TECHNICAL REVIEW DOCUMENT
for
OPERATING PERMIT 96OPAD130
to be issued to:

Public Service Company - Cherokee Station
Adams County
Source ID 0010001

Prepared August thru October 1999
Jacqueline Joyce, Review Engineer
Revised June and August 2000 and September and October 2001
Revised January 28, 2002 to update attainment status of the Denver metro area

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 the report are based on information provided in the original application submittal of February 15, 1996, additional technical information submitted November 15, 1996, March 31 and July 14, 1997, February 18 and November 25, 1998, March 29 and September 24, 1999, August 31, November 28, December 8 and 12, 2000 and March 5, 2001, comments on the draft permit received October 12, 2000 and October 26, 2001, 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 of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

The word "credible" as it is used in the term "credible evidence" shall be applied under the provisions of the permit as defined by Colorado and Federal Rules of Evidence.

II. Source Description:

This source is classified as an electric services facility under Standard Industrial Classification 4911. Electricity is produced through four coal-fired boilers. Although coal is the primary fuel burned, these units use natural gas as a back-up fuel. Unit No. 1 is a 115 MW boiler that is equipped with a baghouse to control particulate matter emissions, low NO_X burners with over-fire air to control NO_X emissions and a dry sodium injection system to control SO_2 emissions. Unit 1 shares a stack with Unit No. 2. Unit No. 2 is a 114 MW boiler that is equipped with a baghouse and over-fire air. Unit No. 3 is a 168 MW boiler that is equipped with a baghouse and low NO_X burners with over-fire air. Unit No. 4 is a 388 MW boiler that is equipped with a baghouse, low NO_X burners with over-fire air and a dry SO_2 scrubber. Note that the low NO_X burners with over-fire air were added to Unit 1 after submittal of the Title V permit application, as was the dry sodium injection system on Unit 1. In addition, the over-fire air that was added to Unit 2 was added after submittal of the Title V permit application. Other emission sources at Cherokee include fugitive emissions from coal handling and storage, ash handling and disposal and from traffic on paved and/or unpaved roads. Finally, Cherokee station has point source emissions from the five (5) ash/spent sorbent storage silos, one (1) ash blower system, two (2) coal crushers, the coal conveying and storage system, five (5) sodium reagent silos, four (4) cooling water towers and two (2) service water towers, emergency generators and one above ground gasoline storage tank.

Note that Public Service Company (PSCo) has entered into a voluntary emission reduction agreement (hereafter referred to as the "Metro Agreement") with the Division. The requirements of this agreement will be included in the operating permit by reopening the permit or upon renewal, depending upon the issuance date of this permit.

This facility is located in Denver at 6198 Franklin Street in Adams county, within the Denver metro area. The area in which the plant operates has been designated as non-attainment for particulate matter less than 10 microns (PM_{10}). In addition, the Denver metro area is classified as attainment/maintenance for ozone and carbon monoxide. Under that classification, all SIP-approved requirements for VOC and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act.

Rocky Mountain National Park and Eagle's Nest National Wilderness Area, both Federal Class I designated areas, are within 100 km of this facility. There are no affected states within 50 miles of this facility.

This facility is a major stationary source for the purposes of prevention of significant deterioration (PSD) and non-attainment area major New Source Review (NSR), however, it was constructed prior to the adoption of PSD/non-attainment area major NSR regulations and the implementation of best available control technology (BACT) and lowest achievable emission rate (LAER) requirements. Based on the information available to the Division and supplied by the application, the Division believes that modifications up to this point have not to triggered PSD or major non-attainment area NSR requirements. Emissions at the facility are as follows:

Pollutant	Potential to Emit (PTE) - 100% Coal[1]	Potential to Emit (PTE) - 100% Natural Gas[2]	Actuals - Combination of Fuels
PM[3]	3,988	3453	412
PM_{10}[4]	3,396	3408	283
SO_2[5]	39,419	37,271	19,146
NO_X[6]	21,655	21,184	11,967
CO	802	1,342	564
VOC	96	57	71
Pb[7]	18	Negl.	.23
HAPs[8]	505	11.1	181.2

[1]Boilers are firing 100% coal: includes emissions from coal and ash handling
[2]Boilers are firing 100% natural gas: does not include emissions from coal and ash handling
[3]PTE for boilers, for all fuels, are based on 0.1 lbs/mmBtu x design heat rate x 8760 hrs/yr
[4] PTE for boilers are based on 92% of PM being PM_{10} for coal and 100% for natural gas
[5]PTE for boilers, for all fuels, are based on 1.1 lbs/mmBtu x design heat rate x 8760 hrs/yr.
[6]PTE for boiler 3, for all fuels, is based on 0.60 lbs/mmBtu x design heat rate x 8760 hrs/yr and boiler 4 PTE, for all fuels, is based on 0.45 lbs/mmBtu x design heat rate x 8760hrs/yr. PTE for boilers 1 and 2, for all fuels, is based on the Acid Rain NO_X limit x design heat rate x 8760 hrs/yr.
[7] PTE for lead is based on uncontrolled emissions, control efficiency is 99.3%
[8]includes uncontrolled metallic HAPs, control efficiencies range from 78.2 - 99.8 for these compounds

Potential to emit is based on the information identified in the table and the maximum

hourly fuel consumption rate, AP-42 emission factors and 8760 hrs/yr of operation. Potential to emit from coal handling, ash handling, haul roads and the cooling towers is based on information supplied in the Title V application for regulated units. Potential to emit from the grandfathered emergency generator is based on the maximum hourly heat input rate (mmBtu/hr), AP-42 emission factors and 500 hrs/yr or operation (as allowed by EPA Guidance memo on determining PTE for emergency generators for purposes of Title V only). Potential to emit from the new ash silos, ash blower, dry sodium reagent silos, gasoline storage tank and the permitted emergency generator is based on permitted emissions. Actual emissions are based on the Division's 2000 inventory. Hazardous Air Pollutant (HAP) Emissions, both potential to emit and actual, for the boilers are based on APENs submitted September 30, 1996, using 1995 data, as a result of the Division's request for public utilities to submit HAP addendums (APENs) on their boilers and information from the Division's 2000 inventory (HCl and HF).

It should be noted that on May 8, 2000, the Division issued a construction permit (99AD0812) for two ash storage silos at the Cherokee facility. The construction permit was issued to Son Haul, Inc., the owners of the ash silo. As part of the construction permit process the Division determined that Son Haul and Cherokee were separate sources. As a result of the Operating Permit review process, the Division re-evaluated the source determination and agrees with the original determination that Son Haul and Cherokee are separate sources. The basis for this decision is that the three criteria for source determination are not met. Although Son Haul's silos are located on contiguous property with Cherokee Station, there is no common ownership or control and these two operations belong to different two-digit SIC codes. In addition, based on information available to the Division and supplied by the source, the Division considers that Son Haul is not a support facility for Cherokee Station. Although Son Haul does take some ash from Cherokee Station, the quantity of ash that Son Haul takes is less than 10% of the potential ash produced at this facility. In addition, although Son Haul has rights to ash at Cherokee Station, they are not required by any contract to take ash from the facility. Ash is loaded into and out of the Son Haul silos by truck and therefore, there is no physical or contractual limitations that prevent Son Haul from taking ash from a source other than Cherokee Station.

The source indicated in their Title V permit application that this facility is subject to 112(r), the Accidental Release Requirements. At that time Cherokee would have been subject to 112(r) since chlorine gas storage exceeded threshold levels. However, chlorine is no longer used in the cooling towers at Cherokee so this facility is not longer subject to the requirements in 112(r).

All four boilers are affected units and are subject to the Title IV Acid Rain provisions.

III. Emission Sources:

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

A. Unit B001: Babcock and Wilcox Top-Fired Boiler, Model No. RB251, Serial No. NY-771302, Rated at 1,392 mmBtu/hr. Coal-Fired with Natural Gas Used as Back-Up.

1. Applicable Requirements - This unit was first placed in service in August 1957. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 1,392 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 852,000 lbs/hr. This maximum steam flow rating cannot be exceeded. This unit shares a stack with Unit 2. Both units are equipped with continuous opacity monitors (COMs) and continuous emission monitors (CEMs) to measure SO_2, NO_X (including diluent gas either CO_2 or O_2), and CO_2. The COM and CEMs for each unit are located in the duct work for that unit, just prior to the common stack.

In 1989 Public Service (PSCo) replaced the electrostatic precipitators and wet scrubbers (ESP/WS) for Units 1 and 4. Although this action decreased emissions of particulate matter, SO_2 emissions would increase due to the removal of the wet scrubber. The NSPS regulations (40 CFR Part 60) exempts the addition of control equipment from the definition of a modification, except when an emission control system is removed or is replaced by a system that is determined to be less environmentally beneficial. However, at the time this modification was requested, modifications subject to PSD review did not have this environmental benefit exemption. Therefore, PSCo agreed to obtain permits (86AD352-1 and -2) for both Units 1 and 4 to reduce SO_2 emissions by 20% (which was the presumed SO_2 control efficiency of the wet scrubbers) in order to avoid PSD review. As part of this permitting process a dry sodium injection system was added to Unit 4 to control SO_2 emissions. In 1998 a dry sodium injection system was added to Unit 1 to provide more operational flexibility.

Permit 86AD352-1, initial approval, was issued November 13, 1986. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the initial approval construction permit was issued and/or the equipment commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self-certification for construction permit 86AD352-1 and the appropriate provisions of the construction permit have been directly incorporated into this operating permit. It should be noted that this permit, specifically the SO_2 emission limitations, is part of the state's Denver PM_{10} SIP Element. As a result the SO_2 emission limitations in this permit cannot be revised without first revising the SIP Element. In addition, this permit was included as part of a Colorado Air Quality Control Commission (AQCC) Order (signed August 28, 1986), which specifically states in the Settlement

Agreement "..this permit shall not contain any conditions that are more stringent than those set forth in Attachment A [draft construction permit] of this agreement." This construction permit, dated November 13, 1986 contains the same language as the draft construction permit attached to the AQCC Order.

In November 1998, PSCo indicated that low NO_X burners with over-fire air would be installed on Unit 1. 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.

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), **exempted** the addition, replacement or use of a pollution control project 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." These units are grandfathered from PSD and major non-attainment area NSR review, were never modified and subsequently were never modeled. Therefore, the addition of the low NO_X burners would not subject this unit to major PSD or non-attainment area review in accordance with the WEPCO rule.

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. The Division believes that emissions of CO may be increased by the addition of the low NO_X burners and 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.

Finally, if the addition of the low NO_X burners would increase emissions of CO, then the minor NSR permitting requirements in Reg 3, Part B would apply. Prior to installing the low NO_X burners, the source agreed to test emissions before the new burners were added and after to determine if there are any emission increases in CO. The source has tested the CO emissions after the addition of the low NO_X burners on this unit on two occasions. In one instance testing demonstrated a minor increase in CO emissions and in a second test there was no increase in CO emissions. Public Service has indicated that the initial test was invalid because the boiler controls were being operated in manual mode and the test protocol was not followed. Low NO_X burners have been added to the two boilers at Public Service's Hayden facility and before and after testing indicates no increase in CO emissions. Therefore, the Division believes that the minor NSR permitting requirements in Reg

3, Part B do not apply to the addition of the low NO_X burners.

Unit 1 is subject to the following applicable requirements as identified in permit 86AD352-1:

- Opacity of emissions shall not exceed 20% (6-minute average) except as allowed in Reg 1, Section II.A.4 (condition 1 & Reg 1, Section II.A.1).
- Particulate matter emissions shall not exceed 0.1 lbs/mmBtu (condition 2 & Reg 1, Section III.A.1.c).
- Opacity of emissions shall be monitored according to Reg 1, Section IV.B.1 [COM]. Equipment shall be located such that any bypasses are monitored. All monitored data shall be recorded and kept on site for two years (condition 3).

  Note that Reg 3, Part C requires that records be kept on site for one year, while the construction permit requires that COM records be kept on site for two years, the operating permit will reflect the more stringent requirement of two years of retention of records on site. Note that the retention of records for five years (not on site) in Reg 3, Part C is still applicable.

- A compliance test shall be conducted for the particulate matter emission standard as required by Reg 1, Section III.A.3 (condition 4).

  A memo, dated December 20, 1989, in the master file indicates that the Division reviewed and approved the results of the particulate matter stack test for Units 1 and 4. This permit condition was satisfied and will not be included in the operating permit, however, the Division will require additional performance tests in the permit as periodic monitoring.

- Emission reporting for particulate matter shall follow the procedures in Reg 1, Section IV.G (condition 5).

  Note that Reg 1, Section IV.G (excess emission reports) only applies to units required to install continuous emission or opacity monitors and therefore this reporting requirement should only apply to opacity and SO_2 emissions but <u>not</u> to particulate matter emissions. This requirement will be streamlined out of the operating permit in favor of the Reg 1, Section IV.B requirement which clearly states that reporting requirements apply to units with continuous emission monitors.

- Continuous emission monitors shall be operated according to Reg 1, Section IV.B [COM for opacity & CEM for SO_2]. The CEM/COM shall be installed in accordance with the performance specifications in 40 CFR Part 60, Appendix B. When emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and

zero and span adjustments, emission data will be obtained by using other monitoring systems as approved by the Division. The systems shall include the portable emissions monitoring system owned by PSCo. If the portable system is not immediately available, PSCo may utilize for a period up to 7 days, process parameter data from the SO_2 removal system so long as a correlation study which relates SO_2 removal efficiencies to the monitored process parameters has been performed (condition 6).

Regarding data replacement, the language in permit 86AD352-1 will be streamlined out of the operating permit. The Division has developed data replacement language for the COM that will be included in the permit. For the SO_2 emissions, the Division will require that data be replaced in accordance with 40 CFR Part 75. Note that the Division will only require that the replaced data be used to determine the outlet SO_2 annual emissions in order to monitor compliance with the percent reduction requirement. This permit was issued primarily to address the SO_2 reduction requirements for Units 1 and 4 and therefore the Division considers that replaced data was not intended to be used for the short term SO_2 emission limitation.

