TECHNICAL REVIEW DOCUMENT
For
OPERATING PERMIT 05OPWE279
to be issued to:

Rocky Mountain Energy Center, LLC
Weld County
Source ID 1231342

Prepared by Jacqueline Joyce
September 2006
Revised October 2006 and March 2007

I. Purpose:

This document establishes the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA, the Public and other interested parties. Conclusions made in this report are based on information provided by the applicant in the Title V application submitted March 14, 2005, comments on the draft permit and technical review document submitted on November 17, 2006 and January 19, 2007, additional information submitted on March 21, 2007, various telephone conversations and e-mail correspondence with the source and review of Division files. This narrative is intended as an adjunct to the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised Construction Permit.

II. Source Description

The Rocky Mountain Energy Center (RMEC) consists of two combined cycle combustion turbines used to generate electric power under Standard Industrial Classification 4911. The facility consists of two natural gas fired combustion turbines, two heat recovery steam generators, each equipped with natural gas fired duct burners, a steam turbine, cooling tower and auxiliary boiler. There are two diesel fired engines, one driving an emergency generator and one driving a fire pump. The RMEC has the capacity to generate up to 630 MW of electricity. Each combustion turbine can

generate approximately 152 MW, with an additional 326 MW from the steam turbine. The turbines are not equipped with a by-pass stack, therefore, the turbines only operate in combined cycle mode (e.g. turbine plus HRSG).

The facility is located at 6211 Weld County Road 51, just east of the town of Hudson, in Weld County Colorado (bounded by CR 49 to the west, CR 16 to the north and CR 51 to the east). The area in which the plant operates is designated as attainment for all criteria pollutants, but is located within the 8-hour Ozone Control Area as defined in Colorado Regulation No. 7, Section II.A.16.

There are no affected states within 50 miles of the facility. Rocky Mountain National Park, a Federal Class I designated area, is within 100 km of the facility.

The facility is considered to be a major stationary source (potential to emit > 100 tpy of any criteria pollutant). Facility wide emissions are as follows:

	Potential To Emit						
Emission Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	HAPS[1]
Turbines/HRSGs[2]	126.8	126.8	11.8	240.4	782.2	50.6	See Table on Page 32
Aux. Boiler[3]	2.28	2.28	0.08	4.7	4.75	0.58	
Fire Water Pump[4]	0.43	0.43	0.03	1.02	0.61	0.13	
Emergency Generator[5]	0.20	0.20	0.08	3.44	4.24	0.50	
Cooling Tower[6]	19.3	19.3				0.89	
Total	149.01	149.01	11.99	249.56	791.80	52.70	13.01

[1]HAP emissions are based on the Division's analysis. The total HAP limit is set at 13.10 tons/yr.
[2]Based on the permitted emissions indicated in Attachment A of the permit.
[3]PM, PM_{10} and CO emissions based on requested emissions provided on the APEN submitted on March 21, 2007. SO_2 and VOC based on the Division's analysis. NO_X based on the permitted emissions indicated in Attachment A of the permit.
[4]Based on the APEN de minimis of 850 hours/year of operation (per Reg 3, Part A, Section II.D.1.sss.(ii)), these are higher than requested and provided for in the construction permit.
[5]Based on the permit de minimis of 250 hours/year of operation (per Reg 3, Part B, Section II.D.1.c.(ii)), these are higher than requested and provided for in the construction permit.
[6]Based on requested PM and PM_{10} emissions on the APEN submitted on March 21, 2007**]**. Note VOC emissions are chloroform emissions, which is also a HAP.

Except as indicated in the footnotes in the above table, potential to emit of criteria pollutants is based on the permitted emission limits specified in Attachment A of the construction permit (02WE0228, initial approval, modification no. 1, issued June 23, 2004). Note that the potential to emit above does not reflect the permitted emissions for a proposed new turbine at this facility (Colorado Construction Permit 05WE0524, initial approval issued July 17, 2006). An application to modify the Title V permit to include that turbine is due twelve months after that turbine commences operation. However, HAP emissions from that turbine are limited to 5.4 tons/yr for all HAPS and 1 tons/yr for

formaldehyde. Therefore, the facility is still a minor source for HAPS (18.5 tons/yr total, formaldehyde 3.44 tons/yr).

The breakdown of HAP emissions for each emission unit is provided for in the table on page 32 of this document. The method for estimating HAP emissions is indicated in the footnotes on this table.

The source indicated that this facility is subject to the 112(r) Accidental Release Requirements. A risk management plan was submitted to EPA as required.

Compliance Assurance Monitoring (CAM) Requirements

CAM applies to any emission unit that is subject to an emission limitation, uses a control device to achieve compliance with that emission limitation and has potential pre-control emissions greater than major source levels. The turbines/HRSGS are equipped with dry low NO_X (DLN) combustion systems and selective catalytic reduction (SCR) to reduce NO_X emissions and an oxidation catalyst to reduce CO and VOC emissions. Although DLN combustion systems are not considered control devices as defined in 40 CFR Part 64 § 64.1, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, since they are considered inherent process equipment, the SCR and oxidation catalysts are considered control devices. The turbines/HRSGS are subject to a variety of short-term and annual NO_X, CO and VOC emission limits. The Division considers that the control devices are necessary to meet the NO_X, CO and VOC short-term BACT emission limits and the annual NO_X, CO and VOC emission limits. The Division does not consider that the SCR is necessary to meet the NSPS GG or Db NO_X limitations. Therefore, CAM does apply to the turbines/HRSGs at this facility.

For large pollutant specific emission units (emissions above the major source level, when control device considered), the CAM plan shall be submitted as part of the Title V permit application, if the application is submitted after April 20, 1998 (40 CFR Part 64 § 64.5(a)(1)(i), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV). Permitted emissions of NO_X and CO exceed the major source level (100 tons/yr), therefore, CAM applies to the turbines/HRSG for NO_X and CO upon initial issuance of the Title V permit. Permitted VOC emissions are below the major source level; therefore, CAM does not apply with respect to VOC emissions until renewal of the Title V permit (40 CFR Part 64 § 64.5(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV

III. Emission Sources

The following sources are specifically regulated under terms and conditions of the Operating Permit for this Site.

Units S001 and S002: Two (2) Westinghouse, Model No. 501FD, Combustion Turbines rated at 1785 mmBtu/hr (HHV at ISO conditions), Serial Nos. 37A8191 and 37A8196 and Two (2) Heat Recovery Steam Generators (HRSG), each

equipped with a duct burner rated at 675 mmBtu/hr. The facility power generating capacity is 630 MW (at peak capacity) from both turbines and both HRSGS. Each turbine is capable of generating 152 MW of power. The HRSGs serve a steam turbine rated at 326 MW. The turbines only operate in combined cycle mode and emissions from the turbines/duct burners are controlled by selective catalytic reduction (NO_X) and an oxidation catalyst (CO and VOC).

1. Applicable Requirements: The initial approval construction permit (02WE0228) for the facility was issued on July 15, 2002, with a modification issued on June 23, 2004. A request was submitted on March 22, 2007 to revise the construction permit; however, the revisions only affected the emergency generator. According to the Title V permit application, the turbines/HRSGs commenced operation in March 2004. It is not clear when the self-certification was submitted and no final approval permit has been issued. Under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect. The appropriate provisions of the initial approval construction permit have been directly incorporated into this Title V operating permit. The applicable requirements included in the construction permit for the turbines/HRSGs/duct burners are as follows:

- Within 180 days after commencement of operation, compliance with the conditions contained in this permit shall be demonstrated to the Division (condition 2).

  According to the Division's August 28, 2006 inspection report, the self-certification was submitted on October 14, 2004. Therefore, this requirement will not be included in the permit.

- Emissions of hazardous air pollutants shall not equal or exceed the thresholds for applicability of MACT standards, prior to reaching these thresholds, this permit shall be suitably modified and standards complied with (condition 4).

  It is not clear why this condition is included in the permit. If facility HAP emissions exceed the major source level, the appropriate MACT standards would apply. This permit contains limitations on formaldehyde and HAP emissions to keep emissions below the major source level. This condition will not be included in the permit.

- Regulation No. 6, Part A, Subpart Da – Standards of Performance for Electrical Steam Generating Units, applies to the duct burners, as follows (condition 7):

  - Particulate matter emissions shall not exceed 0.03 lbs/mmBtu (§ 60.42a(a)(1))
  - Opacity of emissions shall not exceed 20% opacity (6-minute averages), except for one six-minute period not to exceed 27% (§ 60.42a(b))

- SO_2 emissions shall not exceed 0.20 lbs/mmBtu, on a 30-day rolling average (§ 60.43a(b)(2))

  Note that 40 CFR Part 60 Subpart Da ' 60.43a(b)(2) specifically states that the SO_2 limitation is A100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 0.2 lbs/mmBtu@. Since these units burn natural gas, emissions will be below 0.2 lbs/mmBtu (40 CFR Part 75, Appendix D allows sources burning pipeline quality natural gas to use a default emission factor of 0.0006 lbs/mmBtu). Because emissions are below 0.2 lbs/mmBtu the source may emit 100% of the potential combustion concentration, i.e. no limits. However, since this Ano SO_2 limits@ only applies if emissions are below 0.2 lbs/mmBtu, the Division included the upper bound of 0.2 lbs/mmBtu as the emission limitation.

