**TECHNICAL REVIEW DOCUMENT**
**For**
**OPERATING PERMIT 96OPMR129**
**to be issued to**

Public Service Company – Pawnee Station
Morgan County
Source ID 0870011

Prepared by Jacqueline Joyce
May and June 2002
Revised July, August and October 2002
Revised December 2002 Based on Comments from EPA Following the EPA 45-Day Review Period

## I. Purpose

This document will establish 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 and during Public Comment. The conclusions made in this report are based on information provided in the original application submittal of February 15, 1996, additional technical information submitted on July 12, and November 15, 1996, March 6 and 31, 1997, August 7, 1998, December 12, 2000, November 27, 2001, February 8 and June 28, 2002, comments on the draft permit and technical review document received on August 22, 2002, comments on the draft permit received during the Public Comment period, e-mail correspondence and telephone conversations with the source. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

On April 16, 1998, the Colorado Air Quality Control Commission directed the Division to implement new procedures regarding the use of short term emission and production/throughput limits on Construction permits. These procedures are being directly implemented in all operating permits that had not started their Public Comment period as of April 16, 1998. All short term emission and production/throughput limits that appeared in the construction permits associated with this facility that are not required by a specific State or Federal standard or by the above referenced Division procedures have been deleted and all annual emission and production/throughput limits converted to a rolling 12 month total. Note that, if applicable, appropriate modeling to demonstrate compliance with the National Ambient Air Quality Standards was conducted as part of the Construction Permit processing procedures. If required by this permit, portable monitoring results and/or EPA reference test method results will be multiplied by 8760 hours for comparison to annual emission limits unless there is a specific condition in the permit restricting hours of operation.

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 in Regulation No. 3, Part B, Construction Permits, and have been found to meet the 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. Description of Source

This source is classified as an electrical service facility under Standard Industrial Classification 4911. This facility consists of one (1) coal-fired boiler (Unit 1) used to produce electricity. This boiler and turbine generator are rated at 547 gross MW and is equipped with a baghouse to control particulate matter emissions and low $NO_X$ burners with over-fire air to control $NO_X$ emissions. In addition, there is a natural gas-fired auxiliary boiler (Unit 2) at the facility, which is primarily used to provide heat to the facility when Unit 1 is not running. Other significant emission sources at this facility consist of fugitive particulate matter emissions from coal handling and storage, ash handling and disposal and vehicle traffic on paved and unpaved roads. In addition, there are also sources of particulate matter emissions from point sources, including coal handling (crushers, transfer towers and conveying), ash handling (ash silo), and the soda ash handling system (for water treatment system). The facility also has one cooling water tower that emits particulate matter emissions in “drift” and evaporates chloroform.

This facility is located at 14940 County Road 24, near Brush in Morgan County, in an area designated as attainment for all criteria pollutants. There are no affected states within 50 miles of this facility. There are no Federal Class I designated areas within 100 kilometers of this facility.

This facility is a major stationary source for the purposes of Prevention of Significant Deterioration (PSD) requirements. Construction of the facility commenced on May 24, 1977 and the facility was subject to the December 5, 1974 version of the PSD rules. The December 5, 1974 rules applied only new or modified stationary sources, provided the source was one of the 18 types identified in the rule and caused an increase in $SO_2$ and/or particulate matter emissions. Under the December 5, 1974 rules, BACT was defined as the new source performance standards (40 CFR Part 60) or if no standard was promulgated, BACT was case-by-case. EPA issued a PSD permit that addressed the coal-fired boiler on December 6, 1976 and BACT was determined to be compliance with the provisions of 40 CFR Part 60 Subpart D §§ 60.42 and 60.43 (new source performance standards for fossil fuel-fired steam generators for which construction commenced after August 17, 1971). The support operations at the facility (i.e. coal handling, cooling water tower) were not subject to BACT review and were not included in the EPA PSD permit.

For purposes of future PSD review, Boral Material Technologies, Inc. operations (permitted under Colorado Construction Permit 01MR0683) shall be considered in conjunction with this facility. Note that Boral must submit an Operating Permit application for their operations within the near future and Operating Permit No. 02OPPB244 has been assigned for this facility. Although the emissions from the Boral Material Technologies operations must be considered by Public Service Company (PSCo) when performing PSD review, PSCo asserts that the operation of these units in accordance with construction permit 01MR0683 is the sole responsibility of Boral Material Technologies, Inc. Emissions at the facility are as follows:

| Pollutant | Potential to Emit[1] (tons/yr) | Actual Emissions[2] (tons/yr) |
|---|---|---|
| PM[3] | 2,501.7 | 724.2 |
| $PM_{10}$[4] | 2,231.6 | 638.8 |
| $SO_2$[5] | 28,176.9 | 14,677.9 |
| $NO_X$[6] | 11,765 | 4,893.4 |
| VOC | 91.5 | 72.2 |
| CO | 754.7 | 582.6 |
| Pb | 3.3 | Negl. |
| HAPS | 143.6 | 24.8 |

[1]Main Boiler (Unit 1) is firing 100% coal. This unit can use natural gas and/or No. 2 fuel oil for startup, shutdown and/or flame stabilization. The boiler can achieve nominal minimum load on these start-up/stabilization fuels but only operate in this mode for short periods of time before coal firing is established in the unit.
[2]Actual emissions for Unit 1 consider a control efficiency of 99.9% for PM/$PM_{10}$ for the baghouse.
[3]For Unit 1 the PM PTE is based on the Reg 1 limit (0.1 lbs/mmBtu) x design heat rate x 8760 hrs/yr.
[4] $PM_{10}$ PTE for Unit 1 is based on 92% of PM being $PM_{10}$.
[5]For Unit 1 the $SO_2$ PTE is based on Reg 1 limit (1.2 lbs/mmBtu) x design heat rate x 8760 hrs/hr.
[6]For Unit 1 the $NO_X$ PTE is based on the Acid Rain $NO_X$ limit x design heat rate x 8760 hrs/yr. The Acid Rain $NO_X$ limit is 0.50 lbs/mmBtu for Unit 1
[7]PTE for lead is based on uncontrolled emissions, control efficiency is 97.5%.
[8]PTE includes uncontrolled emissions of metallic HAPs, control efficiencies range from 78.2 - 99.8 for these compounds.

It should be noted that the actual and potential emissions identified in the above table do not include emissions from Boral Material Technologies, Inc. operations. Potential emissions from Boral's operation are less than 5 tons/yr, each, of PM and $PM_{10}$.

Potential to emit is based on the information identified in the table, the maximum hourly fuel consumption rate, AP-42 emission factors and 8760 hrs/yr of operation. Potential to emit from the auxiliary boiler, coal handling, ash handling, roads, soda ash system and the cooling water towers is based on permitted emission limits. Actual emissions are based on the Division's 2000 inventory. Hazardous Air Pollutant (HAP) emissions, both potential to emit and actual, are based on the Title V permit application and APENs submitted September 30, 1996 (identifying mainly metallic HAPs), using 1995 data, as a result of the Division's request for public utilities to submit HAP addendums (APENs) on their boilers and the Division's 2000 inventory (HCl and $H_2SO_4$).

## III. Emission Source

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

**A. Unit B001: Foster Wheeler, Opposed Fired, Natural Circulation Boiler, Serial No. 2-79-2381, Rated at 5,346 mmBtu/hr. Coal Fired, with Natural Gas and/or No. 2 Fuel Oil Used for Startup, Shutdown and Flame Stabilization.**

**1. Applicable Requirements –** This unit was first placed in service in November 1981. An EPA PSD permit was issued for this facility on December 6, 1976. In addition, Colorado Construction Permit C-10,967 was issued August 12, 1976 and was subsequently replaced by C-11,674 on December 21, 1977. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 5,356 mmBtu/hr. This maximum can vary somewhat depending on the quality of the fuel used. This unit has a maximum continuous steam flow rating of 3,684,000 lbs/hr. This maximum steam flow rating cannot be exceeded on a continuous basis. The following changes were made to the unit since its initial construction:

<u>Addition of Gas-Fired Ignitors</u>

In 1991, the ignitors were modified to allow dual-fuel firing of either natural gas or No. 2 fuel oil. The ignitors were previously only capable of burning No. 2 fuel oil. The addition of the gas firing capabilities of the ignitors was added following a “notice of violation” issued to PSCo on June 20, 1990 for exceedances of the opacity standard. The boiler was not previously capable of burning natural gas in the ignitors. It should be noted that the boiler is not capable of operating on either natural gas or No. 2 fuel oil alone, that these fuels are only used for startup, shutdown and flame stabilization. The source has submitted data indicating that use of these alternative fuels comprised less than 1% of the total heat input over the past five years. In conjunction with the information discussed in the below paragraphs regarding the replacement of the electrostatic precipitator, the Division considers that the addition of gas firing capabilities for the ignitors is a Pollution Control Project (PCP), as defined in 40 CFR Part 52 § 52.21(b)(32)) since natural gas is an inherently cleaner fuel than No. 2 fuel oil, and therefore, this change is not considered a modification for purposes of PSD review.

Typically when equipment is modified to burn another fuel that it was previously incapable of burning, the change would be a modification for purposes of new source performance standards (NSPS), provided the fuel switch results in an increase in the hourly emission rate for which a standard applies. However, NSPS Subpart Da specifically states that any change to an existing affected unit originally designed to use either gaseous or liquid fossil fuels to accommodate the use of any other fuel shall not bring that unit under the applicability of Subpart Da (40 CFR Part 60 Subpart Da § 60.40a(d). Since the ignitors were originally designed to fire No. 2 fuel oil, the Division

considers that modifying the ignitors to burn natural gas does not make Unit 1 subject to the provisions of 40 CFR Part 60 Subpart Da.

Replaced Electrostatic Precipitator (ESP) with Baghouse

A fabric filter dust collector (FFDC), otherwise known as a baghouse, was installed on this unit in December 1994. The baghouse replaced an ESP. The installation of the baghouse was required by a Consent Decree issued on August 18, 1992 for failing to maintain and operate the boiler in a manner consistent with good air pollution control practices, which resulted in exceedances of the opacity requirements. The Consent Decree required that PSCo use its best efforts to install the baghouse by December 31, 1994 but no later than June 30, 1995 (Paragraph V.5.a). In addition, the Consent Decree stipulated (10th "WHEREAS") that "…the parties agree that the replacement of the ESP's at the Pawnee and Comanche facilities with FFDC's are "pollution control projects" and the parties do not anticipate that the emissions from either one of these facilities will be rendered less environmentally beneficial by such replacements." Following the installation of the baghouse the Division still considers that the replacement of the ESP with the baghouse did not render the boiler less environmentally beneficial. Therefore, the replacement of the ESP with the baghouse is not considered a modification for purposes of PSD review, NSPS or construction permit requirements since there was no increase in emissions and since the control device replacement did not make the unit less environmentally beneficial.

In addition, as part of the August 18, 1992 Consent Decree (Civil Action No. 92-A-1572), PSCo was required to use its best efforts to comply with the 20% opacity standard as indicated by the continuous opacity monitor (COM) until the baghouse was installed and fully operational (Paragraph V.5.c). PSCo was required to submit within 30 days of the Consent Decree an approvable plan outlining measures that would be taken to minimize the time the opacity standard is violated as indicated by the COM. PSCo submitted and the Division approved a plan (dated September 30, 1992) that specified that gas ignitors would be used during unit startup to minimize opacity exceedances. Additionally, the Consent Decree specified in Paragraph V.5.d that "…[f]or purposes of future enforcement of the approved "best effort" plan referenced in Paragraph No. 5.c. of this Section V, said plan shall be considered a final order of the Division, violations of which shall subject Public Service to possible enforcement action…". Therefore, this provides further evidence that use of natural gas instead of No. 2 fuel oil in the ignitors was a PCP since the fuel switch was intended for purposes of controlling emissions.

Addition of Low $NO_X$ Burners

As indicated in the Title V permit application, low $NO_X$ burners were installed on this unit in December 1994. Although this addition will reduce $NO_X$ emissions, the Division believes that CO emissions could be increased as a result. An increase in CO emissions could subject this unit to further permitting requirements. The following discussion addresses these permitting issues.

An increase in the hourly emission rate of any regulated pollutant would subject these units to federal (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A) and state-only NSPS (Colorado Regulation No. 6, Part B) requirements. Although the Division believes that emissions of CO may be increased by the addition of the low $NO_X$ burners, since CO is not a regulated pollutant under the federal NSPS (40 CFR Part 60 D, Da and Db, as adopted by reference in Colorado Regulation No. 6, Part A) or state-only NSPS (Reg 6, Part B, Section II), the Division has determined that no NSPS requirements would apply.

The installation of these low $NO_X$ burners occurred in 1994. At that time, the Division did not express any concern over an associated increase in CO emissions that might result from the addition of low $NO_X$ burners and therefore no official pre and post modification testing was done to determine whether the addition of the low $NO_X$ burners would increase CO emissions. Recently pre and post modification testing has been conducted by PSCo on Hayden Units 1 and 2 and Cherokee Unit 1 and the results indicate that there was no increase in CO emissions with the addition of low $NO_X$ burners. In addition, low $NO_X$ burners were installed on Arapahoe Unit 4 as part of a Department of Energy Clean Coal Technology Round 3 program. As part of the program CO emissions were tested before and after the addition of the low $NO_X$ burners. Test results indicated that there was no increase in CO emissions with the addition of the low $NO_X$ burners.

Revisions (WEPCO rule, May 20, 1992) made to the federal PSD (40 CFR Part 52.21) and major non-attainment area NSR (40 CFR Part 52.24) requirements, exempted the addition, replacement or use of a PCP at existing electric utility steam generating units unless the project would "...result in a significant net increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purpose of Title I <u>and</u> if the Administrator determines that the increase will cause or contribute to a violation of any NAAQS or PSD increment." Since testing of other coal-fired boilers has indicated that CO emissions do not increase with the addition of low $NO_X$ burners, no modeling analysis would be required under the WEPCO provisions for PCPs.

In addition, since testing of other coal-fired boilers has indicated that there would be no increase in CO emissions, then the addition of low $NO_X$ burners would not trigger any permitting requirements under Colorado Regulation No. 3, Part B.