- SO_2 emissions shall not exceed 1.2 lbs/mmBtu on a 3 hour rolling average (condition 7 & Reg 1, Section VI.A.1 & VI.A.3.a.(ii)).
- Total annual SO_2 emissions, on a calendar basis, from Units 1 and 4 shall not exceed 24 tons/yr plus 80% of the uncontrolled SO_2 emissions which would have been emitted by the two Units. Emissions shall not include the sulfur which is retained in the boiler bottom ash nor shall this retained sulfur be counted as controlled emissions. If controls are installed on one unit, uncontrolled emissions of SO_2 shall be calculated for that unit based on AP-42 emission factors (for subbituminous coal, wet-bottom boilers), annual coal use (tons/yr) and average sulfur content (as determined by a weighted average using current coal sampling techniques). The reporting format shall be approved by the Division prior to operation of the units. Daily emissions rate shall be recorded for the Unit containing the SO_2 monitor. Quarterly emission summaries for the first three quarters shall be submitted to the Division listing the SO_2 emissions. An annual compliance demonstration report shall be submitted at the end of the year. These reports shall be due 30 days after the end of the given quarter (condition8).

The Division's project summary, prepared October 9, 1986, indicates that the replacement of the ESP/WS would not result in any increase in SO_2 emissions since the permit would require that the source offset the SO_2 emissions increase, hence the 20% reduction of SO_2 as required by this permit (note that the wet scrubber was presumed to provide a 20% reduction in SO_2 emissions). However, the permit provides for 24 tpy of SO_2 plus the 20% reduction, which means that this permit allows for an increase in SO_2 emissions.

The AQCC order specifically indicates that neither PSD review or NSPS apply to the replacement of the ESP/WS, since the increase in SO_2 emissions is below PSD significance levels (40 tpy) and the replacement of the ESP/WS with a baghouse is not less environmentally beneficial (NSPS does not consider the replacement of a control device with another control device that is not less environmentally beneficial to be a modification). The AQCC order also specifies that "...the petitioner waives any claim it has for an exemption under the common provisions regulation Section I.G." The definition of a modification in the Common Provisions as it was written at the time of this permit (effective dated 4/30/83), specified that the addition of new air pollution control equipment which resulted in an increase in SO_2 emissions in an area designated as attainment for SO_2 is not considered a modification. Colorado Regulation No. 1, Section VI.B applies to sources of SO_2 emissions that were constructed or modified after August 11, 1977 and limits coal fired operations with a coal heat input of greater than 250 mmBtu/hr to SO_2 emissions of 0.4 lbs/mmBtu and since Public Service waived the modification exemption in the Common Provisions regulation it seems that this requirement should apply. However, the construction permit identified an SO_2 limitation of 1.2 lbs/mmBtu (Colorado Regulation No. 1, Section IV.A.3.a.(ii)), which applies to existing (constructed or modified prior to August 11, 1977) coal-fired operations with a coal heat input of greater than 250 mmBtu/hr. Therefore, it appears that the AQCC intended to not consider the replacement of the ESP/WS with a baghouse to be a modification for purposes of Colorado Regulation No. 1.

Therefore, in order to avoid confusion regarding which Reg 1 SO_2 limitation should have been applied (existing vs. new or modified) and to simplify the monitoring, the Division is now removing the 24 tpy in the operating permit. Note that although this is a revision to the SO_2 emission limitations, which was included in the state's PM_{10} SIP Element, the Division believes that the SO_2 emission limitation can be revised, without revising the SIP Element, provided the revision is to <u>decrease</u> SO_2 emissions. In addition, although removing the 24 tons/yr does increase the stringency of the limitation, the Division believes that the benefits of simplifying the permit outweigh the increased stringency.

The project summary (prepared October 9, 1986) for the construction permit indicated that "PSCo chose to offset the increase in SO_2 emissions by either installing a dry injection SO_2 control system or by burning natural gas". The construction permit did not include provisions for natural gas burning to reach the 20% SO_2 reduction requirement and Public Service has since installed dry sodium injection systems on both Units 1 and 4 and therefore, the Division considers the SO_2 limitation to be a 20% reduction in emissions when burning coal.

The method for determining uncontrolled emissions, appears to conflict with condition 9 of this permit, which says that "if an SO_2 control system is installed PSCo shall operate a monitoring system capable of calculating and recording mass sulfur dioxide emissions before and after the control device." Currently a predictive emissions monitoring (PEMS) system is installed on Unit 1 and a continuous emission monitoring system (CEMS) is installed on Unit 4 to monitor inlet SO_2 emissions and both units are equipped with CEMS to monitor outlet SO_2 emissions. In addition, at this time both units are equipped with dry sodium injection systems to control SO_2 emissions. However, when the Metro Agreement takes effect, the dry sodium injection system on Unit 4 will be replaced with a lime spray dryer system. The lime spray dryer system is capable of reducing SO_2 emissions to lower levels (82% on a 30-day rolling average can be achieved) than the dry sodium injection system. With the installation of the lime spray dryer system, the Unit 4 CEMS must be relocated. The current system monitoring the inlet SO_2 emissions is an OPSIS insitu monitor. One requirement of the OPSIS monitor is that the sample probe must be accessible from both sides of the duct or stack. Due to the space limitation encountered with this emission control retrofit, there is not a suitable location to relocate the OPSIS analyzer upstream of the new spray dryer system and a new monitoring system would have to be purchased and installed. For this reason, the source requested that the Division reconsider the requirement to install and operate continuous monitors to measure and record inlet SO_2 emissions. The source requested that they be allowed to use coal sampling to monitor compliance with the 20% reduction requirement. They believe this method to be accurate and that with the implementation of the Metro Agreement, reductions of SO_2 emissions from Units 1 and 4 will far exceed 20%.

The Division and PSCo entered into a voluntary emission reduction agreement that is applicable to the Denver Metro area PSCo power plants. This agreement, which takes effect on January 1, 2003, requires that SO_2 emissions from the Arapahoe, Valmont and Cherokee facilities not exceed 10,500 tons/yr <u>or</u> SO_2 emissions shall be reduced by 70%. PSCo believes and the Division concurs, that once the Metro Agreement becomes applicable, that SO_2 reductions from Cherokee 1 and 4 will far exceed 20%. As specified previously, changes will be made to Unit 4 to achieve a greater reduction of SO_2 emissions than the unit is currently capable of. Compliance with the 70% reduction requirement in the Metro Agreement is monitored by using coal sampling data to determine the inlet SO_2 concentration.

Since the Division believes that with the Metro Agreement, the SO_2 reduction will far exceed the 20% limitation and since the SO_2 control device on Unit 4 is being upgraded with the Metro Agreement, the Division will allow the source to determine the inlet SO_2 concentration from each unit using coal

sampling and the methodology discussed under emission factors. The outlet SO_2 concentration will be based on the outlet SO_2 CEM. The annual percent reduction will be calculated as discussed under the section on emission factors.

In their Title V permit application submittal, the source requested that the requirement to record daily emission rates be removed from the permit since the outlet CEM continuously records SO_2 emissions. The Division agrees that the daily recording of SO_2 emission rates is not necessary when the unit has a continuous emission monitor, which records SO_2 emission rates continuously. Although the requirement to record the SO_2 emission rate continuously is more stringent than the daily requirement that was in the construction permit, this change can be made since Public Service Company has requested this change.

- If an SO_2 control system is installed PSCo shall operate a monitoring system capable of calculating and recording mass SO_2 emissions before and after the control device. The monitoring system shall be approved by the Division prior to installation and shall employ instruments for measuring SO_2, and O_2 and CO_2 (condition 9).

  See the discussion under the condition 8 above. The requirement to install and operate a monitoring system to calculate and record mass SO_2 emissions will not be included in the permit.

  Although, this permit is part of the State's Denver PM_{10} SIP Element the Division believes that this permit condition can be removed because the SO_2 emission limitations are not changed by this change in monitoring methodology. As discussed earlier, the Division has made the SO_2 limitation more stringent by removing the 24 tpy from the permit (as written the permit allows 24 tpy plus 80% of the uncontrolled SO_2 emissions). The Division has submitted the Denver PM_{10} redesignation package to EPA for approval. In preparing this package the Division and industry met with EPA to discuss issues related to the redesignation. Although EPA has not approved the package and approval is not expected for 1 – 2 years, the Division is under the impression that EPA has agreed that the permits that were referenced in the State's Denver PM_{10} SIP Element would be removed from the SIP. In addition, PSCo has agreed to certain SO_2 emission limitations for Units 1 and 4. These limitations are 0.88 lbs/mmBtu, from each unit, on a 30-day rolling average and the limitations are in effect November 1 through March 1. These limitations have been included in Reg 1 and will be included in the operating permit, but are not applicable until EPA approves the designation of the Denver area as PM_{10} attainment/maintenance. These limitations were taken in exchange for removing the permits (86AD352-1 & 2) from the PM_{10} SIP element. The Division believes that these agreements related to the

PM_{10} SIP support our decision to allow PSCo to use coal sampling to monitor the inlet SO_2 concentration from Units 1 and 4.

Although not specifically identified in permit 86AD352-1, Unit 1 is also 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, when burning coal (Reg 1, Section II.A.4)
- Particulate Matter emissions for combined stacks (Reg 1, Section III.A.1.d)

  The previous language in Reg 1 was confusing regarding determining the applicable emission limit for combined stacks. However, Reg 1 was revised, effective September 30, 2001, and now indicates that the maximum allowable emission rate shall be calculated on a lbs/mmBtu basis as calculated from a weighted average of the individual allowable limits for each unit ducting to the common stack. Under this methodology, the effective standard for the combined stack is as follows:

$$PM = \frac{(1{,}392 \text{ mmBtu/hr} \times 0.1 \text{ lbs/mmBtu}) + (1{,}392 \text{ mmBtu/hr} \times 0.1 \text{ lbs/mmBtu})}{(1{,}392 \text{ mmBtu/hr} + 1{,}392 \text{ mmBtu/hr})} = 0.1 \text{ lbs/mmBtu}$$

- Continuous emission monitoring requirements (Reg 1, Section IV) as follows:
  - 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)
- Emission requirements for certain electric generating facilities which include (Reg 1, Section VII.A.1):
  - SO_2 emissions not to exceed 1.1 lbs/mmBtu calculated as a 3 hour rolling average (Reg 1, Section VII.A.1.a).
  - Source shall install, certify and operate continuous emission monitoring equipment in accordance with 40 CFR Part 60.13 for measuring opacity, SO_2, NO_X and either CO_2 or O_2 (Reg 1, Section

VII.A.1.a).

- Effective January 1, 2005, the NO_X limit shall be 0.60 lbs/mmBtu, provided EPA approves the designation of the Denver area as a PM_{10} attainment/maintenance area. Such limit shall be calculated on a 30-day rolling average (Reg 1, Section VII.A.1.b).
- Upon EPA approval of the designation of the Denver area as a PM_{10} attainment/maintenance area, the SO_2 emission rate from Units 1 and 4 shall not exceed 0.88lbs/mmBtu, calculated separately for each unit, based on a 30-day rolling average. Such emission limit shall apply seasonally from November 1 through March 1. This additional SO_2 limit shall not apply unless EPA repeals the incorporation of SO_2 permit limits into the SIP at 40 CFR 52.320(c)(82)(i)(E) (Reg 1, Section VII.A.1.c).

- APEN reporting (Reg 3, Part A, Section 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
- 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 73 to cover emissions for that particular calendar year.
  - Units 1 and 2 are included in a NO_X averaging plan as allowed by 40 CFR Part 76 § 76.11, as adopted by reference in Colorado Regulation No. 18. The Btu weighted annual NO_X average for the two units must be less than or equal to 0.8 lbs/mmBtu, which is the limitation for vertical-fired boilers in accordance with 40 CFR Part 76 § 76.6(a)(4), as adopted by reference in Colorado Regulation No. 18.
  - Acid rain permitting requirements per 40 CFR Part 72, as adopted by reference in Colorado Regulation No.18.
  - Continuous emission monitoring requirements per 40 CFR Part 75.
  - This source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

Streamlining of Applicable Requirements

Continuous Emission Monitors

There are multiple requirements for Continuous Emission Monitoring (CEM)/Continuous Opacity Monitoring (COM) systems. Permit 86AD352-1 and Regulation No. 1, Section IV requires a COM (when burning coal) and either a CEM for SO_2 or fuel sampling. If a CEM is used for monitoring SO_2, then a CEM is required for either CO_2 or O_2. Regulation 1, Section IV and Permit 86AD352-1 identify other requirements for CEMs such as performance specifications,

calibration, notification and recordkeeping and requirements for record retention. This unit is also required by Regulation No. 1, Section VII.A.1.a to have CEMs for opacity, SO_2, NO_X and either CO_2 or O_2. Revisions to Regulation No. 1, Section VII.A.1.a require that the CEMS meet the requirements in 40 CFR Part 60.13. 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 from Regulation No. 1, Sections A & B and Permit 86AD352-1 will be streamlined out in favor of the Acid Rain CEM requirements as they are more stringent. Although recent revisions to Regulation No. 1, Section VII.A.1.a effectively specify that the monitors shall meet NSPS requirements (40 CFR Part 60), as allowed by the EPA (see attached), the requirements in Regulation No. 1, Section VII.A.1.a (40 CFR Part 60.13) for the continuous emission monitoring systems will be streamlined out of the permit in favor of the more stringent Part 75 requirements. However, for the reasons discussed below, the COM will be subject to QA/QC requirements in Regulation No. 1 Section VII.A.1.a (40 CFR Part 60.13). Note that the requirement to monitor opacity emissions from any bypasses in Permit 86AD352-1 will remain in the permit. Streamlining of more specific CEM 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) rather than the permit requirements (40 CFR Part 60 Appendix B) or the Regulation No. 1, Section VII.A.1.a requirements (40 CFR Part 60 Appendix B, as referenced in 40 CFR Part 60.13(a)) as the Part 75 requirements are for the most part more stringent. Note that Part 75 identifies the COM performance specifications as 40 CFR Part 60, Appendix B, Spec 1, which is the same as the COM performance specification requirements in permit 86AD352-1 and Regulation No. 1, Section VII.A.1.a. It should be noted that the Regulation No. 1, Section IV.E CEM performance specification requirements do not apply to this unit.