- NO_X emissions shall not exceed 0.2 lbs/mmBtu.

  The NO_X limit included in the construction permit is not correct. NSPS Subpart Da was revised September 16, 1998 and established different NO_X limitations for sources that commenced construction or modification after July 9, 1997. Since the duct burner/HRSG commenced construction after July 9, 1997 the new NO_X standard of 1.6 lbs/MW-hr in 40 CFR Part 60 Subpart Da § 60.44a(d)(1) applies to each duct burner.

Although not included in the construction permit, the following requirements from NSPS Da also apply:

- Compliance with the NSPS requirements shall be monitored in accordance with the requirements in 60.48a and 60.49a, including but not limited to the following:

  - Demonstrate compliance with the NO_X emissions in accordance with the requirements in § 60.48a(k).

    The NSPS allows the permittee to either conduct a performance test or use a NO_X continuous emission monitoring system (CEMS) to demonstrate compliance with the NSPS NO_X limit. The source conducted performance tests on May 8, 11, 12, 20 and September 16, 2004. Although the incorrect NSPS limit was in the construction permit, the results of the testing indicate compliance with the correct NSPS Da NO_X limits. NSPS Da does not require a NO_X CEMS for duct burners (§ 60.49a(o)) and requires no further NO_X monitoring for duct burners beyond the initial test.

- Performance tests shall be conducted in accordance with the requirements in § 60.50a(f).

  The source has already conducted performance tests in May and September 2004, which included testing for PM and NO_X, as discussed above. A performance test for SO_2 was not required because the units burn natural gas as fuel so a compliance test for SO_2 is not necessary.

- Reporting requirements in § 60.51a

  The source has already submitted the performance test data from the initial performance test as required by 40 CFR Part 60 Subpart Da § 60.51a(a) so this requirement shall not be included in the operating permit. In addition, as discussed previously, since the source elected to demonstrate compliance with the NSPS Da NO_X limits with the one-time performance test, the NSPS Da NO_X CEMS requirements do not apply and therefore, the remaining reporting requirements (all others that potentially apply to this unit are related to CEMS), also do not apply.

- Regulation No. 6, Part A, Subpart GG – Standards of Performance for Stationary Gas Turbines, applies to the turbines, as follows (condition 7):

  - Concentration of NO_X emissions shall not exceed 102 ppmvd at 15% O_2
  - Concentration of SO_2 emissions shall not exceed 150 ppmvd at 15 % O_2 **or** the fuel combusted shall not contain sulfur in excess of 0.8% by weight.

  Although not specifically identified in the construction permit, the source is subject to monitoring requirements on the nitrogen and sulfur content of the fuel.

  It is not clear whether the source submitted an alternative monitoring plan to EPA for approval. However, NSPS GG was revised on July 8, 2004 (Federal Register, Volume 69, No. 130) to provide additional monitoring options for NO_X emissions and nitrogen and sulfur content monitoring that have previously been approved by EPA. The revisions specify that for sources that do not take credit for fuel-bound nitrogen in their NO_X emission limitations that no fuel sampling for nitrogen is required. Finally, for sampling fuel for the sulfur content, the revisions specify that no fuel sampling is required for units burning natural gas. The Division will include the appropriate provisions from the revised NSPS GG in the permit or streamline as appropriate.

- Regulation No. 6, Part A, Subpart A – NSPS General Provisions, applies to the turbines and duct burners (condition 7)

  - Good practices (§ 60.11(d))
  - Circumvention (§ 60.12)

  Note that a more extensive list of requirements from 40 CFR Part 60 Subpart A was included in the construction permit. However, these requirements, if still applicable, will be included in the permit as periodic monitoring or under the continuous emission monitoring requirements and will not be specifically identified as requirements under the NSPS general provisions.

- Regulation No. 6, Part B, Section II – Standards of Performance for New Fuel-Burning Equipment (condition 7). These are **State-only requirements.**

  - Particulate Matter Emissions shall not exceed $PE = 0.5(FI)^{-0.26}$ (Section II.C.2)

Where: PE = Particulate emissions in lbs/mmBtu
FI = Fuel input in mmBtu/hr

Although the construction permit included the particulate matter limit, the limit only applies to units with a design heat input less than 250 mmBtu/hr. The design heat input rate for each turbine and duct burner exceed 250 mmBtu/hr; therefore, the particulate matter requirements do not apply.

- Opacity of emissions shall not exceed 20% (Reg 6, Part B, Section II.C.3)
- SO_2 emissions shall not exceed 0.35 lbs/mmBtu (Reg 6, Part B, Section II.D.3.b). This standard only applies to the turbines.

Note that the NSPS general provisions (40 CFR Part 60 Subpart A) are adopted by reference into Reg 6, Part B, Section I.

- Best available control technology (BACT) shall be applied for control of emissions for NO_X, CO, PM, PM_{10} and VOC, BACT shall be as follows for the turbines and HRSGs (condition 8):

NO_X:

BACT is defined as DLN combustion and SCR with NO_X emissions limits as follows:

- Except as provided for below, emissions not to exceed 3 ppmvd at 15% oxygen on a 1-hour average.
- During startup and shutdown, NO_X emissions shall not exceed 300 ppmvd at 15% oxygen on an hourly average. Mass emissions of NO_X (lbs/hr) during periods of startup and shutdown shall be included in determining compliance with the annual limitations.
- Startup is defined as four (4) hours for cold startup, and one (1) hour for hot startup.
- Shutdown is defined as one (1) hour

It has generally been the Division's policy to define startup and shutdowns in terms of reaching a given operating mode or parameter, rather than a time based definition. Therefore, the Division has revised these definitions to include revised startup and shutdown definitions. Startup shall be defined as 30 minutes after the turbine reaches Stage-C Operation and shutdown shall be defined as when the operator gives the signal to shutdown the unit, until fuel is no longer fired in the turbine. Note that these definitions are consistent with definitions for similar turbines. The Division will provide the source with a chance to comment on and revise those definitions during the pre-public comment review period. Note that the averaging time for the startup and shutdown has also been revised. The limit shall be averaged over the duration of the startup and shutdown period, rather than on a one-hour average.

- Monthly average emissions of NO_X shall not exceed 0.01394 lbs/mmBtu heat input.

  The Division considers that since hourly NO_X BACT limits (in ppm) are provided that a monthly NO_X limit is not necessary. It appears that the lbs/mmBtu limit is based on the annual permitted NO_X emissions divided by the annual permitted heat input (based on a Btu content of 1057 Btu/scf). Therefore, this limit will not be included in the permit.

CO:

BACT is defined as good combustion practices and an oxidation catalyst with CO emission limits as follows:

- Except as provided for below, emissions not to exceed 9 ppmvd at 15% oxygen on a 1-hour average.
- Except as provided below, during startup and shutdown, CO emissions shall not exceed 1,000 ppmvd at 15% oxygen on an hourly average.
- During the first hour of a hot startup, CO emissions shall not exceed 2,000 ppmvd at 15% oxygen on an hourly average.
- Startup and shutdown have the same definitions as provided for NO_X.

  As discussed above under NO_X, the Division will revised the startup and shutdown limits to be parameter or operating mode based rather than time and the limits will be averaged over the entire startup and/or shutdown period. Therefore, the Division considers that a separate CO limit during the first hour of a cold start is not necessary and the limit was not included in the permit.
- Monthly average emissions of CO shall not exceed 0.04537 lbs/mmBtu heat input.

  The Division considers that since hourly CO BACT limits (in ppm) are provided that a monthly CO limit is not necessary. It appears that the lbs/mmBtu limit is based on the annual permitted CO emissions divided by the annual permitted heat input (based on a Btu content of 1057 Btu/scf). Therefore, this limit will not be included in the permit.

PM/PM_{10}

BACT is defined as use of pipeline quality natural gas and application of good combustion practices, with PM/PM_{10} emission limits as follows:

- Emissions of particulate matter shall not exceed 0.00735 lb/mmBtu.

  No averaging time was provided, the Division assumes that the averaging time was intended to be the average of three (3) one-hour test runs. The permit will be revised to clarify that.

VOC

BACT is defined as use of pipeline quality natural gas, application of good combustion practices and the oxidation catalyst, with VOC emission limits as follows:

- o Emissions of particulate matter shall not exceed 0.00293 lb/mmBtu.

  No averaging time was provided, the Division assumes that the averaging time was intended to be the average of three (3) one-hour test runs.

- Prior to final approval being issued, the source shall submit an operating and maintenance plan for all control equipment (condition 9).

