BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF Public Service Company of Colorado, dba Xcel Energy, Pawnee Station Permit Number: 96OPMR129 Issued by the Colorado Department of Public Health and Environment, Air Pollution Control Division	)))))))))))))))	PETITION TO OBJECT TO ISSUANCE OF A STATE TITLE V OPERATING PERMIT Petition Number: VIII-2010-

Pursuant to Section 505(b)(2) of the Clean Air Act, 42 USC § 7661d(b)(2), and 40 CFR § 70.8(d), WildEarth Guardians (hereafter "Petitioner") hereby petitions the Administrator of the U.S. Environmental Protection Agency ("EPA") to object to the issuance of the January 1, 2010 Title V operating permit (hereafter "Title V Permit") issued by the Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") for Public Service Company of Colorado doing business as Xcel Energy (hereafter "Xcel Energy") to operate the Pawnee coal-fired power plant located in Morgan County, Colorado. *See* Exhibit 1, Public Service Company of Colorado, Pawnee Station Title V Permit, Permit Number 96OPMR129 (January 1, 2010).

WildEarth Guardians hereby petitions the Administrator to object to the issuance of the Title V permit due to its failure to assure compliance with prevention of significant deterioration ("PSD") requirements under the Clean Air Act, to require sufficient periodic monitoring to ensure harmful levels of particulate matter are not released from the smokestack of the power plant, to limit and sufficiently monitor fugitive particulate emissions, to limit toxic air emissions in accordance with section112(j) of the Clean Air Act, and to ensure that carbon dioxide emissions are appropriately limited in accordance with the Clean Air Act.

INTRODUCTION

The Pawnee coal-fired power plant is a major stationary source of air pollution located near Brush, Colorado. The power plant consists of one 547 megawatt coal-fired boiler that generates steam to produce electricity. In the process, the power plant releases massive amounts of air pollution that is known to be harmful to public health and the environment. According to the Technical Review Document ("TRD") for the Title V Permit and data from the EPA's Acid Rain Program Database, the Pawnee coal-fired power plant annually releases:

- 4,595 tons of nitrogen oxides ("NO_x");
- 13,217 tons of sulfur dioxide ("SO_2");
- 598.62 tons of carbon monoxide ("CO");
- 73.71 tons of volatile organic compounds ("VOCs");
- 153.91 tons of particulate matter less than 10 microns in diameter ("PM_{10}");
- 20.3 tons of hydrochloric acid;
- 360 pounds of mercury, a potent neurotoxin; and

See Exhibit 2, Technical Review Document for Renewal/Modification of Operating Permit 96OPMR129 (Revised September 2009) at 26-27 and Exhibit 3, 2008 Emissions Data for Pawnee Station from EPA Acid Rain Program Emissions Database (Last Accessed February 19, 2010). Furthermore, according to data submitted to the EPA's Acid Rain Program, in 2008 the Pawnee plant annually releases 3,837,802 tons of carbon dioxide, a greenhouse gas that is fueling global warming.

The Division submitted the proposed Title V Permit for EPA review on November 9, 2009. The EPA's 45 day review period ended on December 24, 2009. To the best of Petitioner's knowledge, the EPA did not object to the issuance of the Title V Permit for the Pawnee coal-fired power plant. Since that time, the Division has issued a final Title V Permit, dated January 1, 2010. This petition is thus timely filed within 60 days following the conclusion of EPA's review period and failure to raise objections.

This petition is based on objections to the permit raised with reasonable specificity during the public comment period. To the extent the EPA may somehow believe this petition is not based on comments raised with reasonable specificity during the public comment period, Petitioner requests the Administrator also consider this a petition to reopen the Title V Permit for the Pawnee coal-fired power plant in accordance with 40 CFR § 70.7(f).[1] A permit reopening and revision is mandated in this case because of one or both of the following reasons:

1. Material mistakes or inaccurate statements were made in establishing the terms and conditions in the permit. *See* 40 CFR § 70.7(f)(1)(iii). As will be discussed in more detail, the Title V Permit for the Pawnee coal-fired plant suffers from material mistakes in violation of applicable requirements, etc.; and

2. The permit fails to assure compliance with the applicable requirements. *See*, 40 CFR § 70.7(f)(1)(iv). As will be discussed in more detail, the Title V Permit for the Pawnee coal-fired power plant fails to assure compliance with several applicable requirements.

[1] To the extent the Administrator may not believe citizens can petition for reopening for cause under 40 CFR § 70.7(f), Petitioner also hereby petitions to reopen for cause in accordance with 40 CFR § 70.7(f) pursuant to 5 USC § 555(b).

PETITIONER

Petitioner WildEarth Guardians is a Santa Fe, New Mexico-based nonprofit membership group dedicating to protecting and restoring the American West. WildEarth Guardians has an office in Denver and members throughout Colorado. On July 3, 2009, Petitioner submitted detailed comments regarding the Division's proposal to renew the Title V Permit for the Pawnee Station. *See* Exhibit 4, WildEarth Guardians Comments on Proposed Title V Permit (July 3, 2009). The objections raised in this petition were raised with reasonable specificity in comments on the draft Title V Permit. As will be explained in more detail, to the extent that objections may not have been raised with reasonable specificity in comments on the draft Title V Permit, this was due to the fact that it was either impracticable to raise such objections during the public comment period or the grounds for such objection arose after the public comment period.

Petitioner requests the EPA object to the issuance of Permit Number 96OPMR129 for the Pawnee coal-fired power plant and/or find reopening for cause for the reasons set forth below.

GROUNDS FOR OBJECTION

I. THE TITLE V PERMIT FAILS TO ASSURE COMPLIANCE WITH PSD REQUIREMENTS

A Title V Permit is required to include emission limitations and standards that assure compliance with all applicable requirements, including requirements under the Clean Air Act's Prevention of Significant Deterioration ("PSD") program, at the time of permit issuance. *See* 42 USC § 7661c(a); 40 CFR § 70.6(c)(1). In this case, evidence indicate that PSD requirements are, in fact, applicable to the Pawnee power plant and that the facility is currently in violation of PSD requirements. Despite this, the Title V Permit fails to both assure compliance with PSD and to bring the Pawnee power plant into compliance with PSD through a compliance plan.

Pursuant to Part C of the Clean Air Act, the Colorado State Implementation Plan ("SIP") requires that no construction or operation of a major modification of a major stationary source occur in an area designated as attainment without first obtaining a permit under 40 CFR § 51.166 and the Colorado SIP. *See* 40 CFR § 51.166(a)(7)(iii) and the Colorado SIP, 5 CCR § 1001-5, Part D. The Colorado SIP further prohibits the operation of a major stationary source after a major modification unless the source has applied Best Available Control Technology ("BACT") to control emissions of harmful air pollutants. *See* 40 CFR § 51.166(j) and the Colorado SIP, 5 CCR § 1001-5, Part D, Section VI.A.1.b.

The Pawnee coal-fired power plant is a major stationary source within an area classified as attainment for all criteria pollutants. According to information from Xcel Energy, the plant underwent major modifications between 1994 and 1997 without first obtaining the required PSD permit. These modifications have resulted in unpermitted and uncontrolled emissions of significant amounts of SO_2, NO_x, and PM_{10}. In response to this information, on June 27, 2002 the EPA issued a notice of violation ("NOV") to Xcel Energy regarding violations of PSD under the Clean Air Act at Pawnee coal-fired power plant. *See* Exhibit 4 at Exhibit 1, EPA Notice of

Violation to Xcel Energy (June 26, 2002). This NOV and the underlying violations have yet to be resolved. For more than fifteen years, and likely longer, the plant has operated and continues to operate in a state of noncompliance with the PSD provisions of the Clean Air Act and the Colorado SIP.

Accordingly, the Division was both required to prepare a Title V Permit that includes PSD requirements, including BACT requirements, and to include a compliance plan to bring the facility into compliance in accordance with 42 USC §§ 7661b(b) and 7661c(a) and 40 CFR § 70.6(b)(3). Unfortunately, the Division failed to do so. Accordingly, the Administrator must object to the issuance of the Title V Permit for the Pawnee coal-fired power plant. Evidence of noncompliance with PSD requirements and the failure of the Title V Permit to ensure compliance with applicable requirements are as follows:

A. EPA Issuance of a Notice of Violation Constitutes a Finding of Noncompliance

The EPA NOV issued to Xcel Energy on June 26, 2002 states:

> Xcel violated and continues to violate Clean Air Act, Part C: Prevention of Significant Deterioration of Air Quality ("PSD"), 42 U.S.C. §§7470 to 7492, and the permitting requirements of Colorado Air Quality Control Commission Regulation No. 3, Part B, IV.D.3 and 40 C.F.R. §52.21, by constructing and operating modifications at the Pawnee Station…without the necessary permits and by constructing and operating without the application of BACT required by the Colorado SIP.

Exhibit 4 at Exhibit 1 at 5. The 2002 NOV establishes that the EPA conclusively found that the Pawnee coal-fired power plant was in violation of PSD requirements..

Indeed, the 2002 NOV is sufficient to demonstrate noncompliance with PSD for the purposes of a Title V Permit. In a situation very similar to the situation regarding the Pawnee NOV, the Second Circuit held that an NOV is sufficient to demonstrate noncompliance with PSD for the purposes of the Title V permitting program. *See* NYPIRG *v. Johnson*, 427 F.3d 172, 180 (2nd Cir. 2005). In *NYPIRG v. Johnson,* the Second Circuit Court of Appeals recognized that "to issue a NOV, the Administrator must first find a source in violation of an applicable plan or permit." *Id.* at 181. The court further reasoned that in issuing an NOV, a permitting authority had determined that PSD requirements "are, indeed, applicable." *Id.* The court held that the issuance of an NOV by the State of New York constituted a finding of noncompliance with PSD requirements and that the EPA was required to object to the issuance of a Title V permit that failed to ensure compliance with PSD. *Id.* at 186.

According to 42 USC § 7413(a)(1), the EPA Administrator shall issue a notice of violation when he finds "that any person has violated or is in violation of any requirement or prohibition of an applicable implementation plan or permit." The statute clearly states that an NOV is issued by the EPA only after making a finding of a violation, or a finding of noncompliance. Further, because the EPA, rather than the stated, issued the NOV, it is even more clear here than in the *NYPIRG* case that the NOV constitutes a sufficient finding of noncompliance.

The Tenth Circuit has not yet addressed the sufficiency of an NOV as legal proof of noncompliance with PSD requirements under Title V. Only one circuit has issued a holding in conflict with the Second Circuit position on NOVs. *See Sierra Club v. Johnson*, 541 F.3d 1257 (11th Circuit 2008). The reasoning in *NYPIRG v. Johnson*, however, applies to the facts here regarding the Pawnee NOV. This reasoning mandates that in this case, the Title V Permit ensure the Pawnee coal-fired power plant complies with PSD. The Title V Permit fails to ensure compliance with PSD in light of the EPA's finding of noncompliance, and therefore the Administrator must object to its issuance.

B. Major Modifications Have Occurred at the Pawnee Plant, Triggering PSD

Even if the EPA rejects WildEarth Guardians' contention that an NOV constitutes a finding of noncompliance, at a minimum the NOV shows clear evidence of a valid suspicion of noncompliance. This valid suspicion is confirmed by actual documents from Xcel Energy that demonstrate major modifications occurred at the Pawnee coal-fired power plant without prior approval under PSD. Indeed, Xcel's own records confirm that at least two major modifications, likely more, were made to Pawnee during the 1990s:

(1) Reheater redesign and replacement.

An Xcel Capital Project Summary Sheet submitted July 7, 1993 states that:

> The top bank plus all 256 reheater assemblies in the two middle banks will be replaced during the planned ten-week outage in 1994. . . In addition to replacing the assemblies, we will upgrade some of the material used, and change some of the manufacturing methods to prevent further similar damage in the past and prolong the life of the new assemblies. The reheater assemblies will also be redesigned so as to prevent the excessive pluggage currently seen.

See Exhibit 4 at Exhibit 2. The Pawnee Planned Outages data shows that there were planned outages for "major turbine overhaul (720 hours or longer)" between 9/30/1994 and 12/31/1994. *See* Exhibit 4 at Exhibit 3. EPA operations data from 1994 shows that Pawnee reported zero hours of operation during the months of October and November, and only 284 hours in December. *See* Exhibit 4 at Exhibit 4. Together, these documents confirm that the 1994 modification noted in the NOV did occur. Further, the fact that Pawnee shut down operations for ten weeks is a strong indication that this modification was not routine maintenance or repair.

(2) Upgrade of condenser tubes.

An Xcel Request for Specific Appropriation dated July 10, 1996 states that $4.5 million in emergency funding was allocated for the new condenser tubes. *See* Exhibit 4 at Exhibit 5. It goes on to state that "The project will be completed during the January 4 through March 2, 1997 outage." *See* Exhibit 4 at Exhibit 6. Pawnee Planned Outages data shows that there were planned outages for "major turbine overhaul (720 hours or longer)" between 2/28/1997 and 4/30/1997. *See* Exhibit 4 at Exhibit 3. EPA operations data from 1997 shows that Pawnee reported 168 hours of operation in February, zero hours in March, and 249 hours in April. *See* Exhibit 4 at Exhibit 7. Together, these documents confirm that the 1997 modification noted in the NOV did occur. Further, Xcel referred to this modification in its own documents as "major."

The NOV explained that these modifications did not fall within exemptions for "routine maintenance," "increased hours of operation," or "demand growth" set forth at 40 CFR § 51.166. The NOV concludes that "Each of the modifications resulted in a net significant increase in emissions for SO_2, NO_x, and/or PM as defined by 40 CFR §§ 51.166(b)(3) and (23) and Colorado SIP Rules at Air Quality Control Commission ("AQCC") Regulation No. 3, Part A, I.B.59 and Part A, I.B.37." Because these were modifications resulting in net significant increases of criteria pollutants, a PSD permit was required to be obtained before those modifications occurred. Xcel did not obtain such a PSD permit for the Pawnee coal-fired power plant, in violation of the Clean Air Act.

(3) Other modifications

Xcel's records also provide evidence of other modifications undertaken during the past twenty years. During April through June of 1989, there were planned outages for a "major turbine overhaul." *See* Exhibit 4 at Exhibit 8. In April of 1998, there was a planned outage for a "major boiler overhaul." Exhibit 4 at Exhibit 3. In March of 2000, there was another planned outage for a "major boiler overhaul." *See* Exhibit 4 at Exhibit 9.

Even if the EPA believes the NOV is not sufficient to constitute a violation of the PSD requirements, the evidence of modifications listed above must be dealt with under the PSD provisions of the Clean Air Act and the Colorado SIP, and accordingly through the Title V Permit for the Pawnee coal-fired power plant. Xcel clearly made at least two modifications to the Pawnee coal-fired power plant. Modifications clearly resulted in significant emissions increases, not only as reported in the NOV but also reported by Xcel Energy to the EPA's Acid Rain Program. *See* table below.

Annual SO_2 and NO_x emissions at Pawnee Coal-fired Power Plant.
***See* Emissions Data Attached as Exhibit 5.**

Year	SO_2 Tons	NO_x Tons
1995	15374.0	4869.0
1996	11633.4	3529.0
1997	13928.7	3817.8
1998	15325.6	3906.1
1999	16665.8	5319.7
2000	14678.1	4892.4
2001	17030.9	5845.4
2002	14832.6	4591.7
2003	16703.0	5369.0
2004	12549.6	4514.6

2005	11248.1	3668.1
2006	13072.5	4602.7
2007	14126.5	4415.3
2008	13217.2	4595.2

The amount of SO_2 emissions considered significant is 40 tons per year. 40 CFR § 51.166(b)(23). The amount of NO_x emissions considered significant is 40 tons per year. *Id.* Emissions data from the EPA shows that after the identified second modification (1997-1998), there occurred an SO_2 increase of 1396.9 tons and a NO_x increase of 88.3 tons annually. Thus, both significance thresholds were met after the 1997 modification. While data immediately before the 1994 modification is not available on the Clean Air Market website, the NOV claims that the 1994 modification did result in significant emissions increases. PM_{10} emissions of 15 tons per year are also considered significant under the regulations. 40 CFR § 51.166(b)(23). The NOV claims that a significant PM emission increase also occurred at Pawnee.

Given that Pawnee is currently in violation of PSD requirements, the Division was required to ensure the Title V Permit assured compliance with PSD and included a compliance plan to bring the Pawnee coal-fired power plant into compliance with PSD. These applicable requirements, however, are missing from the Permit, in violation of 42 USC § 7661c(a) and 40 CFR § 70.6(c)(1), and the Administrator must object to its issuance.

C. The Division's Response to Wild Earth Guardians' Comments Fails to Demonstrate that PSD is not an Applicable Requirement or that a Compliance Plan was not Required

WildEarth Guardians commented that the Division had a minimum responsibility to respond to significant comments regarding noncompliance with PSD as demonstrated by the 2002 NOV, Xcel Energy's own reports providing evidence of major modifications, and emissions data from the EPA. In accordance with prior Title V Petition rulings from the Administrator, WildEarth Guardians commented that the Division was required to "'provide the basis (e.g., citing to current or historical evidence, or the lack thereof) that supports its conclusion that PSD/NSR' was or was not applicable in relation to the aforementioned modifications. *See In the Matter of CEMEX Inc.*, Petition No. VIII-2008-01 (April 20, 2009) at 10." Exhibit 4 at 5. Unfortunately, the Division failed to respond in this manner.

In fact, while the Division agreed that the documentation provided by WildEarth Guardians "reflects that the reheater design and replacement and condenser tube upgrades occurred in the years noted in the EPA NOV," the Division provided no basis for concluding that these modifications did not trigger PSD requirements. *See* Colorado Air Pollution Control Division Response to Comments from WildEarth Guardians on Draft Pawnee Title V Permit (November 6, 2009) at 6-7, attached as Exhibit 6. While the Division implies that it may not believe the reheater design and replacement and condenser tube upgrades constituted physical changes or changes in the methods of operation and/or led to significant net emissions increases using the actual to potential test, the Division neither provides nor points to any explanation, information, or analysis demonstrating that the reheater design and replacement and condenser tube upgrades did not constitute physical changes or changes in the methods of operation and/or lead to significant net emissions increases. *Id.*[2] Although the Division states that "the fact that the [reheater redesign and replacement and condenser tube upgrades] projects took place does necessarily indicate that a major modification occurred," this is not responsive to WildEarth Guardians' comments and fails to demonstrate that the reheater redesign and replacement and condenser tube upgrades did not constitute major modifications of the Pawnee coal-fired power plant. *Id.* at 7.

The only seemingly conclusive response provided by the Division on this issue is as follows:

> PSCo. [Public Service Company of Colorado] and EPA have disagreed on these issues, and EPA has not taken any further action on the 2002 NOV. As is customary, since these projects are addressed in EPA's NOV, the Division used its enforcement discretion and did not file a parallel investigation.

Exhibit 6 at 7. However, this response fails to provide any basis (e.g., citing to current or historical evidence, or the lack thereof) that supports its conclusion that PSD is not an applicable requirement with regards to the reheater redesign and replacement and condenser tube upgrades modifications cited by WildEarth Guardians in its comments. Simply because the Division has exercised enforcement discretion does not absolve the agency from performing its duties under Title V of the Clean Air Act. Furthermore, simply because the Division has chosen not to enforce PSD requirements with regards to the reheater redesign and replacement and condenser tube upgrade identified by WildEarth Guardians, does not mean that PSD is not an applicable requirement at the Pawnee coal-fired power plant. Title V of the Clean Air Act is clear that a Title V Permit must assure compliance with applicable requirements and that where a source is in violation of an applicable requirement, a compliance plan must be included in the Title V Permit to bring the source into compliance. *See* 42 USC § 7661c(a). Neither the Division nor the EPA have the discretion to ignore this statutory duty.

Similarly, in its response to comments, the Division provides no basis for concluding the other modifications, namely the turbine and boiler overhauls, identified by WildEarth Guardians do not demonstrate that PSD requirements were triggered at the Pawnee coal-fired power plant. Citing the evidence provided by WildEarth Guardians, the Division provided a number of inconclusive statements, none of which actually support the Division's assertions and appear to form a rational basis for the Division's ultimate conclusion. For instance, the Division simply

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[2] The Division possibly implies that the reheater redesign and replacement and condenser tube upgrades constitute "routine maintenance, repair and replacement," and therefore are not considered a "physical change or change in the method of operation, or addition to, a major stationary source." *See* Exhibit 6 at 7. However, there is no basis provided for this implied conclusion, no explanation provided that supports such an implied conclusion, and it is unclear whether the Division is or is not actually asserting that the modifications identified by WildEarth Guardians constitute routine maintenance. Importantly, the Division did not analyze the reheater redesign and replacement and condenser tube upgrades in accordance with the standards at 40 CFR § 52.21(cc) or 40 CFR § 51.166(y) to determine whether these modifications in fact constitute routine maintenance, repair, and replacement. Regardless, WildEarth Guardians provided information demonstrating that the reheater redesign and replacement and condenser tube upgrades did not constitute routine maintenance, repair, and replacement. *See* Exhibit 4 at 4. In concluding that PSD is not an applicable requirement at the Pawnee coal-fired power plant, the Division, at a minimum, failed to respond to this information.

claims that, "the turbine and boiler overhauls may not constitute modifications," asserting it is "common practice within the utility industry to conduct maintenance work on boilers and turbines during planned outages on a routine basis" and that such activities "would generally be considered routine, maintenance and repair." Exhibit 6 at 7. Amazingly, rather than analyze whether the specific turbine and boiler overhauls identified by WildEarth Guardians constitute routine maintenance in accordance with the standards at 40 CFR § 51.166(y), the Division simply infers that the overhauls are routine, asserting, "the fact that exhibits 3, 8 and 9 [of WildEarth Guardians' comments] indicate that such activities have occurred frequently over the time periods addressed in the exhibits support the inference that these activities are routine." *Id.*

These responses, however, provide no conclusive basis as to whether the turbine and boiler overhauls identified by WildEarth Guardians do or do not constitute major modifications and ultimately fail to support the Division's conclusions. Simply because the turbine and boiler overhauls "may not" constitute modifications, does not mean they do not constitute modifications, as the Division implies. And simply because maintenance work on boilers and turbines may constitute routine maintenance does not mean that the turbine and boiler overhauls identified by WildEarth Guardians in fact constitute routine maintenance. Furthermore, it is disconcerting that the Division would rely on an "inference," and not a reasoned analysis based on its own SIP and federal regulations, to provide a rational basis for its conclusion that PSD is not an applicable requirement or that a compliance plan is not required to be included in the Pawnee Title V Permit. The Division cannot issue offhand, unsupported "possibilities" or "maybes," or worse yet rely on inferences, to support regulatory findings under Title V of the Clean Air Act.

The Administrator cannot uphold such "inferred" and obviously inconclusive decisionmaking under Title V of the Clean Air Act and certainly cannot uphold the Division's response to comments as demonstrative of the applicability of PSD requirements to the Pawnee coal-fired power plant. The Administrator must object to the issuance of the Title V Permit on the basis of the Division's failure to adequately respond to significant comments presented by WildEarth Guardians.

II. THE TITLE V PERMIT FAILS TO REQUIRE ASSURE COMPLIANCE WITH PARTICULATE MATTER LIMITS APPLICABLE TO THE COAL-FIRED BOILER

Permitting authorities must ensure that a Title V Permit contain monitoring that ensures compliance with the terms and conditions of the permit. *See* 42 USC § 7661c(c) and 70.6(c)(1). Although as a basic matter, Title V Permits must require sufficient periodic monitoring when the underlying applicable requirements do not require monitoring (*see* 40 CFR § 70.6(a)(3)(i)(B)), the D.C. Circuit Court of Appeals has firmly held that even when the underlying applicable requirements require monitoring, permitting authorities must supplement this monitoring if it is inadequate to ensure compliance with the terms and conditions of the permit. As the D.C. Circuit recently explained:

> [40 CFR § 70.6(c)(1)] serves as a gap-filler....In other words, § 70.6(c)(1) ensures that all Title V permits include monitoring requirements "sufficient to assure compliance with

> the terms and conditions of the permit," even when § 70.6(a)(3)(i)(A) and § 70.6(a)(3)(i)(B) are not applicable. This reading provides precisely what we have concluded the Act requires: a permitting authority may supplement an inadequate monitoring requirement so that the requirement will "assure compliance with the permit terms and conditions."

See Sierra Club v. EPA, 536 F.3d 673, 680 (D.C. Cir. 2008). In other words, "a monitoring requirement insufficient 'to assure compliance' with emission limits has no place in a permit[.]" *Id.* at 677.

In this case, the Title V Permit fails to contain monitoring requirements that ensure compliance with underlying particulate matter emission rate for the coal-fired boiler established by the Colorado SIP. That emission rate, which is set forth in Section II, Condition 1.1 of the Title V Permit, limits emissions of particulate matter to no more than 0.1 lb/mmBtu from boiler . *See* Exhibit 1 at 5. The underlying requirements establishing this particulate matter emission limit, in this case the Colorado SIP at AQCC Regulation No. 1, Section III.A.1.c. (5 CCR 1001-3, Section III.A.1.c), do not require monitoring. Therefore, the Division was required to ensure the Title V Permit contained sufficient periodic monitoring to assure compliance with the particulate emission rate. The Division failed to do so, thus issuance of the Title V Permit is contrary to Title V requirements and the Administrator must object. Petitioner raised with reasonable specificity concerns over the failure of the Title V Permit to assure compliance with particulate limits. *See* Exhibit 4 at 5-6.

A. The Title V Permit Does not Require Actual Monitoring of Particulate Emissions

On its face, the Title V Permit is inadequate because it does not require actual monitoring of particulate matter emissions. Section II, Condition 1.1 of the Title V Permit states that compliance with particulate limits is demonstrated by "[m]aintaining and operating the baghouse in accordance with the requirements identified in [Section II] Condition 8.1" and "conducting performance tests annually in accordance with [Section II] Condition 8.2." Exhibit 1 at 6. None of these conditions explicitly require monitoring of actual particulate matter emissions to ensure compliance with the rate set forth in Section II, Condition 1.1 of the Title V Permit.

Indeed, Section II, Condition 8.1 relates only to the operation and maintenance of the baghouse and states only that "The boiler baghouses shall be maintained and operated in accordance with good engineering practices." Exhibit 1 at 28. Compliance with this Condition does not yield particulate matter data necessary to demonstrate compliance with the 0.1 lbs/mmBtu emission rate set forth in Section II, Condition 1.1 of the Title V Permit.

Although the Division may believe that baghouse operation and maintenance can substitute for actual particulate matter monitoring, this belief is unsupported in this case. While compliance with Condition 8.1 may help to keep particulate matter emissions in check, neither the Division, the TRD, nor the Title V Permit cite or otherwise disclose information showing that compliance with Section II, Condition 8.1 will, with any level of certainty, ensure continuous compliance with the quantitative 0.1 lb/mmBtu particulate matter emission rate. Adding to this, Section II, Condition 8.1 is vague and unenforceable. Because good engineering practices are not defined in any specific way in the Title V Permit, it is impossible to understand what such practices are and whether they will, in fact, be sufficient to assure compliance with the particulate matter emission rate at Section II, Condition 1.1.

Furthermore, Section II, Condition 8.2 relates only to stack testing. *See* Exhibit 1 at 28-29. Although the Condition requires stack testing for particulate matter emissions, it does not actually require monitoring of particulate matter emissions to ensure compliance with the emission rate set forth in Section II, Condition 1.1. Because the Title V Permit fails to require actual monitoring of particulate matter emissions, it does not assure compliance with particulate emission rates and therefore, the Administrator must object to its issuance.

B. Stack Testing is too Infrequent, Even if it Could Demonstrate Compliance

The Division may believe that stack testing under Section II, Condition 8.2 can substitute for particulate matter monitoring, but this, too, is unfounded. For one thing, Section II, Condition 8.2 only requires that stack testing occur annually, at most, but even allows less frequent monitoring to occur. Thus, while the 0.1 lbs/mmBtu emission rate applies continuously, the stack testing requirement limits monitoring to only once per year and possibly even less frequently. This is problematic. In essence, even if the Division could reasonably rely on Section II, Condition 8.2 to assure compliance with particulate matter rate, this Condition would assure compliance with the limits only once per year, at best. This necessarily means the Title V Permit fails to assure compliance with the 0.1 lbs/mmBtu emission rate the remainder of the year, or years. If the Title V Permit limited emissions of particulate matter to no more than 0.1 lbs/mmBtu only once per year, then such monitoring may be appropriate. The Title V Permit has no such limit, however, and therefore the monitoring fails to assure compliance.

The failure to ensure more frequent monitoring of particulate matter is further problematic because heat input at the Pawnee coal-fired power plant has varied over the years. For instance, between 1996 and 2008, heat input was as high as 51,115,318 mmBtu and as low as 30,654,706, a difference of more than 20 million mmBtu. *See* Table below. Because the particulate emission rate set forth at Section II, Condition 1.1 is dependent on heat input, such variability calls into question the ability of the Division to reasonably rely on annual stack testing to assure continuous compliance with the particulate emission rate. Clearly a one-time test will not provide data representative of all operations at the Pawnee coal-fired power plant.

Table 1. Heat Input at the Pawnee Coal-fired Power Plant.
***See* Emissions Data Attached as Exhibit 5.**

Year	Heat Input (mmBtu)
1996	30,654,706
1997	36,882,239
1998	36,599,944
1999	45,855,909
2000	45,856,526
2001	51,115,318

2002	38,786,013
2003	45,594,819
2004	40,944,685
2005	34,507,188
2006	43,563,056
2007	39,942,263
2008	36,775,940

The need for continuous monitoring, or at least more frequent than once every year, is further bolstered by Section 302(k) of the Clean Air Act, which defines "emission limitation" as "a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis[.]" 42 USC § 7602(k). Because the particulate emission rate set forth in Section II, Condition 1.1 of the Title V Permit is an "emission limitation," it necessarily applies "on a continuous basis." Logically, for the Title V Permit to assure compliance with particulate emission rate, it must require continuous monitoring, meaning annual stack testing is wholly inadequate. The Administrator must therefore object to the issuance of the Title V Permit.

C. The Division Cannot Rely on Compliance Assurance Monitoring to Meet Title V Monitoring Requirements

In response to Petitioners' comments over the lack of adequate particulate monitoring, the Division re-asserted its belief that that compliance assurance monitoring ("CAM") requirements set forth in Section II, Condition 1.15 constitute sufficient periodic monitoring that ensures compliance with 40 CFR § 70.6(a)(3)(i)(B) and assures compliance with the particulate emission rate in Section II, Condition 1.1 in accordance with 40 CFR § 70.6(c)(1). *See* Exhibit 6 at 8-9. This assertion is invalid and unsupported in several key regards.

To begin with, the Title V Permit does not explicitly state that compliance with the particulate emission rate set forth at Section II, Condition 1.1 can be demonstrated by complying with CAM requirements at Section II, Condition 1.15, or the underlying CAM Plan in Appendix H to the Title V Permit. As already explained, Section II, Condition 1.1 simply states that compliance with the particulate emission rate shall be demonstrated through compliance with Section II, Condition 8.1 and Section II, Condition 8.3. Thus, as written, the Title V Permit does not support a relationship between compliance with CAM requirements and compliance with the particulate emission rate.

Furthermore, it is inappropriate for the Division to rely solely on the CAM requirements set forth in the Title V Permit to demonstrate compliance with the particulate emission rate at Section II, Condition 1.1. For one thing, it does not appear that the Division has established an accurate, quantitative correlation between compliance with CAM requirements and compliance with the numerical emission rate set forth at Section II, Condition 1.1. Further, although the CAM requirements at Section II, Condition 1.15 and the CAM Plan in Appendix H require monitoring of certain parameters, such as the condition of the baghouses, there are no quantitative requirements set forth that ensure any level of performance for these control devices.[3] And although opacity limits apply to both Unit 1 and Unit 2, there is no information or analysis cited or incorporated into the permit that demonstrates compliance with these limits automatically mean compliance with the particulate rate at Section II, Condition 1.[4] Put simply, the Division seems to be attempting to put a square peg in a round hole, conveniently relying on CAM requirements as a misshapen substitute for compliance with a quantitative emission rate.

Although the Division claims that the preamble to the 1997 final CAM rule "indicates that CAM is consistent with the Title V periodic monitoring requirements," (*see* Exhibit 6 at 9), this is not supported by the preamble. While the EPA originally thought that Part 64 CAM requirements would supersede periodic monitoring requirements under Part 70, the EPA ultimately rejected this approach, stating "the existing part 70 monitoring, including periodic monitoring, requirements will continue to apply." 62 Fed. Reg. 54905. Furthermore, although EPA indicated that it may be appropriate, in some instances, to rely on Part 64 monitoring requirements to satisfy Part 70 requirements, the EPA made clear in the preamble to CAM that, "Part 64 is intended to provide a reasonable means of supplementing existing regulatory provisions that are not consistent with the statutory requirements of titles V and VII of the 1990 Amendments to the [Clean Air] Act." 62 Fed. Reg. 54904. In other words, the CAM rule does not supplant existing monitoring requirements, such as those under 40 CFR § 70, but rather aids in filling gaps where existing requirements may fall short of ensuring adequate monitoring. The Division's claim that CAM is "consistent" with Title V periodic monitoring requirements is not only presumptuous, but elevates form over substance. Ultimately, the Division is required to ensure sufficient periodic monitoring that provides reliable and representative data from the relevant time period in accordance with 40 CFR § 70.6.

To this end, the Division has failed to show that the specific CAM requirements set forth at Section II, Condition 1.18 and the CAM Plan in Appendix H assure compliance with the particulate emission rate at Section II, Condition 1.1. Simply because the Division asserts that CAM requirements assure compliance with the particulate emission rate in accordance with 40 CFR § 70.6(c)(1), does not make it so. The Administrator must therefore object to the issuance of the Title V Permit on the basis that the Division inappropriately relied on CAM requirements in the Title V Permit to assure compliance with particulate limits.

D. The Division Inappropriately Rejected Particulate Matter Continuous Emission Monitors as a Means of Ensuring Compliance with Particulate Limits

Compounding the failure to assure compliance with the particulate emission rate at Section II, Condition 1.1, the Division also arbitrarily rejected a means to ensure continuous compliance with the particulate emission rate. In comments, WildEarth Guardians requested that

[3] For example, although the CAM Plan requires that baghouse inspections occur annually (*see* Exhibit 1 at Appendix H, Page 2), neither the CAM Plan nor Section II, Condition 1.15 require any standard of performance for the baghouse.

[4] Although the Division states that a "site-specific opacity trigger level" must be set by the CAM Plan (*see* Exhibit 4 at 6), the CAM Plan actually sets no site-specific opacity trigger that would assure compliance with the particulate emission rate. For instance, although an "excursion" is defined as an opacity value greater than 15% (*see* Exhibit 1 at Appendix G, Page 2), neither the CAM Plan nor the Title V Permit state that such an "excursion" equates to a violation of the particulate matter emission rate.

the Division require the use of particulate matter continuous emission monitoring systems ("PM CEMS") to assure compliance with the particulate emission rate in the Title V Permit. The EPA promulgated performance specifications for PM CEMS at 40 CFR § 60, Appendix B, Specification 11, on January 12, 2004. *See In the Matter of Onyx Environmental Services*, Petition No. V-2005-1 at 13. This promulgation indicates that the use of PM CEMS is an accepted means of assessing compliance with particulate emission rates and limits.

Furthermore, the EPA has required other coal-fired power plants to install, operate, calibrate, and maintain a PM CEMS. In a 2000 consent decree, Tampa Electric Company agreed to install a PM CEMS on one of its coal-fired power plants in Florida to ensure compliance with PM limits. *See* Exhibit 7, *United States v. Tampa Electric Company*, Consent Decree (February 29, 2000) at 20. More recently, through a 2006 consent decree, two North Dakota utilities agreed to install PM CEMS at a coal-fired power plant in North Dakota. *See* Exhibit 8, *United States v. Minnkota Power Cooperative*, Consent Decree (April 24, 2006) at 26-28. Similarly, the EPA reached agreements with other utilities in Wisconsin and Illinois that have led to the installation, calibration, operation, and certification of PM CEMS. *See* Exhibits 9 and 10, *United States v. Wisconsin Electric Power Company*, Consent Decree (April 27, 2003) at 29-31; *United States v. Illinois Power*, Consent Decree (March 7, 2005) at 31-33. These consent decrees are implicit that PM CEMS are to be used to demonstrate compliance with PM limits.

Most recently, in proposed amendments to new source performance standards ("NSPS") for electric utility steam generating units, the EPA stated, "Based on our analysis of available data, there is no technical reason that PM CEMS cannot be installed and operate reliably on electric utility steam generating units." 70 Fed. Reg. 9865, 9872 (February 27, 2006). Although the final amendments to the NSPS for electric utility steam generating units did not require the utilization of PM CEMS, the EPA stated that PM CEMS may be used to demonstrate continuous compliance with particulate emission limits.

In comments, WildEarth Guardians stated that, "The use of PM CEMS would constitute sufficient periodic monitoring that will assure compliance with the particulate limits set forth in the Title V Permit. We request the APCD take advantage of its authority under 40 CFR § 70 to require the installation and operation of PM CEMS at the Pawnee coal-fired power plant through the Title V Permit." Exhibit 4 at 6. **In response, the Division did not deny that PM CEMS would ensure compliance with the requirements of 40 CFR §§ 70.6(a)(3)(i)(B) and 70.6(c)(1).** Indeed, the Division stated that it "agrees that a PM CEMS represents the most direct method to assure continuous compliance with emission limits." Exhibit 6 at 10.

Instead, the Division arbitrarily rejected requiring PM CEMS and restated its belief that the CAM requirements in the Title V Permit assure compliance with the particulate emission rate. However, as already explained, the CAM requirements do not assure compliance. The Division also pointed to EPA's NSPS for electric utility steam generating units, in which the EPA stated that when PM CEMS are not utilized, it may be appropriate to use "site-specific opacity triggers" to ensure continuous compliance. Yet as already explained, the Title V Permit does not actually state that an exceedance of any site-specific opacity trigger represents a violation of the particulate standards at Section II, Condition 1.1. Furthermore, the NSPS require that when a site-specific opacity trigger is utilized in conjunction with the use of a fabric filter baghouse, a bag leak detection system be utilized to ensure compliance with particulate limits in accordance with 40 CFR § 60.48Da(o)(4). As the EPA stated, "[S]ources shall use bag leak detectors…in addition to developing a site-specific opacity trigger level[.]" 70 Fed. Reg. 9865, 9872 (February 27, 2006). The Title V Permit does not require that a bag leak detection system be utilized. Thus, the Division's reliance on the EPA's NSPS to justify its periodic monitoring determination is misplaced. If anything, the NSPS merely underscore the fact that the Division has failed to require sufficient periodic monitoring for particulate matter to ensure compliance with the limits at Section II, Condition 1.1.

The Division's response to Petitioner's comment do not provide a rational basis for rejecting the use of PM CEMS as a means of assuring compliance with the particulate emission rate in the Title V Permit and the requirements of 40 CFR §§ 70.6(a)(3)(i)(B) and 70.6(c)(1). The Administrator must object to the issuance of the Title V Permit based on the Division's arbitrary rejection of PM CEMS as a means to assure compliance with the particulate rate at Section II, Condition 1.1.

III. THE TITLE V PERMIT FAILS TO ENSURE COMPLIANCE AND SUFFICIENTLY MONITOR FUGITIVE PARTICULATE EMISSIONS

The Title V Permit sets forth limits on particulate matter, including PM_{10}, from fugitive sources associated with coal handling and storage, ash handling and disposal, and paved and unpaved roads. *See* Exhibit 1 at 18, Section II, Condition 4.1. Unfortunately, the Title V Permit fails to ensures compliance with these limits and fails to include adequate monitoring requirements sufficient to assure compliance in accordance with 40 CFR §§ 70.6(a)(3)(i)(B) and 70.6(c)(1). The Administrator must therefore object on this issue for the reasons set forth below.[5]

A. The Title V Permit Does not Actually Require Monitoring of Particulate Matter or PM_{10} from Coal Handling and Storage, Ash Handling and Disposal, and Paved and Unpaved Roads

To begin with, The Title V Permit requires no actual monitoring of particulate matter from fugitive sources associated with coal handling and storage, ash handling and disposal, and paved and unpaved roads. As a threshold matter, the Title V Permit fails to require sufficient periodic monitoring because it does not require any actual monitoring of particulate emissions from these sources.

[5] WildEarth Guardians raised objections with reasonable specificity with regards to the adequacy of the Title V Permit at Section II, Condition 4 in comments. *See* Exhibit 4 at 7-8. WildEarth Guardians concerns focused on the failure of the Title V Permit to ensure compliance with opacity limits. In response, the Division asserted that the opacity limits under Section II, Condition 4 were unenforceable in accordance with the Colorado SIP and asserted instead that provisions related to the control of fugitive particulate emissions were sufficient under Title V. *See* Exhibit 6 at 11-13. Thus, to the extent the Administrator may not believe that WildEarth Guardians' objections related to the adequacy of Section II, Condition 4 were raised with reasonable specificity during the public comment period, the grounds for objection arose after the public comment period based on the Division's response to comments.

The Title V Permit states that, "In the absence of credible evidence to the contrary, compliance with the PM and PM_{10} emission limits are presumed provided the material handling limits (Condition 4.3) are met and control measures (Conditions 4.2 and 4.4 are followed)." Exhibit 1 at 18. However, Section II, Conditions 4.2, 4.3, and 4.4 do not actually require monitoring of particulate emissions from fugitive sources associated with coal handling and storage, ash handling and disposal, and paved and unpaved roads.

B. Conditions 4.2, 4.3, and 4.4 Fail to Limit Particulate Matter, are Unenforceable and/or Fail to Constitute Sufficient Monitoring

Compounding the failure of the Title V Permit to require monitoring of particulate emissions from fugitive sources associated with coal handling and storage, ash handling and disposal, and paved and unpaved roads is that the provisions of Section II, Conditions 4.2, 4.3, and 4.4 are unenforceable and/or fail to constitute sufficient monitoring in accordance with Title V and Title V regulations.

(1) Condition 4.2

Condition 4.2 states that "the source shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions." Exhibit 1 at 19. However, this Condition does not actually require that control measures and operating procedures be implemented in order to meet the particulate limits at Section II, Condition 4.1, only that emissions be "minimized." Furthermore, "minimized" is vague and undefined. It is unclear exactly what "minimized" means. In fact, the tables at Section II, Condition 4 of the Title V Permit explicitly state "N/A" with regards to minimizing emissions, at least for coal handling and storage and paved and unpaved roads, indicating there is no standard for minimizing emissions.

The Condition also states that a "fugitive dust control plan, or a modification to an existing plan" shall be required to be submitted only "if the Division determines that for this source or activity visible emissions are in excess of 20% opacity; or visible emissions are being transported off the property; or if this source or activity is operating with emissions that create a nuisance." Exhibit 1 at 19, Section II, Condition 4.2.1.[6] This provision indicates that a fugitive dust control plan may not even be required to address fugitive particulate emissions from coal handling and storage, ash handling and disposal, and paved and unpaved roads, which seems to imply that the control measures required by Section II, Condition 4.2 may also not be required. Indeed, the SIP states that AQCC Regulation No. 1, Section III.D. is only enforceable "through the procedures specified...in Section III.D.1.b. through III.D.1.e." AQCC Regulation No. 1, Section III.D.1.a.(iii)., 5 CCR 1001-3 Section III.D.1.a.(iii). The procedures in Regulation No. 1, Section III.D.1.b. through III.D.1.e. restate that a fugitive particulate matter control plan is only required:

[6] This Condition references a "fugitive dust" control plan, however the underlying authority as identified in the Title V Permit, AQCC Regulation No. 1, Section III.D.1.c., refers to a "fugitive particulate" control plan.

> If the Division determines that a source of activity which is subject to this Section III.D. (whether new or existing) is operating with emissions in excess of 20% opacity and such source is subject to the 20% emission limitation guideline; or if it determines that the source or activity which is subject to this Section III.D. is operating with visible emissions that are being transported off the property on which the source is located and such source is subject to the no off property transport emission limitation guideline; or if it determines that any source or activity which is subject to this Section III.D. is operating with emissions that create a nuisance[.]

AQCC Regulation No. 1, Section III.D.1.c. Thus, as a practical matter, the Title V Permit, as echoed in the Colorado SIP, allows Xcel Energy to avoid controlling fugitive particulate matter altogether. This hardly serves to ensure compliance with the particulate limits at Section II, Condition 4.1.

Although we do not take issue with the Colorado SIP, we do take issue with the fact that the Title V Permit relies on Section II, Condition 4.2 to ensure compliance with the applicable particulate emission limits set forth at Condition 4.1. Although the Title V Permit must include the underlying requirements within the Colorado SIP, the Title V Permit must supplement those requirements with terms and conditions necessary both to ensure the enforceability of and to ensure compliance with the limits for fugitive particulate emissions from coal handling and storage, ash handling and disposal, and paved and unpaved roads at the Pawnee coal-fired power plant. The Administrator must object to the Title V Permit on the basis that Condition 4.2 fails to ensure compliance with the fugitive particulate emission limits at Section II, Condition 4.

(2) Condition 4.3

Section II, Condition 4.3 simply sets limits on materials processing, in this case coal unloading and fly ash disposed. However, there is no information provided or referenced in the Title V Permit or the TRD indicating that meeting the relevant materials processing limits will in fact ensure compliance with the fugitive particulate emission limits set forth at Section II, Condition 4.1. There does not appear to be any correlation between the materials processing limits and particulate emissions that would support a finding that compliance with the limits at Condition 4.3 automatically ensures compliance with the particulate limits at Condition 4.1.

(3) Condition 4.4

It is unclear whether Section II, Condition 4.4 is enforceable. Based on our concerns over Section II, Condition 4.2 stated above, it appears that Xcel Energy is not actually required to follow the fugitive particulate control requirements of Condition 4.4. unless the Division "determines that for this source or activity visible emissions are in excess of 20% opacity; or visible emissions are being transported off the property; or if this source or activity is operating with emissions that create a nuisance." This is problematic. For one thing, there are no opacity or visible emissions monitoring requirements set forth in Section II, Condition 4, which at a minimum would be necessary to determine whether a fugitive particulate matter control plan is required. Most importantly however, if the control measures set forth at Condition 4.4 do not have to be followed, there is no basis for concluding that the fugitive particulate limits for coal handling and storage, ash handling and disposal, and paved and unpaved roads will be met.

Adding to this, several of the measures set forth at Condition 4.4 are vague and unenforceable as a practical matter. For instance, while Section II, Condition 4.4.1.1 states that "Water shall be sprayed on the ash pit as necessary to minimize fugitive emissions [from ash handling and disposal]," it is unclear exactly when water must be sprayed on the ash pit, to what extent fugitive emissions must be minimized, and how exactly this measure will ensure particulate emissions from the ash pit will not exceed the limits in Section II, Condition 4.1. Furthermore, the Title V Permit actually requires no monitoring, recordkeeping, or reporting requirements to ensure compliance with Condition 4.4.1.1. Although a semi-annual compliance certification is required in accordance with Section II, Condition 4.4, a compliance certification fails to provide reliable data demonstrating that a source compliance with the control measures at Condition 4.4. Similarly, with regards to Section II, Condition 4.4.2.1, which sets a vehicle speed limit of no more than 15 miles per hour, the Title V Permit requires no monitoring, recordkeeping, or reporting to ensure compliance with this control measure. Condition 4.4.2.2, which requires that active unpaved haul roads be watered on a daily basis, suffers from the same flaws.

Finally, Section II, Condition 4.4 does not actually prescribe any measures to control fugitive particulate emissions from coal handling and storage, making it even more inappropriate for the Division to have relied on this Condition to ensure compliance with the fugitive particulate emission limits set forth in Condition 4.1.

C. The Title V Permit Fails to State that Failure to Comply with Conditions 4.2, 4.3, or 4.4 Constitutes a Violation of Particulate Limits

The Title V Permit finally fails to ensure compliance with the fugitive particulate standards at Section II, Condition 4.1 because it does not actually state that the failure to comply with any provision of Section II, Conditions 4.2, 4.3, and 4.4 constitutes a violation of the particulate emission limits. The Title V Permit states that, "In the absence of credible evidence to the contrary, compliance with the PM and PM_{10} emission limits are presumed provided the material handling limits (Condition 4.3) are met and control measures (Conditions 4.2 and 4.4 are followed)." Exhibit 1 at 18. This statement is problematic because while it presumes that compliance with the particulate standards is met when Section II, Conditions 4.2, 4.3, and 4.4 are met, it is unclear whether it presumes noncompliance with the particulate standards when any provision of Section II, Condition 4.2, 4.3, and 4.4 is not met. The Administrator must object to the issuance of the Title V Permit because nothing in the Permit actually states that a failure to comply with any provision of Condition 4.2, 4.3, and 4.4 constitutes a violation of the particulate limits at Section II, Condition 4.1.

IV. THE 20 PERCENT OPACITY LIMIT UNDER NSPS SUBPART Y APPLIES TO COAL UNLOADED TO STORAGE

The Administrator must object to the issuance of the Title V Permit because it fails to ensure compliance with NSPS Subpart Y with regards to coal unloaded to storage activities at the Pawnee coal-fired power plant. The NSPS at Subpart Y apply to coal preparation and processing plants. Both in the TRD and in response to comments, the Division asserted that the NSPS Subpart Y in effect at the time of the Title V Permit issuance did not apply to coal unloaded to storage activities at the Pawnee coal-fired power plant. The Division's assertion is simply wrong.

Indeed, the Division's assertion is based on EPA's 1998 interpretation of the NSPS at 40 CFR Part 60, Subpart Y, which was published October 5, 1998 (63 Fed. Reg. 53288-43290). The 1998 interpretive rule appeared to exclude coal unloading to coal storage areas from its 20% opacity requirement. This interpretation was not explained nor was there a rational basis for this exclusion. While courts typically give some deference to interpretive rules, they do not merit *Chevron* deference, nor do they have any legally binding effect. *See U.S. v. Mead Corp.*, 533 U.S. 218, 232 (2001). In this case, the NSPS in effect clearly applied to "coal storage systems, and coal transfer and loading systems" that processes more than 200 tons/day. *See* 40 CFR § 60.250 (2008). In this case, the Division failed to demonstrate that coal unloaded to storage at the Pawnee coal-fired power plant is not a "coal storage system, and coal transfer and loading system" that processes more than 200 tons/day, and therefore not subject to the NSPS at Subpart Y. The Administrator must therefore object to the issuance of the Title V Permit.

V. THE TITLE V PERMIT FAILS TO ENSURE COMPLIANCE AND SUFFICIENTLY MONITOR PARTICULATE EMISSIONS FROM POINT SOURCES

The Title V Permit further fails to ensure compliance with particulate limits, including PM_{10} limits, from point sources under Section II, Condition 5, including the coal handling system, ash silo, soda ash handling system, and sorbent storage silos. The Title V Permit fails to ensure sufficient monitoring and lacks enforceable standards to assure compliance in accordance with Title V. The EPA must object to the Title V Permit for the reasons set forth below.

A. Section II, Condition 5 Requires no Actual Monitoring of Particulate Emissions

To begin with, the Title V Permit does not actually require any monitoring of particulate emissions from any point associated with the coal handling system, ash silo, soda ash handling system, and sorbent storage silos. As a practical matter, the Title V Permit does not require sufficient monitoring that provides reliable data from the relevant time period that is representative of the source's compliance with the particulate limits, in violation of 40 CFR § 70.6(a)(3)(i)(B).

B. Condition 5.1

Section II, Condition 5.1 establishes presumptive compliance with the PM and PM_{10} limitations for the coal handling system. Presumptive compliance is based on fulfilling the work practices listed in Conditions 5.1.1 through 5.1.5. *See* Exhibit 1 at 22, Section II, Condition 5.1.6. As explained below, however, these conditions are vague and unenforceable, and a system of presumptive compliance is insufficient to ensure that the particulate matter limitations are met.

To begin with, Section II, Condition 5.1.1, which relates to operation of the plant transfer tower/tripper deck and crusher baghouses, is vague and unenforceable because it does not define "good engineering practices." This undefined term implies certain practices, but it does not state what they are or explain whether such practices will actually ensure compliance with the applicable particulate emission limits. Moreover, these conditions do not state how operation in accordance with good engineering practices will be reported or monitored. Without any periodic monitoring requirements, this condition is unenforceable as a practical matter and in violation of 40 CFR § 70.6(a)(3)(i)(B). At a minimum, the Title V Permit must describe periodic monitoring that is sufficient to assess whether "good engineering practices" have been followed. To achieve this, the Title V Permit must define "good engineering practices" so that there is a standard to which actual operations can be compared.

Section II, Condition 5.1.3, which relates to the operation of conveyors and crushers, is vague and unenforceable because it does not define "integrity of the enclosures," nor does it state how such integrity will be maintained to prevent particulate emissions. Moreover, 5.1.3 does not explain what "used as necessary" means with regards to the operation of water spray suppression systems. Furthermore, there is no reporting or monitoring to ensure compliance with this requirement. To ensure compliance with this condition, the Title V Permit must include periodic monitoring of the conveyor and crusher enclosures and periodic monitoring of the use of the water spray suppression systems. Without such monitoring, Condition 5.1.3 is in violation of 40 CFR § 70.6(a)(3).

Section II, Condition 5.1.5, which relates to the number of transfer points, does not contain any periodic monitoring, thus it also violates 40 CFR § 70.6(a). The transfer points must be identified and reported in the Title V Permit so that the number of transfer points can be monitored to ensure compliance with the 13-transfer point limit in 5.1.5.

C. Condition 5.6

Conditions 5.6.2 and 5.6.3 also use the term "good engineering practices" without defining what that term means. These conditions fail to comply with 40 CFR § 70.6(a)(3)(i)(B) for the same reasons that Condition 5.1.1 fails, as described above. Sufficient periodic monitoring must be added to the Title V Permit to assure compliance with the relevant good engineering practices that are implied (but not properly explained) by Conditions 5.6.2 and 5.6.3.