The CEM and COM will be subject to the QA/QC requirements in 40 CFR Part 75 since Regulation No. 1, Section IV and Permit 86AD352-1 do not identify specific QA/QC requirements and the QA/QC requirements in Regulation No. 1, Section VII.A.1.a. (40 CFR Part 60.13) are less stringent than the QA/QC requirements in 40 CFR Part 75. In the case of the COM, 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 requirements in Regulation No. 1, Section VII.A.1.a (40 CFR Part 60.13) will be included in the permit to identify the QA/QC requirements for the COM. 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. The calibration requirements in Regulation No. 1, Section IV.F will be streamlined out of the permit, since the QA/QC requirements in 40 CFR Part 60.13 are more stringent. Note that permit 86AD352-1 did not contain any QA/QC requirements.

The excess emissions notification requirements from Regulation No. 1, Section IV.G have been included in the Operating Permit. The reporting requirement in Permit 86AD352-1, condition 5 references Regulation No. 1, Section IV.G, and therefore the reporting requirement in Permit 86AD352-1 will be streamlined out of the permit.

The Regulation No. 1, Section IV.H requirements for record retention shall be streamlined out of the permit in favor of the requirements in Permit 86AD352-1. Both sections require records be retained for 2 years, but Permit 86AD352-1 requires records be retained on site. The Division believes this is a more stringent requirement, therefore, the permit will indicate that the records from Units 1 and 4 will be retained on site for two years, rather than the requirement to retain records on site for one year in accordance with Regulation No. 3, Part C, Section V.C.6.b (General Condition No. 21 b and c). Note that the requirement in Regulation No. 3 to retain records for five years – not specifically on site (Regulation No. 3, Part C, Section V.C.6.b, in General Condition No. 21.b and c) still applies.

Finally, the Division is streamlining the data replacement requirements identified in permit 86AD352-1. The Division is streamlining the data replacement requirements as follows. When the COMs are down, the monitoring requirements developed by the Division and the CUC shall apply. When the SO_2 stack monitors are down, data shall be replaced in accordance with the requirements in 40 CFR Part 75. Note that the SO_2 data replacement requirements only apply when monitoring compliance with the annual reduction requirement and not the short term SO_2 limitation.

Sulfur Dioxide (SO_2)

This unit is subject to two different SO_2 standards (in units of lbs/mmBtu). The standard in Permit 86AD352-1 and Regulation No. 1, Section VI.A.3.a.(ii) is 1.2 lbs/mmBtu averaged on a 3-hour rolling average. The Regulation No. 1, Section VII.A.1.a standards are 1.1 lbs/mmBtu calculated as a 3-hour rolling average. Since the Regulation No. 1, Section VII.A.1.a standard is more stringent it has been included in the Operating Permit.

Note that upon EPA's approval of the designation of the Denver area as a PM_{10} attainment/maintenance area, Unit 1 will be subject to an SO_2 emission limitation of 0.88 lbs/mmBtu (Regulation No. 1, Section VII.A.1.c). Although this SO_2 limitation is less than the Regulation No. 1, Section VII.A.1.a limitation of 1.1 lbs/mmBtu, neither requirement can be streamlined out of the permit, since the averaging times are

different and the 0.88 lbs/mmBtu requirement does not apply on a year round basis.

This unit is subject to a construction permit (86AD352-1) requirement to reduce annual (calendar year) emissions of SO_2 by 20%. Since this limitation cannot be compared with the Regulation No. 1 requirements for stringency, this limitation cannot be streamlined out of the permit.

Finally, there is an Acid Rain SO_2 limit, which is a ton/yr limit based on the number of allowances (1 allowance = 1 ton per year of SO_2) a unit has available. The number of allowances can increase or decrease for a unit depending on allowance availability. Allowances are obtained through EPA 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 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 and Regulation No. 1, Section VII.A.1 standards. The Acid Rain SO_2 limitation appears only in Section III (Acid Rain Requirements) of the permit.

<u>Nitrogen Oxides (NO_X)</u>

Beginning January 1, 2005, provided the EPA approves the designation of the Denver areas as a PM_{10} attainment/maintenance area, this source will subject to both the Regulation No. 1, Section VII.A.1.a standards and the Acid Rain NO_X requirements. The Acid Rain NO_X requirement is 0.80 lbs/mmBtu based on a calendar annual average. The Regulation No. 1, Section VII.A.1.a standard is 0.60 lbs/mmBtu, based on a 30-day rolling average. Although the Acid Rain NO_X requirements and the Regulation No. 1, Section VII.A.1 standards appear to be equivalent, it is possible that the source could deviate from the Regulation No. 1, Section VII.A.1 30 day rolling average and still comply with the Acid Rain NO_X requirement. In addition, the source will be averaging emissions from Units 1 and 2, as allowed by the Acid Rain Program, to demonstrate compliance with the NO_X standards. In addition, NO_X data used to determine compliance with the Acid Rain requirements are submitted (electronically) to EPA for compliance demonstration. Finally, 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 cannot be streamlined. The source will have to demonstrate compliance with both the Acid Rain and Regulation No. 1, Section VII.A.1.a requirements. Note that the Acid Rain NO_X limitations only appear in Section III (Acid Rain Requirements) of the permit.

2. Emission Factors - Emissions from these boilers are from combustion of fossil fuels. Type and quantities of emissions are dependent on the fuels being burned.

This unit burns primarily coal; however, natural gas may be used as back-up fuel. The pollutants of concern are Particulate Matter, (PM and PM_{10}), Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC). Some hazardous air pollutants (HAPs) are generated through the combustion process. Approval of emission factors for this unit is necessary to the extent that accurate actual emissions are required to verify the need to submit Revised APENs to update the Division's Emission Inventory.

The source proposed to use emission factors from EPA's Compilation of Emission Factors (AP-42), for coal consumption - Section 1.1 (9/98), Tables 1.1-3, 1.1-6 and 1.1-19 for pre-NSPS wall-fired boilers burning sub bituminous coal and for natural gas - Section 1.4 (3/98), Tables 1.4-1 and 1.4-2 for wall-fired fired boilers.

The proposed emission factors are as follows:

Pollutant	Emission Factor (Coal)	Emission Factor (Natural Gas)
PM	Source Test	1.9 lbs/mmCF
PM_{10}	0.92(PM)	1.9 lbs/mmCF
SO_2	CEM	CEM
NO_X	CEM	CEM
CO	0.5 lbs/ton	84 lbs/mmCF
VOC	0.06 lbs/ton	5.5 lbs/mmCF

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, and to monitor compliance with the emission limitations. The emission factor for PM (coal combustion) shall be determined by source testing of the boiler.

This boiler is equipped with a baghouse, low NO_X burners with over-fire air and a dry sodium injection system to control particulate, NO_X and SO_2 emissions respectively. Provided the source maintains the baghouse per manufacturer's recommendations and the sources operating experience, a 99.9% efficiency can be

applied to the PM and PM_{10} emission factors when burning natural gas 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 other control devices since the source will be required to use their CEM to determine NO_X and SO_2 emissions and monitor compliance with the emission limitations.

The source is required to demonstrate compliance with a requirement to emit no more than 80% of the uncontrolled SO_2 emissions from Units 1 and 4, together, on a calendar year basis. This requirement shall be monitored as a reduction requirement and a reduction of 20% or more is required to comply with the emission limitation.

The percent reduction will be determined using coal sampling for the inlet SO_2 emission rate and the continuous emission monitor will be used to determine the outlet SO_2 emission rate. The following methodology will be used to determine the percent emission reduction:

$$\text{Red.} = 100\% \times \frac{[\text{Annual inlet } SO_2 \text{ emission rate (lbs/mmBtu)} - \text{Annual outlet } SO_2 \text{ emission rate (lbs/mmBtu)}]}{\text{Annual inlet } SO_2 \text{ emission rate (lbs/mmBtu)}}$$

Note that: inlet = uncontrolled
outlet = controlled

INLET SO_2 CALCULATIONS

Unit Monthly SO_2 emission rate:

$$\text{Lbs/mmBtu} = \frac{(10^6 \text{ Btu/mmBtu}) \times (64 \text{ lbs } SO_2/32 \text{ lbsS}) \times \text{avg. S content of coal (lbs S/lb coal)}}{\text{avg heat content of coal (Btu/lb coal)}}$$

Unit Monthly SO_2 emissions:

Tons/mo = Monthly SO_2 emission rate x Monthly coal heat input x 1 ton/2000 lbs

Annual SO_2 emissions = Sum of Unit 1 and Unit 4 monthly SO_2 emissions

$$\text{Annual } SO_2 \text{ emission rate} = \frac{\text{Annual } SO_2 \text{ emissions (tons/yr)} \times 2000 \text{ lbs/1 ton}}{\text{Annual heat input, coal (mmBtu/yr)}}$$

HEAT INPUT CALCULATIONS

Unit Monthly heat input, coal:

$$\text{mmBtu/mo} = \frac{\text{coal burned (tons/mo) x avg heat content of coal (Btu/lb) x 2000 lbs/ton}}{10^6 \text{ Btu/mmBtu}}$$

Annual heat input, coal = Sum of Unit 1 and Unit 4 monthly heat input, coal

Unit Annual heat input, gas

mmBtu/yr = gas burned (mmSCF/yr) x heat content of gas (mmBtu/mmSCF)

Annual heat input, gas = Sum of Unit 1 and Unit 4 annual heat input, natural gas

OUTLET SO_2 CALCULATIONS

Annual SO_2 emission rate:

$$\text{Lbs/mmBtu} = \frac{[\text{Unit 1 } SO_2 \text{ emissions + Unit 4 } SO_2 \text{ emissions (from CEMS in tons/yr)}] \text{ x 2000 lbs/ton}}{\text{Annual Heat input, coal (mmBtu/yr) + Annual Heat input, gas (mmBtu/yr)}}$$

Note that the above method to calculate the percent reduction is intended to follow the methodology in the Metro Agreement. However, one clarification and one change were made regarding the Metro Agreement Methodology. The Metro Agreement specifies that "the unit total monthly tons of coal will be matched, as nearly as possible, with the heat content (measured in Btus per pound) determined from the unit train coal sample analysis". It is the Division's impression that for each train load of coal, the vendor provides an analysis of the heat and sulfur content of the coal in that train load. The Division is also under the impression that PSCo may receive several train loads of coal each month. Therefore, it is not clear how coal burned in any unit can be tied to any one coal train analysis. Therefore, the Division is requiring that the average heat and sulfur content of coal be used in the above calculations. All vendor analyses will be used to determine the average values to be used in the above calculations.

In addition, the Metro Agreement requires that the heat input from natural gas be determined monthly and the Metro Agreement does not specify that sampling is required to determine the heating value of the natural gas. The permit shall be written to allow the source to use an annual average heating value for the natural gas and therefore it seems unnecessary to require monthly calculations of the heat input from natural gas. Therefore, the Division will only require that the source determine the heat input from natural gas on an annual basis.

Note that if the SO_2 reduction is calculated to be 35% or less, then the inlet SO_2 emission rate, from each unit, shall be determined, using the emission factor from AP-42, Section 1.1, Table 1.1-3 as follows:

$$\text{Inlet } SO_2 \text{ emission rate} = \frac{35 \text{ (lbs } SO_2\text{/ton) x avg. wt percent sulfur in coal x } 10^6 \text{ Btu/mmBtu}}{\text{Avg. heat content coal (Btu/lb) x 2000 lbs/ton}}$$

Note that as indicated in the methodology for the Metro Agreement, the above inlet

SO_2 emission rate shall be calculated monthly using the average sulfur and heat content of the coal received that month. All vendor analyses will be used to determine the average values to be used in the above calculations. The above monthly inlet SO_2 emission rate will then be used to calculate the percent reduction as specified in the Metro Agreement.

3. Monitoring Plan - Compliance demonstration and monitoring requirements for this unit are identified in Sections 1-3 of Section II of the draft Operating Permit. Conditions 1.1 through 1.14 address coal burning and 2.1 through 2.12 address natural gas burning. Condition 3.1 addresses the firing of a combination of fuels.

Since the source was 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 CEM/COM to demonstrate compliance with the opacity and SO_2 requirements. When burning natural gas, the Division will not require the source to use the CEM to monitor compliance with the SO_2 requirements, since § 75.10(d) does not require the source to use the CEM to determine SO_2 emissions [§ 75.11(e) exception as identified in § 75.10(d)].

Compliance with the SO_2 percent reduction requirement for Units 1 and 4 shall be based on coal sampling to determine the inlet SO_2 concentration and CEMS to determine the outlet SO_2 emissions. The 20% SO_2 reduction requirement was applied to units that burn coal as their primary fuel. Therefore, in the absence of credible evidence to the contrary, when burning natural gas, Units 1 and 4 will be presumed to be in compliance with the 20% SO_2 reduction requirement. Note however, that when burning natural gas, the permit will require that the heat input to the boilers from natural gas shall be calculated annually and used in the calculations to monitor compliance with the 20% reduction requirement.

