periods of upset conditions or because of unavoidable circumstances that render the equipment inoperable. If at any time between November 1 and March 1 of any year the equipment is not operated for a period of 24 hours or longer, Public Service Company of Colorado shall report the event to the Division in accordance with the Common Provisions Regulation.
- Public Service Company of Colorado shall install, certify and operate continuous emission monitoring equipment for measuring opacity, SO₂, NO_x, and either O₂ or CO₂ on Units 1, 2, 3 and 4 no later than January 1, 1995.
- 3. Valmont Electric Generating Station, 1800 North 63rd Street, Boulder, CO

	NO _x (lb/mmBTU)	SO ₂ (lb/mmBTU)
Unit 5	0.45	1.1

- The ${\rm NO_{x}}$ limit will be calculated based on a 30-day rolling average, and is effective November 1, 1994.
- The SO₂ limit will be calculated as a three-hour rolling average, and is effective November 1, 1994.
- Public Service Company of Colorado shall install, certify and operate continuous emission monitoring equipment for measuring opacity, SO₂, NO_x, and either O₂ or CO₂ on Units 1, 2, 3 and 4 no later than January 1, 1995.
- B. Public Service Company of Colorado shall submit to the Division for approval, no later than June 30, 1994, the procedure to be used for the measurement and calculation of the emission averages and emission reductions from these electric generating stations.
- VIII. RESTRICTIONS ON THE USE OF OIL AS A BACKUP FUEL

A. Applicability

The provisions of this section are applicable to all points at the following stationary sources in the Denver PM10 nonattainment area that use oil as a backup fuel for natural gas, which is the primary process fuel:

- 1. Public Service Company of Colorado, Zuni Electric Generating Station;
- 2. Public Service Company of Colorado, Valmont Electric Generating Station;
- 3. Public Service Company of Colorado, Delgany Steam Generating Station;
- Fitzsimmons Army Medical Center;

- 5. US Department of Energy, Rocky Flats Plant;
- 6. Gates Rubber Company; and
- 7. Coors Brewing Company, Coors Brewery, Golden, CO.

B. Requirements

Beginning November 1, 1993, natural gas shall be the only fuel used from November 1 to March 1 of each year, except under the following circumstances:

- the supplier of transporter or natural gas imposes a curtailment or an interruption of service;
- for necessary testing of equipment used to operate the unit on oil, testing of fuel and training of personnel; or
- when an equipment malfunction at the facility makes it impossible or unsafe for the unit to operate on natural gas.

C. Recordkeeping

Each stationary source subject to the provisions shall maintain records for a period of two years which include the following information:

- 1. dates and number of hours fuel oil is burned;
- 2. percent sulfur analysis of the fuel oil that is burned;
- 3. number of gallons burned each day; and
- 4. reason(s) for the use of the fuel oil.

D. Reporting

Beginning April 1, 1994 and by April 1 of each year thereafter, each stationary source subject to these provisions shall submit to the division a report containing the information listed in Section VIII.C.

E. Alternate Recordkeeping and Reporting

Where the information required under subsections C and D above is otherwise made available to the Division, for example in EIS reports submitted by the source or pursuant to operating permit requirements, the requirements of subsections C and D of this Section VIII are satisfied.

IX. EMISSION REGULATIONS CONCERNING AREAS WHICH ARE NONATTAINMENT FOR CARBON MONOXIDE - REFINERY FLUID BED CATALYTIC CRACKING UNITS:

Appendix E.2 T5 Emission Factors

2002 Maximum Allowable Emissions Major NOx, SO2 & PM10 Sources

Source	Maximum Operation	ration				802				NOX	×				PM10		
	Design Rate				_	Emission Rate	Emission Rate	Emission Rate	Emission Emi	Emission Rate	Emission Rate	Emission Rate	Reg. 1 Emission Limit	Fraction PM10 of	Emission Rate	Emission Emission Rate Rate Rate	Emission Rate
herokee	mmBtu/hr	hryr	ton/lb	ton/lb lb/mmBtu	(%)	ᆌ		(tons/day)		٦		(tons/day) Ib/mmBtu	Ib/mmBtu	M.	=		(tons/day)
Unit 1	1392	8760	0.0005		20		1,225	14.7	96.0	5,853	1336	16.0	0.1	0.92		128	
Unit 2	1392	8760	0.0005		o		1,531	18.4			1336	16.0		0.92			
Unit 3	1877	8760	8760 0.0005	-	ö		2,065	24.8			1126	13.5		0.92			
Unit 4	3520	8760	8760 0.0005	1.	20	13,567	3,098	37.2	0.45	6,938	1584	19.0		0.92			3.9
TOTAL				•••••			7,918	95.0		23,577	5,383	64.6			3,297		
Aranahoo																	
Arabanos						ı		۱						0		1	
Jnit 1	754.8	8760	0.0005	-	Ö		830			3,240	740	8.9		0.67			
Unit 2	754.8	8760	0.0005	-	0		830			3,240	740	8.9		0.67			9.0
Unit 3	754.8	8760	0.0005		0		830		86.0	3,240	740	8.9	0.1	0.92		69	
Unit 4	1709.0	8760	0.0005		20	6,587	1,504			4,491	1025	12.3		0.92			1.9
2 Turbines (2002)		8760	0.0005	••••		0.5*	0.4			39*	62	0.7			&		
TOTAL						17,498	3,995	47.9		14,250	3,307	39.7			1,444	334	4
Valmont			ļ														
Jult 5	1845	8760	0.0005	1.1	Ö	8.889	2.030				830						
Unit 6	920	8760	0.0005	0.0		_	0	0.0	0.32	799	182	2.2					
2 Turbine (2002)		8760	0.0005			0.5	0.4				9						
TOTAL					•••••	8,891	2,030			4,474	1,074						
Trigen																	
Boiler 1 (gas)	288	8760	0.0005	9000'0		1	0	0.0			81	1.0			139		
Boiler 2 (gas)	288	8760	0.0005	9000:0			0			353	8	1.0			139		
Boiler 3	225	8760	0.0005	1.8		1,774	405		0.4		88	1.1	0.12	•	118	27	0.3
Boiler 4	360	8760	0.0005	1.2		1,892	432				252	3.0		-	158		
Boiler 5	650	8760		1.2		3,416	780	4.0		1,993	455	5.5		_	 282		
SIP reduction			0.0005		•••••	-125	67.			677.	<u>ب</u>	9.0			ŝ		
Pochy Men Bottle						60,40	600			2,302	COR	6.01			200	l	
ochy man Doule			I	Ī	Ī	. 000				100	200	,					
PIE by stack test				•••••		698	2 %	1.0		424	26	2. 6.					
Conoco Refinery	Barrels/day													b/barrel Em Factor			
-ccu**	20,000	8760	0.0005										0.051		185.4		
See attachment		8760	0.0005												4	6	0.1
TOTAL						****											
UDS Refinery	lb Coke/hr												Ib/Ib Coke Em. Factor	Em. Factor			
-ccu***	5,789	8760	0.0005										0.00788		200		
See attachment		8760	0.0005			*****									45	б	0.1
TOTAL															241		
Robinson Brick	Design Rate												Ibs PM/hr				
Rotary Dryer	35/Tons/Hr.	8760	0.0005										30.57		32	7	0.1
Tunnel Dryer (2)	Reg. 1 Limit	8760	0.0005										17.9	-			
Rotary Calciner	10 Tons/Hr	8760	0.0005										14.97				
TOTAL															186		

TOTAL

**Amutal Permit Limits, ple emissions nodeled at maximum hourly emissions rate

***Amutal Permit Limits, per emissions nodeled at maximum hourly emissions rate late. PM10/1000 barrels and total ple emissions calculation by source

***Total ple emissions calculation by Source

NOTE: This revision includes pte calculations for Cherokee 1-2, Arapahoe 1-3, Trigen 3 and RMB for NOx and RMB for SO2. Also, addition of Valmont 6.

2003 Maximum Allowable Emissions Major NOx, SO2 & PM10 Sources

Source	Maximum Operation	tion				802				Š	×				PM10		
	Design Rate			Emission	Control	ш	Emission	Emission Rate	Emission	Emission	Emission Emission Emission Limit Rate Rate Rate	Emission Rate	Reg. 1 Emission Limit	Fraction PM10 of	Emission Rate	Emission Emission Emission Rate Rate Rate	Emission
Cherokee	mmBtu/hr	hrlyr	ton/lb	프	(%)	(tpy)	(lb/hr)	(tons/day)	lb/mmBtu	(tpy)	(lb/hr)	(tons/day)	ا	Æ	(tpy)	(lb/hr)	(tons/day)
Unit 1	1392	8760	0.0005	1.1	20	1	1,225	14.7						0.92			
Unit 2	1392	8760	0.0005		0		1,531	18.4	96.0	5,853		16.0	0.1	0.92	561	128	5.
Unit 3	1877	8760	0.0005			9,043	2,065	24.8						0.92			
Unit 4	3520	8760	0.0005			13,567	3,098	37.2			1584			0.92			
TOTAL						34,683	7,918	95.0		23,577					3,297		
Arenehoo																	
Alaballoe																	
Unit 1 (ret. by 1/1/03)	754.8				0 0		*****		25.0				5 6	79.0			
Unit 2 (ret. by 1/1/03)	0.40	0200	2000			3 637		10.0									
00E 3	134.0	00/00	0.000				200	18.0		4 491	1025	12.3			889	157	0,0
Unit 4	0.60	8760			3		40	0.0									
TOTAL		5				10.224	2.335	28.0		7.770	1.827				1,00		
Valmont											L						
Init 5	1845	8760	0.0005	1.1	°	688'8	2,030	24.4		κ							
Unit 6	920	8760	0.0005	0.0			0	0.0	0.32								
2 Turbine (2002)		8760	0.0005			0.5	0.4	0.0		39	9	0.7					
TOTAL						8,891	2,030	24.4		4,474		Ì					
Trigen																	
Boiler 1 (gas)	288	8760				_	0	0.0	0.28	353	20.0				139	33	0.4
Boiler 2 (gas)	288	8760		0.0			0 ;										
Boiler 3	225	8760		200		1,7/4	405 605						2.0		158		
Boiler 4	040	8/20	0.000			1,092				- 6							
Boller 5	nce	8				2,410	3 8					9 9					
TOTAL	•••••		3			6.959	_			3,962	902				838	191	2.3
Rocky Mtn. Bottle																	
PTE by stack test			L			696	28	1.0		424	16	1.2					
TOTAL						369		1.0		424			1	1000			
Conoco Refinery	Бапеіs/day												Dipallel	LIN. PACIO			
FCCU**	20,000	8760	0.0005										0.05 1		185.4	47	5. 5
See attachment	•••••	0/0	0.000	-											226		
UDS Refinery	lb Coke/hr												lb/lb Coke	Ib/Ib Coke Em. Factor			
FCCU***	5,789	8760	0.0005										0.00788		200		
See attachment		8760	0.0005												42	2.0	0.1
Robinson Brick	Design Rate												lbs PM/hr				
Rotary Dryer	35/Tons/Hr	8760	0 0005										30.57	0.24			
Tunnel Dryer (2)	Reg. 1 Limit	8760	8760 0.0005										17.9		131*	18	3 0.2
Rotary Calciner	10 Tons/Hr	8760	0.0005										14.97	9.34			
TOTAL															186		

i TOTAL

i Annual Permit Limits, ple emissions modeled at maximum hourly emissions rate

Annual Permit Limits, ple day-Emissions Rate las PM10/1000 barnels and total ple emissions calculation by source

Total ple emissions calculation by Source

NOTE. This revision includes ple calculations for Cherokee 1-2, Arapahoe 1-3, Trigen 3 and RMB for NOX and RMB for SO2. Also, addition of Valmont 6.

2005 Maximum Allowable Emissions Major NOx, SO2 & PM10 Sources

Source	Maximum Operation	eration				802				NOX	×				PM10		
					Control		Emission	Emission	Emission		nission	Emission	Reg. 1 Emission	Fraction		Emission	Emission
Cherokee	Design Rate mmBtu/hr	hrýr	ton/lb	Limit 15/mmBtu	Efficiency Emission (%) Rate (tpv)	Emission Rate (tpy)	Rate (lb/hr)		Limit Ib/mmBtu	Emission Rate (tpy)	Rate (Ib/hr)	Rate (tons/day)	Limit Ib/mmBtu	PM10 of PM	mission ate (tpy)	Rate (lb/hr)	Rate (tons/day)
Unit 1	1392	8760	0 0005	-	20	5.365	1		09:0	3,658	835		O	0.92	561	128	1.5
Unit 2	1392	8760	0.0005	-	Ö	6,707	1,53	18.4	96.0	5,853	1336	16.0	0.1	0.92	561	128	1.5
Unit 3	1877	8760	0.0005		0			24.8	0.60	4,933	1126	13.5		0.92			2.1
Unit 4	3520	8760	0.0005		20			37.2	0.45	6,938	1584	19.0		0.92			3.9
TOTAL						34,683		95.0		21,382	4,882	58.6			3,297		9.0
Arapahoe							Ш										
Unit 1 (ref. by 1/1/03)	754.8			1.1	0				0.98				0.1	19'0			
Unit 2 (ret. by 1/1/03)	754.8		••••	7	0	•••••	•••••		0.98	•••••	•••••		0.1	0.67		•••••	
Unit 3	754.8	8760	0.0005		0		830	10.0	0.98	3,240	740	8.9		0.92		8	
Unit 4	1709.0	8760	0.0005		20		1,504	18.0	9.0	4,491	1025	12.3		0.92		157	
2 Turbines (2002)		8760	0.0005				0.4	0.0		39	62	0.7			***	9	0.1
TOTAL						10,224	2,335	28.0		7,770	1,827	21.9			1,001	233	
Valmont																	
Unit 5	1845	8760	0.0005	1.1	0	8,889	2,030	24.4	0.45	3,636	830	10.0					
Unit 6	920	8760	0.0005	0.0			0	0.0	0.32	799	182	2.2					
2 Turbine (2002)	••••	8760	0.0005			0.5	0.4	0.0	••••	39*	19	0.7					
TOTAL				•••••		8,891	2,030	24.4		4,474	1,074	12.89				****	
Trigen																••••	
Boiler 1 (das)	288		0.0005	90000		1	ō	0.0	0.28	353	81				139	32	0.4
Boiler 2 (das)	288	8760	0.0005	0.0006		-	0	0.0	0.28	353	8		0.11		139	32	0.4
Boiler 3	225		0.0005	1.8		1,774	405	4.9	0.4	384	88			_	118	27	0.3
Boiler 4	360		0.0005	1.2		1,892	432	5.2	0.7	4,	252				158	98	0.4
Boiler 5	920		0.0005	1.2		3,416	780	9.4	0.7	1,993	455	5.5		_	285	65	0.8
SIP reduction			0.0005	•••••		-125	-29	-0.3		-225	-5						
TOTAL						6,959	1,589	19.1		3,962	902	Ì			838	191	2.3
Rocky Mtn. Bottle																	
PTE by stack test						369	2 3	1.0		424	97	1.2					
Conoco Refinery	Ramels/dav					200	\$	2.		*7	ĥ	7	lb/barrel	Em Facto			
FCCU**	20.000	8760	0.0005										0.051		185.4	42	0.5
See attachment		8760	0.0005												4	····	0.1
TOTAL							••••									52	9.0
UDS Refinery	lb Coke/hr												lb/lb Coke	b/lb Coke Em. Factor			
FCCU***	5,789	8760	0.0005										0.00788		200		
See attachment		8760	0.0005												45	· · · ·	0.1
TOTAL															241		
Robinson Brick	Design Rate												lbs PM/hr				
	35/Tons/Hr.	8760	0.0005										30.57				
(3)	Reg. 1 Limit	8760	0.0005				••••						17.9		131*	18	0.2
	10 Tons/Hr	8760	0.0005										14.97				
TOTAL						•••	•••			•••					186		

TOTAL

TO

MAXIMUM ALLOWABLE EMISSIONS

	o de la constantina della cons	- 7 - 7 - 7 - 7 - 7 - 7 - 7 - 7 - 7 - 7	ublic Service Co	Sublic Service Company - Zuni Station		noisein oto	Emission Data Emission Data	miceion Date
Source	(mmBtu/hr)	(lb/mmBtu)	(lb/mmBtu) of PM	Hours of Operation	dl/uot	(tpy)	(lb/hr)	(tpd)
Unit 1A (coal)	450	0.102	0.71	8760	0.0005	143		0.39
Jnit 1B (coal)	200	0.126	0.71	8760	0.0005	78		0.21
Jnit 2 (coal)	1075	0.1	0.71	8760	0.0005	334		0.92
Total						555	127	2

APCD staff included Zuni in the ISC modeling for major sources of PM10 and used the Regulation 1 emissions limit for combustion sources, which is fuel neutral. Regulation 1, however, includes a provision that requires Zuni to be operated on gas during the winter season; and a more appropriate calculation is included below. The ISC modeling indicates that at the the emission rate calculated using the Regulation 1 limit above (555 tpy) has a negligible effect on receptor concentration. Additional ISC modeling with the more appropriate 56 tpy was considered unnecessary.

	Design Rate	Heat Value	lbs. PM10/			Emission Rate	Emission Rate Emission Rate Emission Rate	Emission Rate
Source	(mmBtu/hr)	(mmBtu/hr) (scf/1000 Btu)	mmscf	Hours of Operation	ton/lb	(tpy)	(lb/hr)	(pd)
Unit 1A (gas)	450	0.001	7.45	8760	0.0005	15	3.35	0.0
Unit 1B (gas)	200		7.45	8760	0.0005	7	1.49	0.02
Unit 2 (gas)	1075		7.45	8760	0.0005	35	8.01	0.10
Total						99	13	0
	Design Rate	Heat Value	lbs. NOx/			Emission Rate	Emission Rate Emission Rate	Emission Rate
Source	(mmBtu/hr)	(mmBtu/hr) (scf/1000 Btu)	mmscf*	Hours of Operation	ton/lb	(tpy)	(lb/hr)	(pd)
Unit 1A (gas)	450	0.001	280	8760	0.0005	552		1.51
Unit 1B (gas)	200	0.001	280	8760	0.0005	245		0.67
Unit 2 (gas)	1075		280	8760	0.0005	1318	301.00	3.61
Total						2116	483	5.80

^{*} new AP-42 emission factor

	Design Rate	Heat Value	lbs. SO2/			Emission Rate	Emission Rate Emission Rate	Emission Rate
Source	(mmBtu/hr)	(scf/1000 Btu)	mmscf	Hours of Operation	ton/lb	(tpy)	(lb/hr)	(pd)
Unit 1A (gas)	450	0.001	9.0	8760	0.0005	1	0.27	00.00
Unit 1B (gas)	200	0.001	9.0	8760	0.0005	_	0.12	00.0
Unit 2 (gas)	1075	0.001	9.0	8760	0.0005	n	0.65	0.01
Total						5	1	0

Prepared by Jerry Dilley

Appendix E.3 AP – 42 Emission Factors

Table 1.1-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR DRY BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS AND SUBBITUMINOUS COAL^a

		Baghouse	0.02A	0.02A	0.02A	0.01A		0.006A	0.006A 0.006A	0.006A 0.006A 0.002A
(ton)	۰	ESP ^e B _e	0.064A	0.054A	0.024A	0.024A		0.01A	0.01A 0.01A	0.01A 0.01A 0.01A
ssion Factor ^c (lb	Controlled	Scrubber®	0.48A (0.42A	0.38A	0.3A		0.22A		
Cumulative Emission Factor ^e (1b/ton)		Multiple Cyclones ^f Sc	1.08A	0.58A	0.28A	0.06A		0.02A	0.02A 0.02A	0.02A 0.02A 0.02A
		Uncontrolled⁴	3.2A	2.3A	1.7A	0.6A		0.2A	0.2A 0.2A	0.2A 0.2A 0.10A
		Baghouse U	-64	92	11	53	_	31	31 25	31 25 14
1 Size	led	ESP	79	<i>L</i> 9	20	59		17	17	17 14 12
iss % < Statec	Controlled	Scrubber	81	7.1	62	51	30	CC	31 31	33 20
Cumulative Mass % ≤ Stated Size		Multiple Cyclones	54	29	14	3	-	•		
		Uncontrolled	32	23	17	9	2		2 2	7 7 1
		Particle Size ^b	15	10	9	2.5	1.25		00.1	1.00

Reference 33. Applicable Source Classification Codes are 1-01-002-02, 1-02-002-06, 1-01-002-12, 1-02-002-12, and 1-03-002-16. To convert from lbfton to kg/Mg, multiply by 0.5. Emission Factors are lb of pollutant per ton of coal combusted, as fired. ESP = Electrostatic precipitator.

Expressed as aerodynamic equivalent diameter.

A = coal ash weight percent, as fired. For example, if coal ash weight is 8.2%, then A = 8.2.

Estimated control efficiency for multiple cyclones is 80%; for scrubber, 94%; for ESP, 99.2%; and for baghouse, 99.8%.

EMISSION FACTOR RATING = E.

EMISSION FACTOR RATING = D.

Table 1.3-4. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UTILITY BOILERS FIRING RESIDUAL OIL*

	Scrubber Controlled	EMISSION FACTOR RATING	D	Ω	D	Q	D	D	Q	D
(Scrubber C	Emission Factor	0.50A	0.50A	0.50A	0.48A	0.46A	0.42A	0.32A	0.50A
Cumulative Emission Factor lb/10 ³ gal)	trolled ^d	EMISSION FACTOR RATING	Э	ш	ш	ш	ш	ш	ш	Е
Cumulative Emissi	ESP Controlled ^d	Emission Factor	0.05A	0.042A	0.035A	0.028A	0.021A	0.018A	0.007A	0.067A
Uncontrolled®		EMISSION FACTOR RATING	C	ပ	၁	ပ	၁	C	C	С
	Uncon	Emission Factor	6.7A	5.9A	4.8A	4.3A	3.6A	3.3A	1.7A	8.3A
fass % ize	Controlled	Scrubber	100	100	100	76	91	84	64	100
Cumulative Mass % stated Size	نَّ	ESP	75	63	52	41	31	28	20	100
Cumt		Uncon- trolled	80	71	58	52	43	39	20	100
		Particle Size ^b (µm)	15	10	9	2.5	1.25	1.00	0.625	TOTAL

Reference 26. Source Classification Codes 1-01-004-01/04/05/06 and 1-01-005-04/05. To convert from lb/1d gal to kg/m³, multiply by 0.120. ESP = electrostatic precipitator.

Expressed as aerodynamic equivalent diameter.
 Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.00% sulfur, then S = 1.
 No. 6 oil: A = 1.12(S) + 0.37
 No. 5 oil: A = 1.2
 No. 4 oil: A = 0.84

^d Estimated control efficiency for ESP is 99.2%.
 * Estimated control efficiency for scrubber is 94%

Table 11.25-8. PARTICLE SIZE DISTRIBUTIONS FOR FIRE CLAY PROCESSING^a EMISSION FACTOR RATING: D

		Multiclone	Cyclone	Cyclone/Sambhan
	Uncontrolled	Controlled	Controlled	Cyclone/Scrubber Controlled
Diameter (μm)	Cumulative % Less Than Diameter	Cumulative % Less Than Diameter	Cumulative % Less Than Diameter	Cumulative % Less Than Diameter
Rotary Dryers (SC	C 3-05-043-30) ^b			
2.5	2.5	ND	14	ND
6.0	10	ND	31	ND
10.0	24	ND	46	ND
15.0	37	ND	60	ND
20.0	51	ND	68	ND
Rotary Calciners (S	SCC 3-05-43-40)°		·	
1.0	3.1	13	ND	31
1.25	4.1	14	ND	43
2.5	6.9	23	ND	46
6.0	17	39	ND	55
10.0	34	50	ND	69
15.0	50	63	ND	81
20.0	62	81	ND	91

a For filterable PM only. SCC = Source Classification Code. ND = no data.
b Reference 11.
c References 12-13 (uncontrolled). Reference 12 (multiclone-controlled). Reference 13 (cyclone/scrubber-controlled).

Table 1.1-3. UNCONTROLLED EMISSION FACTORS FOR SO, NO, AND CO FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[®]

		os	so _x ^b	N	NO _x c	σ	CO ^{d,e}
Firing Configuration	SCC	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
PC-fired, dry bottom, wall-fired	1-01-002-02/22 1-02-002-02/22 1-03-002-06/22	38S (35S)	V	21.7	V	0.5	¥
PC-fired, bituminous coal, dry bottom, cell burner fired ^f	1-01-002-15	38S (35S)	∢	31.1	Ü	0.5	∢
PC-fired, dry bottom, tangentially fired	1-01-002-12/26 1-02-002-12/26 1-03-002-16/26	38S (35S)	∢	14.4	ď	0.5	V
PC-fired, wet bottom	1-01-002-01/21 1-02-002-01/21 1-03-002-05/21	38S (35S)	Q	34.0	ပ	0.5	V
Cyclone fumace	1-01-002-03/23 1-02-002-03/23 1-03-002-03/23	38S (35S)	Q	33.8	ပ	0.5	V
Spreader stoker	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	38S (35S)	æ	13.7	∢	ν,	∢
Spreader stoker, with multiple cyclones, and reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	38S (35S)	m	13.7	∢ .	v o	∢ .
Spreader stoker, with multiple cyclones, no reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	38S (35S)	A	13.7	A	٠,	V

Table 1.1-3 (cont.).