  According to the Division's August 28, 2006 inspection report, since the continuous emission monitoring systems and data acquisition and handling system monitor compliance with virtually all permit conditions no operating and maintenance plan is required. It should be noted that the operating permit includes appropriate periodic monitoring to insure compliance with the requirements in this permit.

- The turbines/HRSGs are subject to the following processing limits (condition 10).

  - o Consumption of natural gas shall not exceed 32,625 MMscf/yr.

- Total facility emissions are subject to the following limitations (condition 11).

  Attachment A of the permit includes individual emission limits for the equipment at the facility. The Division does not consider that an overall facility limit is appropriate or necessary for this facility, therefore, the Division will only include emission limits in the permit for the various pieces of equipment.

  The permit included facility wide emission limits for formaldehyde and total of other HAPS. Based on the Division's analysis these HAP emission limits are not adequate. Based on the performance tests for formaldehyde, emissions are 2.44 tpy alone from the turbines/HRSGS, this is based on using the highest average test result (turbine 1, 0.00015 lb/mmBtu), multiplied by the design heat input rate (2,311 mmBtu/hr) at 8760 hrs/yr of operation and the lowest average test result (turbine 2, 0.00013 lb/mmBtu) multiplied by the design heat input rate and the remainder of the hours (hours of operation are based on the fuel consumption limit multiplied by 1057 Btu/scf and divided by the combined heat rate of the turbine/duct burner (2,311 mmBtu/hr)). Note that based on the highest average test result multiplied by allowable heat input (permitted fuel multiplied by 1057 Btu/scf), formaldehyde emissions are 2.59 tpy. In addition, there were other HAPS for which the Division could not confirm the source of the emission factor; therefore, we are requiring use of a different emission factor to set the permit limits. Therefore, the HAPS emission limits need to be revised the reflect formaldehyde emissions based on test results and the different emission factors for other HAPS. The emission limits that will be included in the permit for the facility are as follows:

  - o PM (includes condensables) 126.8 tons/yr
  - o PM_{10} (includes condensables) 126.8 tons/yr
  - o SO_2 11.8 tons/yr

- o NO_X 240.4 tons/yr
- o CO 782.2 tons/yr
- o VOC 50.6 tons/yr
- o Facility wide Formaldehyde 2.44 tons/yr
- o Facility wide total HAPS 13.1 tons/yr

The source submitted revised APENs on March 21, 2007 to reflect the change in HAP emissions.

- For the turbines/HRSG, CEMS shall be installed, calibrated, certified, maintained and operated to measure and record the following (condition 12):

  - o Hourly concentration of NO_X, ppmvd, corrected to 15% O_2
  - o Hourly concentration of O_2, in percent
  - o Emissions of NO_X, tons/month, and tons per rolling twelve month periods
  - o Hourly concentration of CO, ppmvd, corrected to 15% O_2
  - o Emissions of CO, tons/month, tons per rolling twelve month periods
  - o Fuel flow rate, SCF per hour for natural gas
  - o The CEMS shall meet the QA/QC requirements in 40 CFR Part 60 Appendix F and Subpart A, 40 CFR Part 75 and Division approved plan.

  Note that the Division will indicate in the Title V permit that the CEMS shall also record emissions of NO_X and CO in lbs/hr, as well as tons/month. The Division presumes that the rolling twelve month totals are not recorded on the data acquisition and handling system (DAHS) for the CEMS. Therefore, the twelve month rolling totals will not be identified as values recorded on the CEMS.

- Performance tests shall be conducted to demonstrate compliance with the emission limitations (condition 13).

  Performance tests were conducted on May 8, 11, 12, 20 and September 16, 2004 and the results of the test have been approved by the Division. Therefore, the performance test requirements will not be included in the permit.

- APEN reporting requirements (condition 14).

  The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section V (General Conditions) of the permit, condition 22.e.

Although not specifically identified in Colorado Construction Permit 02WE0228, the turbines are subject to the following applicable requirements:

- Particulate matter emissions, from each turbine and duct burner, shall not exceed 0.1 lbs/mmBtu (Reg 1, Section III.A.1.c)

- Sulfur dioxide emissions, from each turbine and duct burner, shall not exceed 0.35 lbs/mmBtu, on a 3-hour rolling average (Reg 1, Section VI.B.4.c.(ii) and VI.B.2).

- Compliance Assurance Monitoring Requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV. Note that no CAM plan was submitted, the NO_X and CO CEMS will be used to directly monitor compliance with the emission limitations.

- Each turbine/HRSG is subject to the Acid Rain requirements as follows:

    - Allocated SO_2 allowances are listed in 40 CFR Part 73.10(b), however, since these are new units, no allowances were allocated. SO_2 allowances must be obtained per 40 CFR Part 73 to cover SO_2 emissions for the particular calendar year.
    - There are no NO_X emission limitations since these units are not coal-fired boilers.
    - Acid rain permitting requirements per 40 CFR Part 72.
    - Continuous emission monitoring requirements per 40 CFR Part 75.
    - This source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

Streamlining of Applicable Requirements

<u>Opacity</u>

The turbines and duct burners are subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for certain specific operational activities. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. The turbines and duct burners are also subject to the state-only Reg 6, Part B 20% opacity requirement. The duct burners are subject to the NSPS opacity requirements (20% / 27%). The NSPS opacity requirements are not applicable during periods of startup, shutdown and malfunction in accordance with the requirement in 40 CFR Part 60 Subpart A § 60.11(c). Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20% / 30% requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction. While the Reg 6, Part B 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. The NSPS opacity requirements are more stringent than the Reg 1 30% requirements under all the specific operating conditions except startup but are less stringent than the state-only Reg 6 requirements. The Reg 1 (20%/30%) opacity requirements are more stringent than the NSPS requirements during startup, shutdown and malfunction. Therefore, since no one opacity requirement is more stringent than

the other at all times, all four opacity requirements are included in the operating permit. See the attached grid for a clarified view on the opacity requirements and their relative stringency.

It should be noted that since the turbines and duct burners use natural gas as fuel, the Division will presume, in the absence of credible evidence to the contrary, that these units are in compliance with all of the opacity requirements.

SO_2

Only the Regulation No. 1, Regulation No. 6, Part B (which only applies to the turbine) and NSPS Subpart Da (which only applies to the duct burner) SO_2 requirements are in the same units and can therefore be compared for the purposes of streamlining.

The Regulation No. 1 and No. 6, Part B SO_2 standards are the same, 0.35 lbs/mmBtu. The Regulation No. 6, Part B requirement is a state-only requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. Although not specifically stated in the general provisions, the Division has concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported in the excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "…it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, the Division considers that the Reg 6, Part B SO_2 requirements do not apply during periods of startup, shutdown and malfunction. Therefore, the Regulation No. 1 SO_2 requirement is more stringent than the Regulation No. 6, Part B requirement and the Regulation No. 6, Part B requirements will be streamlined out of the permit.

The NSPS Subpart Da requirement of 0.2 lbs/mmBtu applies to the duct burner and the Reg 1 SO_2 requirement applies to the turbine. Since the duct burner cannot be operated without the turbine and since the duct burner and turbine share a stack, for all practical purposes the turbine and duct burner combination together are subject to the Reg 1 and the NSPS Da SO_2 requirements. Although the NSPS Da requirement of 0.2 lbs/mmBtu appears to be more stringent than the Regulation No. 1 requirement, the NSPS Da requirement is based on a 30-day rolling average and the Reg 1 requirement is on a 3-hour rolling average. It is likely that the Reg 1 limit could be violated without violating the NSPS Da requirement. Therefore, these requirements cannot be adequately compared for stringency so both requirements will be included in the operating permit.

These units (turbine/HRSG/duct burner) are also subject to the Acid Rain SO_2 requirements. Sources subject to Acid Rain must hold adequate SO_2 allowances to cover annual emissions of SO_2 (1 allowance = 1 ton per year of SO_2) for a given unit in a given year. The number of allowances can increase or decrease for a unit depending on allowance availability. Allowances are obtained through EPA, other units operated by the utility or the allowance trading market and compliance information is submitted (electronically) to EPA. Pursuant to Regulation No. 3, Part C, Section V.C.1.b, if a federal requirement is more stringent than an Acid Rain requirement, both the federal requirement and the Acid Rain requirement shall be incorporated into the permit and shall be federally enforceable. For these reasons, the Acid Rain SO_2 requirements have not been streamlined out of the permit. The source will have to demonstrate compliance with the Acid Rain SO_2 requirements and the Reg 1 and NSPS Da SO_2 requirements. Note that the Acid Rain SO_2 allowances appear only in Section III (Acid Rain Requirements) of the permit.