Operation of the CEM/COM 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 CEM/COM system. Part 75 defines the QA/QC requirements for the COM in § 75.21(b) and indicates that the COM 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 method listed appears to address opacity monitors. It appears that this reference is an error. However, the EPA has indicated that this reference is not an error, however, the reference method to address opacity monitors (reference method 203) has not been promulgated yet. Therefore, the Division is including the requirements in Reg 1, Section VI.A.1.a (40 CFR Part 60.13, specifically 60.13(d)) in the permit for the COM QA/QC requirements. It should be noted that § 75.24(e), which addresses COM out of control periods, also references 40 CFR Part 51, Appendix M. The permit provides/requires alternate monitoring requirements when the COM is out-of-control.

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.

When burning a combination of fuels, the source shall be subject to the most stringent requirements and periodic monitoring. The most stringent periodic monitoring requirements are for coal-firing of the unit.

4. Compliance Status - The source indicated in their permit application that this unit was in compliance with all applicable requirements. The Division concurs with this determination.

B. Unit B002: Babcock and Wilcox Top-Fired Boiler, Model No. RB295, Serial No. NY-771602, Rated at 1,392 mmBtu/hr. Coal Fired with Natural Gas Used as Back-Up.

1. Applicable Requirements - Unit 2 was first placed in service in May 1959. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 1,392 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 852,000 lbs/hr. This maximum steam flow rating cannot be exceeded. This unit shares a stack with Unit 1.

After the Title V permit application was submitted, PSCo indicated that over-fire air and low NO_X burners would be installed on Unit 2. At a later date, however, PSCo determined that the installation of low NO_X burners was not necessary to meet the Acid Rain NO_X limitations and therefore, only over-fire air was added to this unit. Although this addition will reduce NO_X emissions, the Division believes that CO emissions could be increased as a result. For the same reasons as discussed for Unit 1, which is equipped with over-fire air in conjunction with low NO_X burners, the Division believes that an increase in emissions would not subject this unit to PSD,

major non-attainment area NSR or NSPS requirements. However, as discussed for Unit 1, this unit could be subject to Reg 3, Part B permitting requirements if an increase in CO emissions results from the addition of the over-fire air. The Division would expect that over-fire air, alone, would be less likely to increase CO emissions than low NO_X burners, combined with over-fire air and to that end, the Division has witnessed before and after testing at PSCo's Hayden facility (Units 1 and 2) and Unit 1 at this facility. This testing has shown that there is no increase in CO emissions. Therefore, the Division considers that this unit is not subject to minor NSR permitting under Regulation No. 3, Part B.

An Envirotech Buell fabric filter baghouse was added in May 1985. This addition to the boiler did not constitute a modification because no increase in emissions occurred.

This boiler can be considered a "grandfathered" source and is exempt from Colorado Construction Permit requirements because this unit was in service prior to February 1, 1972 and based on the information available to the Division and supplied by the application has not been modified since then. As a grandfathered unit, this boiler has 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 matter emissions shall not exceed 0.1 lbs/mmBtu (Reg 1, Section III.A.1.c)
- Particulate matter emissions for combined stack (Reg 1, Section III.A.1.d)

  See discussion under Unit 1, regarding calculation of the standard for combined stacks.

- Continuous emission monitoring requirements (Reg 1, Section IV) as follows:
  - 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)

Note that the unit is equipped with a CEM to monitor SO_2, therefore provisions for fuel sampling to monitor SO_2 emissions will not be included in the permit.

- Sulfur dioxide emissions shall not exceed 1.2 lbs/mmBtu, on a 3-hour rolling average, **when firing coal** (Reg 1, Section VI.A.1 & VI.A.3.a.(ii))
- Emission requirements for certain electric generating facilities which include (Reg 1, Section VII.A.1):
  - SO_2 emissions not to exceed 1.1 lbs/mmBtu, calculated as a 3 hour rolling average (Reg 1, Section VII.A.1.a)
  - Source shall install, certify and operate continuous emission monitoring equipment in accordance with 40 CFR Part 60.13 for measuring opacity, SO_2, NO_X and either CO_2 or O_2 (Reg 1, Section VII.A.1.a).
- APEN reporting (Reg 3, Part A, Section 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
- 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 73 to cover emissions for that particular calendar year.
  - Units 1 and 2 are included in a NO_X averaging plan as allowed by 40 CFR Part 76 § 76.11, as adopted by reference in Colorado Regulation No. 18. The Btu weighted annual NO_X average for the two units must be less than or equal to 0.8 lbs/mmBtu, which is the limitation for vertical-fired boilers in accordance with 40 CFR Part 76 § 76.6(a)(4), as adopted by reference in Colorado Regulation No. 18.
  - Acid rain permitting requirements per 40 CFR Part 72, as adopted by reference in Colorado Regulation No. 18.
  - Continuous emission monitoring requirements per 40 CFR Part 75.
  - This source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

<u>Streamlining of Applicable Requirements</u>

<u>Continuous Emission Monitors</u>

There are multiple requirements for Continuous Emission Monitoring

(CEM)/Continuous Opacity Monitoring (COM) systems. Colorado Regulation No. 1, Section IV requires a COM (when burning coal) and either a CEM for SO_2 or fuel sampling. If a CEM is used for monitoring SO_2, then a CEM is required for either CO_2 or O_2. Regulation No. 1, Section IV identifies other requirements for CEMs such as performance specifications, calibration, notification and recordkeeping and requirements for record retention. This unit is also required by Regulation No. 1, Section VII.A.1 to have CEMs for opacity, SO_2, NO_X and either CO_2 or O_2. Revisions to Regulation No. 1, Section VII.A.1.a require that the CEMS meet the requirements in 40 CFR Part 60.13. 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 from Regulation No. 1, Sections A & B will be streamlined out in favor of the Acid Rain CEM requirements which are more stringent. Although recent revisions to Regulation No. 1, Section VII.A.1.a effectively specify that the monitors shall meet NSPS requirements (40 CFR Part 60), as allowed by the EPA (see attached), the requirements in Regulation No. 1, Section VII.A.1.a (40 CFR Part 60.13) will be streamlined out of the permit in favor of the more stringent Part 75 requirements. However, for the reasons discussed below, the COM will be subject to QA/QC requirements in Regulation No. 1, Section VII.A.1.a (40 CFR Part 60.13). Streamlining of more specific CEM requirements is addressed in the paragraph below.

The performance specification requirements for these CEMS will be subject to the Acid Rain requirements (40 CFR Part 75) rather than the Regulation No. 1, Section VII.A.1.a requirements (40 CFR Part 60 Appendix B, as referenced in 40 CFR Part 60.13(a)) as the Part 75 requirements are for the most part more stringent. Note that Part 75 identifies the COM performance specifications as 40 CFR Part 60, Appendix B, Spec 1, which is the same as the COM performance specification requirements in Regulation No. 1, Section VII.A.1.a. It should be noted that the Regulation No. 1, Section IV.E CEM performance specification requirements do not apply to this unit.

The CEM and COM will be subject to the QA/QC requirements in 40 CFR Part 75 since Regulation No. 1, Section IV does not identify specific QA/QC requirements and the QA/QC requirements in Regulation No. 1, Section VII.A.1.a. (40 CFR Part 60.13) are less stringent than the QA/QC requirements in 40 CFR Part 75. In the case of the COM, 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 requirements in Regulation No. 1, Section VII.A.1.a (40 CFR Part 60.13) will be included in the permit to identify the QA/QC requirements for the COM. 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. The calibration requirements in Regulation No. 1, Section IV.F will be streamlined out of the permit since the QA/QC requirement in 40 CFR Part 60.13(d) are more stringent.

The excess emissions notification and recordkeeping requirements from Regulation No. 1, Section IV.G have been included in the Operating Permit. Note that the record retention in Regulation No. 1, Section IV.H (maintain records for 2 years) is less stringent than the Regulation No. 3, Part C recordkeeping requirements 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).

Sulfur Dioxide (SO_2)

This unit is subject to two Regulation No. 1 standards. The Regulation No. 1, Section VI.A.3.a.(ii) standard is 1.2 lbs/mmBtu on a 3-hour rolling average (note Regulation No. 1, Section VI.A.1 provides for an averaging time if not otherwise specified in the regulation). The Regulation No. 1, Section VII.A.1.a standard is 1.1 lbs/mmBtu calculated as a 3-hour rolling average. Since the Regulation No. 1, Section VII.A.1.a standard is more stringent it has been included in the Operating Permit.

The SO_2 Acid Rain Allowances will not be streamlined out of the permit for the reasons discussed in the Unit No. 1 streamlining section for SO_2.

2. Emission Factors - See discussion for Boiler No. 1 emission factors. Note that Unit 2 does not have a control device for SO_2.

3. Monitoring Plan - See discussion for Boiler No. 1 monitoring plan. Note that Unit 2 does not have an SO_2 reduction requirement. In addition, since a dry sodium injection system will be added to Unit 2 in the near future, the initial performance test, when burning coal, shall be conducted by July 1, 2003, rather than within the first year of permit issuance.

4. Compliance Status - The source indicated in their permit application that this unit was in compliance with all applicable requirements. The Division concurs with this determination.

C. Unit B003: Babcock and Wilcox Front-Fired Boiler, Model No. RB344, Serial No. NY-771802, Rated at 1,877 mmBtu/hr. Coal Fired with Natural Gas Used as Back-Up.

1. Applicable Requirements - Unit 3 was first placed in service in May 1964. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 1,877 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 1,140,000 lbs/hr. This maximum steam flow rating cannot be exceeded.

An Envirotech Buell fabric filter baghouse was added in February 1988. This addition to the boiler did not constitute a modification because no increase in emissions occurred.

Low NO_X burners with over-fire air were added to this unit sometime prior to submitting the Title V permit application (no date provided in application). Although this addition reduced NO_X emissions, the Division believes that CO emissions may have been increased as a result. For the same reasons as discussed for Unit 1, the Division believes that an increase in emissions would not subject this unit to PSD, major non-attainment area NSR or NSPS requirements. However, as discussed for Unit 1, this unit may have been subject to Reg 3, Part B permitting requirements if an increase in CO emissions resulted from the addition of the low NO_X burners. The low NO_X burners were added prior to performing any "before" and "after" source testing to determine if there was an increase in CO emissions. As discussed for Unit 2, the Division considers that there is sufficient data demonstrating that there is no increase in CO emissions from the addition of low NO_X burners, therefore, no minor NSR permitting (Reg 3, Part B) is required.

Unit 3 is considered a "grandfathered" source and therefore is exempt from Colorado Construction Permit requirements because this unit was in service prior to February 1, 1972 and based on the information available to the Division and supplied by the applicant has not been modified since then. As a grandfathered unit, this boiler has the same applicable requirements as identified for Unit No. 2, with the following exceptions:

- The provisions for the particulate matter limitations for units with combined stacks (Reg 1, Section III.A.1.d) **do not apply** to this unit.
- Emission requirements for certain electric generating facilities which include (Reg 1, Section VII.A.1):
  - NO_X emissions not to exceed 0.60 lbs/mmBtu, calculated on a 30 day rolling average (Reg 1, Section VII.A.1.a)
- Acid Rain Requirements as follows:
  - NO_X emissions of 0.50 lbs/mmBtu on an annual average basis

(source opted to comply with Phase I limits (§ 76.5(a)(2) by early election (§ 76.8))

Streamlining of Applicable Requirements

Continuous Emission Monitors

See streamlining of continuous emission monitors discussion for Unit No. 2.

Sulfur Dioxide (SO_2)

See streamlining of SO_2 requirement discussion for Unit No. 2.

Nitrogen Oxides (NO_X)

This source is subject to both the Regulation No. 1, Section VII.A.1.a standards and the Acid Rain NO_X requirements. The Acid Rain NO_X requirement is 0.50 lbs/mmbtu based on a calendar annual average. The Regulation No. 1, Section VII.A.1.a standard is 0.60 lbs/mmbtu, based on a 30-day rolling average. Although the Acid Rain NO_X requirements and the Regulation No. 1, Section VII.A.1.a standards appear to be equivalent, it is possible that the source could deviate from the Regulation No. 1, Section VII.A.1.a 30 day rolling average and still comply with the Acid Rain NO_X requirement. In addition, NO_X data used to determine compliance with the Acid Rain requirements are submitted (electronically) to EPA for compliance demonstration. Finally, 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 Regulation No. 1, Section VII.A.1.a requirements. Note that the Acid Rain NO_X limitations only appear in Section III (Acid Rain Requirements) of the permit.

2. Emission Factors - See discussion for Boiler No. 1 emission factors. Note that this unit does not have a control device for SO_2.

3. Monitoring Plan - See discussion for Boiler No. 1 monitoring plan. Note that Unit 3 does not have an SO_2 reduction requirement. In addition, since a lime spray dryer system will be added to Unit 3 in the near future, the initial performance test, when burning coal, shall be conducted by July 1, 2003, rather than within the first year of permit issuance.

4. Compliance Status - The source indicated in their permit application that this unit was in compliance with all applicable requirements. The Division concurs with this determination.

D. Unit B004: Combustion Engineering Tangentially-Fired Boiler, Model No. 12465, Rated at 3,520 mmBtu/hr, Serial No. 217803. Coal Fired with Natural Gas Used as Back-Up.

1. Applicable Requirements - Unit 4 was first placed in service in November 1968. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 3,520 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 2,616,265 lbs/hr. This maximum steam flow rating cannot be exceeded.

As discussed under the applicable requirements section for Unit No. 1, the electrostatic precipitator and wet scrubber for Unit 4 were removed in 1989. With the installation of the baghouse a dry sodium injection system was added to Unit 4 to control SO_2 emissions.

Low NO_X burners with over-fire air were added to this unit sometime prior to submitting the Title V permit application (no date provided in application). Although this addition reduced NO_X emissions, the Division believes that CO emissions may have been increased as a result. For the same reasons as discussed for Unit 1, the Division believes that an increase in emissions would not subject this unit to PSD, major non-attainment area NSR or NSPS requirements. However, as discussed for Unit 1, this unit may have been subject to Reg 3, Part B permitting requirements if an increase in CO emissions resulted from the addition of the low NO_X burners. The low NO_X burners were added prior to performing any "before" and "after" source testing to determine if there was an increase in CO emissions. As discussed for Unit 2, the Division considers that there is sufficient data demonstrating that there is no increase in CO emissions from the addition of low NO_X burners, therefore, no minor NSR permitting (Reg 3, Part B) is required.