An EPA PSD permit was issued for this facility on December 6, 1976 and was revised on September 11, 1995 to remove two conditions for coal sampling and blending (conditions e and f). The revised EPA PSD permit contains the following applicable requirements:

- The source shall not cause to be discharged into the atmosphere any boiler gases which are in violation of 40 CFR 60.42 (e.g., particulate matter in excess of 0.10 lbs/mmBtu) and 60.43 (e.g., sulfur dioxide in excess of 1.2

lbs/mmBtu derived from coal) as promulgated on this date. 40 CFR 60.42(a)(2) is revised to read as follows: Exhibit greater than 20 percent opacity except for one 6-minute period per hour of not more than 27 percent average opacity. Performance testing shall be conducted under 40 CFR 60.8 and 60.46 (condition a).

It is not clear whether EPA intended the BACT emission limits to apply during periods of startup and shutdown as it is not specifically stated in the permit. NSPS specifically states that the opacity limits do not apply during startup, shutdown and malfunction (40 CFR Part 60 Subpart A § 60.11(c)). This specific exemption has been in the general provisions since October 1973. In addition, although not specifically stated in NSPS Subpart D, the Division has determined after reviewing EPA determinations that the NSPS standards are no applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported with the quarterly 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)."

Current EPA guidance indicates that BACT limits apply during startup and shutdown. Specifically, EPA guidance indicates (John B. Rasnic to Linda M. Murphy, dated January 28, 1993, "Automatic or Blanket Exemptions for Excess Emissions during Startup and Shutdowns Under PSD") that "... PSD permits cannot contain automatic exemptions which allow excess emissions during startup and shutdown....the exemptions granted under some New Source Performance Standards (NSPS) are not applicable to this issue under PSD. The NSPS are technology based standards that are not directly required for meeting ambient standards." Furthermore EPA guidance (Kathleen M. Bennett to Regional Administrators, dated February 15, 1983, "Policy on Excess Emissions During Startups, Shutdowns, Maintenance and Malfunction") indicates that "...startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the design and implementation of the operating procedure for the process and control equipment. Accordingly, it is reasonable to expect that careful planning will eliminate violations of emission limitations during such periods."

The BACT analysis prepared by John Dale and dated July 26, 1976 (see attached) for Pawnee Unit 1, identifies BACT as the control techniques necessary to meet NSPS emission limits and identifies the $SO_2$ standard of

1.2 lbs/mmBtu and the particulate matter standard of 0.1 lbs/mmBtu. The EPA BACT analysis does not discuss opacity at all. Therefore, it appears that EPA did not intend the NSPS opacity standard to be considered a BACT emission limit. Since it appears that the EPA did not consider the NSPS opacity requirement to be a BACT limit, the Division presumes that exemptions from the opacity limit during periods of startup and shutdown are allowed. Since NSPS provides a specific exemption (40 CFR Part 60 Subpart A § 60.11(c)) from the opacity limits during periods of startup, shutdown and malfunction, the Division considers that Unit 1 is exempt the opacity limits in the EPA PSD permit during periods of startup, shutdown and malfunction.

In addition, the fact that the PSD permit for Unit 1 was issued under the December 5, 1974 PSD rules provides a compelling argument that EPA did not intend for the particulate matter and sulfur dioxide requirements and even the opacity requirement, if it were a BACT limit, to apply during periods of startup and shutdown.

On May 31, 1972, EPA had published initial approvals and disapprovals of State Implementation Plans (SIPs) submitted pursuant to the 1970 Clean Air Act Amendments (CAAA). On November 9, 1972, all SIPs were disapproved in that they failed to include provisions for prevention of significant deterioration. This action was taken in response to a preliminary injunction which also required EPA to promulgate regulations addressing prevention of significant deterioration. Initial PSD rules were proposed on August 27, 1974 (39 FR 31000) with the final PSD rules published December 15, 1974 (39 FR 42510). The preamble to the final rule indicates that there was a lack of precise direction in the 1970 CAAA and in the Court order to promulgate PSD rules. The preamble to the final rule specifically says (pg 42510) that “The regulations issued herein are necessary because the Court has ruled that the current Clean Air Act requires the Administrator to prevent significant deterioration and this requirement must be met even though it is possible that Congress may provide additional guidance and/or legislative changes in the future.” The December 5, 1974 rules specifically defined BACT as the control technology necessary to meet the NSPS standard and sources would be required to meet an emissions limitation that represents the level of emissions achieved by the application of BACT (i.e. the BACT emission limitation would be the NSPS emission limitation).

Amendments to the CAA were made in 1977 (August 7, 1977) and with these amendments revisions to the PSD rules were made. The proposed revisions to the PSD rules were published on November 3, 1977 (42 FR 57479) and the final rules were published on June 19, 1978 (43 FR 26380). These revisions applied to sources that commenced construction or modification after August 7, 1977. The preamble to the proposed rule indicates that the proposal will greatly expand the coverage of the current rules and generally impose more stringent requirements. The preamble to the proposed rule also specifically states that the definition of BACT is more stringent. The final rule

defines the BACT determination as case-by-case, with the minimum BACT as the technology necessary to meet the NSPS emission limitations.

Therefore, considering that the PSD permit for Unit 1 was processed under less stringent rules and since those rules specifically defined BACT as the technology to meet the NSPS standards, the Division considers that if the NSPS provided exemptions from the standards during certain periods, that those exemptions would apply to the BACT limits in an EPA issued PSD permit. Therefore, if the opacity limit had been considered a BACT limit, the Division would consider that Unit 1 was exempt from the opacity limit during periods of startup and shutdown, since the NSPS specifically states that the opacity limit does not apply during those periods. Although the NSPS does not specifically exempt the particulate matter and sulfur dioxide emission limitations during periods of startup and shutdown, as discussed previously, the Division considers that based on EPA determinations that the NSPS particulate matter and sulfur dioxide standards also do not apply during startup and shutdown.

- Continuous monitoring systems for measuring sulfur dioxide emissions and opacity shall be installed, calibrated, maintained, and operated by the owner or operator. Procedures to be followed for such monitoring are specified in applicable Sections of 40 CFR 60.45(a), (b)(1), (d), (e), (f), and (g). The owner or operator shall comply with the notification and recordkeeping requirements specified in 40 CFR 60.7 and with the monitoring requirements specified in 40 CFR 60.13. During the first year of operation excess emission reports shall be submitted monthly no later than ten days following the end of each calendar month (condition b).

  Note that since the unit has been operating for more than one year, the language regarding submitting excess emission reports monthly will not be included in the permit.

  - Results of the performance tests required under 40 CFR 60.46 and reports of excess sulfur dioxide emissions required on by 60.45(g)(2) on a continuing basis thereafter shall constitute, in any proceeding to enforce the terms of this permit, prima facie evidence that emissions from the Source exceed the limits set forth in condition (a) (condition b.1).
  - For the purpose of reporting opacity emissions under 40 CFR 690.45(g)(1) only, excess emissions are defined as any 6-minute period during which the average opacity of emissions exceeds 20 percent opacity except that one 6-minute period per hour of not more than 27 percent opacity need not be reported (condition b.2).

- The applicant shall obtain a permit from the Colorado APCD pursuant to Regulation 3 of the Colorado APCD for its coal blending system before commencing any construction of such system (condition c).

Since the Division has issued construction permits for both the boiler and portions of the coal handling system, this requirement will not be included in the operating permit.

- The company shall develop operating and stockpiling procedures for use by Source personnel on how and when to utilize the coal blending equipment to ensure that sulfur dioxide emission limits specified in condition (a) shall not be violated. A copy of such procedures shall be submitted to and approved by EPA prior to commencement of construction of Pawnee 1. EPA shall review such procedures within 30 days of receipt to determine if they will clearly achieve proper coal blending to meet the $SO_2$ emission limits. If EPA notifies the Company that its procedures are not approvable, the Company shall have ten days thereafter to submit acceptable procedures. If acceptable procedures are not received by EPA, the Company shall be notified that this authority to construct is void ab initio for non-compliance with this condition. Such blending procedures shall be modified from time to time as is necessary. A current copy of the procedures shall be maintained at plant headquarters for inspection during business hours (condition d).

  Since submittal and approval of the plan was to occur prior to commencing construction, this portion of the condition has already been completed. The requirements to modify the procedures and maintain a copy onsite for inspection will not be included in the permit, since the requirement to operate a coal blending system has been removed from the permit in accordance with EPA's September 15, 1995 letter.

This emission unit is subject to the conditions in Colorado Construction Permit 11MR674 (final approval, issued July 30, 1986). PSCo requested certain changes to their permit in the Title V permit application, as discussed below. No revised construction permit was issued as the appropriate changes were included in the operating permit as a combined construction/operating permit. Permit 11MR674 contains the following applicable requirements:

- Visible Emissions shall not exceed 20% opacity (condition 1).

  It is not clear whether the source of this requirement is the NSPS opacity limit or the Reg 1 opacity limit, however, the operating permit will include all applicable opacity limits.

- This source shall be limited to a maximum consumption rate as listed below:

  Consumption of coal shall not exceed 335 tons/hr or $2.9 \times 10^6$ tons/yr

  In accordance with the Division's short term emission limits policy, the hourly coal consumption limits will not be included in the operating permit.

  Although the permit does not address the use of alternative fuels for use during startup, shutdown and flame stabilization, the Division is not including a specific fuel usage limit on these alternate fuels. The permit will include provisions to reopen the permit if the use of alternative fuels exceeds more than 5% of the total heat input in a year. If such reopening occurs the

Division will include a fuel consumption limit on alternative fuels in the revised permit.

- Emissions of particulate matter shall not exceed 0.1lbs/mmBtu (condition 4)
- Emissions nitrogen oxides shall not exceed 0.7 lbs/mmBtu (condition 5)
- Emissions of sulfur dioxide shall not exceed 1.2 lbs/mmBtu (condition 6)

  Note that a review of the preliminary analysis for the final approval permit indicates that the above PM, $SO_2$ and $NO_X$ emission limits are the NSPS emission limitations.

- A continuous emission monitor for opacity, sulfur dioxide, and nitrogen oxides shall be installed, calibrated, operated and maintained according to criteria established by the Division (condition 7).

  Although not specifically stated, the Division presumes that this requirement originated from NSPS Subpart D. It should be noted that NSPS Subpart D does not require an $SO_2$ CEMS if there is no flue gas desulfurization device (40 CFR Part 60 Subpart D § 60.45(b)(2)) but allows compliance with the $SO_2$ limitations to be monitored using fuel sampling and analysis. In addition, if performance testing indicates that $NO_X$ emissions are less than 70% of the standard, a $NO_X$ CEMS is not required (40 CFR Part 60 Subpart D § 60.45(b)(3)).

- Quarterly reports of coal properties (sulfur content and Btu value) as measured by AMAX and in-stack sulfur dioxide emission rates shall be submitted to the Division. Violations of the in-stack measured 1.2 lbs/mmBtu shall be reported immediately to the Division in a manner approved by the Division (condition 8).

  In their Title V permit application, the source indicated that they wish to have this condition removed from the permit, since coal sampling and blending operations are no longer required by the EPA PSD permit and since $SO_2$ emissions are monitored and reported using the continuous emission monitoring system (CEMS). The Division agrees that quarterly reports of coal properties need not be submitted to the Division, since compliance with the $SO_2$ emission limits shall be monitored using the CEMS. It should be noted however that the Division may require coal sampling and analysis as periodic monitoring for other applicable requirements.

  In addition, the Division typically only requires that $SO_2$ emissions that exceed an emission standard be reported and submitted to the Division on a quarterly basis, not a summary of all emissions as this condition implies. Also, as previously stated, reporting of emissions in excess of an emission standard is generally required on a quarterly basis and not immediately, unless the source wishes to claim such exceedance as due to an upset condition. Therefore, the requirements in this permit condition that are not related to coal sampling and blending are addressed by other applicable requirements and therefore this condition will not be included in the permit.

- Violations of the $SO_2$ emission standard due to a lack of coal of suitable quality shall not be considered as arising from an "upset" condition (condition 9).
- A revised Air Pollution Emission Notice shall be filed annually if a significant change in emissions occurs as required by Regulation No. 3.II.B (condition 10).

  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.
- This source is subject to the requirements of the New Source Performance Standards for Fossil-Fuel Fired Steam Generators which were in effect at the time of application. Excess emission reports shall be submitted as required by this regulation (condition 11).

  This permit condition indicates that the source is only subject to the NSPS requirements which were in effect at the time of application. The Division would agree that for purposes of a PSD permit and BACT analysis that defined the NSPS standards as the BACT emission limitation that an emission unit would only be subject to the NSPS emission limitations that were in effect at the time of the application. However, we would disagree that an affected facility that is subject to NSPS requirements would only subject to the NSPS requirements which were in effect at the time of the application. Any revisions made to the NSPS would apply to such a unit. Typically upon revising an existing regulation, the EPA usually indicates if the revisions do not apply to existing facilities, or if facilities constructed in the interim between proposed and final revisions are provided special consideration. None of the revisions to Subpart D contain relief for existing or interim facilities. Many of the revisions serve to clarify the applicable requirements, and in some instances are beneficial to the source operator. Therefore, since the construction permit issued by the Division is not a PSD permit and the NSPS standards are not identified as BACT standards, this source is subject to the NSPS standards that are currently in effect and are subject to any revisions to the NSPS standards that may occur in the future, unless such future revisions exempt existing facilities.

  In addition, the Division did not specifically identify the requirements from the NSPS that apply, although excess emission reporting is specifically mentioned and the NSPS PM, $NO_X$ and $SO_2$ limits and continuous emission monitoring requirements are already included in this permit. In general these are the primary requirements from NSPS Subpart D, except that for the NSPS opacity requirement (20% with one 6 minute period per hour not to exceed 27%) is also applicable to this unit.

  It should be noted that the NSPS requires that prorated $NO_X$ and $SO_2$ limits be calculated when a combination of fuels is burned (40 CFR Part 60

Subparts §§ 60.43(b) and 60.44(b)). Coal is the primary fuel for this boiler. Natural gas and/or No. 2 fuel oil is used during non-routine periods such as startup, shutdown and/or other flame stability efforts. The NSPS, Subpart D sets forth emission limits when fuels are combined for combustion (i.e. prorating). The permittee submitted information which indicates that, for the past five years, "alternative" fuel use has comprised less than 1% of total heat input. By calculation, the Subpart D emission limits for this amount of natural gas remain essentially unchanged from the coal emission limit. The Division therefore assumes the source is in compliance with Subpart D emission limits whenever alternate fuel use comprises less than 1% of total heat input. If alternate fuel use comprises more than 5% of total heat input during a year, the permit must be reopened to include Subpart D requirements for combined fuel combustion.