D. Conditions 5.7 and 5.8

Although in response to WildEarth Guardians' comments, the Division agreed to revise Section II, Condition 5.7 to require annual Method 9 observations to assure compliance with the opacity limits for the transfer tower/tripper deck and crusher baghouses, it is unclear how a one-per-year Method 9 reading will provide reliable data that is representative of the source's compliance with the applicable opacity limits. This concern is bolstered by the fact that the opacity limit applies continuously, not annually. It is unclear how annual monitoring can assure continuous compliance with the applicable 20% opacity limit.

Section II, Conditions 5.7 and 5.8 are also problematic because they fail to require sufficient periodic monitoring to ensure compliance with opacity limits for other coal handling system point sources, besides the transfer/tower/tripper deck and crusher baghouses. Indeed, Conditions 5.7 and 5.8 are clear that opacity emissions from all point sources associated with the coal handling system shall not exceed 20%, including from crushers and conveyors 7 through 13, 17, and 18. Both Conditions 5.7 and 5.8 state that these opacity requirements "shall be presumed to be in compliance" if Section II, Conditions 5.1.1 through 5.1.3 are being met. As previously described however, Conditions 5.1.1 and 5.1.3 do not define key standards nor do they contain sufficient monitoring to ensure compliance with applicable requirements. Due to these failures, it will be impossible to ensure compliance with the opacity limits Conditions 5.7 and 5.8.

Moreover, even if Conditions 5.1.1 and 5.1.3 were corrected to include monitoring, presumptive compliance with the opacity requirements is not sufficient to comply with 40 CFR § 70.6(c)(1). If permit terms and conditions include monitoring but that monitoring is insufficient to ensure compliance with terms and conditions, the permitting authority must supplement the permit so that the Title V Permit meets Title V requirements. *See* Sierra *Club v. EPA*, 536 F.3d 673, 678 (D.C. Cir. 2008). Actual monitoring of opacity for all point sources associated with the coal handling system, including all sources subject to NSPS Subpart Y, must be written into the Title V Permit to assure compliance. The Administrator must therefore object to the issuance of the Title V Permit due to its failure to provide sufficient monitoring to assure compliance with opacity limits applicable to the coal handling system set forth at Section II, Conditions 5.7 and 5.8.

VI. THE TITLE V PERMIT FAILS TO ENSURE COMPLIANCE WITH AIR TOXIC LIMITS UNDER SECTION 112(J) OF THE CLEAN AIR ACT

The Title V Permit fails to assure compliance with section 112(j), 42 USC § 7412(j), of the Clean Air Act. In particular, the Title V Permit fails to assure compliance with case-by-case maximum achievable control technology ("MACT") requirements for the electric utility steam generating unit ("EGU") in operation at the Pawnee coal-fired power plant.

Indeed, the Title V Permit fails to assure compliance with Section 112(j) in the context of mercury and other hazardous air pollutant ("HAP") emissions from the EGU in operation at the Pawnee coal-fired power plant. As the TRD notes, "on February 8, 2008 a DC Circuit Court vacated the CAMR regulations for both new and existing units." Exhibit 2 at 7. In particular, the D.C. Circuit held in early 2008 that the EPA had inappropriately delisted EGUs from the list of sources whose emissions are regulated under Section 112 of the Clean Air Act. In light of this ruling, as well as the EPA's failure to promulgate a MACT standard for EGUs, the Division was required to develop a case-by-case MACT for the EGU in operation at the Pawnee coal-fired power plant and to include such case-by-case MACT in the Title V Permit. Such a case-by-case MACT was required to include mercury emission limits, as well as limits for other HAPs regulated under Section 112 of the Clean Air Act, such as lead compounds, hydrofluoric acid, and hydrochloric acid. It was especially critical for the Division to assure compliance with Section 112 given that the TRD discloses that the Pawnee coal-fired power plant is indeed a major source of HAPs. *See* Exhibit 2 at 5.

In response to WildEarth Guardians' comments, the Division asserted, "Although electric utility steam generating units (EUSGUs) were added to the list of source categories in Section 112(c) in December 2000, a deadline for promulgation of those standards was never set. Therefore, the case-by-case MACT requirements of 112(j) do not apply to EUSGUs." Exhibit 6 at 17. This response is misplaced. For one thing, there was a deadline for promulgation of MACT standards for EGUs. This deadline was "within 2 years after the date" on which EGUs were added to the list of source categories under Section 112, in accordance with Section 112(c)(5), 42 USC § 7412(c)(5), therefore putting the deadline at December 2002. Pursuant to Section 112(j), a case-by-case MACT standard was required 18 months after the deadline for promulgation of a MACT standard, and thus Section 112(j) requirements have applied since May 2004. The Division's rationale for determining Section 112(j) is not an applicable requirement with regards to the EGU is therefore unsupported.

Although it may be argued that Section 112(j) simply does not apply to EGUs on the basis that they may not be subject to the schedule for MACT promulgation set forth under Section 112(e)(1) or (3) due to the fact that they were added as a source category under Section 112 subsequent to the Clean Air Act Amendments of 1990, this argument makes little sense. For one thing, Section 112(e)(1) and (3) specifically reference Section 112(c)(1), which explicitly provides that the list of source categories promulgated under Section 112 may be periodically revised. Section 112(c)(5) of the Clean Air Act sets forth the standards for listing new source categories, as provided for under Section 112(c)(1), and sets forth deadlines for MACT promulgation for new sources. Taken together, Section 112(j)'s reference to Section 112(e)(1) and (3), which in turn references Section 112(c)(1), appears to strongly indicate that Section 112(j) requirements were meant to apply to new source categories listed under Section 112(c)(1) in accordance with Section 112(c)(5). To that end, it would make little sense in light of the purpose of Section 112(j), which is to ensure that all major sources of toxic pollutants meet strict regulatory standards, even when issuance of national MACT standards are delayed, to allow newly added source categories to somehow escape the application of Section 112(j).

The Administrator must therefore object to the issuance of the Title V Permit. Not only is the Division's rationale for not assuring compliance with Section 112(j) baseless, but clearly the Pawnee coal-fired power plant is subject to case-by-case MACT requirements under Section 112(j).

VII. The Title V Permit Fails to Ensure Compliance with Prevention of Significant Deterioration Requirements in Regards to Carbon Dioxide Emissions

In issuing the Title V Permit, the Division failed to appropriately assess whether CO_2 is subject to regulation in accordance with PSD requirements and therefore failed to ensure compliance with PSD under the Clean Air Act, PSD regulations, and the Colorado SIP. Of particular concern is that the Division failed to assess the source's PSD compliance status in the context of CO_2 and therefore failed to ensure that the Title V Permit assures compliance with all applicable requirements.

Under Colorado regulations incorporated into the SIP, any source that emits more than 250 tons per year "of any air pollutant subject to regulation under the Federal Act" is subject to PSD permitting requirements, including the requirement that BACT be utilized to keep air emissions in check. *See* Air Quality Control Commission ("AQCC") Regulation Number 3, Part D § VI.A.1.a; *see also* 42 U.S.C. § 7475(a) and 40 C.F.R. § 51.166(j)(2). Similarly, the SIP requires that any major source that undergoes a modification leading to a significant emissions increase is also required to utilize BACT. AQCC Regulation No. 3, Part D § VI.A.1.b. The Clean Air Act makes clear that the BACT requirements extend to "each pollutant subject to regulation" under the Act. 42 U.S.C. § 7479(3) and 40 C.F.R. § 52.21(b)(12); *see also* AQCC Regulation No. 3, Part D § II.A.8. In this case, the Division failed to assess whether CO_2 is subject to regulation in accordance with PSD and whether the Title V Permit ensures compliance with PSD requirements under the Colorado SIP, the Clean Air Act, and PSD regulations in relation to CO_2 emissions from the Pawnee coal-fired power plant.

A. The Division did not Assess Whether Carbon Dioxide is Subject to Regulation under the Clean Air Act, in accordance with the Recent Environmental Appeals Board Ruling

At issue is the fact that the Division has inappropriately relied on EPA's interpretation of the phrase "subject to regulation" when issuing the Title V Permit and completely ignored whether CO_2 emissions should be limited by the application of BACT as required by PSD provisions in the Colorado SIP, the Clean Air Act, and PSD regulations. The EAB determined this interpretation fails to set forth "sufficiently clear and consistent articulations of an Agency interpretation to constrain" authority the EPA would otherwise have under the Clean Air Act. *Deseret Power*, slip op. at 37. In light of the EAB's ruling, it was therefore inappropriate for the Division to ignore CO_2 emissions by relying on EPA's prior interpretation of the phrase "subject to regulation" when issuing the Title V Permit.

Although EPA may claim that a December 18, 2008 interpretive memo issued by former EPA Administrator Stephen Johnson (hereafter "Johnson memo") "clarifies" EPA's position that CO_2 is not subject to regulation under PSD requirements (*see* Memorandum from Stephen L. Johnson, Administrator, to all Regional Administrators, "EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program" (December 18, 2008)) and therefore addresses the EAB's ruling, this is simply not true in this case. For one thing, the Johnson memo is clear that it does not bind states, such as Colorado, that administer the PSD program under their own SIP. Thus, the Johnson memo does not absolve the Division from rendering its own, independent interpretation of the meaning of the phrase "subject to regulation" as set forth in the Colorado SIP.

This is a major oversight on the Division's part. Indeed, the Colorado SIP appears to support a finding that CO_2 emissions are subject to regulation, and therefore subject to PSD requirements. Although the phrase "subject to regulation" is not explicitly defined in the Colorado SIP, there are three reasons to interpret the Colorado SIP to allow the State of Colorado to find that CO_2 emissions are subject to regulation under the Clean Air Act.

First, the U.S. Supreme Court recently held in *Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), that CO_2 is a "pollutant" under the Clean Air Act. Although the EAB noted that the *Massachusetts* decision "did not address whether CO_2 is a pollutant 'subject to regulation' under the Clean Air Act" (*Deseret Power*, slip op. at 8) the EAB did not reject the interpretation that the decision supports a finding that CO_2 emissions are subject to regulation under the Clean Air Act. In fact, the EAB noted that the *Massachusetts* decision rejected key EPA memos that were relied upon when interpreting the phrase "subject to regulation" (*see e.g.*, *Id.* at 52, "The reasoning of the Fabricant Memo was subsequently rejected and overruled by the Supreme Court in *Massachusetts v. EPA*, 549 U.S. 497, slip op. at 29-30 (2007)").

Second, CO_2 is explicitly regulated by the Colorado SIP. In fact, AQCC Regulation No. 1 § VII. contains specific provisions requiring Public Service Company of Colorado monitor CO_2 at its coal-fired power plants. The Title V Permit also explicitly requires Xcel Energy to "install, certify and operate" CO_2 CEMs at the Pawnee coal-fired power plant. *See* Exhibit 1 at 8, Section II, Condition 1.8.

Finally, CO_2 is "subject to regulation" because it falls under the definition of "air pollutant" set forth in the Colorado SIP. Indeed, the AQCC Common Provisions Regulation, which is incorporated into the Colorado SIP, defines air pollutant as:

> Any fume, smoke, particulate matter, vapor, gas or any combination thereof that is emitted into or otherwise enters the atmosphere, including, but not limited to, any physical, chemical, biological, radioactive (including source material, special nuclear material, and by-product materials) substance or matter, but not including water vapor or steam condensate or any other emission exempted by the commission consistent with the Federal Act.

CO_2 is a gas that is emitted into the atmosphere, and therefore clearly regulated as a pollutant under the Colorado SIP. Furthermore, this definition derives directly from the Colorado Air Pollution and Prevention Control Act (*see* CRS § 25-7-103(1.5), a fact that seems to compel a finding that CO_2 is "subject to regulation" under the PSD. Indeed, the SIP explicitly states that PSD provisions apply "to any major stationary source and major modification **with respect to each pollutant regulated under the [Colorado Air Pollution and Prevention Control] Act** and the Federal Act that it would emit, except as this Regulation No. 3 would otherwise allow." AQCC Regulation No.3, Part D § VI.A. (emphasis added). The Colorado Air Pollution and Prevention Control Act clearly regulates CO_2, therefore the Colorado SIP seems to make clear that PSD provisions apply to any major sources and modifications with respect to CO_2 emissions.

Thus, not only has the recent EAB decision called into question the validity of the Division's failure to address CO_2 emissions in order to ensure the Title V Permit assures compliance with PSD requirements under the Clean Air Act, PSD regulations, and the Colorado SIP, but it appears as if the Division's failure to address CO_2 emissions in the context of PSD is contrary to the Colorado SIP. The Administrator must therefore object to the issuance of the Title V Permit to ensure a consistent and reasonable interpretation of PSD in the context of CO_2 emissions from the Pawnee coal-fired power plant.

B. Significant Increases in CO_2 Emissions Have Occurred at the Pawnee Coal-fired Power Plant

The need for Administrator to object and the Division to appropriately assess whether CO_2 emissions should be limited by the application of BACT as required by the Clean Air Act, PSD regulations, and the Colorado SIP, is especially evident in light of the fact that significant increases in CO_2 emissions have occurred at the Pawnee coal-fired power plant over the years. Based on data from the EPA's Clean Air Market's website, between the years 1998 and 2008, net CO_2 emissions increases occurred at the plant in 2000, 2001, 2003, 2006, and 2007.[7] *See* Table below. In 2006 alone, a more than 600,000 ton/year net increase in CO_2 emissions occurred at the Pawnee coal-fired power plant.

Pawnee CO_2 Emissions, 1997-2007.
***See* Emissions Data Attached as Exhibit 5.**

Two-year Baseline	Average Baseline CO_2 Emissions (tons/year)	Year	Total CO_2 Emissions(tons/year)	Increase/ Decrease (tons/year)
2007/2006	4283151.75	2008	3837802.3	-445349.45
2006/2005	4000332.30	2007	4097660.4	**97328.1**
2005/2004	3862073.70	2006	4468643.1	**606569.4**
2004/2003	4432818.70	2005	3532021.5	-900797.2
2003/2002	4320938.65	2004	4192125.9	-128812.75
2002/2001	4604664.10	2003	4673511.5	**68847.4**
2001/2000	4966282.65	2002	3968365.8	-997916.85
2000/1999	4693548.80	2001	5240962.4	**547413.6**
1999/1998	4221244.05	2000	4691602.9	**470358.85**

Under the Colorado SIP, a net increase in any pollutant "subject to regulation" under either the Colorado Air Pollution and Prevention Control Act or the Clean Air Act, but not specifically listed in the Colorado SIP, is "significant" at "any emissions rate." AQCC Regulation No. 3, Part D § II.A.44.b. If CO_2 is subject to regulation under the Colorado SIP, then any increase in emissions at a major stationary source is significant and triggers BACT requirements.

Because the Pawnee coal-fired power plant is a major stationary source under PSD, the increases in CO_2 emissions reported in 2000, 2001, 2003, 2006, and 2007 would be significant and would therefore trigger BACT requirements if it is determined that CO_2 emissions are

[7] Net emission increases and decreases were calculated by averaging actual CO_2 emissions from a consecutive 24-month period (i.e., the baseline) and comparing that average with actual emissions reported for the following year, a method similar to the "actual-to-projected-actual" PSD applicability test set forth in PSD regulations at 40 CFR § 51.166(a)(7)(iv)(*c*).

subject to regulation under the Colorado SIP. Coupled with the EAB's recent ruling and the Division's failure to adequately address whether CO_2 is subject to regulation under the Colorado SIP, these emission increases underscore the need for the Administrator to object to the issuance of the Title V Permit.

CONCLUSION

For the reasons stated above, Petitioner requests the Administrator object to the Title V Permit issued by the Division for the Pawnee coal-fired power plant. The Administrator has a nondiscretionary duty to issue an objection to the Title V Permit within 60 days in accordance with Section 505(b)(2) of the Clean Air Act.

Respectfully submitted this 20th day of February 2010

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Director
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Denver, CO 80246

TABLE OF EXHIBITS

1. Public Service Company of Colorado, Pawnee Station Title V Permit, Permit Number 96OPMR129 (January 1, 2010).
2. Technical Review Document for Renewal/Modification of Operating Permit 96OPMR129 (January 1, 2010).
3. 2008 Emissions Data for Pawnee Station from EPA Acid Rain Program Emissions Database.
4. WildEarth Guardians Comments on Proposed Title V Permit (July 3, 2009).
5. Emissions Data for Pawnee Station from EPA Acid Rain program Database
6. Colorado Air Pollution Control Division Response to Comments from WildEarth Guardians on Draft Pawnee Title V Permit (November 6, 2009).
7. *United States v. Tampa Electric Company*, Consent Decree (February 29, 2000).
8. *United States v. Minnkota Power Cooperative*, Consent Decree (April 24, 2006).
9. *United States v. Electric Power Company*, Consent Decree (April 27, 2003).
10. *United States v. Illinois Power*, Consent Decree (March 7, 2005).

Exhibit 1 to Title V Petition

Colorado Department of Public Health and Environment

OPERATING PERMIT

Public Service Co - Pawnee Station

First Issued: January 1, 2003
Renewed: January 1, 2010

AIR POLLUTION CONTROL DIVISION
COLORADO OPERATING PERMIT

FACILITY NAME:	Pawnee Station	OPERATING PERMIT NUMBER
FACILITY ID:	0870011	**96OPMR129**
RENEWED:	January 1, 2010	
EXPIRATION DATE:	January 1, 2015	
MODIFICATIONS:	See Appendix F of Permit	

Issued in accordance with the provisions of Colorado Air Pollution Prevention and Control Act, 25-7-101 et seq. and applicable rules and regulations.

ISSUED TO:	PLANT SITE LOCATION:
Public Service Company P. O. Box 840 Denver, CO 80201-0840	14940 County Road 24 Brush, CO 80723 Morgan County

INFORMATION RELIED UPON

Operating Permit Renewal Application Received:	November 20, 2006
And Additional Information Received:	December 19, 2008 and May 7, 14 and 28, 2009

Nature of Business:	Coal-Fired Electric Generating Station
Primary SIC:	4911

RESPONSIBLE OFFICIAL		FACILITY CONTACT PERSON	
Name:	Steve Mills	Name:	Dean Metcalf
Title:	General Manager – Power Generation, Colorado	Title:	Director, Air and Water
Phone:	(303) 628-2679	Phone:	(720) 497-2007

SUBMITTAL DEADLINES

Semi-Annual Monitoring Period:	January 1 – June 30, July 1 – December 31
Semi-Annual Monitoring Report:	Due on August 1, 2010 & Feb. 1, 2011 & subsequent years
Annual Compliance Period:	January 1 to December 31
Annual Compliance Certification:	Due on February 1, 2011 & subsequent years

Note that the Semi-Annual Monitoring Reports and Annual Compliance Certifications must be received at the Division office by 5:00 p.m. on the due date. Postmarked dates will not be accepted for the purposes of determining the timely receipt of those reports/certifications.

FOR ACID RAIN SUBMITTAL DEADLINES SEE SECTION III.4 OF THIS PERMIT

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SECTION I - General Activities and Summary

1. Permitted Activities

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

In December 2008, the source submitted an application to incorporate the mercury limits from Colorado Regulation No. 6, Part B, Section VIII into their permit. In order to meet the mercury limits, the source is proposing to use an activated carbon (sorbent) injection system as a primary control option for mercury with a chemical injection system to be considered as a secondary control option (either in conjunction with the sorbent injection system or as a stand-alone mercury control system). As part of the sorbent injection system, the source proposes to construct and operate two sorbent storage silos. The appropriate applicable requirements for these storage silos have been incorporated into the permit.

Public Service Company's (PSCo's) Pawnee Station is co-located with the Manchief Generating Station. Since the two facilities are located on contiguous and adjacent property, belong to the same industrial grouping (first two digits of the SIC code are the same) and are under common control (via a power purchase agreement with PSCo), they are considered a single stationary source for purposes of major stationary source new source review and Title V operating permit applicability. A separate Title V operating permit was issued for the Manchief Generating Station (01OPMR236). In addition, Boral Material Technologies, Inc. (BMTI) conducts ash conditioning, handling and blending operations at Pawnee station. BMTI is considered a support facility for PSCo's Pawnee Station and as such is considered a single source with PSCo's Pawnee Station and subsequently BMTI is also considered a single source with Manchief Generating Station. A separate Title V permit was issued for BMTI Pawnee Station (03OPMR244).

This facility is located at 14940 County Road 24, near Brush in Morgan County. The area in which the plant operates is designated as attainment for all criteria pollutants.

There are no affected states within 50 miles of the plant. There are no Federal Class I designated areas within 100 kilometers of the plant.

1.2 Until such time as this permit expires or is modified or revoked, the permittee is allowed to discharge air pollutants from this facility in accordance with the requirements, limitations, and conditions of this permit.

1.3 The Operating Permit incorporates the applicable requirements contained in the underlying construction permits, and does not affect those applicable requirements, except as modified during review of the application or as modified subsequent to permit issuance using the modification procedures found in Regulation No. 3, Part C. These Part C procedures meet all applicable substantive New Source Review requirements of Part B. Any revisions made using the provisions of Regulation No. 3, Part C shall become new applicable requirements for purposes of this Operating Permit and shall survive reissuance. Any requirements that were designated in the Compliance Order on Consent (issued February 27, 1996) as applicable requirements have been incorporated into this operating permit and shall survive reissuance as applicable requirements. This permit incorporates the applicable requirements (except as noted in Section II) from the following construction permits: EPA PSD Permit, 11MR674 and C-12,093-1 and –4.

1.4 All conditions in this permit are enforceable by US Environmental Protection Agency, Colorado Air Pollution Control Division (hereinafter Division) and its agents, and citizens unless otherwise specified. **State-only enforceable conditions are:** Permit Condition Number(s): Section II - Conditions 1.10 (Lead) and 1.16 (Mercury) and Section V - Conditions 3.d, 3.g. (last paragraph), 14 and 18 (as noted).

1.5 All information gathered pursuant to the requirements of this permit is subject to the Recordkeeping and Reporting requirements listed under Condition 22 of the General Conditions in Section V of this permit. Either electronic or hard copy records are acceptable.

2. Alternative Operating Scenarios

2.1 The permittee shall be allowed to make the following changes to its method of operation without applying for a revision of this permit.

2.1.1 The facility may use natural gas, No. 2 fuel oil or combination for startup, shutdown and flame stabilization as specified under Section II.

2.1.2 Evaporation of chemical cleaning solutions may be performed in Boiler No. 1 under the following conditions:

2.1.2.1 All air pollution control equipment shall be in operation during evaporation of cleaning solutions.

2.1.2.2 The permittee shall retain records, on site, of each cleaning event. These records shall include the date and time the event begins and ends and the amount and types of solutions used in the cleaning event.

2.2 The facility must, contemporaneously with making a change from one operating scenario to another, maintain records at the facility of the scenario under which it is operating (Colorado Regulation No. 3, Part A, Section IV.A.1). Either electronic or hard copy records are acceptable.

3. Prevention Of Significant Deterioration (PSD)

3.1 This facility is a major stationary source (potential to emit of any criteria pollutant $\geq$ 100 tpy) for the purposes of PSD review requirements (Colorado Regulation 3, Part D, Section VI). An EPA PSD Permit was issued on December 6, 1976. Future modifications to this facility resulting in a significant net emissions increase (see Reg 3, Part D, Section II.A.26 and 42) for any pollutant as listed in Regulation No. 3, Part D, Section II.A.42, or are major by themselves will result in the application of the PSD review requirements.

3.2 Operating Permits 02OPMR244 (BMTI – Pawnee) and 01OPMR236 (Manchief Generating Station) are to be considered in conjunction with this operating permit for purposes of determining the applicability or non-applicability of PSD regulations.

4. Accidental Release Prevention Program (112(r))

4.1 Based upon the information provided by the applicant, this facility is subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act).

5. Compliance Assurance Monitoring (CAM)

5.1 The following emission points at this facility use a control device to achieve compliance with an emission limitation or standard to which they are subject and have pre-control emissions that exceed or are equivalent to the major source threshold. They are therefore subject to the provisions of the CAM program as set forth in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV:

Units B001 – Unit 1 Boiler

See Section II, Condition 1.15 for compliance assurance monitoring requirements.

6. Summary of Emission Units

6.1 The emissions units regulated by this permit are the following:

Emission Unit Number	AIRS Stack Number	Facility Identifier	Description	Startup Date	Pollution Control Device
B001	001	B001	Boiler No. 1 (Unit 1), Foster Wheeler, Opposed Fired, Natural Circulation Boiler, Serial No. 2-79-2381, Rated at 5,346 mmBtu/hr. Coal Fired, with Natural Gas Used for Startup, Shutdown and Flame Stabilization.	November 1981 Baghouse and Low NO_X Burners with Over-Fire Air - December 1994 Sorbent Injection/ Chemical Injection - December 2011	Baghouse (PM), Low NO_X Burners with Over-Fire Air (NO_X) and Sorbent Injection and/or Chemical Injection (Hg)
B002	002	B002	Boiler No. 2 (Auxiliary Boiler), Babcock and Wilcox, Package Boiler, Model and Serial No. FM-2763, 98 mmBtu/hr. Natural Gas Fired.	November 1981	Uncontrolled
F001	003	F001	Fugitive Particulate Emissions from Coal Handling and Storage (Rail Car Unloading, Storage Pile and Coal Dozing)	November 1981	Water/Surfactant Sprays at Railcar Unloading
F002	006	F002	Fugitive Particulate Emissions from Ash Handling and Disposal	November 1981	Uncontrolled
F003	011	F003	Fugitive Particulate Emissions from Paved and Unpaved Roads	November 1981	Water Spray on Unpaved Roads
P001	004 and 005	P001	Coal Handling System (Crusher, Transfer Tower and Conveying)	November 1981	Baghouses for Crusher and Plant Transfer Tower/Tripper Deck, Water/Surfactant Spray Systems for Crusher and Live Storage Rotary Plow and Enclosures for Crushers and Conveyors
P002	006	P002	Ash Silo	November 1981	Baghouse
P003	013	P003	Soda Ash Handling System	November 1981	Baghouse
M001	012	M001	Cooling Water Tower, rated at 190,000 GPM	November 1981	Drift Eliminators
P004	021	P004	Two (2) Sorbent Storage Silos	December 2011	Baghouses

SECTION II - Specific Permit Terms

1. B001 - Boiler No. 1 (Unit 1) Rated at 5,346 mmBtu/hr, Coal Fired

Parameter	Permit Condition Number	Limitations Short Term	Limitations Long Term	Compliance Emission Factor	Monitoring Method	Monitoring Interval
Particulate Matter (PM)	1.1.	0.1 lbs/mmBtu		N/A	Baghouse Maintenance and Source Testing	See Condition 1.1.
Particulate Matter (PM and PM_{10}) - Emission Calculations	1.2.	N/A	N/A	From Source Testing Required By Condition 1.1	Calculation and Recordkeeping	Annually
SO_2	1.3.	1.2 lbs/mmBtu		N/A	Continuous Emission Monitor	Continuous, 3-Hour Rolling Average
NO_X	1.4.	0.7 lbs/mmBtu		N/A	Continuous Emission Monitor	Continuous, 3-Hour Rolling Average
Emission Calculations	1.5.	N/A	N/A	in lbs/ton SO_2 CEM NO_X CEM CO 0.50 VOC 0.06	Recordkeeping and Calculation	Annually
Coal Usage	1.6.	N/A	Coal: 2.9×10^6 tons/yr	N/A	Recordkeeping	Monthly
Coal Sampling	1.7.	N/A	N/A	N/A	ASTM Methods	See Condition 1.7.
Continuous Emission Monitoring Requirements	1.8.	N/A	N/A	N/A	See Condition 1.8.	
NSPS Subpart A General Provisions	1.9.	N/A	N/A	N/A	As Required by NSPS General Provisions	Subject to NSPS General Provisions
Lead (Pb) - **State Only**	1.10.	1.5 µg/SCM		See Condition 1.10	Modeling, Recordkeeping and Calculation	See Condition 1.10.
Opacity	1.11.	Not to Exceed 20%, Except as Provided for in 1.12 Below		N/A	Continuous Opacity Monitor	Continuous, Six Minute Intervals

Parameter	Permit Condition Number	Limitations Short Term	Limitations Long Term	Compliance Emission Factor	Monitoring Method	Monitoring Interval
Opacity	1.12.	For Certain Operational Activities - Not to Exceed 30% for a Period or Periods Aggregating More than Six (6) Minutes in Any 60 Consecutive Minutes		N/A	Continuous Opacity Monitor	Continuous, Six Minute Intervals
NSPS Opacity	1.13.	Not to Exceed 20% Except for one Six (6) Minute Average Not to Exceed 27% Per Hour		N/A	Continuous Opacity Monitor	Continuous, Six Minute Intervals
Acid Rain Requirements	1.14.	See Section III of this Permit			Certification	Annually
Compliance Assurance Monitoring Requirements	1.15.	See Condition 1.15			See Condition 1.15	
Mercury (Hg) **State-Only**	1.16	Beginning January 1, 2012: 0.0174 lb/GWh on a 12-month rolling average		N/A	Hg Monitoring System	Continuous

1.1 Particulate Matter (PM) emissions shall not exceed the limitation stated above (Colorado Regulation No. 1, Section III.A.1.c). Compliance with this standard shall be demonstrated by the following:

1.1.1 Maintaining and Operating the baghouses in accordance with the requirements identified in Condition 8.1.

1.1.2 Conducting performance tests in accordance with Condition 8.2.

During each of the performance tests conducted as required by this condition, a baseline opacity limit shall be established for the compliance assurance monitoring (CAM) requirements specified in Conditions 1.15. The value of the baseline opacity level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurement recorded during each of the test run intervals conducted for the performance test, and then adding the appropriate percent opacity (see table below) to the calculated average value for all of the test runs.

Results of PM performance test	Opacity to add-on
Less than or equal to 50% of the PM standard	5.0 %
Greater than 50% but less than or equal to 75 % of the PM standard	3.5 %
Greater than 75% of the PM standard	2.5 %

If the calculated opacity value (COMS average plus add-on) is less than 5.0 percent, then the opacity baseline level is set at 5.0 percent.

1.1.3 Following the compliance assurance monitoring requirements specified in Condition 1.15.

1.2 Annual emissions of PM and PM_{10} for the purposes of APEN reporting and payment of annual fees will be determined using the emission factor for PM determined from the source testing required in Condition 1.1 and the annual heat input in the following equation:

PM: $$\text{Tons/yr} = \frac{[\text{EF (lbs/mmBtu) x annual heat input (mmBtu/yr)}]}{2000 \text{ lbs/ton}}$$

PM_{10}: Tons/yr = 0.92 x (Annual Emissions of PM)

The annual heat input, from coal, shall be determined using the annual coal consumption and the average heat content of the coal, as determined by the required coal sampling in Condition 1.7.

1.3 Sulfur Dioxide (SO_2) emissions shall not exceed 1.2 lbs/mmBtu on a 3 hour rolling average (Colorado Regulation No. 1, Section VI.A.3.a.(ii) and VI.A.1). Compliance with this standard shall be monitored using the continuous emission monitor (CEM) required by Condition 1.8 of this permit.

1.4 Nitrogen Oxide (NO_X) emissions shall not exceed 0.7 lbs/mmBtu, on a 3-hour rolling average (40 CFR 60.44(a)(3) and 60.45(g)(3), as adopted by reference in Colorado Regulation No. 6, Part A). Compliance with this standard shall be monitored using the continuous emission monitor (CEM) required by Condition 1.8 of this permit.

Note that the NO_X emission limits are not applicable during times of startup, shutdown and malfunction. However, those instances during startup, shutdown and malfunction when the NO_X limitation is exceeded shall be identified in the Excess Emission Report required in Condition 9.5.

1.5 The emission factors listed above have been approved by the Division and shall be used to calculate emissions from the boiler (EPA's Compilation of Emission Factors (AP-42), dated September 1998, Section 1.1). Annual emissions for the purposes of APEN reporting and the payment of annual fees shall be calculated using the above emission factors and the annual coal usage, as required by Condition 1.6, in the following equation:

$$\text{Tons/yr} = \frac{[\text{EF (lbs/ton) x annual coal usage (tons/yr)}]}{2000 \text{ lbs/ton}}$$

Annual emissions of SO_2 and NO_X shall be determined from the Continuous Emission Monitors (CEMs) required by Condition 1.8.

1.6 Coal Usage shall not exceed the above limitations (Colorado Construction Permit 11MR675, as modified under the provisions of Section I, Condition 1.3). Coal consumed by the boiler shall be monitored and recorded monthly using belt scales and corporate records as necessary. Monthly coal consumption shall be summed and used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

1.7 Coal shall be sampled in accordance with the requirements identified in Condition 12. Vendor sample results from all coal shipments shall be used to determine the average heat, sulfur, ash and moisture content of the fuel used in monitoring compliance with permit conditions.

1.8 The source shall install, certify and operate continuous emission monitoring (CEM) equipment for measuring opacity, SO_2, NO_X (including diluent gas either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 75). The CEM systems shall meet the requirements in Condition 9.

1.9 This unit is subject to the requirements in 40 CFR Part 60 Subpart A - General Provisions, as adopted by reference in Colorado Regulation No. 6, Part A. Specifically, this unit is subject to the requirements identified in Condition 7.

1.10 **State-Only Requirement:** Emissions of Lead (Pb) shall not result in an ambient lead concentration exceeding 1.5 micrograms per standard cubic meter averaged over a one-month period (Colorado Regulation No. 8, Part C, Section I.B). Compliance with this standard shall be demonstrated in accordance with Condition 11.1.

Annual emissions for the purposes of APEN reporting and the payment of annual fees shall be calculated as required by Condition 11.2.

1.11 Compliance with this standard shall be monitored in accordance with the requirements in Condition 10.1.

1.12 Compliance with this standard shall be monitored in accordance with the requirements in Condition 10.2.

1.13 Compliance with this standard shall be monitored in accordance with the requirements in Condition 10.3.

1.14 This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

1.15 The Compliance Assurance Monitoring (CAM) requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, apply to Boiler 1 (Unit 1) with respect to the particulate matter limitations identified in Condition 1.1 as follows:

1.15.1 The permittee shall follow the CAM Plan provided in Appendix H of this permit. Excursions, for purposes of reporting are as follows:

1.15.1.1 An opacity value greater than 15% occurring for 60 seconds; or

1.15.1.2 Any 24-hour period in which the average opacity exceeds the baseline level established by the performance test required by Condition 1.1.2; or

1.15.1.3 Failure to perform the annual internal baghouse inspection within 60 days of the scheduled completion date.

1.15.1.4 Failure to perform an additional internal baghouse inspection within three months of an opacity excursion (initial excursion if more than one) as defined in Conditions 1.15.1.1 and 1.15.1.2.

Note that no more than two internal baghouse inspections are required in any calendar year period.

Excursions shall be reported as required by Section V, Conditions 21 and 22.d of this permit.

1.15.2 Operation of Approved Monitoring

1.15.2.1 At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment (40 CFR Part 64 § 64.7(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.2.2 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of these CAM requirements, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions (40 CFR Part 64 § 64.7(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.2.3 Response to excursions or exceedances

a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable (40 CFR Part 64 § 64.7(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

b. Determination of whether the owner of operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process (40 CFR Part 64 § 64.7(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.2.4 After approval of the monitoring required under the CAM requirements, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Division and, if necessary submit a proposed modification for this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters (40 CFR Part 64 § 64.7(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.3 Quality Improvement Plan (QIP) Requirements

1.15.3.1 Based on the results of a determination made under the provisions of Condition 1.15.2.3.b, the Division may require the owner or operator to develop and implement a QIP (40 CFR Part 64 § 64.8(a), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.3.2 The owner or operator shall maintain a written QIP, if required, and have it available for inspection (40 CFR Part 64 § 64.8(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.3.3 The QIP initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

a. Improved preventative maintenance practices (40 CFR Part 64 § 64.8(b)(2)(i), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

b. Process operation changes (40 CFR Part 64 § 64.8(b)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

c. Appropriate improvements to control methods (40 CFR Part 64 § 64.8(b)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

d. Other steps appropriate to correct control performance (40 CFR Part 64 § 64.8(b)(2)(iv), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

e. More frequent or improved monitoring (only in conjunction with one or more steps under Conditions 1.15.3.3.a through d above) (40 CFR Part 64 § 64.8(b)(2)(v), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.3.4 If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined (40 CFR Part 64 § 64.8(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.3.5 Following implementation of a QIP, upon any subsequent determination pursuant to Condition 1.15.2.3.b, the Division or the U.S. EPA may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

a. Failed to address the cause of the control device performance problems (40 CFR Part 64 § 64.8(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); or

b. Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions (40 CFR Part 64 § 64.8(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.3.6 Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act (40 CFR Part 64 § 64.8(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.4 Reporting and Recordkeeping Requirements

1.15.4.1 Reporting Requirements: The reports required by Section V, Condition 22.d, shall contain the information specified in Appendix B of the permit and the following information, as applicable:

a. Summary information on the number, duration and cause (including unknown cause, if applicable), for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable) ((40 CFR Part 64 § 64.9(a)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); and

b. The owner or operator shall submit, if necessary, a description of the actions taken to implement a QIP during the reporting period as specified in Condition 1.15.3 of this permit. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring (40 CFR Part 64 § 64.9(a)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.4.2 General Recordkeeping Requirements: In addition to the recordkeeping requirements in Section V, Condition 22.a through c.

a. The owner or operator shall maintain records of any written QIP required pursuant to Condition 1.15.3 and any activities undertaken to implement a QIP, and any supporting information required to be maintained under these CAM requirements (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions) (40 CFR Part 64 § 64.9(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements (40 CFR Part 64 § 64.9(b)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.5 Savings Provisions

1.15.5.1 Nothing in these CAM requirements shall excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act. These CAM requirements shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purposes of determining the monitoring to be imposed under separate authority under the federal clean air act, including monitoring in permits issued pursuant to title I of the federal clean air act. The purpose of the CAM requirements is to require, as part of the issuance of this Title V operating permit, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of CAM (40 CFR Part 64 § 64.10(a)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.5.2 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to impose additional or more stringent monitoring, recordkeeping, testing or reporting requirements on any owner or operator of a source under any provision of the federal clean air act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable (40 CFR Part 64 § 64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.15.5.3 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to take any enforcement action under the federal clean air act for any violation of an applicable requirement or of any person to take action under section 304 of the federal clean air act (40 CFR Part 64 § 64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

1.16 **State-Only Requirements:** Unit 1 is subject to the Standards of Performance for Coal-Fired Electric Steam Generating Units in Colorado Regulation No. 6, Part B, Section VIII, as follows:

1.16.1 Beginning January 1, 2012, Hg emissions from Unit 1 shall not exceed 0.0174 lbs/GWh. Compliance with the Hg standard shall be monitored on a twelve (12) month rolling average basis with the first compliance demonstration on December 31, 2012 (Colorado Regulation No. 6, Part B, Section VIII.C.1.a). Hg emissions shall be determined using the Hg monitoring system required by Condition 1.16.2.

1.16.2 The permittee shall comply with the Hg monitoring and recordkeeping requirements as incorporated by reference into Colorado Regulation No. 6, Part A, beginning January 1, 2009, except that Hg monitoring and recordkeeping provisions incorporated by reference into Colorado Regulation No. 6, Part A, addressing the activities listed in Conditions 1.16.2.1 through 4 shall not be required unless otherwise specified (Colorado Regulation No. 6, Part B, Section VIII.D.2). Note that the Hg monitoring and recordkeeping provisions incorporated by reference in Colorado Regulation No. 6, Part A, are specific sections of 40 CFR Part 75.

1.16.2.1 Referenced Hg continuous emission monitoring systems (CEMS) data substitution and bias adjustment for lbs/GWh or percent Hg capture compliance monitoring (Colorado Regulation No. 6, Part B, Section VIII.E.2.a).

1.16.2.2 Referenced Electronic Data Reporting (Colorado Regulation No. 6, Part B, Section VIII.E.2.b).

1.16.2.3 Referenced NIST traceability requirements are not applicable until EPA finalizes its NIST Traceability Protocol and it has been incorporated into Colorado Regulation No. 6, Part A (Colorado Regulation No. 6, Part B, Section VIII.E.2.c).

1.16.2.4 Referenced CEMS QA/QC testing, reporting and recordkeeping of Hg related monitoring equipment (stack flow monitor, CO_2 monitor, moisture monitor) that is already regulated under the Acid Rain Program (Colorado Regulation No. 6, Part B, Section VIII.E.2.d).

1.16.3 In place of reporting requirements for Hg emissions as incorporated by reference into Colorado Regulation No. 6, Part A, the owner or operator shall submit written quarterly reports to the Division within 30 days of the end of each calendar quarter that include the information specified in Conditions 1.16.3.1 through 5. Part A specifies that Hg concentration monitoring and sorbent trap monitoring systems produce a continuous readout or pollutant emission rates or pollutant mass emissions (as applicable) in the appropriate units (e.g., lbs/hr, lbs/mmBtu, ounces/hr, tons/hr). Other appropriate units of measurement may include lbs/GWh, percent Hg capture, and lbs/TBtu, however the Hg emissions reporting specified in this Condition 1.16.3 shall be in units of the applicable standard (Colorado Regulation No. 3, Part VIII.E). The quarterly reports required by this Condition 1.16.3 shall include the following:

1.16.3.1 Applicable Hg lbs/GWh, percent capture or lbs/yr emissions standard in Condition 1.16.1 used to demonstrate compliance (Colorado Regulation No. 6, Part B, Section VIII.E.3.a);

1.16.3.2 For each Hg Budget Unit subject to the emission standards in Condition 1.16.1, above, the three rolling 12 month averages for each calendar month in that calendar quarter in lbs/GWh, percent capture or lbs/yr, depending on the standard used to demonstrate compliance with Condition 1.16.1 (Colorado Regulation No. 6, Part B, Section VIII.E.3.a);

1.16.3.3 Hg Budget Unit operating hours for that quarter (Colorado Regulation No. 6, Part B, Section VIII.E.3.d); and

1.16.3.4 If a continuous Hg monitoring system is used to demonstrate compliance with the Hg monitoring and recordkeeping requirements specified in Condition 1.16.2 of this permit, total and percentage of monitoring system downtime for that quarter (Colorado Regulation No. 6, Part B, Section VIII.E.3.e).

1.16.4 The permittee shall follow the Division-approved monitoring plan submitted in accordance with the requirements in Colorado Regulation No. 6, Part B, Section

VIII.E.4.b. For information purposes, the Division-approved monitoring plan is included in Appendix I of this permit.

1.16.5 The permittee is subject to the enforceability requirements in Colorado Regulation No. 6, Part B, Section VIII.F, as follows:

1.16.5.1 The emissions standards, including any Alternative Emission Standards, and Best Available Mercury Control Technology Standards, permitting and monitoring requirements under Colorado Regulation No. 6, Part B, Sections VIII.C, VIII.D, and VIII.E, above, are enforceable. Any violations of permit terms may be enforced by the Division pursuant to Section 25-7-115, C.R.S.

1.16.5.2 If an Hg Budget Unit demonstrates compliance with the compliance plan required by Colorado Regulation No. 6, Part B, Sections VIII.D.4.b and c, above, but did not comply with the applicable emission standards in Condition 1.16.1, above, that unit shall be considered to be in compliance with such emission standards.

2. B001 - Boiler No. 1 (Unit 1), Alternate Fuels for Startup and Flame Stabilization

2.1 The permittee shall maintain records of annual usage of natural gas and the associated annual heat content. This information shall be used as follows:

2.1.1 Annual natural gas consumption shall be used to calculate emissions for the purposes of APEN reporting, as required by Conditions 1.2 and 1.5. The emission factors (EPA's Compilation of Emission Factors (AP-42), Section 1.4 (dated 3/98)) identified in the table below have been approved by the Division and shall be used to calculate emissions.

Pollutant	Emission Factor - Natural Gas
PM	1.9 lbs/mmSCF
PM_{10}	1.9 lbs/mmSCF
CO	84 lbs/mmSCF
VOC	5.5 lbs/mmSCF

Annual emissions shall be calculated, for the purposes of APEN reporting and payment of annual fees, using the above emission factors and the annual natural gas usage in the following equation:

$$\text{Tons/yr} = \frac{\text{EF (lbs/mmSCF) x Annual Natural Gas Usage (mmSCF/yr)]}}{\text{2000 lbs/ton}}$$

2.1.2 If the total annual heat content of natural gas exceeds 5 percent of the total heat content of all fuels combusted, this permit shall be reopened to incorporate appropriate applicable requirements for combusting combined/alternative fuels.

3. B002 – Natural Gas-Fired Auxiliary Boiler, Rated at 98 mmBtu/hr

Parameter	Permit Condition Number	Limitations Short Term	Limitations Long Term	Compliance Emission Factor	Monitoring Method	Monitoring Interval
Emission Limitations	3.1	N/A	NO_X 35.4 tons/yr CO 29.7 tons/yr	NO_X: 100 lbs/mmSCF CO: 84 lbs/mmSCF	Recordkeeping and Calculation	Monthly
Natural Gas Usage	3.2.	N/A	707 mmSCF/yr	N/A	Fuel Meter	Monthly
Particulate Matter (PM)	3.3.	0.152 lbs/mmBtu		N/A	Fuel Restriction	Only Natural Gas is Used as Fuel
Opacity	3.4.	Not to Exceed 20% Except as Provided for in Condition 3.5 Below		N/A	See Condition 3.4.	
Opacity	3.5.	For Certain Operational Activities - Not to Exceed 30%, for a Period or Periods Aggregating More than Six (6) Minutes in any 60 Consecutive Minutes		N/A	See Condition 3.5.	
Case-by-Case MACT Requirements	3.6.	Submit 112(j) Application by Deadline		N/A	See Condition 3.6.	

3.1 NO_X and CO emissions shall not exceed the above limitations (Colorado Construction Permit C-12,093-4, as modified under the provisions of Section I, Condition 1.3 based on requested emissions identified in the APEN submitted May 28, 2009). Monthly emissions from the boiler shall be calculated by the end of the subsequent month using the above emission factors (EF) (from "EPA's Compilation of Emission Factors (AP-42)", Section 1.4 (dated 3/98)) and the monthly natural gas consumption, as required by Condition 3.2 in the following equation:

$$\text{Tons/mo} = \frac{[\text{EF (lbs/mmSCF) x monthly natural gas use (mmSCF/mo)}]}{\text{2000 lbs/ton}}$$

Monthly emissions shall be summed and used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

3.2 Natural Gas Usage shall not exceed the above limitations (Colorado Construction Permit C-12,093-4, as modified under the provisions of Section I, Condition 1.3 based on the requested fuel consumption rates identified in the APEN submitted May 28, 2009). Natural gas consumed by the boiler shall be monitored and recorded monthly using fuel meters and corporate records as necessary. Monthly natural gas usage shall be summed and used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

3.3 Particulate Matter (PM) emissions from the boiler shall not exceed the above limitation (Colorado Regulation No. 1, Section III.A.1.b). In the absence of credible evidence to the contrary, compliance with the particulate matter emission limits is presumed since only natural gas and is permitted to be used as fuel in the boiler.

Note that the numeric PM standards were determined using the design heat input for the boiler (98 mmBtu/hr) in the following equation:

$PE = 0.5 \text{ x } (FI)^{-0.26,}$ where: PE = particulate standard in lbs/mmBtu
FI = fuel input in mmBtu/hr

3.3.1 Except as provided for in Condition 3.5, below, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity (Colorado Regulation No. 1, Section II.A.1). In the absence of credible evidence to the contrary, compliance with the opacity limitation shall be presumed since only natural gas is permitted to be used as fuel in the boiler.

3.4 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, process modifications or adjustment or occasional cleaning of control equipment which is in excess of 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, Section II.A.4). In the absence of credible evidence to the contrary, compliance with the opacity limitation shall be presumed since only natural gas is permitted to be used as fuel in the boiler.

3.5 This boiler falls under the Maximum Achievable Control Technology (MACT) source category of Industrial, Commercial and Institutional Boilers and Process Heaters. Since the MACT provisions for this source category (codified in 40 CFR Part 63 Subpart DDDDD) were vacated as of July 30, 2007, this boiler will be subject to the case-by-case MACT determination requirements of 112(j) of the Clean Air Act Amendments (codified in 40 CFR Part 63 Subpart B §§ 63.50 through 63.56). The permittee shall submit a 112(j) application by the deadline specified by EPA. As of the issuance date of this permit, the deadline has not been set; however, the Division will notify the permittee of the deadline for the 112(j) application at a later date.

4. Particulate Matter Emissions - Fugitive Sources

F001 - Coal Handling and Storage

Parameter	Permit Condition Number	Limitations Short Term	Limitations Long Term	Compliance Emission Factor	Monitoring Method	Monitoring Interval
PM	4.1.	N/A	35.84 tons/yr	See Appendix G	Recordkeeping and Calculation	As Needed
PM_{10}			8.7 tons/yr			
Coal Unloaded	4.3	N/A	4,000,000 tons/yr	N/A	Recordkeeping	Monthly
Minimize Emissions	4.2.	N/A	N/A	N/A	Certification	Semi-Annually

F002 – Ash Handling and Disposal

Parameter	Permit Condition Number	Limitations Short Term	Limitations Long Term	Compliance Emission Factor	Monitoring Method	Monitoring Interval
PM	4.1.	N/A	19.66 tons/yr	See Appendix G	Recordkeeping and Calculation	As Needed
PM_{10}			7.08 tons/yr			
Fly Ash Disposed	4.3.	N/A	136,656 tons/yr	N/A	Recordkeeping	Monthly
Fugitive Particulate Control Plan	4.2.1, 4.4.	N/A	N/A	N/A	Certification	Semi-Annually

F003 - Paved and Unpaved Roads

Parameter	Permit Condition Number	Limitations Short Term	Limitations Long Term	Compliance Emission Factor	Monitoring Method	Monitoring Interval
PM	4.1.	N/A	47.9 tons/yr	See Appendix G	Recordkeeping and Calculation	As Needed
PM_{10}			12.2 tons/yr			
Minimize Emissions	4.2.1, 4.4.	N/A	N/A	N/A	Certification	Semi-Annually

4.1 Particulate Matter (PM and PM_{10}) emissions from fugitive emission sources shall not exceed the above limitations (<u>for coal handling</u>: Colorado Construction Permit 12MR093-1, as modified under the provisions of Section I, Condition 1.3 and <u>for ash handling and roads:</u> as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7, based on the information provided in the modeling analysis submitted on November 27, 2001). In the absence of credible evidence to the contrary, compliance with the PM and PM_{10} emission limits are presumed provided the material handling limits (Condition 4.3) are met and control measures (Conditions 4.2 and 4.4) are followed.

Permitted emissions were determined using the emission factors identified in Appendix F of this permit.

Fugitive Particulate Matter emissions are subject to the General Conditions in Section V of this Permit including the Recordkeeping and Reporting requirements listed under Condition 22.

4.2 The source shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions (Colorado Regulation No. 1, Section III.D.1.a).

4.2.1 A fugitive dust control plan, or a modification to an existing plan, shall be required to be submitted if the Division determines that for this source or activity visible emissions are in excess of 20% opacity; or visible emissions are being transported off the property; or if this source or activity is operating with emissions that create a nuisance. The control plan shall be submitted to the Division within the time period specified by the Division (Colorado Regulation No. 1, Section III.D.1.c). The 20% opacity, no off-property transport, and nuisance emission limitations are guidelines and not enforceable standards and no person shall be cited for violation thereof pursuant to C.R.S. 25-7-115 (Colorado Regulation No. 1, Section III.D.1.e.(iii)).

4.3 Materials processed are subject to the following limitations:

4.3.1 Coal unloaded shall not exceed the above limitations (C-12,093-1, as modified under the provisions of Section I, Condition 1.3, based on comments on the draft operating permit received August 22, 2002). The quantity of coal delivered shall be monitored and recorded monthly, using vendor records of coal delivered.

4.3.2 Fly ash disposed of shall not exceed the limitations stated above (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7, based on the maximum ash disposal rate identified in the modeling analysis submitted on November 27, 2001). Monthly quantities of fly ash disposed of shall be determined and recorded monthly, using the methodology defined in Condition 5.3.2 and facility records as necessary.

Monthly quantities of fly ash disposed of and coal delivered shall be used in a twelve month rolling total to monitor compliance with annual limitations. Each month, a new twelve month total shall be calculated using the previous twelve months data.

4.4 The source shall certify semi-annually that they have utilized the following control measures to minimize fugitive particulate emissions from ash handling and disposal (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7):

4.4.1 The following control measures shall be used to minimize fugitive particulate matter emissions from ash handling and disposal:

4.4.1.1 Water shall be sprayed on the ash pit as necessary to minimize fugitive emissions.

4.4.1.2 Ash haul trucks shall be covered.

4.4.2 The following control measures shall be used to minimize fugitive particulate matter emissions from vehicle traffic on haul roads:

4.4.2.1 Vehicle speed shall not exceed 15 mph. This limit shall be posted.

4.4.2.2 All active unpaved haul roads shall be watered daily to reduce visible emissions. Daily watering is not required when no haul trucks are using the unpaved roads, following rain or snow events that provide sufficient moisture to control fugitive dust, and when the application of water creates a safety hazard due to ice formation on the roads. Chemical stabilization of the unpaved road surfaces can also be used to reduce the need for daily watering.