<u>NO_X</u>

Since the NSPS Subpart GG and BACT concentration limits are in the same units, they can be compared for purposes of streamlining. The BACT concentration limits are applicable at all times. The Division considers that the NSPS Subpart GG requirements are not applicable during periods of startup, shutdown and malfunction (as discussed in the SO_2 streamlining section above). The BACT NO_X limits are much more stringent than the NSPS limits (3 ppmvd vs 102 ppmvd) and the averaging times for the BACT limit are more stringent are different (1-hr for BACT and 4-hr for NSPS). Therefore, since the NSPS Subpart GG limits are less stringent than the BACT concentration limits, the NSPS Subpart GG limits will be streamlined out of the operating permit.

Note that streamlined conditions are subsumed within the requirements identified in Section II of the permit. For purposes of compliance demonstration, compliance with the conditions in Section II of the permit also serve as compliance demonstration for the subsumed condition. Since the NSPS GG NO_X limit has been streamlined out in favor of the BACT NO_X limits, the source may wish to retain records of ambient temperature and humidity data which is used to convert NO_X values to ISO standard day conditions, in the event that the NO_X BACT limit is violated at such a level that compliance with the NSPS GG BACT limit is uncertain.

The duct burner is subject to an NSPS Subpart Da NO_X limit of 1.6 lbs/MW-hr gross energy output, on a 30-day rolling average. The source submitted information on January 19, 2007 demonstrating that the NSPS Da NO_X limit is less stringent than the NO_X BACT limit. The Division agrees and therefore, the NSPS Da NO_X limit has been streamlined out of the permit in favor of the NO_X BACT limit.

<u>PM</u>

The turbines and duct burners (alone and together) are subject to a Reg 1 particulate matter standard and the BACT limit and the duct burners are subject to the NSPS Da particulate matter standard. Since the duct burners would not be operated without the

turbines and since the duct burners and turbines share a stack, for all practical purposes the turbine/duct burner combinations together are subject to the NSPS Da particulate matter standard. The NSPS Da requirement does not apply during periods of startup, shutdown and malfunction, as specifically stated in § 60.48a(c). The Reg 1 and the BACT particulate matter standards apply at all times. The particulate matter BACT limit is more stringent than both the Reg 1 and NSPS Da limit at all times (see attached grid). In addition, the testing requirements for the PM BACT limit and the Reg 1 BACT limit are based on three (3) one-hour tests, while NSPS Da PM limit is based on the average of three (3) two-hour tests; consequently the averaging times for the Reg 1 and NSPS Da limit are as stringent or more stringent than the averaging time for the PM BACT limit. Therefore, the NSPS Da and the Reg 1 particulate matter limits will be streamlined in favor of the BACT limit.

Monitoring

These units (turbines/HRSGs) are subject to several types of monitoring requirements. The construction permit requires that the stacks be equipped with continuous emission monitoring systems (CEMS) to monitor and record NO_X and CO emissions and the construction permit requires that these monitors be installed, maintained, calibrated and operated according to 40 CFR Part 60, Appendix F and Subpart A, 40 CFR Part 75 and a Division approved plan. These units are also subject to the Acid Rain requirements and as such are required to monitor emissions in accordance with the requirements in 40 CFR Part 75. The duct burner is subject to NSPS subpart Da. For combined cycle units (turbine plus duct burner) NSPS Da allows compliance with the NO_X requirements to be demonstrated with either a one-time performance test or a CEMS. NSPS Da specifically states that combined cycle units are not required to have NO_X CEMS (40 CFR Part 60 Subpart Da § 60.47a(o)). Since the source demonstrated compliance with the NSPS Da NO_X limit with a one-time performance test, the NSPS Da NO_X CEMS requirements do not apply to the duct burner and therefore need not be considered further for purposes of streamlining.

Since the source has installed Part 75 NO_X (and diluent) CEMS, the permit will specify that the NO_X (and diluent) CEMS must meet the requirements in 40 CFR Part 75. This is consistent with the language in the construction permit, so no streamlining of requirements is necessary.

It should also be noted that the 40 CFR Part 60 excess emission reporting requirements for NO_X will remain in the permit as 40 CFR Part 75 does not contain any NO_X excess emission reporting requirements.

It should be noted that the NSPS GG revisions indicate that no nitrogen sampling is required if credit was not taken for fuel-bound nitrogen in setting the NO_X emission limitations. This was the case for these units. Therefore, since sampling the fuel for the nitrogen content is not required, there are no requirements to streamline.

Under the Acid Rain provisions, sources that demonstrate that the gas burned meets the definition of pipeline quality natural gas may use an emission factor to calculate

hourly SO_2 emissions, as allowed by 40 CFR Part 75 Appendix D. The NSPS GG revisions specify that no fuel sampling is required if natural gas is used as fuel, since these turbines burn pipeline quality natural gas, which has a lower sulfur content then natural gas, the methods to demonstrate that natural gas is used as fuel will be streamlined in favor of the Part 75 pipeline quality natural gas requirement.

Miscellaneous

Since the turbines and duct burners are subject to federal NSPS requirements (Subparts Da and GG) and state-only NSPS requirements (Reg 6, Part B, Section II), they are subject to the general provisions on a federal and state-only basis. The state-only general provisions will be streamlined in favor to the federal general provisions.

2. Emission Factors: Emissions from these turbines are produced during the combustion process, and are dependent upon operating conditions and specific properties of the natural gas being burned. The pollutants of concern are Nitrogen Oxides (NO_X), Carbon Monoxide (CO), Volatile Organic Compounds (VOC) and Particulate Matter (PM and PM_{10}). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted dependent upon the makeup of the fuel and combustion efficiency.

NO_X and CO emissions shall be determined using the continuous emission monitoring system required by the construction permit. SO_2 emissions shall be determined using monitoring methods required by 40 CFR Part 75, Appendix D.

The source proposed to use the following emission factors to monitor compliance with the emission limits:

Pollutant	Emission Factor (lbs/mmBtu)	Source
PM	0.001	From performance tests conducted May 8, 11, 12, 20 and September 16, 2004.
PM_{10}	0.001	
VOC	Unit 1 - 7.3×10^{-4} Unit 2 – 1.5×10^{-4}	

The above emission factors are based on the test results (average of 3 tests) for each turbine/HRSG. The Division agrees that the emission factors are appropriate to use to monitor compliance with the annual PM, PM_{10} and VOC annual limitations.

The facility is also subject to HAP limits, which include a facility wide total HAP limit and a formaldehyde limit. Since there are significant HAPS from the turbines/duct burners, the source will be required to demonstrate compliance with the facility wide HAP limits. Since permitted HAP emissions are well below the major source level, the Division will only require that emissions from significant HAPS be calculated. The HAP emission factors to be used in these calculations are as follows:

Pollutant	Emission Factor	Source
Formaldehyde	S001 – 1.5 x 10^{-4} lb/mmBtu S002 – 1.3 x 10^{-4} lb/mmBtu	From performance tests conducted May 8, 11, 12, 20 and September 16, 2004.
Acetaldehyde	**1.37 x 10^{-1} lb/mmSCF**	From California Air Toxics Emission Factor (databases) for natural gas-fired turbines with COC and SCR.
Acrolein	**1.89 x 10^{-2} lb/mmSCF**	
Benzene	**1.33 x 10^{-2} lb/mmSCF**	
Ethylbenzene	1.79 x 10^{-2} lb/mmSCF	
Hexane	2.59 x 10^{-1} lb/mmSCF	
Propylene Oxide	4.78 x 10^{-2} lb/mmSCF	
Toluene	7.10 x 10^{-2} lb/mmSCF	
Xylene	2.61 x 10^{-2} lb/mmSCF	

Note that the emission factors listed in bold are not the same as the emission factors used in the initial construction permit application because the Division could not confirm those emission factors.

3. Monitoring Plan: The source will be required to monitor compliance with the NO_X and CO BACT and annual emission limitations using the CEMS. Compliance with the annual SO_2 emission limits will be monitored using the continuous monitoring system required by 40 CFR Part 75 Appendix D. Compliance with the annual VOC, PM and PM_{10} emission limitations shall be monitored using emission factors and the fuel consumption from the turbines and duct burners.

Compliance with the various short term SO_2 requirements and the opacity requirements shall be presumed, in the absence of credible evidence to the contrary, since only natural gas is permitted to be used as fuel in the turbines and duct burners.

Performance tests were conducted to demonstrate compliance with the PM and VOC BACT emission limits and the results of the tests were much less than 50% of the standard (for PM, average test results 0.001 lb/mmBtu vs. 0.00735 lb/mmBtu BACT limit (14% of BACT limit) and for VOC, highest average test result 0.00073 lb/mmBtu vs. 0.00293 lb/mmBtu BACT limit (25% of BACT limit)). Compliance with the PM BACT limit shall be presumed, in the absence of credible evidence to the contrary, since natural gas is the only fuel permitted for use in the turbines/duct burners. In addition, the Division will require that a performance test be conducted within the last 18 months of the permit term to verify compliance with the PM/PM_{10} BACT limit. Since VOC emissions are controlled by the oxidation catalyst, which also controls CO emissions and CO emissions are monitored with the CO CEMS, the Division considers that compliance with the VOC BACT limit is presumed, in the absence of credible evidence to the contrary, provided compliance with the CO BACT limit is demonstrated. Because compliance with the VOC BACT limit will be monitored continuously using compliance with the CO BACT limits as a surrogate and the fact that only pipeline quality natural

gas is permitted to be used as fuel, the Division considers that no further performance tests are required for the VOC BACT limit.