In addition to the requirements in the EPA PSD permit and permit 11MR674 this source is subject to the following applicable requirements:

- Opacity shall not exceed 20% except as provided for in Reg 1, Section II.A.4 (Reg 1, Section II.A.1)
- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)
- Particulate emissions shall not exceed 0.1 lbs/mmBtu (Reg 1, Section III. A.1.c)
- Continuous emission monitoring (Reg 1, Section IV)
    - A continuous emission monitoring system for the measurement of opacity shall be installed, calibrated, maintained and operated, when burning coal (Reg 1, Section IV.B.1)
    - Either a continuous emission monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained and operated or a Division approved sampling plan shall be developed and implemented for determining the amount of sulfur in the fuel in order to calculate sulfur oxide emissions (Reg 1, Section IV.B.2)
    - If continuous emission monitor for $SO_2$, then continuous emission monitor for either $O_2$ or $CO_2$ (Reg 1, Section IV.B.3)
    - Calibration of continuous emission monitors (Reg 1, Section IV.F)
    - Notification and Recordkeeping (Reg 1, Section IV.G)
    - Recordkeeping duration (Reg 1, Section IV.H)

- Reporting requirements – if fuel sampling (Reg 1, Section VI.I)

- Sulfur dioxide emissions shall not exceed 1.2 lbs/mmBtu, on a 3-hour rolling average, when burning coal (Reg 1, Sections VI.A.1 and VI.A.3.a.(ii))
- Lead (Pb) emissions shall not be such that emissions result in an ambient lead concentration exceeding 1.5 Fg/SCM averaged over a one-month period (Reg 8, Part C) - This is a **State-only** requirement
- NSPS General Provisions (40 CFR Part 60 Subpart A, as adopted by reference in Colorado Regulation No. 6, Part A), specifically:
  - Notification and recordkeeping requirements (§ 60.7)
  - Opacity monitoring requirements (§ 60.11)
  - Continuous emission monitoring requirements (§ 60.13)
  - Good practices (§ 60.11(d))
  - Circumvention (§ 60.12)
- Acid Rain requirements as follows:
  - This unit has been allocated, on an annual basis, $SO_2$ allowances as listed in 40 CFR 73.10(b). If annual $SO_2$ emissions exceed the allocated allowances for that year, additional allowances must be obtained per 40 CFR Part 75 to cover emissions for that particular calendar year.
  - $NO_X$ emissions of 0.45 lbs/mmBtu on an annual average basis (source opted to comply with Phase I limits (§ 76.5(a)(2) by early election (§ 76.8)).
  - Acid rain permitting requirements per 40 CFR Part 72.
  - Continuous emission monitoring requirements per 40 CFR Part 75.
  - The source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emission requirements (40 CFR Part 77).

Since construction of this unit commenced prior to January 30, 1979 the state-only requirements in Colorado Regulation No. 6, Part B, Section II (Standards of Performance for New Fuel-Burning Equipment) do not apply. In addition, since modifying the boiler to burn natural gas did not cause an increase in PM or $SO_2$ emissions, the provisions in Colorado Regulation No. 6, Part B, Section II (State-only Standards of Performance for New Fuel Burning Equipment) do not apply, since PM and $SO_2$ are the only regulated pollutants under this standard.

## Streamlining of Applicable Requirements

Continuous Emission Monitors

There are multiple requirements for Continuous Emission Monitoring (CEMS)/Continuous Opacity Monitoring (COMS) systems. Colorado Regulation No. 1, Section IV requires COMS (when burning coal) and either a CEMS for $SO_2$ or fuel sampling. If a CEMS is used for monitoring $SO_2$, then a CEMS is required for either $CO_2$ or $O_2$. Regulation 1, Section IV identifies other requirements for CEMs such as performance specifications, calibration, and notification and recordkeeping and requirements for record retention. This unit is also subject to CEMS requirements as specified in their EPA PSD permit, Colorado Construction permit 11MR674 and in 40 CFR Part 60 Subpart D § 60.45(a) to install, calibrate, maintain and operate CEMS for opacity, $SO_2$ and $NO_X$. It should be noted that the EPA PSD permit only requires continuous emission monitoring systems for opacity and $SO_2$ and that the CEMS meet the requirements in NSPS Subpart D. Permit 11MR764 requires CEMS for opacity, $NO_X$ and $SO_2$ and the source of the requirement is NSPS Subpart D. Additional monitoring requirements are identified in 40 CFR Part 60 Subpart D §§ 60.45(c), (e) and (f). This unit is also subject to the Acid Rain Requirements and as such is required to continuously measure and record emissions of $SO_2$, $NO_X$ (and diluent gas either $CO_2$ or $O_2$), and $CO_2$ as well as volumetric flow, and opacity. The Acid Rain CEM requirements are specified in 40 CFR Part 75. The general requirement to install, calibrate, operate and maintain COMS/CEMS in Reg 1, Section IV will be streamlined out in favor of the Acid Rain CEMS requirements as they are more stringent. In addition, as allowed by the EPA (see attached), the requirements in 40 CFR Part 60 Subparts A and D, for the CEMS will be streamlined out in favor of the more stringent Part 75 requirements. For the same reasons, the CEMS requirements from the EPA PSD permit and permit 11MR674 have been streamlined out of the permit. Streamlining of more specific CEMS requirements is addressed in the paragraphs below.

The performance specification requirements for these CEMS will be subject to the Acid Rain requirements (40 CFR Part 75), since Reg 1, Section IV.E CEM performance specification requirements do not apply to this unit and since the Part 75 performance specification requirements are more stringent than the performance specification requirements in 40 CFR Part 60. Note that both Part 60 and Part 75 specify that COMS shall meet the performance specification requirements in 40 CFR Part 60 Appendix B, Performance Specification 1.

The CEMS will be subject to the QA/QC requirements in 40 CFR Part 75 as Reg 1 does not identify specific QA/QC requirements and the Part 75 QA/QC requirements are more stringent than the QA/QC requirements in 40 CFR Part 60. In the case of the COMS, the QA/QC requirements in Part 75 reference 40 CFR Part 51, Appendix M and the reference method in Appendix M that addresses the COMS (RM 203) has not been promulgated as of this date. Therefore, the COMS will be subject to the QA/QC requirements in 40 CFR Part 60 Subparts A and D. In general, the NSPS QA/QC

requirements for continuous opacity monitoring systems are in 40 CFR Part 60 Subpart A § 60.13, however, some specific COM QA/QC requirements are included in 40 CFR Part 60 Subpart D § 60.45(c)(3). A review of 40 CFR Part 60.13 indicates that only 40 CFR Part 60.13(d) would apply to the COM as a QA/QC requirement. The remaining requirements in 40 CFR Part 60.13 are either applicable to the CEM or are addressed in 40 CFR Part 75. Since the NSPS QA/QC requirements (for the COM) will be included in the permit, the calibration requirements in Reg 1, Section IV.F will be streamlined out of the permit in favor of the NSPS requirements.

In addition, Part 75 does not specify procedures for converting hourly $SO_2$ concentration data into units of lbs/mmBtu, except for qualifying Phase I technologies. Reg 1, Section IV also does not specify procedures for converting $SO_2$ concentrations to units of lbs/mmBtu. In order to convert $SO_2$ data to units of lbs/mmBtu, to monitor compliance with the lbs/mmBtu $SO_2$ emission limitations, the permit will specify that the conversion procedures in 40 CFR Part 60, Appendix A, Method 19 be used. Note that since the NSPS $SO_2$ emission limitation has been streamlined out of the permit in favor of the Reg 1 $SO_2$ emission limitation (see below), the specific conversion requirements in 40 CFR Part 60 Subpart D §§ 60.45(e) and (f) will still be streamlined out of the permit, since they apply to the NSPS $SO_2$ emission limitation.

The excess emission reporting requirements in 40 CFR Part 60 Subpart D § 60.45(g) specifies that excess emission reports shall be submitted semi-annually and include the information specified in 40 CFR Part 60 Subpart A § 60.7(c). 40 CFR Part 60 Subpart A § 60.7(c) specifies that reports shall be submitted semi-annually, except when either the subpart requires more frequent reporting or the Division determines that more frequent reporting is necessary to accurately asses the compliance status of the source. The Division has determined that more frequent reporting is necessary and therefore, excess emission reports shall be submitted quarterly. Since the excess emission reports specified in Reg 1, Section IV.G and the NSPS excess emission reporting requirements both require quarterly submittals, the Reg 1, Section IV.G reporting requirements will be streamlined out of the permit in favor of the NSPS reporting requirements.

Note that the record retention requirement in Regulation No. 1, Section IV.H (maintain records for 2 years) is less stringent than the Regulation No. 3, Part C recordkeeping requirement therefore, the Regulation No. 1, Section IV.H record retention requirement will be streamlined out of the permit in favor of the Regulation No. 3, Part C requirements (General Condition No. 21b & c).

<u>Opacity</u>

This unit 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. This unit is also subject to the NSPS opacity requirements (20% with one 6 minute average not to exceed 27%) and opacity

requirements as specified in the EPA PSD permit, which are essentially the NSPS opacity requirements. The NSPS/EPA PSD permit opacity requirements are not applicable during periods of startup, shutdown and malfunction in accordance with the provisions in 40 CFR Part 60 Subpart A § 60.11(c). The Reg 1 20%/30% opacity requirements are more stringent than the NSPS/EPA PSD permit opacity requirements during periods of startup, shutdown and malfunction. While the NSPS/EPA PSD permit opacity requirements are more stringent than the Reg 1 30% opacity requirement during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. Since the EPA PSD permit and NSPS opacity requirements are the same, the EPA PSD permit opacity requirements will be streamlined out of the permit in favor of the NSPS opacity requirements. In regards to the NSPS and Reg 1 20/30% opacity requirements, since no one opacity requirement is more stringent than the other <u>at all times</u>, 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.

<u>Sulfur Dioxide ($SO_2$)</u>

This unit is subject to a Reg 1 $SO_2$ standard of 1.2 lbs/mmBtu, an NSPS $SO_2$ standard of 1.2 lbs/mmBtu and an EPA PSD Permit $SO_2$ standard of 1.2 lbs/mmBtu, which is essentially the NSPS $SO_2$ requirement, all on a 3 hour rolling average.

Although not specifically stated in NSPS Subpart D, the Division has determined 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 with the quarterly 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)." As discussed previously, the Division also considers that since it is essentially the NSPS standard, that the EPA PSD permit $SO_2$ limitation also does not apply during startup, shutdown and malfunction. Therefore, since the Regulation No. 1 $SO_2$ limit is equal to the EPA PSD permit and the NSPS D $SO_2$ limit and since the Reg 1 $SO_2$ limit applies all the time, the Division has streamlined out the NSPS D and EPA PSD permit $SO_2$ limits in favor of the Reg 1 $SO_2$ limit. Note that although the Reg 1 $SO_2$ limit, which is included in the operating permit applies all the times, a malfunction may be reported to the Division as an upset condition in accordance with the requirements in Section II.E of the Common Provisions Regulation.

This unit is 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 Reg 1 and the Acid Rain $SO_2$ requirements 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 both the Acid Rain $SO_2$ requirements and the Reg 1 $SO_2$ standard. Note that the Acid Rain $SO_2$ allowances appear only in Section III (Acid Rain Requirements) of the permit.

Particulate Matter (PM)

This unit is subject to Regulation No. 1 PM standards, the NSPS PM standards and PM standards as identified in the EPA PSD permit, which is essentially the NSPS PM requirement. Colorado Regulation No. 1 Section III.A.1.c limits PM emissions to 0.1 lbs/mmBtu. The NSPS Subpart D standard is 0.1 lbs/mmBtu. As discussed under $SO_2$ above, the NSPS and the EPA PSD permit particulate matter standards do not apply during periods of startup, shutdown and malfunction. The Reg 1 standard applies all the time. Therefore, since the Regulation No. 1 particulate matter standard is equal to the NSPS D and EPA particulate matter standards and since the Reg 1 particulate matter standard applies all the time, the Division has streamlined out the NSPS D and EPA permit particulate matter standards in favor of the Reg 1 particulate matter standard. Note that although the Reg 1 particulate matter standard, which is included in the operating permit applies all the time, a malfunction may be reported to the Division as an upset condition in accordance with the requirements in Section II.E of the Common Provisions Regulation.

Nitrogen Oxides ($NO_X$)

This source is subject to NSPS $NO_X$ requirement and the Acid Rain $NO_X$ requirement. The Acid Rain $NO_X$ requirement is 0.50 lbs/mmBtu based on a weighted annual average. The NSPS Subpart D $NO_X$ requirement is 0.7 lbs/mmBtu for coal based on a 3-hour rolling average. Although the Acid Rain $NO_X$ requirements appear to be more stringent, it is possible that the source could deviate from the NSPS 3-hour average and still comply with the Acid Rain $NO_X$ requirement since it is an annual average. $NO_X$ data used to determine compliance with the Acid Rain requirements are submitted (electronically) to EPA for compliance demonstration. In addition, Regulation No. 3, Part C, Section V.C.1.b, requires that if a federal requirement is more stringent than an Acid Rain requirement, both requirements shall be incorporated into the permit and shall be federally enforceable. Therefore, for these reasons the $NO_X$ requirements have not been streamlined. The source will have to demonstrate compliance with both the Acid

Rain and NSPS $NO_X$ requirements. Note that the Acid Rain $NO_X$ limitations only appear in Section III (Acid Rain Requirements) of the permit.

Note that as discussed for $SO_2$ above, the NSPS $NO_X$ standard does not apply under conditions of startup, shutdown and malfunction. Note that the NSPS still requires that those instances during periods of startup, shutdown or malfunction when the $NO_X$ standard is exceeded be identified in the quarterly excess emission report.

**2. Emission Factors -** Emissions from boilers are generated from the combustion of fossil fuels. Type and quantities of emissions are dependent on the fuels being burned. This unit primarily burns coal, however, natural gas and No. 2 fuel oil is used for startup, shutdown and flame stabilization. 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, primarily with the combustion of coal. Approval of these emission factors 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.