5. Particulate Matter Emissions - Point Sources

P001 - Coal Handling System (Crushing, Transfer Tower and Conveying)

Parameter	Permit Condition Number	Limitations Short Term	Limitations Long Term	Compliance Emission Factor	Monitoring Method	Monitoring Interval
PM	5.1.	N/A	15.4 tons/yr	See Condition 5.1.	See Condition 5.1.	
PM_{10}		N/A	6.8 tons/yr			
Coal Handled	5.3.	N/A	**Coal Delivered and Sent to Storage:** 4,000,000 tons/yr **Coal from Storage to Plant:** 2,921,460 tons/yr	N/A	Recordkeeping and Calculation	Monthly
Control Device Maintenance	5.4.	N/A	N/A	N/A	Inspections	Quarterly
NSPS General Provisions	5.5.	N/A	N/A	N/A	As Required by NSPS General Provisions	Subject to NSPS General Provisions
Opacity	5.7.	Not to Exceed 20%		N/A	See Condition 5.7.	
NSPS Opacity	5.8.	Less Than 20%		N/A	See Condition 5.8.	

P002 – Ash Silo

Parameter	Permit Condition Number	Limitations Short Term	Limitations Long Term	Compliance Emission Factor	Monitoring Method	Monitoring Interval
PM	5.2.	N/A	2.13 tons/yr	0.61 lbs/ton	Recordkeeping and Calculation	Monthly
PM_{10}			2.13 tons/yr	0.61 lbs/ton		
Ash Handled	5.3.	N/A	136,656 tons/yr	N/A	Recordkeeping	Monthly
Opacity	5.6.	Not to Exceed 20%		N/A	See Condition 5.6.	

P003 – Soda Ash Handling System

Parameter	Permit Condition Number	Limitations Short Term	Limitations Long Term	Compliance Emission Factor	Monitoring Method	Monitoring Interval
PM	5.2.	N/A	0.007 tons/yr	1.7 lbs/ton	Recordkeeping and Calculation	Monthly
PM_{10}		N/A	0.007 tons/yr	1.7 lbs/ton		
Soda Ash Processed	5.3.	N/A	4,000 tons/yr	N/A	Recordkeeping	Monthly
Opacity	5.6.	Not to Exceed 20%		N/A	See Condition 5.6.	

P004 – Two (2) Sorbent Storage Silos

Parameter	Permit Condition Number	Limitations Short Term	Limitations Long Term	Compliance Emission Factor	Monitoring Method	Monitoring Interval
PM	5.2.	N/A	0.38 tons/yr	0.043 lbs/hr	Recordkeeping and Calculation	Monthly
PM_{10}		N/A	0.38 tons/yr	0.043 lbs/hr		
Sorbent Processed	5.3.	N/A	560 tons/yr	N/A	Recordkeeping	Monthly
Opacity	5.6.	Not to Exceed 20%		N/A	See Condition 5.6.	
Hours of Operation	5.9.	N/A	N/A	N/A	Recordkeeping	Monthly
Commence Construction	5.10.	Construction Must Commence within 18 Months		N/A	See Condition 5.10.	
Startup Notice	5.11.	Notify Division within 30 Days After Startup		N/A	Notification	Within 30 Days
Compliance Certification	5.12.	Certify Compliance within 180 Days of Startup of Each Unit		N/A	Certification	Within 180 Days

5.1 Particulate Matter (PM and PM_{10}) emissions, **from the Coal Handling System**, shall not exceed the limitations stated above (Colorado Construction Permit 12MR093-1, as modified under the provisions of Section I, Condition 1.3). Compliance with the annual limitations shall be monitored as follows:

5.1.1 The plant transfer tower/tripper deck and crusher baghouses shall be operated and maintained in accordance with manufacturers' recommendations and good engineering practices.

5.1.2 The plant transfer tower/tripper deck and crusher baghouses and the crusher and live storage rotary plows water/surfactant spray systems shall be inspected as required by Condition 5.4.

5.1.3 The conveyors and crushers shall be enclosed and the integrity of the enclosures maintained. Water/surfactant spray suppression systems for the conveyors shall be used as necessary.

5.1.4 The moisture content of the coal, as determined through coal sampling required in Condition 1.7, shall not be less than 9.2%.

5.1.5 The number of transfer points in the coal handling system shall not be increased. Note that permitted emissions are based on 13 transfer points, 5 transfer points from delivery to storage and 8 from storage to the plant.

5.1.6 In the absence of credible evidence to the contrary, compliance with the PM and PM_{10} emission limitations shall be presumed, provided the requirements in Conditions 5.1.1 through 5.1.5 are met and that the coal handling limit identified in Condition 5.3.1 is met.

5.2 Particulate Matter (PM and PM_{10}) emissions **from the ash silo, the soda ash handling system and sorbent silos** are subject to the following limitations:

5.2.1 Particulate Matter (PM and PM_{10}) emissions **from the ash silo** shall not exceed the above limitations (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7, based on the information provided in the modeling analysis submitted on November 27, 2001). Monthly emissions shall be calculated by the end of the subsequent month using the above emission factors (EPA's Compilation of Emission Factors (AP-42), dated January 1995, Section 11.17) and the monthly quantity of ash processed, as determined by Condition 5.3.2, in the equations identified below:

Ash Silo Emissions = Silo Loading + Silo Unloading

Where:

$$\text{Silo Loading} = \frac{[\text{EF (lbs/ton) x monthly ash loaded (tons/mo)}]}{2000 \text{ lbs/ton}}\text{; Control efficiency} = 99.9\%$$

$$\text{Silo Unloading} = \frac{[\text{EF (lbs/ton) x monthly ash unloaded (tons/mo)}]}{2000 \text{ lbs/ton}}\text{; Control efficiency} = 95\%$$

Note that in order to use the control efficiencies identified the following conditions shall be met:

5.2.1.1 The boiler baghouse shall be operated and maintained in accordance with the requirement in Condition 8.1.

5.2.1.2 When unloading into an enclosed truck the hose shall be attached, operated and maintained in accordance with good engineering practices.

5.2.2 Particulate Matter (PM and PM_{10}) emissions **from the soda ash handling system** shall not exceed the above limitations (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7, based on the requested emissions provided in the APEN received on August 7, 1998). Monthly emissions shall be calculated by the end of the subsequent month using the above emission factors (Background Document for AP-42, Sodium Carbonate Production (formerly Section 5.16, now Section 8.12), dated January 1996, average stack test results for test 23b) and the quantity of soda ash processed the soda ash handling system, as determined by Condition 5.3.3, in the following equation:

$$\text{tons/month} = \frac{\text{EF (lbs/ton) x soda ash processed through system (tons/mo)}}{\text{2000 lbs/ton}}$$

A control efficiency of 99.9% can be applied to these calculations provided the bin vent filters on the silos and day tanks are operated and maintained in accordance with manufacturer's recommendations and good engineering practices.

5.2.3 Particulate Matter (PM and PM_{10}) emissions **from the sorbent silos** shall not exceed the above limitations (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7, based on requested emissions included on the APEN submitted on December 19, 2008). Monthly emissions shall be calculated by the end of the subsequent month using the above emission factors (based on grain-loading specification (0.01 gr/scf) and the rated air flow of 500 dscfm) and hours of operation, as required by Condition 5.9, in the following equation:

$$\text{Tons/month} = \frac{\text{EF (lbs/hr) x monthly hours of operation (hrs/month)}}{\text{2000 lbs/ton}}$$

Monthly emissions **from ash silo, the soda ash handling system and the sorbent silos** shall be used in a rolling twelve month total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

5.3 The quantity of materials processed **through the coal handling system, ash silo, soda ash handling system and sorbent** silos are subject to the following limitations:

5.3.1 The quantity of coal handled **through the Coal Handling System** shall not exceed the above limitation (Colorado Construction Permit 12MR093-1, as modified under the provisions of Section I, Condition 1.3). The quantity of coal handled through the coal handling system shall be monitored and recorded monthly. The quantity of coal handled shall be determined using belt scales and corporate records as necessary.

5.3.2 The quantity of ash processed **through the Ash Silo** shall not exceed the above limitation (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7, based on the maximum quantity of ash processed as identified in the November 27, 2001 modeling analysis). The ash processed through the ash silo shall be monitored and recorded monthly. The quantity of ash processed shall be determined using the average ash content of the coal, as determined through coal sampling required in Condition 1.7 and coal consumption records (Condition 1.6). An 80% fly-ash factor shall be assumed.

5.3.3 The quantity of soda ash processed **through the Soda Ash Handling System** shall not exceed the above limitation (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7, based on the requested throughput provided in the APEN received on August 7, 1998). The quantity of soda ash handled **through the Soda Ash Handling System** shall be monitored and recorded monthly.

5.3.4 The quantity of sorbent processed **through the Sorbent Silos** shall not exceed the above limitation (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7, based on the information provided in the December 19, 2008 permit application). The quantity of sorbent handled **through the Sorbent Silos** shall be monitored and recorded monthly.

Monthly quantities of material processed through **the coal handling system, ash silo, soda ash handling system and sorbent silos** shall be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

5.4 The plant transfer tower/tripper deck and crusher baghouses and the water/surfactant spray systems on the crusher and the live storage rotary plows are subject to the following inspection requirements:

5.4.1 The permittee shall conduct inspections of each baghouse and the spray systems on at least a quarterly basis and perform any necessary repairs or maintenance pursuant to the quarterly inspections (Compliance Order on Consent, Issued February 27, 1996, Paragraph II.7).

5.4.2 The permittee shall maintain records of each inspection required in Condition 5.4.1 above. The records shall be kept on site and shall be made available to Division inspectors, or their duly delegated representatives, upon request, and may be kept in computerized format. The Division considers that if the PSCo inspector has signed the inspection or work order form with no comments, the inspection has been fully performed and no problems with the control equipment were noted (Compliance Order on Consent, Issued February 27, 1996, Paragraph II.8).

5.5 The following portions of the coal handling system (conveyors 7 thru 13, 17 and 18) are subject to the requirement in 40 CFR Part 60, Subpart A – General Provisions, as adopted by Colorado Regulation No. 6, Part A. Specifically the coal handling system is subject to the following requirement and the requirements in Condition 7.

5.5.1 The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility or any malfunction of the air pollution control equipment (40 CFR Part 60 Subpart A § 60.7(b), as adopted by reference in Colorado Regulation No. 6, Part A).

5.6 Opacity of emissions **from the ash silo, the soda ash silo, each soda ash day tank and each sorbent silo** shall not exceed 20% (Colorado Regulation No. 1, Section II.A.1). Compliance with the opacity limitation shall be monitored as follows:

5.6.1 In the absence of credible evidence to the contrary, **the Ash Silo** shall be presumed to be in compliance with the 20% opacity limit provided the requirements in Conditions 5.2.1.1 and 5.2.1.2 are met.

5.6.2 In the absence of credible evidence to the contrary, **the Soda Ash Silo and each Soda Ash Day tank** shall be presumed to be in compliance with the 20% opacity limit provided the bin vent filters are operated and maintained in accordance with manufacturer's recommendations and good engineering practices.

5.6.3 In the absence of credible evidence to the contrary, **each Sorbent Silo** shall be presumed to be in compliance with the 20% opacity limit provided the bin vent filters are operated and maintained in accordance with manufacturer's recommendations and good engineering practices.

5.7 Opacity of emissions from **the coal handling system** shall not exceed 20% (Colorado Regulation No. 1, Section II.A.1). Compliance with the opacity requirements shall be monitored as follows:

5.7.1 In the absence of credible evidence to the contrary, **the Coal Handling System** shall be presumed to be in compliance with the opacity requirements provided the requirements in Conditions 5.1.1 through 5.1.3 are met.

5.7.2 A six (6) minute EPA Method 9 opacity observation shall be conducted annually on the transfer tower/tripper deck and crusher baghouses. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit. The EPA Reference Method 9 opacity observations shall be performed by an observer with current and valid Method 9 certification. All observations shall be recorded and kept on site to be made available to the Division upon request.

5.8 The owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system or coal transfer and loading system processing coal, gases which exhibit 20% opacity or greater (40 CFR Part 60 Subpart Y § 60.252, as adopted by reference in Colorado Regulation No. 6, Part A). These opacity provisions apply to the following pieces of equipment: both crushers and conveyors 7 thru 13, 17 and 18. Compliance with the opacity requirements shall be monitored as follows:

5.8.1 In the absence of credible evidence to the contrary, the coal handling system shall be presumed to be in compliance with the opacity requirements provided the requirements in Conditions 5.1.1 through 5.1.3 are met.

5.8.2 In the absence of credible evidence to the contrary, compliance with the opacity standard for the transfer tower/tripper deck and crusher baghouses is presumed provided the visible emission observations required by Condition 5.7.2 meets the opacity standard specified in Condition 5.8.

5.9 Hours of operation of **each Sorbent Silo** shall be monitored monthly and recorded and maintained to be made available to the Division upon request. The hours of operation shall be used to calculate the monthly emissions as required by Condition 5.2.3.

5.10 The permit conditions in this Section II.5 of this permit, **that apply to the Sorbent Silos**, shall expire if construction does not commence within 18 months of issuance of the renewal permit [January 1, 2010]; construction is discontinued for a period of 18 months of more; or construction is not completed within a reasonable time of the estimated completion date (Colorado Regulation No. 3, Part B, Section III.F.4.a.(i) thru (ii)).

5.11 The permittee shall notify the Division, in writing, thirty (30) days prior to startup of **the Sorbent Silos** (Colorado Regulation No. 3, Part B, Section III.G.1).

5.12 Within one hundred eighty (180) calendar days after commencement of operation **of the Sorbent Silos**, the permittee shall certify compliance with the conditions in this Section II.5 of this permit **that apply to the Sorbent Silos** (Colorado Regulation No. 3, Part B, Section III.G.2). Submittal of the first required semi-annual monitoring report (Appendix B), after startup of the sorbent silos shall serve as the self-certification that the newly installed sorbent silos can comply with the conditions in this Section II.5 of this permit that apply to them.

6. M001–Cooling Water Tower

Parameter	Permit Condition Number	Limitations Short Term	Limitations Long Term	Compliance Emission Factor	Monitoring Method	Monitoring Interval
Water Circulated	6.1.	N/A	99,864 mmgal/yr	N/A	Recordkeeping	Monthly
Total Dissolved Solids Analysis	6.2.	N/A	N/A	N/A	Laboratory Analysis	Semi-Annually
PM	6.3.	N/A	36.5 tons/yr	See Condition 6.3	Recordkeeping and Calculation	Monthly
PM_{10}			36.5 tons/yr			
VOC			2.6 tons/yr	0.0527 lbs/mmgal (as $CHCl_3$)		
Opacity	6.4.	Not to Exceed 20%		N/A	See Condition 6.4	

6.1 The water circulated through the cooling water tower shall not exceed the above limitation (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7, based on the maximum water circulation rate identified in the modeling analysis submitted on November 27, 2001). The quantity of water circulated through the tower shall be monitored and recorded monthly. Monthly quantities of water circulated shall be used in the emission calculations identified in Condition 6.3. Monthly quantities of water circulated shall be used in a twelve month rolling total to monitor compliance with the annual limitation. Each month, a new twelve month total shall be calculated using the previous twelve months data.

6.2 Samples of water circulated from the tower shall be taken and analyzed to determine the total solids concentration semi-annually. The total solids concentration shall be used to calculate particulate matter emissions as required by Condition 6.3. A copy of the procedures used to obtain and analyze samples shall be maintained and made available to the Division upon request.

6.3 Emissions of PM, PM_{10} and VOC from the cooling water tower shall not exceed the above limitations (as provided for under the provisions of Section I, Condition 1.3 and Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7, based on the emissions identified in the modeling analysis submitted on November 27, 2001). Emissions shall be calculated monthly for the tower using the equations identified below.

$$PM = PM_{10}\ (\text{tons/month}) = \frac{\text{Q x d x \% drift x 31.3\% drift dispersed x total solids concentration}}{\text{2000 lbs/ton}}$$

Where:
Q = water circulated, gal/month
d = density of water, lbs/gal (from T5 application d = 8.34 lbs/gal)
% drift = 0.001% (from T5 application)
31.3% drift dispersed (from EPA-600/7-79-251a, November 1979, AEffects of Pathogenic and Toxic Materials Transported Via Cooling Device Drift - Volume1 - Technical Report@, Page 63)

Total solids concentration = total solids concentration, in ppm (lbs solids/10^6 lbs water) - to be determined by Condition 6.2.

$$VOC = CHCl_3 \text{ (tons/month)} = \frac{Q \times EF \times (1 \text{ mmgal}/10^6 \text{ gal})}{2000 \text{ lbs/ton}}$$

Where: Q = water circulated, gal/yr or gal/month
EF = 0.0527 lbs/mmgal (from letter from Wayne C. Micheletti to Ed Lasnic, dated November 11, 1992)

Monthly emissions shall be used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous twelve months data.

6.4 Opacity of emissions from the cooling water tower shall not exceed 20% (Colorado Regulation No. 1, Section II.A.1). In the absence of credible evidence to the contrary, compliance with the opacity standard shall be presumed, provided the drift eliminators on the tower are operated and maintained in accordance with the manufacturers' recommendations and good engineering practices.

7. NSPS General Provisions

7.1 At all times, including periods of startup, shutdown, and malfunction owners and operators shall to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether 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 (40 CFR Part 60 Subpart A § 60.11(d) as adopted by Reference in Colorado Regulation No. 6, Part A).

7.2 No article, machine, equipment or process shall be used to conceal an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gasses discharged to the atmosphere (40 CFR Part 60 Subpart A § 60.12, as adopted by reference in Colorado Regulation No. 6, Part A).

8. Particulate Matter Emission Periodic Monitoring Requirements

8.1 Operation and Maintenance Requirements

The boiler baghouse shall be maintained and operated in accordance with good engineering practices. Any maintenance performed on the boiler baghouses shall be documented and made available to the Division upon request.

8.2 Stack Testing

Stack testing for particulate matter emissions shall be performed on the main boiler within 180 days of renewal permit issuance [January 1, 2010] in accordance with the requirements and procedures set forth in EPA Test Method 5 as set forth in 40 CFR Part 60, Appendix A. Frequency of testing, thereafter shall be annual except that: (1) if the first test required by this renewal permit or any subsequent test results indicate emissions are less than or equal to 50% of the emission limit, another test is required within five years; (2) if the first test required by this renewal permit or any subsequent test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, another test is required within three years; (3) if the first test required by this renewal permit or any subsequent test results indicate emissions are greater than 75% of the emission limit, an annual test is required until the provisions of (1) or (2) are met.

A stack testing protocol shall be submitted for Division approval at least thirty (30) calendar days prior to any performance of the test required under this condition. No stack test required herein shall be performed without prior written approval of the protocol by the Division. The Division reserves the right to witness the test. In order to facilitate the Division's ability to make plans to witness the test, notice of the date (s) for the stack test shall be submitted to the Division at least thirty (30) calendar days prior to the test. The Division may for good cause shown, waive this thirty (30) day notice requirement. In instances when a scheduling conflict is presented, the Division shall immediately contact the permittee in order to explore the possibility of making modifications to the stack test schedule. The required number of copies of the compliance test results shall be submitted to the Division within forty-five (45) calendar days of the completion of the test unless a longer period is approved by the Division.

9. Continuous Emission Monitoring and Continuous Opacity Monitoring Systems

9.1 CEM and COM Monitoring Systems QA/QC Plan

Continuous Emission Monitoring (CEM) and Continuous Opacity Monitoring (COM) systems are required for measurement of the stack SO_2, CO_2, NO_X (and diluent monitor for either CO_2 or O_2), gas flow rate and opacity emissions. The quality assurance/quality control plan required by 40 CFR Part 75, Appendix B shall be made available to the Division upon request. Revisions shall be made to the plan at the request of the Division.

9.2 General Provisions

9.2.1 The permittee shall ensure that all continuous emission and opacity monitoring systems required are in operation and monitoring unit emissions or opacity at all times that the boiler combusts any fuel except as provided in 40 CFR Part 75 § 75.11(e) and during periods of calibration, quality assurance, or preventative maintenance performed pursuant to 40 CFR Part 75 § 75.21 and Appendix B, periods of repair, periods of backups of data from a data acquisition and handling system or recertification performed pursuant to 40 CFR Part 75 § 75.20. The permittee shall also ensure, subject to the exceptions just noted, that the continuous opacity monitoring systems required are in operation and monitoring opacity during the time following combustion when fans are still operating unless fan operation is not required to be included under any other applicable requirement (40 CFR Part 75 § 75.10(d)).

9.2.2 Alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring systems shall not be used without having obtained prior written approval from the appropriate agency, either the Division or the U.S. EPA, depending on which agency is authorized to approve such alternative under applicable law. Any alternative continuous emission monitoring systems or continuous opacity monitoring systems must be certified in accordance with the requirements of 40 CFR Part 75 prior to use.

9.2.3 All test and monitoring equipment, methods, procedures and reporting shall be subject to the review and approval by the appropriate agency, either the Division or the U.S.EPA, depending on which agency is authorized to approve such alternative under applicable law, prior to any official use. The Division shall have the right to inspect such equipment, methods and procedures and data obtained at any time. The Division shall provide a witness(es) for any and all tests as Division resources permit.

9.2.4 A file shall be maintained of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by applicable portions of 40 CFR Part 75 recorded in a permanent form suitable for inspection.

9.2.5 Records shall be maintained of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the source; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative (40 CFR Part 60 Subpart A § 60.7(b), as adopted by reference in Colorado Regulation No. 6, Part A).

9.3 Continuous Emission Monitoring (CEM) Systems

9.3.1 The Continuous Emission Monitoring (CEM) Systems are subject to the requirements of 40 CFR Part 75. Each monitoring system shall meet the equipment, installation and performance specifications of 40 CFR Part 75, Appendix A.

9.3.2 The permittee shall follow the 40 CFR Part 75 quality assurance and quality control procedures of Appendix B and the conversion procedures of Appendix F. For purposes of monitoring compliance with the SO_2 emission limitations in Condition 1.3, hourly SO_2 data shall be converted to lbs/mmBtu in accordance with the procedures in 40 CFR Part 60 Appendix A Method 19.

9.4 Continuous Opacity Monitoring (COM) Systems

9.4.1 The Continuous Opacity Monitoring (COM) Systems are subject to the requirements of 40 CFR Part 75. Each continuous opacity monitoring system shall meet the design, installation, equipment and performance specifications in 40 CFR Part 60, Appendix B, Performance Specification 1.

9.4.2 The permittee shall follow the quality assurance and quality control procedures of 40 CFR Part 60, Subpart A §60.13(d) and Subpart D § 60.45(c)(3).

9.5 Notification and Recordkeeping

9.5.1 The owner or operator of a facility required to install, maintain, and calibrate continuous monitoring equipment shall submit to the Division, by the end of the calendar month following the end of each calendar quarter, a report of excess emissions for all pollutants monitored for that quarter (40 CFR Part 60 Subpart A § 60.7(c)). This report shall consist of the following information and/or reporting requirements as specified by the Division:

9.5.1.1 The magnitude of excess emissions computed in accordance with 40 CFR Part 60 Subpart A § 60.13(h) and Division guidelines, as applicable, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions and the process operating time during the reporting period (40 CFR Part 60 Subpart A § 60.7(c)(1)).

9.5.1.2 Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted (40 CFR Part 60 Subpart A § 60.7(c)(2)).

9.5.1.3 The date and time identifying each period of equipment (continuous emission monitoring equipment) malfunction and the nature of the system repairs or adjustments, if any, made to correct the malfunction (40 CFR Part 60 Subpart A § 60.7(c)(3)).

9.5.1.4 When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report (40 CFR Part 60 Subpart A § 60.7(c)(4)).

9.5.2 The owner or operator of a facility required to install, maintain, and calibrate continuous monitoring equipment shall submit to the Division, by the end of the calendar month following the end of each calendar quarter, a summary report for that quarter (40 CFR Part 60 Subpart A § 60.7(c)). One summary report form shall be submitted for each pollutant monitored. This report shall contain the information and be presented in the format provided in 40 CFR Part 60 Subpart A § 60.7(d), Figure 1.

If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and continuous monitoring system (CMS) downtime is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in Condition 12.6.1 need not be submitted unless required by the Division (40 CFR Part 60 Subpart A § 60.7(d)(1)).

9.5.3 If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in Condition 8.6.1 shall both be submitted (40 CFR Part 60 Subpart A § 60.7(d)(1)).

10. Opacity Requirements and Periodic Monitoring

10.1 Opacity – Colorado Regulation No. 1, Section II.A.1

Except as provided for in Condition 10.2 below, no owner or operators of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity (Colorado Regulation No. 1, Section II.A.1).

The permittee shall operate, calibrate and maintain a continuous in-stack monitoring device for the measurement of opacity. Unless otherwise specified in this permit, the continuous opacity monitor (COM) shall be used to monitor compliance with the 20% opacity limit set forth above. The requirements for the opacity monitoring system are defined in Condition 9 of this permit.

10.2 Opacity – Colorado Regulation No. 1, Section II.A.4

No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, process modifications or adjustment or occasional cleaning of control equipment which is in excess of 30% opacity for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, Section II.A.4). Compliance with this standard shall be monitored, during the aforementioned events, using the continuous opacity monitor (COM) as required by this permit.

The permittee shall operate, calibrate and maintain a continuous in-stack monitoring device for the measurement of opacity. Unless otherwise specified in this permit, the continuous opacity monitor (COM) shall be used to monitor compliance with the 30% opacity limit set forth above. The requirements for the opacity monitoring system are defined in Condition 9 of this permit.

A record shall be kept of the type, date and time of the commencement and completion of each and every condition subject to Colorado Regulation No. 1, Section II.A.4 that results in an exceedance. The records shall be made available for review upon request by the Division.

10.3 NSPS Opacity Requirements

Opacity of emissions shall not exceed 20% for any six-minute period, except for one six-minute period not to exceed 27% per hour (40 CFR Part 60 Subpart D § 60.42(a)(2), as adopted by reference in Colorado Regulation No. 6, Part A). Compliance with this standard shall be monitored using the continuous opacity monitor (COM) as required by this permit.

Note that this opacity standard shall apply at all times except during periods of startup, shutdown and malfunction (40 CFR Part 60 Subpart A § 60.11(c), as adopted by reference in Colorado Regulation No. 6, Part A), however, those instances during startup, shutdown and malfunction when the opacity standard is exceeded shall be identified in the Excess Emission Report required by Condition 9.5.

Also note that this opacity standard is more stringent than the opacity standard identified in Condition 10.2 during periods of fire building, cleaning of fire boxes, soot blowing, process modifications, and adjustment and occasional cleaning of control equipment.

11. Lead Periodic Monitoring

11.1 **State-Only Requirement:** Emissions of Lead (Pb) shall not be such that emissions, **from the facility**, result in an ambient lead concentration exceeding 1.5 micrograms per standard cubic meter averaged over a one-month period (Colorado Regulation No. 8, Part C, Section I.B). A copy of the source's modeling analysis, indicating that lead emissions meet the State-only lead standard shall be maintained and made available to the Division upon request. No further modeling is required unless changes to the fuels processed would significantly increase lead emissions above the modeled levels.

11.2 Lead emissions from the facility are subject to the General Conditions in Section V of this Permit including Recordkeeping and Reporting requirements and Fee Payment listed under Conditions 22 and 8. Annual emissions for the purposes of APEN reporting and payment of annual fees shall be based on the information submitted in the annual Toxic Release Inventory (TRI) report. The TRI report and calculation methodology shall be made available to the Division upon request.

12. Coal Sampling Requirements

Coal shall be sampled to determine the heat content, weight percent sulfur, weight percent ash and moisture content of the coal. Vendor receipts used for contractual purposes to insure fuel is delivered within specifications shall be adequate to provide the necessary data for the purposes of emission calculations and monitoring compliance with permit conditions. The permittee shall use vendor sample results from all shipments of coal received.

13. Emission Factors

The permittee shall comply with the provisions of Regulation No. 3 concerning APEN reporting. Emission factors that are approved compliance factors specified within this permit can not be adjusted without requiring a permit modification. Emission factors and/or other emission estimating methods used only to comply with the reporting requirements of this regulation can be updated and modified as specified. These changes by themselves, do not require any permitting activities though the resulting emission estimate may trigger permitting activities."

14. Regional Haze Requirements – Unit 1 Boiler

The Regional Haze Requirements included in this section do not apply until EPA approves the BART portion Colorado's Regional Haze State Implementation Plan (SIP). Upon approval of the SIP, a compliance date will be determined in accordance with the requirements specified in Condition 14.5.

Parameter	Permit Condition Number	Limitations Short Term	Limitations Long Term	Compliance Emission Factor	Monitoring Method	Monitoring Interval
Control Requirements	14.1	N/A	N/A	N/A	See Condition 14.1	
SO_2 Requirements	14.2	0.15 lb/mmBtu, on a 30-day rolling average 0.12 lb/mmBtu, on a 12-month rolling average		N/A	Continuous Emission Monitor	Continuous
NO_X Requirements	14.3	0.23 lbs/mmBu, on a 30-day rolling average		N/A	Continuous Emission Monitor	Continuous
PM Requirements	14.4.	0.03 lb/mmBtu		N/A	Baghouse Maintenance, Source Testing and CAM	See Condition 14.4.
Compliance Schedule	14.5.	See Condition 14.5		N/A	See Condition 14.5	
Reporting Requirements	14.6	See Condition 14.6		N/A	See Condition 14.6	

14.1 A lime spray dryer shall be installed on this unit to control SO_2 emissions. The existing low NO_X burners and over-fire air systems shall be modified and/or new burners installed to further reduce NO_X emissions (Colorado Construction Permit 07MR0111B).

14.2 SO_2 emissions from Unit 1 are subject to the following limitations:

14.2.1 SO_2 emissions shall not exceed 0.15 lb/mmBtu, on a 30-day rolling average, including emissions from shutdown and malfunction events. The first two hours average coal is first fed to the boiler during a cold startup shall be excluded from the calculation of that day's SO_2 emissions (Colorado Construction Permit 07MR0111B).

14.2.2 SO_2 emissions shall not exceed 0.12 lb/mmBtu, on a 12-month rolling average basis including emissions from startup, shutdown and malfunction events (Colorado Construction Permit 07MR0111B).

Compliance with the SO_2 emission limitations shall be monitored using the continuous emissions monitoring systems required by Condition 1.8 of this permit. Compliance demonstrations shall be made according to procedures in the revised New Source Performance Standard provisions of 40 CFR Part 60 Subpart Da, including the definition of boiler operating day, for units constructed after February 28, 2005 (Colorado Construction permit 07MR0111B).

14.3 NO_X emissions from Unit 1 are subject to the following limitations:

14.3.1 NO_X emissions shall not exceed 0.23 lbs/mmBtu, on a 30-day rolling average basis, including shutdown and malfunction events. During cold startups, the following shall be excluded from the calculation of that day's NO_X emissions (Colorado Construction permit 07MR0111B).

14.3.1.1 The first two hours when natural gas-fired igniters are in use, and

14.3.1.2 The first four hours after coal is first fed to the boiler.

Compliance with the NO_X emission limitations shall be monitored using the continuous emissions monitoring systems required by Condition 1.8 of this permit. Compliance demonstrations shall be made according to procedures in the revised New Source Performance Standard provisions of 40 CFR Part 60 Subpart Da, including the definition of boiler operating day, for units constructed after February 28, 2005 (Colorado Construction permit 07MR0111B).

14.4 Particulate matter emissions from Unit 1 shall not exceed 0.03 lbs/mmBtu, based on the average of three 2-hour test runs (Colorado Construction permit 07MR0111B). Compliance with this standard shall be monitored as required by Condition 1.1 of this permit. The first performance test required by Condition 1.1.2 shall be conducted as required by the compliance schedule developed in accordance with the requirements in Condition 14.5.

14.5 The permittee shall comply with the BART emission limits for SO_2, NO_X and particulate matter as expeditiously as practicable, but in no event later than five years after EPA approval of the implementation plan revision. In order to establish the compliance date, PSCo shall submit to the Division a proposed compliance schedule within sixty days after EPA approves the BART portion of the Regional Haze SIP. The Division shall publish the proposed schedule and provide for a thirty-day public comment period following publication. The Division shall publish its final determination regarding the proposed schedule for compliance within sixty days after the close of the public comment period and will respond to all public comments received. PSCo shall comply with all conditions of this permit by the compliance date published by the Division (Colorado Construction permit 07MR0111B).

14.6 Upon EPA's approval of the BART portion of the Colorado's Regional Haze SIP, the permittee shall attach to its Semi-Annual Monitoring and Permit Deviation Report (Appendix B) a Progress Report on the status of BART not to exceed one page in length. This report shall include the following (Colorado Construction permit 07MR0111B):

14.6.1 The installation date (expected or actual) for the BART controls, if any;

14.6.2 The anticipated date on which the source will achieve the BART emission limits set forth in this permit;

14.6.3 A description of the progress made since the prior BART Progress Report toward the installation of BART controls, if relevant and toward achieving the BART emission limits set forth in this permit.

The permitte shall be not be required to submit BART Progress Reports once the source demonstrates compliance with the BART emission limits set forth in this permit.

SECTION III - Acid Rain Requirements

1. Designated Representative and Alternate Designated Representative

Designated Representative:

Name: Steve Mills
Title: General Manager, Power Generation, CO
Phone: (303) 628-2679

Alternate Designated Representative:

Name: Dean Metcalf
Title: Director, Air and Water
Phone: (720) 497-2007

2. Sulfur Dioxide Emission Allowances and Nitrogen Oxide Emission Limitations

Unit 1	2010	2011	2012	2013	2014	2015
SO_2 Allowances, per 40 CFR Part 73.10(b), Table 2	14327*	14327*	14327*	14327*	14327*	14327*
NO_X Limits, per 40 CFR Part 76.7	0.46 lbs/mmBtu	0.46 lbs/mmBtu	0.46 lbs/mmBtu	0.46 lbs/mmBtu	0.46 lbs/mmBtu	0.46 lbs/mmBtu

* Under the provisions of § 72.84(a) any allowance allocations to, transfers to and deductions from an affected unit=s Allowance Tracking System account is considered an automatic permit amendment and as such no revision to the permit is necessary. Numerical allowances shown in this table are from the 1996 edition of the CFR.

3. Standard Requirements

Unit 1 of this facility is subject to and the source has certified that they will comply with the following standard conditions.

Permit Requirements.

(1) The designated representative of each affected source and each affected unit at the source shall:
- (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
- (ii) Submit in a timely manner any supplemental information that the Division determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
- (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the Division; and
- (ii) Have an Acid Rain Permit.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Federal Clean Air Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each affected unit at the source shall:
   (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance account (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
   (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Federal Clean Air Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
   (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
   (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan to the Administrator of the U. S. EPA, as required under 40 CFR part 77.

(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:

(i) Pay without demand, to the Administrator of the U. S. EPA, the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or the Division:
 (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
 (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
 (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
 (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Federal Clean Air Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Federal Clean Air Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.

(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Federal Clean Air Act.

Effect on Other Authorities. No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Federal Clean Air Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Federal Clean Air Act, including the provisions of title I of the Federal Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Federal Clean Air Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

4. Reporting Requirements

Reports shall be submitted to the addresses identified in Appendix D.

Pursuant to 40 CFR Part 75.64 quarterly reports and compliance certification requirements shall be submitted to the Administrator **within 30 days after the end of the calendar quarter**. The contents of these reports shall meet the requirements of 40 CFR 75.64.

Pursuant to 40 CFR Part 75.65 excess emissions of opacity shall be reported to the Division. These reports shall be submitted in a format approved by the Division.

Revisions to this permit shall be made in accordance with 40 CFR Part 72, Subpart H, §§ 72.80 through 72.85 (as adopted by reference in Colorado Regulation 18). Permit modification requests shall be submitted to the Division at the address identified in Appendix D.

Changes to the Designated Representative or Alternate Designated Representative shall be made in accordance with 40 CFR 72.23.

SECTION IV - Permit Shield

Regulation No. 3, 5 CCR 1001-5, Part C, §§ I.A.4, V.D., & XIII.B and § 25-7-114.4(3)(a), C.R.S.

1. Specific Non-Applicable Requirements

Based on the information available to the Division and supplied by the applicant, the following parameters and requirements have been specifically identified as non-applicable to the facility to which this permit has been issued. This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modifications or reconstruction on which construction commenced prior to permit issuance.

Emission Unit Description & Number	Applicable Requirement	Justification
Cooling Tower	40 CFR Part 63, Subpart Q (as adopted by reference in Colorado Regulation No. 8, Part E)	These requirements are not applicable because the cooling towers do not use chromium-based water treatment chemicals.

2. General Conditions

Compliance with this Operating Permit shall be deemed compliance with all applicable requirements specifically identified in the permit and other requirements specifically identified in the permit as not applicable to the source. This permit shield shall not alter or affect the following:

2.1 The provisions of §§ 25-7-112 and 25-7-113, C.R.S., or § 303 of the federal act, concerning enforcement in cases of emergency;

2.2 The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

2.3 The applicable requirements of the federal Acid Rain Program, consistent with § 408(a) of the federal act;

2.4 The ability of the Air Pollution Control Division to obtain information from a source pursuant to § 25-7-111(2)(I), C.R.S., or the ability of the Administrator to obtain information pursuant to § 114 of the federal act;

2.5 The ability of the Air Pollution Control Division to reopen the Operating Permit for cause pursuant to Regulation No. 3, Part C, § XIII.

2.6 Sources are not shielded from terms and conditions that become applicable to the source subsequent to permit issuance.

3. Streamlined Conditions

The following applicable requirements have been subsumed within this operating permit using the pertinent streamlining procedures approved by the U.S. EPA. For purposes of the permit shield, compliance with the listed permit conditions will also serve as a compliance demonstration for purposes of the associated subsumed requirements.

Permit Condition(s)	Streamlined (Subsumed) Requirements
Section II, Conditions 9.1, 9.2, 9.3 & 9.4	Colorado Regulation No. 1, Sections IV.A & B [general continuous emission monitoring requirements]
Section V, Conditions 22.b & c	Colorado Regulation No. 1, Section IV. H [continuous emission monitoring requirements - maintaining a file of continuous emission monitoring records]
Section II, Condition 9.4.2	Colorado Regulation No. 1, Section IV. F [continuous emission monitoring requirements – calibration requirements]
Section II, Condition 9.5	Colorado Regulation No. 1, Section IV.G [continuous emission monitoring requirements - excess emission reporting requirements]
Section II, Condition 1.13	EPA PSD Permit, Condition III.a **opacity requirement ONLY** [opacity not to exceed 20% except for one 6-minute period per hour of not more than 27% average opacity]
Section II, Condition 1.1	40 CFR Part 60 Subpart D § 60.42(a), as adopted by reference in Colorado Regulation No. 6, Part A and EPA PSD Permit [particulate matter emissions shall not exceed 0.1 lbs/mmBtu]
Section II, Condition 1.3	40 CFR Part 60 Subpart D § 60.43(a)(2), as adopted by reference in Colorado Regulation No. 6, Part A and EPA PSD Permit [SO_2 emissions shall not exceed 1.2 lbs/mmBtu, when burning coal]
Section II, Conditions 9.1, 9.2, 9.3 & 9.4	40 CFR Part 60 Subpart D §§ 60.45(a), (c) and EPA PSD Permit **EXCEPT (c)(3) as it applies to COMS**, (e) and (f) as adopted by reference in Colorado Regulation No. 6, Part A [continuous emission monitoring requirements]
Section II, Condition 9.5	40 CFR Part 60 Subpart D § 60.45(g) and EPA PSD Permit, **EXCEPT (g)(3) as it applies to identifying NO_X excess emissions**, as adopted by reference in Colorado Regulation No. 6, Part A [excess emission reporting requirements]

SECTION V - General Permit Conditions

7/21/09 version

1. Administrative Changes

Regulation No. 3, 5 CCR 1001-5, Part A, § III.

The permittee shall submit an application for an administrative permit amendment to the Division for those permit changes that are described in Regulation No. 3, Part A, § I.B.1. The permittee may immediately make the change upon submission of the application to the Division.

2. Certification Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.9., V.C.16.a.& e. and V.C.17.

a. Any application, report, document and compliance certification submitted to the Air Pollution Control Division pursuant to Regulation No. 3 or the Operating Permit shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

b. All compliance certifications for terms and conditions in the Operating Permit shall be submitted to the Air Pollution Control Division at least annually unless a more frequent period is specified in the applicable requirement or by the Division in the Operating Permit.

c. Compliance certifications shall contain:

(i) the identification of each permit term and condition that is the basis of the certification;

(ii) the compliance status of the source;

(iii) whether compliance was continuous or intermittent;

(iv) method(s) used for determining the compliance status of the source, currently and over the reporting period; and

(v) such other facts as the Air Pollution Control Division may require to determine the compliance status of the source.

d. All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

e. If the permittee is required to develop and register a risk management plan pursuant to § 112(r) of the federal act, the permittee shall certify its compliance with that requirement; the Operating Permit shall not incorporate the contents of the risk management plan as a permit term or condition.

3. Common Provisions

Common Provisions Regulation, 5 CCR 1001-2 §§ II.A., II.B., II.C., II,.E., II.F., II.I, and II.J

a. To Control Emissions Leaving Colorado

When emissions generated from sources in Colorado cross the State boundary line, such emissions shall not cause the air quality standards of the receiving State to be exceeded, provided reciprocal action is taken by the receiving State.

b. Emission Monitoring Requirements

The Division may require owners or operators of stationary air pollution sources to install, maintain, and use instrumentation to monitor and record emission data as a basis for periodic reports to the Division.

c. Performance Testing

The owner or operator of any air pollution source shall, upon request of the Division, conduct performance test(s) and furnish the Division a written report of the results of such test(s) in order to determine compliance with applicable emission control regulations.

Performance test(s) shall be conducted and the data reduced in accordance with the applicable reference test methods unless the Division:

(i) specifies or approves, in specific cases, the use of a test method with minor changes in methodology;

(ii) approves the use of an equivalent method;

(iii) approves the use of an alternative method the results of which the Division has determined to be adequate for indicating where a specific source is in compliance; or

(iv) waives the requirement for performance test(s) because the owner or operator of a source has demonstrated by other means to the Division's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Commission's or Division's authority to require testing under the Colorado Revised Statutes, Title 25, Article 7, and pursuant to regulations promulgated by the Commission.

Compliance test(s) shall be conducted under such conditions as the Division shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Division such records as may be necessary to determine the conditions of the performance test(s). Operations during period of startup, shutdown, and malfunction shall not constitute representative conditions of performance test(s) unless otherwise specified in the applicable standard.

The owner or operator of an affected facility shall provide the Division thirty days prior notice of the performance test to afford the Division the opportunity to have an observer present. The Division may waive the thirty day notice requirement provided that arrangements satisfactory to the Division are made for earlier testing.

The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(i) Sampling ports adequate for test methods applicable to such facility;

(ii) Safe sampling platform(s);

(iii) Safe access to sampling platform(s); and

(iv) Utilities for sampling and testing equipment.

Each performance test shall consist of at least three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic mean of results of at least three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the owner or operator's control, compliance may, upon the Division's approval, be determined using the arithmetic mean of the results of the two other runs.

Nothing in this section shall abrogate the Division's authority to conduct its own performance test(s) if so warranted.

d. Affirmative Defense Provision for Excess Emissions during Malfunctions

Note that until such time as the U.S. EPA approves this provision into the Colorado State Implementation Plan (SIP), it shall be enforceable only by the State.

An affirmative defense to a claim of violation under these regulations is provided to owners and operators for civil penalty actions for excess emissions during periods of malfunction. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of evidence that:

(i) The excess emissions were caused by a sudden, unavoidable breakdown of equipment, or a sudden, unavoidable failure of a process to operate in the normal or usual manner, beyond the reasonable control of the owner or operator;

(ii) The excess emissions did not stem from any activity or event that could have reasonably been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;

(iii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded;

(iv) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(v) All reasonably possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence;

(viii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(ix) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This section is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement; and

(x) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in the Commissions' Regulations that could be attributed to the emitting source.

The owner or operator of the facility experiencing excess emissions during a malfunction shall notify the division verbally as soon as possible, but no later than noon of the Division's next working day, and shall submit written notification following the initial occurrence of the excess emissions by the end of the source's next reporting period. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to failures to meet federally promulgated performance standards or emission limits, including, but not limited to, new source performance standards and national emission standards for hazardous air pollutants. The affirmative defense provision does not apply to state implementation plan (sip) limits or permit limits that have been set taking into account potential emissions during malfunctions, including, but not necessarily limited to, certain limits with 30-day or longer averaging times, limits that indicate they apply during malfunctions, and limits that indicate they apply at all times or without exception.

e. Circumvention Clause

A person shall not build, erect, install, or use any article, machine, equipment, condition, or any contrivance, the use of which, without resulting in a reduction in the total release of air pollutants to the atmosphere, reduces or conceals an emission which would otherwise constitute a violation of this regulation. No person shall circumvent this regulation by using more openings than is considered normal practice by the industry or activity in question.

f. Compliance Certifications

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in the Colorado State Implementation Plan, nothing in the Colorado State Implementation Plan shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. Evidence that has the effect of making any relevant standard or permit term more stringent shall not be credible for proving a violation of the standard or permit term.

When compliance or non-compliance is demonstrated by a test or procedure provided by permit or other applicable requirement, the owner or operator shall be presumed to be in compliance or non-compliance unless other relevant credible evidence overcomes that presumption.

g. Affirmative Defense Provision for Excess Emissions During Startup and Shutdown

An affirmative defense is provided to owners and operators for civil penalty actions for excess emissions during periods of startup and shutdown. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of the evidence that:

(i) The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

(ii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance;

(iii) If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(iv) The frequency and duration of operation in startup and shutdown periods were minimized to the maximum extent practicable;

(v) All possible steps were taken to minimize the impact of excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence; and,

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This subparagraph is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement.

The owner or operator of the facility experiencing excess emissions during startup and shutdown shall notify the Division verbally as soon as possible, but no later than two (2) hours after the start of the next working day, and shall submit written quarterly notification following the initial occurrence of the excess emissions. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to State Implementation Plan provisions or other requirements that derive from new source performance standards or national emissions standards for hazardous air pollutants, or any other federally enforceable performance standard or emission limit with an averaging time greater than twenty-four hours. In addition, an affirmative defense cannot be used by a single source or small group of sources where the excess emissions have the potential to cause an exceedance of the ambient air quality standards or Prevention of Significant Deterioration (PSD) increments.

In making any determination whether a source established an affirmative defense, the Division shall consider the information within the notification required above and any other information the Division deems necessary, which may include, but is not limited to, physical inspection of the facility and review of documentation pertaining to the maintenance and operation of process and air pollution control equipment.

4. Compliance Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.C.9., V.C.11. & 16.d. and § 25-7-122.1(2), C.R.S.

a. The permittee must comply with all conditions of the Operating Permit. Any permit noncompliance relating to federally-enforceable terms or conditions constitutes a violation of the federal act, as well as the state act and Regulation No. 3. Any permit noncompliance relating to state-only terms or conditions constitutes a violation of the state act and Regulation No. 3, shall be enforceable pursuant to state law, and shall not be enforceable by citizens under § 304 of the federal act. Any such violation of the federal act, the state act or regulations implementing either statute is grounds for enforcement action, for permit termination, revocation and reissuance or modification or for denial of a permit renewal application.

b. It shall not be a defense for a permittee in an enforcement action or a consideration in favor of a permittee in a permit termination, revocation or modification action or action denying a permit renewal application that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

c. The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of any request by the permittee for a permit modification, revocation and reissuance, or termination, or any notification of planned changes or anticipated noncompliance does not stay any permit condition, except as provided in §§ X. and XI. of Regulation No. 3, Part C.

d. The permittee shall furnish to the Air Pollution Control Division, within a reasonable time as specified by the Division, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permittee, including information claimed to be confidential. Any information subject to a claim of confidentiality shall be specifically identified and submitted separately from information not subject to the claim.

e. Any schedule for compliance for applicable requirements with which the source is not in compliance at the time of permit issuance shall be supplemental, and shall not sanction noncompliance with, the applicable requirements on which it is based.

f. For any compliance schedule for applicable requirements with which the source is not in compliance at the time of permit issuance, the permittee shall submit, at least every 6 months unless a more frequent period is specified in the applicable requirement or by the Air Pollution Control Division, progress reports which contain the following:

(i) dates for achieving the activities, milestones, or compliance required in the schedule for compliance, and dates when such activities, milestones, or compliance were achieved; and

(ii) an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

g. The permittee shall not knowingly falsify, tamper with, or render inaccurate any monitoring device or method required to be maintained or followed under the terms and conditions of the Operating Permit.

5. Emergency Provisions

Regulation No. 3, 5 CCR 1001-5, Part C, § VII.

An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed the technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. "Emergency" does not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error. An emergency constitutes an affirmative defense to an enforcement action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates, through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. an emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. the permitted facility was at the time being properly operated;

c. during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. the permittee submitted oral notice of the emergency to the Air Pollution Control Division no later than noon of the next working day following the emergency, and followed by written notice within one month of the time when emissions limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

This emergency provision is in addition to any emergency or malfunction provision contained in any applicable

6. Emission Controls for Asbestos

Regulation No. 8, 5 CCR 1001-10, Part B

The permittee shall not conduct any asbestos abatement activities except in accordance with the provisions of Regulation No. 8, Part B, " asbestos control."

7. Emissions Trading, Marketable Permits, Economic Incentives

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.13.

No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are specifically provided for in the permit.

8. Fee Payment

C.R.S. §§ 25-7-114.1(6) and 25-7-114.7

a. The permittee shall pay an annual emissions fee in accordance with the provisions of § 25-7-114.7. A 1% per month late payment fee shall be assessed against any invoice amounts not paid in full on the 91st day after the date of invoice, unless a permittee has filed a timely protest to the invoice amount.

b. The permittee shall pay a permit processing fee in accordance with the provisions of C.R.S § 25-7-114.7. If the Division estimates that processing of the permit will take more than 30 hours, it will notify the permittee of its estimate of what the actual charges may be prior to commencing any work exceeding the 30 hour limit.

c. The permittee shall pay an APEN fee in accordance with the provisions of § 25-7-114.1(6) for each APEN or revised APEN filed.

9. Fugitive Particulate Emissions

Regulation No. 1, 5 CCR 1001-3, § III.D.1.

The permittee shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions into the atmosphere, in accordance with the provisions of Regulation No. 1, § III.D.1.

10. Inspection and Entry

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.16.b.

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Air Pollution Control Division, or any authorized representative, to perform the following:

a. enter upon the permittee's premises where an Operating Permit source is located, or emissions-related activity is conducted, or where records must be kept under the terms of the permit;

b. have access to, and copy, at reasonable times, any records that must be kept under the conditions of the permit;

c. inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the Operating Permit;

d. sample or monitor at reasonable times, for the purposes of assuring compliance with the Operating Permit or applicable requirements, any substances or parameters.

11. Minor Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, §§ X. & XI.

The permittee shall submit an application for a minor permit modification before making the change requested in the application. The permit shield shall not extend to minor permit modifications.

12. New Source Review

Regulation No. 3, 5 CCR 1001-5, Part B

The permittee shall not commence construction or modification of a source required to be reviewed under the New Source Review provisions of Regulation No. 3, Part B, without first receiving a construction permit.

13. No Property Rights Conveyed

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.11.d.

This permit does not convey any property rights of any sort, or any exclusive privilege.

14. Odor

Regulation No. 2, 5 CCR 1001-4, Part A

As a matter of state law only, the permittee shall comply with the provisions of Regulation No. 2 concerning odorous emissions.

15. Off-Permit Changes to the Source

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.B.

The permittee shall record any off-permit change to the source that causes the emissions of a regulated pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from the change, including any other data necessary to show compliance with applicable ambient air quality standards. The permittee shall provide contemporaneous notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit . The permit shield shall not apply to any off-permit change.

16. Opacity

Regulation No. 1, 5 CCR 1001-3, §§ I., II.

The permittee shall comply with the opacity emissions limitation set forth in Regulation No. 1, §§ I.-II.

17. Open Burning

Regulation No. 9, 5 CCR 1001-11

The permittee shall obtain a permit from the Division for any regulated open burning activities in accordance with provisions of Regulation No .9.

18. Ozone Depleting Compounds

Regulation No. 15, 5 CCR 1001-17

The permittee shall comply with the provisions of Regulation No. 15 concerning emissions of ozone depleting compounds. Sections I., II.C., II.D., III. IV., and V. of Regulation No. 15 shall be enforced as a matter of state law only.

19. Permit Expiration and Renewal

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.6., IV.C., V.C.2.

a. The permit term shall be five (5) years. The permit shall expire at the end of its term. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted.

b. Applications for renewal shall be submitted at least twelve months, but not more than 18 months, prior to the expiration of the Operating Permit. An application for permit renewal may address only those portions of the permit that require revision, supplementing, or deletion, incorporating the remaining permit terms by reference from the previous permit. A copy of any materials incorporated by reference must be included with the application.

20. Portable Sources

Regulation No. 3, 5 CCR 1001-5, Part C, § II.D.

Portable Source permittees shall notify the Air Pollution Control Division at least 10 days in advance of each change in location.

21. Prompt Deviation Reporting

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.7.b.

The permittee shall promptly report any deviation from permit requirements, including those attributable to malfunction conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken.

"Prompt" is defined as follows:

a. Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit; or

b. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

(i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report shall be made within 24 hours of the occurrence;

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two hours in excess of permit requirements, the report shall be made within 48 hours; and

(iii) For all other deviations from permit requirements, the report shall be submitted every six (6) months, except as otherwise specified by the Division in the permit in accordance with paragraph 22.d. below.

c. If any of the conditions in paragraphs b.i or b.ii above are met, the source shall notify the Division by telephone (303-692-3155) or facsimile (303-782-0278) based on the timetables listed above. *[Explanatory note: Notification by telephone or facsimile must specify that this notification is a deviation report for an Operating Permit.]* A written notice, certified consistent with General Condition 2.a. above (Certification Requirements), shall be submitted within 10 working days of the occurrence. All deviations reported under this section shall also be identified in the 6-month report required above.

"Prompt reporting" does not constitute an exception to the requirements of "Emergency Provisions" for the purpose of avoiding enforcement actions.