	Z ~ m							
CO ^{d,e}	EMISSION FACTOR RATING	A	¥	∢	¥	Ø	a	田
O	Emission Factor (lb/ton)	0.5	0.5	5	5	9	=	275
),	EMISSION FACTOR RATING	Ą	U	В	В	¥.	V .	凹
, NO,	Emission Factor (lb/ton)	33	17	==	80 80	7.5	9.5	9.1
q ×	EMISSION FACTOR RATING	A	₹	М	Д	В	В	D
SO _v s	Emission Factor (lb/ton)	38S	35S	38S	35S	38S (35S)	31S	318
	SCC	1-01-002-03 1-02-002-03 1-03-002-03	1-01-002-23 1-02-002-23 1-03-002-23	1-01-002-04 1-02-002-04 1-03-002-09	1-01-002-24 1-02-002-24 1-03-002-24	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	1-02-002-06 1-03-002-08	1-03-002-14
	Firing Configuration	Cyclone Furnace, bituminous	Cyclone Furnance, sub- bituminous	Spreader stoker, bituminous	Spreader Stoker, sub-bituminous	Overfeed stoker	Underfeed stoker	Hand-fed units

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO $_{\chi}$) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors ^a												
Turbine Type	Nitroger	1 Oxides	Carbon Monoxide									
Natural Gas-Fired Turbines ^b	(lb/MMBtu) ^c (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^c (Fuel Input)	Emission Factor Rating								
Uncontrolled	3.2 E-01	A	8.2 E-02 ^d	Α								
Water-Steam Injection	1.3 E-01	Α	3.0 E-02	Α								
Lean-Premix	9.9 E-02	D	1.5 E-02	D								
Distillate Oil-Fired Turbines ^e	(lb/MMBtu) ^f (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^f (Fuel Input)	Emission Factor Rating								
Uncontrolled	8.8 E-01	С	3.3 E-03	C C Emission Factor Rating								
Water-Steam Injection	2.4 E-01	В	7.6 E-02									
Landfill Gas-Fired Turbines ^g	(lb/MMBtu) ^h (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^h (Fuel Input)									
Uncontrolled	1.4 E-01	A	4.4 E-01	A								
Digester Gas-Fired Turbines	(lb/MMBtu) ^k (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^k (Fuel Input)	Emission Factor Rating								
Uncontrolled	1.6 E-01	D	1.7 E-02	D								

a Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

b Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

^c Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10° scf), multiply by 1020.

d It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

^e SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

f Emission factors based on an average distillate oil heating value of 139 MMBtu/10³ gallons. To convert from (lb/MMBtu) to (lb/10³ gallons), multiply by 139.

g SCC for landfill gas-fired turbines is 2-03-008-01.

h Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to (lb/106 scf) multiply by 400.

^j SCC for digester gas-fired turbine is 2-03-007-01.

k Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf) multiply by 600.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO,) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION⁸

	NC	NO _x ^b		00
Combustor Type (MMBtu/hr Heat Input) [SCC]	Emission Factor (lb/10 ⁶ scf)	Emission Factor Rating	Emission Factor (lb/10° scf)	Emission Factor Rating
Large Wall-Fired Boilers		:		
[1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)°	280	A	84	В
Uncontrolled (Post-NSPS)	190	A	84	В
Controlled - Low NO _x burners	140	А	84	В
Controlled - Flue gas recirculation	100	D	84	В
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-03]				
Uncontrolled	100	В	84	В
Controlled - Low NO _x burners	50	D	84	В
Controlled - Low NOx burners/Flue gas recirculation	32	O	84	В
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	O
Controlled - Flue gas recirculation	9/	Q	86	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	В	40	В

Reference 13. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from 1b/10 ° scf to kg/10° m³, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from 1b/10 ° scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable. Expressed as NO₂. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO × emission factor. For targential-fired boilers to RX control, apply a 13 percent reduction to the appropriate NO × emission factor. NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION^a

Pollutant	Emission Factor (lb/10 ⁶ scf)	Emission Factor Rating
CO ₂ ^b	120,000	A
Lead	0.0005	D
N ₂ O (Uncontrolled)	2.2	E
N ₂ O (Controlled-low-NO _X burner)	0.64	Е
PM (Total) ^c	7.6	D
PM (Condensable) ^c	5.7	D
PM (Filterable) ^c	1.9	В
SO ₂ ^d	0.6	A
тос	11	В
Methane	2.3	В
VOC	5.5	С

^a Reference 13. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from lb/10⁶ scf to kg/10⁶ m³, multiply by 16. To convert from lb/10⁶ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds.
VOC = Volatile Organic Compounds.

b Based on approximately 100% conversion of fuel carbon to CO₂. CO₂[lb/106 scf] = (3.67) (CON) (C)(D), where CON = fractional conversion of fuel carbon to CO₂, C = carbon content of fuel by weight (0.76), and D = density of fuel, 4.2x10⁴ lb/10⁶ scf.

d Based on 100% conversion of fuel sulfur to SO₂.

Assumes sulfur content is natural gas of 2,000 grains/10⁶ scf. The SO₂ emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO₂ emission factor by the ratio of the site-specific sulfur content (grains/10⁶ scf) to 2,000 grains/10⁶ scf.

^c All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM₁₀, PM_{2.5} or PM₁ emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

Appendix E.4 Emission Inventory Supporting Information

Conoco Refinery

APCD

303-692-3106 303-782-0278

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Conoco

JAY CHRISTOPHER

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Cowoco Dewek Refinery PM Dota/Colouletions Waso Fon TileV PTE

Emission Factor Source	AP-42, Section 1.4 (1/95 update)	AP-42, Section 1.4 (1/95 update) AP-42, Section 1.4 (1/95 update)		AP-42, Section 1.4 (1/95 update)	AP-42, Section 1.4 (1/95 update)															
Calc. PTE (TPY)	2.27	0.86	2.04	1.79	0.40	1.77	3.43	3.50	0.36	1.75	0.84	3.59	1.71	1.46	2.12	0.32	0.32	00.0	4.59	5.32
Calc. PTE (Ibs/year)	4536.481	1728.118	4082.874	3571.59	807.36	3545.149	6869.454	7008.646	714.84	3501,994	1680.168	7171.95	3416.4	2917.08	4231.08	630.72	630.72	0	9178.452	10633.12
TV Factor (Ib/mmscf)	13.7	13.7	13.7	13.7	12	13.7	13.7	13.7	12	13.7	13.7	13.7	ო	က	ო	12	5		13.7	13.7
	331.13	126.14	298.02	260.7	67.28	258.77	501.42	511.58	59.57	255.62	122.64	523.5	1138.8	972.36	1410.36	52.56	52.56		96.699	776.14
PM-10 PTE provide in table to APCD	2.27	0.86	20.	1.79	0.40	1.77	3.43	3.50	0.36	1.75	0.84	3.59	1.71	1.46	2.12	0.32	0.32	0.01	4.59	5.32
APEN # Source ID	3 H-32	4 4 6 5 H 6	7 H-10	9 H-11	10 H-33	11 H-12	12 H-37	13 H-17	14 H-13	16 H-19	17 H-20	18 H-22	19 B-4	21 B-6	23 B-8	51 H-18	52 H-16	53 #1 SRU	54 H-27	78 H-28,29,30

Emission Factor Source
PM emissions from the unit are
controlled by a 2-stage cyclone.
The emission factor is determined
by applying an 85% control
efficiency (see AP-42, Section 5.1,
page 5.1-9) to the uncontrolled
factors of 340 bs/mBbi fresh feed.

(TPY)

(lbs/year) 370840

(lb/mBbl) 50.8

(mBb(/yr) 7300

APEN # Source ID PM-10 PTE 25 FCC 194.69

TV Feed Rate

TV Factor Calc, PTE Calc, PTE

Alous Lead earlin docusion about 20019 lown Food Asta 185.42 is my number to wa. From: "Congram, Anthony R." < Anthony.R.Congram@usa.conoco.com>

To: 'MIKE Silverstein' <mcsilver@smtpgate.dphe.state.co.us>

Date: 3/26/01 2:15PM

Subject: RE: FCC Control Efficiency Question

FCC cyclones are completely integral. No means to bypass.

Tony Congram

Voice: 303-286-5890

Fax: 5866

anthony.r.congram@usa.conoco.com <mailto:anthony.r.congram@usa.conoco.com>

----Original Message-----

From: MIKE Silverstein [SMTP:mcsilver@smtpgate.dphe.state.co.us]

Sent: Monday, March 26, 2001 2:05 PM
To: Anthony.R.Congram@usa.conoco.com

Subject: Re: FCC Control Efficiency Question

Next question: Are the cyclones inherent to the system - can they

be

by-passed/shut down and the FCCU still operated?

>>> "Congram, Anthony R." <Anthony.R.Congram@usa.conoco.com> 03/26/01

11:03AM >>>

Mike, is this enough of a reference (from AP-42, Chapter 5)?

Third paragraph under 5.1.2.2.2, page 8 or 9 of the document (depending

on

formatting).

"FCC particulate emissions are controlled by cyclones and/or electrostatic

precipitators.

Particulate control efficiencies are as high as 80 to 85 percent.3,5

Carbon

monoxide waste heat boilers

reduce the CO and hydrocarbon emissions from FCC units to negligible levels.3 TCC catalyst

regeneration produces similar pollutants to FCC units, but in much smaller

quantities (Table 5.1-1).

The particulate emissions from a TCC unit are normally controlled by

high-efficiency cyclones.

Carbon monoxide and hydrocarbon emissions from a TCC unit are incinerated to negligible levels by passing the flue gases through a process heater firebox or smoke plume burner. In some installations,

burner. In some installations, sulfur oxides are removed by passing the regenerator flue gases through

water or caustic scrubber.2-3,5"

If that's not what you need, please call me back. Thanks.

Tony Congram

Voice: 303-286-5890

Fax: 5866

anthony.r.congram@usa.conoco.com

<mailto:anthony.r.congram@usa.conoco.com>

CC: "Christopher, Jay S." <Jay.S.Christopher@usa.conoco.com>, "Walker, Constance M. (Tance)" <Constance.M.Walker@usa.conoco.com>

From: "Christopher, Jay S." <Jay.S.Christopher@usa.conoco.com> **To:** "MIKE Silverstein' <mcsilver@smtpgate.dphe.state.co.us>

Date: 3/27/01 3:26PM

Subject: RE: FCC Control Efficiency Question

Mike - sorry I have been difficult to get a hold of recently (traveling), and glad Tony Congram was able to provide some information for you. I thought it might be useful to package things together in one note, plus add some more detail. I am also copying Jerry Dilley since he has been involved in this discussion in the past.

Are the cyclones in the FCCU an inherent part of the process? Yes, they are. The cyclones are not a control device in the sense of an add-on control device, but are a standard part of the design and operation of the unit. In fact, if one looked at a petroleum refining text, cyclones would be included in the basic diagrams of a FCCU. The cyclones cannot be bypassed and the FCCU could not operate without the cyclones in place and functioning. Also, no one would have an incentive to operate without cyclones, as that would increase losses of expensive catalyst to the atmosphere, and I do not believe that a FCCU could achieve any reasonable opacity limit without the cyclones operating appropriately.

More background on the FCCU emission factor used by Conoco - As you know, the AP-42 emission factor (Table 5.1-1) is 242 pounds particulate per 1000 barrels of fresh feed to the unit. AP-42 also includes a range of 93 - 340 pounds. Conoco uses the upper end factor (i.e., the most conservative value) of 340, and then applies a control efficiency factor to that rate. As mentioned in the AP-42 text forwarded to you on 3/26/01(paragraph following Section 5.1.2.2.2), AP-42 states "FCC particulate emissions are controlled by cyclones and/or electrostatic precipitators. Particulate control efficiencies are as high as 80 - 85%." Conoco has relied on that combination of factor and efficiency to estimate the particulate emissions from our FCCU.

A recent EPA publication reinforces Conoco's view that this control efficiency factor is reasonable. EPA's CHIEF website includes a program called the "Enhanced Particulate Matter Controlled Emissions Calculator," dated September 2000. This program is designed to determine control efficiencies for different particulate matter fractions. EPA lists three levels of cyclone efficiencies (high, medium, and low) in this database. Since coarser particulate fractions are controlled more effectively, the percentages shown for PM10 are conservative. EPA states that a medium efficiency cyclone is considered 85% effective for PM10 control. This, in our view, confirms the appropriateness of applying the 85% factor noted discussed in the initial paragraph.

Finally, we have also looked at our losses from a mass balance perspective. Conoco knows the average amount of catalyst that it adds to the unit, the average amount of spent catalyst that it sends offsite for reclamation, and the amount of catalyst that is suspended in the heavy oil bottoms from the unit (generally called slurry oil or clarified oil). The balance is unaccounted for losses that are assumed to be stack emissions. Using recent typical data, our mass data shows about 130 tons/year of these unaccounted for losses. In 2000, using the emission factor as above, we estimated about 165 tons/year of particulate emissions, providing further backup to our view that our numbers are conservative.

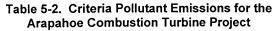
Therefore, Conoco feels that our use of the most conservative emission rate (340 instead of 242) and a reasonable efficiency factor (85%) results in a very reasonable derived emission factor of 51 pounds particulate per 1000 barrel feed.

I hope that this provides the information that you were looking for to resolve this issue. Thank you for your time in trying to get everyone on the same page.

Jay Christopher
Conoco Inc.
Air Program Leader - Denver
Rocky Mountain Business Unit
303-286-5731 (ETN 473)
303-286-5866 (fax)
jay.s.christopher@usa.conoco.com < jay.s.christopher@usa.conoco.com>

CC: "'jdilley@raqc.org'" <jdilley@raqc.org>

Public Service Company-Arapahoe Station



	Imal Imksfors Irom Bo Turbics								
Pollutant	Ibihr	(ipxy							
CO	290	90.8							
NO _x	62	39.0							
SO ₂	0.4	0.3							
PM ₁₀	6	4.0							
Pb	0	0							

^aAnnual emissions based on an annual heat input of 883,854 MMBTU/year.

Notes:

CO carbon monoxide lb/hr = pounds per hour

 NO_x nitrogen oxides

fine particulate matter PM_{10}

sulfur dioxide

tons per year

Emissions exceed the CDPHE thresholds for dispersion modeling analysis for NOx, and CO. Although the emissions for PM₁₀ are below the modeling threshold, a modeling analysis was conducted to verify that the turbines would not cause or contribute to any violation of a PM₁₀ NAAQS. Dispersion modeling analyses were conducted for these pollutants, and those analyses are described in detail in later sections of this report.

On-site PSD Increment Emission Inventory (Item #8 On APCD Review 5.7 Checklist)

The Arapahoe Combustion Turbine Project is not a major modification, nor will it produce significant impacts of any criteria pollutant, as described in detail in later sections of this report. Therefore, an inventory of on-site increment consuming sources was not required.

74.99 N

Unit 1 Public Service Company of Colorado, Arapahoe Station Criteria and HAP Emissions

	Code:	S001		Unit Code:	B001		
	Seasonal Fue				rmal Operation of	Unit	Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
25	26	25	24	24	7	8760	0
	BOILER SPECI				STA	CK DATA	
Furnace Type:	Top-fired wet bot			Height (ft)	***		250
Manufacturer:	Babcock & Wilco	x		Inside Diameter ((ft)		15.75
Model & Serial #:	NB 16230			Exhaust Flow Ra	te (acfm)		
Unit Description:		P and SO3 gas con	ditioning	Normal	204,000	Max	240,000
First Service or Last		10/7/50		Velocity (fps)			17.5
Max Continuous Ra	ting (MMBtu/hr) :	754.8	Coal	Calculated or Sta	ck Test (C/ST)		С
			Natural Gas	Exhaust Tempera			265
	laximum Hourly Fu				Content (if modi	fied) (%)	
Fuel		Unit	Rate	Normal	7	Max	9
	ous Coal	ton/hr	34	Orientation of Re			Up
Natur	al Gas	Mcf/hr	750	Rainhat or Other	Obstruction		None
					Control 7	echnology, %	
Does the boiler/furn	ace have control tec	hnology (Y/N) ?	Y	Control	NOx	PM	SOx
			ESI	P-SO3 conditioning	0	99.03	0
				-			
Miscell		Conde			orbers	Catalytic/Ti	nermal Oxidation
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Setti		Electrostatic			tion Systems		s/Fabric Filters
2000-404	NONE	2000-405	C001	2000-406	NONE	2000-407	NONE
			OPERATING	PARAMETERS			
	1994			1	P	otential	
Coal (tons) =			136,821	Coal (tons) =			
Max Sulfur Content	(%) =		0.50	Max Sulfur Cont	(0()		297,840
Max Ash Content (%			10.00	Max Ash Conten			1.00
HHV Coal (BTU/lb)				11,100 HHV Coal (BTU/b) =			10.00
Natural Gas (Mcf) =						11,100	
Max Sulfur Content				Natural Gas (Mc		6,570,000	
Max Ash Content (%			NA NA	Max Sulfur Conte			NA NA
HHV Gas (BTU/scf)			998	Max Ash Conten	V Gas (BTU/scf) =		
Operation Hours =			7,985	Operation Hours			998
			7,783	Operation riours			8,760
			EMISSION C.	ALCULATIONS			
	Source of	Units of			Actual	PTE	PTE
Pollutant	Emission	Emission		n Factors	Emissions	100% Coal	100% Natural Gas
	Factor	Factor	Coal	Natural Gas	(ton/yr)	(ton/yr)	(ton/yr)
NOx	AP-42'	lb/ton	21.7		1,487	3,232	<u> </u>
	AP-42 ²	Ib/MMCF		550			1,807
co	AP-42'	lb/ton	0.50		34	74	
	AP-42 ²	lb/MMCF		40		1	131
NMTOC	AP-42'	lb/ton	0.06		4	9	
	AP-42	lb/MMCF		1.7		Į.	6
	AP-42'	lb/ton	100.00		66	331	
PM							
	AP-42 ²	lb/MMCF		3.00			10
	AP-42*	lb/MMCF % PM	67.00		44	222	10
PM ₁₀	AP-42* AP-42*	Ib/MMCF % PM Ib/MMCF		3.00	44	222	10
PM ₁₀	AP-42* AP-42* AP-42*	lb/MMCF % PM lb/MMCF lb/ton	67.00 17.50	3.00	1,237	222	
PM _{te}	AP-42* AP-42*	Ib/MMCF % PM Ib/MMCF					
PM _{ie} SO _x ³ Antimony	AP-42* AP-42* AP-42*	lb/MMCF % PM lb/MMCF lb/ton		3.00			10
PM _{ie} SO _a ³ Antimony Arsenic	AP-42* AP-42* AP-42*	lb/MMCF % PM lb/MMCF lb/ton		3.00			10
PM _{ie} SO _a ³ Antimony Arsenic Beryllium	AP-42* AP-42* AP-42*	lb/MMCF % PM lb/MMCF lb/ton		3.00			10
PM _{ie} SO _x ³ Antimony Arsenic Beryllium Cadmium	AP-42* AP-42* AP-42*	lb/MMCF % PM lb/MMCF lb/ton		3.00			10
PM ₁₀ SO ₆ ³ Antimony Arsenic Beryllium Cadmium Chromium	AP-42* AP-42* AP-42*	lb/MMCF % PM lb/MMCF lb/ton		3.00			10
PM _{ie} SO _a ³ Antimony Arsenic Beryllium Cadmium Chromium	AP-42* AP-42* AP-42' AP-42*	lb/MMCF % PM lb/MMCF lb/ton		3.00			10
PM _{1e} SO _e ³ Antimony Arsenic Beryllium Cadmium Cotomium	AP-42* AP-42* AP-42*	lb/MMCF % PM lb/MMCF lb/ton		3.00			2
PM ₁₀ SO ₃ Antimony Arsenic Beryllium Cadmium Chromium Chobalt Lead	AP-42* AP-42* AP-42' AP-42*	Ib/MMCF % PM Ib/MMCF Ib/ton Ib/MMCF	17.50	3.00	1,237	2,606	10
PM PM ₁₀ SO, Antimony Arsenic Beryllium Cadmium Chromium Cobalt Lead Mercury	AP-42* AP-42* AP-42' AP-42*	Ib/MMCF % PM Ib/MMCF Ib/ton Ib/MMCF	17.50	3.00	1,237	2,606	2
PM ₁₆ SO ₆ ³ Antimony Arsenic Beryllium Cadmium Chromium Cobalt Lead Manganese	AP-42* AP-42* AP-42' AP-42*	Ib/MMCF % PM Ib/MMCF Ib/ton Ib/MMCF	17.50	3.00	1,237	2,606	2
PM ₁₁ SO ₂ Antimony Arsenic Beryllium Cadmium Chromium Cobalt Lead Manganese Mercury	AP-42* AP-42* AP-42' AP-42*	Ib/MMCF % PM Ib/MMCF Ib/ton Ib/MMCF	17.50	3.00	1,237	2,606	2
PM _{is} SO, ³ Antimony Ansenic Beryllium Cadmium Chromium Cobalt Lead Manganese Mercury Nickel	AP-42* AP-42* AP-42' AP-42*	Ib/MMCF % PM Ib/MMCF Ib/ton Ib/MMCF	17.50	3.00	1,237	2,606	2
PM _{is} SO _s Antimony Arsenic Beryllium Cadmium Chromium Cobalt Lead Manganese Mercury Nickel Selenium	AP-42* AP-42* AP-42' AP-42*	Ib/MMCF % PM Ib/MMCF Ib/ton Ib/MMCF	17.50	3.00	1,237	2,606	2

- Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, wall fired Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled Includes SO, conditioning emissions

 PM₁₀ is 67% of PM (Electrostatic precipitator controlled emissions, AP-42 Table 1.1-5)

Unit 2 Public Service Company of Colorado, Arapahoe Station Criteria and HAP Emissions

Stack Identification (5001		Unit Code:	B002		
	Seasonal Fue	l Usage (%)		No	rmal Operation of	Unit	Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	1
28	30	27	15	24	7	8760	0
	BOILER SPECI	FICATIONS			STA	CK DATA	
Furnace Type:	Top-fired Wet Bo			Height (ft)		CKDATA	250
Manufacturer:	Babcock & Wilco	ox		Inside Diameter (ft)		15.75
Model & Serial #:	NB 16231			Exhaust Flow Ra			15.75
Unit Description:	Top fired with ES	SP and SO3 gas cond	litioning	Normal	204,000	Max	240,000
First Service or Last	Mod. Date:	3/1/51	Ū	Velocity (fps)			17.5
Max Continuous Rati	ing (MMBtu/hr):	754.8	Coal	Calculated or Sta	ck Test (C/ST)		C
		748.5	Natural Gas	Exhaust Tempera	iture (F)		265
M	aximum Hourly Fu	el Usage (units/hr)			Content (if modi	fied) (%)	
Fuel 7	Гуре	Unit	Rate	Normal	7	Max	9
Bitumino		ton/hr	34	Orientation of Re	lease		Up
Natura	l Gas	Mcf/hr	750	Rainhat or Other	Obstruction		None
					C17	C11 0/	
Does the boiler/furna	ce have control tec	hnology (VAI) 2	Y	Control		Fechnology, %	
Socs are concentanta	oc nave conduit tec	iniology (1/14) !		-SO3 conditioning	NOx 0	PM 97,92	SOx
			ESP	-505 continuoning	U	91.92	0
Miscella	aneous	Conde	nsers	A.de.	orbers	Catalysis /T	hermal Oxidation
2000-400	NONE		NONE	2000-402	NONE	2000-403	NONE
		·- ·-•				2000-103	HONE
Cyclones/Settli	ing Chambers	Electrostatic l	Precipitators	Wet Collec	tion Systems	Baghouse	es/Fabric Filters
2000-404	NONE		C002	2000-406	NONE	2000-407	NONE
				PARAMETERS			
	1994		OPERATING	FARAMETERS		otential	
	122-	·			r	otential	
Coal (tons) =			148,645	Coal (tons) =			297,840
Max Sulfur Content			0.50	Max Sulfur Cont			1.00
Max Ash Content (%			10.00	Max Ash Conten			10.00
HHV Coal (BTU/lb)	=		11,100	HHV Coal (BTU/lb) =			11,100
Natural Gas (Mcf) =	•		6,274	Natural Gas (Mc			6,570,000
Max Sulfur Content			NA	Max Sulfur Content (%) = NA			
Max Ash Content (%			NA	Max Ash Conten			NA
HHV Gas (BTU/scf)	=		998	HHV Gas (BTU/			998
Operation Hours =			7,246	Operation Hours	-		8,760
			EMISSION C.	ALCULATIONS			
	Source of	Units of				T	
Pollutant	Emission	Emission	E-1-1-	. r	Actual	PTE	PTE
Pollucant	Factor	Factor	Coal	n Factors Natural Gas	Emissions	100% Coal	100% Natural Gas
NOx	AP-42'	lb/ton	21.7	IVALUIAI GAS	(ton/yr) 1,615	(ton/yr)	(ton/yr)
	AP-42 ²	lb/MMCF	21./	550	1,015	3,232	1,807
СО	AP-421	lb/ton	0.50		37	74	1,007
	AP-42 ²	1b/MMCF	0.50	40	"	"	131
NMTOC	AP-421	lb/ton	0.06		4	9	131
	AP-42 ²	Ib/MMCF	00	1.7		'	6
PM	AP-421	lb/ton	100.00	-	155	331	
	AP-42 ²	lb/MMCF		3.00			10
PM ₁₀	AP-42*	% PM	67.00		104	222	
	AP-422	Ib/MMCF		3.00		1,	10
so,3	AP-42'	lb/ton	17.50		1,341	2,606	†
	AP-422	lb/MMCF		0.60	1	1	2
Antimony							
Arsenic						1	1
Beryllium						T	
Cadmium						1	1
Chromium						1	1
Cobalt				L			1
Lead	AP-42	1b/10^12 BTU	507	NA	0.017	0.037	NA NA
Manganese						1	1
Mercury				1		T	
Nickel	1.			l			
INCACI		. —				·	
				l .	Į.	1	1
Selenium Thallium						 	
Selenium Thallium Formaldehyde POM							

- Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, wall fired Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled Includes SO, conditioning emissions PM₁₀ is 67% of PM (Electrostatic precipitator controlled emissions, AP-42 Table 1.1-5)