Unit 4 is permitted under 86AD352-2 (final approval, April 30, 1992). As discussed under Unit 1, this permit, specifically the SO_2 emission limitations, is part of the state's Denver PM_{10} SIP Element and was included as part of a Colorado Air Quality Control Commission (AQCC) Order (signed August 28, 1986). This permit includes the same applicable requirements as discussed under Unit 1 for permit 86AD352-1 with the following exceptions:

- The requirement for a particulate matter performance test (bullet 4 under permit 86AD352-1 discussion for Unit 1) **was not included** as the test had been completed.
- The condition in bullet 6 [CEM /COM requirements] for permit 86AD352-1 as discussed for Unit 1 is included in this permit, however the reference to the CEM/COM performance specification requirements has not been included.
- The condition in bullet 9 [monitoring requirements if an SO_2 removal system

is installed] for permit 86AD352-1 as discussed for Unit 1 **was not included** in this permit.

- The condition in bullet 10 [installation of baghouse shall not inhibit later installation of an SO_2 removal system] for permit 86AD352-1 as discussed for Unit 1 **was not included** in this permit.

  These conditions were removed from the permit since the SO_2 removal system had been installed and these conditions no longer apply.

- PSCo shall operate a monitoring system capable of calculating and recording mass SO_2 emissions before and after the control device. The monitoring system shall employ instruments for measuring SO_2 and O_2 or CO_2 (condition 8, Permit 86AD852-2). **Note this requirement was not in Permit 86AD852-1.** However, permit 86AD852-1 includes a similar condition that specifies that if a SO_2 removal system is installed then PSCo shall operate monitoring system capable of calculating and recording mass SO_2 emissions before and after the control device.

  Note that as discussed under Unit 1, the Division is removing the requirement to operate a monitoring system capable of calculating and recording mass SO_2 emissions before the control device. The source will determine pre-control SO_2 emissions using coal sampling data.

As with Unit 1, there were several applicable requirements that were not included in the permit but are applicable to this unit. The same additional requirements as discussed for Unit 1 are also applicable to this unit with the following exceptions:

- The provisions for the particulate matter limitations for units with combined stacks (Reg 1, Section III.A.1.d) **do not apply** to this unit.
- Emission requirements for certain electric generating facilities which include (Reg 1, Section VII.A.1):
  - NO_X emissions not to exceed 0.45 lbs/mmBtu, calculated on a 30 day rolling average (Reg 1, Section VII.A.1.a).
- Acid Rain Requirements as follows:
  - NO_X emissions of 0.45 lbs/mmBtu on an annual average basis (source opted to comply with Phase I limits (§ 76.5(a)(1) by early election (§ 76.8))

Streamlining of Applicable Requirements

Continuous Emission Monitors

See streamlining discussion for Unit 1, with the exception that since the performance specification requirements for the CEMs and COM were not included in permit 86AD352-1, streamlining is not necessary. The permit will specify that the CEMs meet the performance specifications of 40 CFR Part 75.

Sulfur Dioxide (SO_2)

See streamlining discussion for Unit 1.

Nitrogen Oxides (NO_X)

See streamlining discussion for Unit 3.

2. Emission Factors - See discussion for Boiler No. 1 emission factors, except that the emission factor for CO when burning natural gas is 24 lbs/mmSCF.

3. Monitoring Plan - See discussion for Boiler No. 1 monitoring plan. In addition, since the dry sodium injection system will be replaced with a lime spray dryer system on Unit 4 in the near future, the initial performance test, when burning coal, shall be conducted by July 1, 2003, rather than within the first year of permit issuance.

4. Compliance Status - The source indicated in their permit application that this unit was in compliance with all applicable requirements. The Division concurs with this determination.

E. Unit F001: Fugitive Particulate Emissions from Coal Handling and Transportation

F. Unit F002: Fugitive Particulate Emissions from Ash Handling and Transportation

G. Unit F003: Fugitive Particulate Emissions from Vehicle Travel on Paved and Unpaved Roads

1. Applicable Requirements - The above sources of fugitive particulate emissions were first placed into service in May of 1964. Based on the information available to the Division and supplied by the applicant, these sources have not been modified since then. Therefore these fugitive emissions sources are grandfathered from construction permit requirements. Fugitive particulate emissions from coal handling are generated from storage and movement (dozing) of coal at the pile and unloading of coal from rail cars. Fugitive particulate emissions are generated from

ash handling (transfer points) and operation of any outdoor ash storage piles. The pertinent applicable requirements for these sources of fugitive particulate emissions are as follows:

- Minimize fugitive particulate emissions (Reg 1, Section III.D.1.a)
- APEN reporting (Reg 3, Part A, Section II)

The 20% opacity, no off-property transport, and nuisance emission limitations identified in Regulation No. 1, Section III.D.1.c are guidelines, not enforceable standards. Failure to comply with the guidelines may trigger the Division to require the source to submit a fugitive particulate control plan. Per Reg 1, Section II.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.

As a result of investigations regarding several nuisance fugitive dust complaints from neighbors around Cherokee Station, the Division required a fugitive dust control plan for a number of activities at the site. This plan was revised and submitted to the Division on March 29, 1999 and the Division approved the plan on March 30, 1999. The elements in this fugitive dust control plan will be included in the permit.

One element of the fugitive dust control plan is to use and maintain the water spray system on the rotary coal dumper at all times, when weather permits. In their comments received November 30, 2001, during the public comment period, the source indicated that the water spray system was being replaced with a chemical dust suppression system. Therefore, the term “water spray” was replaced with “dust suppression” to reflect future changes to the facility.

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 material 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 nor specify the emission factors the source must use to calculate emissions. 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 merely identify the emission factors the source has proposed to use for the types of fugitive emission sources identified in their Title V permit

application.

1. Coal Handling and Transportation

In their Title V permit application the source identified fugitive emission sources as emissions from coal dozers, the storage pile and unloading. After the source had submitted their Title V permit application, it was determined by the source and concurred with by the Division that they had been double counting fugitive emissions from the coal pile by performing a separate calculation for coal dozing. The emission factors the source had proposed (in their Title V permit application) to use for the storage pile, actually take into account emissions from movement and activity at the pile (i.e. coal dozing). Therefore, the source now has proposed to use the following emission factors to estimate emissions from storage and dozing at the pile.

A. Emissions from coal pile maintenance and storage: The source used emission factors from AP-42 (dated January 1995), Section 11.9, Table 11.9-2. The emission factors used were:

Pollutant	Task	Emission Factor[1]
PM	Storage Pile	1.6μ lbs/acre-hr
PM_{10}	Storage Pile[2]	$0.226(1.6\mu)$ lbs/acre-hr

[1] where: μ = wind speed, m/sec

[2] AP-42 did not provide an emission factor for PM_{10} source assumed 23 % of PM is PM_{10}

B. Unloading of Coal from Rail Cars: 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. Emissions were 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
U = mean wind speed, mph
D = number of transfer points, dimensionless
M = moisture content, %

2. Ash Handling and Transportation

PSCo indicated in their Title V permit application that fugitive emissions from ash handling occur when ash haul trucks are unloaded at an ash disposal site or at some other location that is not enclosed. There is currently no ash disposal site at Cherokee, however, in the future there may be some stockpiling of ash on site for sale if an appropriate buyer were found. The Title V permit application indicated that fugitive emissions from ash handling would be estimated using emission factors for drop/transfer points from AP-42 (dated January 1995), Section 13.2.4 (see equation under coal unloading above).

3. Vehicle Travel on Paved and Unpaved Roads

To estimate emissions from travel on unpaved roads, the source proposed to use emission factors from AP-42 (dated January 1, 1995), Section 13.2.2 Unpaved Roads, as follows:

$$E = k \times 5.9 \times (s/12) \times (S/30) \times (W/3)^{0.7} \times (w/4)^{0.5} \times [(365-p)/365] \times VMT$$

where: E = particulate emissions, in lbs/yr
VMT = vehicle miles traveled per year
k = particle size multiplier, dimensionless
s = silt content of road surface material, in %
S = mean vehicle speed, in miles per hour
W = mean weight of vehicle, in tons
w = mean number of wheels
p = number of days with at least 0.01 in. of precipitation per year

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), Sections 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%.

3. Monitoring Plan -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 in the fugitive dust control plan submitted by PSCo and these have been included in the permit. The source will be required to certify semi-annually that they have followed the requirements in their fugitive dust control plan to minimize particulate matter emissions.

4. Compliance Status - The source certified that they were in compliance with all

applicable requirements for coal handling and ash handling. Revised APENs were submitted for these sources with the permit application. The source indicated in its permit application that they were out of compliance with APEN reporting requirements for fugitive particulate emissions generated from vehicle traffic on paved and unpaved roads; however, the source submitted an APEN with its T5 permit application. This source is currently in compliance with the applicable requirements for fugitive particulate emission sources.

H. Unit P001 thru P003 and P006 thru P008: Three (3) Grandfathered Ash Silos and Two (2) Permitted Ash Silos, Each Equipped with a Baghouse and One (1) Ash Blower

1. Applicable Requirements - In its Title V permit application, the source had grouped all of its particulate emission sources from ash handling together and identified all sources as fugitive sources. However, not all emissions from ash handling are fugitive. The loading and unloading of the ash silos is considered a point source and as such is subject to emission fees. The source indicated that ash handling operations first began operation in August 1957 and were last modified in November 1968, which corresponds to the dates the boilers began operation. The source clarified the information in their Title V permit application by indicating that there were three (3) ash silos installed as part of the original facility (i.e. in operation prior to February 1, 1972). One silo was used for Unit 4, one silo was used for Unit 1 and one silo was used for Units 2 and 3. These ash silos are grandfathered from construction permit requirements.

The Metro Agreement takes effect on January 1, 2003 and requires that either a certain level of SO_2 emissions from all the Denver metro area PSCo coal-fired power plants (Valmont, Cherokee and Arapahoe) be met or that uncontrolled SO_2 emissions from these plants be reduced by 70%. In order to meet the conditions of the agreement, the source has indicated that additional control devices will be installed on the various boilers at each of the facilities. In general, these control devices and supporting equipment will be addressed by reopening the operating permit within twelve months after the Metro Agreement takes effect. However, there is some support equipment that will be operational at the time of original permit issuance or soon thereafter and will therefore be included in the operating permit at this time. Note that construction permits have already been received for the majority of the support equipment necessary for the additional control devices. To this end, the following equipment is being addressed in this permit now: new waste ash storage silos for Units 2 and 4 (the grandfathered silo previously used for unit 4 will be used for Unit 3) and an ash blower that will be used for Unit 3 (used to transport ash from the baghouse hoppers to either the waste ash silo or recycle ash silo, when operational). It should be noted that an ash blower system is used for Unit 2, however, emissions from this system are below APEN de minimis and therefore is not included in the permit as a significant emission unit but is in Appendix A of the permit as an insignificant activity. In addition, it should also be noted that the

grandfathered silo previously used for Units 2 and 3 will be used as a recycle ash silo, which will support some of the new control devices to be installed at this facility and will be clarified when the operating permit is reopened to address the Metro Agreement.

Colorado Construction Permit 00AD0570 (initial approval) was issued on December 22, 2000 for the Unit 4 ash silo, Colorado Construction permit 00AD0833 (initial approval) was issued on March 27, 2001 for the Unit 2 ash silo and Colorado Construction Permit 00AD0813 (initial approval) was issued on March 27, 2001 for the Unit 3 ash blower system. The due date of the first semi-annual monitoring report 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.

The three (3) grandfathered ash silos are subject to the following applicable requirements:

- 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 (Regulation No. 3, Part A, Section II)

The applicable requirements for the new Unit 4 and Unit 2 ash silos (00AD0570 and 00AD0833, respectively) and the Unit 3 ash blower system (00AD0813) from the construction permits issued for these units are as follows:

- Visible emissions shall not exceed 20% opacity except as provided for below (00AD0570 - condition 1, 00AD0833 - condition 1, 00AD0813 - condition 1 and Reg 1, Section II.A.1)..
- During periods of startup, process modification or adjustment or occasional cleaning of control equipment, visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (00AD0570 - condition 1, 00AD0833 - condition 1, 00AD0813 - condition 1 and Reg 1, Section II.A.4).

  Based on engineering judgement, the Division has not included the 30%

opacity requirement (Reg 1, Section II.A.4) for startup, process modification and adjustment of control equipment 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.

- Construction of this source must commence within 18 months of initial permit issuance date or within 18 months of date on which such construction or activity was scheduled to commence as stated in the application. If commencement does not occur within the stated time the permit will expire on June 22, 2002 (00AD0570 - condition 4) and September 27, 2002 (00AD0833 - condition 4 and 00AD0813 - condition 4).

  This requirement will not be included as construction has commenced on both silos and the ash blower system.

- Emissions of air pollutants shall not exceed the following limitations (00AD0570 - condition 5, 00AD0833 - condition 5 and 00AD0813 - condition 5):

<u>Unit 4 ash silo:</u>			
PM	0.85 tons/mo	and	10.3 tons/yr
PM_{10}	0.85 tons/mo	and	10.3 tons/yr
<u>Unit 2 ash silo:</u>			
PM	0.32 tons/mo	and	3.7 tons/yr
PM_{10}	0.32 tons/mo	and	3.7 tons/yr
<u>Unit 3 ash blower system:</u>			
PM	191.3 lbs/mo	and	1.13 tons/yr
PM_{10}	191.3 lbs/mo	and	1,13 tons/yr

- Raw material processing shall not exceed the following limitations (00AD0570 - condition 6, 00AD0833 - condition 6 and 00AD0813 - condition 6):

<u>Unit 4 ash silo:</u>			
Ash/spent sorbent	11,353 tons/mo	and	136,234 ton/yr
<u>Unit 2 ash silo:</u>			
Ash/spent sorbent	4,584 tons/mo	and	55,000 ton/yr
<u>Unit 3 ash blower:</u>			
Ash	5,000 tons/mo	and	60,000 tons/yr

  Note that for the above two conditions, the monthly limits apply during the first twelve months of operation. The permit will indicate the start-up date of each unit in the permit for easier reference to applicability of the monthly limitations, unless the unit has not started up prior to permit issuance.