22. Record Keeping and Reporting Requirements

Regulation No. 3, 5 CCR 1001-5, Part A, § II.; Part C, §§ V.C.6., V.C.7.

a. Unless otherwise provided in the source specific conditions of this Operating Permit, the permittee shall maintain compliance monitoring records that include the following information:

(i) date, place as defined in the Operating Permit, and time of sampling or measurements;

(ii) date(s) on which analyses were performed;

(iii) the company or entity that performed the analysis;

(iv) the analytical techniques or methods used;

(v) the results of such analysis; and

(vi) the operating conditions at the time of sampling or measurement.

b. The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of the monitoring sample, measurement, report or application. Support information, for this purpose, includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the Operating Permit. With prior approval of the Air Pollution Control Division, the permittee may maintain any of the above records in a computerized form.

c. Permittees must retain records of all required monitoring data and support information for the most recent twelve (12) month period, as well as compliance certifications for the past five (5) years on-site at all times. A permittee shall make available for the Air Pollution Control Division's review all other records of required monitoring data and support information required to be retained by the permittee upon 48 hours advance notice by the Division.

d. The permittee shall submit to the Air Pollution Control Division all reports of any required monitoring at least every six (6) months, unless an applicable requirement, the compliance assurance monitoring rule, or the Division requires submission on a more frequent basis. All instances of deviations from any permit requirements must be clearly identified in such reports.

e. The permittee shall file an Air Pollutant Emissions Notice ("APEN") prior to constructing, modifying, or altering any facility, process, activity which constitutes a stationary source from which air pollutants are or are to be emitted, unless such source is exempt from the APEN filing requirements of Regulation No. 3, Part A, § II.D. A revised APEN shall be filed annually whenever a significant change in emissions, as defined in Regulation No. 3, Part A, § II.C.2., occurs; whenever there is a change in owner or operator of any facility, process, or activity; whenever new control equipment is installed; whenever a different type of control equipment replaces an existing type of control equipment; whenever a permit limitation must be modified; or before the APEN expires. An APEN is valid for a period of five years. The five-year period recommences when a revised APEN is received by the Air Pollution Control Division. Revised APENs shall be submitted no later than 30 days before the five-year term expires. Permittees submitting revised APENs to inform the Division of a change in actual emission rates must do so by April 30 of the following year. Where a permit revision is required, the revised APEN must be filed along with a request for permit revision. APENs for changes in control equipment must be submitted before the change occurs. Annual fees are based on the most recent APEN on file with the Division.

23. Reopenings for Cause

Regulation No. 3, 5 CCR 1001-5, Part C, § XIII.

a. The Air Pollution Control Division shall reopen, revise, and reissue Operating Permits; permit reopenings and reissuance shall be processed using the procedures set forth in Regulation No. 3, Part C, § III., except that proceedings to reopen and reissue permits affect only those parts of the permit for which cause to reopen exists.

b. The Division shall reopen a permit whenever additional applicable requirements become applicable to a major source with a remaining permit term of three or more years, unless the effective date of the requirements is later than the date on which the permit expires, or unless a general permit is obtained to address the new requirements; whenever additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program; whenever the Division determines the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or whenever the Division determines that the permit must be revised or revoked to assure compliance with an applicable requirement.

c. The Division shall provide 30 days' advance notice to the permittee of its intent to reopen the permit, except that a shorter notice may be provided in the case of an emergency.

d. The permit shield shall extend to those parts of the permit that have been changed pursuant to the reopening and reissuance procedure.

24. Section 502(b)(10) Changes

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.A.

The permittee shall provide a minimum 7-day advance notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permittee shall attach a copy of each such notice given to its Operating Permit.

25. Severability Clause

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.10.

In the event of a challenge to any portion of the permit, all emissions limits, specific and general conditions, monitoring, record keeping and reporting requirements of the permit, except those being challenged, remain valid and enforceable.

26. Significant Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, § III.B.2.

The permittee shall not make a significant modification required to be reviewed under Regulation No. 3, Part B ("Construction Permit" requirements) without first receiving a construction permit. The permittee shall submit a complete Operating Permit application or application for an Operating Permit revision for any new or modified source within twelve months of commencing operation, to the address listed in Item 1 in Appendix D of this permit. If the permittee chooses to use the "Combined Construction/Operating Permit" application procedures of Regulation No. 3, Part C, then the Operating Permit must be received prior to commencing construction of the new or modified source.

27. Special Provisions Concerning the Acid Rain Program

Regulation No. 3, 5 CCR 1001-5, Part C, §§ V.C.1.b. & 8

a. Where an applicable requirement of the federal act is more stringent than an applicable requirement of regulations promulgated under Title IV of the federal act, 40 Code of Federal Regulations (CFR) Part 72, both provisions shall be incorporated into the permit and shall be federally enforceable.

b. Emissions exceeding any allowances that the source lawfully holds under Title IV of the federal act or the regulations promulgated thereunder, 40 CFR Part 72, are expressly prohibited.

28. Transfer or Assignment of Ownership

Regulation No. 3, 5 CCR 1001-5, Part C, § II.C.

No transfer or assignment of ownership of the Operating Permit source will be effective unless the prospective owner or operator applies to the Air Pollution Control Division on Division-supplied Administrative Permit Amendment forms, for reissuance of the existing Operating Permit. No administrative permit shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage, and liability between the permittee and the prospective owner or operator has been submitted to the Division.

29. Volatile Organic Compounds

Regulation No. 7, 5 CCR 1001-9, §§ III & V.

a. For sources located in an ozone non-attainment area or the Denver Metro Attainment Maintenance Area, all storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing shall be conducted as in Regulation No. 7, Section VIII.C.3.

Except when otherwise provided by Regulation No. 7, all volatile organic compounds, excluding petroleum liquids, transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

b. The permittee shall not dispose of volatile organic compounds by evaporation or spillage unless Reasonably Available Control Technology (RACT) is utilized.

c. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Colorado Regulation No. 7, Section VI, shall permit gasoline to be intentionally spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

30. Wood Stoves and Wood burning Appliances

Regulation No. 4, 5 CCR 1001-6

The permittee shall comply with the provisions of Regulation No. 4 concerning the advertisement, sale, installation, and use of wood stoves and wood burning appliances.

OPERATING PERMIT APPENDICES

A - INSPECTION INFORMATION
B – MONITORING AND PERMIT DEVIATION REPORT
C - COMPLIANCE CERTIFICATION REPORT
D - NOTIFICATION ADDRESSES
E - PERMIT ACRONYMS
F - PERMIT MODIFICATIONS
G - EMISSION FACTORS FOR SOURCES OF FUGITIVE PARTICULATE MATTER EMISSIONS
H – COMPLIANCE ASSURANCE MONITORING PLAN
I - MERCURY (HG) MONITORING PLAN

*DISCLAIMER:

None of the information found in these Appendices shall be considered to be State or Federally enforceable, except as otherwise provided in the permit, and is presented to assist the source, permitting authority, inspectors, and citizens.

APPENDIX A - Inspection Information

Directions to Plant:

This facility is located at 14940 County Road 24.

Safety Equipment Required:

Eye Protection
Hard Hat
Safety Shoes
Hearing Protection
Respirator (required in some areas)

Facility Plot Plan:

Figure 1 (following page) shows the plot plan as submitted on February 15, 1996 with the source's Title V Operating Permit Application.

List of Insignificant Activities:

The following list of insignificant activities was provided by the source to assist in the understanding of the facility layout. Since there is no requirement to update such a list, activities may have changed since the last filing.

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

Boiler Steam Vents – emit VOC from injection of VOCs as treatment chemicals (< 1 ton/yr VOC)
Solvent Cold Cleaners (< 1 ton/yr of VOC from each unit)
Lime storage silo for water treatment process (< 1 ton of PM/PM_{10})

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

Plant Laboratory

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

Propane Portable Heaters

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

Maintenance Welding Machine

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

Cooling Tower Scale Inhibitor Day Tank (50 gal inside water treatment bldg)
High Pressure Treated Water Chemical Feed Tank (500 gal treated water pond)
R. O. Acid Feed Tank (50 gal inside water treatment bldg)
R. O. Anti-Scalant Feed Tank (50 gal inside water treatment bldg)
R. O. Sodium Bisulfite Feed Tank (50 gal inside water treatment bldg)
R. O. Caustic Feed Tank (50 gal inside water treatment bldg)
Building Cooling Water Head Tank (500 gal inside main plant)
Oxygen Scavenger Chemical Feed Tank (50 gal inside main plant)
Phosphate Chemical Feed Tank (50 gal inside main plant)
Amine Chemical Feed Tank (50 gal inside main plant)
Ash Water Chemical Feed Tank (265 gal inside main plant)
Auxiliary Boiler Chemical Feed Tank (50 gal inside main plant)
Bleach Feedwater Tank (100 gal inside water treatment bldg)
Sewage Bleach Feed Tank (75 gal inside sewage treatment bldg)

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

Battery Storage Area

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

Mowers, Snowblowers, Etc.

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

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

Portable Welding Torches

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

Oil Drum Storage Areas
Warehouse
Water Treatment Buildings

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

Wastewater Operations
Evaporation Ponds (east and south sides of facility)
Holding Ponds (east and south sides of facility)
Raw Water Storage Reservoir (north side of facility)

Treated Water Pond (west of water treatment bldg)

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

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

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

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

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

Fuel Oil Spill Tank (19,750 gal underground)
Emergency Oil Spill Drain Tank (12,530 gal underground)
Diesel Tank (10,000 gal above ground)
Diesel Tank (10,000 gal underground)
Diesel Fuel Tank for Emergency Generator (575 gal above ground)
Fire Pump Diesel Day Tank (200 gal above ground)
Turbine Lube Oil Batch Tank A (12,000 gal above ground)
Turbine Lube Oil Batch Tank B (12,000 gal above ground)
Hydrogen Seal Oil Tank (840 gal above ground)

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

Emergency Diesel Generator (runs < 100 hrs/yr)

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

Sandblasting Machine

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

Emergency Fire Pump – 230 hp (runs < 850 hrs/yr)

Non-Road Engines

Joy Air Compressor (< 175 hp and runs < 1,450 hrs/yr)
Portable Light Generator (< 175 hp and runs < 1,450 hrs/yr)
Two (2) Water Pumps (< 175 hp and runs < 1,450 hrs/yr)
Sullair Air Compressor (< 175 hp and runs < 1,450 hrs/yr)
Four (4) Portable Welders (< 175 hp and runs < 1,450 hrs/yr)

Not sources of emissions

Turbine Lube Oil System (closed system)
Waste Water Neutralization Tank (30,000 gal underground)
R. O. Product Storage Tank (10,000 gal inside water treatment bldg)
Sludge Thickener Supernatant Tank (8,000 gal inside water treatment bldg)
Acid Storage Tank A (15,000 gal inside water treatment bldg)
Waste Water Conc. Product Storage Tank (60,000 gal above ground)
Condensate Storage A (150,000 gal above ground)
Condensate Storage B (150,000 gal above ground)
Potable Water Storage Tank (6,000 gal inside main plant)
Soot Blower Water Deslagger Supply Tank (12,000 gal inside main plant)
Acid Stabilization Tank (24,000 gal above ground)
Chem Lab D.I. Water Storage Tank (300 gal inside main plant)
Waste Tank (2,500 gal inside waste water concentrator bldg)
Seed Tank (600 gal inside waste water concentrator bldg)
Primary Feed Tank (4,500 gal inside waste water concentrator bldg)
Cooling Tower Scale Inhibitor Storage (4,000 gal inside water treatment bldg)
Caustic Storage Tank A (15,000 gal inside water treatment bldg)
Alum Storage Tank (12,000 gal inside water treatment bldg)
Main Plant Heat Head Tank (3,300 gal inside main plant)
Sludge Thickener Tank (940,000 gal N of water treatment)
Clarifier/Softener Tank (715,000 gal N of water treatment)
Feed Tank (4,500 gal inside waste water concentrator bldg)
Brine Tank (16,000 gal W of water treatment bldg)
Bleach Tank (16,000 gal W of water treatment bldg)
Tolyltriazole Tank (1,000 gal in main plant bldg)
Scale Inhibitor Tank (1,000 gal in main plant bldg)

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APPENDIX B

Reporting Requirements and Definitions

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Please note that, pursuant to 113(c)(2) of the federal Clean Air Act, any person who knowingly:

(A) makes any false material statement, representation, or certification in, or omits material information from, or knowingly alters, conceals, or fails to file or maintain any notice, application, record, report, plan, or other document required pursuant to the Act to be either filed or maintained (whether with respect to the requirements imposed by the Administrator or by a State);

(B) fails to notify or report as required under the Act; or

(C) falsifies, tampers with, renders inaccurate, or fails to install any monitoring device or method required to be maintained or followed under the Act shall, upon conviction, be punished by a fine pursuant to title 18 of the United States Code, or by imprisonment for not more than 2 years, or both. If a conviction of any person under this paragraph is for a violation committed after a first conviction of such person under this paragraph, the maximum punishment shall be doubled with respect to both the fine and imprisonment.

The permittee must comply with all conditions of this operating permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

The Part 70 Operating Permit program requires three types of reports to be filed for all permits.
All required reports must be certified by a responsible official.

Report #1: Monitoring Deviation Report (due at least every six months)

For purposes of this operating permit, the Division is requiring that the monitoring reports are due every six months unless otherwise noted in the permit. All instances of deviations from permit monitoring requirements must be clearly identified in such reports.

For purposes of this operating permit, monitoring means any condition determined by observation, by data from any monitoring protocol, or by any other monitoring which is required by the permit as well as the recordkeeping associated with that monitoring. This would include, for example, fuel use or process rate monitoring, fuel analyses, and operational or control device parameter monitoring.

Report #2: Permit Deviation Report (must be reported "promptly")

In addition to the monitoring requirements set forth in the permits as discussed above, each and every requirement of the permit is subject to deviation reporting. The reports must address deviations from permit requirements, including those attributable to upset conditions and malfunctions as defined in this Appendix, the probable cause of such deviations, and any corrective actions or preventive measures taken. All deviations from any term or condition of the permit are required to be summarized or referenced in the annual compliance certification.

For purposes of this operating permit, "malfunction" shall refer to both emergency conditions and malfunctions. Additional discussion on these conditions is provided later in this Appendix.

For purposes of this operating permit, the Division is requiring that the permit deviation reports are due as set forth in General Condition 21. Where the underlying applicable requirement contains a definition of prompt or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. For example, quarterly Excess Emission Reports required by an NSPS or Regulation No. 1, Section IV.

In addition to the monitoring deviations discussed above, included in the meaning of deviation for the purposes of this operating permit are any of the following:

(1) A situation where emissions exceed an emission limitation or standard contained in the permit;

(2) A situation where process or control device parameter values demonstrate that an emission limitation or standard contained in the permit has not been met;

(3) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit; or,

(4) A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only if the emission point is subject to CAM)

For reporting purposes, the Division has combined the Monitoring Deviation Report with the Permit Deviation Report.

Report #3: Compliance Certification (annually, as defined in the permit)

Submission of compliance certifications with terms and conditions in the permit, including emission limitations, standards, or work practices, is required not less than annually.

Compliance Certifications are intended to state the compliance status of each requirement of the permit over the certification period. They must be based, at a minimum, on the testing and monitoring methods specified in the permit that were conducted during the relevant time period. In addition, if the owner or operator knows of other material information (i.e. information beyond required monitoring that has been specifically assessed in relation to how the information potentially affects compliance status), that information must be identified and addressed in the compliance certification. The compliance certification must include the following:

- The identification of each term or condition of the permit that is the basis of the certification;
- Whether or not the method(s) used by the owner or operator for determining the compliance status with each permit term and condition during the certification period was the method(s) specified in the permit. Such methods and other means shall include, at a minimum, the methods

and means required in the permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Clean Air Act, which prohibits knowingly making a false certification or omitting material information;

- The status of compliance with the terms and conditions of the permit, and whether compliance was continuous or intermittent. The certification shall identify each deviation and take it into account in the compliance certification. Note that not all deviations are considered violations.[1]

- Such other facts as the Division may require, consistent with the applicable requirements to which the source is subject, to determine the compliance status of the source.

The Certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only for emission points subject to CAM)

Note the requirement that the certification shall identify each deviation and take it into account in the compliance certification. Previously submitted deviation reports, including the deviation report submitted at the time of the annual certification, may be referenced in the compliance certification.

Startup, Shutdown, Malfunctions and Emergencies

Understanding the application of Startup, Shutdown, Malfunctions and Emergency Provisions, is very important in both the deviation reports and the annual compliance certifications.

Startup, Shutdown, and Malfunctions

Please note that exceedances of some New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards that occur during Startup, Shutdown or Malfunctions may not be considered to be non-compliance since emission limits or standards often do not apply unless specifically stated in the NSPS. Such exceedances must, however, be reported as excess emissions per the NSPS/MACT rules and would still be noted in the deviation report. In regard to compliance certifications, the permittee should be confident of the information related to those deviations when making compliance determinations since they are subject to Division review. The concepts of Startup, Shutdown and Malfunctions also exist for Best Available Control Technology (BACT) sources, but are not applied in the same fashion as for NSPS and MACT sources.

Emergency Provisions

Under the Emergency provisions of Part 70, certain operational conditions may act as an affirmative defense against enforcement action if they are properly reported.

[1] For example, given the various emissions limitations and monitoring requirements to which a source may be subject, a deviation from one requirement may not be a deviation under another requirement which recognizes an exception and/or special circumstances relating to that same event.

DEFINITIONS

Malfunction (NSPS) means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Malfunction (SIP) means any sudden and unavoidable failure of air pollution control equipment or process equipment or unintended failure of a process to operate in a normal or usual manner. Failures that are primarily caused by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

Emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

Monitoring and Permit Deviation Report - Part I

1. Following is the **required** format for the Monitoring and Permit Deviation report to be submitted to the Division as set forth in General Condition 21. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

2. Part II of this Appendix B shows the format and information the Division will require for describing periods of monitoring and permit deviations, or malfunction or emergency conditions as indicated in the Table below. One Part II Form must be completed for each Deviation. Previously submitted reports (e.g. EER's or malfunctions) may be referenced and the form need not be filled out in its entirety.

FACILITY NAME: Public Service Company – Pawnee Station
OPERATING PERMIT NO: 96OPMR129
REPORTING PERIOD:____________ (see first page of the permit for specific reporting period and dates)

Operating Permit Unit ID	Unit Description	Deviations noted During Period?[1]		Malfunction/ Emergency Condition Reported During Period?	
		YES	NO	YES	NO
B001	Boiler No. 1 (Unit 1), Foster Wheeler, Opposed Fired, Natural Circulation Boiler, Rated at 5,346 mmBtu/hr. Coal-Fired, with Natural Gas and/or No. 2 Fuel Oil Used for Startup, Shutdown and/or Flame Stabilization.				
B002	Boiler No. 2 (Auxiliary Boiler), Babcock and Wilcox, Package Boiler, Model and Serial No. FM-2763, Rated at 114.3 mmBtu/hr (No. 2 Fuel Oil) and 98 mmBtu/hr (Natural Gas). Natural Gas, No. 2 Fuel Oil or Combination Fired.				
F001	Fugitive Particulate Emissions from Coal Handling and Storage (Railcar Unloading, Storage Pile and Coal Dozing)				
F002	Fugitive Particulate Emissions from Ash Handling and Disposal				
F003	Fugitive Particulate Emissions from Paved and Unpaved Roads				
P001	Coal Handling System (Crushers, Transfer Towers, and Conveying)				
P002	Ash Silo				
P003	Soda Ash Handling System				
M001	Cooling Water Tower				
P004	Two (2) Sorbent Storage Silos				
	General Conditions				
	Insignificant Activities				

[1] See previous discussion regarding what is considered to be a deviation. Determination of whether or not a deviation has occurred shall be based on a reasonable inquiry using readily available information.

Monitoring and Permit Deviation Report - Part II

FACILITY NAME: Public Service Company – Pawnee Station
OPERATING PERMIT NO: 96OPMR129
REPORTING PERIOD:

Is the deviation being claimed as an: Emergency ______ Malfunction ______ N/A _____

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown ______ Malfunction _____
Normal Operation ____________

OPERATING PERMIT UNIT IDENTIFICATION:

Operating Permit Condition Number Citation

Explanation of Period of Deviation

Duration (start/stop date & time)

Action Taken to Correct the Problem

Measures Taken to Prevent a Reoccurrence of the Problem

Dates of Malfunctions/Emergencies Reported (if applicable)

Deviation Code (for Division Use Only)

SEE EXAMPLE ON THE NEXT PAGE

EXAMPLE

FACILITY NAME: Acme Corp.
OPERATING PERMIT NO: 96OPZZXXX
REPORTING PERIOD: 1/1/06 - 6/30/06

Is the deviation being claimed as an: Emergency ______ Malfunction __XX__ N/A ____

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown ______ Malfunction ____
Normal Operation ____________

OPERATING PERMIT UNIT IDENTIFICATION:

Asphalt Plant with a Scrubber for Particulate Control - Unit XXX

Operating Permit Condition Number Citation

Section II, Condition 3.1 - Opacity Limitation

Explanation of Period of Deviation

Slurry Line Feed Plugged

Duration

START- 1730 4/10/06
END- 1800 4/10/06

Action Taken to Correct the Problem

Line Blown Out

Measures Taken to Prevent Reoccurrence of the Problem

Replaced Line Filter

Dates of Malfunction/Emergencies Reported (if applicable)

5/30/06 to A. Einstein, APCD

Deviation Code (for Division Use Only)

Monitoring and Permit Deviation Report - Part III

REPORT CERTIFICATION

SOURCE NAME: Public Service Company – Pawnee Station

FACILITY IDENTIFICATION NUMBER: 0870011

PERMIT NUMBER: 96OPMR129

REPORTING PERIOD:_______________ (see first page of the permit for specific reporting period and dates)

All information for the Title V Semi-Annual Deviation Reports must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B.38. This signed certification document must be packaged with the documents being submitted.

STATEMENT OF COMPLETENESS

I have reviewed the information being submitted in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this submittal are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in Sub-Section 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of Sub-Section 25-7 122.1, C.R.S.

____

Printed or Typed Name | Title

____

Signature | Date Signed

Note: Deviation reports shall be submitted to the Division at the address given in Appendix D of this permit. No copies need be sent to the U.S. EPA.

APPENDIX C

Required Format for Annual Compliance Certification Report

no codes ver 2/20/07

Following is the format for the Compliance Certification report to be submitted to the Division and the U.S. EPA annually based on the effective date of the permit. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

FACILITY NAME: Public Service Company – Pawnee Station

OPERATING PERMIT NO: 96OPMR129
REPORTING PERIOD:

I. Facility Status

___ During the entire reporting period, this source was in compliance with **ALL** terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference. The method(s) used to determine compliance is/are the method(s) specified in the Permit.

___ With the possible exception of the deviations identified in the table below, this source was in compliance with all terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference, during the entire reporting period. The method used to determine compliance for each term and condition is the method specified in the Permit, unless otherwise indicated and described in the deviation report(s). Note that not all deviations are considered violations.

Operating Permit Unit ID	Unit Description	Deviations Reported [1]		Monitoring Method per Permit?[2]		Was Compliance Continuous or Intermittent[3]	
		Previous	Current	YES	NO	Continuous	Intermittent
B001	Boiler No. 1 (Unit 1), Foster Wheeler, Opposed Fired, Natural Circulation Boiler, Rated at 5,346 mmBtu/hr. Coal-Fired, with Natural Gas and/or No. 2 Fuel Oil Used for Startup, Shutdown and/or Flame Stabilization.						
B002	Boiler No. 2 (Auxiliary Boiler), Babcock and Wilcox, Package Boiler, Model and Serial No. FM-2763, Rated at 114.3 mmBtu/hr (No. 2 Fuel Oil) and 98 mmBtu/hr (Natural Gas). Natural Gas, No. 2 Fuel Oil or Combination Fired.						

Operating Permit Unit ID	Unit Description	Deviations Reported [1]		Monitoring Method per Permit?[2]		Was Compliance Continuous or Intermittent[3]	
		Previous	Current	YES	NO	Continuous	Intermittent
F001	Fugitive Particulate Emissions from Coal Handling and Storage (Railcar Unloading, Storage Pile and Coal Dozing)						
F002	Fugitive Particulate Emissions from Ash Handling and Disposal						
F003	Fugitive Particulate Emissions from Paved and Unpaved Roads						
P001	Coal Handling System (Crushers, Transfer Towers, and Conveying)						
P002	Ash Silo						
P003	Soda Ash Handling System						
M001	Cooling Water Tower						
P004	Two (2) Sorbent Storage Silos						
	General Conditions						
	Insignificant Activities [4]						

[1] If deviations were noted in a previous deviation report, put an "X" under "previous". If deviations were noted in the current deviation report (i.e. for the last six months of the annual reporting period), put an "X" under "current". Mark both columns if both apply.

[2] Note whether the method(s) used to determine the compliance status with each term and condition was the method(s) specified in the permit. If it was not, mark "no" and attach additional information/explanation.

[3] Note whether the compliance status with of each term and condition provided was continuous or intermittent. "Intermittent Compliance" can mean either that noncompliance has occurred or that the owner or operator has data sufficient to certify compliance only on an intermittent basis. Certification of intermittent compliance therefore does not necessarily mean that any noncompliance has occurred.

NOTE:

The Periodic Monitoring requirements of the Operating Permit program rule are intended to provide assurance that even in the absence of a continuous system of monitoring the Title V source can demonstrate whether it has operated in continuous compliance for the duration of the reporting period. Therefore, if a source 1) conducts all of the monitoring and recordkeeping required in its permit, even if such activities are done periodically and not continuously, and if 2) such monitoring and recordkeeping does not indicate non-compliance, and if 3) the Responsible Official is not aware of any credible evidence that indicates non-compliance, then the Responsible Official can certify that the emission point(s) in question were in continuous compliance during the applicable time period.

[4] Compliance status for these sources shall be based on a reasonable inquiry using readily available information.

II. Status for Accidental Release Prevention Program:

A. This facility _______ is subject _______ is not subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act)

B. If subject: The facility ___________ is _________ is not in compliance with all the requirements of section 112(r).

1. A Risk Management Plan _________ will be _______ has been submitted to the appropriate authority and/or the designated central location by the required date.

III. Certification

All information for the Title V Semi-Annual Deviation Reports must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B.38. This signed certification document must be packaged with the documents being submitted.

I have reviewed this certification in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this certification are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in § 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of § 25-7 122.1, C.R.S.

____

Printed or Typed Name   Title

____

Signature   Date Signed

NOTE: All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

APPENDIX D

Notification Addresses

1. **Air Pollution Control Division**

Colorado Department of Public Health and Environment
Air Pollution Control Division
Operating Permits Unit
APCD-SS-B1
4300 Cherry Creek Drive S.
Denver, CO 80246-1530

ATTN: Jim King

2. **United States Environmental Protection Agency**

Compliance Notifications:

Office of Enforcement, Compliance and Environmental Justice
Mail Code 8ENF-T
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

Permit Modifications, Off Permit Changes:

Office of Partnerships and Regulatory Assistance
Air and Radiation Programs, 8P-AR
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

APPENDIX E

Permit Acronyms

Listed Alphabetically:

AIRS -	Aerometric Information Retrieval System
AP-42 -	EPA Document Compiling Air Pollutant Emission Factors
APEN -	Air Pollution Emission Notice (State of Colorado)
APCD -	Air Pollution Control Division (State of Colorado)
ASTM -	American Society for Testing and Materials
BACT -	Best Available Control Technology
BTU -	British Thermal Unit
CAA -	Clean Air Act (CAAA = Clean Air Act Amendments)
CCR -	Colorado Code of Regulations
CEM -	Continuous Emissions Monitor
CF -	Cubic Feet (SCF = Standard Cubic Feet)
CFR -	Code of Federal Regulations
CO -	Carbon Monoxide
COM -	Continuous Opacity Monitor
CRS -	Colorado Revised Statute
EF -	Emission Factor
EPA -	Environmental Protection Agency
FI -	Fuel Input Rate in mmBtu/hr
FR -	Federal Register
G -	Grams
Gal -	Gallon
GPM -	Gallons per Minute
HAPs -	Hazardous Air Pollutants
HP -	Horsepower
HP-HR -	Horsepower Hour (G/HP-HR = Grams per Horsepower Hour)
LAER -	Lowest Achievable Emission Rate
LBS -	Pounds
M -	Thousand
MM -	Million
MMscf -	Million Standard Cubic Feet
MMscfd -	Million Standard Cubic Feet per Day
N/A or NA -	Not Applicable
NOx -	Nitrogen Oxides
NESHAP -	National Emission Standards for Hazardous Air Pollutants
NSPS -	New Source Performance Standards
P -	Process Weight Rate in Tons/Hr
PE -	Particulate Emissions
PM -	Particulate Matter
PM_{10} -	Particulate Matter Under 10 Microns

PSD -	Prevention of Significant Deterioration
PTE -	Potential To Emit
RACT -	Reasonably Available Control Technology
SCC -	Source Classification Code
SCF -	Standard Cubic Feet
SIC -	Standard Industrial Classification
SO_2 -	Sulfur Dioxide
TPY -	Tons Per Year
TSP -	Total Suspended Particulate
VOC -	Volatile Organic Compounds

APPENDIX F

Permit Modifications

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION

APPENDIX G

Emission Factors For Sources of Fugitive Particulate Matter Emissions

Coal Handling

Emissions from wind erosion of coal pile:

The following equation was used to estimate emissions from wind erosion (from "Control of Open Fugitive Dust Sources", EPA-450/3-88-008, dated September 1988, Section 4.1.3):

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

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

In addition, PSCo presumed that $PM_{10} = 0.36 \times PM$. This value since it is consistent with the information currently in AP-42.

Unloading of Coal:

Emissions from Coal Unloading were estimated using the equation for emissions from drop/transfer points in AP-42 (dated January 1995), Section 13.2.4.

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

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

Coal Dozing:

Emission factors from AP-42 (dated July 1998), Section 11.9 (Western Surface Coal Mining), Table 11.9-1 were used to estimate emissions from coal dozing.

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

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

Where: E = emissions, in lbs/hr
s= silt content, in percent [PSCo used 2.2% per AP-42 (dated 1/95), Table 13.2.4-1 (coal as received from coal-fired power plant)]
M = moisture content, % [PSCo used 4.5% per AP-42 (dated 1/95), Table 13.2.4-1 (coal as received from coal-fired power plant)]

Ash Handling

Emissions from Wind Erosion of Ash Pit

Emissions were estimated using the same equation for wind erosion as for coal handling as discussed above. The only difference being that a silt content of 80% was used for the ash pit (from AP-42 (dated 1/95), Table 13.2.4-1 (fly ash).

Ash Dumping

Emissions were estimated using emission factors from the AWMA Air Pollution Engineering Manual (Second Edition, 2000), Table 1, page 693:

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

PM_{10} is presumed to be 0.36 x PM

Vehicle Travel on Paved and Unpaved Roads

Unpaved Roads

Emissions from travel on unpaved roads were estimated using emission factors from AP-42 (dated September 1998), Section 13.2.2 Unpaved Roads, as follows:

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

where:

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

Constant	PM	PM_{10}
k	10	2.6
a	0.8	0.8
b	0.5	0.4
c	0.4	0.3

Paved Roads

Emissions from travel on paved roads are estimated using the emission factor for unpaved roads and applying a control efficiency of 85%.

APPENDIX H

Compliance Assurance Monitoring Plan

I. Background

a. Emission Unit Description:

Unit 1, Foster Wheeler Boiler, Serial No. 2-79-2381, Opposed Fired, Natural Circulation, Rated at 5,346 mmBtu/hr. Coal-Fired with Natural Gas and/or No. 2 Fuel Oil Used for Startup, Shutdown and/or Flame Stabilization.

b. Applicable Regulation, Emission Limit, Monitoring Requirements:

Regulations:	Operating Permit Condition 1.1 (Colorado Regulation No. 1, Section II.A.1.c)
Emission Limitations:	PM 0.1 lb/mmBtu
Monitoring Requirements:	Visible Emissions (Opacity) and Preventative Maintenance

c. Control Technology:

This boiler is equipped with a fabric filter dust collector (FFDC) to control particulate matter emissions generation from the combustion of coal. The FFDC has a particulate removal efficiency greater than 99%.

II. Monitoring Approach

	Indicator 1	Indicator 2
I. Indicator	Visible Emissions (Opacity)	Preventative Maintenance
Measurement Approach	Opacity emissions will monitored by a Continuous Opacity Monitor (COM).	Internal inspections of the baghouse will be conducted annually. In the event of an opacity excursion (opacity either exceeds 15% for 60 seconds or more or the 24-hour average opacity exceeds the baseline level) an additional internal baghouse inspection shall be conducted within three (3) months of the excursion (initial excursion if more than one). No more than two internal baghouse inspections are required in any calendar year. The baghouse is inspected visually for deterioration and areas of corrosion or erosion. The bags are inspected for holes and tears, and are repaired and replaced as necessary. Door seals are inspected for tightness.
II. Indicator Range	An excursion is defined as an opacity value greater than 15% for 60 seconds or more. When this occurs, the last compartment to be cleaned in automatic cycle is isolated. An excursion is also defined as any 24-hour period in which the average opacity exceeds the baseline level established by the performance test required by Condition 1.1.2. In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.	An excursion is defined as failure to perform the annual inspection within 60 days of its scheduled completion date. An excursion is also defined as failure to perform an additional inspection within three months of an opacity excursion (initial excursion if more than one excursion occurs). An excursion triggers an immediate inspection.

	Indicator 1	Indicator 2
III. Performance Criteria		
a. Data Representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.	Internal inspections can be used to identify torn bags and/or bags with diminished integrity. Torn bags and/or bags with diminished integrity can be an indication of baghouse issues and potentially an increase in particulate matter emissions.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).	Documentation in plant records will serve as the verification that the semi-annual inspection has been performed.
i)c. QA/QC Practices and Criteria	The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75.	Trained personnel perform inspections and maintenance using an established procedures and checklist. Such procedures and checklists shall be made available to the Division upon request.
d. Monitoring Frequency	Continuous	Semi-Annual
e. Data Collection Procedures	Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60 Subpart A § 60.13. The emissions data will be stored in the unit's DAHS.	Results of inspections and maintenance activities are recorded by the plant and made available upon request.
f. Averaging Time	COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60 Subpart A § 60.13. All 6-minute averages in each 24-hour period (7 am to 7 am) will be averaged together to get a 24-hour average. Periods of startup, shutdown and malfunction may be excluded from the 24-hour average.	N/A

III. Justification

a. Background:

The pollutant specific emission unit is one (1) coal fired boiler, with natural gas and/or No. 2 fuel oil used for startup, shutdown and/or flame stabilization. The boiler is equipped with a FFDC to control particulate matter emissions.

Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter. According to the CAM plan submitted by the source, the baghouse manufacturer guarantees a particulate removal efficiency greater than 99%. The results of the performance test conducted in 2003 are indicated below:

Particulate Matter Emissions	
lb/mmBtu	Gr/dscf
0.00673	0.0033

b. Rationale for Selection of Performance Indicators

Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on this unit, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

Visible Emissions (Opacity)

Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

Preventative Maintenance

Preventative maintenance is performed on the baghouses to ensure that they are operated and maintained in accordance with the manufacturer's guidelines.

c. Rationale for Selection of indicator Ranges

Visible emissions (opacity)

A spike in opacity, defined as an opacity reading greater than 15% for sixty (60) seconds or more is an indication that a bag in that compartment has failed. The compartment is isolated and the bags in the compartment are inspected.

Although the source proposed an indicator range of "an increase in opacity above baseline conditions during normal operations to opacity emissions greater than 10% over an extended period of time", the Division considered such a range to be inappropriate, since neither the time period was defined and it was not clear how the 10% opacity related to the PM emission limitations. Therefore, the Division is including as CAM, an indicator range consistent with the monitoring used for the PM emission limitations that have been set for new (constructed after February 28, 2005) electric utility steam generating units in 40 CFR Part 60 Subpart Da. Since the monitoring set in the NSPS is for the same control device (fabric filter) and pollutant (PM), the Division considers that this monitoring is appropriate and represents presumptively acceptable monitoring in accordance with the provisions in 40 CFR Part 64 § 64.4(b)(1)(4). Therefore, an excursion will be any 24-hour average opacity that exceeds the baseline level established by the performance test. Note that as provided for in 40 CFR Part 60 Subpart Da § 60.48Da(o)(2)(iv), periods of startup, shutdown and malfunction may be excluded from the 24-hour average. In addition, the baseline opacity level will be set using the same methodology specified in 40 CFR Part 60 Subpart Da § 60.48Da(o)(2)(iii), except that the opacity add-on (specified as 2.5% specified in the NSPS) will be based on the results of the performance test.

Preventative Maintenance

Although the source proposed to use monthly reviews of historic minute opacity data and that those reviews would be used to trigger repairs or corrective action. Since it isn't clear how these reviews would trigger repairs the Division considered that a more definitive measure for defining preventative maintenance would be annual internal inspections of the baghouse. The Division would consider that failure to conduct annual inspections may compromise the ability of the FFDC to function as designed. Note that the Division considers that an additional inspection shall be required in the event of an opacity excursion. As such, the Division is including in this CAM plan a requirement to perform internal inspections in order to ensure proper baghouse function and perform required repairs and maintenance of the bags as needed.

APPENDIX I

Mercury (Hg) Monitoring Plan

Public Service submitted a Hg Monitoring Plan on December 19, 2008 as required by Colorado Regulation No. 6, Part B, Section VIII.E.4.b. The Plan was subsequently revised and resubmitted on May 7, 2009. The revised Hg Monitoring Plan is attached.

CONTINUOUS MERCURY MONITORING SYSTEM

MONITORING PLAN

Source Designation:
Public Service Company of Colorado
Pawnee Station Unit 1
14940 County Road 24
Brush, Co 80723

Concerning:
Thermo Scientific Mercury Freedom System
Serial No: 0713822425

INTRODUCTION

The Public Service Company of Colorado (PSCo) Pawnee Station is located in Brush, Colorado, and consists of a single dry bottom, wall-fired boiler supplying steam to a single turbine for the purpose of generating electricity. The boiler currently operates with a low NOx burner system with overfire air. Continuous mercury (Hg) emission monitoring will be performed for Unit 1 with sampling ports located on the stack.

This monitoring plan is presented in accordance with Colorado Air Quality Control Commission Regulation Number 6, Part B, Section VIII E.4.

MONITORING PLAN

1. Overview and Monitoring Approach

The Thermo Scientific Mercury Freedom monitoring system at Pawnee will provide a flue gas mercury concentration, on a wet basis, in units of $\mu g/m^3$. This will be done by sampling on a 10 second averaging period, upon which minute data, then 15 minute data, and eventually one hour average concentrations are calculated by the Data Acquisition and Handling System (DAHS). This monitoring approach satisfies the requirements of 40 CFR Part 60.50Da.(h) along with the intent of the Mercury Monitoring Requirements of Colorado Regulation Number 6.

The entire mercury monitoring system consists of the following; a stack mounted dilution probe, a mercury chloride generator, and a dry converter housed in an insulated enclosure that is mounted at the 420-foot level of the Pawnee Unit 1 stack along with the existing continuous emissions monitoring (CEMs) equipment. A sample line, or umbilical, connects the stack-mounted equipment with the equipment located adjacent to the stack wall in the existing CEMs shelter.

Three separate instruments in the shelter consisting of a probe controller, a mercury analyzer, and an elemental mercury calibrator. The probe controller connects to the stack probe and mercury converter and automates probe calibration. The analyzer, which uses advanced cold vapor atomic fluorescence analysis, provides continuous measurement. The elemental mercury generator utilizes a vapor generator to provide the required elemental mercury gas for the appropriate certification and ongoing quality assurance (QA) testing. This calibration gas is injected upstream of the inertial filter.

2. Quality Assurance/Quality Control

PSCo will perform the following certification and ongoing quality assurance testing on the mercury monitoring system:

Initial certification:
7-day Calibration Error Test
Linearity Check
Three-level System Integrity Check
Cycle Time Test
Relative Accuracy Test Audit (RATA)

On-going quality assurance:
Daily Calibration Error Test
Weekly One-level System Integrity Check
Quarterly Linearity Check
Annual RATA

3. CALCULATIONS

PSCo is using the following equation to determine the hourly Hg mass emissions when using a Hg concentration monitoring system that measures on a wet basis in conjunction with a stack flow monitor:

$$E_h = (K\, C_h\, Q_h\, t_h)/16 \quad \text{(Eq. 1)}$$

Where:
E_h= Hg mass emissions for the hour, (lb);
K = Units conversion constant, 9.978×10^{-10} oz-scm/µgm-scf.
C_h= Hourly H_g concentration, wet basis, (µgm/wscm).
Q_h= Hourly stack gas volumetric flow rate, (scfh).
t_h= Unit operating time, i.e., the fraction of the hour for which the unit operated. For example, t_h = 0.50 for a half-hour of unit operation and 1.00 for a full hour of operation.

PSCo will use the equation below to calculate the monthly Hg emission rate on an output basis in pounds/Giga-watt hours (lb/GWh).

$$ER = \frac{M}{P} \quad \text{(Eq. 2)}$$

Where:
ER = Monthly Hg emission rate, (lb/GWh);
M = Total mass of Hg emissions for the month, from Equation 1, above, (lb); and
P = Total electrical output for the month, for the hours used to calculate M, (GWh).

When 12 monthly Hg emission rates have been accumulated on December 31, 2012, the first 12-month rolling total will be calculated using equation 3 below. Then, for each subsequent calendar month, equation 3 below will be used to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months. The only acceptation to this approach will be for calendar months in which the unit does not operate (zero unit operating hours). In this case, those months with zero operating hours will not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=1}^{12} (ER_i \times n_i)}{\sum_{i=1}^{12} n_i} \quad \text{(Eq. 3)}$$

Where:
E_{avg}= Weighted 12-month rolling average Hg emission rate, (lb/GWh).
ER_i= Monthly Hg emission rate, for month "i", (lb/GWh).
n = Number of unit operating hours in month "i" with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction.

Exhibit 2 to Title V Petition

TECHNICAL REVIEW DOCUMENT
For
RENEWAL of OPERATING PERMIT 96OPMR129

Public Service Company – Pawnee Station
Morgan County
Source ID 0870011

Prepared by Jacqueline Joyce
January 2009
Revised March, May and September 2009

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 by the renewal and modification to the Operating Permit proposed for this site. The original Operating Permit was issued January 1, 2003. The expiration date for the permit was January 1, 2008. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal Operating Permit is issued and any previously extended permit shield continues in full force and operation. After submittal of the renewal application, the source submitted an application on December 19, 2008 to revise their permit to incorporate the mercury requirements in Colorado Regulation No. 6, Part B, Section VIII. The Division considers that this modification must be processed as a significant modification. A significant modification is processed under the same procedures as a renewal, i.e. it must go through a 30-day public comment period and EPA 45-day review period. Therefore, since the renewal application has been submitted the Division is incorporating the modification with the renewal.

This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted November 20, 2006, the modification application submitted on December 19, 2008, comments on the draft permit and technical review document received on May 7, 2009, additional information submitted on May 14 and 28, 2009, comments received on July 3, 2009 during the public comment period, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

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

II. Description of Source

This facility consists of one (1) coal-fired boiler (Unit 1) used to produce electricity. This boiler and turbine generator is rated at 547 gross MW and is equipped with a baghouse to control particulate matter emissions and low NO_X burners with over-fire air to control NO_X emissions. In addition, there is natural gas-fired auxiliary boiler (Unit 2) at the facility, which is primarily used to provide heat to the facility when Unit 1 is not running. Other significant emission sources at this facility consist of fugitive particulate matter emissions from coal handling and storage, ash handling and disposal and vehicle traffic on paved and unpaved roads. In addition, there are also sources of particulate matter emissions from point sources, including coal handling (crushers, transfer towers and conveying), ash handling (ash silo), and the soda ash handling system (for water treatment system). The facility also has one cooling tower that emits particulate matter emissions in "drift" and evaporates chloroform. In December 2008, the source submitted an application to incorporate the mercury limits from Colorado Regulation No. 6, Part B, Section VIII into their permit. In order to meet the mercury limits, the source is proposing to use an activated carbon (sorbent) injection system as a primary control option for mercury with a chemical injection system to be considered as a secondary control option (either in conjunction with the sorbent injection system or as a stand-alone mercury control system). As part of the sorbent injection system, the source proposes to construct and operate two sorbent storage silos. The appropriate applicable requirements for these storage silos have been incorporated into the permit.

Public Service Company's (PSCo's) Pawnee Station is co-located with the Manchief Generating Station. Since the two facilities are located on contiguous and adjacent property, belong to the same industrial grouping (first two digits of the SIC code are the same) and are under common control (via a power purchase agreement with PSCo), they are considered a single stationary source for purposes of major stationary source new source review and Title V operating permit applicability. A separate Title V operating permit was issued for the Manchief Generating Station (01OPMR236). In addition, Boral Material Technologies, Inc. (BMTI) conducts ash conditioning, handling and blending operations at Pawnee station. BMTI is considered a support facility for PSCo's Pawnee Station and as such is considered a single source with PSCo's Pawnee Station and subsequently BMTI is also considered a single source with Manchief Generating Station. A separate Title V permit was issued for BMTI Pawnee Station (03OPMR244).

This facility is located at 14940 County Road 24, near Brush In Morgan County. The area in which the plant operates is designated as attainment for all criteria pollutants.

There are no affected states within 50 miles of the plant. There are no Federal Class I designated areas within 100 kilometers of the plant.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit issuance has been modified to more appropriately identify the **potential to emit (PTE)** of both criteria and hazardous air pollutants. Emissions (in tons/yr) at the facility are as follows:

Emission Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	Pb[1]	HAPS
PSCo – Pawnee Station (96OPMR129)								
Main Boiler (Unit 1)	2,341.5	2,154.2	28,098.6	10,771.1	725	87	0.61	See Page 26
Aux. Boiler	0.7	0.7	0.2	35.4	29.7	1.9		
Coal Handling (fugitives)	35.84	8.7						
Coal Handling (point sources)	15.3	6.8						
Ash Handling (fugitives)	19.66	7.08						
Haul Roads (fugitives)	47.9	12.2						
Ash Silo	2.13	2.13						
Soda Ash	0.007	0.007						
Cooling Tower	36.5	36.5				2.6		
Sorbent Silos	0.38	0.38						
PSCo Total Emissions	**2,499.9**	**2,228.7**	**28,098.8**	**10,806.5**	**754.7**	**91.5**	**0.61**	**97.33**
BMTI – Pawnee Station (03OPMR244)								
Fly Ash Conditioning System/MACS Bldg.	4.23	2.69						Negl.
Fugitive Emissions	18.7	6.22						Negl.
BMTI Total Emissions	**22.93**	**8.91**						**Negl.**
Manchief Generating Station (01OPMR236)								
Turbine 1	66.2	48.6	3.5	396.7	153.7	21.9		See Page 26
Turbine 2	66.2	48.6	3.5	396.7	153.7	21.9		
Diesel Generator	0.3	0.3	1.0	15.4	4.2	0.4		
Water Bath Heater	0.3	0.3	0.02	3.9	3.3	0.2		
Manchief Total Emissions	**133.0**	**97.8**	**8.02**	**812.7**	**314.9**	**44.4**		**11.78**
FACILITY Total Emissions	**2,655.83**	**2,335.41**	**28,106.82**	**11,619.2**	**1,069.6**	**135.9**	**0.61**	**109.11**

[1]Lead (Pb) emissions are based on emission factors from AP-42, Section 1.1 (dated 9/98), Table 1.1-17.

Potential to emit used in the above table are based on the following information:

Criteria Pollutants

PSCo – Pawnee: Potential to emit for all emission units except the main boiler and the sorbent silos are based on permitted emission limitations. Potential to emit for NO_X, SO_2 and PM from the main boiler are based on regulatory limits (Reg 1 for SO_2 and PM (1.2 lb/mmBtu and 0.1 lb/mmBtu, respectively) and Acid Rain for NO_X (0.46 lb/mmBtu)), the design heat input rate and 8760 hours per year of operation. PM_{10} emissions from the main boiler are presumed to be 92% of PM emissions (per AP-42, Section 1.1 (dated 9/98), Table 1.1-6. VOC and CO emissions from the main boiler are based on AP-42 emission factors (Section 1.1, dated 9/98, Tables 1.1-3 and 1.1-19) and the permitted coal consumption limit. Potential to emit from the sorbent silos is based on requested emissions provided on the APEN received December 19, 2008. Note that for the auxiliary boiler, permitted emission limitations were not included in the permit for PM, PM_{10} and VOC, the potential to emit for those pollutants are based on the requested emissions from the APEN submitted June 28, 2002 (noted in the technical review document prepared for the original Title V permit for PSCo Pawnee Station).

BMTI – Pawnee: Potential to emit is based on permitted emission limitations.

Manchief: Potential to emit for the turbines, heater and starter engine are based on permitted emission limitations. Note that for the heater and starter engine, permitted emission limitations were not included in the permit for certain criteria pollutants (PM, PM_{10}, CO (engine only), SO_2 and VOC) because emissions were below the APEN reportable level. Emissions for those pollutants are shown in the above table and emissions are based on the permitted fuel consumption limit and AP-42 emission factors.

Hazardous Air Pollutants (HAP)

The potential to emit table on page 3 provides total HAPs for each operating permit. The breakdown of HAP emissions by individual HAP and emission unit is provided on page 26 of this document. HAP emissions, as shown in the table on page 26, are based on the following information:

PSCo – Pawnee: Potential to emit of HAPS were only determined for the main boiler, the auxiliary boiler and the cooling tower. HAPS were not estimated for the other emission units as HAPs were presumed to be negligible from these sources.

HAP emissions from the auxiliary boiler are based on AP-42 emission factors (for natural gas Section 1.4, dated 3/98, Tables 1.4-3 and 1.4-4 and for No. 2 fuel oil Section 1.3, dated 9/98, Tables 1.3-9 and 1.3-11) and the permitted fuel consumption limit. Note that at the permitted fuel limits for both fuels, hours of operation would exceed 8760 hours per year, so an adjusted fuel limit for No. 2 fuel oil was used.

Metal HAP emissions from the main boiler are based on AP-42 emission factors (Section 1.1, dated 9/98, Table 1.1-18) and the permitted coal consumption limit. Mercury emissions from the main boiler are based on the average projected mercury emissions that were used in the development of Colorado's Mercury Rule. HF and HCl emissions from the main boiler are based on the maximum emission factor, in units of lbs/ton, determined from reported HF and HCl emissions and coal consumption on several current APENS (2007, 2006 and 2004 data) and the permitted coal consumption limit.

Manchief: HAP emissions are based on AP-42 emission factors and the permitted fuel consumption limits.

Note that actual emissions are typically less than potential emissions and actual emissions from the PSCo sources are shown on page 27 of this document.

Compliance Assurance Monitoring (CAM) Requirements

The source addressed the applicability of the CAM requirements in their renewal application and is discussed further in this document under Section III – Discussion of Modifications Made, under "Source Requested Modifications".

MACT Requirements

Case-by-Case MACT - 112(j) (40 CFR Part 63 Subpart B §§ 63.50 thru 63.56)

Under the federal Clean Air Act (the Act), EPA is charged with promulgating maximum achievable control technology (MACT) standards for major sources of hazardous air pollutants (HAPs) in various source categories by certain dates. Section 112(j) of the Act requires that permitting authorities develop a case-by-case MACT for any major sources of HAPs in source categories for which EPA failed to promulgate a MACT standard by May 15, 2002. These provisions are commonly referred to as the "MACT hammer".

Owners or operators that could reasonably determine that they are a major source of HAPs which includes one or more stationary sources included in the source category or subcategory for which the EPA failed to promulgate a MACT standard by the section 112(j) deadline were required to submit a Part 1 application to revise the operating permit by May 15, 2002. The source submitted a notification indicating that Pawnee Station was a major source for HAPS, with equipment under the source category for industrial, commercial and institutional boilers and process heaters.

Since the EPA has signed off on final rules for all of the source categories, which were not promulgated by the deadline, the case-by-case MACT provisions in 112(j) no longer apply. Note that there is a possible exception to this, as discussed later in this document (see under industrial, commercial and institutional boiler and process heaters).

RICE MACT (40 CFR Part 63 Subpart ZZZZ)

The RICE MACT (40 CFR Part 63 Subpart ZZZZ) was signed as final on February 26, 2004 and was published in the Federal Register on June 15, 2004. An affected source under the RICE MACT is any existing, new or reconstructed stationary RICE with a site-rating of more than 500 hp.; however, only existing (commenced construction or reconstruction prior to December 19, 2002) 4-stroke rich burn (4SRB) engines with a site-rating of more than 500 hp were subject to requirements. There are several engines included in the insignificant activity list. One of these, an emergency generator, is greater than 500 hp and another, an emergency fire pump engine, could be greater than 500 hp (it is listed between 300 hp and 750 hp). The remaining engines are less than 500 hp. Since the emergency generator and fire pump are existing compression ignition engines they do not have to meet the requirements of Subparts A and ZZZZ, including the initial notification requirements as specified in 40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3).

In addition, revisions were made to the RICE MACT to address engines ≤ 500 hp at major sources and all size engines at area sources. These revisions were published in the Federal Register on January 18, 2008. Under these revisions, existing compression ignition (CI) engines, 2-stroke lean burn (2SLB) and 4-stroke lean burn (4SLB) engines were not subject to any requirements in either Subparts A or ZZZZ (40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3)). For purposes of the MACT, for engines ≤ 500 hp, located at a major source, existing means commenced construction or reconstruction before June 12, 2006. The remaining engines included in the insignificant activity list are considered existing and therefore are not subject to the MACT. Since the source has not indicated that any additional engines have been installed at the facility, the Division considers that there are no new engines and therefore, no engines subject to the RICE MACT.

Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)

The final rule for industrial, commercial and institutional boilers and process heaters was signed on February 26, 2004 and was published in the Federal Register on September 13, 2004. There are propane portable heaters included in the insignificant activity list in Appendix A of the permit. However, these units do not meet the definition of boiler or process heater specified in the rule (the definition of process heater excludes units used for comfort or space heat). Therefore the heaters included in the insignificant activity list would not be subject to the Boiler MACT requirements.

The auxiliary boiler, which is included in Section II of the permit uses only natural gas as fuel. Existing large gaseous fuel units are only subject to the initial notification requirements as specified in 40 CFR Part 63 Subpart DDDDD § 63.7506(b)(2). The initial notification for the auxiliary boiler was submitted on February 16, 2005, prior to the March 12, 2005 deadline.

As of July 30, 2007, the Boiler MACT was vacated; therefore, the provisions in 40 CFR Part 63 Subpart DDDDD are no longer in effect and enforceable. The vacatur of the Boiler MACT triggers the case-by-case MACT requirements in 112(j), referred to as the MACT hammer, since EPA failed to promulgate requirements for the industrial, commercial and institutional boilers and process heaters by the deadline. Under the 112(j) requirements (codified in 40 CFR Part 63 Subpart B §§ 63.50 through 63.56) sources are required to submit a 112(j) application by the specified deadline. As of this date, EPA has not set a deadline for submittal of 112(j) applications to address the vacatur of the Boiler MACT. Although this unit was only subject to initial notification requirements, the Division considers that a 112(j) application should be submitted for this unit. Therefore, the Division will include a requirement to submit a 112(j) application in the permit by the deadline set by the Division and/or EPA.

Gasoline Distribution MACTs

A 500 gallon aboveground gasoline tank is included in the insignificant activity list (listed as an insignificant activity because emissions are less than the APEN de minimis level per Reg 3, Part C, Section II.E.3.a). There are potential MACT standards that could apply to this operation: Gasoline Distribution (Stage I) – 40 CFR Part 63 Subpart R (final rule published in the Federal Register on December 14, 1994), Gasoline Dispensing Facilities – 40 CFR Part 63 Subpart CCCCCC (final rule published in the Federal Register on January 10, 2008) and Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities – 40 CFR Part 63 Subpart BBBBBB (final rule published in the Federal Register on January 10, 2008). Both of the rules published on January 10, 2008 only apply at area sources. Since this facility is a major source for HAPS, the requirements in those rules do not apply to the gasoline tank at this facility. The Gasoline Distribution (Stage I) MACT applies to bulk gasoline terminals and pipeline break-out stations. The gasoline dispensing equipment at this facility does not meet the definition of a bulk gasoline terminal or a pipeline break-out station. Therefore, none of the MACT requirements associated with gasoline distribution apply to the equipment at this facility.

Federal Clean Air Mercury Rule Requirements

The EPA published final rules to address mercury emissions from coal-fired electric steam generating units on March 15, 2005. These rules are referred to as the Clean Air Mercury Rule (CAMR), which required mercury standards for new and modified emission units and provided a trading program for existing units. Under this program, sources would be required to get a permit (application due date July 10, 2008) and to meet monitoring system requirements (install and conduct certification testing) by January 1, 2009.

However, on February 8, 2008 a DC Circuit Court vacated the CAMR regulations for both new and existing units. Therefore, the federal CAMR requirements are not in effect, as of the issuance of this renewal permit.

State Clean Air Mercury Rule Requirements

Although the Division did adopt provisions from the federal CAMR rule into our Colorado Regulation No. 6, Part A, the Division also adopted State-only mercury requirements in Colorado Regulation No. 6, Part B, Section VIII. As discussed above the provisions from the federal CAMR rule have been vacated and are no longer applicable. While the state-only mercury requirements rely in some part of the federal CAMR rule, there are emission limitations and permit requirements that do not rely on the federal rule and are still in effect. In addition, on November 20, 2008, the Colorado Air Quality Control Commissions (AQCC) adopted into Reg 6, Part B, Section VIII, the monitoring, recordkeeping and reporting requirements in the vacated CAMR rule. The revisions to Reg 6, Part B take effect on December 30, 2008.

To that end, beginning on January 1, 2012, Unit 1 is required to comply with either of the following standards on a 12-month rolling average basis (Colorado Regulation No. 6, Part B, Section VIII.C.1.a):

0.0174 lb/GWh **OR** 80 percent capture of inlet mercury

Unit 1 would be subject to more stringent mercury standards beginning January 1, 2018 as set forth in Colorado Regulation No. 6, Part B, Section VIII.C.1.c.

As specified in Colorado Regulation No. 6, Part B, Section VIII.D.2, a permit application for Unit 1 must be submitted by January 1, 2009 to incorporate the requirements of Colorado Regulation No. 6, Part B, Section VIII and the Division must issue a revised permit by January 1, 2010. As such the source submitted an application on December 19, 2008 to incorporate the mercury control requirements and the Division is including the appropriate requirements in the draft renewal permit. Note that the requirements that will be included in the permit are discussed further in this document under Section III – Discussion of Modifications Made, under "Source Requested Modifications".

Regional Haze Requirements

The main boiler (Unit 1) at this facility is subject to the regional haze requirements for best available retrofit technology (BART) and as such a BART analysis was conducted and a permit has been issued to address the BART requirements. The BART requirements have been included in Colorado Construction Permit 07MR0111B, which was issued September 12, 2008.

The BART permit requires the installation of a lime spray dryer on Unit 1 and either the modification of the existing low NO_X burners and over-fire air system or the installation of new low NO_X burners and over-fire air system. In addition, the permit sets new emission limits for SO_2, NO_X and PM.

The BART permit specifies that PSCo shall demonstrate compliance with the BART emission limits as expeditiously as practicable, but in no event later than five years following EPA approval of the state implementation plan for regional haze that incorporates these BART requirements. Although the PM, SO_2 and NO_X requirements in the BART permit do not take effect until EPA approves the Regional Haze SIP and the BART permit does not require that a Title V permit application to incorporate the BART provisions be submitted until 12 months after startup of the SO_2 and NO_X control equipment, the provisions in the BART permit have been included in the renewal permit.

III. Discussion of Modifications Made

Source Requested Modifications

November 20, 2006 Renewal Application

The source did no request any changes in their November 20, 2006 renewal application, but did conduct a CAM analysis and submitted a CAM plan for the main boiler (Unit 1).

The CAM requirements apply to any emission unit that uses a control device to meet an emission limitation or standard and has pre-controlled emissions above the major source level. There are several emission points at the facility that could potentially be subject to the CAM requirements. The source provided information regarding the applicability of the CAM requirements to the emission units at the facility as discussed below.

Emission sources with no emission limitations

All of the emission sources at this facility that are included in Section II of the permit have emission limitations.

Emission sources with emission limitations

No control device

The source identified the following sources/activities as units with no controls and therefore not subject to the CAM requirements: the auxiliary boiler, fugitive emissions from coal handling and storage, fugitive emissions from ash handling and disposal and fugitive emissions from vehicle traffic on paved and unpaved roads. The Division agrees that the auxiliary boiler and fugitive emissions from coal handling do not utilize any control devices to meet their emission limitations. However, the permit requires that water be sprayed on the ash pit as necessary to minimize fugitive emissions and that all active unpaved haul roads be watered daily to reduce visible emissions. The use of water to reduce fugitive or visible emissions can certainly be considered a control measure used to reduce emissions and meet emission limitations. However, the Division does not think that water sprays meet the definition of control equipment. The preamble to the CAM rule provides more insight into the control technology definition and provides the following (from October 22, 1997 Federal Register, page 54912, 3rd column, under *control devices criterion*)

> The final rule provides a definition of "control device" that reflects the focus of Part 64 on those types of control devices that are usually considered as "add-on" controls." This definition does not encompass all conceivable control approaches but rather those types of control devices that may be prone to upset and malfunction, and that are most likely to benefit from monitoring of critical parameters to assure that they continue to function properly. In addition, a regulatory obligation to monitor control devices is appropriate because these devices generally are not a part of the source's process and may not be watched as closely as devices that have a direct bearing on the efficiency or productivity of the source.

The Division considers that the use of water sprays to reduce fugitive and/or visible emissions is not considered an add-on control device and is not the type of device that would benefit from monitoring critical parameters. Therefore, the Division agrees that based on the specific provisions in the CAM requirements that fugitive emissions from ash handling and disposal and vehicle traffic on haul roads are uncontrolled activities. Therefore, the Division considers that the CAM requirements do not apply to fugitive emissions from ash handling and disposal and vehicle traffic on haul roads.

Pre-control emissions below the major source level

The source identified the following sources/activities as units with pre-controlled emissions below the major source level and therefore not subject to CAM: coal handling system (point sources), the ash silo, the soda ash handling system and the cooling tower. The Division's analysis of the applicability of CAM to these units is as follows:

<u>cooling water tower</u> – the cooling water tower is equipped with drift eliminators which reduce drift to 0.001%. Without the drift eliminators, uncontrolled PM and PM_{10} emissions from the cooling water tower would exceed the major source level. However, the Division considers that the drift eliminators are not considered a control device. In 40 CFR Part 64, § 64.1, control device means "equipment other than inherent process equipment that is used to destroy or remove pollutants prior to discharge to the atmosphere...For purposes of this part, a control device does not include passive control measures, that act to prevent pollutants from forming, such as the use of seals, lids or roofs to prevent the release of pollutants". The Division considers that the drift eliminators are considered inherent process equipment and are passive devices and as such are not considered control equipment. Therefore, the Division considers that the CAM requirements do not apply to the cooling water tower.

Soda ash handling system: The Division agrees that using the uncontrolled emission factor and permitted processing rate that emissions from the soda ash handling system are below the major source level.

Ash silo: According the technical review document prepared for the original Title V permit (issued January 1, 2003), the bin vent fan for the ash silo exhausts through the boiler baghouse. Therefore, the ash silo shares a control device with the baghouse. Particulate matter emissions from the ash silo are estimated separately using the emission factors and assumed control efficiencies and are much less than particulate matter emissions from the boiler itself. As discussed below, the boiler baghouse is subject to CAM and the source has submitted a CAM plan based on the boiler operation. Therefore, nothing further is required to address the emissions from ash silo operations.

Coal handling (conveying and crusher): As discussed in the technical review document prepared for the original Title V permit, the emission limits that were set for the coal handling system do not take credit for controls such as the baghouses (transfer tower and crusher), the water sprays or the enclosures (conveyors are covered); except that some credit is taken for the crusher enclosures. Permitted emissions from coal handling (except the crusher) are based on emission factors for conveying that rely on wind speed and the moisture content of the coal. The calculations were performed using a high wind speed (8.7 mph), which the Division considers does not take credit for covered conveyors. At the permitted coal processing rate, uncontrolled emissions from the crushers are below the major source level, therefore, CAM does not apply to the coal handling system.

Although not addressed in the renewal application, the Division made the following determination regarding the applicability of CAM to the proposed new sorbent silos as follows:

Requested emissions from these emission units are based on assumptions for grain loading specifications and air flow. Therefore estimating uncontrolled emissions are difficult. Based on the requested emission rate, the associated control devices would have to have a control efficiency of greater than 99.8% (for one silo alone) in order to have uncontrolled emissions below the significance level. Although typically silos have been considered to have control efficiency of 99.9%, the Division considers that based on the low requested throughput, uncontrolled emissions are unlikely to exceed the major source level. Using the AP-42 emission factor of 1.5 lbs/ton for lime manufacturing, product loading, open truck (AP-42 (dated 2/98), Section 11.17, Table 11.17-4), which the Division considers to be conservative, uncontrolled emissions are well below the major source level. In fact, based on the requested throughput limit, it would require an emission factor of 350 lbs/ton to put uncontrolled emissions above the major source level. Therefore, the Division considers that the sorbent silos are not subject to the CAM requirements.

Pre-control emissions above the major source level

The source identified the main boiler (Unit 1) as being subject to CAM, since a control device is required to meet the PM emission limitations. Unit 1 is subject to PM, SO_2 and NO_X emission limitations. Controlled emissions of these pollutants exceed the major source level and this unit uses emission controls (baghouse for PM and low NO_X burners with over-fire air for NO_X) to meet its PM and NO_X emission limitations. Therefore, Unit 1 is potentially subject to the CAM requirements.

Unit 1 is subject to SO_2 and NO_X emission limitations under the Acid Rain Program (Section III of the current permit). Pursuant to 40 CFR Part 64 § 64.2(b)(1)(iii), the CAM requirements do not apply to Acid Rain Program emission limitations.

Unit 1 is subject to short-term SO_2 and NO_X emission limitations (both on 3-hr rolling average). The current Title V permit requires that the source use continuous emission monitoring systems to demonstrate compliance with the SO_2 and NO_X emission limitations. Therefore, since the Title V permit specifies a continuous compliance method for these emission limitations, the CAM requirements do not apply in accordance with the provisions in 40 CFR Part 64 § 64.2(b)(1)(iv).

CAM does apply to the Unit 1 with respect to the PM emission limitations. Note that although the unit is subject to opacity limits, they are not emission limitations subject to CAM requirements. The source submitted a CAM plan with their renewal application. In their CAM plan, the source proposed visible emissions, pressure differential and preventative maintenance as indicators. For visible emissions, excursions are identified as an opacity value exceeding 15% for one minute or more and any long term increase in opacity of 10% above baseline levels for normal operation. For pressure differential, an excursion is defined as an increase in differential pressure of 3 inches of water column or greater from normal baseline levels accompanied by a sustained increase in opacity over 10%.

The Division has reviewed the CAM plan submitted and while we accept the plan in part, we consider that changes to the plan are necessary. The Division considers that the following changes are necessary to the plan.

Visible Emissions

The Division accepts the indicator range of 15% opacity for one minute or more and will include this in the permit.

The second indicator range of "a long term increase in opacity emissions from baseline conditions during normal operations to opacity emissions greater than 10% over an extended period of time" is non-specific as to the time frame and it is not clear that the 10% opacity represents an acceptable opacity level as an indicator range. Therefore, the Division will include as CAM, the compliance provisions required for new (constructed after February 28, 2005) electric utility steam generating units subject to

PM fuel based emission limitations (i.e. units of lb/mmBtu) in 40 CFR Part 60 Subpart Da, since such monitoring represents presumptively acceptable monitoring in accordance with the provisions in 40 CFR Part 64 § 64.4(b)(1)(4). The compliance provisions specified in Subpart Da require that a baseline opacity level be set during a performance test and then requires monitoring of opacity emissions on a 24-hour average. If the opacity 24-hour average exceeds the baseline level, then the source must investigate and take the appropriate corrective action. Note that as provided for in 40 CFR Part 60 Subpart Da § 60.48Da(o)(2)(iv), periods of startup, shutdown and malfunction may be excluded from the 24-hour average.

The baseline opacity level determined under the provisions of NSPS Subpart Da specify that 2.5% opacity be added to the average opacity determined during the performance test, although the baseline opacity level can be no lower than 5% opacity. Since the units required to conduct this monitoring under NSPS Subpart Da are subject to more stringent particulate matter limitations, the opacity add-on will be based on the results of the performance test. However, in no case would the baseline opacity be set lower than 5%.

Pressure Differential

The source has indicated that an excursion would be "an increase in differential pressure across a baghouse of 3 inches of water column or greater from the unit's normal specific operating load during normal operating conditions, as well as a sustained increase in opacity greater than 10%". While the proposed language does not specifically define the pressure differential for the "unit's normal specific operating load", in their justification the source indicates that the normal pressure differential varies based on the operating load. While the Division understands that it may be difficult to identify specific ranges since the appropriate pressure differential varies depending on the load, failure to identify the specific range makes it difficult for the Division to independently determine whether an excursion has occurred. In addition, as indicated in the CAM plan, an increase or decrease in the pressure differential from the normal level at a specific operating load is not necessarily considered an indicator of decreased baghouse performance by itself. However, an increase or decrease in the pressure differential from the normal level, accompanied by a sustained increase in opacity is an indication of potential baghouse problems.

Since the normal pressure differential is specific to load and cannot be easily defined and because pressure differential by itself is not necessarily an indicator of potential problems with the baghouse, the Division will not include pressure differential in the CAM plan as an indicator. In accordance with 40 CFR Part 64 § 64.4(b)(4), presumptive CAM is monitoring included for standards that are exempt from CAM (i.e. NSPS standards promulgated after November 15, 1990) to the extent that such monitoring is applicable to the performance of the control device (and associated capture system). As discussed previously, the Division has revised the source's CAM plan to require that visible emissions be monitored in accordance with the monitoring required for new boilers subject to 40 CFR Part 60 Subpart Da. The emission limitations and monitoring for new boilers were published as final in the February 27, 2006 Federal Register, although changes to the monitoring requirements were published as final in the Federal Register on June 13, 2007. New boilers subject to the revised PM emissions limits in 40 CFR Part 60 Subpart Da are required to monitor compliance with the PM emission limitation using their COM by establishing a baseline opacity. Therefore, the baseline opacity monitoring that the Division is including in the CAM plan represents presumptive CAM and the Division does not believe that it is necessary to include pressure differential as an additional indicator.

It should be noted that new sources subject to the NSPS Da PM limitation are also required to conduct annual performance tests. While the Division has not included annual performance testing in the permit as part of the CAM plan, the Division does require performance tests as periodic monitoring to demonstrate compliance with the PM limitations. Frequency of testing is annual, unless the results of the testing are much lower than the standard, then less frequent testing is allowed.

Preventative Maintenance

The preventative maintenance that the source has proposed is a monthly review of historic minute opacity data and that based on this review, if warranted, repairs will be initiated to internal and/or external baghouse components. It is not clear what specifically the source would be looking for in the historic minute opacity data and what would trigger any repairs. The Division considers that preventative maintenance is important to the proper operation of the baghouse, therefore, the Division has revised the preventative maintenance indicator to require annual internal inspections of the baghouse. Although the CAM plans for other PSCo facilities specify semi-annual internal baghouse inspections, PSCo provided information indicating that at this facility semi-annual internal inspections would be burdensome. The Division has however, included a requirement to conduct an additional internal baghouse inspection in the event of an opacity excursion, although no more than two internal baghouse inspections are required in any calendar year.

In general, the CAM plan has been included in Appendix H of the permit as submitted, except that the corrections indicated above have been made to the plan and some language has been omitted, revised or relocated in order to streamline the plan.

December 19, 2008 Application for Permit Modification

The source submitted an application on December 19, 2008 to incorporate the mercury (Hg) control requirements in Colorado Regulation No. 6, Part B, Section VIII into their permit. In accordance with the requirements in Reg 6, Part B, Section VIII.D.2 an application was to be submitted for the Pawnee facility by January 1, 2009 and a revised permit shall be issued by January 1, 2010. Since the renewal application had been received for this facility the Hg requirements are being directly incorporated into the renewal permit.

Reg 6, Part B, Section VIII Hg Requirements

Reg 6, Part B, Section VIII.D.4 states that all permit applications shall include the following:

- a statement indicating that the Hg budget units in the State under the control of the owner or operator shall comply with the emission standards and other requirements of this Section VIII
- a detailed compliance plan for each applicable emission standard, or schedule for achieving compliance with that standard, including monitoring and reporting, and
- a description of the assumptions on which the plan is based.

In their application, the source indicated that they proposed to use sorbent injection using a halogenated activated carbon to reduce Hg emissions and that they expected this control method would also allow the unit to meet both the 2012 and 2018 Hg emission limits. The source also proposed to use chemical injection, either by itself or in conjunction with a sorbent injection system. The source is in the process of evaluation this technology further but believe that it could be effective in meeting the 2012 emission limitation. The chemical injection system sprays chemicals such as calcium chloride or calcium bromide on the coal as it is being conveyed to the bunkers or fed into the boiler. During the combustion process, these chemicals oxidize mercury so it can be collected in the baghouse.

Reg 6, Part B, Section VIII.D.1, specifies that the emission standards, low emitter provisions, and permitting, monitoring and enforceability requirements shall be incorporated into the permit for each subject Hg Budget unit. However, the provisions in Section VIII.D.5 specify that all permits shall include all applicable requirements, including requirements to comply with the emission standards in Section VIII.C and requirements to comply with the permitting and monitoring requirements of Sections VIII.D and VIII.E and 40 CFR Part 75 (this section does not require that the enforceability requirements be included). These sections appear to contradict each other; however, the Division has determined that it is appropriate to include the following requirements in the permit:

- the Hg emission limitations in Section VIII.C.1.a

  Note that since the source indicated in their December 19, 2008 application that they would meet the output limit only the outlet limit has been included in the permit.

- the monitoring requirements in Section VIII.E

- the enforceability requirements in Section VIII.F

In general the Division included the requirements in the permit that were identified in Section VIII.D.1, with the following exceptions.

The Division did not include the low emitter provisions since this unit is not a low emitter and is specifically required to meet the Hg emission limits in Section VIII.C.1.a. Along those same lines the Division did not include the reporting requirements for low emitters specified in Section VIII.E.3.c.

In addition, it is not clear which parts of the permitting section in the regulation would be relevant to include in a permit, since this section merely sets out the requirements for what is to be included in the permit application and the permit and the deadline for source's to submit permit applications and the Division to issue permits. Therefore, the Division did not include any of the permitting requirements specified in Section VIII.D.

Finally, Section VIII.E.4 specifies the submittal of a monitoring plan for Division approval for any units that are either demonstrating compliance with the percent capture limits or the outlet emission standards. The source submitted a monitoring plan that included the elements in Section VIII.E.4.b for the meeting the outlet standards. Since the plan has been submitted, the Division considers that the requirements in this Section VIII.E.4 have been fulfilled and therefore, will not be included in the permit. However, the Division will include a requirement in the permit to follow the Division-approved monitoring plan.

Sorbent Injection Silos

In addition, since the source has proposed a sorbent injection system, which requires sorbent storage silos, the Division has included the appropriate applicable requirements for the storage silos into Section II.5 of the renwal permit as a combined construction/operating permit as provided for in Colorado Regulation No. 3, Part C, Sections I.A.7 and III.B.7. These requirements include the following:

- Construction of this source must commence within 18 months of initial approval permit issuance date or within 18 months of date on which such construction or activity was scheduled to commence as stated in the application (Reg 3, Part B, Section III.g.4.a.(i) thru (ii)).
- Within 180 days after commencement of operation, compliance with the conditions contained on this permit shall be demonstrated to the Division (Reg 3, Part B, Section III.G.2)

  Note that the Division considers that the first semi-annual monitoring and permit deviation report submitted after the units commence operation will serve as the self-certifcation.
- The permittee shall notify the Division, in writing, thirty (30) days prior to startup (Reg 3, Part B, Section III.G.1).

  Note that by policy the Division currently asks that the startup notice be submitted within 30 days after the units commence operation.
- 20% opacity (Regulation No. 1, Section II.A.1)

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

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

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

- Sorbent processing not to exceed 560 tons/yr (based on information provided in December 19, 2008 permit application)
- PM emissions not to exceed 0.38 tons/yr (based on requested emissions provided in the APEN received on December 19, 2008)
- PM_{10} emissions not to exceed 0.38 tons/yr (based on requested emissions provided in the APEN received on December 19, 2008)

The Division determined that neither the Regulation No. 1 (Section III.C.1) nor the Regulation No. 6 (Part B, Section III.C, including opacity) particulate matter standards were applicable to the sorbent silos. The Division does not consider these to be manufacturing processes since the sorbent is used to control Hg emissions from Unit 1.

Emission Factors

Emissions from the sorbent silos are based on the assumed baghouse rating of 0.01 gr/dscf, the rated air flow of 500 dscfm and 8,760 hrs/yr of operation. The emission rate in lbs/hr from each of the silos was determined as follows:

$$\text{Emissions (PM and } PM_{10}\text{)} = \frac{0.01 \text{ gr/dscf} \times 500 \text{ dscfm} \times 60 \text{ min/hr}}{7{,}000 \text{ gr/lb}} = 0.043 \text{ lbs/hr}$$

May 7, 2009 Comments on the Draft Permit and Technical Review Document

Main Boiler (Unit 1) and Auxiliary Boiler

In their comments, the source indicated that the main boiler (Unit 1) and the auxiliary boiler are no longer capable of burning No. 2 fuel oil and requested that language related to No. 2 fuel oil burning be removed. To that end the Division revised the description of the auxiliary boiler in Section I, Condition 1.1 and the descriptions of the main boiler and auxiliary boiler in the tables in Section I, Condition 6.1 ("old" Condition

5.1) and Appendices B and C. In addition, Section II.2 (Unit 1) was revised to remove references to No. 2 fuel oil. Finally, Section II.3 (Auxiliary Boiler) was revised to remove references to No. 2 fuel oil and permit conditions 3.4, 3.5, 3.6.2 and 3.7.2, which are related to No. 2 fuel oil use. The source submitted a revised APEN on May 28, 2009, to reflect that natural gas will be the only fuel used. Emissions from PM, PM_{10}, SO_2 and VOC, when burning natural gas are below the APEN de minimis level, therefore, emission limitations for PM, PM_{10}, SO_2 and VOC have not been included in the permit.

Section II, Condition 5.4

The phrase "transfer tower" was replaced with "transfer tower/tripper deck" to more appropriately identify one of the baghouses referenced in this permit condition.

Appendix A – Insignificant Activity List

In their comments on the draft permit (submitted on May 7, 2009), the source requested the following changes to the insignificant activity list.

The following changes were made to the list under the category of "chemical storage tanks or containers < 500 gal":

- The following equipment was removed:
  - R.O. Acid dilution feed tank (200 gal)
  - R.O. Scale inhibitor feed tank (180 gal)
- The following equipment was added:
  - R.O. Acid feed tank
  - R.O. Anti-scalant feed tank
  - R.O. Sodium bisulfate feed tank
  - R.O. Caustic feed tank
  - Bleach feedwater tank
  - Sewage bleach feed tank

The category for "fuel storage and dispensing equipment < 400 gal/day" was revised to indicate there are two 1,000 gal unleaded gasoline storage tanks.

Under the category for "storage tanks with annual throughput less than 400,000 gal/yr and meeting content specifications", the following changes were made:

- Removed the 325,000 gal No. 2 fuel oil storage tank
- Revised to indicate there is a 10,000 gal above ground diesel storage tank in addition to a 10,000 gal underground diesel storage tank

Added the facility's warehouse and water treatment buildings under the category for "chemical storage areas < 5,000 gal".

The description of the holding and evaporation ponds under the category "emissions of air pollutants that are not criteria or non-criteria reportable pollutants" was corrected to indicate they are located on the east and south sides of the facility.

Under the category for "not sources of emissions" the following changes were made:

- Corrected the description of the seed tank to indicate it is 600 gal, rather than 400 gal
- Added the following equipment:
  - Feed tank (4,500 gal)
  - Brine tank (16,000 gal)
  - Bleach tank (16,000 gal)
  - Tolyltriazole tank (1,000 gal)
  - Scale inhibitor tank (1,000 gal)

The lime silo used in the water treatment process was added under the category "units with emissions less than APEN de minimis – criteria pollutants". The source indicated that emissions are estimated to be 0.5 tons/yr of PM and PM_{10}.

The source indicated in an e-mail received May 14, 2009 that the fire pump engine is rated at 240 hp, therefore, the Division corrected this entry under the category "stationary internal combustion engines – limited size or hours".

<u>Other Modifications</u>

In addition to the modifications requested by the source, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Pawnee Station Operating Permit with the source's requested modifications. These changes are as follows:

<u>General</u>

- The Reg 3 citations were revised throughout the permit, as necessary, based on the recent revisions made to Reg 3.

Page Following Cover Page

- Monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

- Changed the responsible official.

Section I - General Activities and Summary

- Revised the description under Condition 1.1 to address the three separate operating permits issued for the facility and to indicate that the auxiliary boiler can burn either natural gas or No. 2 fuel oil.

- Removed construction permit 12MR093-2 from the list in Condition 1.3.

- Section V, Conditions 3.d and 3.g (last paragraph) were added as state-only requirements in Condition 1.4. Note that Section V, Condition 3.d (affirmative defense provisions for excess emissions during malfunctions) is state-only until approved by EPA in the SIP.

- Made minor revisions to the language in Condition 3 (prevention of significant deterioration) to be more consistent with other permits.

- Added a column to the Table in "old" Condition 5.1 for the startup date of the equipment. In addition, added "Unit 1" to the description of Boiler 1 and "auxiliary boiler" to the description of Boiler 2 to more appropriately identify the units.

- Added "new" Condition 5.1 for compliance assurance monitoring (CAM) requirements.

Section II.1 – Main Boiler (Unit 1), Coal Firing

- Added "Unit 1" to the table header to more clearly identify the unit.

- References to fuel usage or fuel sampling were replaced with coal usage or coal sampling.

- The second paragraph in Condition 1.3 (violations of the SO_2 emission standard shall not be considered as arising from an "upset" condition) was removed. This paragraph was included incorrectly in the Title V permit. In the underlying construction permit, this paragraph included the phrase "due to a lack of coal of suitable quality" after the word "standard"; however that phrase was not included in the Title V permit. Lack of coal of suitable quality would not qualify as a malfunction, as defined in the Common Provisions language; therefore, the Division is removing this language, rather than restoring it to the language included in the construction permit.

- Revised Condition 1.7 (fuel sampling) to remove lead.

- Revised the language in Condition 1.1.2 to specify that the performance tests shall be used to set the baseline opacity for the CAM plan and specified how the baseline opacity shall be determined.

- Removed the last sentence from Condition 1.14. This condition already refers the reader to Section III for Acid Rain provisions and this last sentence is not necessary.

Section II.3 – Auxiliary Boiler

- Based on EPA's response to a petition on another Title V operating permit, minor language changes were made to various permit conditions (both in the table and the text) to clarify that only natural gas or No. 2 fuel oil is used as fuel for permit conditions that rely on fuel restriction for the compliance demonstration.

- Added a requirement to submit a case-by-case MACT analysis.

Section II.4 – Particulate Matter Emissions – Fugitive Emissions

- Removed the language from Condition 4.1 that indicates that the emissions provided in the table are included for information purposes only. These emission rates are used in the modeling analysis and are considered limitations. Although the Division does consider that if the materials handling limits are met and the control measures are followed, then the source is in compliance with the emission limitations. To that effect the Division has revised the language in Condition 4.1.

- Based on comments received during the public comment period, the following phrase was added to Condition 4.2.1 "[t]he 20% opacity, no off-property transport, and nuisance emission limitations are guidelines and not enforceable standards and no person shall be cited for violation thereof pursuant to C.R.S. 25-7-115."

Section II.5 – Particulate Matter Emissions – Point Sources

- Corrected the PM limit for the coal handling system (P001). The technical review document prepared for the original Title V permit (issued January 1, 2003) indicated that permitted PM emissions from coal handling was set at 15.4 tons/yr; however, a limit of 15.3 tons/yr was included in the permit.

- The references to "Colorado Construction Permit 12MR093-2" were replaced with "Colorado Construction Permit 12MR093-1". As discussed in the technical review document for the original Title V permit (issued January 1, 2003), there were three construction permits issued for coal handling: 12MR093-1 (fugitive emissions), 12MR093-2 (crusher) and 12MR093-2 (transfer tower). The Division intended that the fugitive emission sources be addressed on permit 12MR093-1 and that point sources be addressed on 12MR093-2 and that permit 12MR093-3 would be cancelled. However, the Division's database is indicating that both permits 12MR093-2 and 12MR093-3 are cancelled. Since the source reports emissions from coal handling (both fugitive and point source emissions) on one APEN, including all coal handling on one permit is more appropriate.

- Removed Condition 5.8.1 (initial performance test requirement) since the initial performance test was conducted. The language in Condition 5.8.2 was incorporated into Condition 5.8.

- Based on comments received during the public comment period, the Division included requirements to conduct annual Method 9 visible emission observations on the transfer tower/tripper deck and crusher baghouses.

Section II.7 – NSPS General Provisions

- Removed the reference to Colorado Regulation No. 1, Section VI.B.4.a.(iv) in the citation for Condition 7.1. The good practices language in Colorado Regulation No. 1 has been removed.

Section II.8 – Particulate Matter Emission Periodic Monitoring Requirements

- Removed the language in Condition 8.1 regarding the COMS and opacity spikes. The Division considers that with the CAM plan requirements this language is no longer necessary.

- Revised the stack testing language in Condition 8.2 to clarify the frequency of testing. The language in the permit addresses testing within the expected five-year permit term. The permit terms may be extended, provided a timely and complete renewal application has been submitted. For the most part, complete and timely renewal applications have been submitted and the term of the permits have been extended beyond the originally anticipated five-year permit term. Therefore, the language has been revised to set specific deadlines for testing, which more appropriately reflects the Division's intent to require testing for particulate matter at a minimum of every five years. To that end, the language regarding waiving testing within the last two years of the permit term, in the event that annual testing was triggered, has been removed. In general, the results of the initial tests have not been above 75% of the standard and annual testing has not been triggered. Therefore, the Division considers that the language is not necessary.

Section II.9 – Continuous Emissions Monitoring System Requirements

- Removed the phrase "and the traceability protocols of Appendix H" from Condition 9.3.2, since Appendix H of the current version of 40 CFR Part 75 is "reserved". Note that Condition 9.3.1 specifies that the continuous emission monitoring systems are subject to the requirements of 40 CFR Part 75 and that would include any applicable appendices, regardless of whether or not they are specifically called out in this condition.

- Based on citizen comments on another Title V permit, Condition 9.4.3 (monitoring opacity when the COM is down) was removed from the permit.

Condition 11 – Lead Periodic Monitoring

- Revised Condition 11.2 to indicate that lead emissions would be based on the annual TRI Report.

"New" Section II.14 – Regional Haze Requirements

As discussed previously in this document, a construction permit (07MR0111B) was issued on September 12, 2008 to address the regional haze requirements for BART. The appropriate applicable requirements from this permit have been included in the permit as follows:

- Control technology requirements (condition 1). This condition will be included in the permit.

- CEMS requirements (condition 2). The CEMS requirements are already included in the Title V permit.

- Emission limitations (conditions 3a, b & c). The SO_2, NO_X and PM emission limitations will be included in the permit.

- Compliance schedule (condition 3.d). This condition will be included in the permit.

- Submittal of Title V permit application (condition 4). Since the conditions of the BART permit are being incorporated into the Title V permit at this time, this condition is no longer relevant and won't be included in the permit.

- O & M plan requirements (condition 5). The appropriate monitoring requirements will be included in the Title V permit; therefore, this requirement will not be included in the permit.

- Demonstrating compliance with permit conditions (condition 6). The Division considers that the Responsible Official certification submitted in conjunction with the first semi-annual monitoring and permit deviation report submitted after the compliance date for the BART requirements will serve as the compliance demonstration; therefore, this requirement will not be included in the permit.

- General terms and conditions (condition 7). This condition addresses the applicability of general terms and conditions in the construction permit. They are not relevant to the title V permit and will not be include in this permit.

- Reporting requirements (condition 8). This condition will be included in the permit.

<u>Condition 12 – Coal Sampling Requirements</u>

- Since the permit no longer requires that the lead emission calculations use the lead content of the coal, the requirement to sample coal for the lead content in Condition 14.1 has been removed.

<u>Section III – Acid Rain Requirements</u>

- Revised the Designated Representative.

- Revised the table in Section 2 to include calendar years corresponding to the relevant permit term for the renewal.

- Revised the NO_X limit in the table in Section 2. The source had elected to comply with the Phase I NO_X requirements in 1997. Beginning in January, the source was subject to the Phase II NO_X requirements. Therefore, those limits have been included in the permit.

- Removed Section 3, since the NO_X early election expired beginning in January 2008.

- Minor changes were made to the standard requirements (Section 4), based on changes made to 40 CFR Part 72 § 72.9.

- Removed the requirement in Section 5 to submit a copy of any revised certificate of representation to the Division. Submitting a copy of the certificate of representation to the permitting authority is not required under the regulations.

- Removed the requirement to submit the annual reports and compliance certifications in Section 5. As a result of revisions to the Acid Rain Program made with the Clean Air Interstate Rule (final published in the Federal Register on May 12, 2005), annual compliance certifications are no longer required, beginning in 2006. Note that although the CAIR rule was vacated (July 2008), this revision was unrelated to the CAIR rule and it is expected that these changes will not be affected by the CAIR vacatur. Note that in December 2008, the vacatur of the CAIR rule was over-turned.

Section IV – Permit Shield

- The citation for the permit shield has been revised to reflect revisions and restructuring of Reg 3, to correct the citation of Reg 3, Part C, Section XIII to XIII.B and to remove Reg 3, Part C, Section V.C.1.b and C.R.S. § 25-7-111(2)(l) since they don't address the permit shield.

Section V – General Conditions

- Added a version date to the General Conditions.

- Revisions were made to the Common Provisions Regulation (general condition 3), effective September 30, 2002 and December 15, 2006 (effective March 4, 2007). The appropriate revisions were made to the language in the permit. The September 30, 2002 revisions were minor in nature. The December 15, 2006 revisions replaced the upset provisions with the affirmative defense provisions for excess emissions during malfunctions. Note that these provisions for malfunctions are state-only enforceable until approved by EPA into Colorado's state implementation plan (SIP).

- Replaced the reference to "upset" in Condition 5 (emergency provisions) and 21 (prompt deviation reporting) with "malfunction".

- The title for Condition 6 was changed from "Emission Standards for Asbestos" to "Emission Controls for Asbestos" and in the text the phrase "emission standards for asbestos" was changed to "asbestos control".

- General Condition No. 21 (prompt deviation reporting) was revised to include the definition of prompt in 40 CFR Part 71.

- Replaced the phrase "enhanced monitoring" with "compliance assurance monitoring" in General Condition No. 22.d.

Appendices

- Created a category under Appendix A – Insignificant Activities for non-road engines. All but the fire pump engine listed under the "stationary internal combustion engine" category are non-road engines.

- Replaced Appendices B and C with the latest versions. In addition replace "Unit 2" with "Auxiliary Boiler" to the description of B002 to more appropriately identify the unit.

- Changed the mailing address for EPA in Appendix D. Removed the Acid Rain addresses in Appendix D, since annual certification is no longer required and submittal of quarterly reports/certifications is done electronically.

- Added a column labeled "Type of Revision" to the Table in Appendix F.

Total Facility HAP Emissions (tons/yr)

Emission Unit	acetaldehyde	acrolein	BTEX	formaldehyde	chloroform	Hexane	HCL	HF	Mercury	Metals	Total
Manchief Equipment (01OPMR236)											
Turbine 1	0.243	0.0389	1.25	4.32							5.85
Turbine 2	0.243	0.0389	1.25	4.32							5.85
Starter Engine	1.24E-04	3.89E-05	6.17E-03	3.89E-04							6.72E-03
Heater			2.14E-04	2.92E-03		7.01E-02				1.79E-04	7.34E-02
PSCo Pawnee Equipment (96OPMR129)											
Main boiler							20.3	53.65	0.18	19.93	94.06
Auxiliary boiler			1.94E-03	2.65E-02		6.36E-01				7.42E-04	0.67
Cooling Tower					2.6						2.60
Facility Total	0.49	0.08	2.51	8.67	2.60	0.71	20.30	53.65	0.18	19.93	109.11
PSCo Total				0.03	2.60	0.64	20.30	53.65	0.18	19.93	97.33
Manchief Total	0.49	0.08	2.51	8.64		0.07					11.78

Manchief Generating Station HAPS are based on AP-42 emission factors and permitted fuel consumption limits

PSCo Pawnee HAPS are based on the following. Auxiliary boiler: AP-42 emission factors and fuel consumption limit requested in APEN submitted May 28, 2009. Cooling Tower: permitted VOC emission limits all VOC assumed to be chloroform. Main Boiler: Metals are based on AP-42 emission factors and permitted fuel consumption limit, HCl and HF based on emission factors determined using emissions and fuel consumption reported on APENS (using 2007, 2006 and 2004 data), and mercury emissions from average projected emissions used to support development of Colorado Mercury Rule.

PSCo Pawnee Actual Emissions (tons/yr)

Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	HAPS
Main Blr (Unit 1)	132.6	122	14126.5	4415.2	598.5	71.2	61.36
Aux. Blr	0.003	0.003	0.0008	0.14	0.12	0.008	
Coal - fugitive	13.9	4.6					
Coal - pt source	3.4	1.2					
Ash - fugitive	6.6	2.4					
Ash - pt source (silo)	1.2	1.2					
Haul Roads - fug	33.3	8,5					
Soda Ash Silo	0.005	0.005					
Cooling Twr	22.5	22.5				2.5	0.12
Total	213.51	153.91	14,126.50	4,415.34	598.62	73.71	61.48
Total – Fugitive	53.80	15.50					
Total – Point Sources	159.71	146.91	14,126.50	4,415.34	598.62	73.71	61.48

Actual emissions from main boiler, coal handling and soda ash from APEN submitted 4/30/08 (2007 data)
Actual emissions from auxiliary boiler, haul roads and cooling tower from APEN submitted 4/9/07 (2006 data)
Actual emissions from ash handling from APEN submitted 4/19/05 (2004 data)
HAP emissions from cooling tower are chloroform
HAP emissions from main boiler consist of HCl, HF, manganese and nickel

Exhibit 3 to Title V Petition

Unit Level Emissions Quick Report
February 19, 2010

Your query will return data for 1 facilities and 1 units.

You specified: **Year(s)**: 2008 **Program**: ARP **Facility**: Pawnee

State	Facility Name	Facility ID (ORISPL)	Unit ID	Associated Stacks	Year	Program(s)	Operating Time	# of Months Reported	SO_2 Tons	Avg. NO_x Rate (lb/mmBtu)	NO_x Tons	CO_2 Tons	Heat Input (mmBtu)
CO	Pawnee	6248	1		2008	ARP	8,223	12	13,217.2	0.25	4,595.2	3,837,802.3	36,775,940
Total									**13,217.2**		**4,595.2**	**3,837,802.3**	**36,775,940**

Exhibit 4 to Title V Petition

WildEarth Guardians
A FORCE FOR NATURE

July 3, 2009

Jacqueline Joyce
Colorado Air Pollution Control Division
4300 Cherry Creek Drive South
Denver, CO 80246
comments.apcd@state.co.us

Re: Renewed Title V Permit for Public Service Company's Pawnee Coal-fired Power Plant, Permit Number 96OPMR129

Dear Ms. Joyce:

WildEarth Guardians, Clean Energy Action, and the Sierra Club submit the following comments in response to the Air Pollution Control Division's ("APCD's") proposal to issue a renewed Title V Permit for Public Service Company's Pawnee coal-fired power plant in Morgan County, Colorado (Permit Number 96OPMR129). We have serious concerns over the draft Title V Permit and its ability to ensure compliance with all applicable requirements in accordance with 40 CFR § 70.6. In accordance with Air Quality Control Commission ("AQCC") Regulation No. 3, Part C, Section VI.B.8., these comments are hereby submitted within 30 days following publication of public notice of the permit, which according to the APCD occurred on June 3, 2009. Our concerns are as follows:

1. **The Title V Permit must include a compliance plan to bring the Pawnee coal-fired power plant into compliance with the Prevention of Significant Deterioration program.**

A Title V Permit is required to include emission limitations and standards that assure compliance with all applicable requirements at the time of permit issuance. *See* 42 USC § 7661c(c); 40 CFR § 70.6(c)(1). Pawnee is currently in violation of PSD requirements. A PSD compliance plan is an applicable requirement of any Title V Permit. *See* 42 USC § 7661 b(b); 40 CFR § 70.6(b)(3). The Permit fails to include a compliance plan to bring the Pawnee Station into compliance with PSD.

Pursuant to Part C of the Clean Air Act, the Colorado State Implementation Plan ("SIP") requires that no construction or operation of a major modification of a major stationary source occur in an area designated as attainment without first obtaining a permit under 40 CFR § 51.166, and prohibits the operation of a major stationary source after a major modification unless the source has applied Best Available Control Technology ("BACT") pursuant to 40 CFR §

51.166(j) and the Colorado SIP, 5 CCR § 1001-5. The EPA has approved all the PSD provisions of the Colorado SIP, as well as subsequent amendments to those provisions.

The Pawnee coal-fired power plant is a major stationary source within an area classified as attainment for all criteria pollutants. According to information from Public Service Company, the plant underwent major modifications in 1994 and 1997 without obtaining the required PSD permit. These modifications have resulted in unpermitted emissions of significant amounts of SO_2, NO_x, and PM. On June 27, 2002 the Environmental Protection Agency ("EPA") issued a notice of violation ("NOV") to Xcel Energy, Inc. regarding violations of PSD under the Act at Pawnee coal-fired power plant. This NOV is attached to these comments as Exhibit 1. For the past fifteen years, the plant has operated and continues to operate in a state of noncompliance with the PSD provisions of the Clean Air Act. Accordingly, the Title V Permit must bring the Pawnee coal-fired power plant into compliance with PSD requirements. Evidence of noncompliance with PSD requirements at the Pawnee coal-fired power plant is as follows:

a. The June 27, 2002 NOV issued for the Pawnee Station constitutes a finding of non-compliance with the PSD program for the purposes of Title V.

The NOV issued to Xcel Energy, Inc. on June 27, 2002 states:

> Xcel violated and continues to violate Clean Air Act, Part C: Prevention of Significant Deterioration of Air Quality ("PSD"), 42 U.S.C. §§7470 to 7492, and the permitting requirements of Colorado Air Quality Control Commission Regulation No. 3, Part B, IV.D.3 and 40 C.F.R. §52.21, by constructing and operating modifications at the Pawnee Station...without the necessary permits and by constructing and operating without the application of BACT required by the Colorado SIP.

NOV at 5. Clearly, the EPA concluded that the Pawnee coal-fired power plant was violating PSD requirements when it issued the NOV.

The 2002 NOV is sufficient to demonstrate noncompliance with PSD for the purposes of a Title V Permit. In a situation very similar to the situation regarding the Pawnee NOV, the Second Circuit held that an NOV is sufficient to demonstrate noncompliance with PSD for the purposes of the Title V permitting program. *See* NYPIRG *v. Johnson*, 427 F.3d 172, 180 (2nd Cir. 2005). In *NYPIRG v. Johnson,* the Second Circuit Court of Appeals recognized that "to issue a NOV, the Administrator must first find a source in violation of an applicable plan or permit." *Id.* at 181. The court further reasoned that in issuing an NOV, a permitting authority had determined that PSD requirements "are, indeed, applicable." *Id.* The court held that the issuance of an NOV by the State of New York constituted a finding of noncompliance with PSD requirements and that the EPA was required to object to the issuance of a Title V permit that failed to ensure compliance with PSD. *Id.* at 186.

According to 42 USC § 7413(a)(1), the EPA Administrator shall issue a notice of violation when he finds "that any person has violated or is in violation of any requirement or prohibition of an applicable implementation plan or permit." The statute clearly states that an NOV is issued by the EPA only after making a finding of a violation. Further, because the EPA, rather than the state, issued the NOV to Pawnee, it is even more clear here than in the *NYPIRG* case that the NOV constitutes a sufficient finding of noncompliance.

The Tenth Circuit has not yet addressed the sufficiency of an NOV as legal proof of noncompliance with PSD requirements under Title V. Only one circuit has issued a holding in conflict with the Second Circuit position on NOVs; *see Sierra Club v. Johnson*, 541 F.3d 1257 (11th Circuit 2008). The reasoning in *NYPIRG v. Johnson*, mentioned above, applies to the facts here regarding the Pawnee NOV. This reasoning mandates that the Title V Permit require the Pawnee coal-fired power plant comply with PSD.

b. Regardless of the NOV, Evidence of Major Modifications Exist.

If the APCD believes that the EPA NOV is not legally sufficient to demonstrate noncompliance with established PSD requirements, at a minimum the NOV shows clear evidence of a valid suspicion of noncompliance. This evidence is further bolstered by actual documents from Xcel Energy that demonstrate major modifications occurred at the Pawnee coal-fired power plant without prior approval under PSD. Indeed, Xcel's own records confirm that at least two major modifications were made to Pawnee during the 1990s:

(1) Reheater redesign and replacement.

An Xcel Capital Project Summary Sheet submitted July 7, 1993 states that:

> The top bank plus all 256 reheater assemblies in the two middle banks will be replaced during the planned ten-week outage in 1994. . . In addition to replacing the assemblies, we will upgrade some of the material used, and change some of the manufacturing methods to prevent further similar damage in the past and prolong the life of the new assemblies. The reheater assemblies will also be redesigned so as to prevent the excessive pluggage currently seen.

See Exhibit 2 attached to these comments. The Pawnee Planned Outages data shows that there were planned outages for "major turbine overhaul (720 hours or longer)" between 9/30/1994 and 12/31/1994. *See* Exhibit 3 attached to these comments. EPA operations data from 1994 shows that Pawnee reported zero hours of operation during the months of October and November, and only 284 hours in December. *See* Exhibit 4 attached to these comments. Together, these documents confirm that the 1994 modification noted in the NOV did occur. Further, the fact that Pawnee shut down operations for ten weeks is a strong indication that this modification was major.

(2) Upgrade of condenser tubes.

An Xcel Request for Specific Appropriation dated July 10, 1996 states that $4.5 million in emergency funding was allocated for the new condenser tubes. *See* Exhibit 5 attached to these comments. It goes on to state that "The project will be completed during the January 4 through

March 2, 1997 outage." *See* Exhibit 6 attached to these comments. Pawnee Planned Outages data shows that there were planned outages for "major turbine overhaul (720 hours or longer)" between 2/28/1997 and 4/30/1997. *See* Exhibit 3. EPA operations data from 1997 shows that Pawnee reported 168 hours of operation in February, zero hours in March, and 249 hours in April. *See* Exhibit 7 attached to these comments. Together, these documents confirm that the 1997 modification noted in the NOV did occur. Further, Xcel referred to this modification in its own documents as "major."

The NOV explained that these modifications did not fall within exemptions for "routine maintenance," "increased hours of operation," or "demand growth" set forth at 40 CFR § 51.166. The NOV concludes that "Each of the modifications resulted in a net significant increase in emissions for SO_2, NO_x, and/or PM as defined by 40 CFR §§ 51.166(b)(3) and (23) and Colorado SIP Rules at AQCC Regulation No. 3, Part A, I.B.59 and Part A, I.B.37." Because these were modifications resulting in net significant increases of criteria pollutants, a PSD permit was requied to be obtained before those modifications occurred. Xcel did not obtain such a PSD permit for the Pawnee coal-fired power plant, in violation of the Clean Air Act.

Xcel's records also seem to provide evidence of other modifications undertaken during the past twenty years. During April through June of 1989, there were planned outages for a "major turbine overhaul." *See* Exhibit 8 attached to these comments. In April of 1998, there was a planned outage for a "major boiler overhaul." Exhibit 3. In March of 2000, there was another planned outage for a "major boiler overhaul." *See* Exhibit 9 attached to these comments. At a minimum, the APCD has a duty to investigate these modifications and make a determination whether or not they were major modifications under the PSD regulations.

Even if the APCD believes the NOV is not sufficient to constitute a violation of the PSD requirements, the evidence of modifications listed above must be dealt with under the PSD provisions of the Clean Air Act and the Colorado SIP. Xcel clearly made at least two modifications to the Pawnee coal-fired power plant. Modifications clearly resulted in significant emissions increases, not only as reported in the NOV but also reported by the EPA Clean Air Market Data. *See* table below.

Annual Emissions at Pawnee Coal-fired Power Plant (Data from EPA Clean Air Market Data. Available at: http://camddataandmaps.epa.gov/gdm/index.cfm (last accessed June 29, 2009).

Year	SO_2 Tons	NO_x Tons
1995	15374.0	4869.0
1996	11633.4	3529.0
1997	13928.7	3817.8
1998	15325.6	3906.1
1999	16665.8	5319.7
2000	14678.1	4892.4
2001	17030.9	5845.4
2002	14832.6	4591.7

2003	16703.0	5369.0
2004	12549.6	4514.6
2005	11248.1	3668.1
2006	13072.5	4602.7
2007	14126.5	4415.3

The amount of SO_2 emissions considered significant is 40 tons per year. 40 CFR § 51.166(b)(23). The amount of NO_x emissions considered significant is 40 tons per year. *Id.* The data after the second modification (1997-1998) shows a SO_2 increase of 1396.9 tons and a NO_x increase of 88.3 tons. Thus, both significance thresholds were met after the 1997 modification. While data immediately before the 1994 modification is not available on the Clean Air Market website, the NOV claims that the 1994 modification did result in significant emissions increases. PM10 emissions of 15 tons per year are also considered significant under the regulations. 40 CFR § 51.166(b)(23). The NOV claims that a significant PM emission increase also occurred at Pawnee.

Given that Pawnee is currently in violation of PSD requirements, the Title V Permit must include a compliance plan to bring the Pawnee coal-fired power plant into compliance with PSD. If these applicable requirements are missing from the Permit, it will be in violation of 42 USC § 7661c(c) and 40 CFR § 70.6(c)(1).

At the least, the APCD has a minimum responsibility to respond to our significant comments about the valid suspicion of noncompliance with PSD as demonstrated by the 2002 NOV and Xcel Energy's own reports providing evidence of major modifications. *See In the Matter of CEMEX Inc.*, Petition No. VIII-2008-01 (April 20, 2009). In particular, the APCD must "provide the basis (e.g., citing to current or historical evidence, or the lack thereof) that supports its conclusion that PSD/NSR" was or was not applicable in relation to the aforementioned modifications. *Id.* at 10.

2. The Title V Permit Must Include Regional Haze Requirements

The Title V Permit must incorporate emission limits established under Colorado's regional haze rules, as required by 40 CFR § 70.6. As the Technical Review Document ("TRD") notes, the Pawnee coal-fired power plant is subject to stronger particulate matter ("PM") and nitrogen oxide ("NOx") emission limits under a recently issued Best Available Retrofit Technology ("BART") construction permit issued by the APCD. *See* TRD at 8-9. These emission limits are applicable requirements under Title V, which include "any term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D, of the [Clean Air] Act." 40 CFR § 70.2.