4. Compliance Status: In the Title V permit application, the source indicated that the turbines/HRSGS were in compliance with all applicable requirements. Upon issuance of the Title V permit to adjust the HAP emission limits, the Division agrees that the source will be in compliance with all applicable requirements.

Unit S003. John Deere, Model No. 6081AF001, Serial No. RG6081A159985, Internal Combustion Engine Driving an Emergency Fire Water Pump, Rated at 182 hp and 1.26 mmBtu/hr. Diesel Fuel Fired.

Unit S005: Caterpillar, Model No. 3512B, Serial No. 1GZ01360, Internal Combustion Engine Driving an Emergency Generator, Rated at 1810 hp and 12.2 mmBtu/hr. Diesel Fuel Fired.

1. Applicable Requirements: The two diesel fuel-fired engines are included in Colorado Construction Permit 02WE0228 (initial approval, modification 1, issued June 23, 2004), the permit includes diesel fuel consumption limits for the two engines, operating limits of 200 hrs/yr for the fire pump and 100 hrs/yr for the emergency generator and presumably the emission limits are included in the facility wide limitations (individual emission limits are included in Attachment A of the permit).

The fire pump is exempt from APEN reporting provided it is operated for less than 850 hrs/yr (Colorado Regulation No. 3, Part A, Section III.D.1.sss.(ii)). While it is necessary to consider emissions from APEN exempt equipment in determining whether a project is subject to PSD review (i.e. emissions above the major stationary source threshold and/or significance level), it is not necessary to conduct a BACT analysis on an emission unit that would not be required to have a permit, nor would it be necessary to require a permit for an emission unit that would otherwise be exempt from permitting because it is part of a project that has triggered PSD review. Therefore, the fire pump will be included in the Title V permit as an insignificant activity.

As identified in the construction permit and in the Title V permit application, the emergency generator exceeds the size of APEN exempt emergency generators noted in Colorado Regulation No. 3, Part A, Section II.D.1.ttt; however, all emergency generators operated less than 250 hrs/yr are exempt from construction permit requirements according to Colorado Regulation No. 3, Part B, Section II.D.1.c.(ii). As discussed above for the fire pump, since a permit is not required for the emergency generator a BACT analysis was not conducted for the emergency generator. The Division does not feel that a BACT analysis would be necessary for such a unit and that such analysis would not result in any add-on controls on this unit.

In their January 19, 2007 submittal, the source provided information indicating that the emergency generator was actually rated at 1810 hp, not the 2000 hp indicated in the construction permit and the Title V permit application. Emergency generators less than

1840 hp are exempt from the APEN reporting requirements if they are operated for less than 100 hrs per year and may be considered insignificant activities (Colorado Regulation No. 3, Part A, Section II.D.1.ttt.(iii) and Part C, Section II.E.3.nnn.(iii)). Based on that information, the Division could consider this engine an insignificant activity and include it in the list of insignificant activities in Appendix A of the permit.

However, the source submitted an application to modify the construction permit on March 22, 2007 to increase the number of hours the emergency generator is permitted to run and to increase the quantity of permitted diesel fuel for both the fire-pump and the generator. Due to an outage in May of 2007, the diesel generator will need to run for more than 100 hours per year but less than 250 hours per year. At that level, the emergency generator would be subject to APEN reporting requirements but exempt from construction permit requirements. Therefore, the Division will include the emergency generator in the Section II of the Title V permit, rather than in the insignificant activity list. Note that since it is expected that in future years, the engine will be operated at less than 100 hours per year and would be exempt from APEN reporting requirements the Division will include provisions for lesser monitoring requirements for this unit if hours of operation in any year fall below 100 hours per year.

In addition, to the APEN reporting requirements, the emergency generator is subject the following applicable requirements:

- Visible emissions shall not exceed twenty percent (20 %) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity (condition 6).

  Note that Colorado Regulation No. 1 does not identify the 20% opacity requirement as a condition that only applies during normal operation and EPA has objected, in comments on another operating permit, to the term “normal operations” applied to the 20% opacity standard. The specific operational activities subject to the 30% opacity requirement are also conditions that can be considered “normal operation”. In addition, there are additional specific operational conditions included under the 30% opacity limit. Based on engineering judgment the Division considers that building a new fire, cleaning of fire boxes and soot-blowing does not apply to the operation of this engine when burning No. 2 fuel oil. In addition, this engine does not have a control device, so adjustment or occasional cleaning of control devices do not apply to this unit. Process modifications may apply to engines, however, based on engineering judgment, the Division believes that such activities would be unlikely to occur for longer than six minutes. Startup is an activity that applies to this engine, however based on engineering judgment the Division believes that startup for this engine is quick and lasts less than twelve (12) minutes. Under the Reg 1 30% opacity standard, one 6 minute interval in each hour while one of the specific activities is occurring is not subject to an opacity limitation. For the remainder of the hour, the opacity emissions are limited to 30%, however, the 30% opacity standard is based on a six minute average. Therefore, for an

emission unit that takes less than twelve (12) minutes to start up, the 30% opacity standard is not applicable. Therefore, the 30% opacity requirement has not been included in the operating permit.

- Sulfur dioxide emissions shall not exceed 0.8 lb/mmBtu (Colorado Regulation No. 1, Section B.4.b.(i)).

  Note that this requirement was not included in the construction permit

Although the construction permit included fuel consumption and emission limits, as well as hours of operation for the emergency generator, since this unit is exempt from construction permit requirements, the Division is not including the fuel consumption and emission limits in the Title V permit. However, it should be noted that if hours of operation for this unit exceed 250 hrs/yr, then a construction permit would be required and emission and throughput limits would be required. The Division would reopen the permit for cause to include such requirements if the hours of operation exceeded the permit exempt level of 250 hrs/yr.

2. Emission Factors: Emissions from this engine is from the combustion of fuel oil. The pollutants of concern are Particulate Matter, (PM and PM_{10}), Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC). Some hazardous air pollutants (HAPs) are generated through the combustion process, although emissions are minimal. Approval of emission factors for this unit is necessary to the extent that accurate actual emissions are required to verify the need to submit revised APENs to update the Division=s Emission Inventory.

In the Title V permit application the source indicated that they were basing emissions from the engine on emissions factors from the manufacturer, with SO_2 emissions based on a fuel sulfur content of 0.05 % by weight (fuel oil density of 7.05 lb/gal). The emission factors to be included in the permit are as follows:

Pollutant	Emission Factor
PM	0.4 g/hp-hr
PM_{10}	0.4 g/hp-hr
SO_2	5.14×10^{-2} lb/mmBtu
NO_X	6.9 g/hp-hr
CO	8.5 g/hp-hr
VOC	1 g/hp-hr

Note that at 250 hrs/yr of operation, PM, PM_{10}, VOC and SO_2 emissions are below the APEN de minimis level, so the source will not be required to calculate emissions of these pollutants from this unit; however, emissions from all criteria pollutants are to be included on any revised APENS.

3. Monitoring Plan: The source will be required to record hours of operation annually for purposes of calculating emissions to determine APEN reporting requirements.

Emissions shall be based on hours of operation and the maximum horsepower of the engine.

4. Compliance Status: In the Title V permit application, the source indicated that the engines were in compliance with all applicable requirements.

Unit S004: Rentech, Natural Gas Fired Boiler, Rated at 129 mmBtu/hr, Serial No. 2002-49. Equipped with Low NO_X Burners.

1. Applicable Requirements: The initial approval construction permit (02WE0228) for the facility was issued on July 15, 2002, with a modification issued on June 23, 2004. A request was submitted on March 22, 2007 to revise the construction permit; however, the revisions only affected the emergency generator. According to the Title V permit application, the boiler commenced operation in February 2004. It is not clear when the self-certification was submitted and no final approval permit has been issued. Under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect. The appropriate provisions of the initial approval construction permit have been directly incorporated into this Title V operating permit. The applicable requirements included in the construction permit for the boiler are as follows:

- Conditions 2 (self-certification), 5 (emissions of hazardous air pollutants), 9 (submittal of operating and maintenance plan), 13 (performance test) and 14 (APENs) are addressed as discussed above under Units S001 and S002 (combustion turbines/HRSGs).

- Visible emissions shall not exceed twenty percent (20 %) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity (condition 6).

  Note that Colorado Regulation No. 1 does not identify the 20% opacity requirement as a condition that only applies during normal operation and EPA has objected, in comments on another operating permit, to the term “normal operations” applied to the 20% opacity standard. The specific operational activities subject to the 30% opacity requirement are also conditions that can be considered “normal operation”. Therefore, the language in the permit will not specify “normal operation”. The 30% opacity requirement will be written to include all the specific operational activities identified in Reg 1.