The source proposed to use emission factors from EPA's Compilation of Emission Factors (AP-42), Section 1.1 (dated 9/98), Tables 1.1-3, 1.1-6, and 1.1-19 (sub-bituminous coal, NSPS dry bottom wall-fired boilers), Section 1.3 (dated 9/98), Tables 1.3-1, 1.3-3 and 1.3-6 (industrial boilers/boilers > 100 mmBtu/hr, using No. 2 (distillate) fuel oil) and Section 1.4 (dated 3/98), Tables 1.4-1 and 1.4-2 (natural gas, boilers > 100 mmBtu/hr, NSPS).

The proposed emission factors are as follows:

| Pollutant | Emission Factor | | |
|---|---|---|---|
| | Coal (lbs/ton) | Natural Gas (lbs/mmSCF) | No. 2 Fuel Oil (lbs/$10^3$ gal) |
| PM | Source Test | 1.9 | 2 |
| $PM_{10}$ | 0.92(PM) | 1.9 | 1 |
| $SO_2$ | CEM | CEM | CEM |
| $NO_X$ | CEM | CEM | CEM |
| CO | 0.50 | 84 | 5 |
| VOC | 0.06 | 5.5 | 0.2 |

Lead emissions shall be calculated as follows:

Lead emissions (tons/yr) = Ash emitted x quantity of lead in ash

$$\text{Ash emitted (tons/yr)} = \frac{\text{10A lbs ash/ton coal x quantity of coal burned (tons/yr)}}{\text{2000 lbs/ton}}$$

where: A = weight percent ash in coal (10A is the AP-42 (Section 1.1, dated 9/98) emission factor for PM)

$$\text{Quantity of Lead in Ash (lbs/lbs)} = \frac{\text{content of lead in coal (ppm)}}{\text{content of ash in coal (wt \%)}} \times 10^{-4}$$

The source will be required to use their CEMS to determine annual emissions of $SO_2$ and $NO_X$ for the purposes of APEN reporting and payment of fees. The emission factor for PM (when burning coal) shall be determined by annual source testing of the boiler. Note that depending on the results of the performance test, the frequency of stack testing for PM emissions may be decreased.

This boiler is equipped with a baghouse to control particulate matter emissions and low $NO_X$ burners to control $NO_X$ emissions. Provided the source maintains the baghouse per manufacturer's recommendations and good engineering practices, a 99.9% efficiency can be applied to the PM and $PM_{10}$ emission factors when burning natural gas or No. 2 fuel oil and an efficiency of 99.3% can be included in the lead emission calculation when burning coal. The permit will not specifically identify any maintenance requirements for the low $NO_X$ burners since the source will be required to use their CEM to determine $NO_X$ emissions and monitor compliance with the emission limitations.

**3. Monitoring Plan -** Compliance monitoring requirements for this unit are identified in sections 1 - 2 of Section II of the Operating Permit. Conditions 1.1 through 1.13 cover coal and Condition 2.1 addresses the firing of a natural gas and/or No. 2 fuel oil as secondary fuels.

Since the source is required to install, certify and operate continuous emission monitoring equipment for opacity, $SO_2$, $NO_X$ (including diluent gas either $CO_2$ or $O_2$), $CO_2$ and volumetric flow, the Division will require the source to use their CEMS/COMS to demonstrate compliance with the opacity, $NO_X$ and $SO_2$ requirements.

Operation of the CEMS/COMS in accordance with the requirements in 40 CFR Part 75 (Acid Rain Continuous Emission Monitoring Requirements) is sufficient to satisfy the requirements for operating the CEMS/COMS. Part 75 defines the QA/QC requirements for the COMS in § 75.21(b) and indicates that the COMS shall be operated, maintained and calibrated in accordance with the procedures in 40 CFR Part 51, Appendix M. Appendix M addresses EPA reference methods and no reference methods listed appear to address opacity monitors. It appears that this reference is an error. However, the EPA has indicated that this reference is not an error, although, the reference method to address opacity monitors (reference method 203) has not been promulgated yet. Therefore, the Division is including the COMS calibration requirements in 40 CFR Part 60 Subpart A § 60.13(d) and Subpart D § 60.45(c)(3) in the permit for the COMS QA/QC requirements.

It should be noted that § 75.24(e), which addresses COMS out of control periods, also references 40 CFR Part 51, Appendix M. The permit addresses alternate monitoring requirements when the COMS is out of control.

It should also be noted that Part 75 does not specify procedures for converting hourly $SO_2$ concentration data into units of lbs/mmBtu, except for qualifying Phase I technologies. In order to convert $SO_2$ data to units of lbs/mmBtu, to monitor compliance with the Reg 1 $SO_2$ emission limitations, the permit will specify that the conversion procedures in 40 CFR Part 60, Appendix A, Method 19 be used.

Compliance with the Acid Rain requirements are monitored by submitting quarterly data reports and annual compliance certifications to EPA electronically. With each quarterly data report, the source is required to submit a certification to EPA indicating that the monitoring data submitted was recorded in accordance with the applicable requirements. The permit requires that a copy of the annual compliance certification be sent to the Division.

Annual emission calculations, for all pollutants except $SO_2$ and $NO_X$, will be required to determine compliance with APEN reporting and for determination of annual emission fees. The CEMS will be used to determine annual emissions of $SO_2$ and $NO_X$. In addition, when burning coal, annual performance tests will be required to demonstrate compliance with the PM limitation. Note that depending on the results of the performance test, the frequency of stack testing for PM emissions may be decreased. The source has modeled lead emissions at "worst case" for a one-time only demonstration of compliance. The source shall be required to retain these modeling results and make them available to the Division upon request.

The source has indicated natural gas and/or No. 2 fuel oil may be used in startup, shutdown and/or flame stabilization. Use of natural gas and No. 2 fuel oil shall be recorded annually and used to calculate emissions for the purposes of APEN reporting.

**4. Compliance Status –** The source certified in their Title V permit application that this unit was in compliance with all applicable requirements. The Division accepts that this unit is in compliance with all applicable requirements.

**B. Unit B002: Babcock & Wilcox, Package Boiler, Model and Serial No. FM-2763, Rated at 114.3 mmBtu/hr (fuel oil) and 98 mmBtu/hr (natural gas). Natural Gas, No. 2 Fuel Oil or Combination Fired.**

**1. Applicable Requirements –** This unit was first placed in November 1981. This unit was modified in 1991 to burn natural gas and natural gas is currently used as the primary fuel, with No. 2 fuel oil used for back-up. Colorado Construction Permit C-12,093-4 was issued on November 27, 1978 for this unit.

In order to determine whether the fuel switch triggered any NSPS requirements, the Division looked at the hourly emission rates for the boiler burning No. 2 fuel oil and natural gas. The hourly emission rates were determined by converting the AP-42 emission factors to units of lbs/mmBtu (heating values of 1020 Btu/SCF for natural gas and 140,000 Btu/gal for No. 2 fuel oil) and then multiplying by the design heat rate of the boiler. The modifications made to the boiler to allow natural gas burning results in

higher hourly emission rates of CO and VOC. Since CO and VOC are not regulated pollutants under NSPS Db or Dc, the auxiliary boiler is not subject to any federal NSPS requirements. In addition, neither CO or VOC are regulated under the state-only NSPS provisions in Colorado Regulation No. 6, Part B, Section II, no state-only NSPS requirements apply.

Since the auxiliary boiler is generally operated infrequently, PSCo is not permitting this unit at design rate and 8760 hrs/yr of operation. Permitted emissions for this unit will be below PSD significance levels for all pollutants and therefore no PSD review requirements were triggered by the fuel switch. It should be noted that actual emissions from the auxiliary boiler since the fuel switch have been well below the requested permitted emission levels and therefore also well below the PSD significance levels.

This emission unit is subject to the conditions in Colorado Construction Permit C-12,093-4 (final approval, issued December 8, 1980). PSCo requested certain changes to their permit in the Title V permit application, as discussed below. No revised construction permit was issued as the appropriate changes were included in the operating permit as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the equipment commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self-certification that the auxiliary boiler can comply with the new applicable requirements.

Permit C-12,093-4 contains the following applicable requirements:

- Opacity shall not exceed 20% (condition 1)
- Particulate Matter emissions shall not exceed either of the following limitations (condition 2): 1.7 lbs/hr or 1.1 tons/yr
- Sulfur dioxide ($SO_2$) emissions shall not exceed either of the following limitations (condition 3): 37 lbs/hr or 24 tons/yr

  In accordance with the Division's short term emission limits policy, the hourly emission limits will not be included in the operating permit.

  In addition, in order to accommodate the fuel switch, the source requested the following emission limitations on an APEN submitted on June 28,:

  PM 1.1 tons/yr, $PM_{10}$ 1.1 tons/yr, $SO_2$ 25.9 tons/yr, $NO_X$ 35.4 tons/yr, CO 29.7 tons/yr and VOC 1.9 tons/yr.

  No modeling analysis was required for the increase in $NO_X$ and CO emissions, as the requested increase in emissions from these pollutants are below the threshold for modeling as indicated in the Division's Modeling Guidance (40 tpy $NO_X$ and 100 tpy CO) and the Division believes that the boiler does not have poor dispersion characteristics. It should be noted that modeling has been conducted previously for the auxiliary boiler, for $SO_2$ and PM emissions when this emission unit was first permitted. The modeling

indicated that emissions from the auxiliary boiler would not cause or contribute to a violation of the NAAQS.

Note that only the emission limits for $SO_2$, $NO_X$ and CO will be included in the operating permit. Since requested emissions from the other pollutants are below the APEN de minimis levels at the requested fuel consumption limits they will not be included in the operating permit.

- The sulfur content of the fuel oil shall not exceed 0.3 % by weight (condition 4)
- The amount of No. 2 fuel oil shall not exceed either of the following limitations (condition 5): 850 gal/hr or 1,100,000 gal/yr

  In accordance with the Division's short term emission limits policy, the hourly fuel consumption limits will not be included in the operating permit.

  In addition in order to accommodate the fuel switch, a natural gas consumption limit of 707 mmSCF/yr was added as indicated on the APEN submitted June 28, 2002.

In addition to the requirements in permit C-12,093-4 this source is subject to the following applicable requirements:

- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)
- Particulate matter emissions shall not exceed $0.5(FI)^{-0.26}$ lbs/mmBtu, where FI is the fuel input in mmBtu/hr (Reg 1, Section III.A.1.b)

  At the maximum design fuel input rate (114.3 mmBtu/hr for No. 2 fuel oil and 98 mmBtu/hr for natural gas), this requirement is calculated as 0.146 lbs/mmBtu for No. 2 fuel oil and 0.152 lbs/mmBtu for natural gas. The numerical value will be included in the permit rather than the equation.
- Sulfur dioxide emissions shall not exceed 0.8 lbs/mmBtu (Reg 1, Section VI.B.4.b.(i))

**2. Emission Factors -** See discussion for Boiler No. 1 emission factors. Note that Boiler No. 2 does not have any continuous emission monitoring systems so $NO_X$ and $SO_2$ emissions will be monitored using emission factors and fuel consumption. The AP-42 emission factors for $NO_X$ and $SO_2$ (based on boilers < 100 mmBtu/hr for natural gas and > 100 mmBtu/hr for No. 2 fuel oil) are as follows:

| Pollutant | Emission Factor | |
|---|---|---|
| | Natural Gas (lbs/mmSCF) | No. 2 Fuel Oil (lbs/$10^3$ gal) |
| $NO_X$ | 100 | 24 |
| $SO_2$ | 0.6 | 147.7S |

"S" = weight percent sulfur in fuel

In addition, this boiler is not equipped with a baghouse or low $NO_X$ burners to control either particulate matter or $NO_X$ emissions, respectively.

**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.

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 permit specifies that the No. 2 fuel oil used cannot exceed 0.3 weight percent sulfur. Based on the fuel sulfur content limit, the source is in compliance with the $SO_2$ limit provided the fuel oil has a heat content greater than 55,388 Btu/gallon and is in compliance with the PM limit provided the fuel oil has a heat content greater than 13,670 Btu/gallon. These values are far below the heat content (140,000 Btu/gallon) identified in AP-42, Appendix A, Page A-5, dated September 1985 (reformatted January 1995). Therefore, the Division will consider that, in the absence of credible evidence to the contrary, the boiler is in compliance with the $SO_2$ and PM requirements when burning No. 2 fuel oil. Compliance with the opacity limit, when burning No. 2 fuel oil shall be monitored by conducting Method 9 opacity observations annually.

**4. Compliance Status –** The source certified in their Title V permit application that this unit was in compliance with all applicable requirements. The construction permit issued for this unit did not address burning natural gas as fuel, however, with the Title permit application submittal, the source submitted an APEN and requested that the construction permit be revised to allow for natural gas firing.

**C. Unit F001: Fugitive Particulate Emissions from Coal Handling and Storage**
**D. Unit F002: Fugitive Particulate Emissions from Ash Handling, Hauling and Disposal**
**E. Unit F003: Fugitive Particulate Emissions from Paved and Unpaved Roads**

**1. Applicable Requirements –** The coal handling/storage system, ash handling/disposal system and plant roads all commenced construction after February 1, 1972 and therefore are subject to the permitting requirements in Colorado Regulation No. 3, Part B. A timeline in the master files for this facility indicated that the first permit application for the facility was submitted October 10, 1975, this application was for the main boiler. A permit application for the coal handling system was submitted August 23, 1978 and permits C-12,093-1 (fugitive emissions), -2 (coal crusher) and –3 (plant transfer tower) were issued for the coal handling system on November 27, 1978. No construction permits were ever issued for ash handling or fugitive emissions from

vehicle travel on roads. With their Title V permit application, PSCo submitted an APEN and a construction permit application to address the fugitive emissions from roads and the emissions from ash handling. Construction permit numbers 96MR131-1F (roads) and –3 (ash handling) were assigned to these sources. The construction permits for these sources were never issued and the appropriate applicable requirements were included in the operating permit by processing these units as combined construction/operating permits as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the equipment commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self-certification that the ash handling and haul road emission sources can comply with the applicable requirements..

In their Title V permit application, PSCo grouped all coal handling and ash handling together and indicated that all sources are fugitive. However, some of the sources identified in the permit application can be and are reasonably controlled and therefore are not considered fugitive emission sources. For coal handling, the Division considers that only the activities associated with the outdoor storage pile (i.e. wind erosion and coal dozing) and railcar unloading are fugitive emission sources. For ash handling, the Division considers that only disposal of ash at the ash pit and maintenance of the ash pit are fugitive emissions sources.