TitleIL

	Duk	lic Service C	Uni Company of (it 3 Colorado, Ai	anahoa Sta	tion	I	
	rub			LAP Emissio		uon		
Stack Identification (Code :	S002		Unit Code:	B003			
	Seasonal Fuel	Usage (%)		No	rmal Operation of	Unit	Space Heat (%)	
Dec-Feb 25	Mar-May 28	Jun-Aug 24	Sep-Nov 23	Hours/Day 24	Days/Week 7	Hours/year 8760	0	
	BOILER SPECIA	ICATIONS			STA	CK DATA		
Furnace Type:	Top-fired			Height (ft)			250	
Manufacturer: Model & Serial #:	Babcock & Wilco: NB 16911	•		Inside Diameter (Exhaust Flow Rat			15.75	
Unit Description:	Top Fired with fab	ric filter dust collec	ctors(FFDC)	Normal	211,063	Max	255,067	
First Service or Last		11/17/51	C1	Velocity (fps)	1 T . (C/CT)		18.1	
Max Continuous Ra	ing (MMBtivnr) :		Coal Natural Gas	Calculated or Star Exhaust Tempera			C 268	
	faximum Hourly Fue				Content (if modif	ied) (%)	200	
	Туре	Unit	Rate	Normal	7	Max	9	
	ous Coal al Gas	ton/hr Mcf/hr	34 750	Orientation of Re Rainhat or Other			Up None	
				I		Paralle of		
Does the boiler/furn	ace have control tech	nology (Y/N) ?	Y	Control	NOx	Fechnology, % PM	SOx	
3000014819		-07 (-11.7)	•	Baghouse	0	99.9	0	
	1							
Miscel 2000-400	laneous NONE	Conde 2000-401	nsers NONE		orbers NONE	Catalytic/Th 2000-403	nermal Oxidation NONE	
Curl/C ::	line Chambers	E1	D:-:		C			
Cyclones/Sett 2000-404	ling Chambers NONE	Electrostatic 2000-405	Precipitators NONE	Wet Collec 2000-406	tion Systems NONE	Baghouse 2000-407	s/Fabric Filters C003	
				PARAMETERS				
	1994				F	otential		
Coal (tons) =			141,609	Coal (tons) =			297,840	ł
Max Sulfur Content			0.50	Max Sulfur Cont			1.00	
Max Ash Content (9 HHV Coal (BTU/lb)			10.00 11,100				10.00 11,100	
Natural Gas (Mcf) =			4,742	Natural Gas (Mc	,		6,570,000	
Max Sulfur Content			NA	Max Sulfur Cont			NA	
Max Ash Content (9 HHV Gas (BTU/scf			NA 998	Max Ash Conten HHV Gas (BTU/			NA 998	
Operation Hours =	,-		7,925	Operation Hours			8,760	
			EMISSION C	ALCULATIONS				
	Source of	Units of	1		Actual	PTE	PTE	ll .
Pollutant	Emission	Emission		n Factors	Emissions	100% Coal	100% Natural Gas	
NOx	Factor AP-42 ¹	Factor lb/ton	Coal 21.7	Natural Gas	(ton/yr) 1,538	(ton/yr)	(ton/yr)	h. ~
	AP-42 ²	ib/MMCF	l. ***	550	1,338	3,232	1,807	46.4
СО	AP-42'	lb/ton	0.50		35	74		
NMTOC	AP-42 ² AP-42 ⁴	lb/MMCF lb/ton	0.06	40	4	9	131	1
	AP-42 ²	Ib/MMCF		1.7	}		6	
PM	AP-42'	lb/ton	100.00		7	331		
PM ₁₀	AP-42 ² AP-42 ³	lb/MMCF % PM	92.00	3.00	7	304	10	3
	AP-42 ²	lb/MMCF	2.00	3.00	′	3043	10	
SOx	AP-421	lb/ton	17.50		1,239	2,606		50 B
Antimony	AP-42 ²	lb/MMCF		0.60		 	2 ,	1
Arsenic				<u> </u>	<u> </u>	 	<u> </u>	1
Beryllium				ļ <u> </u>				1
Cadmium			ļ	ļ				-
Cobalt		 	 	 		+		1
CODZII	AP-42	lb/10^12 BTU	507	NA	0.001	0.037	NA NA	1
Lead								1
Lead Manganese					4	ł		II .
Lead Manganese Mercury				 		+		11
Lead Manganese								1
Lead Manganese Mercury Nickel								

Footnotes

- Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, wall fired Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled PM₁₀ is 92% of PM (Baghouse controlled emissions, AP-42 Table 1.1-5)

Title

			Un			
ation	rapahoe Stati	Colorado, Ai	Company of criteria and H	lic Service (C	Pub	
	8004			S002	ode :	Stack Identification C
f Unit Space Heat (%)	mal Operation of U				Seasonal Fuel	- I deliditation c
Hours/year	Days/Week	Hours/Day	Sep-Nov	Jun-Aug	Маг-Мау	Dec-Feb 25
8760 0	7	24	24	25	26 BOILER SPECII	
ACK DATA 250	STACE	Height (ft)	air	om with under fire		Furnace Type:
15.75	e (acfm)	Inside Diameter (Exhaust Flow Rat			Babcock & Wilco HSB 18469	Manufacturer: Model & Serial #:
Max 469,812 32.9	384,033	Normal Velocity (fps)	, DSI	overfire air, FFDC 8/22/55		Unit Description: First Service or Last !
c		Calculated or Sta	Coal	1709.4	ng (MMBtu/hr) :	Max Continuous Rati
270	ture (F) Content (if modifie	Exhaust Tempera	Natural Gas	1706.58	ximum Hourly Fue	Ma
Max 9	7	Normal	Rate	Unit	уре	Fuel T
Up		Orientation of Re	77	ton/hr Mcf/hr		Bitumino Natural
None	Obstruction	Rainhat or Other	1710	MCUAR	Gas	Natura
Technology, %		C 1		malam, (SIAD 6	na hava general ()	Does the boiles/6
PM SOx 99.9 20	NOx 60.3	Control Low NOx, & DSI	Y Baghouse,	unology (Y/N)?	ce nave control tech	Does the boiler/furnac
Catalytic/Thermal Oxidation 2000-403 NONE	orbers NONE 2		nsers NONE	Conde 2000-401	C004,C005	Miscella 2000-400
Baghouses/Fabric Filters 2000-407 C006	ion Systems		Precipitators NONE	Electrostatic 2000-405	ng Chambers NONE	Cyclones/Settlin 2000-404
		ARAMETERS	OPERATING I			
Potential	Pote				1994	······
674,520 1.00 10.00	(%) =	Coal (tons) = Max Sulfur Conte Max Ash Content	323,480 0.50 10.00) =	Coal (tons) = Max Sulfur Content (*) Max Ash Content (*)
11,100 14,979,600 NA) =	HHV Coal (BTU) Natural Gas (Mcf Max Sulfur Conto	11,100 34,237 NA			HHV Coal (BTU/lb) : Natural Gas (Mcf) = Max Sulfur Content (
NA 998	(%) = scf) =	Max Ash Content HHV Gas (BTU/s	NA 998 8,490			Max Ash Content (%) HHV Gas (BTU/scf) Operation Hours =
8,760		Operation Hours				
PTE PTE	Actual	- LECOLATIONS	2	Units of	Source of	
100% Coal 100% Natural Gas	Emissions	n Factors	Emission	Emission	Emission	Pollutant
(ton/yr) (ton/yr)	(ton/yr)	Natural Gas	Coal	Factor	Factor AP-42 ¹	NOx
4,492	1,397	550	21.7	lb/ton lb/MMCF	AP-42*	11-VA
169	82		0.50	lb/ton	AP-42' AP-42 ²	со
234	10	40	0.06	lb/MMCF lb/ton	AP-42'	NMTOC
16		1.7	100.00	lb/MMCF lb/ton	AP-42 ² AP-42 ¹	PM
749 748	16	3.00	100.00	lb/MMCF	AP-42 ¹ AP-42 ¹	
689 726	15		92.00	% PM Ib/MMCF	AP-42' AP-42'	PM ₁₀
6,589	2,264	3.00	17.50	lb/ton	AP-421	SO ₂
2,953		0.60		lb/MMCF	AP-42 ²	Antimony
+						Antimony Arsenic
						Beryllium
						Cadmium Chromium
+						Cobalt
		NA	507	lb/10^12 BTU	AP-42	Lead
0.084 NA	0.002					
0.084 NA	0.002					Manganese
0.084 NA	0.002					Manganese Mercury Nickel
0.084 NA	0.002					Mercury
0.084 NA	0.002					Mercury Nickel

- Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, tangentially fired Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, Controlled Low NOx burners PM₁₀ is 92% of PM (Baghouse controlled emissions, AP-42 Table 1.1-5)

Public Service Company-Cherokee Station

Seasonal Fuel Usage (%) Normal Operation of Unit Space Heat (%)
Dec-Feb Mar-May Jun-Aug Sep-Nov Hours/Day Days/Week Hours/year 24 7 8,760 0
BOILER SPECIFICATIONS
Height (ft) 300
Inside Diameter (ft)
it Description: N/A st Service or Last Mod. Date: Aug. 12, 1957 st Scrotienuous Rating (mmBTU/hr): 1,392 Coal 1,259 Natural Gas Maximum Hourly Fuel Usage (units/hr) Maximum Hourly Fuel Usage (units/hr) Rhormal 789,395 Max 937,595 Velocity (fps) 65,5 Calculated or Stack Test (C/ST) ST Exhaust Temperature (F) 265 Exhaust Moisture Content (if modified) (%)
st Service or Last Mod. Date: Aug. 12, 1957 x Continuous Rating (mmBTU/hr): 1,392 Coal 1,259 Natural Gas Maximum Hourly Fuel Usage (units/hr): Stabaust Temperature (F) Exhaust Temperature (F)
ax Continuous Rating (mmBTU/hr): 1,392 Coal 1,259 Natural Gas Maximum Hourly Fuel Usage (units/hr) Exhaust Temperature (F) 265 Exhaust Moisture Content (if modified) (%)
Maximum Hourly Fuel Usage (units/hr) Exhaust Moisture Content (if modified) (%)
Bituminous Coal ton/hr 61.8 Orientation of Release Up
Natural Gas mct/hr 1,240 Rainhat or Other Obstruction None
Control Technology, % Does the boilet/furnace have control technology (Y/N) Y Control NOx PM SOx
Ooes the boiler/furnace have control technology (Y/N) Y Control NOx PM SOx Baghouse 0 99.9 0
Miscellaneous Condensers Adsorbers Catalytic/Thermal Oxidation
2000-400 NONE 2000-401 NONE 2000-402 NONE 2000-403 NONE
Cyclones/Settling Chambers Electrostatic Precipitators Wet Collection Systems Baghouses/Fabric Filters
000-404 NONE 2000-405 NONE 2000-406 NONE 2000-407 C001
OPERATING PARAMETERS 1994 Potential
oal (ton) = 371,282 Coal (ton) = 541 vg. Sulfur Content (%) = 0.39 Avg. Sulfur Content (%) =
Avg. Ash Content (%) = 9.95 Avg. Ash Content (%) = 9
HV Coal (BTU/lb) = 11,262
Avg. Sulfur Content (%) = N/A Avg. Sulfur Content (%) =
Avg. Ash Content (%) = N/A Avg. Ash Content (%) =
HHV Gas (BTU/scf) = 1,015 HHV Gas (BTU/scf) = 1 Operation Hours = 7,771 Operation Hours = 8
EMISSION CALCULATIONS
Source of Units of Actual PTE PTE Pollutant Emission Emission Emission Factors Emissions 100% Coal 100% Natural C
Factor Factor Coal Natural Gas (ton/yr) (to
CO AP-42(1) lb/ton 0.50 96 135
AP-42(2) lb/mmCF 40 / 92 217
MTOC AP-42(1) lb/ton 0.06 11 16 16 9.2
PM AP-42(1) lb/ton 99.50 18 610 55
AP-42(2) lb/mmCF lb/A 3 16 PM ₁₀ AP-42(3) % PM 92.00 17 561
AP-42(2) Ib/mmCF 3
SOx AP-42(1) lb/ton 13.65 / 2,534 6,707 6065 V
AP-42(2) lb/mmCF $\sqrt{385} = \sqrt{18}$ 0.60 $\sqrt{275}$ 3.3
Arsenic
Seryllium VV
Admium V 5 5 5 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
Cobalt
ead AP-42 lb/10^12 BTU 507 NA 0.015 0.49 NA
langanese 2 2 1 + μ 7 3 2 1 erctiry
lickel
Thellium Tomaldehyde Tootnotes 1. Section 1.1 Biruminous and Subbiruminous Coal Combustion; Pulverized coal fired, dry bottom, wall fired 2. Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled 3. PM10 h.92% of PM (baghouse controlled emissions, AP-42 Table 1.1-5) Which is in the controlled of the controlled emission emi
hallium ormaldehyde
DM

	Pub		Company of			ation	
Stack Identification (Code:	S001		Emission Unit Co	de:	B002	
	Seasonal Fuel	Usage (%)		No	rmal Operation of	Unit	Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	.,
31	33	11	25	24	7	8,760	0
	BOILER SPECI	FICATIONS			STACK	DATA (S001)	
Furnace Type: Manufacturer:	Top Fired Babcock & Wilco:	-		Height (ft)	6 \		300
Model & Serial #:	RB 295 NY-7716			Inside Diameter (I Exhaust Flow Rat			16
Jnit Description:	N/A	•		Normal	789,395	Max	937,595
First Service or Last	Mod. Date:	May. 19, 1959		Velocity (fps)	·		65.5
Max Continuous Rat	ting (mmBTU/hr) :	1,392	Coal	Calculated or Stat			ST
			Natural Gas	Exhaust Tempera		- n.a.	265
	Maximum Hourly Fue Type	Unit Usage (units/hr)	Rate	Exhaust Moisture Normal	Content (if modif	ied) (%) Max	10
	ous Coal	ton/hr	61.8	Orientation of Re		Max	Up
	al Gas	mcf/hr	1,240	Rainhat or Other			None
					****	Technology, %	
Does the boiler/furns	ace have control tech	nology (Y/N)	Y	Control	NOx	PM	SOx
				Baghouse	0	99.9	0
Miscel	laneous	Conde	ensers	Adso	orbers	Catalytic/Th	ermal Oxidation
2000-400	NONE		NONE		NONE		NONE
Cyclones/Sett	ling Chambers	Electrostatic	Precipitators	Wet Collec	tion Systems	Baghouses	Fabric Filters
2000-404	NONE	2000-405	NONE		NONE		C002
			OPERATING F	ARAMETERS			
	1994				I	Potential	
Coal (ton) =			261,335	Coal (ton) =			541,368
Avg. Sulfur Content			0.39	Avg. Sulfur Conte			1.00
Avg. Ash Content (%			9.95	Avg. Ash Conten			9.95
HHV Coal (BTU/lb) Natural Gas (mcf) =) ==		11,262 311,320	HHV Coal (BTU/ Natural Gas (mcf			11,262 10,862,400
Avg. Sulfur Content	(%) =		N/A	Avg. Sulfur Cont			10,802,400 N/A
Avg. Ash Content (%			N/A	Avg. Ash Conten	. ,		N/A
HHV Gas (BTU/scf)) =		1,015	HHV Gas (BTU/s			1,015
Operation Hours =			6,669	Operation Hours	=		8,760
			EMISSION CA	ALCULATIONS			
	Source of	Units of			Actual	PTE	PTE
Pollutant	Emission	Emission	Emission	1 Factors	Emissions	100% Coal	100% Natural Gas
	Factor	Factor	Coal	Natural Gas	(ton/yr)	(ton/yr)	(ton/yτ)
NOx	AP-42(1)	lb/ton	21.7	/	2,921	5,874	
CO	AP-42(2) AP-42(1)	lb/mmCF lb/ton	0.50	550	2835	135	2,987
50	AP-42(1) AP-42(2)	lb/mmCF	0.30 /	40 /	16 1/2 /	1330	217
NMTOC	AP-42(1)	lb/ton	0.06		8.1	16	
	AP-42(2)	lb/mmCF		1.7 🗸	18		9.2
PM	AP-42(1)	lb/ton	99.50		13 🗸	610	551
L 1AT	AP-42(2) AP-42(3)	lb/mmCF % PM	92.00	3 /	12	561	16'
	AP-42(3) AP-42(2)	lb/mmCF	92.00	3 /	12 0	361	201/
PM PM ₁₀		lb/ton	(13.65)		1,784	6,707	6065
PM ₁₀	AP-42(1)		365-14.82	0.60	1936		3.3
PM ₁₀	AP-42(1) AP-42(2)	lb/mmCF	י שחיווי כשע ו			1	
PM ₁₀ SOx Antimony	1 7	lb/mmCF	363-11.00				
PM ₁₀ GOx Antimony Arsenic	1 7	lb/mmCF	203-11.05				
PM ₁₀ SOx Antimony Arsenic Beryllium	1 7	lb/mmCF	1000 CON				
PM ₁₀ SOx Antimony Arsenic Beryllium Cadmium	1 7	lb/mmCF (100 CO				
PM ₁₀ SOx Antimony Arsenic Beryllium Cadmium Chromium	1 7	lb/mmCF	365 (00)		/	4	
	1 7	lb/mmCF	365 11110	NA	0.010	0.49	NA NA
PM ₁₀ SOx Antimony Arsenic Beryllium Cadmium Chromium	AP-42(2)		305 (100)	NA	0.010	0.49	NA
PM., SOx Antimony Arsenic Beryllium Connium Chromium Cobalt Lead Manganese Mercury	AP-42(2)		305 (100)	NA NA	0.010		NA
PM ₁₀ SOx Antimony Arsenic Beryllium Cadmium Chromium Cobalt Lead Manganese Mercury Nickel	AP-42(2)		305 (100)	NA NA	0.010		NA NA
PM ₁₀ SOX Antimony Arsenic Beryllium Cadmium Chromium Cobalt Lead Manganese Mercury Wickel Selenium	AP-42(2)		305 (100)	NA NA	0.010		NA NA
PM ₁₀ SOX Antimony Arsenic Beryllium Cadmium Choronium Cobalt Lead danganese Mercury Nickel	AP-42(2)		305 (100)	NA	0.010		NA NA

- Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, wall fired Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled PM10 is 92% of PM (baghouse controlled emissions, AP-42 Table 1.1-5)

Unit 3
Public Service Company of Colorado, Cherokee Station
Criteria and HAP Emissions

Stack Identification	Code:	S002		Emission Unit Co	ode:	B003	
	Seasonal Fuel	Usage (%)		N	ormal Operation of	f Unit	Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	· ` ` `
25	27	29	19	24	7	8,760	0
	BOILER SPECI	FICATIONS			STAC	K DATA (\$002)	
Furnace Type:	Front Fired			Height (ft)			300
Manufacturer:	Babcock & Wilco:	x		Inside Diameter	(ft)		19.5
Model & Serial #:	RB 344 NY-77180	02		Exhaust Flow Ra	te (acfm)		
Unit Description:	Low NOx burner,	with overfire air		Normal	495,419	Max	745,517
First Service or Last	First Service or Last Mod. Date: Apr. 28, 1962			Velocity (fps)			27.7
Max Continuous Ra	ting (mmBTU/hr) :	1,877	Coal	Calculated or Sta	ick Test (C/\$T)		ST
		1,697	Natural Gas	Exhaust Tempera	ature (F)		267
,	Maximum Hourly Fue	el Usage (units/hr)	Exhaust Moistur	e Content (if mod	ified) (%)	
Fuel	Туре	Unit	Rate	Normal	6	Max	10
Bitumin	Bituminous Coal ton/hr 83.3		Orientation of Release			Up	
Natur	ral Gas	mcf/hr	1,673	Rainhat or Other	Obstruction		None
		•			Contr	ol Technology, %	
Does the boiler/furn	ace have control tech	nology (Y/N)	Y	Control	NOx	PM	SOx
			Bag	house & Low NOx	53.5	99.9	0
Miscel	llaneous	Con	idensers	Ads	sorbers	Catalytic/Th	ermal Oxidation
2000-400	C005	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Sett	tling Chambers	Electrostati	ic Precipitators	Wet Colle	ction Systems	Baghouses	Fabric Filters
2000-404	NONE	2000-405	NONE	2000-406	NONE		C003
			OPERATING	PARAMETERS		·	
	1994					Potential	
Coal (ton) =		•••	425,597	Coal (ton) =			729,708
Avg. Sulfur Content	t (%) =		0.39	Avg. Sulfur Con	tent (%) =		1.00
Avg. Ash Content (%) =		9.95	Avg. Ash Content (%) =			9.95
HHV Coal (BTU/lb)=		11,262	HHV Coal (BTU/lb) =			11,262
Natural Gas (mcf) =			479,215	Natural Gas (mc	f) =		14,655,480 (
Avg. Sulfur Content	t (%) =		N/A	Avg. Sulfur Con	tent (%) =		N/A
Avg. Ash Content (%) =		N/A	Avg. Ash Conte	nt (%) =		N/A
HHV Gas (BTU/scf) =		1,015	HHV Gas (BTU	/scf) =		1,015
Operation Hours =			7,576	Operation Hours	=		8,760

EMISSION CALCULATIONS

	Source of	Units of			Actual	PTE	PTE
Pollutant	Emission	Emission	Emission	Factors	Emissions	100% Coal	100% Natural Gas
	Factor	Factor	Coal	Natural Gas	(ton/yr)	(ton/yr) /	(ton/yr)
NOx	AP-42(1)	lb/ton	21.7		2,279	4,931	4460
	AP-42(2)	lb/mmCF		550	2147	/	4,030
СО	AP-42(1)	lb/ton	0.50		116	182	
	AP-42(2)	lb/mmCF		40	100		293
NMTOC	AP-42(1)	lb/ton	0.06		13 🗸	22	
	AP-42(2)	lb/mmCF		1.7			12
PM	AP-42(1)	lb/ton	99.50	/	21	822	743
	AP-42(2)	lb/mmCF	401	3 /			22
PM ₁₀	AP-42(3)	% PM	92.00		19	756	743
	AP-42(2)	lb/mmCF		3 -			22
SOx	AP-42(1)	lb/ton	(13.65)		2,905	9,040	8176
	AP-42(2)	lb/mmCF	1385-14.89	0.60	3168		4.4
Antimony			7				
Arsenic		T	ł				
Beryllium	T	[1000				
Cadmium			1000 CNO				
Chromium			100 -50				
Cobait	1		19 TO				·
Lead	AP-42	1b/10^12 BTU	507	NA	0.017	0.66	NA
Manganese		[4.2	
Mercury						,	
Nickel							
Selenium							
Thallium							
Formaldehyde				-			
POM							

Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, wall fired Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled PM10 is 92% of PM (baghouse controlled emissions, AP-42 Table 1.1-5)

burner.

Soortinger.