3. The Title V Permit Fails to Assure Compliance with Particulate Limits for the Coal-fired Boiler

We are further concerned that the proposed Title V Permit fails to require sufficient periodic monitoring to ensure compliance with particulate limits from emission unit B001, the coal-fired boiler at the Pawnee plant. Condition 8.2 of the Title V Permit requires only annual stack testing, although this Condition allows for less frequent monitoring. Annual stack testing is wholly insufficient, particularly given that National Ambient Air Quality Standards ("NAAQS") limit particulate matter, including both PM-10 and PM-2.5, on a 24-hour basis. The Title V Permit must at least require daily particulate matter monitoring to protect the NAAQS and also to ensure sufficient periodic monitoring in accordance with 40 CFR § 70.6.

Although the Title V Permit may rely on baghouses to meet particulate standards, there are no conditions that require any monitoring, recordkeeping, or reporting to ensure the baghouses are operated consistently to assure compliance with the particulate limits. Put simply, there are no terms and conditions that ensure the baghouses will assure compliance with the particulate limits. Furthermore, to the extent that

Regardless of the effectiveness of the baghouses however, we are concerned that the baghouses do not limit condensable particulates, which are a component of particulate matter. The Title V Permit must require more frequent particulate matter monitoring. We would request the APCD require the use of particulate matter continuous emission monitoring systems ("PM CEMS") to assure compliance with the particulate limits in the Title V Permit. The U.S. Environmental Protection Agency ("EPA") promulgated performance specifications for PM CEMS at 40 CFR § 60, Appendix B, Specification 11, on January 12, 2004. *See*, *In the Matter of Onyx Environmental Services*, Petition No. V-2005-1 at 13. This promulgation indicates that the use of PM CEMS is an accepted means of assessing compliance with particulate emissions.

Furthermore, the EPA has required other coal-fired power plants to install, operate, calibrate, and maintain a PM CEMS. In a 2000 consent decree, Tampa Electric Company agrees to install a PM CEMS on one of its coal-fired power plants in Florida to ensure compliance with PM limits. More recently, through a 2006 consent decree, two North Dakota utilities agreed to install PM CEMS at a coal-fired power plant in North Dakota. Similarly, the EPA reached agreements with other utilities in Wisconsin and Illinois that have led to the installation, calibration, operation, and certification of PM CEMS. All these consent decrees are implicit that the PM CEMS are to be used to demonstrate compliance with PM limits.

Most recently, in proposed amendments to new source performance standards ("NSPS") for electric utility steam generating units, the EPA stated, "Based on our analysis of available data, there is no technical reason that PM CEMS cannot be installed and operate reliably on electric utility steam generating units." 70 Fed. Reg. 9728. Although the final amendments to the NSPS for electric utility steam generating units did not require the utilization of PM CEMS, the EPA stated that PM CEMS may be used to demonstrate continuous compliance with particulate limits.

The use of PM CEMS would constitute sufficient periodic monitoring that will assure compliance with the particulate limits set forth in the Title V Permit. We request the APCD take advantage of its authority under 40 CFR § 70 to require the installation and operation of PM CEMS at the Pawnee coal-fired power plant through the Title V Permit.

4. The 20 Percent Opacity Limit Applies to Fugitive Emissions from Coal Handling and Storage, Ash Handling and Disposal, and Paved and Unpaved Roads.

While the 2002 Technical Review Document states that the 1974 NSPS at 40 CFR § 60.252 ("Subpart Y") apply to the coal handling system, at page 26 it asserts that the 20 percent opacity limit is not actually a requirement for fugitive emissions. The Title V Permit therefore does not include an opacity limit for following sources: coal handling and storage, ash handling and disposal, and paved and unpaved roads. This is incorrect. The Title V Permit must ensure that the 20% opacity limit in Subpart Y applies to fugitive, as well as point source, emissions from coal handling and storage, ash handling and disposal, and paved and unpaved roads.

Indeed, Subpart Y mandates that the operator "shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater." 40 CFR § 60.252. Subpart Y includes and applies to all emissions from these sources, regardless of whether the emissions come from a point source or a fugitive source.

5. The 20 Percent Opacity Limit under NSPS Subpart Y Applies to Coal Unloaded to Storage

The 2002 Technical Document at 28 incorrectly states that coal unloaded to storage is exempt from Subpart Y. Coal unloaded to storage is a "coal storage system," and "coal storage system" is written in the plain language of the regulation. The Title V Permit must be written so that the 20 percent opacity limitation applies to all parts of the coal handling system.

Indeed, the 2002 Technical Document at 36 relied on EPA's 1998 interpretation of 40 CFR Part 60 Subpart Y § 60.252, published at 63 FR 53288 (Oct. 5, 1998), to assert that unloading and conveying coal to storage were not subject to Subpart Y. The 1998 interpretive rule appeared to exclude coal unloading to coal storage areas from its 20% opacity requirement. This rule was not explained nor was there a rational basis for this exclusion. *See* 63 FR 53289. While courts typically give some deference to interpretive rules, they do not merit *Chevron* deference, nor do they have any legally binding effect. *U.S. v. Mead Corp.*, 533 U.S. 218, 232 (2001).

Further, the EPA recently proposed revisions to the NSPS at Subpart Y that strongly indicate the 1998 interpretive rule is, in fact, flawed. On May 27, 2009, the EPA proposed changing the previous interpretation under Subpart Y to include all open storage piles as affected facilities. *See* 74 FR 25312. This new interpretation has been issued via notice and comment, in contrast to the 1998 rule which was simply interpretive and was not issued with notice and comment. This proposed rule further indicates that the 1998 interpretive rule cannot be relied upon to assert that coal unloaded to storage is exempt from Subpart Y.

6. Opacity Must Be Monitored and Reported for All Coal Handling and Storage, Ash Handling and Disposal, and Paved and Unpaved Roads.

The Title V Permit must contain periodic monitoring to assure compliance with all terms and conditions. 40 CFR § 70.6. The draft Title V Permit currently lacks opacity monitoring for fugitive emissions from coal handling and storage, ash handling and disposal, and paved and unpaved roads. The APCD must add "periodic monitoring sufficient to yield reliable data form the relevant time period that are representative of the source's compliance with the permit" to comply with 40 CFR § 70.6(a)(3)(i)(B). *See In re Citgo Refining and Chemicals Co. L.P.*, Petition No. VI-2007-01 (May 28, 2009) at 7. Periodic monitoring for these sources of fugitive emissions must be included in the Title V Permit to ensure compliance with the 20 percent opacity limitation.

7. Particulate Limits at Section II, Condition 5 Appear Unenforceable

Condition 5.1 establishes presumptive compliance with the PM and PM10 limitations for the coal handling system. Presumptive compliance is based on fulfilling the work practices listed in Conditions 5.1.1 through 5.1.5. *See* Condition 5.1.6. As explained below, these conditions are vague and unenforceable, and a system of presumptive compliance is insufficient to ensure that applicable particulate matter limitations are met.

Condition 5.1.1 is vague and unenforceable because it does not define "good engineering practices." This undefined term implies certain practices, but it does not state what they are. Moreover, these conditions do not state how operation in accordance with good engineering practices will be reported or monitored. Without any periodic monitoring requirements, this condition is unenforceable as a practical matter and in violation of 40 CFR § 70.6(a)(3)(i)(B).

At a minimum, the Permit must describe periodic monitoring that is sufficient to assess whether "good engineering practices" have been followed. To achieve this, the Permit must define "good engineering practices" so that there is a standard to which actual operations can be compared.

Conditions 5.6.2 and 5.6.3 also use the term "good engineering practices" without defining what that term means. These conditions fail to comply with 40 CFR § 70.6(a)(3)(i)(B) for the same reasons that Condition 5.1.1 failed above. Sufficient periodic monitoring must be added to the Permit to assure compliance with the relevant good engineering practices that are implied (but not properly explained) by Conditions 5.6.2 and 5.6.3.

Condition 5.1.3 is vague and unenforceable because it does not define "integrity of the enclosures," nor does it state how such integrity will be maintained to prevent particulate emissions. Moreover, 5.1.3 does not explain what "used as necessary" means in the operation of water spray suppression systems. As it stands, there is no reporting or monitoring to ensure compliance with this requirement. To ensure compliance with this condition, the Permit must include periodic monitoring of the conveyor and crusher enclosures and periodic monitoring of the use of the water spray suppression systems. Without such monitoring, Condition 5.1.3 is in violation of 40 CFR § 70.6(a)(3).

Condition 5.1.5 does not contain any periodic monitoring, thus it also violates 40 CFR § 70.6(a). The transfer points must be identified and reported so that the number of transfer points can be monitored to ensure compliance with the 13-transfer point limit in 5.1.5. Transfer points should also be designated as PM and opacity monitoring points because there is significant potential for particulate emissions at transfer points.

Conditions 5.1.1 through 5.1.3 are extremely important for ensuring compliance with the two similar 20% opacity limits in Conditions 5.7 and 5.8. Condition 5.7 states that opacity emissions from the coal handling system shall not exceed 20%. Condition 5.8 states that "any coal processing and conveying equipment, coal storage system or coal transfer and loading system processing coal" shall not discharge gases which exhibit 20% opacity or greater, as required by 40 CFR § 60.252. Both 5.7 and 5.8 state that these opacity requirements "shall be presumed to be in compliance" if Conditions 5.1.1 through 5.1.3 are being met. As previously described, Conditions 5.1.1 and 5.1.3 do not define key standards nor do they contain sufficient monitoring to ensure compliance with applicable requirements. Due to these failures, it will be impossible to ensure compliance with Conditions 5.7 and 5.8 until the failures in 5.1.1 and 5.1.3 are corrected.

Moreover, even if Conditions 5.1.1 and 5.1.3 were corrected to include monitoring, presumptive compliance with the two opacity requirements is not sufficient to comply with 40 CFR § 70.6(c)(1). If permit terms and conditions include monitoring but that monitoring is insufficient to ensure compliance with terms and conditions, the permitting authority must supplement the permit so that the Permit meets Title V requirements. *Sierra Club v. EPA*, 536 F.3d 673, 678 (D.C. Cir. 2008).

Actual monitoring of opacity for the coal handling system, and for coal transfer and storage as defined in 40 CFR § 60.252, must be written into the Title V Permit. Condition 5 lists emissions unit P001, which includes crushing, transfer tower and conveying, as point sources for particulate matter and opacity. First, point sources must be identified for monitoring. The transfer points in Condition 5.1.5 should be potential monitoring points, as well as any opening in an enclosure. Second, opacity monitoring by Method 9 or other approved methods must occur at those points on a daily basis in accord with general requirements at 40 CFR § 60.11(b). Third, all opacity measurements must be recorded and reported to ensure compliance with the 20 percent limit. Without such revisions, the Title V Permit will fail to require sufficient monitoring to assure compliance with all applicable requirements.

8. The Title V Permit Fails to Assure Compliance with Section 112 of the Clean Air Act

The Title V Permit fails to assure compliance with section 112(j) of the Clean Air Act. In particular, the Title V Permit fails to assure compliance with case-by-case maximum achievable control technology ("MACT") requirements, both for any industrial boilers that may be in operation at the Pawnee coal-fired power plant and any electric utility steam generating unit ("EGU").

We are particularly concerned that the Title V Permit fails to assure compliance with section 112(j) in the context of mercury emissions from the coal-fired power plant. As the TRD notes, "on February 8, 2008 a DC Circuit Court vacated the CAMR regulations for both new and existing units." TRD at 7. In particular, the D.C. Circuit held in early 2008 that the EPA had inappropriately delisted EGUs from the list of sources whose emissions are regulated under section 112 of the Clean Air Act. In light of this ruling, as well as the EPA's failure to promulgate a MACT standard for EGUs, the APCD must develop a case-by-case MACT for the EGU in operation at the Pawnee coal-fired power plant. Such a case-by-case MACT must include mercury emission limits, as well as limits for other hazardous air pollutants ("HAPs") regulated under section 112 of the Clean Air Act, such as lead compounds, hydrofluoric acid, and hydrochloric acid. It is especially critical that the APCD assure compliance with section 112 given that the TRD discloses that the Pawnee coal-fired power plant is indeed a major source of HAPs. *See* TRD at 5.

We are further concerned that the Title V Permit fails to assure compliance with section 112 in the context of any industrial boilers that are in operation at the Pawnee coal-fired power plant. The TRD indicates that the "EPA has not set a deadline for submittal of 112(j) applications to address the vacatur of the Boiler MACT." TRD at 7. Yet compliance with section 112(j) does not hinge upon any EPA deadline. The Clean Air Act is clear that section 112(j) requirements apply whenever EPA fails to promulgate a standard within 18 months of the date established pursuant to section 112(e)(1) and (3) of the Clean Air Act. Thus, the deadline for Public Service Company to submit a 112(j) permit application has passed, meaning the Title V Permit must ensure that an application is submitted as soon as possible to assure compliance with section 112 of the Clean Air Act. To this end, the Title V Permit must contain a compliance schedule to bring the Pawnee coal-fired power plant into compliance with section 112(j) of the Clean Air Act in accordance with 40 CFR § 70.6(c)(3).

9. The Title V Permit Fails to Address Carbon Dioxide Emissions to Assure Compliance with PSD

In proposing to issue the Title V Permit, it appears that the APCD has failed to assess whether carbon dioxide ("CO_2") is subject to regulation in accordance with Prevention of Significant Deterioration ("PSD") requirements and therefore failed to ensure compliance with PSD under the Clean Air Act, PSD regulations, and the Colorado State Implementation Plan ("SIP").

Under Colorado regulations incorporated into the SIP, any source that emits more than 250 tons per year "of any air pollutant subject to regulation under the Federal Act" is subject to PSD permitting requirements, including the requirement that Best Available Control Technology ("BACT") be utilized to keep air emissions in check. *See* AQCC Regulation Number 3, Part D § VI.A.1.a; *see also* 42 USC § 7475(a) and 40 CFR § 51.166(j)(2). Similarly, the SIP requires that any major source that undergoes a modification leading to a significant emissions increase is also required to utilize BACT. AQCC Regulation No. 3, Part D § VI.A.1.b. The Clean Air Act makes clear that the BACT requirements extend to "each pollutant subject to regulation" under the Act. 42 USC § 7479(3) and 40 CFR § 52.21(b)(12); *see also* AQCC Regulation No. 3, Part D § II.A.8. In this case, the it appears the APCD failed to ensure assess whether CO_2 is subject to regulation in accordance with PSD and whether the Title V Permit ensures compliance with PSD requirements under the Colorado SIP, the Clean Air Act, and PSD regulations in relation to CO_2 emissions from the Pawnee coal-fired power plant.

At issue is the fact that the APCD may be relying upon EPA's interpretation of the phrase "subject to regulation" when issuing the Title V Permit and completely ignored whether CO_2 emissions should be limited by the application of BACT as required by PSD provisions in the Colorado SIP, the Clean Air Act, and PSD regulations. The U.S. Environmental Appeals Board ("EAB") determined this interpretation fails to set forth "sufficiently clear and consistent articulations of an Agency interpretation to constrain" authority the EPA would otherwise have under the Clean Air Act. *In re Deseret Power Electric Cooperative*, PSD Appeal No. 07-03, slip op. at 37 (EAB November 13, 2008), 14 E.A.D. at ___. In light of the EAB's ruling, it would be inappropriate for the APCD to ignore CO_2 emissions by relying on EPA's prior interpretation of the phrase "subject to regulation" when issuing the Title V Permit.

Although the APCD may claim that a December 18, 2008 interpretive memo issued by former EPA Administrator Stephen Johnson (hereafter "Johnson memo") "clarifies" EPA's position that CO_2 is not subject to regulation under PSD requirements (*see* Memorandum from Stephen L. Johnson, Administrator, to all Regional Administrators, "EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program" (December 18, 2008)) and therefore addresses the EAB's ruling, this is simply not true in this case. For one thing, the Johnson memo is clear that it does not bind states, such as Colorado, that administer the PSD program under their own SIP. Thus, the Johnson memo does not absolve the APCD from rendering its own, independent interpretation of the meaning of the phrase "subject to regulation" as set forth in the Colorado SIP.

Furthermore, EPA Administrator Jackson recently granted a petition for reconsideration of the Johnson memo "to allow for public comment on the issues raised in the memorandum." *See* Letter from EPA Administrator Lisa Jackson to David Bookbinder, Chief Climate Counsel, Sierra Club (February 17, 2009). Although Administrator Jackson declined to stay implementation of the Johnson memo while the EPA solicits public comment, she advised that "PSD permitting authorities should not assume the memorandum is the final word on the appropriate interpretation of Clean Air Act requirements." *Id.* It is further apparent that it would be inappropriate for the APCD to simply rely on the Johnson memo in assessing whether CO_2 emissions should be limited by the application of BACT as required by the Clean Air Act, PSD regulations, and the Colorado SIP.

Indeed, it would be further inappropriate because the Colorado SIP appears to support a finding that CO_2 emissions are subject to regulation, and therefore subject to PSD requirements. Although the phrase "subject to regulation" is not explicitly defined in the Colorado SIP, there are three reasons to interpret the Colorado SIP to allow the State of Colorado to find that CO_2 emissions are subject to regulation under the Clean Air Act.

First, the U.S. Supreme Court recently held in *Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), that CO_2 is a "pollutant" under the Clean Air Act. Although the EAB noted that the *Massachusetts* decision "did not address whether CO_2 is a pollutant 'subject to regulation' under the Clean Air Act" (*Deseret Power*, slip op. at 8), the EAB did not reject the interpretation that the decision supports a finding that CO_2 emissions are subject to regulation under the Clean Air Act. In fact, the EAB noted that the *Massachusetts* decision rejected key EPA memos that were relied upon when interpreting the phrase "subject to regulation" (*see e.g.*, *Id.* at 52, "The reasoning of the Fabricant Memo was subsequently rejected and overruled by the Supreme Court in *Massachusetts v. EPA*, 549 U.S. 497, slip op. at 29-30 (2007)").

Second, CO_2 is "subject to regulation" because it falls under the definition of "air pollutant" set forth in the Colorado SIP. Indeed, the AQCC Common Provisions Regulation, which is incorporated into the Colorado SIP, defines air pollutant as:

> Any fume, smoke, particulate matter, vapor, gas or any combination thereof that is emitted into or otherwise enters the atmosphere, including, but not limited to, any physical, chemical, biological, radioactive (including source material, special nuclear material, and by-product materials) substance or matter, but not including water vapor or steam condensate or any other emission exempted by the commission consistent with the Federal Act.

CO_2 is a gas that is emitted into the atmosphere, and therefore clearly regulated as a pollutant under the Colorado SIP. Furthermore, this definition derives directly from the Colorado Air Pollution and Prevention Control Act (*see* CRS § 25-7-103(1.5), a fact that seems to compel a finding that CO_2 is "subject to regulation" under the PSD. Indeed, the SIP explicitly states that PSD provisions apply "to any major stationary source and major modification **with respect to each pollutant regulated under the [Colorado Air Pollution and Prevention Control] Act** and the Federal Act that it would emit, except as this Regulation No. 3 would otherwise allow." AQCC Regulation No.3, Part D § VI.A. (emphasis added). The Colorado Air Pollution and Prevention Control Act clearly regulates CO_2, therefore the Colorado SIP seems to make clear that PSD provisions apply to any major sources and modifications with respect to CO_2 emissions.

Thus, not only does the recent EAB decision call into question the validity of the APCD's apparent failure to address CO_2 emissions in order to ensure the Title V Permit assures compliance with PSD requirements under the Clean Air Act and PSD regulations, but it appears as if the APCD's failure to address CO_2 emissions in the context of PSD is contrary to the Colorado SIP. The APCD must therefore address CO_2 emissions to ensure compliance with PSD requirements in the context of the Pawnee coal-fired power plant.

10. The Title V Permit Fails to Meet Clean Water Act 401 Certification Requirements

Section 401 of the Clean Water Act requires that, "Any applicant for a Federal license or permit to conduct any activity including, but not limited to, the construction or operation of facilities, which may result in any discharge into the navigable waters," shall provide a certification to the State in which the discharge originates that any discharge will comply with sections 301, 302, 303, 306, and 307 of the Clean Water Act. In this case, the APCD has failed to ensure that air pollution from the Pawnee coal-fired power plant will be limited such that waters designated as outstanding within Rocky Mountain National Park will be protected pursuant to section 303 of the Clean Water Act. All streams in Rocky Mountain National Park have been designated as "outstanding waters" by the Colorado Water Quality Control Commission ("WQCC") pursuant to section 303 of the Clean Water Act. *See* WQCC Regulation No. 38. Of particular concern is that Public Service Company of Colorado has not certified that the discharge of NOx emissions from the Pawnee coal-fired power plant, which contribute to nitrogen deposition in the streams and lakes of Rocky Mountain National Park, will comply with Colorado Water Quality Control Commission Standards that have been established pursuant to section 303 of the Clean Water Act.

Under the Clean Water Act, the APCD cannot renew the Title V Permit for the Pawnee coal-fired power plant until Public Service Company of Colorado can certify that its discharge of NOx emissions will protect the outstanding waters within Rocky Mountain National Park.

We appreciate the opportunity to submit comments. Please keep us apprised of any future action related to the Title V Permit for the Pawnee coal-fired power plant. If you have any questions, comments, or concerns, please contact us at the information below. Thank you.

Sincerely,

Jeremy Nichols
Climate and Energy Program Director
WildEarth Guardians
1536 Wynkoop, Suite 302
Denver, CO 80202
(303) 573-4898 x 1303
jnichols@wildearthguardians.org

on behalf of:

Leslie Glustrom
Clean Energy Action
PO Box 1399
Boulder, CO 80306
(303) 245-8637
lglustrom@gmail.com

Roger Singer
Regional Representative
Sierra Club
1650 38th St. #102W
Boulder, CO 80301
(303) 449-5595
roger.singer@sierraclub.org

EXHIBIT 1

TO WILDEARTH GUARDIANS' JULY 2, 2009 COMMENTS ON PROPOSED TITLE V PERMIT FOR PAWNEE STATION

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET - SUITE 300
DENVER, CO 80202-2466
http://www.epa.gov/region08

02 JUN 27 PM 12: 44

FILED
EPA REGION VIII
HEARING CLERK

JUN 26 2002

Ref: 8ENF-T

BY CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Olon Plunk
Vice President
Environmental Services
Xcel Energy
4653 Table Mountain Drive
Golden, CO 80403

Re: Notice of Violation

Dear Mr. Plunk:

Enclosed is a Notice of Violation ("NOV") issued pursuant to Section 113(a)(1) of the Clean Air Act ("the Act"), 42 U.S.C. §7413(a)(1). The U.S. Environmental Protection Agency ("EPA") has alleged that Xcel Energy Inc., who owns and operates the Pawnee Station and Comanche Station, power plants in Morgan County and Pueblo County, respectively, has failed to comply with the Clean Air Act, Part C: Prevention of Significant Deterioration of Air Quality ("PSD"), 42 U.S.C. §§ 7470 to 7492, and the permitting requirements of Colorado Air Quality Control Commission Regulation No. 3, 5 C.C.R. 1001-5 and 40 C.F.R. Part 52.21.

Pursuant to Section 113(a)(1) of the Act. 42 U.S.C. 7413(a), any time after the expiration of 30 days following the date of the issuance of this NOV, the Regional Administrator may, without regard to the period of violation, issue an order requiring compliance with the requirements of the state implementation plan or permit, and/or bring a civil action pursuant to Section 113(b) for injunctive relief and/or civil penalties of not more than $25,000 per day for each violation on or before January 30, 1997, and no more than $27,500 per day for each violation after January 30, 1997. Pursuant to §113(c) of the Act, 42 U.S.C. §7413(c), criminal sanction may also be imposed, to redress knowing violations of the Act. Pursuant to §306 of the Act, 42 U.S.C. 7606, federal contracts may be barred with any facility found in violation of the Act.

Please note that the NOV outlines a procedure for the respondent to request an informal conference with EPA representatives. We urge your prompt attention to this matter.

Sincerely,

Carol Rushin

Carol Rushin
Assistant Regional Administrator
Office of Enforcement, Compliance
and Environmental Justice

Enclosure

cc: Doug Benevento, Environmental Programs Director
Colorado Department of Public Health and Environment

Bruce Buckheit, Director
Air Enforcement Division
US EPA Office of Enforcement and Compliance Assurance

02 JUN 27 PM 12: 44

FILED
EPA REGION VIII
HEARING CLERK

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Region 8

IN THE MATTER OF:	)	
	)	**Notice of Violation**
Xcel Energy, Inc.	)	
	)	
Pawnee (Morgan County) and	)	
Comanche (Pueblo County) Stations,	)	Docket No. CAA-08-2002-06
Colorado	)	
	)	
Proceedings Pursuant to	)	
Section 113(a)(1) of the	)	
Clean Air Act, 42 U.S.C.	)	
§7413(a)(1)		

NOTICE OF VIOLATION

This Notice of Violation ("NOV") is issued to Xcel Energy, Inc. ("Xcel") for violations of the Clean Air Act ("Act") at the coal-fired power plants identified below. Xcel has embarked on a program of modifications intended to extend the useful life, regain lost generating capacity, and/or increase capacity at these coal-fired power plants.

Commencing at various times since at least 1994 and continuing to today, Xcel has modified and operated the coal-fired power plants identified below without obtaining New Source Review ("NSR") Prevention of Significant Deterioration ("PSD") permits authorizing the construction and operation of physical modifications of its boiler units as required by the Act. In addition, for each physical modification at these power plants, Xcel has operated these modifications without installing pollution control equipment required by the Act. These violations of the Act and the State Implementation Plan ("SIP") of Colorado have resulted in the release of massive unpermitted and, therefore, illegal amounts of Sulfur Dioxides ("SO_2"), Nitrogen Oxides ("NOx") and/or Particulate Matter ("PM") into the environment. Until these violations are corrected, Xcel will continue to release massive amounts of illegal emissions into the environment.

This NOV is issued pursuant to §113(a)(1) of the Act, as amended, 42 U.S.C. §§7401-7671q. §113(a) of the Act requires the Administrator of the United States Environmental Protection Agency ("EPA") to notify any person in violation of a state implementation plan or permit of the violations. The authority to issue this NOV has been delegated to the Regional Administrator for EPA Region 8 and further redelegated to the Assistant Regional Administrator for the Office of Enforcement, Compliance and Environmental Justice.

STATUTORY AND REGULATORY BACKGROUND

1. When the Clean Air Act was passed in 1970, Congress exempted existing facilities from many of its requirements. However, Congress also made it quite clear that this exemption would not last forever. As the United States Court of Appeals for the D.C. Circuit explained in Alabama Power v. Costle, 636 F.2d 323 (D.C. Cir. 1979), "the statutory scheme intends to 'grandfather' existing industries; but...this is not to constitute a perpetual immunity from all standards under the PSD program." Rather, the Act requires grandfathered facilities to install modern pollution control devices whenever the unit is proposed to be modified in such a way that its projected representative actual annual emissions may increase.

2. The NSR provisions of Parts C and D of Title I of the Act require preconstruction review and permitting for modifications of stationary sources. Pursuant to applicable regulations, if a major stationary source is planning upon making a major modification, then that source must obtain either a PSD permit or a nonattainment NSR permit, depending on whether the source is located in an attainment or a nonattainment area for the pollutant being increased above the significance level. To obtain the required permit, the source must agree to install the Best Available Control Technology ("BACT") for an attainment pollutant or achieve the Lowest Achievable Emission Rate ("LAER") in a nonattainment area. Sources may not operate unless they meet the emission limits that would have been imposed by the permitting process.

3. Pursuant to Part C of the Act, the Colorado SIP requires that no construction or operation of a major modification of a major stationary source occur in an area designated as attainment without first obtaining a permit under 40 CFR § 52.21, and prohibits the operation of a major stationary source after a major modification unless the source has applied BACT pursuant to 40 CFR §52.21(j) and the Colorado SIP at Code of Colorado Regulations 5 1001-5. The PSD portion of the Colorado SIP was originally approved by EPA on 9/2/86 at 51 Fed. Reg. 31125, and amendments were later approved by EPA as follows: on 2/13/87(52 Fed. Reg.4622), 6/15/87 (52 Fed. Reg.22638), 5/8/89 (54 Fed. Reg. 9780), 5/28/91 (56 Fed. Reg. 12849), 7/17/02 (57 Fed. Reg. 26997), 11/10/94 (59 Fed. Reg. 51376), 10/17/94 (59 Fed. Reg. 42500), 2/20/97(62 Fed. Reg.2910), 5/16/97, 62 Fed. Reg.13332; and 4/24/98, 63 Fed. Reg. 14357. The PSD provisions of the Colorado SIP are implemented by the Colorado Air Quality Control Commission ("CAQCC")in its Air Quality Control Regulation No. 3 ("AQCR").

4. The Colorado SIP for PSD provides that no emission unit or source subject to that rule shall be constructed without obtaining an air construction permit that meets the requirement of that rule.

5. The SIP provisions identified in paragraph 3 above are all federally enforceable pursuant to §§110 and 113 of the Act.

FACTUAL BACKGROUND

6. Xcel operates the Pawnee Station, a fossil-fuel-fired electric utility steam generating plant located in Morgan County, near Brush, Colorado. The plant consists of one boiler unit with a total generating capacity of 505 megawatts that began operations in 1981.

7. Xcel operates the Comanche Station, a fossil-fuel-fired electric utility steam generating plant located in Pueblo County near Pueblo, Colorado. The plant consists of two boiler units, Unit 1 with a total generating capacity of 325 megawatts that began operation in 1973 and Unit 2 with a total generating capacity of 335 megawatts that began operation in 1975.

8. The Pawnee Station is located in an area that has the following attainment/nonattainment classifications, found at 40 C.F.R. 81.306:

   For NO_2, the entire state has been classified as "better than national standards".

   For SO_2, the entire state has been classified as "better than national standards".

   For carbon monoxide ("CO"), the area has been classified as unclassifiable/attainment.

   For ozone, the area has been classified as unclassifiable/attainment.

   For PM10, the area has been classified as unclassifiable.

9. The Comanche Station is located in an area that has the following attainment/nonattainment classifications, found at 40 C.F.R. 81.306:

   For NO_2, the entire state has been classified as "better than national standards".

   For SO_2, the entire state has been classified as "better than national standards".

   For CO, the area has been classified as unclassifiable/attainment.

   For ozone, the area has been classified as unclassifiable/attainment.

   For PM10, the area has been classified as unclassifiable.

10. Each of the plants identified in paragraphs 6 and 7 above emits or has the potential to emit at least 100 tons per year of NOx, SO_2 and particulate matter and is a stationary source under the Act.

VIOLATIONS

11. Xcel has made "major modifications" of the Pawnee and Comanche Stations as defined by both 40 CFR §52.21 and Colorado SIP Rules at CAQCC Regulation No. 3, Part A §I.B.36.
    - i) The major modifications at its Pawnee Station include but are not limited to the following physical or operational changes, alone or in combination: a reheater redesign and replacement in 1994, and a redesign and upgrade of the condenser tubes in 1997 to regain lost generation due to condenser tube failures.
    - ii) The major modifications at its Comanche Station include but are not limited to the following physical or operational changes, alone on in combination: a reheater redesign and replacement at Comanche Unit 2 which was completed in 1994, and a replacement and redesign of a reheater and arch wall at Comanche Unit 1 in 2000.

12. Each of the modifications resulted in a net significant increase in emissions for SO_2, NO_X, and/or PM as defined by 40 CFR §§52.21(b)(3) and (23) and Colorado SIP Rules at CAQCC Regulation No. 3, Part A, I.B.59 and Part A, I.B.37.

13. For each of the modifications identified in 11 above, Xcel did not obtain a PSD permit pursuant to 40 CFR §52.21 and Colorado SIP Rules at CAQCC Regulation No. 3, Part B. In addition, for modifications after 1992, no information was provided to the permitting agency on an annual basis for a period of five years following the date the unit resumed regular operation demonstrating that the modification did not result in an emissions increase in accordance with 40 CFR §52.21(b)(21)(v).

14. The modifications do not fall within the "routine maintenance, repair and replacement" exemption found at 40 CFR §52.21(b)(2)(iii)(a) and Colorado SIP Rules at CAQCC Regulation No. 3, Part A, I.B.36. Each of these modifications was an expensive capital expenditure performed infrequently at the plant that constituted the replacement and/or redesign of a boiler component with a long useful life. In each instance, the modification was performed to regain lost capacity and/or availability, extend the life of the unit, and/or increase capacity and/or availability. That the "routine maintenance, repair and replacement" exemption does not apply where construction activity is at issue was known to the utility industry since at least 1988 when EPA issued a widely publicized applicability determination regarding utility modifications at a Wisconsin Electric Power Co. ("WEPCO") facility. EPA's interpretation of this exemption was upheld by the Court of Appeals in 1990. Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990).

15. None of the modifications fall within the "increase in hours of operation or in the production rate" exemption found at 40 CFR §52.21(b)(2)(iii)(f), or Colorado CAQCC Regulation No. 3, Part A, I.B.36. This exemption is limited to stand-alone increases in operating hours or production rates, not where such increases follow or are otherwise linked to construction activity.

16. None of the modifications fall within the "demand growth" exemption found at 40 CFR §52.21(b)(33)(ii) and Colorado SIP Rules at CAQCC Regulation No. 3, because for each modification a physical change was performed which resulted in an increase of representative actual annual emissions.

17. Therefore, Xcel violated and continues to violate Clean Air Act, Part C: Prevention of Significant Deterioration of Air Quality ("PSD"), 42 U.S.C. §§7470 to 7492, and the permitting requirements of Colorado Air Quality Control Commission Regulation No. 3, Part B, IV.D.3 and 40 C.F.R.§52.21, by constructing and operating modifications at the Pawnee Station and the Comanche Station without the necessary permits and by constructing and operating without the application of BACT required by the Colorado SIP.

18. Each of these violations exists from the date of start of construction of each modification until the time that Xcel obtains the appropriate NSR permit and operates the necessary pollution control equipment to satisfy the Colorado SIP.

ENFORCEMENT

Section 113(a)(1) of the Act provides that at any time after the expiration of 30 days following the date of the issuance of this NOV, the Regional Administrator may, without regard to the period of violation, issue an order requiring compliance with the requirements of the state implementation plan or permit, and/or bring a civil action pursuant to §113(b) for injunctive relief and/or civil penalties of not more than $25,000 per day for each violation on or before January 30, 1997, and no more than $27,500 per day for each violation after January 30, 1997. §113(c) of the Act, 42 U.S.C. §7413(c), provides that criminal sanctions may also be imposed, to redress knowing violations of the Act. §306 of the Act, 42 U.S.C. 7606, allows that federal contracts may be barred with any facility found in violation of the Act.

OPPORTUNITY FOR CONFERENCE

Respondent may, upon request, confer with EPA. The conference will enable Respondent to present evidence bearing on the findings of violations, on the nature of the violations, and on any efforts Respondent may have taken or proposes to take to achieve compliance. Respondent has the right to be represented by counsel. A request for a conference must be made within 10 calendar days of receipt of this NOV, and the request for a conference or other inquiries concerning the NOV should be made in writing to:

James Eppers
Enforcement Attorney
Office of Enforcement, Compliance
& Environmental Justice
U.S. EPA Region 8
999 18th Street, Suite 300
Denver, CO 80202
303-312-6893

By offering the opportunity for a conference or participating in one, EPA does not waive or limit its right to any remedy available under the Act.

EFFECTIVE DATE

This NOV shall be effective immediately upon issuance.

Date Issued: June 27th, 2002.

Carol Rushin
Carol Rushin
Assistant Regional Administrator
Office of Enforcement, Compliance
& Environmental Justice
U.S. EPA, Region 8

EXHIBIT 2

TO WILDEARTH GUARDIANS' JULY 2, 2009 COMMENTS ON PROPOSED TITLE V PERMIT FOR PAWNEE STATION

PUBLIC SERVICE COMPANY OF COLORADO
CAPITAL PROJECT SUMMARY SHEET

PROJECT TITLE	IN-SERVICE DATE	TOTAL ESCALATED CAPITAL EXPENDITURE (in thousands)
001129 Pawnee Replace Reheater Assemblies	10/30/94	4522

INTER-RELATED PROJECTS

N/A

CRITERIA: (check all applicable and indicate the most important one with an asterisk)

Community Benefit ___ Customer Retention ___ Employee ___ Grow Core Business ___ Law ___ Reliability X Safety ___

PREPARED BY:	DATE SUBMITTED:	DIVISION:	COMPANY:	Check if:
M. Trabue	7/2/93	Generation Engineering	PSCo X CLF&P ___ Gas Subs ___ Other ___	___ In Progress ___ Non-Regulated

DESCRIPTION:

The top three reheater banks will be replaced. The top bank plus all 256 of the reheater assemblies in the two middle banks will be replaced during the planned ten-week outage in 1994. This work will be done by an outside boiler contractor. In addition to replacing the assemblies, we will upgrade some of the material used, and change some of the manufacturing methods to prevent further similar damage in the past and prolong the life of the new assemblies. The reheater assemblies will also be redesigned so as to prevent the excessive pluggage currently seen.

NECESSITY AND BENEFITS:

Replacement during the 1994 outage will enhance unit reliability and availability, by eliminating the threat of tuber failures. Significant cost savings can be realized by purchasing and installing all of the reheat assemblies at the same time as opposed to doing only one half at a time, and additional unplanned outages can be avoided by expediting the project to meet the 1994 outage schedule.

Was a present value comparative or cost/benefit analysis (regulated) or cash flow/return analysis (non-regulated) done? Y ___ N X

ALTERNATIVES:

Do nothing. Allow tube failures to occur and repair as needed. Reliability of the unit will decrease dramatically over the next 10 years.

CONSEQUENCE OF NOT DOING PROJECT:

The existing reheater assemblies have suffered significant damage over the life of the unit. The estimated remaining useful life for some of the tubes has been calculated to be 2-4 years. Continued operation without replacement of the reheat assemblies will result in a continued high number of unplanned unit outages due to tube leaks in the reheat tubes.

IMPLICATIONS OF DEFERRAL (latest start date and in-service date if deferred)

Deferral will result in an increase of forced outages as more reheat tubes reach the end of useful life.

ESCALATED DOLLARS

ECONOMIC CONSIDERATIONS (in thousands)	1994	1995	1996	1997	1998
Financial Impact for doing project					
Capital Dollars	3368	1154			
Capital Master Lease Dollars	3283	1094			
O&M Change					
Cost of Gas or Fuel (change)					
Revenue Change					
Financial Impact for NOT doing project					
Capital Dollars					
Capital Master Lease Dollars					
O&M Change					
Cost of Gas or Fuel (change) SAVING DURING OUTAGE	876	876	876	876	876
Revenue Change (REPLACEMENT POWER)	1892	1892	1892	1892	1892

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CONFIDENTIAL BUSINESS INFORMATION

EXHIBIT 3

TO WILDEARTH GUARDIANS' JULY 2, 2009 COMMENTS ON PROPOSED TITLE V PERMIT FOR PAWNEE STATION

Pawnee GADS Data
Planned Outages

Pawnee Unit 1	3/31/1994	CONDENSER TUBE LEAKS	12.00	2,339.87
Pawnee Unit 1	3/31/1994	PRIMARY AIR DUCTS AND DAMPERS	119.93	59,366.84
Pawnee Unit 1	3/31/1994	CONDENSER TUBE LEAKS	8.80	1,716.17
Pawnee Unit 1	4/30/1994	FURNACE WALL LEAKS	54.67	27,010.67
Pawnee Unit 1	6/30/1994	PULVERIZER LUBE OIL SYSTEM	2.50	87.62
Pawnee Unit 1	7/31/1994	PULVERIZER MOTORS AND DRIVES	3.50	157.41
Pawnee Unit 1	7/31/1994	COOLING TOWER FAN MOTORS	0.98	162.36
Pawnee Unit 1	9/30/1994	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	167.02	82,673.42
Pawnee Unit 1	10/31/1994	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	745.00	368,775.00
Pawnee Unit 1	11/30/1994	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	720.00	356,400.00
Pawnee Unit 1	12/31/1994	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	190.78	94,437.59
Pawnee Unit 1	1/31/1995	PULVERIZED FUEL AND AIR PIPING (PULVERIZER TO WIND BOX)	7.00	314.82
Pawnee Unit 1	3/31/1995	OTHER PULVERIZER PROBLEMS	17.00	935.06
Pawnee Unit 1	8/31/1995	AUTOMATIC TURBINE CONTROL SYSTEMS - DIGITAL CONTROL & MONITORING	41.90	20,740.50
Pawnee Unit 1	2/29/1996	BOILER INSPECTIONS	220.10	108,949.50
Pawnee Unit 1	2/29/1996	OTHER LOW PRESSURE TURBINE PROBLEMS	95.98	47,511.59
Pawnee Unit 1	3/31/1996	OTHER LOW PRESSURE TURBINE PROBLEMS	304.08	150,521.09
Pawnee Unit 1	5/31/1996	OTHER CONDENSER TUBE CASING OR SHELL AND INTERNAL PROBLEMS	14.87	7,359.17
Pawnee Unit 1	6/30/1996	PULVERIZED FUEL AND AIR PIPING (PULVERIZER TO WIND BOX)	24.83	12,292.34
Pawnee Unit 1	11/30/1996	BOILER DRUM RELIEF/SAFETY VALVES	49.72	24,609.92
Pawnee Unit 1	2/28/1997	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	504.45	249,702.75
Pawnee Unit 1	3/31/1997	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	744.00	368,280.00
Pawnee Unit 1	4/30/1997	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	150.00	74,250.00
Pawnee Unit 1	4/30/1997	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	137.90	68,260.50
Pawnee Unit 1	4/30/1997	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	21.70	10,741.50
Pawnee Unit 1	4/30/1997	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	7.58	3,753.59
Pawnee Unit 1	4/30/1997	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	1.18	585.59
Pawnee Unit 1	6/30/1997	FEEDWATER PUMP DRIVE - CONTROLS	1.25	306.41
Pawnee Unit 1	11/30/1997	SECOND SUPERHEATER SLAGGING/FOULING	3.98	497.97
Pawnee Unit 1	11/30/1997	SECOND SUPERHEATER SLAGGING/FOULING	4.00	499.95
Pawnee Unit 1	4/30/1998	MAJOR BOILER OVERHAUL (720 HOURS OR LONGER)	422.12	208,947.92
Pawnee Unit 1	6/30/1998	PRIMARY AIR DUCTS AND DAMPERS	88.07	43,593.17
Pawnee Unit 1	7/31/1998	MAIN STEAM RELIEF/SAFETY VALVES	28.12	13,917.92
Pawnee Unit 1	7/31/1998	MAIN STEAM RELIEF/SAFETY VALVES	1.03	511.34
Pawnee Unit 1	8/31/1998	MAIN STEAM RELIEF/SAFETY VALVES	26.80	13,266.00

EXHIBIT 4

TO WILDEARTH GUARDIANS' JULY 2, 2009 COMMENTS ON PROPOSED TITLE V PERMIT FOR PAWNEE STATION

Pawnee - Unit 1 - 1997

Parameter	January	February	March	April	May	June	July	August	September	October	November	December	Total
Gross Generation (MWHR)	352314	74706	0	88430	[illegible]	344642	358214	350040	334114	354886	340818	354538	3312697
Net Generation (MWHR)	331825	68032	-2635	80055	339056	324406	337769	329615	314834	334528	320814	333884	3112183
Hours of Operation (Hours)	738.0	168.0	0	249.0	744.0	720 0	744.0	744.0	720.0	745.0	720 0	744.0	7036
Gross Monthly Maximum Hourly Load (MW)	521	514	0	549	562	549	540	534	530	530	530	515	
Net Capacity Factor (%)	90 10	20.45	-0.72	22.46	92.06	91.02	91.72	89.50	88.34	90.84	90.02	90.66	71.77
Availability Factor (%)	99.31	24.93	0.00	31 40	100.00	100,00	100.00	100.00	100.00	100 00	100.00	100.00	80.06
Coal Burned (Tons)	210015	44341	0	52282	210726	201777	211119	205585	193517	209290	203072	211185	1952909
Net Unit Heat Rate (BTU/NKWH)	10560	10879	0	11505	10375	10409	10364	10308	10319	10391	10582	10586	
Fuel Quality: Coal													
a. Heat Content (BTU/Pound)	8328	8200	8250	8319	8336	8363	8287	8262	8372	8301	8328	8367	
b. Sulfur Content (% by weight)	0.35	0.27	0.27	0.30	0.34	0.40	0.40	0.39	0.40	0.40	0.43	0.42	
c. Ash Content (% by weight)	4.81	4.19	4.19	4.36	4 07	4.73	4.77	4.72	4.74	4.76	4 75	4.85	

C 0019517

EXHIBIT 5

TO WILDEARTH GUARDIANS' JULY 2, 2009 COMMENTS ON PROPOSED TITLE V PERMIT FOR PAWNEE STATION

→ Niehoff - FYI GLTT

REQUEST FOR SPECIFIC APPROPRIATION

COMPANY

[X] PUBLIC SERVICE [ ] WELTON PROPERTIES, INC [ ] CHEYENNE L.F & P [ ] WESTGAS SUBS [ ] FUELCO

ORIGINATING ORGANIZATION UNIT	GENERATION ENGINEERING
TITLE OF PROJECT	PAWNEE UNIT 1 CONDENSER RETUBING
PROJECT NUMBER	010888
AFDC	(Y) N
BY	P YAKIMOW
LOCATION OF WORK	PAWNEE STEAM PLANT - UNIT NO 1 - LOCATION CODE 01041
IN-SERVICE DATE	3/2/97
R- CODE NUMBER	R9620360
DATE	JULY 10, 1996
FUNCTIONAL GROUP	CES

SCHEDULE OF EXPENDITURES (Thousands of Dollars)

YEAR	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1996							$20	$50	$200	$3,970	$110	$150	$4,50[illegible]
1997	$400	$600	$1,190	$320	$10	$5	$5	$3					$2,53[illegible]

NET ESTIMATED EXPENDITURE $7,033,000

DATE	APPROVALS
7/12/96	[signature]
7/12/96	[signature] Holland
7/15/96	[signature] Niehoff

PROJECT SYNOPSIS

The Pawnee shell and tube type condenser is 15 years old. Pawnee is a zero discharge plant where the cooling water is similar to sea water due to continuous chemical treatment and recycling, and it is inherently corrosive. An accelerated rate of corrosion has been occurring in the condenser tubes since the November 1994 acid cleaning. Severe throughwall tube failures and leaks began in January 1996. A short term repair to epoxy coat the tubes was tried unsuccessfully in May/June 1996 and canceled. No other viable short term repair options exist.

Currently, 33% of condenser tubes with 70% or greater throughwall corrosion are plugged. Unit load restrictions of up to 60MW during the summer months are expected with the current number of plugged tubes. Complete tube bundle failure is expected within one year or less. Failure of the tube bundle will cause the condenser to be inoperable and require that an extended forced outage be taken on the 500MW electric generating unit.

Retubing is the only permenant solution for maintaining the operability and performance of the condenser. The existing 90/10 Cu-Ni tubes and tubesheets will be removed. New corrosion-resistent Titanium tubes and tubesheets will be installed. A cathodic protection system and coatings will be installed to prevent galvanic corrosion of the carbon steel water box. The tubes will be delivered to Pawnee in early September and drilled tubesheets in late October 1996 as a precaution to assure that material is on-site if the condenser fails prior to the unit outage. Retubing will occur during the unit outage scheduled for January 4 through March 2, 1997

The PSCo Budget Advisory Committee (BAC) approved the $4.5 million emergency funding required in 1996 at their July 1, 1996, meeting. Due to the long lead times of the tubes and drilled tubesheets, funding is required in 1996 for material procurement, heat exchanger consultant services, internal engineering and the installer's preparatory work to meet the January 4, 1997 outage start date. The 1997 required funding is $2,533,000 and has been submitted as part of Production's 1997 proposed capital budget.

C 0037032

CONFIDENTIAL BUSINESS INFORMATION

RETURN TO FINANCIAL FORCASTS

EXHIBIT 6

TO WILDEARTH GUARDIANS' JULY 2, 2009 COMMENTS ON PROPOSED TITLE V PERMIT FOR PAWNEE STATION

PAWNEE UNIT 1 CONDENSER RETUBING

PROJECT DESCRIPTION

The existing Cu-Ni tubes and tubesheets will be removed from the shell of the condenser. They will be replaced with Titanium tubes and tubesheets using the existing tube pattern and arrangement. Tube stakes will be added and footer and/or other structural modifications will be made for vibration prevention as necessary due to the lighter weight of the Titanium as compared to the existing Cu-Ni. The retubing will be performed on-site at Pawnee. The project cost is estimated using a contractor who has specialized expertise in on-site retubing with Titanium in a condenser of this size. A redesign for enhanced performance of the condenser was considered but could not be accomplished due to the requirement of meeting the first quarter 1997 outage schedule. A redesign would have involved significant engineering/design analysis by a condenser supplier and the manufacture of entire tube bundles. The suppliers contacted could not achieve this type of schedule and the benefit of slightly enhanced performance was not deemed to be economical.

An impressed current or sacrificial anode type cathodic protection system will be installed to protect against the galvanic corrosion which can occur when dissimilar metals are used in the same equipment. In this case the dissimilar metals are the carbon steel used in the existing water boxes versus the new Titanium tubes and tubesheets. This is a normal use of different materials within a condenser; it is not cost effective for the water box to be constructed of Titanium. Nor is carbon steel an adequate corrosion resistant metal for the tubes and tubesheets. Additionally, the water boxes will be epoxy coated as part of the overall cathodic protection scheme.

NECESSITY AND BENEFITS

At the accelerated rate of corrosion that is occurring, the condenser will eventually suffer a complete tube bundle failure. This failure is expected within one year or less. This would necessitate a forced plant shutdown and subsequent loss of generation for sale for a minimum of 4 to 6 months if an order for the Titanium tubesheets has not already been placed.

Titanium is the best material in terms of corrosion resistance, bio-fouling resistance, and heat transfer properties under the constraint of using the existing condenser design. However, there is only one major supplier in the United States that can produce the quality of material and manufacturing, size of the tubesheets and number of tubes required. Due to these factors as well as current demand, there is a long lead time for delivery especially for the manufacture and drilling of the tubesheets. The other corrosion resistant alloys considered including AL6XN and AL29-4C (Stainless Steel Super Alloys) have poorer heat transfer qualities compared to Titanium and would have negatively impacted the condenser performance. Cost of the Stainless Steel Super alloys are virtually identical to Titanium. Replacement with 90/10 Cu-Ni which is the existing material is not recommended; it is unlikely the condenser retubed with Cu-Ni would even last a full 15 years due to the current water conditions at Pawnee.

There are no other satisfactory long term repair options. The one short term repair option thought to be viable was the epoxy coating process which was tried and canceled due to increased tube damage during the surface preparation process. The only option left is to plug tubes suspected of impending failure due to a high percentage of throughwall corrosion or after leaks develop. The short term consequences of plugging tubes are an increasing heat rate penalty and unit load restrictions until the retubing can be performed.

C 0037034

SCHEDULE

The project will be completed during the January 4 through March 2, 1997 outage. However, the tubes will be scheduled for delivery to Pawnee by early September and the tubesheets by late October 1996. The new materials will then be on-site and ready for installation, in case the tubes fail to an extent that the condenser becomes inoperable before the scheduled outage.