- Regulation No. 6, Part A, Subpart Db – Standards of Performance for Industrial-Commercial – Institutional Steam Generating Units, as follows (condition 7):

  - The boiler operates exclusively on natural gas, and the operation does not exceed 1,900 hrs/yr.

This condition is listed in the construction permit as a requirement under NSPS Subpart Db, however, NSPS Db does not require any limitations on hours of operation unless the source wishes to limit the capacity factor in order to have lesser monitoring requirements. The hours of operation limit is not sufficient to allow for the lesser monitoring and the fuel consumption limit provided later in the permit stipulates limited operation on only natural gas, therefore, this requirement will not be included in the permit.

- Nitrogen oxide emissions shall not exceed 0.20 lb/mmBtu, the NO_X emission limitation is on a 30-day rolling average and apply at all times including periods of startup, shutdown and malfunction (40 CFR Part 60 Subpart Db §§ 60.44b(l)(1), (h) and (i)).
- Compliance with the NO_X emission limits under § 60.44b shall be determined through performance testing under paragraph (e) and (f), or under paragraphs (g) and (h) of this section as applicable (40 CFR Part 60 Subpart Db § 60.46b(c)).

  Note that paragraph (f) applies to duct burners and paragraphs (g) and (h) apply to units that meet the requirements in 60.44b(j). The boiler does not meet the provisions of 60.44b(j). Since the boiler runs infrequently the Division allowed compliance with the NO_X limit to be demonstrated with a performance test (three (3) one hour test runs). The performance test were conducted May 8, 11, 12, 20 and September 16, 2004 and demonstrated compliance with the NO_X limits.
- The owner or operator subject to the NO_X limitation under 60.44b shall install, calibrate, maintain and operate a continuous monitoring system (40 CFR Part 60 Subpart Db § 60.48b(b)(1)). The NO_X continuous monitoring system is subject to the requirements in 60.48b(c), (d), (e) and (f).
- Reporting and recordkeeping requirements under § 60.49b(a) - startup notice, (b) – performance test data, (d) – daily fuel, capacity factor, (g) – recordkeeping, (h) – excess emission reports, (i) – NO_X monitoring reports and (o) – recordkeeping duration.

Note that, except for the hours of operation limit discussed above, the construction permit only included the NSPS Db NO_X emission limits in the permit, the other monitoring requirements are specified in NSPS Subpart Db be were not included in the permit.

- Regulation No. 6, Part A, Subpart A – NSPS General Provisions (condition 7)
  - Good practices (§ 60.11(d))
  - Circumvention (§ 60.12)

  Note that a more extensive list of requirements from 40 CFR Part 60 Subpart A was included in the construction permit. However, these requirements, if still applicable, will be included in the permit as periodic monitoring or under the

continuous emission monitoring requirements and will not be specifically identified as requirements under the NSPS general provisions.

- Regulation No. 6, Part B, Section II – Standards of Performance for New Fuel-Burning Equipment (condition 7). These are **State-only requirements.**

  - Particulate Matter Emissions shall not exceed $PE = 0.5(FI)^{-0.26}$ (Section II.C.2)

    Where: PE = Particulate emissions in lbs/mmBtu
    FI = Fuel input in mmBtu/hr

  - Opacity of emissions shall not exceed 20% (Reg 6, Part B, Section II.C.3)

  Note that the NSPS general provisions (40 CFR Part 60 Subpart A) are adopted by reference into Reg 6, Part B, Section I.

- BACT shall be applied for control of emissions for NO_X, CO, PM, PM_{10} and VOC, BACT shall be as follows for the auxiliary boiler (condition 8):

  - 1,900 hrs/yr of operation
  - NO_X – dry low NO_X combustion system, emissions shall not exceed 0.038 lb/mmBtu
  - CO – good combustion practices, emissions shall not exceed 0.039 lb/mmBtu

  It should be noted that the permit did not include a BACT analysis for VOC, PM or PM_{10} emissions. The Division considers that good combustion practices would be BACT for CO as well as VOC. In addition, the Division considers that use of pipeline quality natural gas as fuel would be BACT for the boiler. The Division has on occasion not set BACT emission limitations for PM, PM_{10} and VOC emissions for sources relying on good combustion practices and fuel restriction as the control technology. These BACT determinations will be included in the Title V permit; however, no emission limitations will be provided for PM, PM_{10} and VOC.

  In addition, the permit does not specify the averaging time for the BACT limits for NO_X and CO. Since the construction permit did not require a continuous emission monitoring system for the boilers, it is presumed that compliance would be demonstrated based on the performance test (the average of three (3) one hour tests). The permit will be revised to specify that the averaging time for the CO BACT limit shall be the average of three (3) one hour tests and that the NO_X BACT limit is based on a 3-hr rolling average, since the boiler is equipped with a NO_X CEMS as required by NSPS Subpart Db.

  Finally, since the permit also includes a fuel consumption limit in the permit for the boiler, the Division does not believe that a limit on the hours of operation is also necessary. Therefore the Division will not include the hours of operation limit in the permit.

- The boiler subject to the following processing limits (condition 10).

- Consumption of natural gas shall not exceed 231,882,687 scf/yr.

It should be noted that Attachment A of the permit lists individual fuel consumption and emission limits for specific equipment. The fuel consumption limit provided in Attachment A is 259,070,700 scf/yr. The Division considers that most likely the fuel consumption limit provided in the main part of the permit is probably correct and has included that limitation in the Title V permit.

In addition, the Division will round this limit to 231.9 mmSCF/yr in the permit to simplify the recordkeeping.

- Total facility emissions are subject to the following limitations (condition 11).

As discussed above, Attachment A includes individual emission limits for the equipment at the facility. The Division does not consider that an overall facility limit is appropriate or necessary for this facility; therefore, the Division will only include emission limits in the permit for the various pieces of equipment. The permit included facility wide emission limits for formaldehyde and total of other HAPS. Based on the fuel consumption limits and the emissions factors in the construction permit application, total HAP emissions from the boiler are 0.003 tpy (based on AP-42 emission factors, total HAPS are 0.22 tpy). Since the boiler is not equipped with a control device to reduce HAP emissions and based on the requested fuel consumption limit, HAP emissions from the boiler are so low, the Division does not consider that a HAP emission limit is necessary for the boiler. Therefore, no HAP limit has been included for the boiler. The emission limits that will be included in the permit for the boiler are as follows:

- PM 2.28 tons/yr
- PM_{10} 2.28 tons/yr
- NO_X 4.7 tons/yr
- CO 4.75 tons/yr

SO_2 and VOC emissions are below the APEN de minimis level so emission limits for those pollutants have not been included in the permit; however, all criteria pollutants must be reported on APENS. In addition, Attachment A of the construction permit lists individual CO emissions at 2.8 tons/yr. Based on the emission factor in the permit application (same as the BACT limit), the CO emission limit would be exceeded at the permitted fuel consumption rate. Therefore, the Division has increased the CO emission limit in the Title V permit. In addition, Attachment A of the permit did not include PM and PM_{10} emission limits. Based on the emission factors and permitted natural gas consumption rate, emissions of PM and PM_{10} are above the APEN de minimis level; therefore, limits on PM and PM_{10} emissions will be included in the permit. The source submitted a revised APEN on March 21, 2007, requesting CO, PM and PM_{10} emissions of 4.75, 2.28 and 2.28 tons/yr, respectively.

Although not specifically identified in Colorado Construction Permit 02WE0228, the boiler is subject to the following applicable requirements:

- Particulate Matter Emissions shall not exceed $PE = 0.5(FI)^{-0.26}$ (Reg 1, Section III.A.1.b)

Where: PE = Particulate emissions in lbs/mmBtu
FI = Fuel input in mmBtu/hr

Streamlining of Applicable Requirements

Opacity

The boiler is subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for certain specific operational activities. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. The boiler is also subject to the state-only Reg 6, Part B 20% opacity requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20%/30% requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction. While the Reg 6, Part B 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. Therefore, since no one opacity requirement is more stringent than the other at all times, all three opacity requirements are included in the operating permit. See the attached grid for a clarified view on the opacity requirements and their relative stringency.

PM

The boiler is subject to the Reg 1 particulate matter requirements and the state-only, Reg 6, Part B particulate matter requirements. The particulate matter requirements in both Reg 1 and Reg 6, Part B are the same standard. The Reg 1 particulate matter requirements apply at all times. For the same reasons as indicated under the SO_2 streamlining section for the turbines/HRSGs the Reg 6, Part B particulate matter requirements are not applicable during startup, shutdown and malfunction. As a result, the Reg 6, Part B requirements have been streamlined out of the permit.