TitleI

		CI	riteria and H	THE LINES IV	113		l
tack Identification	Code:	S003		Emission Unit Co	de:	B004	
Dec-Feb	Seasonal Fuel Mar-May	Usage (%) Jun-Aug	Sep-Nov	No Hours/Day	rmal Operation of U Days/Week	Unit Hours/year	Space Heat (%)
25	24	27	24	24	7	8,760	0
	BOILER SPECI	ICATIONS			STACK I	DATA (\$003)	
imace Type: lanufacturer:	Corner tilting tange Combustion Engin	_		Height (ft) Inside Diameter (& \		400 22
Iodel & Serial #:	12465 C400016	ecting		Exhaust Flow Ra			22
nit Description:	Low NOx burner,			Normal	1,041,916	Max	1,389,927
irst Service or Last Iax Continuous Ra	t Mod. Date: iting (mmBTU/hr) :	Nov. 20, 1968 3,520	Coal	Velocity (fps) Calculated or Sta	ck Test (C/ST)		45.7 C
	36	11.00	Natural Gas	Exhaust Tempera			267
	Maximum Hourly Fue Type	Usage (units/hr)	Rate	Exhaust Moisture Normal	Content (if modifie	ed) (%) Max	10
Bitumir	nous Coal	ton/hr	156.3 V	Orientation of Re	lease		Up
Natu	ral Gas	mcf/hr	1749	Rainhat or Other			None
Tope the bailou/f	ace have control techi	nology (VAI)	x 134	16g Control	Control NOx	Technology, % PM	SOx
ocs uie ooner/ium	sace mave control techi	iiology (1/N)		Control , Low NOx, & DSI	62	РМ 99.9	37.5
Misce	llaneous	Conde			orbers	Catalytic/Th	ermal Oxidation
000-400	C006, C007	2000-401	NONE	2000-402	NONE	2000-403	NONE
	tling Chambers	Electrostatic			tion Systems		Fabric Filters
1000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	C004
	1994		OPERATING	PARAMETERS	Pe	otentiai	
oal (ton) =			981,255	Coal (ton) =			1,369,188
Avg. Sulfur Conten			0.39	Avg. Sulfur Cont			1.00
Avg. Ash Content (' HV Coal (BTU/Ib			9.95 11,262	Avg. Ash Conten HHV Coal (BTU			9.95 11,262
Vatural Gas (mcf) =			333,192	Natural Gas (mcf	*		15,321,240
Avg. Sulfur Conten	t (%) =		N/A	Avg. Sulfur Cont	ent (%) =		N/A
•	, ,		***		. (0.1)		
Avg. Ash Content (%) =		N/A 1,015	Avg. Ash Conter HHV Gas (BTU/			N/A 1,015
Avg. Ash Content (' HHV Gas (BTU/scf	%) =		N/A 1,015 8,102	Avg. Ash Conten HHV Gas (BTU/ Operation Hours	scf) =		N/A 1,015 8,760
•	%) =		1,015 8,102	HHV Gas (BTU/	scf) =		1,015
Avg. Ash Content (' HHV Gas (BTU/scf	%) =	Units of	1,015 8,102	HHV Gas (BTU/ Operation Hours	scf) =	PTE	1,015
Avg. Ash Content (' HHV Gas (BTU/scf	%) = f) = Source of Emission	Emission	1,015 8,102 EMISSION C	HHV Gas (BTU/ Operation Hours ALCULATIONS In Factors	scf) = = Actual Emissions	100% Coal	1,015 8,760 PTE 50% Coal/50%Gas
Avg. Ash Content (* HHV Gas (BTU/scf Operation Hours = Pollutant	%) = f) = Source of Emission Factor	Emission Factor	EMISSION C Emission C Coal	HHV Gas (BTU/ Operation Hours ALCULATIONS	Actual Emissions (ton/yr)	100% Coal (ton/yr)	1,015 8,760 PTE
Avg. Ash Content (* HHV Gas (BTU/scf Operation Hours = Pollutant	%) = f) = Source of Emission Factor AP-42(1) AP-42(2)	Emission Factor lb/ton lb/mmCF	EMISSION C. Emissio Coal 14.4	HHV Gas (BTU/ Operation Hours ALCULATIONS In Factors	Actual Emissions (ton/yr) 2-776	100% Coal (ton/yr) 6,939	1,015 8,760 PTE 50% Coal/50%Gas
Avg. Ash Content (' HHV Gas (BTU/scf Operation Hours =	%) = f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(1)	Emission Factor lb/ton lb/mmCF lb/ton	EMISSION C Emission C Coal	HHV Gas (BTU/ Operation Hours ALCULATIONS In Factors Natural Gas	Actual Emissions (10n/yr) 2-776 2-52	100% Coal (ton/yr)	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969
Avg. Ash Content (* HHV Gas (BTU/scf Operation Hours = Pollutant	%) = f) = Source of Emission Factor AP-42(1) AP-42(2)	Emission Factor lb/ton lb/mmCF	EMISSION C. Emissio Coal 14.4	HHV Gas (BTU/ Operation Hours ALCULATIONS In Factors Natural Gas 550	Actual Emissions (ton/yr) 2-776	100% Coal (ton/yr) 6,939	1,015 8,760 PTE 50% Coal/50%Gas (ton/yτ)
Avg. Ash Content (* HHV Gas (BTU/scf) Operation Hours = Pollutant NOx CO	%) = f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(2) AP-42(2) AP-42(1) AP-42(2)	Emission Factor lb/ton lb/mmCF lb/ton lb/mmCF lb/ton lb/mmCF	1,015 8,102 EMISSION C. Coal 14.4 0.50	HHV Gas (BTU/ Operation Hours ALCULATIONS In Factors Natural Gas	Actual Emissions (tonlyn) 2 252 252 254 30	100% Coal (ton/yr) 6,939	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969
Avg. Ash Content (* HHV Gas (BTU/scf) Operation Hours = Pollutant NOx CO	%) = (f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(1) AP-42(1)	Emission Factor Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/ton	1,015 8,102 EMISSION C. Emission Coal 14.4 0.50 0.06	HHV Gas (BTU/ Operation Hours ALCULATIONS In Factors Natural Gas 550	Actual Emissions (ton/yr)	100% Coal (ton/yr) 6,939	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969
Avg. Ash Content (* HHV Gas (BTU/scf Operation Hours = Pollutant NOx CO NMTOC	%) = f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(3)	Emission Factor Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/ton Ib/mmCF	1,015 8,102 EMISSION C. Coal 14.4 0.50	HHV Gas (BTU/ Operation Hours ALCULATIONS In Factors Natural Gas 550 40 1.7 3	Actual Emissions (tonlyn) 2 252 252 254 30	100% Coal (ton/yr) 6,939	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969 478 34
Avg. Ash Content (* HHV Gas (BTU/scf) Operation Hours = Pollutant NOX O O MTOC	%) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(2) AP-42(1) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(3) AP-42(3) AP-42(2)	Emission Factor Ib/ton Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/mmCF Ib/mmCF % PM Ib/mmCF	1,015 8,102 EMISSION C. Coal 14.4 0.50 0.06 99.50 V 10 Å	HHV Gas (BTU/Operation Hours ALCULATIONS n Factors Natural Gas 550 40 1.7	Actual Emissions 400/yr) 2-776	100% Coal (ton/yr) 6,939 342 41 1,542	1,015 8,760 PTE 50% Coal/50%Gas (ton/yt) 6,969 478
Avg. Ash Content (* HHV Gas (BTU/scf Operation Hours = Pollutant NOx CO NMTOC	%) = f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(3)	Emission Factor Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/ton Ib/mmCF Ib/ton Ib/mmCF	1,015 8,102 EMISSION C. Coal 14.4 0.50 0.06 99.50 V 10 Å 92.00	HHV Gas (BTU/ Operation Hours ALCULATIONS In Factors Natural Gas 550 40 1.7 3	Actual Emissions (ton/yr) 2/2 2776 252 244 49	100% Coal (ton/yr) 6,939 342 41	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969 478 34
Avg. Ash Content (* HTV Gas (BTU/sef) Pollutant NOx CO NMTOC PM PM PM Antimony	%) = (f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(2) AP-42(1) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(3) AP-42(3) AP-42(3) AP-42(3) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(2) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1)	Emission Factor Ib/ton Ib/mmCF	1,015 8,102 EMISSION C. Coal 14.4 0.50 0.06 99.50 V 10 M 92.00 V	HHV Gas (BTU/Operation Hours ALCULATIONS To Factors Natural Gas 550 40 1.7 3	Actual Emissions (100/yr) 2/0 2,776 252 252 245 45	100% Coal (ton/yr) 6,939 342 41 1,542	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969 478 34 794 732
Avg. Ash Content (* HHV Gas (BTU/scf) Operation Hours = Pollutant NOX O NMTOC PM PM O Antimony Arsenic	%) = (f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(2) AP-42(1) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(3) AP-42(3) AP-42(3) AP-42(3) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(2) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1)	Emission Factor Ib/ton Ib/mmCF	1,015 8,102 EMISSION C. Coal 14.4 0.50 0.06 0.06 10]A 92.00 10]A 92.00	HHV Gas (BTU/Operation Hours ALCULATIONS To Factors Natural Gas 550 40 1.7 3	Actual Emissions (100/yr) 2/0 2,776 252 252 245 45	100% Coal (ton/yr) 6,939 342 41 1,542	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969 478 34 794 732
Avg. Ash Content (* HTV Gas (BTU/sef) Pollutant NOx CO NMTOC PM PM PM Antimony	%) = (f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(2) AP-42(1) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(3) AP-42(3) AP-42(3) AP-42(3) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(2) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1)	Emission Factor Ib/ton Ib/mmCF	1,015 8,102 EMISSION C. Coal 14.4 0.50 0.06 99.50 V 10 M 92.00 V	HHV Gas (BTU/Operation Hours ALCULATIONS To Factors Natural Gas 550 40 1.7 3	Actual Emissions (100/yr) 2/0 2,776 252 252 245 45	100% Coal (ton/yr) 6,939 342 41 1,542	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969 478 34 794 732
Nog. Ash Content (* HIV Gas (BTU/scf) Pollutant NOX NMTOC Mu Mu Mu Mu Mu Mu Mu Mu Mu M	%) = (f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(2) AP-42(1) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(3) AP-42(3) AP-42(3) AP-42(3) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(2) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1)	Emission Factor Ib/ton Ib/mmCF	1,015 8,102 EMISSION C. Coal 14.4 0.50 0.06 0.06 10]A 92.00 10]A 92.00	HHV Gas (BTU/Operation Hours ALCULATIONS To Factors Natural Gas 550 40 1.7 3	Actual Emissions (100/yr) 2/0 2,776 252 252 245 45	100% Coal (ton/yr) 6,939 342 41 1,542	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969 478 34 794 732
Avg. Ash Content (* HIV Gas (BTU/set*) HIV Gas (BTU/set*) Pollutant HOX TO MITOC M Min GOX Antimony Avsenic Beryllium Cadmium Cobalt	%) = f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(3) AP-42(2) AP-42(3) AP-42(2) AP-42(4)	Emission Factor Ib/ton Ib/mmCF	1,015 8,102 EMISSION C. Coal 114.4 0.50 0.06 99.50 V 10 A 92.00 32.65 35.5 14.87	HHV Gas (BTU/Operation Hours ALCULATIONS In Factors Natural Gas 550 40 1.7 3 0.60	Actual Emissions Total	100% Coal (ton/yr) 6,939 342 41 1,542 1,419	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969 478 34 794 732 8,485
Nog. Ash Content (* HIV Gas (BTU/sef) Departion Hours = Pollutant NOx CO NMTOC PM PM PM Antimony Arstenic Cadmium Chromium Chodult Cadmium Chromium Chodult Cead Cead	%) = (f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(2) AP-42(1) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(3) AP-42(3) AP-42(3) AP-42(3) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(2) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(1)	Emission Factor Ib/ton Ib/mmCF	1,015 8,102 EMISSION C. Coal 14.4 0.50 0.06 99.50 10A 92.00 32.65 32.5 14.89	HHV Gas (BTU/Operation Hours ALCULATIONS To Factors Natural Gas 550 40 1.7 3	Actual Emissions (100/yr) 2/0 2,776 252 252 245 45	100% Coal (ton/yr) 6,939 342 41 1,542 1,419 16,962	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969 478 34 794 732
AND AND CONTENT (** WHY Gas (BTU/scf) Pollutant NOX O MITOC M M M M M M M M M M M M M	%) = f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(3) AP-42(2) AP-42(3) AP-42(2) AP-42(4)	Emission Factor Ib/ton Ib/mmCF	1,015 8,102 EMISSION C. Coal 114.4 0.50 0.06 99.50 V 10 A 92.00 32.65 35.5 14.87	HHV Gas (BTU/Operation Hours ALCULATIONS In Factors Natural Gas 550 40 1.7 3 0.60	Actual Emissions Total	100% Coal (ton/yr) 6,939 342 41 1,542 1,419	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969 478 34 794 732 8,485
AND AND CONTENT (** WHY GAS (BTU/set*) Pollutant NOX CO NMTOC OM Mino OX Antimony Arsenic Seryllium Cadmium Thromium Cobalt Lead Aanganese decreury Sickel	%) = f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(3) AP-42(2) AP-42(3) AP-42(2) AP-42(4)	Emission Factor Ib/ton Ib/mmCF	1,015 8,102 EMISSION C. Coal 114.4 0.50 0.06 99.50 V 10 A 92.00 32.65 35.5 14.87	HHV Gas (BTU/Operation Hours ALCULATIONS In Factors Natural Gas 550 40 1.7 3 0.60	Actual Emissions Total	100% Coal (ton/yr) 6,939 342 41 1,542 1,419 16,962	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969 478 34 794 732 8,485
AND AND CONTENT (** WAS (BTU/sef) Pollutant NOX O NMTOC M O NMTOC M O Antimony Arsenic Beryllium Cobalt Cobalt Lead Manganese dercury Wickel Gelenium	%) = f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(3) AP-42(2) AP-42(3) AP-42(2) AP-42(4)	Emission Factor Ib/ton Ib/mmCF	1,015 8,102 EMISSION C. Coal 114.4 0.50 0.06 99.50 V 10 A 92.00 32.65 35.14.87	HHV Gas (BTU/Operation Hours ALCULATIONS In Factors Natural Gas 550 40 1.7 3 0.60	Actual Emissions Total	100% Coal (ton/yr) 6,939 342 41 1,542 1,419 16,962	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969 478 34 794 732 8,485
AND AND CONTENT (** WHY GAS (BTU/set*) Pollutant NOX CO NMTOC OM Mino OX Antimony Arsenic Seryllium Cadmium Thromium Cobalt Lead Aanganese decreury Sickel	%) = f) = Source of Emission Factor AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(1) AP-42(2) AP-42(3) AP-42(2) AP-42(3) AP-42(2) AP-42(4)	Emission Factor Ib/ton Ib/mmCF	1,015 8,102 EMISSION C. Coal 114.4 0.50 0.06 99.50 V 10 A 92.00 32.65 35.14.87	HHV Gas (BTU/Operation Hours ALCULATIONS In Factors Natural Gas 550 40 1.7 3 0.60	Actual Emissions Total	100% Coal (ton/yr) 6,939 342 41 1,542 1,419 16,962	1,015 8,760 PTE 50% Coal/50%Gas (ton/yr) 6,969 478 34 794 732 8,485

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Public Service Company-Valmont Station

TABLE 3-1Valmont Combustion Turbine Project Emissions Summary ^a

S Pollutant	Significant Emission Rates (tpy)	Annual Emissions (tpy), Total of Both Turbines plus Unit #8 Air Preheater ^b	Maximum Hourly Emissions (lb/hr), Each of Two Turbines ^c	Maximum Hourly Emissions (Ib/hr), Unit #8 Air Preheater
Carbon Monoxide	100	90.8	220	0.24
Nitrogen Oxides	40	39.1	31	0.24
Sulfur Dioxide d	40	0.3	0.2	0.01
Particulate Matter ^e	25	4.0	3	0.04
Fine Particulate Matter PM	₁₀ e 15	4.0	3	0.04
Ozone	40 (voc)	1.5	5.1	0.04
Lead	0.6	Not Emitted	Not Emitted	Not Emitted
Fluorides	3	Not Emitted	Not Emitted	Not Emitted
Sulfuric Acid Mist	7	Not Emitted	Not Emitted	Not Emitted
Total Reduced Sulfur	10	Not Emitted	Not Emitted	Not Emitted
Reduced Sulfur Compounds	10	Not Emitted	Not Emitted	Not Emitted
Formaldehyde	Not Applicable	0.3	0.2	0.0005
Total HAPs	Not Applicable	0.6	0.4	0.01

^aDetailed emission calculations are provided in Appendix A.

Notes:

tpy = tons per year

lb/hr = pounds per hour

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^bAnnual emissions are based on total heat inputs for the Unit #7 turbine of 442,000 MMBtu per year, for the Unit #8 turbine of 442,000 MMBtu/year, and the Unit #8 air preheater of 6,700 MMBtu/year.

^cHourly emissions are based on operating conditions that result in maximum emissions for each pollutant. For sulfur dioxide, particulate matter, and fine particulate matter, these conditions are: operation at full load across all ambient temperatures. For carbon monoxide, oxides of nitrogen, and volatile organic compounds, maximum emitting conditions are: 100 percent load at 25 degrees Fahrenheit.

^dThe SO₂ emissions were estimated from the EPA default emissions rate of 0.0006 pounds SO₂ per MMBtu, for combustion turbine burning pipeline quality natural gas as obtained from 40 CFR 75, Appendix D, 2.3.2.

^eThe PM and PM₁₀ emissions are the sum of solid and condensable fractions.

Public Service Company-Zuni Station

Unit 1A Public Service Company of Colorado, Zuni Station Criteria and HAP Emissions

Stack Identification		S001		Unit Code:	B001		
	Seasonal Fuel	Usage (%)		No.	ormal Operation o	f Unit	Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	. ,
41	16	20	23	24	7	8760	0
	BOILER SPECIE	FICATIONS			TZ	ACK DATA	
Furnace Type:	Front-fired			Height (ft)	31.	CK DATA	280
Manufacturer:	Babcock & Wilcox			Inside Diameter (A)		13
Model & Serial #:	15253			Exhaust Flow Ra			.,
Unit Description:	N/A			Normal	120.000	Max	240,000
First Service or Las	t Mod. Date:	1948		Exhaust Velocity			15.08
Max Continuous Ra	ating (MMBTU/hr):	450	Natural Gas	Calculated or Sta			ST
		450	#6 Fuel Oil	Exhaust Tempera			500
	Maximum Hourly Fue	Usage (units/hr)			Content (if modi	fied) (%)	200
Fu	el Type	Unit	Rate	Normal	10	Max	16
Nat	ural Gas	Mcf/hr	450	Orientation of Re	lease		Up
#6	Fuel Oil	gal/hr	3,061	Rainhat or Other	Obstruction		None
		<u> </u>				T. 1 1 0/	rione
Doer the bailer/firm	nace have control techno	.l (VAI)	N			Technology, %	
Does the boller/full	ace have control techno	nogy (1/N)	N	Control	NOx	PM	SOx
				None	0	0	0
Misc	ellaneous	Conc	iensers	Ade	orbers	Catalusia/Th	ermal Oxidation
2000-400	NONE	2000-401	NONE	2000-402	NONE		NONE
						2000-403	HOILE
Cyclones/Se	ettling Chambers	Electrostation	Precipitators	Wet Collec	tion Systems	Baghouses	Fabric Filters
2000-404	NONE	2000-405	NONE		NONE	2000-407	NONE
·····			OPERATING P	ADAMÉTERO			
	1994		OPERATING	ARAMETERS		Potential	
				 		Potential	
Natural Gas (Mcf)			508,496	Natural Gas (Mcf	*		3,942,00
Max Sulfur Content			0.01	Max Sulfur Conte			0.01
Max Ash Content (0.00	Max Ash Content			0.00
HHV Gas (BTU/cf)) ≠		1,000	HHV Gas (BTU/	,		1,000
#6 Fuel Oil (gal) =			2,650	#6 Fuel Oil (gal)			26,816,32
Max Sulfur Content			0.79	Max Sulfur Conto			0.7
Max Ash Content (0.1	Max Ash Content			0.
HHV Fuel Oil (MB Operation Hours =	I ∪/gai) =		147	HHV Fuel Oil (M			14
Operation Hours =			3,459	Operation Hours	=		8,76
			EMISSION CA	LCULATIONS			
	Source of	Units of	T				
Pollutant	Emission	Emission	E	n Factors	Actual	PTE	PTE
Tumunt	Factor	Factor			Emissions		100 % #6 Fuel Oil
NOx	AP-42(1)	lb/MMCF	Natural Gas	#6 Fuel Oil	(ton/yr)	(ton/yr)	(ton/yr)
	AP-42(4)	lb/10^3 gal	330		140	1,084	
CO	AP-42(1)	Ib/MMCF	40	67	10.2	79	898
	AP-42(4)	1b/10^3 gal	1 ~	5	10.2	19	
NMTOC	AP-42(3)	lb/MMCF	1.7		0.43	3,4	67
	AP-42(5)	1b/10^3 gal	1	0.76	0.43	3.4	10
PM	AP-42(2)	lb/MMCF	3.0	3.76	0.78	5.9	10
	AP-42(4)	lb/10^3 gal	3.5	10 48	0.78	3.9	1
PM ₁₀	AP-42(2)	lb/MMCF	3.0	10.46	0.55	5.9	141
	AP-42(6)	% PM	1	71	0.33	3.9	100
SOx	AP-42(1)	Ib/MMCF	0.6	, · · ·	0.32	1.2	100
	1		1 0.0	l l	0.32	1.2	I

129

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ÑA

0.0000

NA

1,577

0.22

Manganese Mercury Nickel Selenium Thallium Formaldehyde POM Footnotes

Antimony
Arsenic
Beryllium
Cadmium
Chromium
Cobalt
Lead
Manganese

AP-42(4)

AP-42

- Section 1.4, Natural Gas Combustion; Table 1.4-2.
 Section 1.4, Natural Gas Combustion; Table 1.4-1.
 Section 1.4, Natural Gas Combustion; Table 1.4-3.
 Section 1.3 Fuel Oil Combustion; Table 1.3-2.
 Section 1.3 Fuel Oil Comb