Emissions from the ash blower are estimated using the manufacturer's guarantee, in gr/acf and the maximum blower operation rate, in acf/min and the emission limits in the permit are based on 8760 hrs/yr of operation. Therefore, the Division is removing the ash throughput limits because emissions are no dependent on the ash processed.

- APEN reporting (00AD0570 - condition 7, 00AD0833 - condition 7, 00AD0813 - condition 7 and Reg. 3, Part A Section II.C)

  The APEN reporting requirements will not be identified in the permit as a specific condition but is included in Section V (General Conditions) of the permit, condition 21.e.

- The permittee shall notify the Division 30 days prior to startup (00AD0833 – condition 8, 00AD0813 – condition 8 and Reg 3, Part B, Section IV.H.1)

  Note that this requirement was not included in permit 00AD0570 (unit 4 ash silo) but it also applies to that unit, although the source indicated in their comments made during the Public Comment period that this unit would start-up on December 4, 2001. Therefore, the requirement to submit a startup notice for the unit 4 ash silo will not be included in the operating permit.

  Note that in the event that the unit 3 ash blower system or unit 2 ash silo has started up before permit issuance, this condition will be removed for that unit.

- Within 180 days after commencement of operation, compliance with the conditions contained on this permit shall be demonstrated to the Division (00AD0570 - condition 8, 00AD0833 - condition 9, 00AD0813 - condition 9 and Reg 3, Part B, Section IV.H.2)

  The due date of the first semi-annual monitoring report required by the operating permit, after the unit starts up will suffice as the self-certification that these units comply with the applicable requirements in the construction permit. This requirement will only be included for those units that have not started up as of permit issuance date.

- Prior to final approval, the applicant shall submit to the Division for approval an operating and maintenance plan for all control equipment and control practices and a proposed record keeping format that will outline how the applicant will maintain compliance on an ongoing basis with the requirements of this permit (00AD0570 - condition 9, 00AD0833 - condition 10, 00AD0813 - condition 10 and Reg 3, Part B, Sections IV.B.2 and IV.D.1.g).

  Since the operating permit defines the periodic monitoring that will be used

to monitor compliance with the permit conditions, it is not necessary for the source to submit a proposed record keeping plan that will outline how the source will maintain compliance with the requirements of this permit.

The Division determined that no Regulation No. 1 particulate matter standards are applicable. Operations (loading and unloading) at the ash silo are not considered fugitive emissions (PM requirements - Reg 1, Section III.D). Although particulate emissions from loading of wet ash into an open truck do not vent through a stack, they exhaust through a functionally equivalent opening and therefore do not meet the definition of fugitive emissions as provided in Regulation No. 3, Part A, Section I.B.25. The Division also does not consider the ash silo to be a manufacturing process (PM requirements - Reg 1, Section III.C and Reg 6, Part B, 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.

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

The first source is loading ash from the boiler baghouse to the silo. Fly ash is pneumatically conveyed to the silo. The dry ash goes through a series of separators that drop ash into the silo, which is equipped with a bin vent filter. In the future fly ash will be transported from the Units 2 and 3 baghouses to the silos using an ash blower system. The ash blower system sets up a vacuum that pulls the ash to a filter separator located on top of the silos. With this system, air is vented through the baghouse on the silo and the blower itself.

Note that emissions from the Unit 2 ash blower system are below APEN de minimis and are included in Appendix A of the permit as an insignificant activity.

During unloading, the second source of emissions, ash is fluidized in the bottom of the silo by a paddle-like device. As the ash passes through the fluidizer to the discharge chute, it is continuously wetted with water sprays to control particulate emissions during unloading operations.

The source proposed to use the following emission factors from EPA's Compilation of Emission Factors (AP-42), Section 11.17, 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	1.5	Unloading[2]	Water Spray - 90%
PM_{10}	1.5	Unloading[2]	Water Spray - 90%

[1]Specifically from Table 11.17-4, Product Loading - Enclosed Truck
[2]Specifically from Table 11.17-4, Product Loading - Open Truck

The ash blower generates a vacuum that pulls the ash to a filter-separator located on top of the silos. A 125 hp blower generates a vacuum that pulls the ash to a filter-separator located on top of the silos. The ash drops out in the filter-separator and the air is filtered through a fabric filter dust collector before being discharge through the blower. Emissions from the ash blower are estimated using the manufacturer's guaranteed emission rate of 0.01 gr/acf and the blower operation rate of 3,000 cfm. The following equation will be used to calculate emissions:

$$\text{Lbs/mo} = \frac{\text{\# of hrs operated per mo} \times 3{,}000\ ft^3/min \times 60\ min/hr \times 0.01\ gr/ft^3}{7{,}000\ grains/lb}$$

Note that emissions from the ash blower system are considered uncontrolled. Air from the blower is filtered before being exhausted. Since, the blower cannot be operated without the filter system, the filter system is not considered a control device because it is integral to the operation of the unit.

3. Monitoring Plan - The source shall be required to calculate the ash throughput annually, based on the quantity of coal consumed, the average ash content of the coal and a presumed 80/20 fly ash/bottom ash split and to calculate emissions annually for the grandfathered units. Frequency of the recordkeeping and calculations for the permitted ash silo will be on a monthly basis. Compliance with the ash blower emissions and throughput requirements will be monitored by recording the hours the unit operated and calculating emissions on a monthly basis. Based on an engineering analysis, PSCo has indicated that the quantity of additional sodium and absorbed SO_2 (the spent sorbent) from the dry sodium injection system is about 15%, by weight, of the fly ash produced. Currently Units 1 and 4 are equipped with dry sodium injection systems. In addition, Public Service has indicated that the quantity of additional lime and absorbed SO_2 (the spent sorbent) from the lime spray dryer system are 25%, by weight, of the fly ash produced. Note that currently, none of the units are equipped with lime spray dryer systems but in order to meet the requirements in the Metro Agreement, a lime spry dryer system will be added to Unit 3 and the dry sodium injection system on Unit 4 will be replaced with a lime spray dryer system.

In the absence of credible evidence to the contrary, opacity emissions from the ash

silo loading 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 - The source certified that they were in compliance with all applicable requirements for ash handling. As previously mentioned in the Title V permit application all emissions from ash handling were grouped together and identified as fugitive emissions. A Revised APEN was submitted for emissions from ash handling sources with the permit application. The source applied for and obtained construction permits for the two new ash silos and the ash blower system prior to commencing construction. As mentioned previously, the certification by the Responsible Official in the first semi-annual compliance report will serve as the self-certification that these units can comply with the requirements in their construction permits. These ash silos are currently in compliance with all applicable requirements.

I. Unit P004: Coal Handling System (Conveyors and Two (2) Crushers)

1. Applicable Requirements - In its Title V permit application, the source had grouped all of its particulate emission sources from coal handling together and identified all sources as fugitive sources. However, some of the sources identified as fugitive could be reasonably enclosed and controlled and as a result they are not considered fugitive emission sources. Those activities not associated with the outdoor storage pile (i.e. wind erosion and maintenance) or rail car unloading have been considered non-fugitive sources. Specifically, these sources were the coal conveyors and the two coal crushers. The source indicated in its Title V application that the coal handling system was first placed in service in August 1957 and last modified in November 1968, which corresponds to the periods the boilers came on line. Based on the information available to the Division and supplied by the applicant these sources have not been modified since then. The coal handling system is subsequently grandfathered from construction permit requirements.

The coal handling system is subject to the following applicable requirements:

- 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 crushing or conveying); 2) process modifications are unlikely since the process of crushing or conveying is straightforward and if modifications were to occur, they could not occur while the unit is in operation (i.e. crushing or conveying) and 3) emissions from the crushers and conveyors are controlled due to their location in a building (crushers) or because they are covered (conveyors) and so there is no control equipment

that could be adjusted or occasionally cleaned and affect opacity emissions.

- APEN reporting (Regulation No. 3, Part A, Section II)

The Division determined that no Regulation No. 1 particulate matter standards were applicable. Coal crushing and conveying is not considered a source of fugitive emissions (PM requirements - Reg 1, Section III.D) since emissions can be reasonably controlled. The Division also does not consider coal crushing or conveying 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.

2. Emission Factors - The source indicated that the non-fugitive emission sources from coal handling were the conveyor system and the coal crushers. The Division agrees with this interpretation. Approval of 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 inventory. The source proposed to use the following emission factors:

A. Coal Crushers: 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 used were:

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

B. 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
U = mean wind speed, mph
D = number of transfer points, dimensionless

M = moisture content, %

3. Monitoring Requirements - Monitoring requirements for the coal handling system shall include maintaining annual records of coal throughput and calculating emissions annually. The coal crushers are housed in buildings with no active ventilation system. The coal conveyors are covered. In the absence of credible evidence to the contrary, the Division will consider the coal crushers and conveyors to be in compliance with the 20% opacity requirement, provided the integrity of the crusher buildings are maintained and the coal conveyors are covered and the integrity of the covers is maintained.

4. Compliance Status - The source certified that they were in compliance with all applicable requirements for coal handling. As previously mentioned in the Title V permit application all emissions from coal handling were grouped together and identified as fugitive emissions. A Revised APEN was submitted for emissions from coal handling sources with the permit application. The coal handling system is currently in compliance with all applicable requirements.

I. Unit P005: Five (5) Dry Sodium Reagent Silos, Each Equipped with Bin Vent Filters

1. Applicable Requirements - The dry sodium reagent silos were not included in the original Title V permit application. However, the source submitted additional information on July 14, 1997 identifying four (4) of these silos as emission units to be included in the Title V permit application. A construction permit (97AD0455, initial approval modification No.1, September 15, 1998) was issued for these units. The dry sodium reagent silos were moved to final approval status based on the self-certification submitted March 8, 1999 that these units were fully in compliance with each applicable requirement listed in their initial approval (first modification) construction permit 97AD0455.

In order to meet the requirements in the Metro Agreement, additional SO_2 control devices will be added to the boilers at Cherokee. No changes will be made to Unit 1, which is equipped with a dry sodium injection unit. A dry sodium injection system will be added to Unit 2 and a lime spray dryer system will be added to Unit 3. The dry sodium injection unit on Unit 4 will be replaced with a lime spray dryer system. An additional dry sodium reagent silo will be added to the facility to accommodate the Unit 2 dry sodium injection system. Construction permit 97AD0455 will be modified as a combined construction/operating permit to reflect the additional silo and the source has indicated that no increase in reagent throughput or emissions is necessary. Since the addition of the fifth silo is essentially an administrative change, the final approval status of the construction permit is not changed. Construction on this additional silo is expected to commence in March of 2002. Note that when the lime spray dryer system on Unit 4 is operational, two of the dry sodium reagent silos will be removed.

The following applicable requirements have been identified for these units:

- Visible emissions shall not exceed 20% opacity, except as provided for below (condition 1)
- During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six consecutive minutes in any sixty consecutive minutes (condition1)

  Based on engineering judgement, the Division has not included the opacity requirement for startup, process modification and adjustment of control equipment 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.

- Throughput of sodium reagent shall not exceed 2,920 tons/mo* and 35,050 tons/yr. Monthly records of the actual consumption rate shall be maintained by the applicant and made available to the Division for inspection upon request. During the first twelve months compliance with both the monthly and annual limits shall be required (condition 5).
- Emissions of air pollutants shall not exceed the following limitations:

PM	0.0025 tons/mo*	and	0.03 tons/yr
PM_{10}	0.0025 tons/mo*	and	0.03 tons/yr

  Compliance with the annual limits will be determined on a twelve month rolling total. During the first twelve months compliance with both the monthly and annual limits shall be required (condition 9).

  *Since by the time this permit will be issued these units will have been operating for more than one year, the monthly throughput and emission limits will not be included in the permit.

The Division determined that no Regulation No. 1 particulate matter standards were applicable. Operations at the dry sodium reagent silo are not considered fugitive emissions (PM requirements - Reg 1, Section III.D). The Division also does not consider the dry sodium reagent silo to be a manufacturing process (PM requirements - Reg 1, Section III.C) as dry sodium is not processed further prior to use. The dry sodium reagent is used to reduce SO_2 emissions from the boilers.

2. Emission Factors - Approval of emission factors is necessary to monitor compliance with the emission limitations. The source proposed to use emission factors from the background document for AP-42, Sodium Carbonate Production (formerly Section 5.16, now Section 8.12), dated January 1996. The emission

factors are based on the average stack test results for product silo loading (test 23b). The Division has approved the use of these emission factors. The approved emission factors are as follows:

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

The bin vent filters are presumed to operate at a control efficiency of 99.9%.

3. Monitoring Requirements - Monitoring requirements for these units consist of monitoring and recording monthly quantities of dry sodium processed and calculating monthly emissions. In order to apply the control efficiency of the bin vent filters to emission calculations, the bin vent filters will have to be maintained and operated in accordance with manufacturer's requirements and good engineering practices.

4. Compliance Status - As previously indicated, these emission units were not included in the original Title V permit application, however, additional information was submitted on July 14, 1997 identifying these emission units. A construction permit (97AD0455) was issued for these units and the source subsequently self-certified, on March 8, 1999 that these units were in compliance with all applicable requirements.

J. Unit E001: General Motors, Model 20-645E4, Serial No. 67-H1-1127, Internal Combustion Reciprocating Engine, Rated at 26 mmBtu/hr, Diesel Fuel Fired.