As previously stated, Colorado Construction Permit C12,093-1 was issued for fugitive emissions from coal handling and that fugitive emissions from vehicle traffic on roads and ash handling had not been permitted. Since emissions from roads and ash handling should have been permitted and they are emitted at levels of concern with poor dispersion characteristics in close proximity to the ambient air boundary, modeling of these sources was necessary to demonstrate compliance with the $PM_{10}$ NAAQS/CAAQS. PSCo initially modeled emissions from only the previously un-permitted sources, which included the ash silo (non-fugitive ash handling emissions) and a cooling water tower. The results of this initial modeling indicated that the $PM_{10}$ impacts exceeded the significance level. Therefore, PSCo conducted a full-impact analysis which included other emission sources at Pawnee Station and other nearby sources. PSCo initially submitted this modeling analysis on November 27, 2001 and then revised their analysis on February 8, 2002 to more appropriately address the maximum 24-hour emission rates from some sources. The impacts from the revised analysis were 123.7 $\mu g/m^3$ (highest-second high) for the 24-hr $PM_{10}$ standard and 25.3 $\mu g/m^3$ (maximum) for the annual $PM_{10}$ standard. These impacts include the facility modification, nearby sources and background and are below the appropriate standards (150 $\mu g/m^3$, 24-hr and 50 $\mu g/m^3$ annual) and therefore operation of the previously un-permitted equipment (ash handling, roads and the cooling water tower) does not cause or contribute to an exceedance of the NAAQS or CAAQS.

All fugitive emission sources have the following applicable requirements:

- Minimize fugitive particulate emissions (Reg 1, Section III.D.1.a)

Since ash handling and emissions from vehicle travel on roads were not permitted prior to October 28, 1982 the Division considers that these emission sources shall have a fugitive particulate matter emission control plan. For fugitive emissions from coal handling, no control plan will be required, however, any measures used to limit the emission rates used in the modeling analysis will be included in the permit as an applicable requirement.

- APEN reporting (Reg 3, Part A, Section II)

  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.

The 20% opacity, no off-property transport, and nuisance emission limitations identified in Regulation 1, Section III.D.1.c are guidelines not enforceable standards. However, failure to comply with the guidelines may trigger the Division to require the source to submit a fugitive dust control plan. Per Reg 1, Section III.D.1.e(i)(B) and (C), if a control plan is required, it shall be a permit violation to operate an activity for which a control plan has been disapproved or to fail to comply with the provisions of an approved control plan.

The specific applicable requirements for these fugitive emission sources are as follows:

<u>Coal Handling</u>

The applicable requirements for fugitive emissions from coal handling addressed in Colorado Construction Permit C-12,093-1 (final approval permit, dated March 7, 1983) are as follows:

- Opacity of emissions shall not exceed 20% (condition 1)

  Note that for fugitive emissions, the 20% opacity requirement is not really applicable requirement but the 20% opacity serves as a guideline for the Division to request a fugitive particulate emission control plan or to require that such plan be revised. Therefore, the 20% opacity requirement will not be included in the permit.

- Particulate emissions shall not exceed the following limitations (condition 2): 104.26 lbs/hr and 61 tons/yr

  In accordance with the Division's short term emission limits policy, the hourly emission limit will not be included in the operating permit.

  A review of the preliminary analysis for these emission units indicates that the 61 tons/yr include emissions from such non-fugitive sources as the crusher and the plant transfer tower. The Division and the source, have agreed that fugitive and non-fugitive emissions sources should be addressed and permitted separately. Therefore, it is not appropriate to

include the 61 ton/yr emission limit in the permit, since this limit includes emissions from non-fugitive sources of emissions. The source has indicated that emission levels from fugitive coal handling are as follows (based on the November 27, 2001 modeling analysis):

| Source | PM (tons/yr) | $PM_{10}$ (tons/yr) |
|---|---|---|
| Wind Erosion | 8.61 | 3.10 |
| Coal Dozing | 26.08 | 5.06 |
| Coal Unloading | 1.15 | 0.54 |
| | | |
| Total | 35.84 | 8.7 |

Note that the emission limits will be included in the permit for information purposes only. Compliance with the emission limits will be presumed provided the quantity of coal handled is within the permit limits and that adequate control measures are taken to reduce fugitive particulate emissions.

The construction permit states that the emission limits were imposed to ensure that emissions will not result in an exceedance of the NAAQS. It was not clear from the information in the Division's files, whether modeling was actually conducted for PM emissions from coal handling. However, as discussed previously, a modeling analysis was conducted in order to permit existing equipment that had not previously been permitted. The modeling analysis was conducted using the fugitive emission levels from the coal pile identified in the above table. No control measures, i.e. watering or operating hours were used in the modeling analysis in order to demonstrate compliance with the $PM_{10}$ NAAQS and CAAQS.

- This source shall be limited to handling a maximum coal quantity of 12.3 x $10^6$ tons/yr and 3,300 tons/hr (condition 3).

  In accordance with the Division's short term emission limits policy, the hourly emission limits will not be included in the operating permit.

  The Division believes that the 12.3 x $10^6$ tons/yr throughput limit is an error, since the other 2 coal handling permits issued at the same time as this one, included throughput limits of 2.3 x $10^6$ tons/yr. The permits for the crusher building and transfer tower were modified on April 15, 1997 to increase the coal throughput to 2,921,460 tons/yr, which is consistent with the coal throughput limit on Unit 1. The Division had initially considered reducing the coal processing limit to be consistent with the coal processing limits in the permits for the crusher and the transfer tower. However, in their comments on the draft permit received on August 22, 2002, the source indicated that they typically would receive and store more coal than Unit 1 can actually burn, in order to have coal available in the event that coal could not be delivered at some time in the future. The

source did indicated that the quantity of coal identified in the permit is far more than they would typically have delivered. Therefore, the source requested that the coal processing limit be set at 4,000,000 tons/yr. This change has been included in the permit.

Although not specifically indicated in permit C-12,093-1, since the coal handling system commenced construction after October 24, 1974 the coal handling system is subject to the requirements in 40 CFR Part 60 Subpart Y. The actual unloading of coal is subject to the provisions of NSPS Subpart Y, if it is unloaded directly to coal processing plant machinery (i.e. hopper or a conveyor to a hopper or crusher). If it is unloaded directly to storage or a conveyor to storage, then it is not subject to the provisions of NSPS Y.

From railcar unloading, it is possible to convey coal to three different locations: dead storage (outdoor pile), live storage (enclosed storage with blending capabilities) and to the plant. The preferred option is to transport coal to live storage. Although it is possible to send coal to the power plant from the unloading facility it rarely occurs and there is not enough storage at the power plant to take a full trainload of coal. Therefore, the Division considers that since the option to send coal to the power plant after unloading is rarely used and since the power plant storage silos cannot accommodate a full trainload of coal, the railcar unloading facility is not subject to NSPS Y.

Ash Handling

As previously discussed, fugitive emission sources from ash handling were not previously permitted and should have been. No construction permit will be issued, however, the following applicable requirements will be included in the operating permit:

- Quantity of fly ash disposed of in the ash pit shall not exceed 136,656 tons/yr (as indicated in November 21, 2001 modeling analysis)
- Emissions from fugitive sources of ash handling are as follows (based on November 27, 2001 modeling analysis):

| Source | PM (tons/yr) | $PM_{10}$ (tons/yr) |
|---|---|---|
| Wind Erosion | 5.99 | 2.16 |
| Ash Dumping | 13.67 | 4.92 |
| | | |
| Total | 19.66 | 7.08 |

Note that the emission limits will be included in the permit for information purposes only. Compliance with the emission limits will be presumed provided the quantity of ash handled is within the permit limits and that the provisions in the fugitive particulate emission control plan are followed. As discussed previously, a modeling analysis was conducted in order to permit existing equipment that had not previously been permitted. Note that the modeling analysis was conducted using the fugitive emission levels from the ash pit identified in the above table.

Colorado Regulation No. 1, Section III.D.1.b requires that new sources of fugitive

emissions that are required to obtain a permit shall submit a fugitive particulate emission control plan. Since a permit was not issued for ash handling at this facility prior to October 28, 1982 (the date that the fugitive dust control provisions in Reg 1 were revised), the Division considers that a fugitive particulate emission control plan should be included for ash handling. The following requirements will be included as part of the fugitive particulate emission control plan.

- Water will be sprayed on the ash pit as necessary to control fugitive particulate matter emissions.

  Note that although no control measures (i.e. watering or operating hours) were used in the modeling analysis in order to demonstrate compliance with the $PM_{10}$ NAAQS and CAAQS, a fugitive particulate matter control plan is still required in accordance with Reg 1. Since no control measures were taken to demonstrate compliance with the NAAQS and CAAQS, the frequency of watering is deemed "as necessary", rather than on a required schedule.

- Ash haul trucks shall be covered.

<u>Roads</u>

As previously discussed, fugitive emission sources from vehicle traffic on roads was not previously permitted and should have been. No construction permit will be issued, however, the following applicable requirements will be included in the operating permit:

- Emissions from vehicle travel on paved and unpaved roads are as follows (based on the November 27, 2001 modeling analysis):

  PM = 47.9 tons/yr and $PM_{10}$ = 12.2 tons/yr

  Note that the emission limits will be included in the permit for information purposes only. Compliance with the emission limits will be presumed provided the quantity of ash handled is within the permit limits and that the provisions in the fugitive particulate emission control plan are followed. As discussed previously, a modeling analysis was conducted in order to permit existing equipment that had not previously been permitted. Note that the modeling analysis was conducted using the fugitive emission levels from the ash pit identified in the above table.

Colorado Regulation No. 1, Section III.D.1.b requires that new sources of fugitive emissions that are required to obtain a permit shall submit a fugitive particulate emission control plan. Since a permit was not issued for haul roads at this facility prior to October 28, 1982 (the date that the fugitive particulate emission provisions in Reg 1 were revised), the Division considers that a fugitive particulate emission control plan should be included for haul roads. The following requirements will be included as part of the fugitive particulate emission control plan.

- All active unpaved haul roads shall be watered daily to reduce visible emissions. Daily watering is not require when no haul trucks are using the unpaved roads, following rain or snow events that provide sufficient

moisture to control fugitive dust, and when the application of water creates a safety hazard due to ice formation on the roads. Chemical stabilization of the unpaved road surfaces can also be used to reduce the need for daily watering.

Note that watering unpaved roads was used in the modeling analysis to demonstrate compliance with the NAAQS and CAAQS so frequency is set at daily, unless adequate moisture is present.

- Vehicle speeds on haul roads and service roads shall not exceed 15 miles per hour. Speed limit signs shall be posted.

**2. Emission Factors -** Fugitive emissions are emissions that cannot reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening. The presence of outdoor storage and handling of relatively fine particulate matter subjected to wind and mechanical devices results in fugitive emissions. The emissions of interest include particulate matter (PM) which is typically particulates with a relatively coarse size range and particulate matter less than 10 microns in diameter ($PM_{10}$).

Fugitive PM and $PM_{10}$ emissions are subject to APEN reporting requirements but are not subject to annual fees. New and revised APENs were submitted with the Title V permit application for these fugitive particulate emission sources. The Division will not require emission calculations for these fugitive emission sources on any specified frequency. However, these sources are subject to the requirements of APEN reporting and the source must comply with these requirements. The emission factors included in the following section identify the emission factors used to estimate the emissions used in the modeling analysis. These emission factors are included in Appendix G of the permit for information purposes only.

1. Coal Handling

A. Emissions from wind erosion of coal pile: For the modeling analysis submitted on November 27, 2001, the source estimated emissions from wind erosion and coal dozing separately. The emission factors used for wind erosion are from “Control of Open Fugitive Dust Sources”, EPA-450/3-88-008, dated September 1988, Section 4.1.3, as follows:

$$E = 1.7 \times (s/1.5) \times [(365-p)/235] \times (f/15)$$

Where: E = emissions, in lbs/day/acre
s = silt content of aggregate, percentage [PSCo used 2.2%, per AP-42 (dated 1/95), Table 13.2.4-1 (coal as received from coal-fired power plant)]
p = number of days with > 0.01 inches of precipitation per year [PSCo used 80, per AP-42 (dated 1/95), Figure 13.2.2-1]
f = percentage of time that wind speed exceeds 5.4 m/s at mean pile height [PSCo used 26 % 1985 on-site meteorological data, which is conservative since the ash is dumped into a pit]

In addition, PSCo presumed that $PM_{10}$ = 0.36 x PM. Although this value is not consistent with the document "Control of Open Fugitive Dust Sources", which provides a value of 0.5 x PM, the Division will accept this value since it is consistent with the information currently in AP-42.

Although the AP-42 emission factors are more recent, the Division considers that the method use by the source to estimate emissions is acceptable.

B. Unloading of Coal: In its Title V permit application, the source used emission factors for drop/transfer points from AP-42 (dated January 1995), Section 13.2.4 to estimate emissions from coal unloading, as follows:

$$E = \frac{k \times 0.0032 \times (U/5)^{1.3} \times D \times \text{tons of coal unloaded per year}}{(M/2)^{1.4}}$$

Where:
E = particulate emissions, lbs/yr
k = particle size multiplier, dimensionless (0.74 for PM and 0.35 for $PM_{10}$)
U = mean wind speed, mph
D = number of transfer points, dimensionless
M = moisture content, %

Note that unloading of coal was not included in the modeling analysis conducted for sources of $PM_{10}$ emissions. This is acceptable to the Division since emissions from coal unloading are insignificant compared to emissions from the storage pile activities (i.e. wind erosion and coal dozing). Estimated emissions from railcar unloading are based on 1 transfer point, a moisture content of 9.2% (as indicated in the Title V permit application) and a wind speed of 8.7 mph (as indicated in the Title V permit application).

C. Coal Dozing:

In their modeling analysis submitted November 27, 2001, the source used emission factors from AP-42 (dated July 1998), Section 11.9 (Western Surface Coal Mining), Table 11.9-1 to estimate emissions from coal dozing, as follows:

$$E, PM = \frac{78.4 \times s^{1.2}}{M^{1.3}}$$

$$E, PM_{10} = 0.75 \times \left(\frac{18.6 \times s^{1.5}}{M^{1.4}}\right)$$

Where:
E = emissions, in lbs/hr
s = silt content, in percent [PSCo used 2.2% per AP-42 (dated 1/95), Table 13.2.4-1 (coal as received from coal-fired power plant)]

M = moisture content, % [PSCo used 4.5% per AP-42 (dated 1/95), Table 13.2.4-1 (coal as received from coal-fired power plant)]

2. Ash Handling

A. Emissions from Wind Erosion of Ash Pit

In their modeling analysis the source estimated emissions using the same equation for wind erosion as was used for wind erosion at the coal pile as discussed above under coal handling. The only difference being that a silt content of 80% was used for the ash pit (from AP-42 (dated 1/95), Table 13.2.4-1 (fly ash).