lb/10^3 gal

lb/10^12 BTU

Public Service Company of Colorado, Zuni Station Criteria and HAP Emissions

Stack Identification C	ode :	S002		Unit Code: I	3002		
	Seasonal Fue	Usage (%)		No	rmal Operation of	Unit	Space Heat (%)
Dec-Feb	Маг-Мау	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	•
41	16	20	23	24	7	8760	0
	BOILER SPECI	FICATIONS			ST 4	ACK DATA	
Furnace Type:	Front fired	HEATHORS		Height (ft)	317	CKDAIA	107
Manufacturer:	Babcock & Wilcox			Inside Diameter (fl	n		6
Model & Serial #:	15265			Exhaust Flow Rate	,		•
Unit Description:	N/A			Normal	120,000	Max	204,000
First Service or Last !		1948		Exhaust Velocity (70.77
Max Continuous Rati		200	Natural Gas	Calculated or Stac			ST
	,	200	#6 Fuel Oil	Exhaust Temperat			500
	Maximum Hourly Fu			Exhaust Moisture		ied) (%)	
Fuel		Unit	Rate	Normal	10	Max	16
	al Gas	mcf/hr	200	Orientation of Rel	ease		Up
	el Oil	gal/hr	1,361	Rainhat or Other (None
	•				Control	Technology, %	
D		-1 (VAD	N	C1			60
Does the boiler/furna	ce nave control techn	ology (1/N)	N	Control	NOx	PM	SOx
				None	0	0	0
	laneous	Conde	nsers	Adso	rbers	Catalytic/The	rmal Oxidation
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Sett	ling Chambers	Electrostatic	Precipitators	Wet Collect	ion Systems	Raghouses	Fabric Filters
2000-404	NONE	2000-405	NONE		NONE		NONE
						2000 101	
			OPERATING I	ARAMETERS			
	1994	,				Potential	
Natural Gas (Mcf) =			63,537	Natural Gas (Mcf)	=		1,752,00
Max Sulfur Content (%) =		0.01	Max Sulfur Conte	nt (%) =		0.0
Max Ash Content (%) =		0.00	Max Ash Content			0.0
HHV Gas (BTU/cf) =			1,000	HHV Gas (BTU/c	n) =		1,00
#6 Fuel Oil (gal) =			0	#6 Fuel Oil (gal) =			11.918.36
#6 Fuel Oil (gal) = Max Sulfur Content (%) =		-	#6 Fuel Oil (gal) = Max Sulfur Conte			
Max Sulfur Content (0.79	Max Sulfur Conte	nt (%) =		0.7
Max Sulfur Content (Max Ash Content (%)=		0.79 0.1	Max Sulfur Conte Max Ash Content	nt (%) = (%) =		0.7 0
Max Sulfur Content ()=		0.79	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M	nt (%) = (%) = BTU/gal) =		0.7 0 14
Max Sulfur Content (Max Ash Content (% HHV Fuel Oil (MBT)=		0.79 0.1 147 500	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours	nt (%) = (%) = BTU/gal) =		11,918,36 0.7 0 14 8,76
Max Sulfur Content (Max Ash Content (% HHV Fuel Oil (MBT) = U/gal) =		0.79 0.1 147 500	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M	nt (%) = (%) = BTU/gal) = =		0.7 0 14 8,76
Max Sulfur Content (Max Ash Content (% HHV Fuel Oil (MBT Operation Hours =) = U/gal) = Source of	Units of	0.79 0.1 147 500 EMISSION C	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours	nt (%) = (%) = BTU/gal) = =	PTE	0.7 0 14 8,76
Max Sulfur Content (Max Ash Content (% HHV Fuel Oil (MBT	U/gal) = Source of Emission	Emission	0.79 0.1 147 500 EMISSION C	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours a ALCULATIONS	nt (%) = (%) = BTU/gal) = = Actual Emissions	100% Natural Gas	0.7 0 14 8,76 PTE 100 % #6 Fuel Oil
Max Sulfur Content (Max Ash Content (% HHV Fuel Oil (MBT Operation Hours =	Source of Emission Factor	Emission Factor	0.79 0.1 147 500 EMISSION Co	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours	nt (%) = (%) = BTU/gal) = = Actual Emissions (ton/yr)	100% Natural Gas (ton/yr)	0.7 0 14 8,76
Max Sulfur Content (Max Ash Content (% HHV Fuel Oil (MBT Operation Hours =	Source of Emission Factor AP-42(1)	Emission Factor Ib/MMCF	0.79 0.1 147 500 EMISSION C	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours * ALCULATIONS on Factors #6 Fuel Oil	nt (%) = (%) = BTU/gal) = = Actual Emissions	100% Natural Gas	0.7 0 14 8,76 PTE 100 % #6 Fuel Oil (ton/yr)
Max Sulfur Content (% Max Ash Content (% HHY Fuel Oil (MBT Operation Hours = Pollutant NOx	Source of Emission Factor AP-42(1) AP-42(4)	Emission Factor Ib/MMCF Ib/10^3 gal	0.79 0.1 147 500 EMISSION CA Emissic Natural Gas 550	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours a ALCULATIONS	nt (%) = (%) = BTU/gal) = - Actual Emissions (ton/yr) 17	100% Natural Gas (ton/yr) 482	0.7 0 14 8,76 PTE 100 % #6 Fuel Oil
Max Sulfur Content (Max Ash Content (% HHV Fuel Oil (MBT Operation Hours =) = U/gal) = Source of Emission Factor AP-42(1) AP-42(4) AP-42(1)	Emission Factor Ib/MMCF Ib/10^3 gal	0.79 0.1 147 500 EMISSION Co	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours * ALCULATIONS In Factors #6 Fuel Oil 67	nt (%) = (%) = BTU/gal) = = Actual Emissions (ton/yr)	100% Natural Gas (ton/yr)	0: 0 1 1, 8,70 PTE 100 % #6 Fuel Oi (ton/yr)
Max Sulfur Content (% Max Ash Content (% HTV Fuel Oil (MBT Operation Hours = Pollutant NOx CO	Source of Emission Factor AP-42(1) AP-42(4) AP-42(4)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal	0.79 0.1 147 500 EMISSION C. Emissic Natural Gas 550 40	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours * ALCULATIONS on Factors #6 Fuel Oil	nt (%) = (%) = (%) = BTU/gal) = - Actual Emissions (ton/yr) 17	100% Natural Gas (ton/yr) 482	0. 0 1- 8,70 PTE 100 % #6 Fuel Oi (ton/yr)
Max Sulfur Content (Max Ash Content (MHV Fuel Oil (MBT Operation Hours = Pollutant NOx	Source of Emission Factor AP-42(1) AP-42(4) AP-42(4) AP-42(3)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF	0.79 0.1 147 500 EMISSION CA Emissic Natural Gas 550	Max Sulfur Conte Max Ash Content HHV Fuel Oil Operation Hours * ALCULATIONS In Factors #6 Fuel Oil 67	nt (%) = (%) = BTU/gal) = - Actual Emissions (ton/yr) 17	100% Natural Gas (ton/yr) 482	0.7 0 18,76 PTE 100 % #6 Fuel Oil (ton/yr) 399
Max Sulfur Content (% Max Ash Content (% HHV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC	Source of Emission Factor AP-42(1) AP-42(4) AP-42(3) AP-42(3) AP-42(5) A	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal	0.79 0.11 147 500 EMISSION C. Emission S. Natural Gas 550 40 1.7	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours * ALCULATIONS In Factors #6 Fuel Oil 67	nt (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3	100% Natural Gas (ton/yr) 482 35	0: 0 1 1, 8,70 PTE 100 % #6 Fuel Oi (ton/yr)
Max Sulfur Content (% Max Ash Content (% HTV Fuel Oil (MBT Operation Hours = Pollutant NOx CO	Source of Emission Factor AP-42(1) AP-42(4) AP-42(4) AP-42(5) A	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF	0.79 0.1 147 500 EMISSION C. Emissic Natural Gas 550 40	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours * ALCULATIONS In Factors #6 Fuel Oil 67 5 0.76	nt (%) = (%) = (%) = BTU/gal) = - Actual Emissions (ton/yr) 17	100% Natural Gas (ton/yr) 482	0: 0 1 8,74 PTE 100 % 86 Fuel Oi (ton/yr) 399 30
Max Sulfur Content (% Max Ash Content (% HHY Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM	Source of Emission Factor AP-42(1) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(4) A	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal	0.79 0.1 147 500 EMISSION C. Emissic Natural Gas 550 40 1.7	Max Sulfur Conte Max Ash Content HHV Fuel Oil Operation Hours * ALCULATIONS In Factors #6 Fuel Oil 67	nt (%) = (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3 0.05	100% Natural Gas (ton/yr) 482 35	0.0 0.0 8.76 PTE 100 % #6 Fuel Oi (ton/yr) 399
Max Sulfur Content (% Max Ash Content (% HHV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC	Source of Emission Factor AP-42(1) AP-42(4) AP-42(5) AP-42(4) AP-42(5) AP-42(4) AP-42(4) AP-42(5) AP-42(4) AP-42(4) AP-42(4) AP-42(4) AP-42(2) AP-42(4) A	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF	0.79 0.11 147 500 EMISSION C. Emission S. Natural Gas 550 40 1.7	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours * ALCULATIONS In Factors #6 Fuel Oil 67 5 0.76	nt (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3	100% Natural Gas (ton/yr) 482 35	0: 0 1 8,74 PTE 100 % 86 Fuel Oi (ton/yr) 399 30
Max Sulfur Content (Max Ash Content (Max Ash Content (Max Ash Content (Max Max Ash Content (Max Max Ash Content (Max Max Ash Content (Max Max Max Max Max Max Max Max Max Max	Source of Emission Factor AP-42(1) AP-42(4) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(3) AP-42(4) AP-42(4) AP-42(4) AP-42(4) AP-42(5) AP-42(6) AP-	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF	0.79 0.11 147 500 EMISSION C. Emission Source Natural Gas 550 40 1.7 3.0	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours * ALCULATIONS In Factors #6 Fuel Oil 67 5 0.76	nt (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3 0.05 0.10	100% Natural Gas (ton/yr) 482 35 1.5 2.6	0: 0 1 8,74 PTE 100 % 86 Fuel Oi (ton/yr) 399 30
Max Sulfur Content (% Max Ash Content (% HHY Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM	Source of Emission Factor AP-42(1) AP-42(2) A	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^4 gal Ib/MMCF % PM Ib/MMCF	0.79 0.1 147 500 EMISSION C. Emissic Natural Gas 550 40 1.7	Max Sulfur Conte Max Ash Content HHV Fuel Oil Operation Hours **ALCULATIONS** **In Factors** **In Factors**	nt (%) = (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3 0.05	100% Natural Gas (ton/yr) 482 35 1.5	0: 0
Max Sulfur Content (Max Ash Content (Max Ash Content (Max Ash Content (Max Max Ash Content (Max Max Ash Content (Max Max Ash Content (Max Max Max Max Max Max Max Max Max Max	Source of Emission Factor AP-42(1) AP-42(4) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(3) AP-42(4) AP-42(4) AP-42(4) AP-42(4) AP-42(5) AP-42(6) AP-	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF	0.79 0.11 147 500 EMISSION C. Emission Source Natural Gas 550 40 1.7 3.0	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours * ALCULATIONS In Factors #6 Fuel Oil 67 5 0.76	nt (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3 0.05 0.10	100% Natural Gas (ton/yr) 482 35 1.5 2.6	0: 0
Max Sulfur Content (% Max Ash Content (% HHV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM PM ₁₀	Source of Emission Factor AP-42(1) AP-42(2) A	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^4 gal Ib/MMCF % PM Ib/MMCF	0.79 0.11 147 500 EMISSION C. Emission Source Natural Gas 550 40 1.7 3.0	Max Sulfur Conte Max Ash Content HHV Fuel Oil Operation Hours **ALCULATIONS** **In Factors** **In Factors**	nt (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3 0.05 0.10	100% Natural Gas (ton/yr) 482 35 1.5 2.6	0.0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
Max Sulfur Content (% HTV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM PM SOX Antimony Arsenic	Source of Emission Factor AP-42(1) AP-42(2) A	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^4 gal Ib/MMCF % PM Ib/MMCF	0.79 0.11 147 500 EMISSION C. Emission Source Natural Gas 550 40 1.7 3.0	Max Sulfur Conte Max Ash Content HHV Fuel Oil Operation Hours **ALCULATIONS** **In Factors** **In Factors**	nt (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3 0.05 0.10	100% Natural Gas (ton/yr) 482 35 1.5 2.6	0.0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
Max Sulfur Content (% Max Ash Content (% HHV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM PM ₁₀ SOx Antimony	Source of Emission Factor AP-42(1) AP-42(2) A	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^4 gal Ib/MMCF % PM Ib/MMCF	0.79 0.11 147 500 EMISSION C. Emission Source Natural Gas 550 40 1.7 3.0	Max Sulfur Conte Max Ash Content HHV Fuel Oil Operation Hours **ALCULATIONS** **In Factors** **In Factors**	nt (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3 0.05 0.10	100% Natural Gas (ton/yr) 482 35 1.5 2.6	0.0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
Max Sulfur Content (% HTV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM PM SOX Antimony Arsenic	Source of Emission Factor AP-42(1) AP-42(2) A	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^4 gal Ib/MMCF % PM Ib/MMCF	0.79 0.11 147 500 EMISSION C. Emission Source Natural Gas 550 40 1.7 3.0	Max Sulfur Conte Max Ash Content HHV Fuel Oil Operation Hours **ALCULATIONS** **In Factors** **In Factors**	nt (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3 0.05 0.10	100% Natural Gas (ton/yr) 482 35 1.5 2.6	0.0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
Max Sulfur Content (% HTV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM PM SOx Antimony Arsenic Beryllium Cadmium Cadmium Chromium Chromium	Source of Emission Factor AP-42(1) AP-42(2) A	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^4 gal Ib/MMCF % PM Ib/MMCF	0.79 0.11 147 500 EMISSION C. Emission Source Natural Gas 550 40 1.7 3.0	Max Sulfur Conte Max Ash Content HHV Fuel Oil Operation Hours **ALCULATIONS** **In Factors** **In Factors**	nt (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3 0.05 0.10	100% Natural Gas (ton/yr) 482 35 1.5 2.6	0.0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
Max Sulfur Content (% HTV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM PM ₁₀ SOx Antimony Arsenic Beryllium Cadmium Cadmium Cadmium Cadmium Cadmium Cadmium Cadmium Content (% NMTOC PM PM ₁₀ SOx Antimony Arsenic Beryllium Cadmium Cadmium Content (% NMTOC NMTOC PM PM ₁₀ SOx Antimony Arsenic Paryllium Cadmium Cadmium Content (% NMTOC NMTOC NMTOC PM PM ₁₀ SOx PM PM PM ₁₀ SOX PM	Source of Emission Factor AP-42(1) AP-42(2) A	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^4 gal Ib/MMCF % PM Ib/MMCF	0.79 0.11 147 500 EMISSION C. Emission Source Natural Gas 550 40 1.7 3.0	Max Sulfur Conte Max Ash Content HHV Fuel Oil Operation Hours **ALCULATIONS** **In Factors** **In Factors**	nt (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3 0.05 0.10	100% Natural Gas (ton/yr) 482 35 1.5 2.6	0.0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
Max Sulfur Content (% HTV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM PM SOx Antimony Arsenic Beryllium Cadmium Cadmium Chromium Chromium	Source of Emission Factor AP-42(1) AP-42(2) A	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^4 gal Ib/MMCF % PM Ib/MMCF	0.79 0.11 147 500 EMISSION C. Emission Source Natural Gas 550 40 1.7 3.0	Max Sulfur Conte Max Ash Content HHV Fuel Oil Operation Hours **ALCULATIONS** **In Factors** **In Factors**	nt (%) = (%) = (%) = BTU/gal) = Actual Emissions (ton/yr) 17 1.3 0.05 0.10	100% Natural Gas (ton/yr) 482 35 1.5 2.6	0.0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
Max Sulfur Content (% Max Ash Content (% HHV Fuel Oil (MBT Operation Hours = Pollutant NOX CO NMTOC PM PM ₁₀ SOx Antimony Arsenic Beryllium Cadmium Chromium Cobalt Lead	Source of Emission	Emission Factor Ib/MMCF Ib/10°3 gal Ib/MMCF 1b/10°3 gal	0.79 0.11 147 500 EMISSION C. Emission Natural Gas 550 40 1.7 3.0 3.0 0.60	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours ** LCULATIONS In Factors #6 Fuel Oil 67 5 0.76 10.48 71 128.53	nt (%) = (%)	100% Natural Gas (ton/yr) 482 35 1.5 2.6 2.6 0.53	0: C C C C C C C C C C C C C C C C C C C
Max Sulfur Content (% HTV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM	Source of Emission	Emission Factor Ib/MMCF Ib/10°3 gal Ib/MMCF 1b/10°3 gal	0.79 0.11 147 500 EMISSION C. Emission Natural Gas 550 40 1.7 3.0 3.0 0.60	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours ** LCULATIONS In Factors #6 Fuel Oil 67 5 0.76 10.48 71 128.53	nt (%) = (%)	100% Natural Gas (ton/yr) 482 35 1.5 2.6 2.6 0.53	0: C C C C C C C C C C C C C C C C C C C
Max Sulfur Content (Max Ash Content (Max Ash Content (Max Ash Content (Max Max Ash Content (Max Max Ash Content (Max Max Max Max Max Max Max Max Max Max	Source of Emission	Emission Factor Ib/MMCF Ib/10°3 gal Ib/MMCF 1b/10°3 gal	0.79 0.11 147 500 EMISSION C. Emission Natural Gas 550 40 1.7 3.0 3.0 0.60	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours ** LCULATIONS In Factors #6 Fuel Oil 67 5 0.76 10.48 71 128.53	nt (%) = (%)	100% Natural Gas (ton/yr) 482 35 1.5 2.6 2.6 0.53	0: 0
Max Sulfur Content (Max Ash Content (Max Ash Content (MTV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM PM PM SOx Antimony Arsenic Beryllium Chromium Chromium Cobalt Lead Manganese Mercury Nickel	Source of Emission	Emission Factor Ib/MMCF Ib/10°3 gal Ib/MMCF 1b/10°3 gal	0.79 0.11 147 500 EMISSION C. Emission Natural Gas 550 40 1.7 3.0 3.0 0.60	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours ** LCULATIONS In Factors #6 Fuel Oil 67 5 0.76 10.48 71 128.53	nt (%) = (%)	100% Natural Gas (ton/yr) 482 35 1.5 2.6 2.6 0.53	0: 0
Max Sulfur Content (% HTV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM	Source of Emission	Emission Factor Ib/MMCF Ib/10°3 gal Ib/MMCF 1b/10°3 gal	0.79 0.11 147 500 EMISSION C. Emission Natural Gas 550 40 1.7 3.0 3.0 0.60	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours ** LCULATIONS In Factors #6 Fuel Oil 67 5 0.76 10.48 71 128.53	nt (%) = (%)	100% Natural Gas (ton/yr) 482 35 1.5 2.6 2.6 0.53	0: 0
Max Sulfur Content (Max Ash Content (Max Ash Content (MTV Fuel Oil (MBT Operation Hours = Pollutant NOx CO NMTOC PM PM PM SOx Antimony Arsenic Beryllium Chromium Chromium Cobalt Lead Manganese Mercury Nickel	Source of Emission	Emission Factor Ib/MMCF Ib/10°3 gal Ib/MMCF 1b/10°3 gal	0.79 0.11 147 500 EMISSION C. Emission Natural Gas 550 40 1.7 3.0 3.0 0.60	Max Sulfur Conte Max Ash Content HHV Fuel Oil (M Operation Hours ** LCULATIONS In Factors #6 Fuel Oil 67 5 0.76 10.48 71 128.53	nt (%) = (%)	100% Natural Gas (ton/yr) 482 35 1.5 2.6 2.6 0.53	0: 0

- Section 1.4, Natural Gas Combustion; Table 1.4-2.
 Section 1.4, Natural Gas Combustion; Table 1.4-1.
 Section 1.4, Natural Gas Combustion; Table 1.4-3.
 Section 1.3 Fuel Oil Combustion; Table 1.3-2.
 Section 1.3, Fuel Oil Comb

Unit 2 Public Service Company of Colorado, Zuni Station Criteria and HAP Emissions

		003		Unit Code: B0			Space Heat (%)
	Seasonal Fuel	Usage (%)			nal Operation of U	Hours/year	Space Freak (74)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day 24	Days/Week	8760	0
33	37	28	2				
	BOILER SPECI	ICATIONS			STAC	K DATA	250
ırnace Type:	Wo-Drumb Boiler			Height (ft)			12
lanufacturer:	Babcock & Wilcox		Į	Inside Diameter (ft)	A CENA		
odel & Serial #:	17869			Exhaust Flow Rate (Max	580,000
nit Description:	N/A		!	Normal	210,000	Max	30.96
irst Service or Last Me	od. Date:	1953		Exhaust Velocity (fr			ST
fax Continuous Rating	(MMBTU/hr):		Natural Gas	Calculated or Stack			500
		1075	#6 Fuel Oil	Exhaust Temperatur Exhaust Moisture C		4) (%)	
M	aximum Hourly Fu	el Usage (units/hr)		Normal	10	Max	16
Fuel T		Unit	Rate	Orientation of Relea			Up
Natural		Mcf/hr	1,075	Rainhat or Other Of			None
#6 Fuel	Oil	gal/hr	7,313	Rainnat or Other Or			
						Technology, %	00
Does the boiler/furnace	have control techr	ology (Y/N)	N	Control	NOx	PM	SOx
oes the boller/furnaci	nave control teem	0.08) (1)		None	0	0	0
		Conde		Adsor	bers	Catalytic/Ther	
Miscella		2000-401	nsers NONE		IONE		IONE
2000-400	NONE					Baghouses/I	abric Filters
Cyclones/Settli	ng Chambers	Electrostatic		Wet Collecti	on Systems NONE		NONE
2000-404	NONE	2000-405	NONE		NOINE	2000-401	
			OPERATING	PARAMETERS			
	199	4				Potential	
			139,073	Natural Gas (Mcf)	12		9,417,00
Natural Gas (Mcf) =			0.01	Max Sulfur Conter			0.0
Max Sulfur Content (0.00	Max Ash Content			0.0
Max Ash Content (%)	=		1,000	HHV Gas (BTU/c			1,0
HHV Gas (BTU/cf) =			30	#6 Fuel Oil (gal) =			64,061,2
#6 Fuel Oil (gal) =			0.79	Max Sulfur Conte			0.
Max Sulfur Content (0.1	Max Ash Content			C
Max Ash Content (%			147	HHV Fuel Oil (M			1
HHV Fuel Oil (MBT	∪/gai) ≖		130	Operation Hours			8,7
Operation Hours =							
			EMISSION C	CALCULATIONS			
	Source of	1 11.0			Actual	PTE	
					Actum		PTE
Pollutant	1	Units of	Emissi	ion Factors	Emissions	100% Natural Gas	100 % #6 Fuel Oil
	Emission	Emission		ion Factors #6 Fuel Oil	1	100% Natural Gas (ton/yr)	l
	Emission Factor	Emission Factor	Emissi Natural Gas 550		Emissions	100% Natural Gas	100 % #6 Fuel Oil (ton/yr)
NOx	Emission Factor AP-42(1)	Emission Factor Ib/MMCF	Natural Gas		Emissions (ton/yr)	100% Natural Gas (ton/yr) 2,590	100 % #6 Fuel Oil
NOx	Emission Factor AP-42(1) AP-42(4)	Emission Factor Ib/MMCF Ib/10^3 gal	Natural Gas	#6 Fuel Oil	Emissions (ton/yr)	100% Natural Gas (ton/yr)	100 % #6 Fuel Oil (ton/yr) 2,146
	Emission Factor AP-42(1) AP-42(4) AP-42(1)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF	Natural Gas 550	#6 Fuel Oil	Emissions (ton/yr) 38	100% Natural Gas (ton/yr) 2,590	100 % #6 Fuel Oil (ton/yr)
NOx CO	Emission Factor AP-42(1) AP-42(4) AP-42(1) AP-42(4)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal	Natural Gas 550	#6 Fuel Oil	Emissions (ton/yr) 38	100% Natural Gas (ton/yr) 2,590	100 % #6 Fuel Oil (ton/yr) 2,146
NOx	Emission Factor AP-42(1) AP-42(4) AP-42(1) AP-42(4) AP-42(3)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF	Natural Gas 550 40	#6 Fuel Oil	Emissions (ton/yr) 38 2.8	100% Natural Gas (ton/yr) 2,590 188	100 % #6 Fuel Oil (ton/yr) 2,146
NOx CO NMTOC	Emission Factor AP-42(1) AP-42(4) AP-42(1) AP-42(4) AP-42(3) AP-42(5)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal	Natural Gas 550 40	#6 Fuel Oil 67	Emissions (ton/yr) 38	100% Natural Gas (ton/yr) 2,590	100 % #6 Fuel Oil (ton/yr) 2,146 160 24
NOx CO	Emission Factor AP-42(1) AP-42(4) AP-42(1) AP-42(3) AP-42(3) AP-42(5) AP-42(2)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal	Natural Gas 550 40 1.7	#6 Fuel Oil 67	Emissions (ton/yr) 38 2.8 0.12 0.21	100% Natural Gas (ton/yr) 2,590 188 8.0	100 % #6 Fuel Oil (ton/yr) 2,146
NOx CO NMTOC PM	Emission Factor AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(3) AP-42(5) AP-42(2) AP-42(2)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal	Natural Gas 550 40 1.7	#6 Fuel Oil 67 5	Emissions (ton/yr) 38 2.8	100% Natural Gas (ton/yr) 2,590 188	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336
NOx CO NMTOC	Emission Factor AP-42(1) AP-42(4) AP-42(1) AP-42(4) AP-42(3) AP-42(5) AP-42(2) AP-42(4) AP-42(2)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal Ib/MMCF Ib/10^3 gal	Natural Gas 550 40 1.7 3.0	#6 Fuel Oil 67 5	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15	100% Natural Gas (ton/yr) 2,590 188 8.0 14	100 % #6 Fuel Oil (ton/yr) 2,146 160 24
NOx CO NMTOC PM PM _{te}	Emission Factor AP-42(1) AP-42(4) AP-42(1) AP-42(4) AP-42(3) AP-42(5) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(6)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF	Natural Gas 550 40 1.7 3.0	#6 Fuel Oil 67 5 1 10.48	Emissions (ton/yr) 38 2.8 0.12 0.21	100% Natural Gas (ton/yr) 2,590 188 8.0	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238
NOx CO NMTOC PM	Emission Factor AP-42(1) AP-42(1) AP-42(3) AP-42(3) AP-42(3) AP-42(2) AP-42(4) AP-42(4) AP-42(6) AP-42(6) AP-42(6) AP-42(6) AP-42(6)	Emission Factor Ib/MMCF Ib/10°3 gal Ib/MMCF	Natural Gas 550 40 1.7 3.0	#6 Fuel Oil 67 5 1 10.48	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15	100% Natural Gas (ton/yr) 2,590 188 8.0 14	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336
NOx CO NMTOC PM PM SOx	Emission Factor AP-42(1) AP-42(4) AP-42(1) AP-42(4) AP-42(3) AP-42(5) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(2) AP-42(6)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF	Natural Gas 550 40 1.7 3.0	#6 Fuel Oil 67 5 1 10.48	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15	100% Natural Gas (ton/yr) 2,590 188 8.0 14	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238
NOX CO NMTOC PM PM ₁₀ SOX Antimony	Emission Factor AP-42(1) AP-42(1) AP-42(3) AP-42(3) AP-42(3) AP-42(2) AP-42(4) AP-42(4) AP-42(6) AP-42(6) AP-42(6) AP-42(6) AP-42(6)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF	Natural Gas 550 40 1.7 3.0	#6 Fuel Oil 67 5 1 10.48	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15	100% Natural Gas (ton/yr) 2,590 188 8.0 14	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238
NOX CO NMTOC PM PM ₁₁ SOX Antimony Arsenic	Emission Factor AP-42(1) AP-42(1) AP-42(3) AP-42(3) AP-42(3) AP-42(2) AP-42(4) AP-42(4) AP-42(6) AP-42(6) AP-42(6) AP-42(6) AP-42(6)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF	Natural Gas 550 40 1.7 3.0	#6 Fuel Oil 67 5 1 10.48	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15	100% Natural Gas (ton/yr) 2,590 188 8.0 14	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238
NOx CO NMTOC PM PM FM SOx Antimony Arsenic Beryllium	Emission Factor AP-42(1) AP-42(1) AP-42(3) AP-42(3) AP-42(3) AP-42(2) AP-42(4) AP-42(4) AP-42(6) AP-42(6) AP-42(6) AP-42(6) AP-42(6)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF	Natural Gas 550 40 1.7 3.0	#6 Fuel Oil 67 5 1 10.48	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15	100% Natural Gas (ton/yr) 2,590 188 8.0 14	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238
NOx CO NMTOC PM PM ₁₀ SOx Antimony Arsenic Beryllium Cadmium	Emission Factor AP-42(1) AP-42(1) AP-42(3) AP-42(3) AP-42(3) AP-42(2) AP-42(4) AP-42(4) AP-42(6) AP-42(6) AP-42(6) AP-42(6) AP-42(6)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF	Natural Gas 550 40 1.7 3.0	#6 Fuel Oil 67 5 1 10.48	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15	100% Natural Gas (ton/yr) 2,590 188 8.0 14	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238
NOx CO NMTOC PM PM ₁₁ SOx Antimony Arsenic Beryllium Cadmium Chromium	Emission Factor AP-42(1) AP-42(1) AP-42(3) AP-42(3) AP-42(3) AP-42(2) AP-42(4) AP-42(4) AP-42(6) AP-42(6) AP-42(6) AP-42(6) AP-42(6)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF	Natural Gas 550 40 1.7 3.0	#6 Fuel Oil 67 5 1 10.48	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15 0.044	100% Natural Gas (ton/yr) 2,590 188 8.0 14 14 2.8	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238 3,767
NOx CO NMTOC PM PM ₁₀ SOx Antimony Arsenic Beryllium Cadmium Cobalt	Emission Factor AP-42(1) AP-42(1) AP-42(1) AP-42(1) AP-42(3) AP-42(5) AP-42(5) AP-42(2) AP-42(2) AP-42(2) AP-42(4) AP-42(4)	Emission Factor Ib/MMCF Ib/10°3 gal	Natural Gas 550 40 1.7 3.0 3.0 0.60	#6 Fuel Oil 67 5 1 10.48	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15	100% Natural Gas (ton/yr) 2,590 188 8.0 14	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238
NOx CO NMTOC PM PM ₁₀ SOx Antimony Arsenic Beryllium Cadmium Chromium Ccoball Lead	Emission Factor AP-42(1) AP-42(1) AP-42(3) AP-42(3) AP-42(3) AP-42(2) AP-42(4) AP-42(4) AP-42(6) AP-42(6) AP-42(6) AP-42(6) AP-42(6)	Emission Factor Ib/MMCF Ib/10^3 gal Ib/MMCF	Natural Gas 550 40 1.7 3.0 3.0 0.60	#6 Fuel Oil 67 5 1 10.48 71 128.53	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15 0.044	100% Natural Gas (ton/yr) 2,590 188 8.0 14 14 2.8	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238 3,767
NOx CO NMTCC PM PM SOx Antimony Arsenic Beryllium Cadmium Chomium Cobail Lead Manganese	Emission Factor AP-42(1) AP-42(1) AP-42(1) AP-42(3) AP-42(5) AP-42(5) AP-42(2) AP-42(2) AP-42(1) AP-42(2) AP-42(4)	Emission Factor Ib/MMCF Ib/10°3 gal	Natural Gas 550 40 1.7 3.0 3.0 0.60	#6 Fuel Oil 67 5 1 10.48 71 128.53	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15 0.044	100% Natural Gas (ton/yr) 2,590 188 8.0 14 14 2.8	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238 3,767
NOx CO NMTOC PM PM PM SOx Animony Arsenic Beryllium Cadmium Chomium Cobalt Lead Manganese Mercury	Emission Factor AP-42(1) AP-42(1) AP-42(1) AP-42(3) AP-42(5) AP-42(5) AP-42(2) AP-42(2) AP-42(1) AP-42(2) AP-42(4)	Emission Factor Ib/MMCF Ib/10°3 gal	Natural Gas 550 40 1.7 3.0 3.0 0.60	#6 Fuel Oil 67 5 1 10.48 71 128.53	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15 0.044	100% Natural Gas (ton/yr) 2,590 188 8.0 14 14 2.8	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238 3,767
NOx CO NMTOC PM PM ₁₀ SOx Antimony Arsenic Beryllium Cadmium Chromium Ccobalt Lead Manganese Mercury Nickel	Emission Factor AP-42(1) AP-42(1) AP-42(1) AP-42(3) AP-42(5) AP-42(5) AP-42(2) AP-42(2) AP-42(1) AP-42(2) AP-42(4)	Emission Factor Ib/MMCF Ib/10°3 gal	Natural Gas 550 40 1.7 3.0 3.0 0.60	#6 Fuel Oil 67 5 1 10.48 71 128.53	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15 0.044	100% Natural Gas (ton/yr) 2,590 188 8.0 14 14 2.8	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238 3,767
NOx CO NMTOC PM PM SOx Antimony Arsenic Beryllium Cadmium Chornium Cobalt Lead Manganese Mercury Nickel Selenium	Emission Factor AP-42(1) AP-42(1) AP-42(1) AP-42(3) AP-42(5) AP-42(5) AP-42(2) AP-42(2) AP-42(1) AP-42(2) AP-42(4)	Emission Factor Ib/MMCF Ib/10°3 gal	Natural Gas 550 40 1.7 3.0 3.0 0.60	#6 Fuel Oil 67 5 1 10.48 71 128.53	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15 0.044	100% Natural Gas (ton/yr) 2,590 188 8.0 14 14 2.8	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238 3,767
NOx CO NMTOC PM PM PM FOX SOX Antimony Arsenic Beryllium Cadmium Chromium Cobatt Lead Manganese Mercury Nickel Selevinum Thalium	Emission Factor AP-42(1) AP-42(1) AP-42(1) AP-42(3) AP-42(5) AP-42(5) AP-42(2) AP-42(2) AP-42(1) AP-42(2) AP-42(4)	Emission Factor Ib/MMCF Ib/10°3 gal	Natural Gas 550 40 1.7 3.0 3.0 0.60	#6 Fuel Oil 67 5 1 10.48 71 128.53	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15 0.044	100% Natural Gas (ton/yr) 2,590 188 8.0 14 14 2.8	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238 3,767
NOx CO NMTCC PM PM ₁₀ SOx Antimony Arsenic Beryllium Cadmium Chromium Cobalt Lead Manganese Mercury Nickel Selenium	Emission Factor AP-42(1) AP-42(1) AP-42(1) AP-42(3) AP-42(5) AP-42(5) AP-42(2) AP-42(2) AP-42(1) AP-42(2) AP-42(4)	Emission Factor Ib/MMCF Ib/10°3 gal	Natural Gas 550 40 1.7 3.0 3.0 0.60	#6 Fuel Oil 67 5 1 10.48 71 128.53	Emissions (ton/yr) 38 2.8 0.12 0.21 0.15 0.044	100% Natural Gas (ton/yr) 2,590 188 8.0 14 14 2.8	100 % #6 Fuel Oil (ton/yr) 2,146 160 24 336 238 3,767

- Section 1.4, Natural Gas Combustion; Table 1.4-2.
 Section 1.4, Natural Gas Combustion; Table 1.4-1.
 Section 1.4, Natural Gas Combustion; Table 1.4-3.
 Section 1.3 Fuel Oil Combustion; Table 1.3-2.
 Section 1.3, Fuel Oil Comb

Robinson Brick

FOR THE RECORD

January 31, 2001

BY: Mike Jensen

Ref: Robinson Brick FID 0311447 97OPDE189

SUBJECT: PM10 PTE Review

On Friday, January 26, 2001, Mike Silverstein, APCD, called and asked for the PTE numbers for Robinson Brick. I gave him the numbers from the TRD. A copy of that page of the TRD is attached to this review for future reference as needed.