EXHIBIT 7

TO WILDEARTH GUARDIANS' JULY 2, 2009 COMMENTS ON PROPOSED TITLE V PERMIT FOR PAWNEE STATION

Pawnee - Unit 1 - 1994

Parameter	January	February	March	April	May	June	July	August	September	October	November	December	Total
Gross Generation (MWHR)	347209	324458	296826	287802	364492	337128	355311	322933	235163	0	0	80614	2951936
Net Generation (MWHR)	322362	302069	274958	266482	339958	313185	330535	300117	218135	-2414	-2020	71616	2734983
Hours of Operation (Hours)	744	672	624	597.1	744	720	744	668.4	503.2	0	0	284.3	6301
Gross Monthly Maximum Hourly Load (MW)	536	530	533	530	532	531	537	531	535	0	0	513	
Net Capacity Factor (%)	87.53	90.81	74.66	74.77	92.31	87.87	89.75	81.49	61.21	-0.66	-0.57	19.45	63.07
Availability Factor (%)	100.00	100.00	83.88	82.74	100.00	100.00	100.00	89.88	69.91	0.00	0.00	38.24	71.91
Coal Burned (Tons)	213056	201260	183257	176846	224744	206162	219165	199367	144846	0	0	48291	1816994
Net Unit Heat Rate (BTU/NKWH)	10923	11013	11011	10996	10837	10867	10936	10994	10967	0	0	11943	
Fuel Quality: Coal													
a. Heat Content (BTU/Pound)	8263	8264	8246	8216	8195	8249	8243	8253	8218			8257	
b. Sulfur Content (% by weight)	0.35	0.38	0.36	0.38	0.36	0.3	0.38	0.34	0.33		0.41	0.34	
c. Ash Content (% by weight)	4.47	4.6	4.55	4.63	4.61	4.34	4.62	4.56	4.57		4.76	4.59	

C 0019514

EXHIBIT 8

TO WILDEARTH GUARDIANS' JULY 2, 2009 COMMENTS ON PROPOSED TITLE V PERMIT FOR PAWNEE STATION

Pawnee GADS Data
Planned Outages

UNIT	Start Time	DESCRIPTION	Hours	EQUIV MWHRS
Pawnee Unit 1	4/30/1989	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	220.00	108,900.00
Pawnee Unit 1	5/31/1989	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	744.00	368,280.00
Pawnee Unit 1	6/30/1989	MAJOR TURBINE OVERHAUL (720 HOURS OR LONGER)	205.37	101,656.67
Pawnee Unit 1	6/30/1989	EMERGENCY GENERATOR TRIP DEVICES	0.50	247.50
Pawnee Unit 1	6/30/1989	OTHER INTERMEDIATE PRESSURE TURBINE PROBLEMS	66.83	33,082.34
Pawnee Unit 1	11/30/1989	PRIMARY AIR DUCTS AND DAMPERS	96.57	47,800.67
Pawnee Unit 1	1/31/1990	CONDENSER TUBE LEAKS	30.85	15,270.75
Pawnee Unit 1	1/31/1990	CONDENSER TUBE LEAKS	18.32	9,066.92
Pawnee Unit 1	3/31/1990	MAJOR BOILER OVERHAUL (720 HOURS OR LONGER)	529.38	262,044.59
Pawnee Unit 1	4/30/1990	TURBINE OVERSPEED TRIP TEST	6.75	3,341.25
Pawnee Unit 1	4/30/1990	PRIMARY AIR FAN	9.85	3,595.19
Pawnee Unit 1	4/30/1990	MAJOR BOILER OVERHAUL (720 HOURS OR LONGER)	28.58	14,148.59
Pawnee Unit 1	4/30/1990	PRIMARY AIR FAN	7.25	3,588.75
Pawnee Unit 1	7/31/1990	CONDENSER TUBE AND WATER BOX CLEANING	4.98	1,245.92
Pawnee Unit 1	8/31/1990	HIGH PRESSURE HEATER TUBE LEAKS	11.75	528.66
Pawnee Unit 1	9/30/1990	INDUCED DRAFT FAN CONTROLS	5.50	1,259.28
Pawnee Unit 1	1/31/1991	BOILER RECIRCULATION VALVES	5.00	1,249.88
Pawnee Unit 1	2/28/1991	PRIMARY AIR DUCTS AND DAMPERS	46.00	22,770.00
Pawnee Unit 1	2/28/1991	MAIN TRANSFORMER	97.67	48,345.17
Pawnee Unit 1	10/31/1991	CHEMICAL CLEANING/STEAM BLOWS	244.65	121,101.75
Pawnee Unit 1	11/30/1991	CHEMICAL CLEANING/STEAM BLOWS	720.00	356,400.00
Pawnee Unit 1	12/31/1991	CHEMICAL CLEANING/STEAM BLOWS	24.02	11,888.42
Pawnee Unit 1	1/31/1992	OTHER PULVERIZER PROBLEMS	21.60	972.18
Pawnee Unit 1	10/31/1992	BOILER INSPECTIONS	336.98	166,806.59
Pawnee Unit 1	11/30/1992	BOILER INSPECTIONS	342.63	169,603.34
Pawnee Unit 1	12/31/1992	PRIMARY AIR DUCTS AND DAMPERS	24.90	12,325.50
Pawnee Unit 1	4/30/1993	FIRST REHEATER SLAGGING/FOULING	182.20	90,189.00
Pawnee Unit 1	9/30/1993	TOTAL UNIT PERFORMANCE TESTING	2.35	1,163.25
Pawnee Unit 1	9/30/1993	BOILER INSPECTIONS	327.25	161,988.75
Pawnee Unit 1	10/31/1993	BOILER INSPECTIONS	398.63	197,323.34
Pawnee Unit 1	11/30/1993	CONDENSER TUBE LEAKS	11.00	2,475.00
Pawnee Unit 1	12/31/1993	CIRCULATING WATER VALVES	72.48	35,879.09
Pawnee Unit 1	2/28/1994	CONDENSER TUBE LEAKS	0.50	107.42
Pawnee Unit 1	2/28/1994	CONDENSER TUBE LEAKS	19.00	4,274.82

EXHIBIT 9

TO WILDEARTH GUARDIANS' JULY 2, 2009 COMMENTS ON PROPOSED TITLE V PERMIT FOR PAWNEE STATION

Pawnee GADS Data
Planned Outages

Pawnee Unit 1	7/31/1999	GENERATOR LIQUID COOLING SYSTEM	8.85	4,380.75
Pawnee Unit 1	7/31/1999	OTHER BOILER CONTROL PROBLEMS	3.75	1,856.25
Pawnee Unit 1	7/31/1999	GENERATOR LIQUID COOLING SYSTEM	7.77	3,844.67
Pawnee Unit 1	2/29/2000	BOTTOM ASH HOPPERS (INCLUDING GATES)	133.52	66,090.92
Pawnee Unit 1	3/31/2000	PRIMARY AIR FAN DRIVES	130.58	48,315.96
Pawnee Unit 1	3/31/2000	MAJOR BOILER OVERHAUL (720 HOURS OR LONGER)	451.73	223,607.84

Exhibit 5 to Title V Petition

Unit Level Emissions Quick Report
February 19, 2010

Your query will return data for 1 facilities and 1 units.

You specified: Year(s): 2008,2007,2006,2005,2004,2003,2002,2001,2000,1999,1998,1997,1996,1995 Program: ARP Facility: Pawnee

State	Facility Name	Facility ID (ORISPL)	Unit ID	Associated Stacks	Year	Program(s)	Operating Time	# of Months Reported	SO_2 Tons	Avg. NO_x Rate (lb/mmBtu)	NO_x Tons	CO_2 Tons	Heat Input (mmBtu)
CO	Pawnee	6248	1		1995	ARP		0	15,374.0		4,869.0	3,599,281.0	36,756,706
CO	Pawnee	6248	1		1996	ARP		0	11,633.4		3,529.0	3,140,855.0	30,654,570
CO	Pawnee	6248	1		1997	ARP	7,169	12	13,928.7	0.21	3,817.8	3,780,851.5	36,882,139
CO	Pawnee	6248	1		1998	ARP	7,821	12	15,325.6	0.21	3,906.1	3,746,993.4	36,599,944
CO	Pawnee	6248	1		1999	ARP	8,709	12	16,665.8	0.23	5,319.7	4,695,494.7	45,855,909
CO	Pawnee	6248	1		2000	ARP	8,169	12	14,678.1	0.21	4,892.4	4,691,602.9	45,856,526
CO	Pawnee	6248	1		2001	ARP	8,614	12	17,030.9	0.23	5,845.4	5,240,962.4	51,115,318
CO	Pawnee	6248	1		2002	ARP	7,548	12	14,832.6	0.23	4,591.7	3,968,365.8	38,786,013
CO	Pawnee	6248	1		2003	ARP	8,547	12	16,703.0	0.23	5,369.0	4,673,511.5	45,594,819
CO	Pawnee	6248	1		2004	ARP	7,813	12	12,549.6	0.22	4,514.6	4,192,125.9	40,944,685
CO	Pawnee	6248	1		2005	ARP	7,186	12	11,248.1	0.21	3,668.1	3,532,021.5	34,507,188
CO	Pawnee	6248	1		2006	ARP	8,444	12	13,072.5	0.21	4,602.7	4,468,643.1	43,563,056
CO	Pawnee	6248	1		2007	ARP	8,596	12	14,126.5	0.22	4,415.3	4,097,660.4	39,942,263
CO	Pawnee	6248	1		2008	ARP	8,223	12	13,217.2	0.25	4,595.2	3,837,802.3	36,775,940
Total									200,386.0		63,936.1	57,666,171.4	563,835,075

Exhibit 6 to Title V Petition

STATE OF COLORADO

Bill Ritter, Jr., Governor
James B. Martin, Executive Director

Dedicated to protecting and improving the health and environment of the people of Colorado

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Colorado Department of Public Health and Environment

November 6, 2009

Mr. Jeremy Nichols
Climate and Energy Program Director
WildEarth Guardians
1536 Wynkoop, Suite 302
Denver, CO 80202

REF: Public Service Company– Pawnee Station, FID # 0870011, OP # 96OPMR129

SUBJECT: Response to Comments on Draft Renewal Operating Permit

Dear Mr. Nichols:

The comments you provided on the draft Operating Permit (96OPMR129) and Technical Review Document during the Public Comment Period were received via e-mail on July 3, 2009. The Division has addressed your comments as follows:

1. **The Title V Permit must include a compliance plan to bring the Pawnee coal-fired power plant into compliance with the Prevention of Significant Deterioration Program**

Comment: *A Title V Permit is required to include emission limitations and standards that assure compliance with all applicable requirements at the time of permit issuance. See 42 USC § 7661c(c); 40 CFR § 70.6(c)(1). Pawnee is currently in violation of PSD requirements. A PSD compliance plan is an applicable requirement of any Title V Permit. See 42 USC § 7661 b(b); 40 CFR § 70.6(b)(3). The Permit fails to include a compliance plan to bring the Pawnee Station into compliance with PSD.*

Pursuant to Part C of the Clean Air Act, the Colorado State Implementation Plan ("SIP") requires that no construction or operation of a major modification of a major stationary source occur in an area designated as attainment without first obtaining a permit under 40 CFR § 51.166, and prohibits the operation of a major stationary source after a major modification unless the source has applied Best Available Control Technology ("BACT") pursuant to 40 CFR § 51.166(j) and the Colorado SIP, 5 CCR § 1001-5. The EPA has approved all the PSD provisions of the Colorado SIP, as well as subsequent amendments to those provisions.

The Pawnee coal-fired power plant is a major stationary source within an area classified as attainment for all criteria pollutants. According to information from Public Service Company, the plant underwent major modifications in 1994 and 1997 without obtaining the required PSD permit. These modifications have resulted in unpermitted emissions of significant amounts of SO_2, NO_X, and PM. On June 27, 2002 the Environmental Protection Agency ("EPA") issued a notice of violation ("NOV") to Xcel Energy, Inc. regarding violations of PSD under the Act at Pawnee coal-fired power plant. This NOV is attached to these comments as Exhibit 1. For the past fifteen years, the plant has operated and continues to operate in a state of noncompliance with the PSD provisions of the Clean Air Act. Accordingly, the Title V Permit must bring the Pawnee coal-fired power plant into compliance with PSD requirements. Evidence of noncompliance with PSD requirements at the Pawnee coal-fired power plant is as follows:

a. The June 27, 2002 NOV issued for the Pawnee Station Constitutes a finding of non-compliance with the PSD program for the purposes of Title V.

The NOV issued to Xcel Energy, Inc. on June 27, 2002 states:

Xcel violated and continues to violate Clean Air Act, Part C: Prevention of Significant Deterioration of Air Quality ("PSD"), 42 U.S.C. §§7470 to 7492, and the permitting requirements of Colorado Air Quality Control Commission Regulation No. 3, Part B, IV.D.3 and 40 C.F.R. §52.21, by constructing and operating modifications at the Pawnee Station...without the necessary permits and by constructing and operating without the application of BACT required by the Colorado SIP.

NOV at 5. Clearly, the EPA concluded that the Pawnee coal-fired power plant was violating PSD requirements when it issued the NOV.

The 2002 NOV is sufficient to demonstrate noncompliance with PSD for the purposes of a Title V Permit. In a situation very similar to the situation regarding the Pawnee NOV, the Second Circuit held that an NOV is sufficient to demonstrate noncompliance with PSD for the purposes of the Title V permitting program. See NYPIRG v. Johnson, 427 F.3d 172, 180 (2^{nd} Cir. 2005). In NYPIRG v. Johnson, the Second Circuit Court of Appeals recognized that "to issue a NOV, the Administrator must first find a source in violation of an applicable plan or permit." Id. at 181. The court further reasoned that in issuing an NOV, a permitting authority had determined that PSD requirements "are, indeed, applicable." Id. The court held that the issuance of an NOV by the State of New York constituted a finding of noncompliance with PSD requirements and that the EPA was required to object to the issuance of a Title V permit that failed to ensure compliance with PSD. Id. at 186.

According to 42 USC § 7413(a)(1), the EPA Administrator shall issue a notice of violation when he finds "that any person has violated or is in violation of any requirement or prohibition of an applicable implementation plan or permit." The statute clearly states that an NOV is issued by the EPA only after making a finding of a violation.

Further, because the EPA, rather than the state, issued the NOV to Pawnee, it is even more clear here than in the NYPIRG case that the NOV constitutes a sufficient finding of noncompliance.

The Tenth Circuit has not yet addressed the sufficiency of an NOV as legal proof of noncompliance with PSD requirements under Title V. Only one circuit has issued a holding in conflict with the Second Circuit position on NOVs; see Sierra Club v. Johnson, 541 F.3d 1257 (11th Circuit 2008). The reasoning in NYPIRG v. Johnson, mentioned above, applies to the facts here regarding the Pawnee NOV. This reasoning mandates that the Title V Permit require the Pawnee coal-fired power plant comply with PSD.

Response: The Division acknowledges that EPA issued a notice of violation (NOV) to Xcel Energy on June 27, 2002 for Pawnee. The Division considers that the NOV is only an allegation of a violation and not a determination that violations actually occurred. EPA has not initiated any related enforcement action since issuing the NOV seven years ago. The NOV is not a final agency action and cannot be considered conclusive evidence that a violation has occurred. EPA recently confirmed this position with respect to a Colorado emission source in its "Order Partially Denying and Partially Granting Petition for Objection to Permit" in the Matter of CEMEX, Inc., Lyons Cement Plant, Petition Number VIII-2008-01 ("Cemex Order"), as indicated below:

> Contrary to the Petitioner's views, and as explained below and previously explained by EPA in two title V orders, the issuance of an NOV, and reference to information contained therein, alone are not sufficient to satisfy the demonstration requirement under section 505(b)(2)[fn1]. *See generally: In the matter of Georgia Power Company, Bowen Steam – Electric Generating Plant, et al.*, Final Order (January 8, 2007) (*Georgia Power/Bowen Steam Final Order*), at 5-9; and *Spurlock Final Order*, at 13-18[fn2]. Under section 113(a)(1), "[w]henever, on the basis of any information available to the Administrator, the Administrator finds that any person has violated or is in violation of any requirement or prohibition of an applicable implementation plan or permit, the Administrator shall [issue an NOV]." An NOV is simply one early step in the EPA's process of determining whether a violation has, in fact, occurred. These steps are commonly followed by additional investigation or discovery, information gathering, and exchange of views that occur in the context of an enforcement proceeding, and are considered important means of fact-finding under our system of civil litigation. An NOV is not a final agency action and is not subject to judicial review. It is well-recognized that no binding legal consequences flow from an NOV, and an NOV does not have the force or effect of law. *See PacifiCorp v. Thomas*, 883 F.2d 661 (9th Cir. 1988); *Absetec Constr. Servs. V. EPA*, 849 F.2d 765, 768-69 (2nd Cir, 1988); *Union Elec. Co v. EPA*, 593 F.2d 299, 304-06

(8th Cir. 1979); and *West Penn Power Co. v Train*, 522 F.2d 302, 310-11 (3rd Cir. 1975). *See also Sierra Club v. Johnson*, 541 F.3d at 1267: *Sierra Club v. EPA*, 557 F.3d at 406-409.

. . . .

[fn1]. The addition of EPA's compliant that includes the alleged violations in the NOV, without more, is not sufficient to demonstrate applicability and violation of a requirement as the alleged violations in the complaint are just that: alleged.
[fn2]. Petitioner asserts that the Second Circuit Court of Appeals decision, NYPIRG v. Johnson, 427. F.3d 172 (2nd Cir. 2005) (NYPIRG) is applicable here. EPA disagrees. As recently explained by the Sixth Circuit Court of Appeals, in NYPIRG, a notice of violation and enforcement lawsuit were filed by the State of New York, which relied on specific state regulations that may have required a more robust determination than EPA must make before it issues an NOV or files a complaint. *Sierra Club v. EPA*, 557 F.3d 401, 410 (6th Cir. 2009).

Cemex Order, p. 6 (April 20, 2009). The Colorado Court of Appeals has reached a similar conclusion in a separate matter, holding that EPA's issuance of an NOV in 2002 was not a finding that a violation had occurred, and could not preclude issuance of a state permit three years later. *See, Citizens for Clean Air and Water in Pueblo and Southern Colorado v. Colorado Department of Public Health and Environment, Air Pollution Control Division*, 181 P.3d 393, 396 (Colo. 2008). Accordingly, the Division has determined that noncompliance has not been demonstrated in this instance, and that a compliance schedule is not required.

In addition, please be aware that your statement "[t]he EPA has approved all the PSD provisions of the Colorado SIP, as well as subsequent amendments to those provisions" is incorrect. As indicated in Colorado Regulation No. 3, certain provisions related to major stationary source new source review and PSD in Part D of that regulation have not been approved by EPA.

b. Regardless of the NOV, Evidence of Major Modifications Exist

Comment: *If the APCD believes that the EPA NOV is not legally sufficient to demonstrate noncompliance with established PSD requirements, at a minimum the NOV shows clear evidence of a valid suspicion of noncompliance. This evidence is further bolstered by actual documents from Xcel Energy that demonstrate major modifications occurred at the Pawnee coal-fired power plant without prior approval under PSD. Indeed, Xcel's own records confirm that at least two major modifications were made to Pawnee during the 1990s:*

(1) Reheater redesign and replacement

An Xcel Capital Project Summary Sheet submitted July 7, 1993 states that:

The top bank plus all 256 reheater assemblies in the two middle banks will be replaced during the planned ten-week outage in 1994. . . In addition to replacing the assemblies, we will upgrade some of the material used, and change some of the manufacturing methods to prevent further similar damage in the past and prolong the life of the new *assemblies. The reheater assemblies will also be redesigned so as to prevent the excessive pluggage currently seen.*

See Exhibit 2 attached to these comments. The Pawnee Planned Outages data shows that there were planned outages for "major turbine overhaul (720 hours or longer)" between 9/30/1994 and 12/31/1994. See Exhibit 3 attached to these comments. EPA operations data from 1994 shows that Pawnee reported zero hours of operation during the months of October and November, and only 284 hours in December. See Exhibit 4 attached to these comments. Together, these documents confirm that the 1994 modification noted in the NOV did occur. Further, the fact that Pawnee shut down operations for ten weeks is a strong indication that this modification was major.

(2) Upgrade of Condenser Tubes

An Xcel Request for Specific Appropriation dated July 10, 1996 states that $4.5 million in emergency funding was allocated for the new condenser tubes. See Exhibit 5 attached to these comments. It goes on to state that "The project will be completed during the January 4 through March 2, 1997 outage." See Exhibit 6 attached to these comments. Pawnee Planned Outages data shows that there were planned outages for "major turbine overhaul (720 hours or longer)" between 2/28/1997 and 4/30/1997. See Exhibit 3. EPA operations data from 1997 shows that Pawnee reported 168 hours of operation in February, zero hours in March, and 249 hours in April. See Exhibit 7 attached to these comments. Together, these documents confirm that the 1997 modification noted in the NOV did occur. Further, Xcel referred to this modification in its own documents as "major."

The NOV explained that these modifications did not fall within exemptions for "routine maintenance," "increased hours of operation," or "demand growth" set forth at 40 CFR § 51.166. The NOV concludes that "Each of the modifications resulted in a net significant increase in emissions for SO_2, NO_X, and/or PM as defined by 40 CFR §§ 51.166(b)(3) and (23) and Colorado SIP Rules at AQCC Regulation No. 3, Part A, I.B.59 and Part A, I.B.37." Because these were modifications resulting in net significant increases of criteria pollutants, a PSD permit was requied to be obtained before those modifications occurred. Xcel did not obtain such a PSD permit for the Pawnee coal-fired power plant, in violation of the Clean Air Act.

Xcel's records also seem to provide evidence of other modifications undertaken during the past twenty years. During April through June of 1989, there were planned outages for a "major turbine overhaul." See Exhibit 8 attached to these comments. In April of 1998, there was a planned outage for a "major boiler overhaul." Exhibit 3. In March of 2000, there was another planned outage for a "major boiler overhaul." See Exhibit 9 attached to these comments. At a minimum, the APCD has a duty to investigate these modifications and make a determination whether or not they were major modifications under the PSD regulations.

Even if the APCD believes the NOV is not sufficient to constitute a violation of the PSD requirements, the evidence of modifications listed above must be dealt with under the PSD *provisions of the Clean Air Act and the Colorado SIP. Xcel clearly made at least two modifications to the Pawnee coal-fired power plant. Modifications clearly resulted in significant emissions increases, not only as reported in the NOV but also reported by the EPA Clean Air Market Data. See table below.*

Annual Emissions at Pawnee Coal-fired Power Plant (Data from EPA Clean Air MarketData. Available at: http://camddataandmaps.epa.gov/gdm/index.cfm (last accessed June 29, 2009).

Year	***SO_2 Tons***	***NO_X Tons***
1995	*15374.0*	*4869.0*
1996	*11633.4*	*3529.0*
1997	*13928.7*	*3817.8*
1998	*15325.6*	*3906.1*
1999	*16665.8*	*5319.7*
2000	*14678.1*	*4892.4*
2001	*17030.9*	*5845.4*
2002	*14832.6*	*4591.7*
2003	*16703.0*	*5369.0*
2004	*12549.6*	*4514.6*
2005	*11248.1*	*3668.1*
2006	*13072.5*	*4602.7*
2007	*14126.5*	*4415.3*

The amount of SO_2 emissions considered significant is 40 tons per year. 40 CFR § 51.166(b)(23). The amount of NO_X emissions considered significant is 40 tons per year. Id. The data after the second modification (1997-1998) shows a SO_2 increase of 1396.9 tons and a NOx increase of 88.3 tons. Thus, both significance thresholds were met after the 1997 modification. While data immediately before the 1994 modification is not available on the Clean Air Market website, the NOV claims that the 1994 modification did result in significant emissions increases. PM10 emissions of 15 tons per year are also considered significant under the regulations. 40 CFR § 51.166(b)(23). The NOV claims that a significant PM emission increase also occurred at Pawnee.

Given that Pawnee is currently in violation of PSD requirements, the Title V Permit must include a compliance plan to bring the Pawnee coal-fired power plant into compliance with PSD. If these applicable requirements are missing from the Permit, it will be in violation of 42 USC § 7661c(c) and 40 CFR § 70.6(c)(1).

Response: The modifications referenced in these comments are a reheater redesign and replacement in 1994 and upgrade to condenser tubes in 1997, which are both cited in the EPA NOV as the projects that are alleged to have triggered PSD review requirements. To the extent this comment relies on the 2002 EPA NOV, the Division reiterates its response to the previous comment. The Division agrees that the documentation you provided reflects that the reheater redesign and replacement and the condenser tube upgrades occurred in the years noted in the EPA NOV. However, the fact that the projects took place does not necessarily indicate that a major modification occurred.

A modification is a physical change or change in the method of operation, or addition to, a major stationary source. However, routine maintenance, repair and replacement is not considered a physical change or change in the method of operation and therefore is not a modification. A major modification is a physical change or change in the method of operation, or addition to, a major stationary source that would result in a significant net emissions increase using the actual to potential test. Thus there are two issues raised by the EPA NOV. PSCo and EPA have disagreed on these issues, and EPA has not taken any further action on the 2002 NOV. As is customary, since these projects are addressed in EPA's NOV, the Division used its enforcement discretion and did not file a parallel investigation into these projects.

Finally, other activities such as a "major turbine overhaul" in April – June 1989 and "major boiler overhauls" in April 1998 and March 2000 are cited as evidence of major modifications. As used in this context, "major" does not necessarily contemplate the PSD definition of major. In addition, the turbine and boiler overhauls may not constitute modifications. It is common practice within the utility industry to conduct maintenance work on boilers and turbines during planned outages on a routine basis. Such activities would generally be considered routine, maintenance and repair and, as indicated previously, such activities are not considered modifications. The fact that exhibits 3, 8 and 9 indicate that such activities have occurred frequently over the time periods addressed in the exhibits support the inference that these activities are routine.

Comment: *At the least, the APCD has a minimum responsibility to respond to our significant comments about the valid suspicion of noncompliance with PSD as demonstrated by the 2002 NOV and Xcel Energy's own reports providing evidence of major modifications. See In the Matter of CEMEX Inc., Petition No. VIII-2008-01 (April 20, 2009). In particular, the APCD must "provide the basis (e.g., citing to current or historical evidence, or the lack thereof) that supports its conclusion that PSD/NSR" was or was not applicable in relation to the aforementioned modifications. Id. at 10.*

Response: The Division has thoroughly responded to WildEarth Guardian's comments on these issues above, and explicitly cited the basis for its responses. The Division has fulfilled its responsibility to respond to significant comments as well as provided adequate justification for our response.

2. The Title V Permit Must Include Regional Haze Requirements

Comment: *The Title V Permit must incorporate emission limits established under Colorado's regional haze rules, as required by 40 CFR § 70.6. As the Technical Review Document ("TRD") notes, the Pawnee coal-fired power plant is subject to stronger particulate matter ("PM") and nitrogen oxide ("NO_X") emission limits under a recently issued Best Available Retrofit Technology ("BART") construction permit issued by the APCD. See TRD at 8-9. These emission limits are applicable requirements under Title V, which* *include "any term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D, of the [Clean Air] Act." 40 CFR § 70.2.*

Response: WildEarth Guardians' is correct that the conditions in the BART permit are applicable requirements. Therefore, the Division has revised the operating permit to include the requirements contained in construction permit 07MR0111B.

3. The Title V Permit Fails to Assure Compliance with Particulate Limits for the Coal-fired Boiler

Comment: *We are further concerned that the proposed Title V Permit fails to require sufficient periodic monitoring to ensure compliance with particulate limits from emission unit B001, the coal-fired boiler at the Pawnee plant. Condition 8.2 of the Title V Permit requires only annual stack testing, although this Condition allows for less frequent monitoring. Annual stack testing is wholly insufficient, particularly given that National Ambient Air Quality Standards ("NAAQS") limit particulate matter, including both PM-10 and PM-2.5, on a 24-hour basis. The Title V Permit must at least require daily particulate matter monitoring to protect the NAAQS and also to ensure sufficient periodic monitoring in accordance with 40 CFR § 70.6.*

Although the Title V Permit may rely on baghouses to meet particulate standards, there are no conditions that require any monitoring, recordkeeping, or reporting to ensure the baghouses are operated consistently to assure compliance with the particulate limits. Put simply, there are no terms and conditions that ensure the baghouses will assure compliance with the particulate limits. Furthermore, to the extent that [sic]

Response: Annual stack testing is not the only method specified in the permit that is used to monitor compliance with the particulate matter limits. The permit specifies that the baghouse be maintained and operated appropriately (Section II, Condition 8.1) and includes compliance assurance monitoring (CAM) requirements (Section II, Condition 1.15 and Appendix I).

For purposes of CAM, the source is monitoring opacity and performing internal inspections of the baghouse annually.

As indicated by EPA in their "Order Responding to Issues Raised in April 28, 2009 and March 2, 2006 Petitions, and Denying in Part and Granting in Part Requests for Objection to Permit" In the Matter of Louisville Gas and Electric Company, Petition Number IV-2008-3, page 51 (August 12, 2009):

> The concept of the CAM approach is that compliance with an emission standard is assured through requiring monitoring of the operation and maintenance of the control equipment and, if applicable, operating conditions of the PSEU. *62 Fed. Reg. at 54,918.* The CAM analysis is that "[o]nce an owner or operator has shown that the installed control equipment can comply

> with an emission limit, there is a reasonable assurance of ongoing compliance with the emission limit as long as the emissions unit is operated under the conditions anticipated and the control equipment is operated and maintained properly."

As indicated in the preamble for the final CAM rule, published in the Federal Register on October 22, 1997 (page 54902, 1st column, 1st paragraph),

> The CAM approach as defined in part 64 is intended to address the requirement in title VII of the 1990 Amendments that EPA promulgate enhanced monitoring and compliance certification requirements for major sources, and the related requirement in title V that operating permits include monitoring, compliance certification, reporting and recordkeeping provisions to assure compliance.

The CAM requirements were promulgated to meet the obligations of enhanced monitoring which were required under the 1990 revisions to the Federal Clean Air Act (the Act). Language from the CAM rule indicates that the CAM monitoring is consistent with the Title V periodic monitoring requirements. As indicated in the preamble for the final CAM rule, published in the Federal Register on October 22, 1997 (page 54902, 2nd column, 1st paragraph):

> For units not covered by part 64 [the CAM requirements], a similar but less detailed approach is provided for in the monitoring and related recordkeeping requirements of Part 70 (see § 70.6(a)(3)).

In addition, as indicated in 40 CFR Part 64 § 64.5(d), "Prior to approval of monitoring that satisfies this part, the owner or operator is subject to the requirements of § 70.6(a)(3)(i)(B)," which implies that monitoring under CAM is consistent with periodic monitoring. Finally, in situations where the Division disapproves a source's proposed monitoring, 40 CFR Part 64 § 64.6(e)(1) specifies that "The draft or final permit shall include, at a minimum, monitoring that satisfies the requirements of § 70.6(a)(3)(i)(B)."

Previous performance tests conducted on Unit 1 indicate that particulate matter emissions are much less than 50% of the standard (testing showed PM at 0.00673 lb/mmBtu, the standard is 0.1 lb/mmBtu). Therefore, the Division considers that the schedule for performance testing specified in the permit is sufficient. The Division considers that annual performance testing in conjunction with monitoring that meets the CAM requirements and requirements for proper baghouse operation and maintenance is sufficient to meet the periodic monitoring requirements set forth in Title V.

Comment: *Regardless of the effectiveness of the baghouses however, we are concerned that the baghouses do not limit condensable particulates, which are a component of particulate matter. The Title V Permit must require more frequent particulate matter monitoring. We would request the APCD require the use of particulate matter continuous emission monitoring systems ("PM CEMS") to assure compliance with the particulate limits in the*

Title V Permit. The U.S. Environmental Protection Agency ("EPA") promulgated performance specifications for PM CEMS at 40 CFR § 60, Appendix B, Specification 11, on January 12, 2004. See, In the Matter of Onyx Environmental Services, Petition No. V-2005-1 at 13. This promulgation indicates that the use of PM CEMS is an accepted means of assessing compliance with particulate emissions.

Response: While a baghouse may not control condensable particulate matter emissions, the particulate matter limits included in the permit for Unit 1 are for filterable particulate matter only. Unit 1 is not subject to any emission limitations for condensable particulate matter. In addition, a PM CEMS does not measure condensable particulate matter emissions.

Comment: *Furthermore, the EPA has required other coal-fired power plants to install, operate, calibrate, and maintain a PM CEMS. In a 2000 consent decree, Tampa Electric Company agrees [sic] to install a PM CEMS on one of its coal-fired power plants in Florida to ensure compliance with PM limits. More recently, through a 2006 consent decree, two North Dakota utilities agreed to install PM CEMS at a coal-fired power plant in North Dakota. Similarly, the EPA reached agreements with other utilities in Wisconsin and Illinois that have led to the installation, calibration, operation, and certification of PM CEMS. All these consent decrees are implicit that the PM CEMS are to be used to demonstrate compliance with PM limits.*

Most recently, in proposed amendments to new source performance standards ("NSPS") for electric utility steam generating units, the EPA stated, "Based on our analysis of available data, there is no technical reason that PM CEMS cannot be installed and operate reliably on electric utility steam generating units." 70 Fed. Reg. 9728. Although the final amendments to the NSPS for electric utility steam generating units did not require the utilization of PM CEMS, the EPA stated that PM CEMS may be used to demonstrate continuous compliance with particulate limits.

The use of PM CEMS would constitute sufficient periodic monitoring that will assure compliance with the particulate limits set forth in the Title V Permit. We request the APCD take advantage of its authority under 40 CFR § 70 to require the installation and operation of PM CEMS at the Pawnee coal-fired power plant through the Title V Permit.

Response: While the Division agrees that a PM CEMS represents the most direct method to assure continuous compliance with emission limits, we do not believe it is necessary to require the use of a PM CEMS for purposes of periodic monitoring. Currently, PM CEMS are not required by any regulation for compliance monitoring. The Division is aware that EPA has required PM CEMS for several coal-fired power plants in Consent Decrees, however, we do not necessarily agree that the language in all of these Consent Decrees require that the PM CEMS be used directly for compliance purposes. Although EPA considered requiring the use of PM CEMS in their proposed revisions to NSPS Subpart Da in 2005, the final rule (published in the Federal Register on February 27, 2006) did not require a PM CEMS for sources that were meeting the input based (lb/mmBtu) particulate matter emission limitations.

The draft renewal permit includes CAM for the particulate matter emission limitations. The CAM plan includes monitoring that is essentially the same as that required for new (constructed after February 28, 2005) electric utility steam generating units subject to particulate matter fuel based emission limitations (i.e. units of lb/mmBtu) in 40 CFR Part 60 Subpart Da. The CAM plan requires that a site-specific opacity trigger level be set based on the opacity level measured during the performance test. According to EPA (February 26, 2007 Federal Register, page 9872, 3rd column, 2nd paragraph), "...a site-specific opacity trigger is the best approach to monitor continuous compliance." Therefore, the Division considers that the CAM requirements, in conjunction with the requirements for proper baghouse operation and maintenance and annual performance testing, is more than adequate to meet the Title V periodic monitoring requirements.

4. The Percent Opacity Limit Applies to Fugitive Emissions from Coal Handling and Storage, Ash Handling and Disposal, and Paved and Unpaved Roads.

Comment: *While the 2002 Technical Review Document states that the 1974 NSPS at 40 CFR § 60.252 ("Subpart Y") apply to the coal handling system, at page 26 it asserts that the 20 percent opacity limit is not actually a requirement for fugitive emissions. The Title V Permit therefore does not include an opacity limit for following sources: coal handling and storage, ash handling and disposal, and paved and unpaved roads. This is incorrect. The Title V Permit must ensure that the 20% opacity limit in Subpart Y applies to fugitive, as well as point source, emissions from coal handling and storage, ash handling and disposal, and paved and unpaved roads.*

Indeed, Subpart Y mandates that the operator "shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit 20 percent opacity or greater." 40 CFR § 60.252. Subpart Y includes and applies to all emissions from these sources, regardless of whether the emissions come from a point source or a fugitive source.

Response: The opacity limit cited on page 26 of the Technical Review Document for the original Title V permit (referred to as the 2002 Technical Review Document), is not the NSPS Subpart Y opacity limit but is the requirement for fugitive particulate matter emissions in Colorado Regulation No. 1, Section III.D.1.c. Regulation No. 1 indicates that the 20% opacity limit is an emission limitation "guideline" and if a source is subject to the guideline, they must submit control plans to minimize fugitive particulate matter emissions. Thus the control plan requirements for haul roads and ash handling and disposal are incorporated into the Title V permit in Section II, Condition 4.4 to meet the 20% emission guideline. To clarify this, the following language from Colorado Regulation No. 1, Section III.D.1.e.(iii) will be added to Condition 4.2.1: "The 20% opacity, no off-property transport, and nuisance emission limitation are guidelines and not enforceable standards and no person shall be cited for violation thereof pursuant to C.R.S § 25-7-115."

5. The 20 Percent Opacity Limit under NSPS Subpart Y Applies to Coal Unloaded to Storage

Comment: *The 2002 Technical Document at 28 incorrectly states that coal unloaded to storage is exempt from Subpart Y. Coal unloaded to storage is a "coal storage system," and "coal storage system" is written in the plain language of the regulation. The Title V Permit must be written so that the 20 percent opacity limitation applies to all parts of the coal handling system.*

Indeed, the 2002 Technical Document at 36 relied on EPA's 1998 interpretation of 40 CFR Part 60 Subpart Y § 60.252, published at 63 FR 53288 (Oct. 5, 1998), to assert that unloading and conveying coal to storage were not subject to Subpart Y. The 1998 interpretive rule appeared to exclude coal unloading to coal storage areas from its 20% opacity requirement. This rule was not explained nor was there a rational basis for this exclusion. See 63 FR 53289. While courts typically give some deference to interpretive rules, they do not merit Chevron deference, nor do they have any legally binding effect. U.S. v. Mead Corp., 533 U.S. 218, 232 (2001).

Further, the EPA recently proposed revisions to the NSPS at Subpart Y that strongly indicate the 1998 interpretive rule is, in fact, flawed. On May 27, 2009, the EPA proposed changing the previous interpretation under Subpart Y to include all open storage piles as affected facilities. See 74 FR 25312. This new interpretation has been issued via notice and comment, in contrast to the 1998 rule which was simply interpretive and was not issued with notice and comment. This proposed rule further indicates that the 1998 interpretive rule cannot be relied upon to assert that coal unloaded to storage is exempt from Subpart Y.

Response: The 2002 Technical Review Document is not incorrect and the Division was correct to rely on EPA's 1998 interpretation. It is incorrect to state that the May 27, 2009 proposed revisions to NSPS Subpart Y indicate that the 1998 interpretation was flawed, is being revised and cannot be relied upon. In fact, the March 27, 2009 proposed revisions to NSPS Subpart Y confirm the 1998 interpretation, as indicated below (May 27, 2009 Federal Register, page 25312, 3rd column, 4th paragraph):

> Although the source category listing covers the entire coal preparation plant, we have not previously established emission limits for all facilities located at the plant. Because open storage piles were not previously considered affected facilities, unloading and conveying operations to an open storage pile were also not regulated. Only unloading operations that were directly loaded into receiving equipment were subject to an opacity limit.

The proposed changes to NSPS Subpart Y do propose regulating emissions from open storage piles but only for units that are constructed, reconstructed or modified **after** May 27, 2009. The plain language of the proposed rule, clearly does not consider existing open storage piles, such as the one at Pawnee to be a "coal storage system."

Final revisions to NSPS Subpart Y were published in the Federal Register on October 8, 2009 and the final rule defines a "coal storage system" as "any facility used to store coal, except for open storage piles." The final revisions do regulate open storage piles but only piles that are constructed, reconstructed or modified **after** May 27, 2009.

6. Opacity Must be Monitored and Reported for All Coal Handling and Storage, Ash Handling and Disposal and Paved and Unpaved Roads.

Comment: *The Title V Permit must contain periodic monitoring to assure compliance with all terms and conditions. 40 CFR § 70.6. The draft Title V Permit currently lacks opacity monitoring for fugitive emissions from coal handling and storage, ash handling and disposal, and paved and unpaved roads. The APCD must add "periodic monitoring sufficient to yield reliable data form [sic] the relevant time period that are representative of the source's compliance with the permit" to comply with 40 CFR § 70.6(a)(3)(i)(B). See In re Citgo Refining and Chemicals Co. L.P., Petition No. VI-2007-01 (May 28, 2009) at 7. Periodic monitoring for these sources of fugitive emissions must be included in the Title V Permit to ensure compliance with the 20 percent opacity limitation.*

Response: As previously indicated in Items 4 and 5 above, fugitive emissions from coal handling and storage, ash handling and disposal and paved and unpaved roads are not subject to opacity limitations.

7. Particulate Limits at Section II, Condition 5 Appear Unenforceable

Comment: *Condition 5.1 establishes presumptive compliance with the PM and PM10 limitations for the coal handling system. Presumptive compliance is based on fulfilling the work practices listed in Conditions 5.1.1 through 5.1.5. See Condition 5.1.6. As explained below, these conditions are vague and unenforceable, and a system of presumptive compliance is insufficient to ensure that applicable particulate matter limitations are met.*

Condition 5.1.1 is vague and unenforceable because it does not define "good engineering practices." This undefined term implies certain practices, but it does not state what they are. Moreover, these conditions do not state how operation in accordance with good engineering practices will be reported or monitored. Without any periodic monitoring requirements, this condition is unenforceable as a practical matter and in violation of 40 CFR § 70.6(a)(3)(i)(B).

At a minimum, the Permit must describe periodic monitoring that is sufficient to assess whether "good engineering practices" have been followed. To achieve this, the Permit must define "good engineering practices" so that there is a standard to which actual operations can be compared.

Conditions 5.6.2 and 5.6.3 also use the term "good engineering practices" without defining what that term means. These conditions fail to comply with 40 CFR § 70.6(a)(3)(i)(B) for the same reasons that Condition 5.1.1 failed above. Sufficient periodic monitoring must be added to the Permit to assure compliance with the relevant *good engineering practices that are implied (but not properly explained) by Conditions 5.6.2 and 5.6.3.*

Response: While the manufacturers' recommendations and good engineering practices are not specified in the permit, the Division can review these procedures during an inspection as necessary if we believe the control equipment is not being operated and maintained properly. The Division does not believe it is necessary to include specific procedures and requirements in the permit for proper operation of the baghouses and bin vent filters. As EPA noted in their response to Title V Petition No. VIII-2006-4 (In the matter of Pope and Talbot, Inc., Lumber Mill), page 13, dated March 22, 2007:

> EPA has explained its position on manufacturers' specification in other orders responding to Title V petitions. In *Lovett Generating Station*, EPA explained that "…most manufacturers' recommendations are intended to be guidelines and are frequently updated to improve operator and equipment performance as time goes on, therefore, EPA does not require that the specification manual itself be incorporated into a Title V permit." (Petition Order # II-2001-07; In the Matter of the Lovett Generating Station, Petition at 26) Noting that frequent revisions to manufacturers' recommendations could trigger many unnecessary permit re-openings to adopt the latest changes, EPA generally believes that incorporation of these recommendations into a permit would not be practical.

Determination of whether manufacturers' recommendations and good engineering practices are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. The Division does not believe it is necessary to include specific procedures and requirements in the permit for baghouse and bin vent filter operation and maintenance.

Finally, please be aware that in a letter dated September 13, 2000, from EPA Region 8 to the Division, regarding EPA Review of Proposed Title V Operating Permit for TriGen-Colorado Energy Company the phrase "good engineering practice" was a term that the Division and EPA agreed on to address deficiencies noted in that permit, as indicated below (page 9 of letter enclosure):

> Solution: In discussions, the Division and EPA agreed that replacing the objectionable phrase, ". . . or documented operating practices and procedures developed by the permittee," with ". . .or in accordance with good engineering practice," would correct this problem.

Comment: *Condition 5.1.3 is vague and unenforceable because it does not define "integrity of the enclosures," nor does it state how such integrity will be maintained to prevent particulate emissions. Moreover, 5.1.3 does not explain what "used as necessary" means in the operation of water spray suppression systems. As it stands, there is no reporting or* *monitoring to ensure compliance with this requirement. To ensure compliance with this condition, the Permit must include periodic monitoring of the conveyor and crusher enclosures and periodic monitoring of the use of the water spray suppression systems. Without such monitoring, Condition 5.1.3 is in violation of 40 CFR § 70.6(a)(3).*

Condition 5.1.5 does not contain any periodic monitoring, thus it also violates 40 CFR § 70.6(a). The transfer points must be identified and reported so that the number of transfer points can be monitored to ensure compliance with the 13-transfer point limit in 5.1.5. Transfer points should also be designated as PM and opacity monitoring points because there is significant potential for particulate emissions at transfer points.

Response: Based on our experience, enclosures, in conjunction with water spray systems, are effective in controlling particulate matter emissions. In some cases, depending on the moisture content in the coal transported, enclosures alone are effective in controlling particulate matter emissions. In addition, the number of transfer points is limited by the design of the equipment and the addition and/or removal of transfer points is unlikely absent a physical modification to the coal conveying system, such as the addition or removal of conveyor belts. Although the Division conducts routine inspections and investigates complaints, we must always rely to a certain extent on a source correctly operating and maintaining their equipment. One of the key elements of the Title V Operating Permit program is that the Responsible Official who signs the reports is subject to criminal penalties for false certification.

Comment: *Conditions 5.1.1 through 5.1.3 are extremely important for ensuring compliance with the two similar 20% opacity limits in Conditions 5.7 and 5.8. Condition 5.7 states that opacity emissions from the coal handling system shall not exceed 20%. Condition 5.8 states that "any coal processing and conveying equipment, coal storage system or coal transfer and loading system processing coal" shall not discharge gases which exhibit 20% opacity or greater, as required by 40 CFR § 60.252. Both 5.7 and 5.8 state that these opacity requirements "shall be presumed to be in compliance" if Conditions 5.1.1 through 5.1.3 are being met. As previously described, Conditions 5.1.1 and 5.1.3 do not define key standards nor do they contain sufficient monitoring to ensure compliance with applicable requirements. Due to these failures, it will be impossible to ensure compliance with Conditions 5.7 and 5.8 until the failures in 5.1.1 and 5.1.3 are corrected.*

Moreover, even if Conditions 5.1.1 and 5.1.3 were corrected to include monitoring, presumptive compliance with the two opacity requirements is not sufficient to comply with 40 CFR § 70.6(c)(1). If permit terms and conditions include monitoring but that monitoring is insufficient to ensure compliance with terms and conditions, the permitting authority must supplement the permit so that the Permit meets Title V requirements. Sierra Club v. EPA, 536 F.3d 673, 678 (D.C. Cir. 2008).

Actual monitoring of opacity for the coal handling system, and for coal transfer and storage as defined in 40 CFR § 60.252, must be written into the Title V Permit. Condition 5 lists emissions unit P001, which includes crushing, transfer tower and conveying, as point sources for particulate matter and opacity. First, point sources must be identified *for monitoring. The transfer points in Condition 5.1.5 should be potential monitoring points, as well as any opening in an enclosure. Second, opacity monitoring by Method 9 or other approved methods must occur at those points on a daily basis in accord with general requirements at 40 CFR § 60.11(b). Third, all opacity measurements must be recorded and reported to ensure compliance with the 20 percent limit. Without such revisions, the Title V Permit will fail to require sufficient monitoring to assure compliance with all applicable requirements.*

Response: The primary control used to reduce particulate matter emissions, including opacity, from the coal handling system is the use of enclosures. In some cases, a water spray system is utilized within the enclosure to further reduce emissions and in others, air within the enclosure is mechanically vented through a baghouse. The permit requires PSCo to inspect the water/surfactant spray systems on the crusher and the live storage rotary plows and the the plant transfer tower/tripper deck and crusher baghouses quarterly. In general, the coal handling system offers no "points" from which to take a Method 9 opacity reading, because it primarily consists of enclosed conveyors. As indicated previously the Division considers that enclosures are an effective means of reducing particulate matter, including opacity, emissions. However, after further consideration, the Division has revised the permit to require that 6-minute Method 9 opacity observations be conducted annually on the transfer tower/tripper deck and crusher baghouses.

The Division considers that annual Method 9 readings are sufficient periodic monitoring for these sources. The baghouses are operated under negative pressure in order to capture particulate matter emissions and the initial performance tests conducted in 2003 on both baghouses indicated no visible emissions were observed during the three hour period. Our position is supported by EPA in their "Order Granting in Part and Denying in Part Petition for Objection to Permit" in the Matter of Dynergy Northeast Generation, Petition Number II-2001-06, page 11, dated February 14, 2003, as indicated below:

> However, EPA notes that this permit description fails to explain how specific monitoring selected assures compliance with emission standards. For example, the permit at Condition 78 requires an annual Method 9 test to determine opacity compliance at the coal handling facility. An annual opacity reading may appear to be infrequent and even inadequate to assure compliance with 6 NYCRR § 212.6 for the public who is not familiar with the operation and control devices that are already in place at the facility. The adequacy of the annual opacity reading would have been clear had DEC explained in the Statement of Basis that the coal is transported by rail or marine vessels to the Danskammer facility. During the unloading/loading operation, coal fugitives are controlled with water spraying. Coal is transferred through an enclosed conveyor to the coal crushers where coal is ground under negative pressure to capture the coal fugitive emissions. A Method 9 evaluation is performed within 180 days of initial permit issuance when coal is being loaded/unloaded to determine the adequacy of the water

spray control. Because the coal fugitives are properly controlled and a Method 9 test is performed initially, it is acceptable for Danskammer to perform an annual Method 9 subsequently to ensure that compliance with the opacity standard is maintained. Such description would help the reader understand why a Method 9 performed once a year would be adequate in assuring compliance with the opacity standard of 6 NYCRR § 212.6. *See* Section VI. B, *infra*, for a discussion of the kind of monitoring that will be applied to this part of the facility.

8. The Title V Permit Fails to Assure Compliance with Section 112 of the Clean Air Act

Comment: *The Title V Permit fails to assure compliance with section 112(j) of the Clean Air Act. In particular, the Title V Permit fails to assure compliance with case-by-case maximum achievable control technology ("MACT") requirements, both for any industrial boilers that may be in operation at the Pawnee coal-fired power plant and any electric utility steam generating unit ("EGU").*

We are particularly concerned that the Title V Permit fails to assure compliance with section 112(j) in the context of mercury emissions from the coal-fired power plant. As the TRD notes, "on February 8, 2008 a DC Circuit Court vacated the CAMR regulations for both new and existing units." TRD at 7. In particular, the D.C. Circuit held in early 2008 that the EPA had inappropriately delisted EGUs from the list of sources whose emissions are regulated under section 112 of the Clean Air Act. In light of this ruling, as well as the EPA's failure to promulgate a MACT standard for EGUs, the APCD must develop a case-by-case MACT for the EGU in operation at the Pawnee coal-fired power plant. Such a case-by-case MACT must include mercury emission limits, as well as limits for other hazardous air pollutants ("HAPs") regulated under section 112 of the Clean Air Act, such as lead compounds, hydrofluoric acid, and hydrochloric acid. It is especially critical that the APCD assure compliance with section 112 given that the TRD discloses that the Pawnee coal-fired power plant is indeed a major source of HAPs. See TRD at 5.

Response The case-by-case MACT requirements of 112(j) only apply to major sources of HAPS which includes one or more stationary sources included in the source category or subcategory for which the EPA failed to promulgate a MACT standard by the section 112(j) deadline. Although electric utility steam generating units (EUSGUs) were added to the list of source categories in Section 112(c) in December 2000, a deadline for promulgation of those standards was never set. Therefore, the case-by-case MACT requirements of 112(j) do not apply to EUSGUs.

Although the case-by-case MACT requirements of 112(j) do not apply, this unit is subject to the mercury requirements in Colorado Regulation No. 6, Part B, Section VIII. The mercury emission limitation, which takes effect on January 1, 2012, and monitoring requirements have been included in the draft renewal permit.

Comment: *We are further concerned that the Title V Permit fails to assure compliance with section 112 in the context of any industrial boilers that are in operation at the Pawnee coal-fired* *power plant. The TRD indicates that the "EPA has not set a deadline for submittal of 112(j) applications to address the vacatur of the Boiler MACT." TRD at 7. Yet compliance with section 112(j) does not hinge upon any EPA deadline. The Clean Air Act is clear that section 112(j) requirements apply whenever EPA fails to promulgate a standard within 18 months of the date established pursuant to section 112(e)(1) and (3) of the Clean Air Act. Thus, the deadline for Public Service Company to submit a 112(j) permit application has passed, meaning the Title V Permit must ensure that an application is submitted as soon as possible to assure compliance with section 112 of the Clean Air Act. To this end, the Title V Permit must contain a compliance schedule to bring the Pawnee coal-fired power plant into compliance with section 112(j) of the Clean Air Act in accordance with 40 CFR § 70.6(c)(3).*

Response: The required promulgation date for the industrial, commercial and institutional boilers and process heaters was November 11, 2000 and therefore the MACT "hammer" date was May 15, 2002. The source did submit a Part 1 case-by-case MACT application prior to the May 15, 2002 MACT hammer date, as required. At that time, submittal of a Part 2 application was due within 24 months after submittal of the Part 1 application. However, the May 30, 2003 revisions to the 112(j) provisions changed the due date of the Part 2 application to April 28, 2004 . Since the standards for industrial, commercial and institutional boilers and process heaters (hereafter referred to as the "Boiler MACT") were signed as final on February 26, 2004 and published in the Federal Register on September 13, 2004, a Part 2 application was not required.

As of July 30, 2007, the Boiler MACT was vacated, which raises the question of whether or not case-by-case MACT under 112(j) applies. The Division believes that it does apply, but we have deferred submittal of an application until EPA provides further guidance as to the deadline for submittal of Part 2 applications. Although the May 30, 2003 revisions to the 112(j) provisions did set a deadline for Part 2 applications, those revisions anticipated promulgation of the Boiler MACT prior to the Part 2 application deadline (which did occur) but did not anticipate vacatur of the final rules, which would trigger 112(j) requirements at a future date. Because of this, the Division is deferring Part 2 applications until EPA provides additional guidance. We believe our decision is supported by the following EPA statements:

In the April 5, 2002 revisions to the 112(j) provisions (67 FR 16582), the EPA noted the following (pg 16589, 3rd column, 2nd paragraph):

> However, as one commenter noted, there is another provision in the statute which may be construed as providing authority to establish an incremental process for the submission of section 112(j) applications. The hammer provision in section 112(j)(2) itself establishes the requirement to submit permit applications ''beginning 18 months after'' the statutory date for promulgation of a standard. Reading this provision in context, we believe that the statute can be reasonably construed as authorizing us to provide a period of time after the hammer date in which the information necessary for a fully informative section 112(j) application can be compiled.

EPA goes on to state the following (pg 16590, 1st column, 3rd paragraph):

> We received no adverse comment on requiring that the first portion (Part 1) of the section 112(j) application be due on the hammer date. We think that this is the minimum required by the statute.

As indicated previously, the source did submit a Part 1 application prior to the May 15, 2002 hammer date; therefore, the source has submitted the minimum required by the statute. Since the 112(j) provisions (40 CFR Part 63 Subpart B, §§ 63.50 through 63.56) do not address the situation where a 112(j) application may be required in the event of the vacatur of a previously promulgated rule, the Division considers that it is appropriate to delay submittal of the Part 2 application until further guidance is provided by EPA.

In addition, 40 CFR Part 63 Subpart B § 63.53(b)(2)(ii) states the following with respect to the information requirements in Part 2 MACT applications: "[w]hen the Administrator has proposed a standard pursuant to section 112(d) or 112(h) for the Act for a category or subcategory, such information may be limited to those emission points and hazardous air pollutants which would be subject to control under the proposed standard." Based on this language, it seems reasonable to presume that if a standard had been promulgated, but later vacated, that the required information in a Part 2 application would be limited to those emission points and hazardous air pollutants that would have been subject to control under the subsequently vacated standard, provided that the standard was not vacated for the emission points and hazardous air pollutants for which no control was specified. Here, the case-by-case 112(j) MACT requirements specify that if EPA has proposed a MACT and in the proposed MACT certain types of units are not subject to control requirements, then those units do not have to be addressed in a case-by-case 112(j) application. In the Boiler MACT (which has since been vacated), existing large and limited use gaseous fuel units (such as the auxiliary boiler at Pawnee) were not subject to control requirements. While there is no proposed MACT out for industrial boilers, the MACT that was vacated did not require control requirements for units like Pawnee's auxiliary boiler.