B. Ash Dumping

The source used emission factors from the AWMA Air Pollution Engineering Manual (Second Edition, 2000), Table 1, page 693:

PM = 0.2 lbs/ton transferred or conveyed
$PM_{10}$ = 0.072 lbs/ton transferred or conveyed

$PM_{10}$ is presumed to be 0.36 x PM

3. Vehicle Travel on Paved and Unpaved Roads

To estimate emissions from travel on unpaved roads, the source used emission factors from AP-42 (dated September 1998), Section 13.2.2 Unpaved Roads, as follows:

$$E = \frac{k \times (s/12)^a \times (W/3)^b}{(M/0.2)^c}$$

where:
E = particulate emissions, in lbs/VMT
VMT = vehicle miles traveled per year
k = constant, dimensionless, see table below
a = constant, dimensionless, see table below
b = constant, dimensionless, see table below
c = constant dimensionless, see table below
s = silt content of road surface material, in % (PSCo used 6.6, per AP-42, Table 13.2.2-1, for municipal solid waste landfills)
W = mean weight of vehicle, in tons (per PSCo W = 28)
M = surface moisture content, % (PSCo used 1.45 %)

| Constant | PM | $PM_{10}$ |
|---|---|---|
| K | 10 | 2.6 |
| A | 0.8 | 0.8 |
| B | 0.5 | 0.4 |
| C | 0.4 | 0.3 |

In their Title V permit application, the source proposed to estimate emissions from vehicle travel on paved roads using emission factors from AP-42 (dated January 1995), Section 13.2.1 (paved roads). However, after the Title V permit application was submitted, the source was instructed by the Construction Permit Unit to estimate emissions from paved roads using the emission factors in AP-42 (dated January 1995), Section 13.2.2 (unpaved roads) and a control efficiency of 85%. This method for estimating emissions was used to determine emission rates to be used in the modeling, as documented in the source's modeling analysis submitted on November 27, 2001.

**3. Monitoring Plan -** Emission limits are included in the permit for information purposes only. The source is subject to the APEN reporting requirements for these fugitive emission sources. The Division will not require the source to calculate emissions on any specified frequency; however, the source is responsible for submitting revised APENs as specified by Regulation No. 3, Part A, Section II.C.

These fugitive particulate emission sources are also subject to the requirements of Regulation 1, Section III.D which requires existing sources to employ control measures and operating procedures to minimize fugitive particulate emissions using all available practical methods which are technologically feasible and economically reasonable. These may include, but are not limited to watering or chemical stabilization of unpaved roads; restricting the speed of vehicles; the use of enclosures, covers, compacting and watering of storage piles and during material handling and transportation activities. The source will semi-annually certify that they have complied with the intent of this regulation for fugitive emissions from coal handling.

Since the ash handling and disposal operations and haul roads were not issued permits prior to October 28, 1982, the Division considers that these emission sources are required to have a fugitive particulate emission control plan, as required for new emission units in Regulation No. 1, Section III.D.1.b. The source will be required to certify that they are meeting the provisions in the fugitive particulate emission control plans semi-annually.

In addition, there are annual limitations on the quantity of ash disposed of and coal handled. The source will be required to record the quantity of ash disposed of and coal unloaded and maintain 12 month rolling totals to monitor compliance with these limitations. The quantity of coal unloaded shall be determined based on records of coal shipments received. The quantity of fly ash shall be determined based on the quantity of coal consumed, the average ash content of the coal, an 80% fly ash factor and facility records, as necessary

**4. Compliance Status –** The source submitted new APENs for ash handling and vehicle travel on roads and revised APENs for coal handling with their Title V permit application. Ash handling and vehicle traffic on roads are activities which require permits. No construction permits were issued, however, the applicable requirements were included in the operating permit by processing these activities as combined construction/operating permits as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. As mentioned previously, the certification by the Responsible Official in the first semi-annual monitoring report will serve as the self-certification that these activities can comply with their applicable requirements.

## F. P001: Coal Handling System (Crushers, Transfer Towers and Conveying)

**1. Applicable Requirements –** The coal handling system was first placed in operation in 1981. Colorado Construction Permits C-12,093-2 and -3 were first issued on November 27, 1978 for the crusher and transfer tower. These permits did not appear to address emissions from any other portion of the coal handling system, although emissions from all parts of the coal handling system were included in the 61 tons/yr limit on permit C-12,093-1 (fugitive coal handling emissions).

Colorado Construction Permits 12MR093-2 and 12MR093-3 (initial approval modification, dated April 15, 1997) contain the following applicable requirements:

- Visible emissions shall not exceed 20% opacity (condition 1)

  Although it is not specified in the permit, the Division presumes that this is the 20% opacity requirement in Reg 1, Section II.A.1.

  Based on engineering judgement, the Division has not included the Reg 1 30% opacity requirement for startup, process modification and adjustment of control equipment (Reg 1, Section II.A.4) for the following reasons: 1) startup is instantaneous (begin conveying and/or crushing); 2) process modifications are unlikely since the process of conveying or crushing is straightforward and if modifications were to occur, they could not occur while the unit is in operation (i.e. conveying and/or crushing) and 3) the control equipment cannot be adjusted while conveying or crushing is occurring.

- Emissions of air pollutants shall not exceed the following limitations (condition 3):

| | | | |
|---|---|---|---|
| <u>Transfer tower (12MR093-3)</u> | | | |
| PM | 0.00022 lbs/hr | and | 0.00023 tons/yr |
| $PM_{10}$ | 0.00104 lbs/hr | and | 0.00011 tons/yr |
| <u>Crusher (12MR093-2)</u> | | | |
| PM | 0.034 lbs/hr | and | 0.020 tons/yr |
| $PM_{10}$ | 0.010 lbs/hr | and | 0.0053 tons/yr |

- Production rate shall not exceed the following limitations (condition 5)

| | | | |
|---|---|---|---|
| <u>Transfer tower (12MR093-3)</u> | | | |
| Coal processing | 1400 tons/hr | and | 2,921,460 tons/yr |
| <u>Crusher (12MR093-2)</u> | | | |
| Coal processing | 2800 tons/hr | and | 2,921,460 tons/yr |

In accordance with the Division's short term emission limits policy, the hourly emissions and coal processing limits will not be included in the operating permit.

In order to simplify the monitoring and requirements for the coal handling system, the Division will combine all non-fugitive coal handling emission points into one permit (12MR093-2) and include emission limits and a coal processing limit for the entire system. Permit 12MR093-3 will be cancelled upon issuance of the operating permit.

The coal throughput limit that will be included in the operating permit is 4,000,000 tons/yr delivered and sent to storage and 2,921,460 tons/yr for coal from storage to the plant. The PM and $PM_{10}$ limits to be included in the permit are 15.4 tons/yr and 6.8 tons/yr, respectively. These emission limits are based on the longest path (i.e. the most transfer points) in the coal handling system. In addition, these emission limits do not take into account any control efficiency, except that a control efficiency of 90% was applied to emissions from the crushers to account for the fact that the crusher is enclosed. No control efficiencies for the plant transfer tower or crusher baghouses, any water/surfactant spray systems or enclosures on conveyors was taken in consideration in setting this emission limitation.

- The crusher and transfer points shall be completely enclosed and emissions shall be vented to a baghouse which shall reduce uncontrolled emissions of PM and $PM_{10}$ by at least 99.94% (condition 5)

  Since it is difficult to measure efficiency and since the permitted emissions do not take into account the control efficiencies for the baghouses, this efficiency requirement on the baghouses will not be included.

  However, it should be noted that the source will be required to follow operation and maintenance guidelines to assure that the baghouses are functioning properly.

- APEN reporting requirements (conditions 6 and 7)

  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.

The Division determined that no Regulation No. 1 particulate matter standards were applicable. These operations (crushing and conveying) are not considered fugitive emissions (PM requirements - Reg 1, Section III.D) since these sources can be reasonably controlled. The Division also does not consider coal conveying and

crushing to be a manufacturing process (PM requirements - Reg 1, Section III.C) since the coal is not used in manufacturing but is used in fuel burning equipment which has PM requirements in Reg 1, Section III.A.

Although not specifically indicated in permits 12MR093-2 and -3, since the coal handling system commenced construction after October 24, 1974 the coal handling system is subject to the requirements in 40 CFR Part 60 Subpart Y, as adopted by reference in Colorado Regulation No. 6, Part A.

Coal storage systems are an affected facility subject to NSPS Y and coal storage systems are defined as any facility used to store coal except for open storage piles. Therefore it would appear that live storage would be an affected facility under NSPS Y. EPA guidance on determining whether coal unloading is subject to the provisions of NSPS has been issued and was previously discussed under coal handling fugitive emission sources. This guidance was issued in the Federal Register (Volume 63, No. 192, dated October 5, 1998) and states that if coal unloading is subject to NSPS Y if it is unloaded for purposes of conveying to plant machinery. The definition of a coal preparation plant is any facility which prepares coal by one or more of the following processes: breaking, crushing, screening, wet or dry cleaning and thermal drying. At Pawnee, coal is unloaded and placed in either live (enclosed) or dead (outside pile) storage before it is sent to the crusher. Therefore, the Division considers that since both live and dead storage are prior to the crusher, that the conveyors that move coal from the unloading facility to storage are not subject to the provisions of NSPS Y. However, conveying of coal from either live or dead storage to the crusher and ultimately the power plant is subject to NSPS Y. Specifically, the Division considers that conveyors 7 thru 13, 17 and 18 are subject to NSPS Y.

The appropriate applicable requirements from 40 CFR Part 60 Subpart Y are as follows:

- The owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system or coal transfer and loading system processing coal, gases which exhibit 20% opacity or greater (40 CFR Part 60 Subpart Y § 60.252(c))

  Note that as specified in 40 CFR Part 60 Subpart § 60.11(c), the opacity standards apply at all times except during periods of startup, shutdown and malfunction.

In addition, the NSPS general provisions (40 CFR Part 60 Subpart A, as adopted by reference in Colorado Regulation No. 6, Part A) are also applicable to conveyors 7 thru 13, 17 and 18 as follows:

- Good practices (§ 60.11(d))
- Circumvention (§ 60.12)
- Conduct performance test in accordance with provisions of §§ 60.8 and

60.11

Although the coal handling system has been operational since 1981, the requirements in NSPS Subpart Y have never been identified as applicable requirements and therefore, the Division believes that no performance test has been conducted. Hence we are including the performance test requirements in the operating permit.

- Record startups, shutdown and malfunctions (§ 60.7(b))
- Written notification of opacity observation required by § 60.7(a)(6)

In 1995, PSCo disclosed that the transfer tower baghouse and the coal crusher baghouse were fire-damaged and not operational. They also disclosed that the spray systems at the live storage rotary plows and the crusher building were not functioning adequately. A Compliance Order on Consent (COC) was issued on February 27, 1996 and addressed the non-compliance issues associated with the non-functioning control equipment. The COC required PSCo to replace the baghouses on the transfer tower and crusher and to replace the spray systems on the live storage rotary plows and crusher building. In addition, the COC specified that the following requirements be included in the Title V operation permit application:

- PSCo shall conduct inspections of each baghouse and the spray systems on the live storage rotary plows and the crusher on at least a quarterly basis and perform any necessary repairs or maintenance on the baghouses or spray systems promptly after discovery of the need for such repairs or maintenance pursuant to the quarterly inspections (COC, Paragraph II.7).
- PSCo shall maintain records of each inspection required pursuant to this Consent Order. The records shall be kept at the Pawnee Station, shall be made available to Division inspectors, or their duly delegated representatives, upon request, and may be kept in computerized format. The parties hereby agree and understand that if the PSCo inspector has signed the inspection or work order form with no comments, the inspection has been fully performed and no problems with the control equipment were noted (COC, Paragraph II.8).

Paragraph II.9 of the COC states that the provisions of paragraphs II.7 and II.8 shall continue to apply unless and until the air pollution sources identified in this Consent Order become subject to and are regulated by the compliance assurance monitoring (CAM) rule. The emission sources addressed by this COC (crusher baghouse and spray system, transfer tower baghouse and live storage rotary plow spray system) do not have uncontrolled potential to emit above major source levels (100 tons/yr) and therefore these emission sources are not subject to the CAM requirements. Therefore, paragraphs II.7 and II.8 will remain in the permit.

**Streamlining of Applicable Requirements**

Opacity

The coal handling is subject to a Reg 1 20% opacity requirement (not to exceed 20%) and an NSPS opacity requirement of less than 20%. The Reg 1 opacity requirement applies at all times except for the specific operating activities where the 30% opacity requirement applies. However, the Division determined that the specific activities under which the 30% opacity requirement applies are not applicable to the coal handling, so the Reg 1 20% opacity requirement applies at all times. The NSPS opacity requirement applies at all times except for startup, shutdown and malfunction. Therefore, since neither opacity requirement is more stringent at all times, both opacity requirements will remain in the permit.

**2. Emission Factors -** The source indicated that the non-fugitive emission sources from coal handling were conveying of coal and crushing of coal. The Division agrees with this interpretation. Approval of emission factors is necessary to the extent that emission factors shall be used to monitor compliance with the annual emission limits The source identified the following emission factors:

A. Coal Conveying: There are no specific emission factors for conveying coal. Therefore, the source proposed to estimate emissions from coal conveying as emissions from each of the drop or transfer points in conveying the coal from the storage pile to the boilers. The Division believes that this is a reasonable method to estimate emissions from coal conveying. The source proposed to use emission factors for drop/transfer points from AP-42 (dated January 1995), Section 13.2.4. Emissions from each transfer point (dropping material on a received surface) can be estimated using the following equation:

$$E = \frac{k \times 0.0032 \times (U/5)^{1.3} \times D \times \text{tons of coal transferred per year}}{(M/2)^{1.4}}$$

Where:
- E = particulate emissions, lbs/yr
- k = particle size multiplier, dimensionless (0.74 for PM and 0.35 for $PM_{10}$)
- U = mean wind speed, mph
- D = number of transfer points, dimensionless
- M = moisture content, %

Note that permitted emissions are based on the longest path (i.e. the most transfer points) from railcar unloading to the plant. This path is from unloading to dead storage to the power plant and is based on 13 transfer points (5 points from unloading to dead storage and 8 points from dead storage to the plant), a wind speed of 8.7 mph (per Title V permit application submitted 2/15/96), a moisture content of 9.2% (per Title V permit application submitted 2/15/96), and a maximum coal consumption rate of 4,000,000 tons/yr for delivery to storage and 2,921,460 tons/yr for storage to the plant.