Gerry Dilley (303-629-5450 X240) from the RAQC called yesterday with a request for information about how the PTE for the PM10 for Robinson Brick was calculated. I reviewed the file and compiled the following information. The process design rates are taken from the Title V submittal. A copy of the summary page is attached to this review for future reference as needed. Emission factors shown were taken from the Title V permit. Reg 1 sets a particulate matter hourly limit for some sources. This limit would be an upper boundary in that while PM10 may be a fraction of the PM, it can not exceed the PM.

F001/F005 Loader/Storage Piles/Unpaved Roads

This is all fugitive dust and not included in the facility PTE

Material Transfer: $0.1 \times 0.35 = 0.04 \text{ TPY}$ Storage Piles: $24.9 \times 0.35 = 8.72 \text{ TPY}$ **Total: 8.76 TPY**

F002 Primary Crusher

Reg 1 = $17.31(90)^{0.16}$ = 35.56 lb/hr 35.56 lb/hr X 8760 hr/yr X ton/2000 lb = 35.56 X 4.38 = 155.8 TPY

Design Rate: 90 ton/hr X 0.059 lb/ton X 4.38 hr-ton/yr-lb = 23.25 TPY PTE = 23.3 TPY

F003 Grinding/Screening

Reg $1 = 17.31(90)^{0.16} = 35.56 \text{ lb/hr}$ 35.56 lb/hr X 4.38 hr-ton/yr-lb = 155.8 TPY

Design Rate: 90 ton/hr X 0.0265 lb/ton X 4.38 hr-ton/yr-lb = 10.45 TPY

Permit Limit: 4.7 TPY PTE = 4.7 TPY

F004 Conveyor

Reg $1 = 17.31(90)^{0.16} = 35.56 \text{ lb/hr}$

35.56 lb/hr X 4.38 hr-ton/yr-lb = 155.8 TPY

Design Rate: 90 ton/hr X 0.00029 lb/ton X 4.38 hr-ton/yr-lb = 0.11 TPY

PTE = 0.11

TPY

S001 Rotary Dryer

Reg $1 = 17.31(35)^{0.16} = 30.57 \text{ lb/hr}$

30.57 lb/hr X 4.38 hr-ton/yr-lb = 133.9 TPY

Design Rate: 35 ton/hr X 0.16 lb/ton X 4.38 hr-ton/yr-lb = 24.53 TPY

PTE = 24.5

TPY

S002 – S005 Two Tunnel Dryers & two kilns

Reg $1 = 3.59(13.4)^{0.62} = 17.9 \text{ lb/hr}$

17.9 lb/hr X 4.38 hr-ton/yr-lb = 78.59 TPY per line X 2 = 157.18 TPY

From Title V = 199,000 ton/yr X 0.87 lb/ton X ton/ 2000 lb = 86.6 TPY

Permit Limit = 130.8 TPY

PTE = 130.8

PTE = 13.14

TPY

S006 Rotary Calciner Reg 1 = 3.59(10.0)^{0.62} = 14.9 lb/hr

14.9 lb/hr X 4.38 hr-ton/yr-lb = 65.5 TPY

Design Rate: 10 ton/hr X 0.3 lb/ton X 4.38 hr-ton/yr-lb = 13.14 TPY

TPY

PTE SUMMARY

F002	Primary Crusher	23.3 TPY
F003	Grinding/Screening	4.7
F004	Conveyor	0.11
S001	Rotary Dryer	24.5
S002-S005	Two Tunnel Dryers and kilns 130.8	
S006	Rotary Calciner	<u>13.1</u>

TOTAL 196.5 TPY

Rocky Mountain Bottle Company

Trigen-Colorado Energy Corporation

Facility-wide emissions are as follows:

			POTEN	TIAL TO E	MIT, TON	S PER YE	AR	
		PM	PM ₁₀	SO ₂	NOx	VOC	СО	HAPs
B001 - 288 MM	Btu/hr				///		///	
N	G	9.4	1	0.74	346.5	10.8	103.9	
#2	2 FO	18,02	9.01	410.2	216.3	1.8	45.1	
B002 - 288 MM	Btu/hr							
N	G	9.4	54	0.74	346.3	10.8	103.9	
#2	2 FO	18.02	9.01	410)2	216.3	1.8	45.1	
B003 - 225 MM Coal	Btu/hr,	2852.8	570.6	1612.60	380.4	2.16	216.1	
B004 - 360 MM	Btu/hr,						///	
Pe	ermit	158.0	158.0	1892.0	1004.0	19.21	88.30	
C	oal*	5268.55	1218.92	2650.05	639.36	4.86	39.55	
N	G	16.45	16.45	1.30	367.92	18.83	51.94	
#2	2 FO	28.03	14.02	638.15	336.38	2.80	70.08	
B005 - 650 MM	Btu/hr,							
Pe	ermit	285.0	285(0	341160	1993(0)	9.50	103.1	
C	oal*	11084.15	2556.71	5557.73	1346.16	10.02	82.62	
N	G	21.21	21.21	1.67	474.50	24.28	66.99	
#2	2 FO	40.67	20.34	925.89	488.06	4.07	101.68	
M001/C004 - Ra dumper to hoppe		51.6	.51,6					
M001/C005 - Do to transfer conve								
M001/C006 - Conveyor to Unsilos	it 4							
M001/C008 - Conveyor to Unsilos	it 5	22.7	22.7					

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AIR POLLUTION CONTROL DIVISION STATIONARY SOURCES PROGRAM

	TDI	CEN COL		it 1	DBODAT	PLON	
	Criteria	and HAP		NERGY CO from Natura	ıl Gas or		
Stack Identificatio	n Code :	S001		Unit Code:	B001		
	Seasonal Fuel	Usage (%)		Norma	l Operation of	Unit	Space Heat (%)
Dec-Feb 25	Mar-May 25	Jun-Aug 25	Sep-Nov 25	Hours/Day 24	Days/Week 7		0
	BOILER SPECIF	ICATIONS			STACK	DATA	
Furnace Type:	Wall Fired			Height (ft)			130
Manufacturer:	Combustion Eng	incering		Inside Diameter			8
Model & Serial #:			I D - 11	Exhaust Flow R. Normal	ate (ACFM) 110,000	34	120,637
Unit Description: First Service or La		stion waii-rired	Boller	Exhaust Velocit		Max	40.00
Maximum Continu			Natural Gas or	Calculated or St			ST
	(MMBTU/HR)		#2 Fuel Oil	Exhaust Temper		•	380
	mum Hourly Fuel			Exhaust Moistur			
Fuel		Unit	Rate	Normal	. 10	Max	16
Natura #2 Fu		Mcf/hr gal/hr	271	Orientation of R Rainhat or Other			Up None
#2 Pu	ei Oii	gai/nr	2,075	Rainnai or Other			
						Technology,	
Does the boiler/fur	nace have control	technology (Y/	N	Control Devic None	NOx 0	PM 0	SOx 0
Miscell 2000-400	aneous NONE	Conde 2000-401	nsers NONE	Adsor 2000-402	bers NONE	2000-403	mal Oxidation NONE
Cyclones/Settl 2000-404	ing Chambers NONE	Electrostatic 2000-405	Precipitators NONE	Wet Collection 2000-406	on Systems NONE	Baghouses/F 2000-407	abric Filters NONE
			OPERATING	PARAMETERS			
		1994 Revised			F	otential	
						•	
Btu corrected Natu Avg. Sulfur Conte			210,746 0.01	Btu corrected No Avg. Sulfur Cor		:t) =	2,373,960
Avg. Ash Content			0.00	Avg. Ash Conte			0.00
HHV Gas (Btu/SC			1,064	HHV Gas (Btu/S			1,064
#2 Fuel Oil (gal) =			0	#2 Fuel Oil (gal			18,177,000
Btu corrected Fuel			0	Btu corrected Fu			18,021,197
Avg. Sulfur Conte Avg. Ash Content			0.29	Avg. Sulfur Cor Avg. Ash Conte			0.29
HHV Oil (Btu/gal)			138,800	HHV Oil (Btu/g			0.01 138,800
Operation Hours =			8,544	Operation Hours			8,760
	FMISS	ON CALCULA	TIONS			Unit	1
	Source of	Units of			Actual	PTE	PTE
				_		100% Natural	100 % #2
Pollutant	Emission	Emission	Emissi	on Factors	Emissions	Gas	Fuel Oil
	Factor/CEM	Factor	Natural Gas	#2 Fuel Oil	(ton/yr)	(ton/yr)	(ton/yr)
NOx	AP-42[8]	lb/MMCF	280	24	29.50 0.0	332	214
	AP-42[10]	lb/10^3 gal	Total Ca	24 culated Emissions:	29.50		216
co	AP-42[8]	ib/MMCF	84		8.85	100	
	AP-42[10]	lb/10^3 gal		5	0,00		45
				culated Emissions:	8.851		
TNMOC	AP-42[9]	lb/MMCF	8.7	44.0.00	0.9167	10.33	
	AP-42[11]	lb/10^3 gal	Total C		0.000 0.917		2
PM	AP-42[9]	lb/MMCF	7.6	Curattu Ettissions.	0.8008	9.02	
	AP-42[10]	ib/10^3 gal		2	0,0000		18
	` '	, i		culated Emissions:	0.8008		
PM10	AP-42[9]	lb/MMCF	7.6		0.8008	9.02	
	AP-42[12]	lb/10^3 gal	Tatal C	l culated Emissions:	0.0000 0.8008		. 9
SOx	AP-42[9]	lb/MMCF	0.60	curateu Emissions.	0.063	0.71	
JUA	AP-42[10]	1b/10^3 gal		45.53	0.000		410
		J		culated Emissions:	0.063		

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	AIR PULLUTION CONTROL DIVISION
Unit 2 EN-COLORADO ENERGY CORPORAT	CTATIONARY COMPOSE PROGRAM

	TDIC	EEN-COL		it 2 NERGY CO	DDODAT	cion S	TATIONARY SO
	Criteria	and HAP		from Natura	l Gas or l		
Stack Identificatio	n Code :	S002		Unit Code:	B002		
	Seasonal Fuel	Usage (%)		Norma	Operation of		Space Heat (%)
Dec-Feb	Mar-May 25	Jun-Aug 25	Sep-Nov 25	Hours/Day 24	Days/Week 7	Hours/year 8760	0
25			25	6 C 2 C 3 C 4 FT 3 C			
	BOILER SPECIF	ICATIONS			STACK	DATA	
Furnace Type:	Wall Fired			Height (ft)	(0)		130
Manufacturer: Model & Serial #:	Combustion Eng			Inside Diameter Exhaust Flow R			8
Unit Description:			Doiler	Normal	110,000	Max	120,637
First Service or La		1967	Donei	Exhaust Velocit			40.00
Maximum Continu		288	Natural Gas or	Calculated or St			ST
	(MMBTU/HR)		#2 Fuel Oil	Exhaust Temper			380
	mum Hourly Fuel)	Exhaust Moistur			
Fuel		Unit	Rate	Normal	10	Max	16
Natura #2 Fu		Mcf/hr	271	Orientation of R			Up None
#2 Fu	ei Oii	gal/hr	2,075	Rainhat or Othe	r Obstruction		None
					Control	Technology	, %
Does the boiler/fur	rnace have control	technology (Y/	N	Control Devic	NOx	PM	SOx
				None	0	0	0 .
Miscell 2000-400	aneous NONE	Conde 2000-401	nsers NONE	Adsor 2000-402	bers NONE	Catalytic/The 2000-403	rmal Oxidation NONE
Cyclones/Settl 2000-404	ing Chambers NONE	Electrostatic	Precipitators NONE	Wet Collecti 2000-406	on Systems NONE	Baghouses/ 2000-407	Fabric Filters NONE
			OPERATING	PARAMETERS			
		1994 Revised			P	otential	
Btu corrected Natu Avg. Sulfur Conte			200,792	Btu corrected N Avg. Sulfur Cor		ci) =	2,372,960 0.01
Avg. Ash Content			0.00	Avg. Sultur Con			0.00
HHV Gas (Btu/SC			1,064	HHV Gas (Btu/			1.064
#2 Fuel Oil (gal) =			291,439	#2 Fuel Oil (gal) =		18,177,000
Btu corrected Fuel			288,941	Btu corrected Fr		F	18,021,197
Avg. Sulfur Conte			0.29	Avg. Sulfur Cor			0.29
Avg. Ash Content			0.01 138,800	Avg. Ash Conte HHV Oil (Btu/g			0.01 138,800
HHV Oil (Btu/gal) Operation Hours =			7,920	Operation Hour			8.760
Operation rious -			7,520	Operation flour.	, -		0,700
	1	EMISSION CAL	LCULATIONS	•			Unit 2
	Source of	Units of			Actual	PTE	PTE
Pollutant	Emission	Emission	Emissi	on Factors	Emissions	100%	100 % #2
	Factor/CEM	Factor	Natural Gas	#2 Fuel Oil	(ton/yr)	Natural Gas (ton/yr)	Fuel Oil (ton/yr)
NOx	AP-42[8]	lb/MMCF	Natural Gas	#2 Fuel Oil	28.1	332	(ioivyi)
1104	AP-42[10]	lb/10^3 gal	200	24	3.5	""	216
	(,		Total Ca	lculated Emissions:	31.58		
CO	AP-42[8]	lb/MMCF	84		8.43	100	
	AP-42[10]	lb/10^3 gal	i	5	0.72		45
	ļ			culated Emissions:	9.156		
TNMOC	AP-42[9]	Ib/MMCF	8.7	0.20	0.8734	10	
	AP-42[11]	lb/10^3 gal	Total Ca	0.20 lculated Emissions:	0.029 0.902		2
PM	AP-42[9]	Ib/MMCF	7.6	Curateu Emissions:	0.7630	9	
	AP-42[10]	lb/10^3 gal	l	2	0.2889		18
	1	"""	Total Ca	lculated Emissions:	1.052		· ·
PM10	AP-42[9]	lb/MMCF	7.6		0.7630	9	
	AP-42[12]	lb/10^3 gal	l	1	0.1445		9
	18.44			culated Emissions:	0.907	ļ	ļ
SOx	AP-42[9]	lb/MMCF lb/10^3 gal	0.60	45.53	0.060 6.578	1	410
	AP-42[10]	10/10-3 gal	Total Ca	45.53 lculated Emissions:	6.638		410
	I			iculated Emissions:	0.038		

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AIR POLLUTION CONTROL DIVISION STATIONARY SOURCES PROGRAM

		mprons:	Uni		conre	D. ATLC:			
		TRIGEN-0	COLORADO EN Criteria and H			RATION	'		
Stack Identification	1 Code :	S003		1	Unit Code:	B003			
	Seasona	Fuel Usage (%)			Nori	nal Operation	of Unit S	pace Heat (9	6)
Dec-Feb 25	Mar-May 25	Jun-Aug 25	Sep-Nov 25		Hours/Day 24	Days/Week 7	Hours/year 8,760	0	·
	BOILER SPECIF	ICATIONS				STACK	DATA		
Furnace Type: Manufacturer: Model & Serial #: Unit Description: First Service or La: Maximum Continu	Combustion E CE-VU40, 170 External Comb st Mod. Date:	051 oustion Coal-fired 1981 225.0			Normal Exhaust Ve Calculated	neter (ft) ow Rate (acfm 100,000 locity (fps) at or Stack Test (mperature (F)	Max MCR	130 8 105,558 35.00 ST 360	
Maxie	mum Hourly Fue	Usage (units/hr)		1	Exhaust Mc	isture Content	(if modified)	(%)	
Fuel T SubBitumin	ype	Unit ton/hr	Rate 9.90		Normal Orientation	NA	Max	NA Up	
		ŀ		1	Rainhat or 6	Other Obstruct	ion	None	
Does the boiler/furn	nace have contro	technology (Y/	Y	• (Contr Control Devi Baghouse	rol Technology NOx 0	and Efficient PM 99,9	sy (%) SOx	
Miscella 2000-400	neous NONE	Conden 2000-401	sors NONE		Ads 2000-402		Catalytic/Then 2000-403	mal Oxidatio NONE	n
Cyclones/Settli 2000-404	ng Chambers NONE	Electrostatic P 2000-405	NONE		2000-406	NONE	Baghouses/F 2000-407	abric Filters C001	
		1994 Rev	OPERATING Pa	ARAMETEI	RS	Por	ential		
Sub Bit Coal Fired Avg. Sulfur Conter Avg. Ash Content (HHV Coal (Btu/lb) Operation Hours =	it (%) = (%) =		47,876 0.45 7.00 11,400 7,752		Avg. Sulfur	al Fired (tons) Content (%) = ontent (%) = (Btu/lb) =		86,724 1 7 11,400 8,760	
	** ******	EMISSIO	N CALCULATIONS	<u> </u>				Unit 3	
Pollutant	Source of Emission Factor	Units of Emission Factor	Emission			Actual Emissions (tpy)	PTE 100% Coal (tpy)		
NOx	AP-42[1]	lb/ton	8.8			211	382		
со	AP-42[1]	łb/ton	5.00			120	217		
NMTOC	AP-42[1]	lb/ton	0.05			1	2		
РМ	AP-42[1]	lb/ton	66.00			2	121		
PM10	AP-422]	lb/ton	13.20			0	111		
SOx	AP-42[1]	lb/ton	15.8			377	1,774		

TRIGEN-COLORADO ENERGY CORPORATION Criteria and HAP Emissions from Coal, Alcohol, and Waste Oil S004 Stack Identification Code Normal Operation of Unit Space Heat (%) Hours/Day Days/Week Hours/year 24 7, 8,760 Seasonal Fuel Usage (%) -May Jun-Aug 5 25 Mar-May Sep-Nov Dec-Feb 25 25 25 BOILER SPECIFICATIONS STACK DATA Height (ft) Furnace Type: Tangential Firing Manufacturer: Combustion Engineering Model & Serial CE-VU40, 21321 Inside Diameter (ft) 8 Inside Diameter (it) Exhaust Flow Rate (acfm) Normal 150,000 M Exhaust Velocity (fps) at MCR Calculated or Stack Test (C/ST) Exhaust Temperature (F) Model & Serial LE-V-040, 21321 Unit Descriptio External Combustion Tangential Fired Boiler First Service or Last Mod. Date 1976 Maximum Continuous Rating: 371.0 Coal, Natu (MMBTU/HR) & Fue Max 174,924 58.00 ST 380 Coal, Natural Gas, & Fuel Oil Maximum Hourly Fue Fuel Type ibBituminous Coal Exhaust Moisture Content (if modified) (%) Normal 12 Max Orientation of Release sage (unit Unit ton/hr Rate 17.14 Waste Oil gal/hr 11 32.0 Rainhat or Other Obstruction Alcohol gal/hr None Control Technology and Efficiency (%) Control Devi NOx PM SOx Baghouse 0 99.9 0 Y Miscellaneous 0 NONE Catalytic/Thermal Oxidation 2000-403 NONE Adsorbers 2000-402 NONE 2000-400 2000-401 NONE Cyclones/Settling Chambers 2000-404 NONE Electrostatic Precipitators 2000-405 NONE Wet Collection Systems 2000-406 NONE Baghouses/Fabric Filters 2000-407 C002 OPERATING PARAMETERS 1994 Revised Sub Bit Coal Fired (tons) = Sub Bit Coal Fired (tons) = 124,107 150,171 Sub Bit Coal Fired (tons) = Avg. Sulfur Content (%) = Avg. Ash Content (%) = HHV Coal (Btu/lb) = Alcohol (gals) = Avg. Alcohol Sulfur Content (%) = Avg. Alcohol Ash Content (%) = HHV Alcohol (Btu/lon) = Water Oil Eight (each) = 0.45 7.00 11,400 283,445 0.34 Avg. Sulfur Content (%) = Avg. Ash Content (%) = HHV Coal (Btu/lb) = 11,400 283,445 0.34 Alcohol (gals) = Avg. Alcohol Sulfur Content (%) = Avg. Alcohol Ash Content (%) = HHV Alcohol (Btu/ton) = 0.1 2.00E+06 2.00E+06 HHV Alcohol (Btu/ton) = Waste Oil Fired (gals) = Avg. Sulfur Content (%) = Avg. Ash Content (%) = HHV Oil (Btu/gal) = Operation Hours = HHV Alcohol (Btu/ton) = Waste Oil Fired (gals) = Avg. Sulfur Content (%) = Avg. Ash Content (%) = HHV Oil (Btu/gal) = Operation Hours = 15,703 0.5 0.65 149,000 8,208 100,000 0.5 0.65 149,000 8,760 EMISSION CALCULATIONS Unit 4 Source of Units of PTE Coal and Pollutant Emission Emission Emission Factors Emissions 100% Coa Alcohol, Alcohol Waste Oil Factor/CEM Factor Coal Alcohol (tpy) (tpy) (tpy) (tpy) Waste Oil NOx AP-42[1] lb/ton 8.4 521 1.104 AP-42[9] lb/10^3 ga 21 3 1,104 0 AP-42(3) 1b/10^3 gal 19.0 1,104 Total Calculated this shee 524 CEM(5) AP-42[1] AP-42 [9] AP-42(3) NA | NA **644.01** 31.0 NA NA CO 88 00 3.6 1 0.04 88,00 88,00 Total Calculated this shee NMTOC AP-42[1] 5.30 0.4 0.1 AP-42[9] AP-42(3) lb/10^3 gal lb/10^3 gal 1.00 5.30 3.8 AP-42[1] lb/ton 4.3 0.0 0.0 158.00 0.600 lb/10^3 gal lb/10^3 gal AP-42[9] AP-42[8] 158.00 l Calcula d this she AP-42[4] AP-42[9] AP-42[8] lb/ton lb/10^3 gal lb/10^3 gal 158.00 158.00 Total Calcula ed this she 977 AP-42[1] 1,892.00 SOx 15.75 AP-42(2) AP-42(3) lb/10^3 ga 0.03 0 1,892.00 lb/10^3 gal 73.50 1,892.00 Total Calculated this shee

CEM(5)