K. Unit E002: General Motors, Model 20-645E4, Serial No. 67-H1-1080, Internal Combustion Reciprocating Engine, Rated at 26 mmBtu/hr, Diesel Fuel Fired.

1. Applicable Requirements - The Title V permit application identified two emergency generators as insignificant activities. At the time the Title V permit application was submitted, Regulation No. 3, Part C, Section II.E.3.nnn identified emergency power generators which operate no more than 250 hrs per year as an insignificant activity. Changes were made to Reg 3 after submittal of the Operating Permit application, Reg 3 was revised and the insignificant activity definition for emergency generators was changed to include size and hours of operation requirements. These units no longer qualify as insignificant activities and therefore must be included in the permit.

Both emergency generators were placed in service prior to February 1, 1972 and were therefore exempt from construction permit requirements. However, in 1998 Public Service took one of these generators out-of-service and replaced it with an identical model. Therefore, only one unit (unit E002) is still exempt from construction permit requirements. Unit E002 is subject to the following requirements:

- Visible emissions shall not exceed 20% opacity (Reg 1, Section II.A.1)
- Visible emissions shall not exceed 30% opacity, 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, when burning coal (Reg 1, Section II.A.4)

  Based on engineering judgement, the Division believes that the operational activities of fire building, cleaning of fire boxes and soot blowing do not apply to diesel engines. In addition, since this engine is not equipped with control equipment the operational activities of adjustment or occasional cleaning of control equipment also do not apply to this engine. Finally, based on engineering judgement, it is unlikely that process modifications will occur with the emergency generator. Therefore, for this unit the 30% opacity provision only applies during startup.

- SO_2 emission shall not exceed 1.5 lbs/mmBtu (Reg 1, Section VI.A.3.b.(i)).
- APEN reporting requirements (Reg 3, Part A, Section II)

A construction permit, 98AD0119 (initial approval, March 27, 1998), was issued for the new unit, E001. The emergency generator was moved to final approval status based on the self-certification, submitted September 2, 1998 that this unit was fully in compliance with each applicable requirement listed in its initial approval construction permit 98AD0119. The applicable requirements for this unit are as follows:

- Visible emissions shall not exceed 20% opacity (condition 1)
- Emissions of air pollutants shall not exceed the following limitations (condition 3):

NO_X	83.2 lbs/hr*	and	8.3 tons/yr
CO	22.1 lbs/hr*	and	2.2 tons/yr

- Fuel consumption and hours of operation shall not exceed the following (condition 4):

No. 2 diesel fuel	200 gal/hr*	and	40,000 gal/yr
Hours of Operation			200 hrs/yr

  *The short term fuel consumption and emission limitations have not been included in the operating permit as a result of the Division's short term emission limit policy (based on the April 16, 1998 Colorado AQCC directive).

  In addition, the Division is removing the requirement to operate this unit for no more than 200 hrs per year. The fuel consumption limits are based on 200 hrs of operation at the design rate. Because the fuel consumption limits

operation of this unit to a limited number of hours, it is not necessary to place a further limit on the hours of operation.

- At all times, including periods of start-up, shutdown, and malfunction, the facility and control equipment shall, to the extent practicable, be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operating and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source (condition 5).

  This language is essentially the language found in 40 CFR Part 60 Subpart A § 60.11(d), as adopted by reference in Colorado Regulation No. 6 Part A (federal NSPS requirements) and Part B (state-only NSPS requirements) which applies to units that are subject any of either the federal or state-only NSPS requirement. This unit is not subject to any NSPS requirements, therefore this condition will not be included in the Operating Permit. However, the Division will include some general language in the permit requiring that this unit shall be operated and maintained in accordance with manufacturer's recommendations.

Although not specifically identified in the construction permit, the following requirements apply to the emergency generator:

- Visible emissions shall not exceed 30% opacity, 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, when burning coal (Reg 1, Section II.A.4)

  As discussed for Unit E002 above, the 30% opacity requirement only applies during startup.

- SO_2 emission shall not exceed 0.8 lbs/mmBtu (Reg 1, Section VI.B.4.b.(i)).

2. Emission Factors - Approval of emission factors is necessary to monitor compliance with the annual emission limits. The source proposed to use emission factors from AP-42, dated October 1996, Section 3.4, Table 3.4-1. Emission factors are as follows:

Pollutant	Emission Factor (lbs/mmBtu)
NO_X	3.20
CO	0.85

VOC	0.08
SO_X	1.01S
PM	0.07
PM_{10}	0.05

Note that emissions of SO_X, PM, VOC and PM_{10} are below APEN de minimis levels and therefore there are no emission limits in the operating permit for these pollutants.

3. Monitoring Requirements - Monitoring requirements for these units include monitoring and recording fuel consumption and calculating emissions on a monthly basis for Unit E001 and an annual basis for Unit E002. Compliance with the opacity requirements will be monitored by performing EPA Method 9 visible emission observations. The frequency of these observations will be based on the actual time this unit is operated. No. 2 fuel oil cannot be purchased with a sulfur content greater than 0.5 weight percent. Based on this sulfur content and the emission factor (1.01S lbs/mmBtu), the source is always in compliance with the SO_2 requirement. Therefore, the Division will consider, in the absence of credible evidence to the contrary, that the generators are in compliance with the SO_2 requirements when burning No. 2 fuel oil.

4. Compliance Status - As previously indicated, this emergency generator was not at the Cherokee facility at the time the Title V application was prepared. The source received a construction permit prior to installing this unit and have self-certified that this unit is in compliance with all requirements identified in the construction permit.

L. Unit T001: 1,000 Gal Aboveground Gasoline Storage Tank

1. Applicable Requirements - In the Title V permit application submitted for this facility, the source included a 3,000 gal underground gasoline storage tank in their list of insignificant activities. Because the facility is located in the Denver metro area, gasoline storage tanks over 550 gallons are subject to specific requirements in Reg 7. At a later date the Division determined that the 3,000 gal underground storage tank required a construction permit because the tank was subject to requirements in Reg 7. Colorado Construction Permit 93AD977-5S was issued (initial approval, October 13, 1998 and moved to final approval status based on the self-certification submitted September 2, 1998). However, with the installation of the new waste ash silo for Unit 4, the 3,000 gal underground storage tank had to be removed. Colorado Construction Permit 01AD0239S was issued on March 27, 2001 for a 1,000 gal aboveground gasoline storage tank. The due date of the first semi-annual monitoring report 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.

The tank is equipped with a Stage I vapor control system and a submerged fill pipe. The Stage I vapor control system is a vapor balance system with employs a hose that returns gasoline vapors displaced from the underground tank to the tank truck cargo compartments being emptied. Therefore, the vapor control system consists of the tanker truck and the piping associated with the storage tank.

The applicable requirements from Colorado Construction Permit 01AD239S for this unit are as follows:

- Construction of this source must commence within 18 months of initial permit issuance date or within 18 months of date on which such construction or activity was scheduled to commence as stated in the application. If commencement does not occur within the stated time the permit will expire on September 27, 2002 (condition 1)

  This tank commenced operation on April 30, 2001, therefore, this requirement will not be included in the operating permit.

- Total gasoline dispensed from this unit shall not exceed 18,000 gal/yr (condition 2)

  Note that in comments made on the draft permit, received October 12, 2000, the source indicated that they do not routinely monitor the quantity of fuel dispensed and therefore, they requested that they be allowed to monitor the quantity of fuel delivered. This change was made in the operating permit.

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

VOC	0.255 tons/yr

- This source is subject to Control of Volatile Organic Compounds, Regulation No. 7, Section VI.B.3.b, which requires approved fittings for a vapor recovery system to be installed on all gasoline storage tanks. To minimize gasoline vapor emissions, the operator shall ensure that the tanks are only filled with gasoline from a certified delivery truck equipped with an approved vapor recovery system and that the system is properly connected during the entire filling operation (condition 4).
- APEN reporting (condition 5 and Reg. 3, Part A Section II.C)

  The APEN reporting requirements will not be identified in the permit as a specific condition but is included in Section V (General Conditions) of the permit, condition 21.e.

- Within 180 days after commencement of operation, compliance with the conditions contained on this permit shall be demonstrated to the Division

(condition 7 and Reg 3, Part B, Section IV.H.2)

Since the storage tank has already commenced operation, this requirement will not be included. Note that as previously mentioned, the certification by the Responsible Official in the first semi-annual compliance report will serve as the self-certification that these units can comply with the requirements in their construction permits.

Additional requirements in Colorado Regulation No. 7, that were not included in the construction permit, either apply or may be presumed to apply to this tank and are discussed below:

- All new sources shall utilize controls representing Reasonably Available Control Technology (RACT) (Reg 7, Section II.C.2).

  RACT for this unit is the specific requirements identified in Reg 7, which will be included in the operating permit. With those requirements included there is no further need to identify the general RACT requirement in the permit.

- General requirements for maintenance and operation of storage tanks (Reg 7, Section III.A).
- Disposal of VOC compounds - general (Reg 7, Section V.A).

  Note the above two requirements are included in the general conditions (Section V) and therefore will not be specifically identified and addressed in Section II of the permit.

- Disposal of gasoline (Reg 7, Section V.B).
- Requirements for storage of petroleum liquids in tanks less than 40,000 gal (Reg 7, Section VI.B.3). Note that the construction permit identifies requirements from Reg 7, Section VI.B.3.b, however, it is not clear whether all the requirements have been included in the construction permit, therefore, this reviewer believes it is useful to address these requirements and explain which are included in the operating permit and which are not and why they are not.
  - The owner of operator of storage tanks at a gasoline dispensing facility, which receives and stores petroleum liquid, shall not allow the transfer of petroleum liquid from any delivery vessel into any tank unless the tank is equipped with a submerged fill pipe and the vapors displaced from the storage tank during filling are processed by a vapor control system (Reg 7, Section VI.B.3.b)
  - Tanks equipped with a submerged fill pipe shall meet the specifications of Appendix A (Reg 7, Section VI.B.3.c)
  - The vapor control system shall include a vapor-tight line from the storage tank to delivery vessel (i.e. an approved control system) (Reg

7, Section VI.B.3.d.(i)).

- The owner or operator shall ensure that operating procedures are used so that gasoline cannot be transferred into the tank unless the vapor control system is in use (Reg 7, Section VI.B.3.e).

Note that as previously discussed, the vapor control system is essentially the tanker truck (vapor balance system), the following requirements in Reg 7, Section VI.B.3 will not be included in the operating permit as they apply to the tanker truck/vapor control system.

- approved vapor balance system (Reg 7, Section VI.B.3.b.(iii))
- vapor balance system specifications (Reg 7, Section VI.B.3.f)
- vapor balance system and vapor control system shall meet the requirements of Section XV (Reg 7, Section VI.B.3.g)
- control device testing and recordkeeping requirements (Reg 7, Section VI.B.3.h & I)

Note that by having the tank filled by a certified tanker truck (i.e. meeting the requirements in Reg 7, Section VI.D), the storage is being operated in compliance with the above requirements.

In addition, the requirements in Reg 7, Section XV, "Control of VOC Leaks from Vapor Collection Systems and Vapor Control Systems Located at Gasoline Terminals, Gasoline Bulk Plants, and Gasoline Dispensing Facilities" will not be included in the permit as the requirements apply to the operator of a vapor collection or vapor control system, which is the tanker truck. These requirement do not apply to the transfer of gasoline from the tank to a motor vehicle fuel tank, which are operations PSCo performs.

2. Emission Factors - Approval of emission factors is necessary in order to monitor compliance with the emission limits. Tank working and breathing losses were estimated using EPA's TANKS software program version 4.07. Vehicle refueling losses were calculated using the following AP-42 emission factors (Section 5.2 (Jan. 1995), Table 5.2-7):

Vehicle refueling operations (Stage II) – uncontrolled displacement losses	11 lbs/10^3 gal
Vehicle refueling operations (Stage II) – spillage	0.7 lbs/10^3 gal
Total	11.7 lbs/10^3 gal

3. Monitoring Requirements - Monitoring shall include monitoring and recording the quantity of fuel delivered to this unit on a monthly basis. Since the emission limit is directly based on the fuel throughput limitation in the permit, the Division will presume, that in the absence of credible evidence to the contrary, that the tank is in compliance with the emission limitations, provided the fuel throughput limits are met. In addition, PSCo shall be required to certify semi-annually that this tank is only filled by certified tanker trucks and that the remaining Reg 7 requirements are being

met (i.e. VOC disposal, submerged pipe specifications, etc.).

4. Compliance Status - The source received a construction permit (01AD239S) prior to commencing construction on this tank. As mentioned previously, the certification by the Responsible Official in the first semi-annual compliance report will serve as the self-certification that these units can comply with the requirements in their construction permits.

M. Unit M001: Cooling Towers - Four (4) Cooling Water Towers and Two (2) Service Water Towers

1. Applicable Requirements - The cooling towers were first installed August 1955 and modified in 1988 - 1995. The cooling towers and service water towers were modified due to deterioration of the wood structures due to age and microbial/fungus infestation. The source provided the following on the modifications to the cooling water/service water towers:

- cooling towers 1, 2 and 3 were rebuilt on the existing foundation and using the same design and materials. No changes were made to the cooling tower pumps, fans or other support systems and the mist eliminators were replaced with a newer, more efficient design.
- cooling tower 4 was rebuilt on its existing foundation, although the rebuild is a different design (taller, narrower and different air flow direction) than the original. The fans and cooling water flows, as well as the circulating water pumps remain the same. The mist eliminators were replaced with a newer, more efficient design.
- the wooden structures and fill material on the service water towers were replaced. The existing pumps and cooling water collection system were not changed. The fans were replaced with like kind units.

Emissions of VOC and particulate matter from the cooling towers and service water towers are based on the circulation rate of the water. Particulate matter emissions are controlled by the mist eliminators. Since the pumps remain the same and the mist eliminators are more efficient (in the case of the cooling water towers), emissions from the towers will not increase as a result of these modifications. Therefore, the changes to the towers are not considered modifications for purposes of Reg 3, Part B, PSD or major non-attainment area NSR.