No control efficiency was applied to the permitted emissions for the crusher and plant transfer tower baghouse, any water/surfactant spray systems or enclosed conveyors.

B. Coal Crushing: The source proposed to use emission factors from EPA's FIRE Version 5.0, Source Classification Codes and Emission Factor Listing for Criteria Air Pollutants (EPA-454/R-95-012), dated August 1995 (SCC 3-05-010-10). The emission factors are:

| Pollutant | Emission Factor |
|---|---|
| PM | 0.02 lbs/ton coal |
| $PM_{10}$ | 0.006 lbs/ton coal |

Note that permitted emissions are based on a maximum coal consumption rate of 2,921,460 tons/yr. A 90% control efficiency was taken into consideration in the permitted emissions since the crusher is enclosed.

**3. Monitoring Plan –** The source will be required to monitor and record the quantity of coal processed through the coal handling system monthly in order to monitor compliance with the annual limitation. Compliance with the emission limits will be presumed, in the absence of credible evidence to the contrary, provided the control devices are maintained in accordance with manufacturer's recommendations and good engineering practices, and the COC inspection provisions and that the coal processing limit is not exceeded.

An initial performance test is required on the coal handling system to demonstrate compliance with the opacity requirements. Thereafter, compliance with the opacity limits is presumed, in the absence of credible evidence to the contrary, provided the control devices are maintained in accordance with manufacturer's recommendations, good engineering practices, and the COC inspection provisions.

**4. Compliance Status –** PSCo has installed the control equipment required by the February 27, 1996 COC and revised their Title V operating permit application to include the provisions in the COC. As specified previously, all coal handling sources will be consolidated as one construction permit. No revised construction permit was issued, however the applicable requirements were included in the operating permit by processing the coal handling system as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. As mentioned previously, the certification by the Responsible Official in the first semi-annual monitoring report will serve as the self-certification that the coal handling system can comply with its applicable requirements.

## G. Unit P002: Ash Silo

**1. Applicable Requirements –** The ash storage silo was first placed in service in 1981. The Division had previously determined that the source was using inappropriate emission factors for the ash silo and with the Division specified emissions factors, emissions from the ash silo were above the APEN de minimis levels and therefore a construction permit was required. Construction permit number 96MR131-3 was assigned for ash handling (both the ash silo and ash pit), however, the construction permit was never issued. The appropriate applicable requirements have been included in the operating permit by processing the ash silo as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the equipment commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self-certification that the ash silo can comply with the applicable requirements. As discussed under the fugitive particulate matter sources, emissions from the ash silo were modeled and it was determined that emissions from the ash silo do not cause or contribute to an exceedance of the NAAQS or CAAQS.

The applicable requirements from the ash silo are as follows:

- 20% opacity (Regulation No. 1, Section II.A.1)

  Based on engineering judgement, the Division has not included the 30% opacity requirement for startup, process modification and adjustment of control equipment (Reg 1, Section II.A.4) for the following reasons: 1) startup is instantaneous (begin loading or unloading); 2) process modifications are unlikely since the process of loading and unloading is straightforward and if modifications were to occur, they could not occur while the unit is in operation (i.e. loading or unloading) and 3) the control equipment cannot be adjusted while loading or unloading is occurring.

- APEN reporting (Reg 3, Part A, Section II)

  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.

- PM emissions not to exceed 2.13 tons/yr (based on the modeling analysis submitted by the source on November 27, 2001)
- $PM_{10}$ emissions not to exceed 2.13 tons/yr (based on the modeling analysis submitted by the source on November 27, 2001)
- Fly ash handling not to exceed 136,656 tons/yr (based on the modeling analysis submitted by the source on November 27, 2001)

The Division determined that no Regulation No. 1 particulate matter standards were applicable. Operations (loading and unloading) at the ash silo are not considered

fugitive emissions (PM requirements - Reg 1, Section III.D). The Division also does not consider the ash silo to be a manufacturing process (PM requirements - Reg 1, Section III.C) since the ash is a by-product of operating the boiler and no "product" is made with the ash, nor is it processed further. The purpose of the silo is to store ash until it is removed for sale or disposal. In addition, since the Division does not consider the ash silo to be a manufacturing process, the state-only PM requirements in Reg 6, Part B, Section III (Standards of Performance for New Manufacturing Processes) are also not applicable.

**2. Emission Factors -** The source has identified two (2) sources of emissions from the ash silo.

The first source is loading ash from the boiler baghouse to the silo. This is performed by a blower system that pneumatically conveys the ash from the baghouse hoppers to the top of the ash silo. At this point, ash falls into the silo while the conveying air is drawn out of the silo by a bin vent fan which keeps the silo under constant negative pressure of –1 to –3 inches of water. The exhaust from the silo bin vent fan is connected to the boiler baghouse inlet duct. Therefore, air from the ash silo ultimately vents through the boiler baghouse for particulate control and out the boiler stack.

The second source of emissions is from unloading ash into an enclosed truck or rail car. Dry ash is loaded into enclosed trucks or rail car. For this process a long hose is connected to the enclosed truck or rail car. This hose is equipped with an outer exhaust pipe that collects dust from around the inner hose and also pulls air out of the enclosed truck or rail car. Air from this exhaust is ducted to the ash silo and eventually passes through the boiler baghouse.

Approval of emission factors is necessary to the extent that emission factors shall be used to monitor compliance with the annual emission limits. The source proposed using the following emission factors to calculate emissions for the purposes of demonstrating compliance with the emission limits. Emission factors are from EPA's Compilation of Emission Factors (AP-42), Section 11.17, Table 11.17-4, Product Unloading - Enclosed Truck, dated January 1995. The emission factors are as follows:

| Pollutant | EF (lbs/ton) | Source | Assumed Efficiency |
|---|---|---|---|
| PM | 0.61 | loading[1] | Baghouse - 99.9% |
| $PM_{10}$ | 0.61 | loading[1] | Baghouse - 99.9% |
| PM | 0.61 | unloading[1] | Combination[2] - 95% |
| $PM_{10}$ | 0.61 | unloading[1] | Combination[2] - 95% |

[1]Specifically from Table 11.17-4, Product Unloading - Enclosed Truck
[2]Combination of boiler baghouse and hose connection

**3. Monitoring Plan –** The source shall be required to record ash throughput and calculate emissions monthly. Ash throughput shall be based on the quantity of coal consumed, the average ash content of the coal and a presumed 80/20 fly ash/bottom ash split. In the absence of credible evidence to the contrary, opacity emissions from

the ash silo and unloading operations shall be presumed to be in compliance with the opacity requirements provided the control devices are properly maintained and operated.

**4. Compliance Status –** A revised APEN for ash handling was submitted with the Title V application. Upon determination that the ash silo was subject to permitting requirements, PSCo requested a permit. No construction permit was issued, however the applicable requirements were included in the operating permit by processing the ash silo as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. As mentioned previously, the certification by the Responsible Official in the first semi-annual monitoring report will serve as the self-certification that the ash silo can comply with its applicable requirements.

## H. Unit P003: Soda Ash Handling System

**1. Applicable Requirements –** This unit was first placed in service in 1981. Emissions from the soda ash handling system result from the pneumatic loading of soda ash from the truck to the storage silo and the pneumatic transfer of soda ash to one of two day tanks. The soda ash storage silo and each of the day tanks is equipped with a pulse jet-type baghouse for control for particulate matter emissions.

Previous emission estimates made by PSCo indicated that emissions from this system were below the APEN reporting levels and therefore no permit was required. However, in processing other construction permits for similar systems at other PSCo facilities, the Division and PSCo agreed upon emission factors for these types of units. With these new agreed upon emission factors, actual uncontrolled emissions from the soda ash handling system exceeded the APEN de minimis level and as a result PSCo submitted a permit application on August 7, 1998. Construction permit number 98MR0561 was assigned for the soda ash handling system, however, the construction permit was never issued. The appropriate applicable requirements have been included in the operating permit by processing this system as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the equipment commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self-certification that this unit can comply with the applicable requirements. Note that no modeling analysis was required for the soda ash handling system since the requested emissions are very low.

The applicable requirements for the soda ash handling system are as follows

- 20% opacity (Regulation No. 1, Section II.A.1)

  Based on engineering judgment, the Division has not included the 30% opacity requirement for startup, process modification and adjustment of control equipment (Reg 1, Section II.A.4) for the following reasons: 1) startup is instantaneous (begin loading or unloading); 2) process

modifications are unlikely since the process of loading and unloading is straightforward and if modifications were to occur, they could not occur while the unit is in operation (i.e. loading or unloading) and 3) the control equipment cannot be adjusted while loading or unloading is occurring.

- APEN reporting (Reg 3, Part A, Section II)

  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.

- Soda ash processing not to exceed 4,000 tons/yr (based on requested throughput provided in the APEN received on August 7, 1998)
- PM emissions not to exceed 0.007 tons/yr (based on requested emissions provided in the APEN received on August 7, 1998)
- $PM_{10}$ emissions not to exceed 0.007 tons/yr (based on requested throughput provided in the APEN received on August 7, 1998)

The Division determined that no Regulation No. 1 particulate matter standards were applicable. Operations (loading and unloading) of the silo and day tanks are not considered fugitive emissions (PM requirements – Reg 1, Section III.D). The Division also does not consider the soda ash handling system to be a manufacturing process (PM requirements – Reg 1, Section III.C) since the soda ash is used directly in the water treatment process and is not used to manufacture a product for sale. In addition, since the Division does not consider the soda ash handling system to be a manufacturing process, the state-only PM requirements in Reg 6, Part B, Section III (Standards of Performance for New Manufacturing Processes) are also not applicable.

**2. Emission Factors -** Approval of emission factors is necessary to monitor compliance with the emission limitations. The source and the Division have agreed that emission factors from the background document for AP-42, Sodium Carbonate Production (formerly Section 5.16, now Section 8.12), dated January 1996 shall be used to monitor compliance with the emission limits. The emission factors are based on the average stack test results for product silo loading (test 23b). The approved emission factors are as follows:

| Pollutant | Emission Factor (lbs/ton) |
|---|---|
| PM | 1.7 |
| $PM_{10}$ | 1.7 |

The baghouses are presumed to operate at a control efficiency of 99.9%.

**3. Monitoring Plan -** Monitoring requirements for these units consist of monitoring and recording monthly quantities of soda processed through the silo and day tanks and calculating monthly emissions. In order to apply the control efficiency of the baghouses

to emission calculations, the baghouses will have to be maintained and operated in accordance with manufacturer's requirements and good engineering practices.

**4. Compliance Status –** The soda ash handling system was not included in the Title V permit application. PSCo submitted an APEN and construction permit application when they became aware that actual, uncontrolled emissions from the soda ash handling system were above APEN de minimis levels. No construction permit was issued, however the applicable requirements were included in the operating permit by processing the soda ash handling system as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. As mentioned previously, the certification by the Responsible Official in the first semi-annual monitoring report will serve as the self-certification that the soda ash handling system can comply with its applicable requirements.

## I. Unit M001: Cooling Water Tower

**1. Applicable Requirements –** The cooling water tower was first placed in service in 1981 and is rated at 190,000 gal/min. With their Title V permit application, the source submitted an APEN and a construction permit application for this unit, which had not previously been permitted. Construction permit number 96MR131-2 was assigned for the cooling water tower, however, the construction permit was never issued. The appropriate applicable requirements have been included in the operating permit by processing the cooling water tower as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the equipment commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self-certification that the cooling water tower can comply with the applicable requirements. As discussed under the fugitive particulate matter sources, emissions from the cooling water tower were modeled and it was determined that emissions from the cooling water tower do not cause or contribute to an exceedance of the NAAQS or CAAQS.

The applicable requirements for the cooling water tower are as follows:

- 20% opacity (Regulation No. 1, Section II.A.1)

  Based on engineering judgment, the Division believes that for purposes of opacity emissions none of the conditions under Reg 1, Section II.A.4 apply. Specifically activities such as fire building, cleaning of fire boxes and soot blowing are not germane to cooling water towers. In addition, there is really no "startup" involved in operating a cooling water 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 these units.

In their Title V permit application, the source indicated that in a meeting with the Division (September 6, 1995 pre-application meeting), both the Division and Public Service agreed that cooling water towers are always in compliance with the 20% opacity requirement. The Division does believe that it would be highly unlikely that a cooling water tower would ever violate the 20% opacity requirement. The Division considers that although it is unlikely that the cooling/service water towers would violate the 20% opacity requirement, this requirement must be included in the operating permit. Therefore, the Division considers that the cooling water towers are, in the absence of credible evidence to the contrary, in compliance with the opacity requirements provided the cooling/service water towers and their associated drift eliminators are operated and maintained in accordance with the manufacturer's recommendations and good engineering practices.

- APEN reporting (Reg 3, Part A, Section II)

  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.

- Water flow shall not exceed 99,864 mmgal/yr

- Emissions of air pollutants shall not exceed the following (based on the APEN submitted

| | |
|---|---|
| PM | 36.5 tons/yr |
| $PM_{10}$ | 36.5 tons/yr |
| VOC | 2.6 tons/yr |

  Note that the PM and $PM_{10}$ emissions are based on a total solids concentration of 28,000 ppm.

**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 "drift" droplets. Particulate matter contained in the "drift" 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 source proposed 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 (31.3% PM/$PM_{10}$ from drift) x (total solids, ppm)

Where: % drift = 0.001%
31.3% PM from drift - from EPA-600/7-79-251a, November 1979, "Effects of Pathogenic and Toxic Materials Transported Via Cooling Device Drift - Volume 1, Technical Report", page 63

VOC = $CHCl_3$ = (water flow, gpm) x (0.0527 lbs $CHCl_3$/mmgal)

Where: 0.0527 lbs/mmgal emission factor - from letter from Wayne C. Micheletti to Ed Lasnic, dated November 11, 1992 (see attached)

**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. Since the total solids concentration for the cooling water tower has remained fairly consistent and well below 28,000 ppm (the level at which the emission limits were set), the permit will require that the total solids content of the circulating water in each tower be analyzed semi-annually.