NA

NA

Unit 4



FEB 2 2 2000

Unit 5 TRIGEN-COLORADO ENERGY CORPORATION AIR POLLUTION CONTROL DIVISION Criteria and HAP Emissions from Coal, Alcohol, and Waste STATIONARY SOUTCES PROGRAM

	tion Code :	S005		<u> </u>	Unit Code:	B005			
		el Usage (%)				al Operation of		pace Heat (%	6)
Dec-Feb 25	Mar-May 25	Jun-Aug 25	Sep-Nov 25	559097499	Hours/Day 24	Days/Week 7	Hours/year 8,760	- 0	
			4J 800	100000000000000000000000000000000000000	24.00			0	
Furnace Type	BOILER SPEC Tangential Fir			-	Height (ft)	STACK	DATA	200	
Manufacturer:	Combustion E				Inside Diame	ter (ft)		13	
Model & Seria	CE-VU40, 275				Exhaust Flow				
	n External Comb		tial Fired Boiler	ŀ		290,000	Max	302,630	
	Last Mod. Date			i		city (fps) at N		38.00	
Maximum Con	tinuous Rating:	652.5	Coal, Natural Gas			Stack Test (C	C/ST)	ST	
	(MMBTU/HR)		& Fuel Oil		Exhaust Tem	perature (F)		380	
Max	imum Hourly Fr	el Usage (unit	s/hr)	1		sture Content	(if modified)		
Fue	Туре	Unit	Rate]	Normal	12	Max	13	
	inous Coal	ton/hr	36.11	l	Orientation o	f Release		Up	
	te Oil ohol	gal/hr gal/hr	23 129.4		Rainbat or O	ther Obstructi	on	None	
7111	AIIKII	1 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8	127.1						
Down the builty	furnace have co	ntant sankarata	Υ		Contro Control Devic	l Technology NOx	and Efficience	cy (%) SOx	
Does the boller	riurnace nave co	ntroi tecnnoio	,	l '	Baghouse	0	99 9	0 0	
				L					
Misce 2000-400	NONE	2000-401	NONE		Adso 2000-402	orbers (NONE	atalytic/Thei 2000-403		on
Cyclones/Set	ling Chambers		: Precipitators			tion Systems	Baghouses/I		
2000-404	NONE	2000-405	NONI:		2000-406	NONE	2000-407	C003	
		MARKER !		NG PARA	METERS		771		
		1994 Revise	ru	 		Pot	ential		
Sub Bit Coal Fi	red (tons) ~		234,930		Sub Bit Coal	Fired (tons) -		316,333	
Avg. Sulfur Co	ntent (%) ~		0.45	1	Avg Sulfur C	ontent (%) ~		1	
Avg. Ash Cont			7.00		Avg. Ash Co.			7	
HHV Coal (Bu			11,400		HHV Coal (E			11,400	
Alcohol (gals)			1,133,782		Alcohol (gals			1,133,782	
	ulfur Content (% sh Content (%)		0.34 0.1			Sulfur Conte Ash Content		0.34	
HHV Alcohol (Isn Content (%)	-	2,000,000		HHV Alcoho		(70) "	2,000,000	
Waste Oil Fired			31,407		Waste Oil Fir			200,000	
Avg. Sulfur Co			0.5	l	Avg. Sulfur C			0.5	
Avg. Ash Conto	nt (%) =		0.65		Avg. Ash Co	ntent (%) =		0.65	
HHV Oil (Btu/)	gal) =		149,000		Avg. Ash Co HHV Oil (Bt	ntent (%) = u/gal) =		0.65 149,000	
Avg. Ash Conto HHV Oil (Btu/) Operation Hour	gal) =				Avg. Ash Co	ntent (%) = u/gal) =		0.65	
HHV Oil (Btu/)	gal) =	E1 410010	149,000 8,760		Avg. Ash Co HHV Oil (Bt	ntent (%) = u/gal) =		0.65 149,000 8,760	<u>-</u>
HHV Oil (Btu/)	gal) = 5 =		149,000	NS.	Avg. Ash Co HHV Oil (Bt	ntent (%) = u/gal) = ours =		0.65 149,000 8,760 Unit 5	
HHV Oil (Btu/)	gal) =	EMISSIO Units of	149,000 8,760	NS	Avg. Ash Co HHV Oil (Bt	ntent (%) = u/gal) =	PTE	0.65 149,000 8,760	PTE
HHV Oil (Btu/) Operation Hour	gal) = s = Source of	Units of	149,000 8,760 N CALCULATIO		Avg. Ash Coi HHV Oil (Bu Operation Ho	ntent (%) = u/gal) = purs =		0.65 149,000 8,760 Unit 5	Coal
HHV Oil (Btu/)	gal) = 5 =		149,000 8,760 N CALCULATIO	NS sion Factor	Avg. Ash Coi HHV Oil (Bu Operation Ho	ntent (%) = u/gal) = ours =	PTE	0.65 149,000 8,760 Unit 5	Coal
HHV Oil (Btu/) Operation Hour	sal) = s = Source of Emission	Units of Emission	149,000 8,760 N CALCULATIO1 Emis	sion Factor	Avg. Ash Co HHV Oil (Bt Operation Ho	ntent (%) = u/gal) = urs = Actual Emissions	100% Coal	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol	Coal Alcoh Waste
HHV Oil (Btu/) Operation House Pollutant	sal) = s = Source of Emission Factor/CEM	Units of Emission Factor	149,000 8,760 N CALCULATION Emis		Avg. Ash Coi HHV Oil (Bu Operation Ho	ntent (%) = u/gal) = u/gal) = urs = Actual Emissions (tpy)	100% Coal	0.65 149,000 8,760 Unit 5 PTE Coal and	Coal Alcoh Waste
HHV Oil (Btu/) Operation House Pollutant	sal) = 5 = Source of Emission Factor/CEM AP-42[1]	Units of Emission Factor lb/ton	149,000 8,760 N CALCULATIO1 Emis	sion Factor	Avg. Ash Co HHV Oil (Bt Operation Ho	Actual Emissions (tpy) 987	100% Coal	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy)	Coal Alcoh Waste
HHV Oil (Btu/) Operation Hour	Source of Emission Factor/CEM AP-42[1] AP-42[9]	Units of Emission Factor Ib/ton Ib/10^3 gal	149,000 8,760 N CALCULATION Emis	sion Factor	Avg. Ash Coi HHV Oil (Bu Operation Ho	Actual Emissions (tpy) 987 11.90	100% Coal	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol	Coal Alcoh Waste (tpy)
HHV Oil (Btu/) Operation House Pollutant	sal) = 5 = Source of Emission Factor/CEM AP-42[1]	Units of Emission Factor lb/ton	149,000 8,760 N CALCULATION Emis Coal 8.4	Alcohol 21	Avg. Ash Cor HHV Oil (Bu Operation Ho s Waste Oil	Actual Emissions (tpy) 987 11.90 0.30	100% Coal	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy)	Coal Alcoh Waste (tpy)
HHV Oil (Btu/) Operation House Pollutant	Source of Emission Factor/CEM AP-42[1] AP-42[9]	Units of Emission Factor Ib/ton Ib/10^3 gal	149,000 8,760 N CALCULATION Emis Coal 8.4	Alcohol 21	Avg. Ash Coi HHV Oil (Bu Operation Ho	Actual Emissions (tpy) 987 11.90 0.30 999	100% Coal	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy)	Coal Alcoh Waste (tpy)
HHV Oil (Btu/ ₁) Operation Hour Pollutant	Source of Emission Factor/CEM AP-42[1] AP-42[9] AP-42(3) CEM(5)	Units of Emission Factor ib/ton lb/10^3 gal lb/10^3 gal	149,000 8,760 N CALCULATION Emis Coal 8.4	Alcohol 21	Avg. Ash Cor HHV Oil (Bu Operation Ho s Waste Oil	Actual Emissions (tpy) 987 11.90 0.30 999 707.08	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy)	Coal Alcoh Waste (tpy)
HHV Oil (Btu/) Operation House Pollutant	Source of Emission Factor/CEM AP-42[1] AP-42[9] AP-42(3) CEM(5) AP-42[1]	Units of Emission Factor ib/ton lb/10^3 gal lb/10^3 gal NA lb/ton	149,000 8,760 N CALCULATION Emis Coal 8.4	Alcohol 21 tal Calcula	Avg. Ash Cor HHV Oil (Btr Operation Ho s Waste Oil	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73	100% Coal	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA	Coal Alcoh Waste (tpy)
HHV Oil (Btu/ ₁) Operation Hour Pollutant	Source of Emission Factor/CEM AP-42[1] AP-42[3] CEM(5) AP-42[1]	Units of Emission Factor Ib/ton Ib/10/3 gal Ib/10/3 gal NA Ib/ton Ib/10/3 gal	149,000 8,760 N CALCULATION Emis Coal 8.4	Alcohol 21 tal Calcula	Avg. Ash Co. HHV Oil (Bh Operation Ho s Waste Oil 19.0 ted this sheet: NA	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993	Coal Alcoh Waste (tpy)
HHV Oil (Btu/ ₁) Operation Hour Pollutant	Source of Emission Factor/CEM AP-42[1] AP-42[9] AP-42(3) CEM(5) AP-42[1]	Units of Emission Factor ib/ton lb/10^3 gal lb/10^3 gal NA lb/ton	149,000 8,760 N CALCULATION Emis Coal 8,4 To NA 0,50	Alcohol 21 tal Calcula NA 3.6	Avg. Ash Co. HHV Oil (Bti Operation Ho Waste Oil 19 0 ted this sheet: NA 5.0	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA	Coal Alcohe Waste (tpy)
HHV Oil (Btu/) Operation Hous Pollutant NOx	Source of Emission Factor/CEM AP-42[1] AP-42[3] CEM(5) AP-42[1] AP-42[9] AP-42[3]	Units of Emission Factor Ib/ton Ib/10^3 gal Ib/10^3 gal NA Ib/ton Ib/10^3 gal	149,000 8,760 N CALCULATION Emis Coal 8.4 To NA 0.50	Alcohol 21 tal Calcula NA 3.6	Avg. Ash Co. HHV Oil (Bh Operation Ho s Waste Oil 19.0 ted this sheet: NA	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08 61	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA	Coal Alcohe Waste (tpy)
HHV Oil (Btu/ ₁) Operation Hour Pollutant	Source of Emission Factor/CEM AP-42[1] AP-42[3] CEM(5) AP-42[1] AP-42[3] AP-42[4] AP-42[4]	Units of Emission Factor Ib/ton Ib/10/3 gal Ib/10/3 gal NA Ib/ton Ib/10/3 gal Ib/10/3 gal	149,000 8,760 N CALCULATION Emis Coal 8,4 To NA 0,50	Alcohol 21 tal Calcula NA 3.6	Avg. Ash Co. HHV Oil (Bti Operation Ho Waste Oil 19 0 ted this sheet: NA 5.0	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10	Coal Alcohe Waste (tpy)
HHV Oil (Btu/) Operation Hous Pollutant NOx	Source of Emission Factor/CEM AP-42[1] AP-42[3] CEM(5) AP-42[1] AP-42[9] AP-42[3]	Units of Emission Factor Ib/ton Ib/10^3 gal Ib/10^3 gal NA Ib/ton Ib/10^3 gal	149,000 8,760 N CALCULATION Emis Coal 8.4 To NA 0.50	Alcohol 21 tal Calcula NA 3.6	Avg. Ash Co. HHV Oil (Bti Operation Ho Waste Oil 19 0 ted this sheet: NA 5.0	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08 61 7.05	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA	Coal Alcoh Waste (tpy) 1,990 NA
HHV Oil (Btu/) Operation Hous Pollutant NOx	Jal) = 5 s = Source of Emission Factor/CEM AP-42[1] AP-42[9] AP-42[1] AP-42[9] AP-42(3) AP-42[1] AP-42[1] AP-42[1] AP-42[1]	Units of Emission Factor Ib/ton Ib/10^3 gal Ib/10^3 gal NA Ib/ton Ib/10^3 gal Ib/10^3 gal	149,000 8,760 N CALCULATION Emis Coal 8.4 To NA 0.50	Alcohol 21 tal Calcula NA 3.6 tal Calcula	Avg. Ash Co HHV Oil (Bn Operation He s Waste Oil 19.0 ted this sheet: NA 5.0 ted this sheet:	Actual Emissions (tpy) 987 11.90 999 707.08 58.73 2.04 0.08 61 7.05	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10	Coal Alcohol Waste (tpy) 1,992 NA
HHV Oil (Btu/) Operation Hous Pollutant NOx	Source of Emission Factor/CEM AP-42[1] AP-42[3] CEM(5) AP-42[1] AP-42[3] AP-42[4] AP-42[4] AP-42[1] AP-42[1] AP-42[1] AP-42[1]	Units of Emission Factor ib/ton ib/ton2 gal lb/10°3 gal NA lb/ton lb/10°3 gal lb/10°3 gal lb/ton2 lb/10°3 gal	149,000 8,760 N CALCULATION Emis Coal 8.4 To NA 0.50	Alcohol 21 tal Calcula NA 3.6 tal Calcula 0.4	Avg. Ash Co-HHV Oil (Bt Operation He Operation He Operation He Operation He Naste Oil 19.0 (ed this sheet: NA S.0 (ed this sheet: 1.00	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08 61 7.05 0.22 7.3 8.22	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10	Coal Alcohol Waste (tpy) 1,992 NA
HHV Oil (Blu/, Operation House Pollutant NOx	Jal) = 5 = Source of Emission Factor/CEM AP-42[1] AP-42[9] AP-42[1] AP-42[9] AP-42[0] AP-42[0	Units of Emission Factor Ib/ton Ib/10°3 gal Ib/10°3 gal NA Ib/ton Ib/10°3 gal Ib/10°3 gal Ib/10°3 gal	149,000 8,760 N CALCULATION Emis Coal 8,4 To NA 0.50 To 0.06	Alcohol 21 tal Calcula NA 3.6 tal Calcula	Avg. Ash Co-HIVO Oil (Brit) Waste Oil 19.0 ted this sheet: NA 5.0 ted this sheet:	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 0.02 0.30 0.30 0.30 0.30 0.30 0.30 0.3	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10	Coal Alcohe Waste (tpy) 1,992 NA 103.1
HHV Oil (Blu/, Operation House Pollutant NOx	Source of Emission Factor/CEM AP-42[1] AP-42[3] CEM(5) AP-42[1] AP-42[3] AP-42[4] AP-42[4] AP-42[1] AP-42[1] AP-42[1] AP-42[1]	Units of Emission Factor ib/ton ib/ton2 gal lb/10°3 gal NA lb/ton lb/10°3 gal lb/10°3 gal lb/ton2 lb/10°3 gal	149,000 8,760 N CALCULATION Emis Coal 8.4 To NA 0.50 To 0.06	Alcohol 21 tal Calcula NA 3.6 tal Calcula 0.4 tal Calcula	Avg. Ash Co-HHV Oil (Br. Operation Ho Waste Oil 19.0 ted this sheet: NA 5.0 ted this sheet: 1.00 ted this sheet:	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08 61 7.05 0.23 0.22 7.3 8.22 0.00 0.00	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10	Coal Alcohe Waste (tpy) 1,992 NA 103.1
HHV Oil (Blu/, Operation House Pollutant NOx CO	Source of Emission Factor/CEM AP-42[1] AP-42[9] AP-42[9] AP-42[1] AP-42[9] AP-42[8]	Units of Emission Factor Ib/ton Ib/10°3 gai	149,000 8,760 N CALCULATION Emis Coal 8.4 To NA 0.50 To 70.00	Alcohol 21 tal Calcula NA 3.6 tal Calcula 0.4 tal Calcula	Avg. Ash Co-HIVO Oil (Brit) Waste Oil 19.0 ted this sheet: NA 5.0 ted this sheet:	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08 61 7.05 0.23 0.00 0.00 8.2	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10	Coal Alcohe Waste (tpy) 1,992 NA 103.1
HHV Oil (Blu/, Operation House Pollutant NOx	Jab = 5 s = Source of Emission Factor/CEM AP-42[1] AP-42[9] AP-42[1] AP-42[1] AP-42[1] AP-42[3] AP-42[3] AP-42[3] AP-42[3] AP-42[4] AP-42[4] AP-42[8]	Units of Emission Factor Ib/ton Ib/10/3 gal	149,000 8,760 N CALCULATION Emis Coal 8.4 To NA 0.50 To 0.06	Alcohol 21 tal Calcula NA 3.6 tal Calcula 0.4 tal Calcula	Avg. Ash Co-HHV Oil (Br. Operation Ho Waste Oil 19.0 ted this sheet: NA 5.0 ted this sheet: 1.00 ted this sheet:	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08 61 7.05 0.23 0.02 7.3 8.22 0.00 8.21 1.89	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10 9.50	Coal Alcohe Waste (tpy) 1,992 NA 103.1
HHV Oil (Blu/, Operation House Pollutant NOx CO	Jab = 5 s = Source of Emission Factor/CEM AP-42[1] AP-42[3] AP-42[3] AP-42[9] AP-42[9] AP-42[9] AP-42[9] AP-42[8] AP-42[8] AP-42[8] AP-42[8] AP-42[8] AP-42[8] AP-42[9] AP-42[8] AP-42[9] AP-42[8] AP-42[9] AP-42[8] AP-42[8]	Units of Emission Factor Ib/ton Ib/10°3 gal	149,000 8,760 N CALCULATION Emis Coal 8.4 To NA 0.50 To 70.00	Alcohol 21 tal Calcula NA 3.6 tal Calcula 0.4 tal Calcula	Avg. Ash Co-HHV Oil (Br. Operation Ho Waste Oil 19.0 ted this sheet: NA 5.0 ted this sheet: 1.00 ted this sheet:	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08 61 7.05 0.23 0.00 0.00 8.2	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10	Coal Alcoho Waste (tpy) 1,992 NA 103.1
HHV Oil (Blu/, Operation House Pollutant NOx CO	Jab = 5 s = Source of Emission Factor/CEM AP-42[1] AP-42[9] AP-42[1] AP-42[1] AP-42[1] AP-42[3] AP-42[3] AP-42[3] AP-42[3] AP-42[4] AP-42[4] AP-42[8]	Units of Emission Factor Ib/ton Ib/10/3 gal	149,000 8,760 N CALCULATION Emis Coal 8.4 To NA 0.50 To 0.06 To 70.00 To	Alcohol 21 tal Calcula NA 3.6 tal Calcula 0.4 tal Calcula 0.900 tal Calcula	Avg. Ash Co-HHV Oil (Bt-Operation He) Waste Oil 19.0 ted this sheet: NA 1.00 ted this sheet: 41.60 ted this sheet:	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08 61 7.05 0.20 7.3 8.22 0.00 0.00 8.2	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10 9.50	Coal Alcoho Waste (tpy) 1,992 NA 103.1
HHV Oil (Blu/, Operation House Pollutant NOx CO	Jab = 5 s = Source of Emission Factor/CEM AP-42[1] AP-42[9] AP-42[1] AP-42[9] AP-42[3] AP-42[3] AP-42[3] AP-42[4] AP-42[8]	Units of Emission Factor Ib/ton Ib/10/3 gal	149,000 8,760 N CALCULATION Emis Coal 8,4 To NA 0.50 To 70.00	Alcohol 21 tal Calcula NA 3.6 tal Calcula 0.4 tal Calcula 0.000 tal Calcula	Avg. Ash Co-HIVO Oil (Br. HIVO Oil (Br. HIVO Oil (Br. HIVO Oil Collaboration Ho.) Waste Oil 19.0 ted this sheet: NA 5.0 ted this sheet: 41.60 ted this sheet: 33.2	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08 61 7.05 0.23 0.02 7.3 8.22 0.00 0.00 8.2 1.89 0.00 1.89	100% Coal (tpy) 1,993	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10 9.50 285.00	Coal Alcoho Waste (tpy) 1,992 NA 103.1
HHV Oil (Blu/) Operation Hour Pollutant NOx CO NMTOC PM	Source of Emission Factor/CEM AP-42[1] AP-42[9] AP-42[8]	Units of Emission Factor Ib/lon Ib/lon3 gal	149,000 8,760 N CALCULATION Emis Coal 8.4 To NA 0.50 To 0.06 To 70.00 To	Alcohol 21 tal Calcula NA 3.6 tal Calcula 0.4 tal Calcula 0.900 tal Calcula	Avg. Ash Co-HHV Oit (Br. Operation He Waste Oil 19 0 ted this sheet: NA 1.00 ted this sheet: 41.60 ted this sheet: 33.2 ted this sheet:	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08 61 7.05 0.22 7.3 8.22 0.00 0.00 8.2 1.890 0.00 0.00 1.90 1.850	100% Coal (tpy) 1,993 103.10 9.50 285.00	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10 9.50	Coal Alcohol A
HHV Oil (Blu/) Operation Hour Pollutant NOx CO NMTOC PM	Jab = 5 s = Source of Emission Factor/CEM AP-42[1] AP-42[9] AP-42[1] AP-42[9] AP-42[3] AP-42[3] AP-42[3] AP-42[4] AP-42[8]	Units of Emission Factor Ib/ton Ib/10/3 gal	149,000 8,760 N CALCULATION Emis Coal 8,4 To NA 0.50 To 70.00 To 16.10	Alcohol 21 tal Calcula NA 3.6 tal Calcula 0.4 tal Calcula 0.600 tal Calcula 0.600 tal Calcula	Avg. Ash Co-HIVO Oil (Bru) Waste Oil 19.0 ted this sheet: NA 5.0 ted this sheet: 41.60 ted this sheet: 33.2 ted this sheet:	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08 61 7.05 0.23 0.02 7.3 8.22 0.00 0.00 8.2 1.89 0.00 1.850 0.00 1.850 0.00 0.00 0.00 0.00 0.00 0.00 0.00	100% Coal (tpy) 1,993 103.10 9.50 285.00	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10 9.50 285.00	Coal Alcohola Maste (199) 1,993 NA 103.1 9,500 285.0
HHV Oil (Blu/) Operation Hour Pollutant NOx CO NMTOC PM	Source of Emission Factor/CEM AP-42[1] AP-42[9] AP-42[8]	Units of Emission Factor Ib/lon Ib/lon3 gal	149,000 8,760 N CALCULATION Emis Coal 8,4 To NA 0.50 To 70.00 To 16.10	Alcohol 21 tal Calcula NA 3.6 tal Calcula 0.4 tal Calcula 0.600 tal Calcula 0.600 tal Calcula	Avg. Ash Co-HHV Oit (Br. Operation He Waste Oil 19 0 ted this sheet: NA 1.00 ted this sheet: 41.60 ted this sheet: 33.2 ted this sheet:	Actual Emissions (tpy) 987 11.90 0.30 999 707.08 58.73 2.04 0.08 61 7.05 0.22 7.3 8.22 0.00 0.00 8.2 1.890 0.00 0.00 1.90 1.850	100% Coal (tpy) 1,993 103.10 9.50 285.00	0.65 149,000 8,760 Unit 5 PTE Coal and Alcohol (tpy) 1,993 NA 103.10 9.50 285.00	Coal Alcohe Waste (tpy)

UDS Refinery (previously Colorado Refining Company)

COLORADO REFINING COMPANY

A SUBSIDIARY OF TOTAL PETROLEUM, INC.

5800 BRIGHTON BOULEVARD COMMERCE CITY, COLORADO 80022 TELEPHONE 303 295-4500

CERTIFIED MAIL RETURN RECEIPT REQUESTED HAND DELIVERED

January 17, 2000

Mr. Long Nguyen Air Pollution Control Division Colorado Department of Public Health and Environment 4300 Cherry Creek Drive South Denver, Colorado 80246-1530

RE: Emission Calculation – PTE for NOx, SOx, PM10

Dear Mr. Nguyen:

Enclosed please find Colorado Refining Company's (CRC) potential to emit (PTE) calculations for the sources that you had requested.

If you require more information or have any questions or comments, please call me at (303) 227-2414.

Sincerely,

Enclosure

Mark Suyama
Environmental Engineer

RECEIVED

JAN 2 3 2001

STATIONARY SOURCES PROGRAM

CRUDE & VACUUM HEATERS

Potential To Emit

Design Ratings

88 MMBTU/hr Crude Heater Vacuum Heater 31 MMBTU/hr

Vendor

Vendor

Emission Factors

Crude Heater

NOx 85 lb/MMscf

120 ppm/H2S SO₂

Fuel Gas Maximum

AP-42 (Table 1.4-3 Small Industrial Boilers - Low NOx Burners) PM10 13.7 lb/MMscf

Vacuum Heater

0.075 lb/MMBTU NOx

> Fuel Gas Maximum 120 ppm/H2S

AP-42 (Table 1.4-3 Small Industrial Boilers - Low NOx Burners) 13.7 lb/MMscf PM10

Emission Calculations

Crude Heater

SO₂

NOx: (88 MMBTU/hr)(8760 hr/yr)(10⁶ BTU/MMBTU)(Scf/1000BTU)(MMscf/106 Scf)(85 lb/MMscf)(Ton/2000 lb) = 32.8 TPY SO_2 : (88 MMBTU/hr)(MMscf/450 MMBTU)(120 ft3/MMscf)(lb mol/379 ft3)(64 lb SO_2 /lb mol)(8760 hr/yr)(Ton/2000 lb) = 17.3 TPY PM10: $(88 \text{ MMBTU/hr})(8760 \text{ hr/yr})(10^6 \text{ BTU/MMBTU})(\text{Scf}/1000 \text{ BTU})(\text{MMscf}/106 \text{ Scf})(13.7 \text{ lb/MMscf})(\text{Ton/2000lb}) = 5.2 \text{ TPY}$

Vacuum Heater

NOx: (31 MMBTU/hr)(0.075 lb/MMBTU)(Ton/2000 lb)(8760 hr/yr) = 10.1 TPY

 SO_2 : (31 MMBTU/hr)(MMscf/450 MMBTU)(120 ft3/MMscf)(lb mol/379 ft3)(64 lb SO_2 /lb mol)(8760 hr/yr)(Ton/2000 lb) = 6.1 TPY PM10: (31 MMBTU/hr)(8760 hr/yr)(10⁶ BTU/MMBTU)(Scf/1000 BTU)(MMscf/106 Scf)(13.7 lb/MMscf)(Ton/2000lb) = 1.8 TPY

NOX 3 48.9 / SOX 3 17.3 +61 3 23.4/

PM, 0 -) 7.0/

BLACK OIL HEATER

Potential To Emit

Design Ratings

BLACK OIL HEATER

8.1 MMBTU/hr

Emission Factors

Black Oil Heater

100 lb MMscf NOx SO2 120 ppm/H2S

AP-42 (Table 1.4-2) Fuel Gas Maximum

12 lb/MMscf PM10

AP-42 (Table 1.4-1)

Emission Calculations

Black Oil Heater
NOx: (8.1 MMBTU/hr)(0.11 lb/MMBTU)(Ton/2000 lb)(8760 hr/yr) = 3.8 TPY
SO2: (8.1 MMBTU/hr)(MMscf/450 MMBTU)(120 ft3/MMscf)(lb mol/379 ft3)(64 lb SO2/lb mol)(8760 hr/yr)(Ton/2000 lb) = 1.6 TPY
PM10: (8.1 MMBTU/hr)(0.005 lb/MMscf)(Ton/2000lb)(8760 hr/yr) = 0.2 TPY

10000

REFORMER HEATERS

Potential To Emit

Design Ratings

Reformer Heaters

161 MMBTU/hr

Emission Factors

Reformer Heaters

0.075 lb/MMBTU NOx

Source Test Data

SO2

120 ppm/H2S

Fuel Gas Maximum

PM10

13.7 lb/MMscf

AP-42 (Table 1.4-3 Small Industrial Boilers - Low NOx Burners (6.2 + 7.5))

Emission Calculations

Reformer Heaters

Reformer Heaters
NOx: (161MMBTU/hr)(0.075 lb/MMBTU)(Ton/2000 lb)(8760 hr/yr) = 52.8 TPY
SO2: (161MMBTU/hr)(MMscf/450 MMBTU)(120 ft3/MMscf)(lbmol/379 ft3)(64 lb SO2/lbmol)(8760 hr/yr)(Ton/2000 lb) = 31.8 TPY
PM10: (161 MMBTU/hr)(8760 hr/yr)(10⁶ BTU/MMBTU)(Scf/1000 BTU)(MMscf/10⁶ Scf)(13.7 lb/MMscf)(Ton/2000lb) = 9.7 TPY

UTILITIES - BOILERS

Potential To Emit

Design Ratings

225 MMBTU/hr Utilities

Emission Factors

Utilities

140 lb/10⁶ ft3 AP-42 (Table 1.4-2 Small Industrial Boilers) NOx

Fuel Gas Maximum SO2 120 ppm/H2S

AP-42 (Table 1.4-3 Small Industrial Boilers - Low NOx Burners (6.2 + 7.5)) 13.7 lb/MMscf PM10