NO_X

The NSPS Db and BACT limits are in the same units, therefore, they can be compared for purposes of streamlining. The NSPS Db NO_X limits are applicable at all times, including periods of startup, shutdown and malfunction. The NO_X BACT limits are also applicable at all times. The NO_X BACT limits are much more stringent than the NSPS limit (0.038 lb/mmBtu vs 0.20 lb/mmBtu) and the averaging time for the NO_X BACT limit is more stringent than the NSPS Db limits (3-hr rolling average for BACT, 30 day rolling

average for NSPS). Therefore, since the NSPS Db limit is less stringent than the BACT limit, the NSPS Db limit will be streamlined out of the operating permit.

Monitoring

The construction permit does not include any monitoring requirement for the auxiliary boiler, It is presumed that compliance with the NO_X BACT limit would be demonstrated by a performance test. NSPS Db requires that the source be required to install and operate a NO_X CEMS to demonstrate compliance with the NO_X limit. Although the Division is streamlining out the NSPS Db NO_X limit in favor of the NO_X BACT limit, since the monitoring for the NSPS Db limit is more stringent, the source will be required to use the CEMS to demonstrate compliance with the NO_X BACT limit. Note that the CEMS will be required to meet the same requirements in 40 CFR Part 60 Subparts A and Db, except for the data replacement requirements in 40 CFR Part 60 Subpart Db § 60.48b(f), since the minimum data requirements are based on the 30-day averaging period for the NSPS Db emission limit that is being streamlined from the permit.

NSPS Db requires that the NO_X CEMS shall have a span value of 500 ppm (40 CFR Part 60 Subpart Db § 60.48(e)(2)). However, since the BACT emission limit is lower than the NSPS Db limit; therefore, a narrower span value is more appropriate for a lower limitation. Since the Division has streamlined out the NSPS Db NO_X limit, we are also streamlining the 500 ppm span value requirement for the NO_X CEMS in favor of a more appropriate 100 ppm span value.

NSPS Db also includes recordkeeping and reporting requirements, such as submitting startup notices and performance test results, CEMS recordkeeping and CEMS monitoring and excess emission reports. Since the unit has started up and conducted and submitted performance test results, the startup notification and submittal of performance test results have already been submitted and no longer apply. Since the CEMS recordkeeping and monitoring and excess emission reports all related to the 30-day limit that has been streamlined from the permit, the Division considers that these requirements are streamlined under the requirement to report under the excess emission reporting requirements for the NO_X BACT limit.

Under NSPS Db, the source is required to retain records for two years, while under Title V, records must be retained for five years. The Division will streamline the NSPS Db requirement for record retention in favor of the Title V recordkeeping requirement (Section V, Condition 22.b and c).

Miscellaneous

Since the boiler is subject to federal NSPS requirements (Subpart Db) and state-only NSPS requirements (Reg 6, Part B, Section II), they are subject to the general provisions on a federal and state-only basis. The state-only general provisions will be streamlined in favor to the federal general provisions.

2. Emission Factors: Emissions from this boiler are produced during the combustion process, and are dependent upon operating conditions and specific properties of the natural gas being burned. The pollutants of concern are Nitrogen Oxides (NO_X), Carbon Monoxide (CO), Volatile Organic Compounds (VOC), and Particulate Matter (PM and PM_{10}). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted dependent upon the makeup of the fuel and combustion efficiency. Compliance with the emission limits included in the permit shall be based on the following emission factors:

Pollutant	Emission Factor	Source
PM	0.0186 lb/mmBtu	Manufacturer
PM_{10}	0.0186 lb/mmBtu	
CO	0.039 lb/mmBtu	

The NO_X continuous emission monitoring system shall be used to determine compliance with the NO_X emission limitations.

3. Monitoring Plan: – The source will be required to record fuel consumption and calculate emissions monthly to monitor compliance with the annual fuel consumption and emission limitations. Monthly emissions and fuel consumption shall be used in twelve month rolling totals to monitor compliance with the annual limitations. For the annual NO_X emission limitations (both short term and annual), compliance will be monitored using the NO_X CEMS. Compliance with the PM, opacity and SO_2 requirements are presumed, in the absence of credible evidence to the contrary whenever natural gas is used as fuel in the boiler. The results of the initial compliance test for the CO BACT limit were less than 50% of the standard (0.0164 lb/mmBtu), therefore, a performance test shall be required in the last 18 months of the permit term to verify compliance with the CO BACT limit.

4. Compliance Status: In the Title V permit application, the source indicated that the boiler was in compliance with all applicable requirements.

Unit S006: Marley, Model No. F4910, 13 Cell Cooling Water Tower, Rated at 176,000 Gal/Min.

1. Applicable Requirements: The initial approval construction permit (02WE0228) for the facility was issued on July 15, 2002, with a modification issued on June 23, 2004. A request was submitted on March 22, 2007 to revise the construction permit; however, the revisions only affected the emergency generator. The Title V permit application did not indicate when the cooling water tower commenced operation; however, the Division presumes that operation commenced in March 2004 when the turbines/HRSGs commenced operation. It is not clear when the self-certification was submitted and no final approval permit has been issued. Under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect. The appropriate provisions of the initial approval construction permit have been directly

incorporated into this Title V operating permit. The applicable requirements included in the construction permit for the boiler are as follows:

- Conditions 2 (self-certification), 5 (emissions of hazardous air pollutants), 9 (submittal of operating and maintenance plan) and 14 (APENs) are addressed as discussed above under Units S001 and S002 (combustion turbines/HRSGs).

- Visible emissions shall not exceed twenty percent (20 %) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity (condition 6).

  Note that Colorado Regulation No. 1 does not identify the 20% opacity requirement as a condition that only applies during normal operation and EPA has objected, in comments on another operating permit, to the term “normal operations” applied to the 20% opacity standard. The specific operational activities subject to the 30% opacity requirement are also conditions that can be considered “normal operation”. Based on engineering judgment, the Division believes that for purposes of opacity emissions none of the conditions under the 30% opacity requirement apply. Specifically activities such as fire building, cleaning of fire boxes and soot blowing are not germane to cooling towers. In addition, there is really no “startup” involved in operating a cooling tower. Finally, the Division does not believe that adjustment of the control device (drift eliminators) can be done while operating the tower and that process modifications would be limited. Therefore, the 30% opacity requirement will not be included in the operating permit as the specific operating activities under which it applies does not occur with this unit.

- BACT shall be applied for control of PM and PM_{10} emissions, BACT shall be as follows for the cooling tower (condition 8):

  - High efficiency drift eliminators to limit the drift to 0.0005%.
  - Emissions of particulate matter shall not exceed 0.42 lbs per million gallons of water circulation.

  The 0.42 lbs/million gallons of water is based on total solids concentration used to estimate permitted emissions (10,000 ppmw) and the efficiency of the drift eliminators. The level of total solids concentration in the cooling tower is not really a result of the control technology but based more on the method of operation (i.e. number of cycles). Typically PSD permits for cooling towers usually only include as a BACT limitation specifying the efficiency of the drift eliminators, and not a limit based on the total solids concentration. Therefore, the Division will not include the 0.42 lbs/million gallons of water circulation limit in the permit. Note that the annual PM and PM_{10} emission limitations for the cooling tower are based on this hourly limitation multiplied by the annual water circulation rate.

- The cooling tower is subject to the following processing limits (condition 10).

  - Water circulated shall not exceed 91,595,260,800 gal/yr

    In their comments submitted on November 17, 2006, the source indicated that the cooling tower was actually rated at 176,000 gallons per minute; therefore, they submitted a revised APEN on January 19, 2007 to increase the annual limit on the quantity of water circulated to 92,505.6 mmgal/yr.

- Total facility emissions are subject to the following limitations (condition 11).

  As discussed above under the Auxiliary Boiler, the Division does not consider that an overall facility limit is appropriate or necessary for this facility; therefore, the Division will only include emission limits in the permit for the various pieces of equipment. Based on a chloroform emission factor of 2.3 kg/10^9 liter and the requested water circulation limit, chloroform emissions exceed the APEN de minimis level for HAP reporting (emissions are 1775 lbs/yr) but not for criteria pollutant reporting (chloroform is a VOC). Therefore, since chloroform emissions from the cooling tower are significant, they should be included in the total HAP limit for the facility. As discussed above under Units S001 and S002 (turbines/HRSGS), the facility total HAP limit is being revised in the Title V permit. The emission limits that will be included in the permit for the boiler are as follows:

  - PM 19.1 tons/yr
  - PM_{10} 19.1 tons/yr
  - Facility wide total HAPS 13.1 tons/yr

  As discussed previously, the source has requested an increase in the limitation on the quantity of water circulated, which also results in an increase in PM and PM_{10} emissions. The source submitted a revised APEN on January 19, 2007 to increase the PM and PM_{10} emission limits to 19.3 tons/yr. The source submitted a revised APEN on March 21, 2007 that included a HAP addendum to address chloroform emissions.