**4. Compliance Status -** PSCo submitted an APEN and construction permit application with their Title V Permit application. No construction permit was issued, however the applicable requirements were included in the operating permit by processing the cooling water tower as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. As mentioned previously, the certification by the Responsible Official in the first semi-annual monitoring report will serve as the self-certification that the cooling water tower can comply with its applicable requirements.

## IV. Insignificant Activities

General categories of insignificant activities include: in-house experimental or analytical laboratory equipment, fuel (gaseous) burning equipment < 5 mmBtu/hr or < 10 mmBtu/hr (for heating), chemical storage tanks/containers < 500 gal or storage areas < 5,000 gal, landscaping and site housekeeping equipment (< 10 hp), storage of butane, propane or NGL (vessels < 60,000 gal), lube oil storage tanks (< 40,000 gal) and other storage tanks (limited throughput and contents), fuel storage and dispensing equipment, stationary internal combustion engines (limited size and hours of operation) and sources with emissions less than APEN de minimis. Specific insignificant activities identified in the Title V permit application are:

<u>Units with emissions less than APEN de minimis - criteria pollutants (Reg 3 Part C.II.E.3.a)</u>

Boiler Steam Vents – emit VOC from injection of VOCs as treatment chemicals (< 1 ton/yr VOC)
Solvent Cold Cleaners (< 1 ton/yr of VOC from each unit)

<u>In-house experimental and analytical laboratory equipment (Reg 3 Part C.II.E.3.i)</u>

Plant Laboratory

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

Propane Portable Heaters

Welding, soldering and brazing operations using no lead-based compounds (Reg 3 Part C.II.E.3.r)

Maintenance Welding Machine

Chemical storage tanks or containers < 500 gal (Reg 3 Part C.II.E.3.n)

Cooling Water Tower Scale Inhibitor Day Tank (50 gal inside water treatment bldg)
High Pressure Treated Water Chemical Feed Tank (500 gal treated water pond)
R. O. Acid Dilution Feed Tank (200 gal inside water treatment bldg)
R. O. Scale Inhibitor Feed Tank (180 gal inside water treatment bldg)
Building Cooling Water Head Tank (500 gal inside main plant)
Oxygen Scavenger Chemical Feed Tank (50 gal inside main plant)
Phosphate Chemical Feed Tank (50 gal inside main plant)
Amine Chemical Feed Tank (50 gal inside main plant)
Ash Water Chemical Feed Tank (265 gal inside main plant)
Auxiliary Boiler Chemical Feed Tank (50 gal inside main plant)

Battery recharging areas (Reg 3 Part C.II.E.3.t)

Battery Storage Area

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

Mowers, Snowblowers, Etc.

Fugitive emissions from landscaping activities (Reg 3 Part C.II.E.3.cc)

Operations involving acetylene, butane, propane or other flame cutting torches (Reg 3 Part C.II.E.3.kk)

Portable Welding Torches

Chemical storage areas < 5,000 gal capacity (Reg 3 Part C.II.E.3.mm)

Oil Drum Storage Areas

Emissions of air pollutants which are not criteria or non-criteria reportable pollutants (Reg 3 Part C.II.E.3.oo)

Wastewater Operations

Evaporation Ponds (east side of facility)
Holding Ponds (east side of facility)
Raw Water Storage Reservoir (north side of facility)
Treated Water Pond (west of water treatment bldg)

Janitorial activities and products (Reg 3 Part C.II.E.3.pp)

Office emissions including cleaning, copying, and restrooms (Reg 3 Part C.II.E.3.tt)

Fuel storage and dispensing equipment in ozone attainment areas throughput < 400 gal/day averaged over 30 days (Reg 3 Part C.II.E.3.ccc)

Gasoline Tank, Regular (1,000 gal underground)
Gasoline Tank, Unleaded (1,000 gal underground)

Storage tanks with annual throughput less than 400,000 gal/yr and meeting content specifications (Reg 3 Part C.II.E.3.fff)

Fuel Oil Spill Tank (19,750 gal underground)
Emergency Oil Spill Drain Tank (12,530 gal underground)
Diesel Tank (10,000 gal underground)
Diesel Fuel Tank for Emergency Generator (575 gal above ground)
Fire Pump Diesel Day Tank (200 gal above ground)
No. 2 Fuel Oil Storage Tank (325,000 gal above ground)
Turbine Lube Oil Batch Tank A (12,000 gal above ground)
Turbine Lube Oil Batch Tank B (12,000 gal above ground)
Hydrogen Seal Oil Tank (840 gal above ground)

Emergency Power Generators - limited hours or size (Reg 3 Part C.II.E.3.nnn.(iii))

Emergency Diesel Generator (runs < 100 hrs/yr)

Sandblast equipment where blast media is recycled and blasted material is collected (Reg 3 Part C.II.E.3.www)

Sandblasting Machine

Stationary Internal Combustion Engines - limited hours or size (Reg 3 Part C.II.E.3.xxx)

Emergency Fire Pump (> 300 hp and < 750 hp, runs < 340 hrs/yr)
Joy Air Compressor (< 175 hp and runs < 1,450 hrs/yr)
Portable Light Generator (< 175 hp and runs < 1,450 hrs/yr)
Two (2) Water Pumps (< 175 hp and runs < 1,450 hrs/yr)
Sullair Air Compressor (< 175 hp and runs < 1,450 hrs/yr)
Four (4) Portable Welders (< 175 hp and runs < 1,450 hrs/yr)

Not sources of emissions

Turbine Lube Oil System (closed system)
Waste Water Neutralization Tank (30,000 gal underground)
R. O. Product Storage Tank (10,000 gal inside water treatment bldg)
Sludge Thickener Supernatant Tank (8,000 gal inside water treatment bldg)
Acid Storage Tank A (15,000 gal inside water treatment bldg)
Waste Water Conc. Product Storage Tank (60,000 gal above ground)
Condensate Storage A (150,000 gal above ground)
Condensate Storage B (150,000 gal above ground)
Potable Water Storage Tank (6,000 gal inside main plant)
Soot Blower Water Deslagger Supply Tank (12,000 gal inside main plant)
Acid Stabilization Tank (24,000 gal above ground)
Chem Lab D.I. Water Storage Tank (300 gal inside main plant)
Waste Tank (2,500 gal inside waste water concentrator bldg)
Seed Tank (400 gal inside waste water concentrator bldg)
Primary Feed Tank (4,500 gal inside waste water concentrator bldg)
Cooling Water Tower Scale Inhibitor Storage (4,000 gal inside water treatment bldg)
Caustic Storage Tank A (15,000 gal inside water treatment bldg)
Alum Storage Tank (12,000 gal inside water treatment bldg)
Main Plant Heat Head Tank (3,300 gal inside main plant)
Sludge Thickener Tank (940,000 gal N of water treatment)
Clarifier/Softener Tank (715,000 gal N of water treatment)

The source also identified mobile engine tailpipe emissions as an insignificant activity. Emissions from these sources would not necessarily qualify them as an insignificant activity but they are not applicable to Title V permitting requirements since they are mobile sources. Therefore, emissions from mobile sources are not identified in the draft permit as an insignificant activity.

## V. Alternative Operating Scenarios

### A. Alternate Fuels

The primary fuel for Unit 1 is coal. Natural gas and No. 2 fuel oil is used during non-routine periods such as startup, shutdown and/or other flame stability efforts.

### B. Chemical Cleaning of Boiler

The source has also requested, in a November 15, 1996 submittal (see attached), that boiler chemical cleaning be allowed as an insignificant activity. The Division has previously indicated that this activity does not require permitting. After a boiler has been cleaned the waste cleaning solutions are evaporated in a boiler. In order to be consistent with other power plant Operating Permits and because the Division is placing some requirements on the cleaning events, the chemical cleaning of boilers is being included in the Operating Permit as an alternative operating scenario. A permit

(88DE245, initial approval, September 27, 1988) for the temporary evaporation of boiler cleaning solutions was issued for a boiler at Arapahoe Station (see attached). The Division later indicated that no permit was required for this activity and that the source should request that the permit be canceled. Although the permit has been canceled and is no longer valid, it was used as a guide to identify reporting and operating requirements for the alternative operating scenario of evaporating chemical cleaning solutions in the boilers. The only requirement from Permit 88DE245 that was included in the Operating Permit was that any air pollution control equipment shall be operated during evaporation of the cleaning solutions. Permit 88DE245 required that prior notification of the cleaning event, including the amounts and types of cleaning solutions to be evaporated as well as the evaporation rate be provided to the Division. In order to be consistent with the requirement for alternative operating scenarios (Reg 3, Part A, Section IV.A), the Division is requiring that the source maintain records of the date and time the cleaning event starts and ends and the amounts and types of chemicals used in the event. Permit 88DE245 also indicated that the source was subject to the requirements of Regulation No. 8, Sections IV and VI, which limit ambient impacts of mercury and lead. The Division has already included requirements in the Operating Permit for demonstrating compliance with the lead emission requirements in Regulation No. 8, Section IV and therefore does not believe that any further demonstration is required when cleaning the boiler. The Division no longer has a state standard for mercury and the NESHAP for mercury (40 CFR Part 61, Subpart D) is not applicable to mercury emissions that may occur from coal-fired utility boilers.

## VI. Permit Shield

The source requested that the following applicable requirements be included in the permit shield as non-applicable requirements.

A. 40 CFR Part 60 Subpart Y (as adopted by reference in Colorado Regulation No. 6, Part A) – Standards of Performance for Coal Preparation Plants. The permit application states that these requirements do not apply because this NSPS applies only to coal preparation plants and that while this facility does prepare coal for its own use it is not a coal preparation plant as defined in 40 CFR Part 60, Subpart Y (i.e. it does not sell prepared coal to users). This justification is incorrect as the definition of a coal preparation plant in 40 CFR Part 60 Subpart Y § 60.251(a) does not distinguish between facilities preparing coal for their own use and facilities preparing coal for sale to other users, nor does the applicability requirements (§ 60.250) specifically state that the requirements apply only to plants that “sell” prepared coal to other users. The permit shield will not be granted since construction of the facility commenced after October 24, 1974 and the coal handling system is subject to the requirements in 40 CFR Part 60 Subpart Y.

B. 40 CFR Part 63, Subpart Q (as adopted by reference in Colorado Regulation No. 8, Part E) - National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Water Towers - The permit application states that this requirement is

not applicable because the cooling water towers do not use chromium-based water treatment chemicals. The shield was granted based on the source's justification.

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

Boiler No. 1, Unit B001

- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Section IV.A, B, F, G and H), streamlined out since the Acid Rain COM/CEM requirements are more stringent. In the case of Reg 1, Section IV.F, the calibration requirement is streamlined out since the Acid Rain CEM QA/QC requirements are more stringent and the NSPS QA/QC requirements for COMS (40 CFR Parts 60.13 and 60.45(c)(3)) are more stringent. In the case of Reg 1, Section IV.G, the reporting requirements were streamlined out in favor of the NSPS excess emission reporting requirements. In the case of Reg 1, Section IV.H, the requirement for retention of records is streamlined out since the requirements for retaining records in Reg 3, Part C (general condition 22 in the operating permit) is more stringent.
- Continuous Emission Monitoring Requirements (40 CFR Part 60 Subpart D §§ 60.45(a), (c), (e) & (f), EPA PSD Permit and Colorado Construction Permit 11MR674 - install CEMs/COM, performance evaluation & calibration checks and data conversion procedures), streamlined out since Acid Rain COM/CEM requirements (40 CFR Part 75) are more stringent, **except that the QA/QC requirements as they apply to COMs in 60.45(c)(3) will remain in the permit.**
- 0.1 lbs/mmBtu particulate matter emission limit (40 CFR Part 60 Subpart D § 60.42(a)(1), as adopted by reference in Colorado Regulation No. 6, Part A and EPA PSD Permit), streamlined out since the Reg 1, Section III.A.1.c is more stringent as this standard applies at all times.
- 1.2 lbs/mmBtu $SO_2$ emission limit (40 CFR Part 60 Subpart D § 60.43(a)(2), as adopted by reference in Colorado Regulation No. 6, Part A and EPA PSD Permit), streamlined out since the Reg 1, Section VI.A.3.a(ii) is more stringent as this standard applies at all times.
- 20% opacity except for one 6-minute period per hour of not more than 27% opacity (EPA PSD Permit), streamlined out since NSPS opacity requirement is as stringent.

## VII. Acid Rain Provisions

Unit 1 is an affected unit under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78. Unit 1 has been allocated, on an annual basis, $SO_2$ allowances (1 ton per year of $SO_2$) as listed in 40 CFR 73.10(b)(2). The source opted to

comply with the Phase I $NO_X$ limitation which is 0.50 lbs/mmBtu, on an annual average basis.

As an affected unit under the Acid Rain Program, Unit 1 must continuously measure and record emissions of $SO_2$, $NO_X$ (including diluent gas either $CO_2$ and $O_2$), and $CO_2$, as well as volumetric flow and opacity. The source submitted the continuous emission monitoring system (CEMS) certification package on January 1, 1995.

## VIII. Accidental Release Program – 112(r)

Section 112(r) of the Clean Air Act mandates a new federal focus on the prevention of chemical accidents. Sources subject to these provision must develop and implement risk management programs that include hazard assessment, a prevention program, and an emergency response program. They must prepare and implement a Risk Management Plan (RMP) as specified in the Rule.

The source indicated that this facility was subject to the 112(r) Accidental Release Requirements. A risk management plan was submitted to EPA before the June 21, 1999 deadline and a revised RMP was submitted on November 22, 1999.

## IX. Compliance Assurance Monitoring (CAM) Requirements

At this time, no emission points at this facility are subject to the provisions of the CAM program as set forth in 40 CFR Part 64 as adopted by reference into Colorado Regulation No. 3, Part C, Section XIV. The application for this operating permit was deemed administratively complete prior to April 20, 1998. Therefore, emission points at this source will be reviewed for CAM applicability only upon the submission of a significant modification request (and then only for the emission point being modified) or upon renewal of the operating permit after the five-year expiration date.