Emission Calculations

Utilities

NOx: (225 MMBTU/hr)(0.075 lb/MMBTU)(Ton/2000 lb)(8760 hr/yr) = 73.9 TPY

SO2: (225MMBTU/hr)(MMscf/1000 MMBTU)(120 ft3/MMscf)(lbmol/379 ft3)(64 lb SO2/lbmol)(8760 hr/yr)(Ton/2000 lb) = 19.9 TP PM10: (225 MMBTU/hr)(8760 hr/yr)(10⁶ BTU/MMBTU)(Scf/1000 BTU)(MMscf/10⁶ Scf)(13.7 lb/MMscf)(Ton/2000lb) = 13.5 TPY

REFINERY FLARE

Potential To Emit

Design Ratings

131,282 MMBTU/yr

Refinery Flare (Maximum Refinery Throughput ~35,000 bbl)

Emission Factors

Refinery Flare

0.068 lb/MMBTU NOx

AP-42 (Table 13.5-1 Emission Factors for Flare Operations)

SO2

26.9 lb/103 bbl

137 lb/MMBTU PM10

AP-42 (Table 13.5-1 Emission Factors for Flare Operations)

Emission Calculations

Refinery Flare

NOX: (133,282 MMBTU/yr)(0.068 lb/MMBTU)(Ton/2000 lb) = 4.6 TPY SO2: (26.9 lb SO2/1000 bbl)(35,000 bbl/day)(365 day/yr)(Ton/2000 lb) = 172 TPY PM10: $(137 \text{ug/L})(\text{g/10}^6 \text{ ug})(\text{lb/454 g})(28.32 \text{ g/ft}^3)(212.5 \text{ MMft}^3)(\text{Ton/2000 lb}) = 0.9 \text{ TPY}$

FLUID CATALYTIC CRACKING UNIT

Potential To Emit

Design Ratings

75 MMBTU/hr FCCU Preheater (Maximum Refinery Throughput ~35,000 bbl)

Emission Factors

FCCU PH

AP-42 (Table 1.4-2 Emission Factors for Sox, Nox, CO from Natural Gas Combustion) 140 lb/MMscf NOx

120 PPM Max. H2S in Fuel Gas SO2

AP-42 (Table 1.4-2 Emission Factors for Sox, Nox, CO from Natural Gas Combustion) PM10 13.7 lb/MMscf

Emission Calculations

FCCU PH

NOx: (75 MMBTU/hr)(MMscf/450 MMBTU)(8760 hr/yr)(140 lb/MMscf)(Ton/2000 lb) = 102.2 TPY

SO2: (1460 MMscf/yr)(120 ft3 H2S/MMscf)(34 lb H2S/lb moi)(lb moi/379.5 ft3)(64 lb SO2/34lb H2S)(Ton/2000 lb) = 14.77 TPY PM10: (75 MMBTU/hr)(MMscf/450 MMBTU)(8760 hr/yr)(13.7 lb/MMscf)(Ton/2000 lb) = 10.0 TPY

FLUID CATALYTIC CRACKING UNIT

Potential To Emit

Design Ratings

FCCU REGEN - Coke Make

5788.7 lbs/hr 50,709,012 lbs/yr

Emission Factors

FCCU REGEN

NOx 2.41 lbs/1000 lbs Coke Make SO2 17.35 lb/1000 lbs Coke Make

PM10 7.88 lbs/1000 lbs Coke Make

Emission Calculations

FCCU REGEN

NOx: (50,709,012 lbs/yr)(2.41 lbs/1000 lb)(Ton/2000 lb) = 61 TPY SOx: (50,709,012 lbs/yr)(17.35 lbs/1000 lb)(Ton/2000 lb) = 440 TPY PM10: (50,709,012 lbs/yr)(7.88 lbs/1000 lb)(Ton/2000 lb) = 200 TPY

SULFUR RECOVERY UNIT INCINERATOR

Potential To Emit

Design Ratings

Sulfur Recovery Unit 6 Long Tons per Day
21,000 MMBTU/yr Consumption Limit
2.4 MMBTU/yr Maximum Gas Input to the Incinerator

Emission Factors

Sulfur Recovery Unit

NOx 100 lb/MMscf 120 ppm/H2S AP-42 (Table 1.4-2 Commercial Boilers)

SO2

Fuel Gas Maximum

PM10 12.0 lb/MMscf AP-42 (Table 1.4-1 Commercial Boilers (4.5 + 7.5))

Emission Calculations

Sulfur Recovery Unit

The SO₂ PTE is a combination of the SO₂ created by converting the tail gas H₂S to SO₂ in the incinerator and the SO₂ created by combustion of the incinerator pilot feed.

Tail Gas

The maximum amount of sulfur leaving the Claus unit is designed to be constant

The amount of sulfur leaving the Claus unit is designed to be 0.42 long tons per day

6 long tons/day x (1-0.93) = 0.42 long tons/day S

Using a conservative assumption of 100% conversion of H₂S to SO₂, this leads to:

0.42 long tons/day x 5 short tons/4.464 long tons x 2000 lb/ton x lbmole/32 lb S x lbmole H_2S /lbmole S = 29.4 lbmole H_2S /day

29.4 lbmole H_2S /day x 365 days/yr x 64 lb SO_2 /lbmole x lbmole SO_2 /lbmole H_2S x ton/2000 lb = 343.4 ton SO_2 /yr -- out of the SRU tail gas incinerator due to tail gas

Pilot Feed

Some SO_2 will also be formed from combustion of the pilot gas fed to the SRU tail gas incinerator.

Btu Rating of SRU tail gas incinerator = 1.95 mmbtu/hr Refinery gas heat content = 400 Btu/scf Potential fuel feed to the SRU incinerator: $120 \text{ ppmv } H_2S$ in the pilot fuel at a maximum

1.95 mmbtu/hr x mmcf/400 mmbtu x 8760 hr/yr = 42.71 mmcf/yr

This conservatively assumes that the entire feed to the SRU incinerator is fuel gas rather than a mix of fuel gas and tail gas.

42.71 mmcf/yr pilot fuel x 120 ft3 $H_2S/mmcf$ x lbmole $H_2S/379$ ft3 x lbmole SO_2 /lbmole H_2S x 64 lb SO_2 /lbmole x ton/2000 lb = 0.43 ton SO_2 /yr -- From combustion of pilot fuel

80

Total SO₂: $343.4 + 0.43 = 343.83 \text{ ton SO}_2/\text{yr}$

LPG Loading/Unloading FlarePotential To Emit

Design Ratings

Loading of LPG 350,000,000 gal/yr Heat Input = 404,400 MMBTU/yr

Emission Factors

LPG Loading/Unloading Flare

AP-42 (Table 13.5-1 Emission Factors for Flare Operations) NOx 0.068 lb/MMBTU

Emission Calculations

LPG Loading/Unloading Flare

NOx: (404,400 MMBTU/yr)(0.068 lb/MMBTU)(Ton/2000 lb) = 13.75 TPY

Product Dock Loading

Potential To Emit

Design Ratings

Loading of Product 578,160,000 gal/yr Capture efficiency = 95%

Emission Factors

Product Dock Loading

AP-42 (Table 13.5-1 Emission Factors for Flare Operations) 0.068 lb/MMBTU NOx

Emission Calculations

Product Dock Loading

 L_L : (8.15 ib/1000 gal)(578,160,000 gal)(Ton/2000 lb) = 2356 TPY

Quantity Uncaptured: (2356 tpy)(0.01%) = 23.6 TPY
Quantity Flared: (2356-23.6)(0.95) = 2216
Heat Content Flared: (2216 TPY)(2000 lb/Ton)(19000 BTU/lb) = 84,208 MMBTU/yr

NOx: (84,208 MMBTU/yr)(0.068 lb/MMBTU)(Ton/2000 lb) = 2.9 TPY

PM: de minimus de minimus SOx:

Appendix E.5 40CFR Part 60 NSPS Subpart D

TABLE 2 TO SUBPART CE—EMISSIONS LIMITS FOR SMALL HMIWI WHICH MEET THE CRITERIA UNDER § 60.33E(B)

Pollutant	Units (7 percent oxygen, dry basis)	HMIWI emission limits
Particulate matter	Milligrams per dry standard cubic meter (grains per dry standard cubic foot).	197 (0.086).
Carbon monoxide	Parts per million by volume	40.
Dioxins/furans	nanograms per dry standard cubic meter total dioxins/furans (grains per billion dry standard cubic feet) or nanograms per dry standard cubic meter TEQ (grains per billion dry standard cubic feet).	800 (350) or 15 (6.6).
Hydrogen chloride	Parts per million by volume	3100.
Sulfur dioxide	Parts per million by volume	55.
Nitrogen oxides	Parts per million by volume	
Lead	Milligrams per dry standard cubic meter (grains per thousand dry standard cubic feet).	
Cadmium	Milligrams per dry standard cubic meter (grains per thousand dry standard cubic feet).	4 (1.7).
Mercury	Milligrams per dry standard cubic meter (grains per thousands dry standard cubic feet).	7.5 (3.3).

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971

§ 60.40 Applicability and designation of affected facility.

- (a) The affected facilities to which the provisions of this subpart apply
- (I) Each fossil-fuel-fired steam generating unit of more than 73 megawatts heat input rate (250 million Btu perhour).
- (2) Each fossil-fuel and wood-residuefired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 megawatts (250 million Btu per hour).
- (b) Any change to an existing fossilfuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.
- (c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.
- menced construction or modification after August 17, 1971, is subject to the requirements of this subpart.
 (d) The requirements of §§60.44 (a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

(e) Any facility covered under subpart Da is not covered under this subpart.

[42 FR 37936, July 25, 1977, as amended at 43 FR 9278, Mar. 7, 1978; 44 FR 33612, June 17, 1979]

§60.41 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in subpart A of this part.

(a) Fossil-fuel fired steam generating

- (a) Fossil-fuel fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.
- (b) Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat
- ing useful heat.
 (c) Coal refuse means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.
- (d) Fossil fuel and wood residue-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.
- (e) Wood residue means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

§ 60.42

(f) Coal means all solid fuels classi-(i) Coal means an solid liters classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society and Testing and Materials, Designation D388-77 (incorporated by reference—see §60.17).

[39 FR 20791, June 14, 1974, as amended at 40 FR 2803, Jan. 16, 1975; 41 FR 51398, Nov. 22, 1976; 43 FR 9278, Mar. 7, 1978; 48 FR 3736, Jan. 27, 1983]

§60.42 Standard for particulate mat-

- (a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which: (1) Contain particulate matter in ex-
- cess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood
- (2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 per-
- cent opacity.
 (b)(1) On or after December 28, 1979, no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station #I, in Amarillo, TX, any gases which exhibit greater than 35% opacity, except that a maximum or 42% opacity shall be permitted for not more than 6 minutes in
- any hour.
 (2) Interstate Power Company shall (c) Interstate Fower Company Shan not cause to be discharged into the atmosphere from its Lansing Station Unit No. 4 in Lansing, IA, any gases which exhibit greater than 32% opacity, except that a maximum of 39% opacity shall be permitted for not more these interstation and house. than six minutes in any hour.

139 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 42 FR 61537, Dec. 5, 1977; 44 FR 76787, Dec. 28, 1979; 45 FR 50077, May 29, 1980; 45 FR 47146, July 14, 1880; 46 FR 57498, Nov. 24, 1981; 61 FR 49976, Sept. 24, 1996]

§ 60.43 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:

- (1) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.
- (2) 520 nanograms per joule heat input (1.2 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (e) of this section. (b) When different fossil fuels are
- burned simultaneously in any combina-tion, the applicable standard (in ng/J) shall be determined by proration using the following formula:

 $PS_{SO2}=[y(340) + z(520)]/(y+z)$

- PS_{SO2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,
- y is the percentage of total heat input de-rived from liquid fossil fuel, and z is the percentage of total heat input de-rived from solid fossil fuel.
- (c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

(d) [Reserved]

(e) Units 1 and 2 (as defined in appendix G) at the Newton Power Station dix G) at the Newton Power Station owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 paragraphs per joule (11 b) exceed 470 nanograms per joule (1.1 lb per million Btu) combined heat input to Units 1 and 2.

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 52 FR 28954, Aug. 4,

§60.44 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as

- (1) 86 nanograms per joule heat input
- (1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel. (2) 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.
- (3) 300 nanograms per joule heat input (0.70 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent,
- solid lossif luciform of coal refuse).

 (4) 260 nanograms per joule heat input (0.60 lb per million Btu) derived from lignite or lignite and wood residue (except as provided under paragraph (a) (5) of this section).
- (5) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired
- (b) Except as provided under paragraphs (c) and (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{\text{NOx}} = \frac{w(260) + x(86) + y(130) + z(300)}{w + x + y + z}$$

where:

- where:

 PS_{NOx}: is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood resisted. idue fired:

- idue fired;
 w= is the percentage of total heat input derived from lignite;
 x= is the percentage of total heat input derived from gaseous fossil fuel;
 y= is the percentage of total heat input derived from liquid fossil fuel; and
 z= is the percentage of total heat input derived from solid fossil fuel (except lignite).
- (c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for
- nitrogen oxides does not apply.

 (d) Cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota,

South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel com-busted in combination with that lig-

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 43 FR 9278, Mar. 7, 1978; 51 FR 42797, Nov. 25, 1986]

§60.45 Emission and fuel monitoring.

- (a) Each owner or operator shall install, calibrate, maintain, and operate stati, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.
- (b) Certain of the continuous monitoring system requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:
- (1) For a fossil fuel-fired steam generator that burns only gaseous fossil fuel, continuous monitoring systems for measuring the opacity of emissions and sulfur dioxide emissions are not required.
- (2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sul-fur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under paragraph (d) of this
- (3) Notwithstanding §60.13(b), installation of a continuous monitoring sys-tem for nitrogen oxides may be delayed until after the initial performance tests under §60.8 have been conducted. If the owner or operator demonstrates during the performance test that emisduring the performance test that emis-sions of nitrogen oxides are less than 70 percent of the applicable standards in \$60.44, a continuous monitoring system for measuring nitrogen oxides emis-sions is not required. If the initial performance test results show that nitro-gen oxide emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a continuous monitoring system for nitro-gen oxides within one year after the date of the initial performance tests under §60.8 and comply with all other

applicable monitoring requirements under this part.
(4) If an owner or operator does not

- install any continuous monitoring sys-tems for sulfur oxides and nitrogen oxides, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.
- (c) For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the following procedures shall be used:
- (1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring sys tems. Acceptable alternative methods for Methods 6, 7, and 3B are given in §60.46(d).
- (2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.
 (3) For affected facilities burning fos-
- (3) For ameter latinties burning ios-sil fuel(s), the span value for a continu-ous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

(F			
Fossil fuel	Span value for sulfur dioxide	Span value for nitro- gen oxides	
Gas	(1)	500	
Liquid	1,000	500	
Solid	1,500	1000	
Combinations	1,000y+1,500z	500(x+y)+1,000z	

1 Not applicable

where:

where.

**x=the fraction of total heat input derived from gaseous fossil fuel, and y=the fraction of total heat input derived from the following forms of the fo

rfrom liquid fossil fuel, and z=the fraction of total heat input derived from solid fossil fuel.

- (4) All span values computed under paragraph (c)(3) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 $\,$ ppm.
- (5) For a fossil fuel-fired steam gener ator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems

shall be subject to the Administrator's approval.
(d) [Reserved]

- (e) For any continuous monitoring system installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):
- (1) When a continuous monitoring system for measuring oxygen is sesystem for measuring oxygen is se-lected, the measurement of the pollut-ant concentration and oxygen con-centration shall each be on a consistcentration shall each be on a consist-ent basis (wet or dry). Alternative pro-cedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

 $E=CF[20.9/(20.9-percent O_2)]$

E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be

used: E=CF_c [100/percent CO₂]

- E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.
- (f) The values used in the equations under paragraphs (e) (1) and (2) of this section are derived as follows:
- (1) E=pollutant emissions, ng/J (lb/ million Btu).
- (2) C=pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15x10⁴ M ng/dscm per ppm (2.59x10⁻⁹ M lb/dscf per ppm) where M=pollutant molecular weight, g/g-mole (lb/lb-mole). M=64.07 for sulfur dioxide and 46.01 for nitrogen oxides
- oxides. (3) $\%O_2$, $\%CO_2$ =oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under paragraph (a) of this section. (4) F, F_c=a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel

combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted $(F_{\rm c})$, respectively. Values of F and $F_{\rm c}$ are given as

tively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388-77 (incorporated by reference—see \$60.17), F=2,723×10⁻¹⁷ dscm/J (10,140 dscf/million Btu and F_c =0.532×10⁻¹⁷ scm CO_z/J (1,980 scf CO_z/m illion Btu).

scf CO₂/million Btu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388-77 (incorporated by reference—see $\S60.17$), F= 2.637×10^{-7} dscm/J ($\S820$ dscf/million Btu) and F_c= 0.486×10^{-7} scm CO₂/J (1.810 scf CO₂/million Btu).

(iii) For liquid fossil fuels including

million Btu). (iii) For liquid fossil fuels including crude, residual, and distillate oils, $F=2.476\times10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_{c}=0.384\times10^{-7}$ scm CO_{c}/J (1,430 scf CO_{c}/m illion Btu). (iv) For gaseous fossil fuels, $F=2.347\times10^{-7}$ dscm/J (8,740 dscf/million Btu).

Btu). For natural gas, propane, and butane fuels, F_c =0.279×10⁻⁷ scm CO_c/J

(1,040 scf CO_2 /million Btu) for natural gas, 0.322×10^{-7} scm CO_2 /J (1,200 scf CO_2 /million Btu) for propane, and 0.338×10^{-7} scm CO_2 /J (1,260 scf CO_2 /million

0.338×10⁻⁷ scm CO_2/J (1,260 scf CO_2 /million Btu) for butane. (v) For bark F=2.589×10⁻⁷ dscm/J (9.640 dscf/million Btu) and F_c =0.500×10⁻⁷ scm CO_2/J (1.840 scf CO_2/J million Btu). For wood residue other than bark F=2.492×10⁻⁷ dscm/J (9,280 dscf/million Btu) and F_c =0.494×10⁻⁷ scm CO_2/J (1,680 scf CO_2/J million Btu)

(vi) For lignite coal as classified according to ASTM D388-77 (incorporated by reference—see §60.17), F=2.659x10-7 dscm/J (9,900 dscf/million Btu) and F_c =0.516×10⁻⁷ scm CO₂/J (1,920 scf CO₂/ million Btu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO_2/J , or scf CO_2/m illion Btu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6} \frac{\left[227.2 \text{ (pct. II)} + 95.5 \text{ (pct. C)} + 35.6 \text{ (pct. S)} + 8.7 \text{ (pct. N)} - 28.7 \text{ (pct. O)}\right]}{\text{GCV}}$$

$$F_c = \frac{2.0 \times 10^{-5} \text{ (pct. C)}}{\text{GCV} \text{ (SI units)}}$$

$$F = \frac{10^6 \left[3.64 (\%H) + 1.53 (\%C) + 0.57 (\%S) + 0.14 (\%N) - 0.46 (\%O)\right]}{\text{GCV} \text{ (English units)}}$$

$$F_c = \frac{20.0 (\%C)}{\text{GCV} \text{ (SI units)}}$$

$$F_c = \frac{321 \times 10^3 (\%C)}{\text{GCV} \text{ (English units)}}$$

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM method D3178-74 or D3176 (solid fuels) or computed from results using ASTM method D1137-53(75), D1945-64(76), or D1946-77 (gaseous fuels) as applicable.

(These five methods are incorporated

(Hisse live methods are incorporated by reference—see \$60.17.)

(ii) GVC is the gross calorific value (k.J/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015-77 for solid fuels and D1826-77 for gaseous fuels as applicable. (These two methods are incorporated by reference—see §60.17.) (iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F_c value shall be subject to the Administrator's approval.
 (6) For affected facilities firing com-

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the *F* or *F*_c factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \text{ or } F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

where:

X=the fraction of total heat input derived

X_Fthe fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)
F_f or (F_d)=the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.

n=the number of fuels being burned in com-

- (g) Excess emission and monitoring system performance reports shall be submitted to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission and MSP report shall include the information required in \$60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:
- (MS) downtime that shall be reported are defined as follows:

 (1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.
- (i) For sources subject to the opacity standard of \$60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.
- of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

 (ii) For sources subject to the opacity standard of \$60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

- (2) Sulfur dioxide. Excess emissions for affected facilities are defined as:
- (i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under §60.43.
- (3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under \$60.44.

[40 FR 46256, Oct. 6, 1975]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting §60.45, see the List of CFR Sections Affected in the Finding Aids section of this volume.

§60.46 Test methods and procedures.

- (a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.
- (b) The owner or operator shall determine compliance with the particulate matter, SO_2 , and NO_x standards in §§60.42, 60.43, and 60.44 as follows:
- (1) The emission rate (E) of particulate matter, SO_2 , or NO_x shall be computed for each run using the following equation:

 $E=C F_d (20.9)/(20.9-\% 0_2)$

- E = emission rate of pollutant, ng/J (lb/million Btu).
- C = concentration of pollutant, ng/dscm (1b/
- $%O_2$ = oxygen concentration, percent dry basis.
- F_d = factor as determined from Method 19.
- (2) Method 5 shall be used to determine the particular matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B shall be used to determine the particulate matter concentration (C) after FGD systems.

- (i) The sampling time and sample volume for each run shall be at least 60 wontime for each run shail be at least of minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train may be set to provide a gas temperature no greater than 160±14 °C (320±25 °F).
- (ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O₂ concentration $(\%O_2)$. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O2 concentration for the run shall be the arithmetic mean of all the individual O₂ sample concentrations at each traverse point.
- (iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method I is used to locate the 12 O2 traverse points.
- (3) Method 9 and the procedures in §60.11 shall be used to determine opac-
- (4) Method 6 shall be used to determine the SO₂ concentration.
- (i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.
- (ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (% O_2). The O₂ sample shall be taken simultaneously with, and at the same point as, the SO₂ sample. The SO₂ emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of
- (5) Method 7 shall be used to determine the NO_{κ} concentration.
- (i) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab

- samples, with each sample taken at about 15-minute intervals
- about 13-minute intervals.

 (ii) For each NO_x sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B shall be used to determine the O₂ concentration (%O₂). The sample shall be taken simultaneously with, and at
- the same point as, the NO_x sample.

 (iii) The NO_x emission rate shall be computed for each pair of NO_x and O₂ samples. The NO_x emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of sam-
- (c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in §\$60.43(b) and 60.44(b)) shall determine the percentage (w. x. y. or z) of the total heat input derived from each type of fuel as follows:
- (1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.
- (2) ASTM Methods D 2015-77 (solid fuels), D 240-76 (liquid fuels), or D 1826-77 (gaseous fuels) (incorporated by reference—see §60.17) shall be used to determine the gross calorific values of the fuels. The method used to deter-mine the calorific value of wood residue must be approved by the Adminis-
- (3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.
- (d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section or in other sections as speci-
- (1) The emission rate (E) of particulate matter, SO_2 and NO_x may be determined by using the F_c factor, provided that the following procedure is used:
- (i) The emission rate (E) shall be computed using the following equation: E=C F_c (100/%CO₂)

where:

E=emission rate of pollutant, ng/J (lb/million Btu).
C=concentration of pollutant, ng/dscm (lb/

%CO2=carbon dioxide concentration, percent

F_c=factor as determined in appropriate sections of Method 19.

- (ii) If and only if the average $F_{\rm c}$ factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the $\rm O_2$ and $\rm CO_2$ conused to determine the O_2 and CO_2 concentration according to the procedures in paragraph (b) (2)(ii), (4)(ii), or (5)(ii) of this section. Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ± 3 percent than the average F_o value, as bettern than the average F_0 value, as determined from the average values of F_d and F_c in Method 19, i.e., F_{ou} =0.209 (F_{cd}/F_{cu}), then the following procedure shall be followed:

 (A) When F_o is less than 0.97 F_{ou} , then
- (A) When F_{ob}, is less than 0.91 F_{ob}, then E shall be increased by that proportion under 0.97 F_{ob}, e.g., if F_o is 0.95 F_{ob}, E shall be increased by 2 percent. This re-calculated value shall be used to determine compliance with the emission
- (B) When F_o is less than 0.97 F_{on} and when the average difference (d) between the continuous monitor minus the reference methods is negative, then the reference methods is negative, then E shall be increased by that proportion under $0.97~E_{os}$, e.g., if F_{o} is $0.95~E_{os}$, E shall be increased by 2 percent. This re-calculated value shall be used to determine compliance with the relative ac-
- mine compliance with the relative accuracy specification. (C) When F_o is greater than 1.03 F_{ou} and when the average difference d is positive, then E shall be decreased by that proportion over 1.03 F_{ou} , e.g., if F_o is 1.05 F_{ou} , E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification. (2) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average tempera-
- does not exceed an average tempera-ture of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B may be used with Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

- (3) Particulate matter and SO2 may (3) Particulate matter and SO₂ may be determined simultaneously with the Method 5 train provided that the following changes are made:
 (i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 is
- used in place of the condenser (section 2.1.7) of Method 5.
- (ii) All applicable procedures in Method 8 for the determination of SO₂
- (including moisture) are used:
 (i) For Method 6, Method 6C may be used. Method 6A may also be used whenever Methods 6 and 3B data are specified to determine the SO2 emisspecified to determine the SO₂ emission rate, under the conditions in paragraph (d) (1) of this section.

 (5) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or
- 7E is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2 concentration (%O₂) for the emission rate correction
- factor.
 (6) For Method 3, Method 3A or 3B
- may be used.
 (7) For Method 3B, Method 3A may be

[54 FR 6662, Feb. 14, 1989; 54 FR 21344, May 17, 1989, as amended at 55 FR 5212, Feb. 14, 1990]

Subpart Da—Standards of Per-formance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18,

SOURCE: 44 FR 33613, June 11, 1979, unless otherwise noted.

§60.40a Applicability and designation of affected facility.

- (a) The affected facility to which this subpart applies is each electric utility
- steam generating unit:
 (1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and
- (2) For which construction or modification is commenced after September 18. 1978.
- (b) This subpart applies to electric utility combined cycle gas turbines that are capable of combusting more

Appendix E.6