2. Emission Factors: Since cooling water towers provide direct contact between the cooling water and the air passing through the tower, some liquid can be entrained in the air stream and emitted as Adrift@ droplets. Particulate matter contained in the Adrift@ is considered an emission as well as any chloroform from water treatment chemicals used in the cooling water tower. Approval of emission factors for this unit is necessary to monitor compliance with the emission limits. The permit will require the source to calculate emissions from the cooling water towers in the following manner:

PM = PM_{10} = (water flow, gpm) x (water density, lbs/gal) x (% drift) x (total solids, ppm)

Where: % drift = 0.0005% (BACT limit)
Density of water = 8.34 lbs/gallon
Total Solids = to be determined quarterly

$CHCl_3$ = (water flow, gpm) x (3.785 l/gal) x (2.3 kg $CHCl_3$/10^9 liter) x 2.205 lb/kg

Where: 2.3 kb/10^9 liter emission factor - from "Locating and Estimating Air Emissions from Sources of Chloroform", EPA-450/4-84-007c, March 1984, for recirculating units

3. Monitoring Plan: The source will be required to monitor and record the water circulation rate and calculate emissions monthly. In order to calculate emissions, the total solids content of the circulating water in the tower must be analyzed. The permit will require that the total solids content of the circulating water in each tower be analyzed quarterly. In the absence of credible evidence to the contrary, compliance with the opacity requirement will be presumed provided the cooling tower and associated drift eliminators are operated and maintained in accordance with the manufacturer's recommendations and good engineering practices.

4. Compliance Status: In the Title V permit application, the source indicated that the cooling tower was in compliance with all applicable requirements.

IV. Insignificant Activities

The source indicated that the following general categories of insignificant activities at this site include: landscaping and site housekeeping devices < 10 hp, tanks with annual throughput less than 400,000 gal per year (limited contents), and internal combustion engines (limited size and hours of operation). A specific list of insignificant activities was not included in the Title V permit application. However, based on the information in the Title V permit application, the construction permit and information provided by the source, the following insignificant activities are located at this facility:

<u>Units with emissions less than APEN de minims – non-criteria reportable pollutants (Reg 3, Part C.II.E.3.b)</u>

Two (2) 12,000 gal anhydrous ammonia storage tanks

<u>Fuel (gaseous) burning equipment < 5 mmBtu/hr (Reg 3, Part C.II.E.3.k)</u>

Water bath fuel heater

<u>Landscaping and site housekeeping devices < 10 hp (Reg 3, Part C.II.E.3.bb)</u>

Garden tractor

<u>Stationary Internal Combustion Engines - limited size or hours (Reg 3, Part C.II.E.3.xxx.(ii))</u>

Diesel-fired emergency fire water pump (182 hp)

V. Alternative Operating Scenarios

No alternative operating scenarios were requested for this facility.

VI. Permit Shield

Permit Shield for Non-Applicable Requirements

The source indicated that they wanted the permit shield from all Colorado Air Quality Control regulations that were not identified as specifically applicable to the emissions units at their facility on Title V permit application forms 2000-604. No justification was provided for these regulations. The source has the right under Title V of the Clean Air Act Amendments (CAAA) to request the shield for regulations they determine are not applicable to specific equipment at a site in question. However, justification for each non-applicability determination is required. The Title V permit application did not provide a justification for non-applicability determinations, nor was the specific requirement clearly identified. For these reasons, the permit shield was not granted for any non-applicable requirements.

Permit Shield for Streamlined Requirements

These requirements are applicable to the emission units at the Rocky Mountain Energy Center. As discussed previously in this document, under streamlining of applicable requirements, the Division has included the above requirements, as appropriate in the permit shield for streamlined/subsumed conditions.

The following applicable requirements were streamlined out of the permit **for the turbines/HRSGs/duct burners** and have been included in the permit shield.

- 0.1 lb/mmBtu PM requirement (Reg 1, Section III.A.1.c) streamlined out since the PM BACT limit is more stringent.

- **State-only –** 0.35 lbs/mmBtu SO_2 requirement (Reg 6, Part B, Section II.D.3.b), streamlined out since Reg 1 SO_2 requirement is more stringent.

- **State-only –** NSPS general provisions (Reg 6, Part B, Section I), streamlined out since units are subject to federal NSPS general provisions.

- Monitor sulfur content of fuel (40 CFR Part 60 Subpart GG § 60.334(h)(3)), streamlined out in favor of the Acid Rain requirements in 40 CFR Part 75 Appendix D for gas-fired units (sulfur sampling).

- 102 ppmvd NO_X at 15% O_2 and ISO conditions (40 CFR Part 60 Subpart GG § 60.332(b)) streamlined out since NO_X BACT limit is more stringent.

- 1.6 lb/MW-hr NO_X, on a 30-day rolling average (40 CFR part 60 Subpart Da § 60.44a(d)(1)) streamlined out since NO_X BACT limit is more stringent.

- 0.03 lb/mmBtu PM, the average of three (3) two hour tests (40 CFR part 60 Subpart Da § 60.42a(a)(1)) streamlined since the PM BACT limit is more stringent.

The following applicable requirements were streamlined out of the permit **for the auxiliary boiler** and have been included in the permit shield.

- **State-only –** PM emissions shall not exceed $0.5(FI)^{-0.26}$ lb/mmBtu (Reg 6, Part B, Section II.C.2), streamlined out since Reg 1 PM requirement is more stringent.

- **State-only –** NSPS general provisions (Reg 6, Part B, Section I), streamlined out since units are subject to federal NSPS general provisions.

- 0.20 lb/mmBtu NO_X, on a 30-day rolling average (40 CFR Part 60 Subpart Db § 60.44b(l)(1)) streamlined in favor of the NO_X BACT limit.

- NSPS Db requirement for NO_X span value to be 500 ppm (40 CFR Part 60 Subpart Db § 60.48b(e)(2)), streamlined in favor of a 100 ppm, which is more appropriate for the lower BACT limit.

- NSPS Db recordkeeping, monitoring and excess emission reports (40 CFR Part 60 Subpart Db §§ 60.49b(g), (h) and (i)) streamlined in favor of excess emission reporting for NO_X BACT limit.

- Retain records for two (2) years (40 CFR Part 60 Subpart Db § 60.49b(o)) streamlined in favor of Title V recordkeeping requirements.

V. Acid Rain Requirements

Both turbines are affected units under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78 and as such the source is required to have provisions for the Acid Rain requirements in its Title V permit. Units subject to the Acid Rain requirements are required to hold adequate SO_2 allowances and have NO_X limitations. This facility is not listed under 40 CFR 73.10(b)(2) and therefore must obtain SO_2 allowances as needed. Since these units are not coal-fired boilers, they do not have any NO_X limitations under the Acid Rain Program.

Typically, units subject to the Acid Rain requirements are required to continuously measure and record emissions of SO_2, NO_X (with diluent monitor either CO_2 or O_2) and CO_2 as well as opacity and volumetric flow in accordance with the requirements in 40 CFR Part 75. Since these units meet the definition of gas-fired units in 40 CFR Part 72 §72.2, these units are not required to have a continuous opacity monitoring system and can use an alternate monitoring method (Appendix D), in lieu of installing and operating a continuous emission monitoring system for SO_2.

Rocky Mountain Energy Center Potential HAP Emissions (tons/yr)

Emission Unit	acetaldehyde	acrolein	benzene	1,3 butadiene	ethylbenzene	formaldehyde	hexane	naphthalene	PAHs	Chloroform	propylene oxide	toluene	xylene	zinc	total
Turbines/HRSGs[1]	2.23	0.31	0.22	2.07E-03	0.29	2.44	4.22	2.71E-02	1.08E-02		0.78	1.16	0.43		12.11
auxiliary boiler[2]	1.04E-04	9.28E-05	1.97E-04		2.32E-04	4.17E-04	1.51E-04	3.80E-05	1.16E-05			9.04E-04	6.72E-04		2.82E-03
emergency water pump[3]	1.36E-05	4.18E-06	7.54E-04			1.99E-04	5.43E-06	6.25E-05				2.38E-04	8.21E-05	8.76E-05	1.45E-03
emergency generator[3]	3.87E-05	1.19E-05	2.15E-03			5.69E-04	1.55E-05	1.78E-04				6.80E-04	2.34E-04	2.50E-04	4.13E-03
cooling tower[4]										0.89					0.89
Total	2.23	0.31	0.22	2.07E-03	0.29	2.44	4.22	2.73E-02	1.08E-02	0.89	0.78	1.16	0.43	2.21E-04	13.01

[1]Per application, emission factors from air toxics are from Ventura County APCD and CATEF databases. The formaldehyde emission factors are from the 2004 performance test, emissions are based on the unit with higher emissions burning 8760 and the other for the remainder of the time.
[2]Per application, HAP emission factors from Ventura county APCD
[3]Per application, HAP emission factors from CATEF (diesel engines < 13 % O2) and Ventura county APCD (metals), based on 850 hrs/yr for fire pump and 250 hrs/yr for emergency generator
[4]chloroform emission factor from “Locating and Estimating Air Emissions from Sources of Chloroform”, EPA-450/4-84-007c, March 1984 for recirculating units