Two of the cooling water towers are rated at 90,000 gal/min, one at 95,000 gal/min and one at 180,000 gal/min. The service water towers are rated at 8,800 and 8,500 gal/min. Although these units are grandfathered from construction permit requirements, the following requirements apply to these units:

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

Based on engineering judgement, 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 towers. In addition, there is really no "startup" involved in operating a cooling tower. Finally, the Division does not believe that adjustment of the control device (drift eliminators) can be done while operating the tower and that process modifications would be limited. Therefore, the 30% opacity requirement will not be included in the operating permit as the specific operating activities under which it applies does not occur with 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 towers are always in compliance with the 20% opacity requirement. The Division does believe that it would be highly unlikely that a cooling tower would ever violate the 20% opacity requirement. The Division considers that although it is unlikely that the cooling towers would violate the 20% opacity requirement, this requirement must be included in the operating permit. Therefore, the Division considers that the cooling towers are, in the absence of credible evidence to the contrary, in compliance with the opacity requirements provided the cooling 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)

2. Emission Factors - Since cooling 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 chlorine or chloroform from water treatment chemicals used in the cooling tower. Approval of emission factors for these units are necessary to verify compliance with the emission limits. The source proposed to calculate emissions from the cooling 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 Requirements - Monitoring requirements for the cooling water/service water towers consist of monitoring the annual water circulation rate for each tower and calculating emissions annually. In order to calculate emissions, the total solids content of the circulating water from each tower shall be analyzed annually.

4. Compliance Status - The source certified in their Title V application that these units were out of compliance with the APEN reporting requirements. An APEN was submitted with the Title V permit application, therefore, these units are currently in compliance with all applicable requirements.

IV. Insignificant Activities:

General categories of insignificant activities include: in-house experimental and laboratory equipment, fuel (gaseous) burning equipment (< 5 mmBtu/hr), chemical storage tanks or containers (< 500 gal), landscaping and site housekeeping devices (< 10 HP), chemical storage areas (< 5,000 gal), storage of butane, propane and LPG (< 60,000 gal), lube oil storage tanks (< 40,000 gal), venting of compressed natural gas, butane or propane cylinders (< 1 gal capacity), storage tanks with limited contents (< 400,000 gal), fuel (gaseous) burning equipment, for heating (< 10 mmBtu/hr), internal combustion engines (limited size or hours) and APEN de minimis emission sources.

Specific insignificant activities identified in the Operating Permit application are as follows:

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

VOC leaks from natural gas valves and flanges (VOC < 1 tpy)
Unit 2 ash blower system (PM and PM_{10} emissions < 1 tpy)
Lime handling system for wastewater treatment system (PM and PM_{10} emissions < 1 tpy)

<u>Air conditioning or ventilation systems (Reg 3 Part C.II.E.3.c)</u>

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

Plant laboratory

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

propane portable heaters

<u>Chemical storage tanks less than 500 gal (Reg 3 Part C.II.E.3.n)</u>

Brazing, soldering and welding operations - non-lead based (Reg 3 Part C.II.E.3.r)

Welding machine

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

Landscaping/site housekeeping devices less than 10 HP (Reg 3 Part C.II.E.3.bb)

Mowers, snowblowers, etc...

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

Emergency events (Reg 3 Part C.II.E.3.ff)

Operations involving acetylene and other flame cutting torches (Reg 3 Part C.II.E.3.kk)

Acetylene welding

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

Oil drum storage area

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

Turbine hydrogen vents
Wastewater operations
Boiler steam vents

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

Office emissions (Reg 3 Part C.II.E.3.tt)

Restrooms, copiers, etc...

Storage tanks < 400,000 gas containing specific contents (Reg 3 Part C.II.E.3.fff)

Diesel fuel tank for Emergency Generators A and B (20,000 gal underground)
Diesel fuel tank for refueling of heavy equipment (10,000 gal above ground)
Turbine lube oil batch tank

Non-road Engines – limited hours or size (Reg 3, Part C.II.E.3.xxx)

412 hp, diesel-fired engine powering an emergency fire pump (runs < 340 hrs/yr)
140 hp, diesel-fired engine powering a port-a-batch lime slurry pump (runs < 1,450 hrs/yr)

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

Not sources of emissions

Bottom ash handling (bottom ash is sluiced with water to on-site ash ponds, since handled as a slurry there are not emissions)
Unit No. 1 turbine lube oil system (closed system)
Unit No. 2 turbine lube oil system (closed system)
Unit No. 3 turbine lube oil system (closed system)
Unit No. 4 turbine lube oil system (closed system)

The source also identified mobile engine tailpipe emissions and emissions from a diesel switching locomotive as insignificant activities. Although, emissions from these sources would not necessarily qualify them as an insignificant activity, they are not applicable to Title V permitting requirements. Therefore, emissions from these sources are not identified in the Operating Permit as insignificant activities.

V. Alternative Operating Scenarios:

A. Alternate Fuels

The primary fuel used for the boilers is coal. However, the source requested that these boilers be permitted to use natural gas or a combination of coal and natural gas as a back-up.

B. Chemical Cleaning of Boilers

The source 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 alternate 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, Section 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 identified and justified a short list of non-applicable requirements that they wish to be specifically shielded from. Based on the information available to the Division and supplied by the applicant, the shield will be granted for the following non-applicable requirements. This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance.

A. Colorado Regulation 6, Part B, Section II (Standards of Performance for New Fuel-Burning Equipment) - This source did not request the shield for this applicable requirement for the boilers; however, the Division added this to be consistent with other non-applicable requirements the source identified for this facility. These regulations are not applicable to this facility as the boilers commenced operation prior to January 30, 1979. The permit shield was granted for this reason.

In addition, the Division will provide the shield for the emergency generators since they do not meet the definition of “fuel burning equipment”.

B. 40 CFR Part 60 Subparts D, Da, Db and Dc (as adopted by reference in Colorado Regulation 6) - The permit application states that these New Source Performance Standards (NSPS) requirements are not applicable to the facility as the boilers commenced operation prior to August 17, 1971. The permit shield was granted based on the source’s justification.

Note that although the electrostatic precipitators and wet scrubbers (ESP/WS) for Units 1 and 4 were replaced with baghouses in 1989, these replacements were not

considered modifications, because the NSPS regulations (40 CFR Part 60) exempts the addition of control equipment from the definition of a modification, except when an emission control system is removed or is replaced by a system that is determined to be less environmentally beneficial. The baghouse is more efficient at removing particulate matter than the ESP and although the removal of the WS may have resulted in the increase in SO_2 emissions, permits were issued to require that SO_2 emissions be reduced to account for the efficiency of the wet scrubber. To that end, dry sodium injection units were added to Units 1 (1998) and 4 (1989) to reduce SO_2 emissions. The addition of the dry sodium injection units are not considered modifications because these changes result in the reduction of SO_2 emissions. Note that baghouses were added to Units 2 (1985) and 3 (1988) and these additions were not considered modifications as they resulted in a decrease in particulate matter emissions. Finally, low NO_X burners with over-fire air were added to Units 1, 3 and 4 and over-fire air was added to Unit 2 at various times, and although these modifications decrease NO_X emissions they had the potential to increase CO emissions. However, since CO is not a regulated pollutant under NSPS Subparts D, Da, Db and Dc these changes are not considered modifications.

In addition, all of these changes discussed above are not considered modifications because 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 pollution control project at an existing electric utility steam generating unit from PSD or major non-attainment area NSR review. All these changes are considered pollution control projects.

C. 40 CFR Part 60 Subpart Y (as adopted by reference in Colorado Regulation 6) - The permit application states that these requirements do not apply because this NSPS requirement 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. Although the Division does not agree with this justification, these requirements are not applicable because this facility commenced construction prior to October 24, 1974. The shield was granted for this reason.

D. 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 Towers - The permit application states that this requirement is not applicable because the cooling towers do not use chromium-based water treatment chemicals. The shield was granted based on the source's justification.

The source requested the permit shield from the Prevention of Significant Deterioration requirements in 40 CFR 52.21 (Colorado Regulation 3, Part B, Section IV.D.3). The source's justification in the permit application states that this requirement is not applicable as the boilers were constructed before and has had

no major modifications after August 1, 1977. In comments received on another operating permit, EPA indicated that the Division could not grant the shield for PSD review requirements, unless the source was an existing source prior to August 7, 1977. Although this facility was an existing stationary source prior to August 7, 1977, equipment has been added to the facility after August 7, 1977 and therefore the Division cannot grant the permit shield the PSD review requirements.

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

Boiler No. 1, Unit B001

- 1.2 lbs/mmBtu SO_2 emission limit when burning coal (Colorado Regulation No. 1, Section VI.A.3.a.(ii) and Permit 86AD352-1, condition 7), streamlined out since Colorado Regulation No. 1, Section VII.A.1.a SO_2 limit (1.1 lbs/mmBtu) is more stringent.
- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Sections IV.A, B, F and H), streamlined out since Acid Rain COM/CEM requirements (Part 75) are more stringent. In the case of Reg 1, Section IV.F, the calibration requirement is streamlined out since Acid Rain CEM QA/QC requirements are more stringent and Reg 1, Section VII.A.1.a QA/QC requirements (40 CFR Part 60.13) for COM are more stringent. In the case of Reg 1, Section IV.H, the requirement for retention of records is streamlined out since the requirement for retaining records in Permit 86AD352-1 is more stringent.
- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Section VII.A.1.a), except for the QA/QC requirements for the COM (40 CFR Part 60.13(d)), are streamlined out since Acid Rain COM/CEM requirements (Part 75) are more stringent.
- Permit 86AD352-1, Conditions 3 (except for record retention information and requirement to monitor bypasses) and 6 (except for data replacement requirements) have been streamlined out since Acid Rain CEM requirements are more stringent.
- Permit 86AD352-1, Condition 6 (data replacement requirements only), have been streamlined out in favor of the following: for COM, the monitoring language when COMs are down developed by the Division and the CUC and for the outlet SO_2 emissions, the data replacement requirements in 40 CFR Part 75.
- Permit 86AD352-1, Condition 5 (emission reporting requirements) streamlined out of the permit in favor of Reg 1, Section IV.G.

Boiler No. 2, Unit B002

- 1.2 lbs/mmBtu SO_2 emission limit when burning coal (Colorado Regulation No. 1, Section VI.A.3.a.(ii)), streamlined out since Colorado Regulation No.

1, Section VII.A.1.a SO_2 limit (1.1 lbs/mmBtu) is more stringent.

- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Sections IV.A, B, F and H), streamlined out since Acid Rain COM/CEM requirements (Part 75) are more stringent. In the case of Reg 1, Section IV.F, the calibration requirement is streamlined out since Acid Rain CEM QA/QC requirements are more stringent and Reg 1, Section VII.A.1.a QA/QC requirements (40 CFR Part 60.13) for COM are more stringent. In the case of Reg 1, Section IV.H, the requirement for retention of records is streamlined out since the requirement for retaining records in Reg 3, Part C (general condition 21 in the operating permit) is more stringent.
- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Section VII.A.1.a), except for the QA/QC requirements for the COM (40 CFR Part 60.13(d)), streamlined out since Acid Rain COM/CEM requirements (Part 75) are more stringent.

Boiler No. 3, Unit B003

See Boiler No. 2, Unit B002 above. Same conditions streamlined for same reasons.

Boiler No. 4, Unit B004

- 1.2 lbs/mmBtu SO_2 emission limit when burning coal (Colorado Regulation No. 1, Section VI.A.3.a.(ii)) and Permit 86AD352-2, condition 6, streamlined out since Colorado Regulation No. 1, Section VII.A.1.a SO_2 limit (1.1 lbs/mmBtu) is more stringent.
- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Sections IV.A, B, F and H), streamlined out since Acid Rain COM/CEM requirements (Part 75) are more stringent. In the case of Reg 1, Section IV.F, the calibration requirement is streamlined out since Acid Rain CEM QA/QC requirements are more stringent and Reg 1, Section VII.A.1.a QA/QC requirements (40 CFR Part 60.13) for COM are more stringent. In the case of Reg 1, Section IV.H, the requirement for retention of records is streamlined out since the requirement for retaining records in Permit 86AD352-2, condition 3 is more stringent.
- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Section VII.A.1.a), except for the QA/QC requirements for the COM (40 CFR Part 60.13(d)), streamlined out since Acid Rain COM/CEM requirements (Part 75) are more stringent.
- Permit 86AD352-2, Conditions 3 (except for record retention information and requirement to monitor bypasses) and 5 (except for data replacement requirements) have been streamlined out since Acid Rain COM/CEM requirements are more stringent.
- Permit 86AD352-2, Condition 5 (data replacement requirements only), have been streamlined out in favor of the following: for COM, the monitoring

language when COMs are down developed by the Division and the CUC and for the outlet SO_2 emissions, the data replacement requirements in 40 CFR Part 75.

- Permit 86AD352-4, Condition 4 (emission reporting requirements) streamlined out of the permit in favor of Reg 1, Section IV.G.

VII. Acid Rain Provisions:

Boilers No. 1, 2, 3 and 4 (Units 1, 2, 3 and 4) are affected units under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78. This facility 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) for each unit. The source opted to comply with the Phase I NO_X requirements for Units 3 and which are 0.50 and 0.45 lbs/mmBtu, respectively, on an annual average basis. Although the Phase I NO_X requirements are in effect now, they are not enforceable by the State until January 1, 2000. The source submitted a NO_X averaging plan for Units 1 and 2.

As affected units under the Acid Rain Program, Boilers No. 1 thru No. 4 must continuously measure and record emissions of SO_2, NO_X (including diluent gas either CO_2 or O_2), and CO_2, as well as volumetric flow and opacity. The source submitted the continuous emission monitoring (CEM) certification package on January 1, 1995.