Although petitions were received on the Boiler MACT for source categories for which no level of control was specified, the Boiler MACT was not vacated for that reason. The Boiler MACT was vacated for the sole reason that the definition of commercial and industrial waste incineration unit in 40 CFR Part 60 Subparts CCCC and DDDD (Standards of Performance for Commercial and Institutional Solid Waste Incineration (CISWI) Units and Guidelines for CISWI) was not consistent with the definition of a solid waste incineration unit in Section 129 of the Clean Air Act. Because of the difference in the definition, emission units that would be considered CISWI units under Section 129 of the Clean Air Act are considered affected units under the Boiler MACT. To that end, the U.S Court of Appeals for the District of Columbia Circuit vacated the Boiler MACT as indicated below (page 20 of decision):

> As a result of our decision today, neither of the two Rules survives remand in anything approaching recognizable form. As the Environmental Petitioners point out, our rejection for EPA's definition of "commercial or industrial waste," as incorporated into the definition of CISWI, will "shift thousands of units that are currently regulated under the section 112 Boilers Rule into the CISWI category, subject to regulation under section 129" and "[a]s a result, the populations of units subject to EPA's boilers and CISWI rules will change substantially", requiring that EPA "recalculate the stringency of the emissions standards for the newly expanded CISWI category and the newly shrunk boilers category."

Although the Court indicates that it expects that the Boiler MACT will be significantly changed because the number of units regulated under the Boiler MACT will shrink, the Division considers that it is unlikely that the population of gas-fired units will be changed significantly since not many gas-fired boilers and/or process heaters would be classified as CISWI units. As a result, since existing large and small gas-fired units were not subject to control requirements under the previously promulgated Boiler MACT, the Division considers that under the provisions of 63.53(b)(2)(ii) it would be reasonable to expect that an emission unit such as the auxiliary boiler would not need to be addressed in a Part 2 application.

Finally, it should be noted that EPA is under a court-ordered deadline to propose new boiler standards by April 15, 2010 and finalize them by December 16, 2010. In accordance with 40 CFR Part 63 Subpart B § 63.53(g), permitting authorities have 18 months after submittal of a Part 2 application to issue a Title V permit meeting the requirements of 112(j). Given that a final rule is expected within 18 months, the Division considers that requiring a Part 2 application at this point would not be appropriate.

9. The Title V Permit Fails to Address Carbon Dioxide Emissions

Comment: *In proposing to issue the Title V Permit, it appears that the APCD has failed to assess whether carbon dioxide ("CO_2") is subject to regulation in accordance with Prevention of Significant Deterioration ("PSD") requirements and therefore failed to ensure compliance with PSD under the Clean Air Act, PSD regulations, and the Colorado State Implementation Plan ("SIP").*

Under Colorado regulations incorporated into the SIP, any source that emits more than 250 tons per year "of any air pollutant subject to regulation under the Federal Act" is subject to PSD permitting requirements, including the requirement that Best Available Control Technology ("BACT") be utilized to keep air emissions in check. See AQCC Regulation Number 3, Part D § VI.A.1.a; see also 42 USC § 7475(a) and 40 CFR § 51.166(j)(2). Similarly, the SIP requires that any major source that undergoes a modification leading to a significant emissions increase is also required to utilize BACT. AQCC Regulation No. 3, Part D § VI.A.1.b. The Clean Air Act makes clear that the BACT requirements extend to "each pollutant subject to regulation" under the Act. 42 USC § 7479(3) and 40 CFR § 52.21(b)(12); see also AQCC Regulation No. 3, Part D §

II.A.8. In this case, the [sic] it appears the APCD failed to ensure assess whether CO_2 is subject to regulation in accordance with PSD and whether the Title V Permit ensures compliance with PSD requirements under the Colorado SIP, the Clean Air Act, and PSD regulations in relation to CO_2 emissions from the Pawnee coal-fired power plant.

At issue is the fact that the APCD may be relying upon EPA's interpretation of the phrase "subject to regulation" when issuing the Title V Permit and completely ignored whether CO_2 emissions should be limited by the application of BACT as required by PSD provisions in the Colorado SIP, the Clean Air Act, and PSD regulations. The U.S. Environmental Appeals Board ("EAB") determined this interpretation fails to set forth "sufficiently clear and consistent articulations of an Agency interpretation to constrain" authority the EPA would otherwise have under the Clean Air Act. In re Deseret Power Electric Cooperative, PSD Appeal No. 07-03, slip op. at 37 (EAB November 13, 2008), 14 E.A.D. at ___. In light of the EAB's ruling, it would be inappropriate for the APCD to ignore CO_2 emissions by relying on EPA's prior interpretation of the phrase "subject to regulation" when issuing the Title V Permit.

Although the APCD may claim that a December 18, 2008 interpretive memo issued by former EPA Administrator Stephen Johnson (hereafter "Johnson memo") "clarifies" EPA's position that CO_2 is not subject to regulation under PSD requirements (see Memorandum from Stephen L. Johnson, Administrator, to all Regional Administrators, "EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program" (December 18, 2008)) and therefore addresses the EAB's ruling, this is simply not true in this case. For one thing, the Johnson memo is clear that it does not bind states, such as Colorado, that administer the PSD program under their own SIP. Thus, the Johnson memo does not absolve the APCD from rendering its own, independent interpretation of the meaning of the phrase "subject to regulation" as set forth in the Colorado SIP.

Furthermore, EPA Administrator Jackson recently granted a petition for reconsideration of the Johnson memo "to allow for public comment on the issues raised in the memorandum." See Letter from EPA Administrator Lisa Jackson to David Bookbinder, Chief Climate Counsel, Sierra Club (February 17, 2009). Although Administrator Jackson declined to stay implementation of the Johnson memo while the EPA solicits public comment, she advised that "PSD permitting authorities should not assume the memorandum is the final word on the appropriate interpretation of Clean Air Act requirements." Id. It is further apparent that it would be inappropriate for the APCD to simply rely on the Johnson memo in assessing whether CO_2 emissions should be limited by the application of BACT as required by the Clean Air Act, PSD regulations, and the Colorado SIP.

Indeed, it would be further inappropriate because the Colorado SIP appears to support a finding that CO_2 emissions are subject to regulation, and therefore subject to PSD requirements. Although the phrase "subject to regulation" is not explicitly defined in the Colorado SIP, there are three reasons to interpret the Colorado SIP to allow the State of Colorado to find that CO_2 emissions are subject to regulation under the Clean Air Act.

First, the U.S. Supreme Court recently held in Massachusetts v. EPA, 127 S. Ct. 1438 (2007), that CO_2 is a "pollutant" under the Clean Air Act. Although the EAB noted that the Massachusetts decision "did not address whether CO_2 is a pollutant 'subject to regulation' under the Clean Air Act" (Deseret Power, slip op. at 8), the EAB did not reject the interpretation that the decision supports a finding that CO_2 emissions are subject to regulation under the Clean Air Act. In fact, the EAB noted that the Massachusetts decision rejected key EPA memos that were relied upon when interpreting the phrase "subject to regulation" (see e.g., Id. at 52, "The reasoning of the Fabricant Memo was subsequently rejected and overruled by the Supreme Court in Massachusetts v. EPA, 549 U.S. 497, slip op. at 29-30 (2007)").

Second, CO_2 is "subject to regulation" because it falls under the definition of "air pollutant" set forth in the Colorado SIP. Indeed, the AQCC Common Provisions Regulation, which is incorporated into the Colorado SIP, defines air pollutant as:

> *Any fume, smoke, particulate matter, vapor, gas or any combination thereof that is emitted into or otherwise enters the atmosphere, including, but not limited to, any physical, chemical, biological, radioactive (including source material, special nuclear material, and by-product materials) substance or matter, but not including water vapor or steam condensate or any other emission exempted by the commission consistent with the Federal Act.*

CO_2 is a gas that is emitted into the atmosphere, and therefore clearly regulated as a pollutant under the Colorado SIP. Furthermore, this definition derives directly from the Colorado Air Pollution and Prevention Control Act (see CRS § 25-7-103(1.5), a fact that seems to compel a finding that CO_2 is "subject to regulation" under the PSD. Indeed, the SIP explicitly states that PSD provisions apply "to any major stationary source and major modification ***with respect to each pollutant regulated under the [Colorado Air Pollution and Prevention Control] Act*** *and the Federal Act that it would emit, except as this Regulation No. 3 would otherwise allow." AQCC Regulation No.3, Part D § VI.A. (emphasis added). The Colorado Air Pollution and Prevention Control Act clearly regulates CO_2, therefore the Colorado SIP seems to make clear that PSD provisions apply to any major sources and modifications with respect to CO_2 emissions.*

Thus, not only does the recent EAB decision call into question the validity of the APCD's apparent failure to address CO_2 emissions in order to ensure the Title V Permit assures compliance with PSD requirements under the Clean Air Act and PSD regulations, but it appears as if the APCD's failure to address CO_2 emissions in the context of PSD is contrary to the Colorado SIP. The APCD must therefore address CO_2 emissions to ensure compliance with PSD requirements in the context of the Pawnee coal-fired power plant.

Response: The commenter's reliance upon Prevention of Significant Deterioration (PSD) provisions with respect to the Pawnee Station Title V permit renewal appears to be misplaced. EPA issued a PSD permit for Unit 1 on December 6, 1976. The PSD rules in effect at the time of permit issuance were the December 5, 1974 rules, which only required BACT for particulate matter and sulfur dioxide emissions. Therefore, even if CO_2 were currently considered a regulated pollutant for purposes of the Colorado program and subject to PSD review and BACT, the PSD review requirements would not apply unless a major modification was made. It is not apparent that any such modification has been made to Unit 1 based on current proceedings, and thus PSD would not apply for purposes of CO_2 with respect to this Title V permit action.

Although PSD does not directly apply to this permitting decision, the comment raises certain issues that the Division believes warrant further response. The Air Pollution Control Division is sensitive to issues regarding greenhouse gas emissions and their impact on the environment. The Division is working to address relevant elements of Governor Ritter's Climate Action Plan and related Executive Orders. The regulation of CO_2 under the Clean Air Act and all of its various regulatory programs is a new and evolving issue. For purposes of the Clean Air Act PSD program, Colorado is a SIP-approved program and as such adopts its own rules (which must be at least as stringent as EPA's rules), which must then be submitted to and approved by EPA. Relevant and applicable elements of the state's PSD program are part of the Colorado SIP, including pertinent definitions and express PSD program significance levels for activities subject to the PSD program. The specific provisions of the PSD regulations reflected in Colorado's program, which have been approved by EPA, do not directly regulate CO_2, for example, through significance levels. The regulatory provisions of the PSD program thus do not presently afford an explicit foundation for the Division to evaluate this permit with respect to PSD control provisions for CO_2 emissions. EPA is evaluating whether and how CO_2 may relate to the agency's Clean Air Act regulations, and Colorado is monitoring any related administrative developments in this regard. See, e.g., U.S. E.P.A. Proposed Endangerment and Cause or Contribute Finding for Greenhouse Gases Under Section 202(a) of the Clean Air Act (74 Federal Register 18886, 4/24/09); In re Desert Rock Energy Company, LLC, Notice of Partial Withdrawal of Permit (1/7/09). EPA is presently in the process of evaluating for purposes of national relevance, whether and how CO_2 is to be regulated under the Clean Air Act, and has not made at this time any proposals to do so directly for purposes of the Title V or PSD programs, and has not taken any final agency administrative action that serves to regulate CO_2 under these programs.

Comments were made as to whether the Division inappropriately relied upon the December 18, 2008, Johnson memo for the interpretation of the phrase "subject to regulation".

Although the Division was aware of the Johnson memo at the time that the Operating Permit was drafted, our decision not to include CO_2 in the permit was based on the reasoning set forth in the prior paragraphs and not on the Johnson memo.

The Division notes, however, that the analysis in that EPA memorandum is relevant to the Division in its present permitting considerations, i.e., the Division's implementation practices have maintained consistency with the understanding that the phrase "subject to regulation" does not include pollutants which are only subject to monitoring or reporting requirements. While the Acid Rain Program requires that CO_2 emissions be monitored and reported to EPA and the Division has adopted by reference the Acid Rain Program requirements (40 CFR Parts 72 and 76 have been adopted into Colorado Regulation No. 18 and 40 CFR Part 75 has been adopted into Colorado Regulation No. 6, Part A), the Division does not, as a matter of regulation under the State Act at this time, require monitoring and reporting of CO_2 emissions. We require reporting of criteria and non-criteria reportable pollutants on Air Pollutant Emission Notices (APENS). At this time, under Colorado regulation, CO_2 is neither a criteria nor non-criteria reportable pollutant.

The Division has reviewed the Environmental Appeals Board ("EAB") Deseret Power decision and has the following observations.

In regard to the EAB Deseret Power decision ("Order Denying Review in Part and Remanding in Part" In re: Deseret Power Electric Cooperative, PSD Permit No. PSD-OU-0002-04.00, PSD Appeal No. 07-03, Decided November 13, 2008) the Division does not see any conflict with the decision as it relates to this matter.

The Division acknowledges that the EAB stated:

> More particularly, we reject Sierra Club's contentions that either the plain meaning of the statutory phrase "subject to regulation" as used in sections 165 and 169 or the meaning of the term "regulations" as used in section 821 negates the Agency's authority to interpret "subject to regulation" for purposes of the PSD program and compels an interpretation of the statute that necessarily requires that the Permit contain a CO_2 BACT limit. (EAB at page 26)

The Division also considers that the EAB stated:

> Nevertheless, as explained in detail above, we conclude that the Region's rationale for not imposing a CO_2 BACT limit in the Permit – that it lacked the authority to do so because of an historical Agency interpretation of the phrase "subject to regulation under this Act" as meaning "subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant" – is not supported by the administrative record as defined by 40 C.F.R. § 124.18. Thus, we cannot sustain the Region's permitting decision on the grounds stated in the Region's response to comments. (EAB at page 63)

The Division notes that the EAB stated in conclusion that:

> Accordingly, we remand the Permit for the Region to reconsider whether or not to impose a CO_2 BACT limit in light of the Agency's discretion to interpret, consistent with the CAA, what constitutes a "pollutant subject to regulation under this Act." In remanding this Permit to the Region for

> reconsideration of its conclusions regarding application of BACT to limit CO_2 emissions, we recognize that this is an issue of national scope that has implications far beyond this individual permitting proceeding. The Region should consider whether interested persons, as well as the Agency, would be better served by the Agency addressing the interpretation of the phrase "subject to regulation under this Act" in the context of an action of nationwide scope, rather than through this specific permitting proceeding[fn]. In any event, the Region's analysis on remand should address whether an action of nationwide scope may be required in light of the Agency's prior interpretive statements made in various memoranda and published in the Federal Register and the Agency's regulations. The Region should also consider whether development of a factual record to support its conclusions may be more efficiently accomplished through an action of nationwide scope, rather than through this as well as subsequent permitting proceedings.

. . .

> [fn]. Since these same issues have been raised in a multiplicity of permit proceedings, an action of nationwide scope would also seem more efficient than addressing the issues in each individual proceeding. Once the Agency's position is clearly established, it could then be implemented in the various individual permit proceedings, current and future, through the Part 124 procedures.

> (EAB at pages 63-64)

The above discussion of the Johnson memo, the EAB decision, and the present EPA deliberations around whether CO_2 is to be regulated under the Clean Air Act, supports the Division's position that, even if this permit were currently subject to PSD review, the regulatory provisions of the PSD program in the State Act would not presently afford an explicit foundation for the Division to evaluate this permit with respect to PSD control provisions for CO_2 emissions. Moreover, at this time the Division is not interpreting the state regulatory provisions as implying that CO_2 is a regulated pollutant under the Act. The Division agrees that domestic greenhouse gas emissions are an issue of national significance, and are thus better suited for federal action of national scope in the first instance, rather than individual permitting decisions made by the individual states.

Finally, the Division notes that this is a Title V renewal permit for an existing facility. As such, this permitting action differs significantly from that of the Deseret plant or the Desert Rock facility and other new facilities that are subject to PSD review. The Pawnee permit houses currently applicable federal and state requirements. The Pawnee permit will be amended to include new requirements when they become applicable including, potentially, regulation of CO_2 emissions.

For all of the foregoing reasons, the Division is thus not proposing to regulate CO_2 emissions in this Title V permit at this time.

10. The Title V Permit Fails to Meet Clean Water Act 401 Certification Requirements

Comment: *Section 401 of the Clean Water Act requires that, "Any applicant for a Federal license or permit to conduct any activity including, but not limited to, the construction or operation of facilities, which may result in any discharge into the navigable waters," shall provide a certification to the State in which the discharge originates that any discharge will comply with sections 301, 302, 303, 306, and 307 of the Clean Water Act. In this case, the APCD has failed to ensure that air pollution from the Pawnee coal-fired power plant will be limited such that waters designated as outstanding within Rocky Mountain National Park will be protected pursuant to section 303 of the Clean Water Act. All streams in Rocky Mountain National Park have been designated as "outstanding waters" by the Colorado Water Quality Control Commission ("WQCC") pursuant to section 303 of the Clean Water Act. See WQCC Regulation No. 38. Of particular concern is that Public Service Company of Colorado has not certified that the discharge of NOx emissions from the Pawnee coal-fired power plant, which contribute to nitrogen deposition in the streams and lakes of Rocky Mountain National Park, will comply with Colorado Water Quality Control Commission Standards that have been established pursuant to section 303 of the Clean Water Act.*

Under the Clean Water Act, the APCD cannot renew the Title V Permit for the Pawnee coal-fired power plant until Public Service Company of Colorado can certify that its discharge of NOx emissions will protect the outstanding waters within Rocky Mountain National Park.

Response: A Title V operating permit is issued under the provisions of the Clean Air Act and is required to include all applicable requirements for a facility. Requirements under the Clean Water Act do not meet the definition of applicable requirements in Colorado Regulation No. 3, Part A, Section I.B.9. Therefore, Clean Water Act requirements should not be included in Title V operating permits, and the Division does not need to verify that the facility is complying with any allegedly applicable Clean Water Act requirements prior to issuing a Title V operating permit.

The next step for this draft permit is to forward it to EPA for their 45-day review period. We appreciate that you took the time to thoroughly review this draft. Please feel free to call me at (303) 692-3267 if you have any further questions.

Sincerely,

Jacqueline Joyce

Jacqueline Joyce
Permit Engineer
Operating Permit Unit
Stationary Sources Program
Air Pollution Control Division

cc: Chad Campbell, Xcel Energy

Exhibit 7 to Title V Petition

UNITED STATES DISTRICT COURT
MIDDLE DISTRICT OF FLORIDA

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	CIVIL ACTION NO. 99-2524
v.	)	CIV-T-23F
	)	
	)	
TAMPA ELECTRIC COMPANY,	)	
	)	
Defendant.	)	
	)	

CONSENT DECREE

WHEREAS, Plaintiff, the United States of America (Plaintiff or the United States), on behalf of the United States Environmental Protection Agency (EPA) filed a Complaint on November 3, 1999, alleging that Defendant, Tampa Electric Company (Tampa Electric) commenced construction of major modifications of major emitting facilities in violation of the Prevention of Significant Deterioration (PSD) requirements at Part C of the Clean Air Act (Act), 42 U.S.C. §§ 7470-7492;

WHEREAS, EPA issued a Notice of Violation with respect to such allegations to Tampa Electric on November 3, 1999 (the NOV);

WHEREAS, the parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm s length; that the parties have voluntarily agreed to this Consent Decree; that implementation of this Consent Decree will avoid prolonged and complicated litigation between the parties; and that this Consent Decree is fair, reasonable, consistent with the goals of the Act, and in the public interest;

WHEREAS, the United States alleges that the Complaint states a claim upon which relief can be granted against Tampa Electric under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, Tampa Electric has not answered or otherwise responded to the Complaint in light of the settlement memorialized in this Consent Decree;

WHEREAS, Tampa Electric has denied and continues to deny the violations alleged in the NOV and the Complaint; maintains that it has been and remains in compliance with the Clean Air Act and is not liable for civil penalties or injunctive relief; and states that it is agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation and to improve the environment in and around the Tampa Bay area of Florida;

WHEREAS, Tampa Electric is the first electric utility of those against which the United States brought enforcement actions in November, 1999, to come forward and invest time and effort sufficient to develop a settlement with the United States;

WHEREAS, Tampa Electric s decision to Re-Power some of its coal-fired electric generating Units with natural gas will significantly reduce emissions of both regulated and unregulated pollutants below levels that would have been achieved merely by installing appropriate pollution control technologies on Tampa Electric s existing coal-fired electric generating Units;

WHEREAS, prior to the filing of the Complaint or issuance of the Notice of Violation in this matter, Tampa Electric already had placed in service or installed both scrubbers and electrostatic precipitators that serve all existing coal-fired electric generating Units at the company s Big Bend electric generating plant;

WHEREAS, the United States recognizes that a BACT Analysis conducted under existing procedures most likely would not find it cost effective to replace Tampa Electric s existing control equipment at Big Bend for particulate matter, in light of the design and performance of that equipment;

WHEREAS, Tampa Electric and the United States have crafted this Consent Decree to take into account physical and operational constraints resulting from the unique, Riley Stoker wet bottom, turbo-fired boiler technology now in operation at Big Bend, which could limit the efficiency of nitrogen oxides emissions controls installed for those boilers;

WHEREAS, Tampa Electric regularly combusts coal with a sulphur content of five or six pounds per mmBTU heat input;

WHEREAS, Tampa Electric is a mid-sized electric utility and is smaller on a financial basis than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, Tampa Electric owns and operates fewer coal-fired electric generating plants than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, the two Tampa Electric plants addressed by this enforcement action constitute over ninety percent of the entire base load generating capacity of Tampa Electric;

WHEREAS, the United States and Tampa Electric have agreed that settlement of this action is in the best interest of the parties and in the public interest, and that entry of this Consent

Decree without further litigation is the most appropriate means of resolving this matter; and

WHEREAS, the United States and Tampa Electric have consented to entry of this Consent Decree without trial of any issue;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaint or NOV, it is hereby ORDERED AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter herein and over the parties consenting hereto pursuant to 28 U.S.C. § 1345 and pursuant to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying Complaint, Tampa Electric waives all objections and defenses that it may have to the claims set forth in the Complaint, the jurisdiction of the Court or to venue in this District. Tampa Electric shall not challenge the terms of this Consent Decree or this Court s jurisdiction to enter and enforce this Consent Decree. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the United States and Tampa Electric. Tampa Electric consents to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. The provisions of this Consent Decree shall apply to and be binding upon the United

States and upon Tampa Electric, its successors and assigns, and Tampa Electric s officers, employees and agents solely in their capacities as such. If Tampa Electric proposes to sell or transfer any of its real property or operations subject to this Consent Decree, it shall advise the purchaser or transferee in writing of the existence of this Consent Decree, and shall send a copy of such written notification by certified mail, return receipt requested, to EPA sixty (60) days before such sale or transfer. Tampa Electric shall not be relieved of its responsibility to comply with all requirements of this Consent Decree unless the purchaser or transferee assumes responsibility for full performance of Tampa Electric s responsibilities under this Consent Decree, including liabilities for nonperformance. Tampa Electric shall not purchase or otherwise acquire capacity and/or energy from a third party in lieu of obtaining it from Gannon or Big Bend unless the seller or provider agrees that the facilities providing such capacity and/or energy will meet the emission control requirements set forth in this Consent Decree or equivalent requirements approved in advance by the United States.

3. Tampa Electric shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization performing any of the work described in Sections IV or VII of this Consent Decree. Notwithstanding any retention of contractors, subcontractors or agents to perform any work required under this Consent Decree, Tampa Electric shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, Tampa Electric shall not assert as a defense the failure of its employees, servants, agents, or contractors to take actions

necessary to comply with this Consent Decree, unless Tampa Electric establishes that such failure resulted from a Force Majeure event as defined in this Consent Decree.

III. DEFINITIONS

4. Alternative Coal shall mean coal with a sulphur content of no more than 2.2 lb/mmBTU, on an as determined basis.

5. BACT Analysis shall mean the technical study, analysis, review, and selection of recommendations typically performed in connection with an application for a PSD permit. Except as otherwise provided in this Consent Decree, such study, analysis, review, and selection of recommendations shall be carried out in conformance with applicable federal and state regulations and guidance describing the process and analysis for determining Best Available Control Technology (BACT).

6. Big Bend shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric and located in Hillsborough County, Florida, which presently includes four steam generating boilers and associated and ancillary systems and equipment, known as Big Bend Units 1, 2, 3, and 4.

7. Consent Decree shall mean this Consent Decree and the Appendix thereto.

8. Emission Rate shall mean the average number of pounds of pollutant emitted per million BTU of heat input (lb/mmBTU) or the average concentration of a pollutant in parts per million by volume (ppm), as dictated by the unit of measure specified for the rate in question, where:

A. in the case of a coal-fired, steam electric generating unit, such rates shall be calculated as a 30 day rolling average. A 30 day rolling average for an Emission Rate expressed as lb/mmBTU shall be determined by calculating the emission rate for a given operating day, and then arithmetically averaging the emission rates for the previous 29 operating days with that date. A new 30 day rolling average shall be calculated for each new operating day;

B. in the case of a gas-fired, electric generating unit, such rates shall be calculated as a 24-hour rolling average, excluding periods of start up, shutdown, and malfunction as provided by applicable Florida regulations at the time the Emission Rate is calculated. A rolling average for Emission Rates expressed as ppm shall be determined on a given day by summing hourly emission rates for the immediately preceding 24-hour period and dividing by 24;

C. the reference methods for determining Emission Rates for SO_2 and NO_x shall be those specified in 40 C.F.R. Part 75, Appendix F. The reference methods for determining Emission Rates for PM shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, Method 5B, or Method 17; and

D. nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by methods other than the reference methods specified herein.

9. EPA shall mean the United States Environmental Protection Agency.

10. Gannon shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric, located in Hillsborough County, Florida, which presently includes six steam generating boilers and associated and ancillary systems and

equipment, known as Gannon Units 1, 2, 3, 4, 5, and 6. Tampa Electric intends to rename Gannon Bayside Power Station upon completion of the Re-Powering required under this Consent Decree.

11. lb/mmBTU shall mean pounds per million British Thermal Units of heat input.

12. NOx shall mean oxides of nitrogen.

13. NOV shall mean the Notice of Violation issued by EPA to Tampa Electric dated November 3, 1999.

14. PM shall mean total particulate matter, and the reference method for measuring PM shall be that specified in the definition of Emission Rate in this Consent Decree.

15. ppm shall mean parts per million by dry volume, corrected to 15% O_2.

16. Project Dollars shall mean Tampa Electric s expenditures and payments incurred or made in carrying out the dollar-limited projects identified in Paragraph 35 of Section IV of this Consent Decree (Early Reductions of NO_x from Big Bend Units 1 through 3) and in Section VII of this Consent Decree (NO_x Reduction Projects and Mitigation Projects), to the extent that such expenditures or payments both: (A) comply with the Project Dollar and other requirements set by this Consent Decree for such expenditures and payments in Section VII and in Paragraph 35 of Section IV of this Consent Decree, and (B) constitute either Tampa Electric s properly documented external costs for contractors, vendors, as well as equipment, or its internal costs consisting of employee time, travel, and other out-of-pocket expenses specifically attributable to these particular projects.

17. PSD shall mean Prevention of Significant Deterioration within the meaning of Part C of the Clean Air Act, 42 U.S.C. §§ 7470, et seq.

18. Re-Power shall mean the removal or permanent disabling of devices, systems, equipment, and ancillary or supporting systems at a Gannon or Big Bend Unit such that the Unit cannot be fired with coal, and the installation of all devices, systems, equipment, and ancillary or supporting systems needed to fire such Unit with natural gas under the limits set in this Consent Decree (or with No. 2 fuel oil, as a back up fuel only, and under the limits specified by this Consent Decree) plus installation of the control technology and compliance with the Emission Rates called for under this Consent Decree.

19. Reserve / Standby shall mean those devices, systems, equipment, and ancillary or supporting systems that: (1) are not used as part of the Units that must be Re-Powered under Paragraph 26, (2) are not in operation subsequent to the Re-Powering required under Paragraph 26, (3) are maintained and held by Tampa Electric for system reliability purposes, and (4) may be restarted only by Re-Powering.

20. SCR shall mean Selective Catalytic Reduction.

21. Shutdown shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel nor produce any steam for electricity production, other than through Re-Powering.

22. S O_2" shall mean sulphur dioxide.

23. Title V Permit shall mean the permit required under Subchapter V of the Clean Air Act, 42 U.S.C. § 7661, et seq.

24. Total Baseline Emissions shall mean calendar year 1998 emissions of NO_x, SO_2, and PM comprised of the following amounts for each pollutant:

A. for Gannon: 30,763 tons of NO_x, 64,620 tons of SO_2, and 1,914 tons of PM; and

B. for Big Bend: 36,077 tons of NO_x, 107,334 tons of SO_2, and 3,002 tons of PM.

25. Unit shall mean for the purpose of this Consent Decree a generator, the steam turbine that drives the generator, the boiler that produces the steam for the steam turbine, the equipment necessary to operate the generator, turbine and boiler, and all ancillary equipment, including pollution control equipment or systems necessary for the production of electricity. An electric generating plant may be comprised of one or more Units.

IV. EMISSIONS REDUCTIONS AND CONTROLS GANNON AND BIG BEND

A. GANNON

26. Consent Decree-Required Re-Powering of Gannon. Tampa Electric shall Re-Power Units at Gannon with a coal-fired generating capacity of no less than 550 MW (Megawatt), as follows.

A. On or before May 1, 2003, Tampa Electric shall Re-Power Units with a coal-fired generating capacity of no less than 200 MW. On or before December 31, 2004, Tampa Electric shall Re-Power additional Units with a coal-fired generating capacity equal to or greater than the difference between 550 MW of coal-fired generating capacity and the MW value of coal-fired generating capacity that Tampa Electric Re-Powered in complying with the first sentence of this

Subparagraph A.

B. All Re-Powering required by this Paragraph shall include installation and operation of SCR, other pollution control technology approved in advance and in writing by EPA, or any innovative technology demonstration project approved pursuant to Paragraph, 52.C to control Unit emissions. Each Re-Powered Unit shall, in conformance with the definition of Re-Power, use natural gas as its primary fuel and shall meet an Emission Rate for NO_x of no greater than 3.5 ppm.

C. A Unit Re-Powered under this or any other provision of this Consent Decree may be fired with No. 2 fuel oil if and only if: (1) the Unit cannot be fired with natural gas; (2) the Unit has not yet been fired with No. 2 fuel oil as a back up fuel for more than 875 full load equivalent hours in the calendar year in which Tampa Electric wishes to fire the Unit with such oil; (3) the oil to be used in firing the Unit has a sulphur content of less than 0.05 percent (by weight); (4) Tampa Electric uses all emission control equipment for that Unit when it is fired with such oil to the maximum extent possible; and (5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.

D. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing such Re-Powering. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA-approved control technology and a NO_x Emission Rate no greater than 3.5 ppm.

27. Schedule for Shutdown of Units. Tampa Electric shall Shutdown and cease any and all operation of all six (6) Gannon coal-fired boilers with a combined coal-fired capacity of not less than 1194 MW on or before December 31, 2004. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby, unless such Unit is to be, or has been, Re-Powered under Paragraph 26, above. If Tampa Electric later decides to restart any Shutdown Unit retained on Reserve / Standby, then prior to such re-start, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit to meet the NO_x Emission Rate established in the PSD Permit or an Emission Rate for NO_x of 3.5 ppm, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). For any Unit Shutdown and placed on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any such Unit, complies with all requirements issued in such a permit, and complies with all other requirements of this Consent Decree applicable to Re-Powering.

28. Permanent Bar on Combustion of Coal. Commencing on January 1, 2005, Tampa

Electric shall not combust coal in the operation of any Unit at Gannon.

B. <u>BIG BEND</u>

29. Initial Reduction and Control of SO_2 Emissions from Big Bend Units 1 and 2. Commencing upon the later of the date of entry of this Consent Decree or September 1, 2000, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 1 and 2 at all times that either Unit 1 or 2 is in operation. Tampa Electric shall operate the scrubber so that at least 95% of all the SO_2 contained in the flue gas entering the scrubber is removed. Notwithstanding the requirement to operate the scrubber at all times Unit 1 or 2 is operating, the following operating conditions shall apply:

A. Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric:

(1) in calendar year 2000, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than sixty (60) calendar days, or any part thereof (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the sixty (60) day limit), and in calendar years 2001 - 2009, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than forty-five (45) calendar days, or any part thereof, in any calendar year (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the forty-five (45) day limit) ; or

(2) must operate Unit 1 and/or 2 in any calendar year from 2000 through 2009 either to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 1 and/or 2 to meet such emergency.

B. Whenever Tampa Electric operates Units 1 and/or 2 without all emissions from such Unit(s) being treated by the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at the Unit(s) operating during the outage (except for coal already bunkered in the hopper(s) for Units 1 or 2 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Units1 and/or 2; and (3) continue to control SO_2 emissions from Big Bend Units 1 and/or 2 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3).

C. In calendar years 2010 through 2012, Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric complies with the requirements of Subparagraphs A and B, above, and uses only coal with a sulphur content of 1.2 lb/mmBTU, or less, in place of

Alternative Coal.

D. If Tampa Electric Re-Powers Big Bend Unit 1 or 2, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon such compliance the provisions of Subparagraphs 29.A, 29.B, and 29.C shall not apply to the affected Unit.

30. Initial Reduction and Control of SO_2 Emissions from Big Bend Unit 3. Commencing upon entry of the Consent Decree, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 3 and 4 at all times that Unit 3 is in operation. When Big Bend Units 3 and 4 are both operating, Tampa Electric shall operate the scrubber so that at least 93% of all the SO_2 contained in the flue gas entering the scrubber is removed. When Big Bend Unit 3 alone is operating, until May 1, 2002, Tampa Electric shall operate the scrubber so that at least 93% of all SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 for Unit 3 does not exceed 0.35 lb/mmBTU. When Unit 3 alone is operating, from May 1, 2002 until January 1, 2010, Tampa Electric shall operate the scrubber so that at least 95% of the SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 does not exceed 0.30 lb/mmBTU. Notwithstanding the requirement to operate the scrubber at all times Unit 3 is operating, and providing Tampa Electric is otherwise in compliance with this Consent Decree, the following operating conditions shall apply:

A. In any calendar year from 2000 through 2009, Tampa Electric may operate Unit 3 in the case of outages of the scrubber serving Unit 3, but only so long as Tampa

Electric:

(1) does not operate Unit 3 during outages on more than thirty (30) calendar days, or any part thereof, in any calendar year; or

(2) must operate Unit 3 either: to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 3 to meet such emergency.

B. Whenever Tampa Electric operates Unit 3 without treating all emissions from that Unit with the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at Unit 3 during the outage (except for coal already bunkered in the hopper(s) for Unit 3 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Unit 3; and (3) continue to control SO_2 emissions from Big Bend Unit 3 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units, 1, 2, and 3).

C. If Tampa Electric Re-Powers Big Bend Unit 3, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon compliance with Paragraph 40 the provisions of Subparagraphs 30.A and 30.B shall not apply to Unit 3.

D. Nothing in this Consent Decree shall alter requirements of the New Source Performance Standards (NSPS), 40 C.F.R. Part 60 Subpart Da, that apply to operation of the scrubber serving Unit 4.

31. Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3. Tampa Electric shall maximize the availability of the scrubbers to treat the emissions of Big Bend Units 1, 2, and 3, as follows:

A. As soon as possible after entry of this Consent Decree, Tampa Electric shall submit to EPA for review and approval a plan addressing all operation and maintenance changes to be made that would maximize the availability of the existing scrubbers treating emissions of SO_2 from Big Bend Units 1 and 2, and from Unit 3. In order to improve operations and maintenance practices as soon as possible, Tampa Electric may submit the plan in two phases.

(1) Each phase of the plan proposed by Tampa Electric shall include a schedule pursuant to which Tampa Electric will implement measures relating to operation and maintenance of the scrubbers called for by that phase of the plan, within sixty days of its approval by EPA. Tampa Electric shall implement each phase of the plan as approved by EPA. Such plan may be modified from time to time with prior written approval of EPA.

(2) The proposed plan shall include operation and maintenance activities that will minimize instances during which SO_2 emissions are not scrubbed, including but not limited to improvements in the flexibility of scheduling maintenance on the

scrubbers, increases in the stock of spare parts kept on hand to repair the scrubbers, a commitment to use of overtime labor to perform work necessary to minimize periods when the scrubbers are not functioning, and use of all existing capacity at Big Bend and Gannon Units that are served by available, operational pollution control equipment to minimize pollutant emissions while meeting power needs.

(3) If Tampa Electric elects to submit the plan to EPA in two phases, the first phase to be submitted shall address, at a minimum, use of overtime hours to accomplish repairs and maintenance of the scrubber and increasing the stock of scrubber spare parts that Tampa Electric shall keep at Big Bend to speed future maintenance and repairs. If Tampa Electric elects to submit the plan in two phases, EPA shall complete review of the first phase within fifteen business days of receipt. For the second phase of the plan or submission of the plan in its entirety, EPA shall complete review of such plan or phase thereof within 60 days of receipt. Within sixty days after EPA s approval of the plan or any phase of the plan, Tampa Electric shall complete implementation of that plan or phase and continue operation under it subject only to the terms of this Consent Decree.

32. PM Emission Minimization and Monitoring at Big Bend.

A. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete an optimization study which shall recommend the best operational practices to minimize emissions from each Electrostatic Precipitator (ESP) and shall deliver the completed study to EPA for review and approval. Tampa

Electric shall implement these recommendations within sixty days after EPA has approved them and shall operate each ESP in conformance with the study and its recommendations until otherwise specified under this Consent Decree.

B. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete a BACT Analysis for upgrading each existing ESP now located at Big Bend and shall deliver the Analysis to EPA for review and approval. Notwithstanding the definition of BACT Analysis in this Consent Decree, Tampa Electric need not consider in this BACT Analysis the replacement of any existing ESP with a new ESP, scrubber, or baghouse, or the installation of a supplemental pollution control device of similar cost to a replacement ESP, scrubber, or baghouse. Tampa Electric shall simultaneously deliver to EPA all documents that support the BACT Analysis or that were considered in preparing the Analysis. Tampa Electric shall retain a qualified contractor to assist in the performance and completion of the BACT Analysis. On or before May 1, 2004, after EPA approval of the recommendation(s) made by the BACT Analysis, Tampa Electric shall complete installation of all equipment called for in the recommendation(s) of the Analysis and thereafter shall operate each ESP in conformance with the recommendation(s), including compliance with the Emission Rate(s) specified by the recommendation(s).

C. Within six months after Tampa Electric completes installation of the equipment called for by the BACT Analysis, as approved by EPA, Tampa Electric shall revise the previous optimization study and shall recommend the best operational practices to minimize emissions from each ESP, taking into account the recommendations from the BACT Analysis required by this Paragraph, and shall deliver the completed study to EPA for review and approval. Commencing no later than 180 days after EPA approves the study and its recommendation(s), Tampa Electric shall operate each ESP in conformance with the study s recommendation.

D. Tampa Electric shall include the recommended operational practices for each ESP and the recommendations from the BACT Analysis in Tampa Electric s Title V Permit application and all other relevant applications for operating or construction permits.

E. Installation and Operation of a PM Monitor. On or before March 1, 2002, Defendant shall install, calibrate, and commence continuous operation of a continuous particulate matter emissions monitor (PM CEM) in the duct at Big Bend that services Unit 4. Data from the PM CEM shall be used by Tampa Electric, at a minimum, to monitor progress in reducing PM emissions.

F. Continuous operation of the PM CEM shall mean operation at all times that Unit 4 operates, except for periods of malfunction of the PM CEM or routine maintenance performed on the PM CEM. If after Tampa Electric operates this PM CEM for at least two years, and if the parties then agree that it is infeasible to sustain continuous operation of the PM CEM, Tampa Electric shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall include an explanation of the basis for stopping operation of the PM CEM and a proposal for an alternative monitoring protocol. Until EPA approves such plan, Tampa Electric shall continue to operate the PM CEM.

G. Installation and Operation of Second PM Monitor. If Tampa Electric advises EPA, pursuant to Paragraph 36, that it has elected to continue to combust coal at Big Bend Units 1, 2, or 3, and Tampa Electric has not ceased operating the first PM CEM as described in Subparagraph F, above, then Tampa Electric shall install, calibrate, and commence continuous operation of a PM CEM on a second duct at Big Bend on or before May 1, 2007. The requirement to operate a PM CEM under any provision of this Paragraph shall terminate if and when the Unit monitored by the PM CEM is Re-Powered.

H. Testing and Reporting Requirement. Prior to installation of the PM CEM on each duct, Tampa Electric shall conduct a stack test on each stack at Big Bend on at least an annual basis and report its results to EPA as part of the quarterly report under Section V. The stack test requirement in this Subparagraph may be satisfied by Tampa Electric s annual stack tests conducted as required by its permit from the State of Florida. Following installation of each PM CEM, Defendant shall include in its quarterly reports to EPA pursuant to Section V all data recorded by the PM CEM, in electronic format, if available.

I. Nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by the PM CEMs.

33. Election for Big Bend Unit 4: Shutdown, Re-Power, or Continued Combustion of Coal.

Tampa Electric shall advise EPA in writing, on or before May 1, 2005, whether Big Bend Unit 4 will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

34. <u>Reduction of NO_x at Big Bend Unit 4 after 2005 Election</u>. Based on Tampa Electric s election in Paragraph 33, Tampa Electric shall take one of the following actions:

A. If Tampa Electric elects to continue firing Unit 4 with coal, on or before June 1, 2007, Tampa Electric shall install and commence operation of SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the coal-fired Emission Rate of NO_x from Unit 4 to no more than 0.10 lb/mmBTU. Thereafter, Tampa Electric shall continue operation of SCR or other EPA approved control technology, and Tampa Electric shall continue to meet an Emission Rate for NO_x from Unit 4 no greater than 0.10 lb/mmBTU; or

B. If Tampa Electric elects to Re-Power Unit 4, Tampa Electric shall not combust coal at Unit 4 on or after June 1, 2007. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of the Re-Powering of Unit 4. In applying for such permit, Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent; or

C. If Tampa Electric elects to Shutdown Big Bend Unit 4, Tampa Electric shall complete Shutdown of Big Bend Unit 4 on or before June 1, 2007.

Notwithstanding the requirements of this Subparagraph, Tampa Electric may retain this Unit, after it is Shutdown pursuant to this Subparagraph, on Reserve / Standby. If Tampa Electric later decides to restart Unit 4 then, prior to such restart, Tampa Electric shall timely apply for a PSD permit, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Subparagraph, Tampa Electric may never again use coal to fire that Unit.

D. Notwithstanding the provisions of Subparagraphs B and C above or the definition of Re-Power in this Consent Decree, Tampa Electric may also elect to fuel Big Bend Unit 4 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in this Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

35. <u>Early Reductions of NO_x from Big Bend Units 1 through 3</u>: On or before December 31, 2001, Tampa Electric shall submit to EPA for review and comment a plan to reduce NO_x emissions from Big Bend Units 1, 2 and 3, through the expenditure of up to $3 million

Project Dollars on combustion optimization using commercially available methods, techniques, systems, or equipment, or combinations thereof. Subject only to the financial limit stated in the previous sentence, for Units 1 and 2 the goal of the combustion optimization shall be to reduce the NO_x Emission Rate by at least 30% when compared against the NO_x Emissions Rate for these Units during calendar year 1998, which the United States and Tampa Electric agree was 0.86 lb/mmBTU. For Unit 3 the goal of the combustion optimization shall be to reduce the NO_x Emissions Rate by at least 15% when compared against the NO_x Emission Rate for this Unit during calendar year 1998, which the United States and Tampa Electric agree was 0.57 lb/mmBTU. If the financial limit in this Paragraph precludes designing and installing combustion controls that will meet the percentage reduction goals for the NO_x Emission Rates specified in this Paragraph for all three Units, then Tampa Electric s plan shall first maximize the Emission Rate reductions at Units 1 and 2 and then at Unit 3. Unless the United States has sought dispute resolution on Tampa Electric s plan on or before May 30, 2002, Tampa Electric shall implement all aspects of its plan at Big Bend Units 1, 2, and 3 on or before December 31, 2002. On or before April 1, 2003, Tampa Electric shall submit to EPA a report that documents the date(s) of complete implementation of the plan, the results obtained from implementing the plan, including the emission reductions or benefits achieved, and the Project Dollars expended by Tampa Electric in implementing the plan.

36. Election for Big Bend Units 1 through 3: Shutdown, Re-Power, or Continued Combustion of Coal. Tampa Electric shall advise EPA in writing, on or before May 1,

2007, whether Big Bend Units 1, 2, or 3, or any combination of them, will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

37. Further NO_x Reduction Requirements if Big Bend Units 1, 2, and/or 3 Remain Coal-fired. If Tampa Electric advises EPA in writing, pursuant to Paragraph 36, above, that Tampa Electric will continue to combust coal at Units 1, 2, and/or 3, then:

A. Subject only to Subparagraphs B and D, Tampa Electric shall timely solicit contract proposals to acquire, install, and operate SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the Emission Rate of NO_x to no more than 0.10 lb/mmBTU at each Unit that will combust coal. Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve an Emission Rate of NO_x on each such Unit no less stringent than 0.10 lb/mmBTU.

B. Notwithstanding Subparagraph A, Tampa Electric shall not be required to install SCR to limit the Emission Rate of NO_x at Units 1, 2 and/or 3 to 0.10 lb/mmBTU if the installation cost ceiling contained in this Paragraph will be exceeded by such installation. If Tampa Electric decides to continue burning coal at Units 1, 2 and 3, the installation cost ceiling for SCR at Units 1, 2, and 3 shall be three times the cost of installing SCR at Big Bend Unit 4 plus forty-five (45%) percent of the cost of installing SCR at Big Bend 4. If Tampa Electric decides to continue burning coal at only two Units at Big Bend, the installation cost ceiling for SCR at those two Units shall be two times the cost of installing SCR at Big Bend 4 plus forty-five (45) percent of the cost of installing SCR at Big Bend Unit 4. If

Tampa Electric decides to continue burning coal at only one Unit at Big Bend, the installation cost ceiling for SCR at that Unit shall be the cost of installing SCR at Big Bend 4 plus forty five (45) percent.

C. If, based on the contract proposals obtained under Subparagraph A, Tampa Electric determines that the projected cost of proposed control equipment satisfying a 0.10 lb/mmBTU Emission Rate will not exceed the installation cost ceiling, Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve a NO_x Emission Rate on each Unit no less stringent than 0.10 lb/mmBTU. If, based on the contract proposals, Tampa Electric determines that the projected cost will exceed the installation cost ceiling, Tampa Electric shall so advise EPA and shall provide EPA with the basis for Tampa Electric s determination, including all documentation sufficient to replicate and evaluate Tampa Electric s cost projections.

D. Unless EPA contests Tampa Electric s determination that the installation cost ceiling will be exceeded by installing control equipment to reduce NO_x emissions to 0.10 lb/mmBTU or less, Tampa Electric shall install, at each Unit that will continue to combust coal, the NO_x control technology designed to achieve the lowest Emission Rate that can be attained within the installation cost ceiling. Notwithstanding any provision of this Consent Decree, including the installation cost ceiling, Tampa Electric shall install NO_x control technology that is designed to achieve an Emission Rate no less stringent than 0.15 lb/mmBTU. Each Unit combusting coal and its NO_x controls shall meet the Emission Rate for which they are designed.

E. Tampa Electric shall acquire, install, commence operating emission control equipment, and meet the applicable Emission Rate for NO_x at each of the Units to remain coal-fired, as follows: (1) for the first of the Units to remain coal-fired, or if only one Unit is to be coal-fired, on or before May 1, 2008; (2) for the second Unit, if there is one, on or before May 1, 2009; (3) for the third Unit, if there is one, on or before May 1, 2010.

38. Tampa Electric s NO_x Reduction Requirements if Tampa Electric Re-Powers Units 1, 2, and/or 3 . If, by May 1, 2007, Tampa Electric advises EPA that Tampa Electric has elected to Re-Power one or more of Units 1, 2, and 3 at Big Bend, then Tampa Electric shall complete all steps necessary to accomplish such Re-Powering in a time frame to commence operation of the Re-Powered Unit(s) no later than May 1, 2010. Any Unit(s) to be replaced by a Re-Powered Unit may continue to operate until the earlier of six months after the date the Re-Powered Unit begins commercial operation or December 31, 2010. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of any Re-Powered Unit at Big Bend. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate any Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent. Notwithstanding the provisions of this Paragraph or the definition of Re-Power in this

Consent Decree, Tampa Electric may also elect to fuel Units 1, 2, or 3 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in any of these Units, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

39. Requirements Applicable to Big Bend Units 1, 2, and/or 3 if Shutdown. If Tampa Electric elects to Shutdown one or more of Units1, 2, and 3, Tampa Electric shall complete Shutdown of the first such Unit on or before May 1, 2008; of the second Unit, if applicable, on or before May 1, 2009, and of the third Unit, if applicable, on or before May 1, 2010. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby. If Tampa Electric later decides to restart such Unit retained on Reserve / Standby by Re-Powering it then, prior to such restart, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as result of that application, including installation of BACT and its corresponding Emission Rate determined at the time of the restart. Tampa Electric shall operate each Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Paragraph, Tampa Electric may never again use coal to fire that Unit.

For any Unit Shutdown and placed on on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any of such Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

40. Further SO_2 Reduction Requirements if Big Bend Units 1, 2, or 3 Remains Coal-fired. If Tampa Electric elects under Paragraph 36 to continue combusting coal at Units 1, 2, and/or 3, Tampa Electric shall meet the following requirements.

A. Removal Efficiency or Emission Rate. Commencing on dates set forth in Subparagraph C and continuing thereafter, Tampa Electric shall operate coal-fired Units and the scrubbers that serve those Units so that emissions from the Units shall meet at least one of the following limits:

(1) the scrubber shall remove at least 95% of the SO_2 in the flue gas that entered the scrubber; or

(2) the Emission Rate for SO_2 from each Unit does not exceed 0.25 lb/mmBTU.

B. Availability Criteria. Commencing on the deadlines set in this Paragraph and continuing thereafter, Tampa Electric shall not allow emissions of SO_2 from Big Bend Units 1, 2, or 3 without scrubbing the flue gas from those Units and using other equipment designed to control SO_2 emissions. Notwithstanding the preceding sentence, to the extent that the Clean Air Act New Source Performance Standards identify circumstances during which Bend Unit 4 may operate without its scrubber, this Consent Decree shall allow Big Bend Units1, 2, and/or 3 to operate when those same circumstances are present at Big Bend Units 1, 2, and/or 3.

C. Deadlines. Big Bend Unit 3 and the scrubber(s) serving it shall be subject to the requirements of this Paragraph beginning January 1, 2010 and continuing thereafter. Until January 1, 2010, Tampa Electric shall control $S0_2$ emissions from Unit 3 as required by Paragraphs 30 and 31. Big Bend Units 1 and 2 and the scrubber(s) serving them shall be subject to the requirements of this Paragraph beginning January 1, 2013 and continuing thereafter. Until January 1, 2013, Tampa Electric shall control $S0_2$ emissions from Units 1 and 2 as required by Paragraphs 29 and 31.

D. Nothing in this Consent Decree shall alter requirements of NSPS, 40 C.F.R. Part 60 Subpart Da, that apply to operation of Unit 4 and the scrubber serving it.

C. BIG BEND AND GANNON -- PERMITS AND RESOLUTION OF CLAIMS

41. Timely Application for Permits. Except as otherwise stated in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Tampa Electric to secure a permit to authorize constructing or operating any device under this Consent Decree, Tampa Electric shall make such application in a timely manner. Such applications shall be completed and submitted to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request. Failure to comply with this provision shall bar any use by Tampa Electric of the Force

Majeure provisions of this Consent Decree.

42. Title V Permits.

A. On or before January 1, 2004, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Gannon, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

B. On or before January 1, 2009, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Big Bend, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

C. Except as this Consent Decree expressly requires otherwise, this Consent Decree shall not be construed to require Tampa Electric to apply for or obtain a permit pursuant to the Prevention of Significant Deterioration requirements of the Clean Air Act for any work performed by Tampa Electric within the scope of the Resolution of Claims provisions of Paragraphs 43 and 44, below.

43. Resolution of Past Claims - This Consent Decree resolves all of Plaintiff s civil claims

for liability arising from violations of either: (1) the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401, <u>et seq</u> at Units at Big Bend or Gannon, or (2) 40 C.F.R. Section 60.14 at Units at Big Bend or Gannon, that :

A. are alleged in the Complaint filed November 3, 1999, or in the NOV issued on that date;

B. could have been alleged by the United States in the Complaint filed November 3, 1999, or in the NOV issued on that date; or

C. have arisen from Tampa Electric s actions that occurred between November 3, 1999 and the date on which this Consent Decree is entered by the Court.

44. <u>Resolution of Future Claims - Covenant not to Sue</u>. The United States covenants not to sue Tampa Electric for civil claims arising from the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401 <u>et seq</u>., at Big Bend or Gannon Units and that are based on failure to obtain PSD or nonattainment New Source Review (NSR) permits for:

A. work that this Consent Decree expressly directs Tampa Electric to undertake; or

B. physical changes or changes in the method of operation of Big Bend or Gannon Units not required by this Consent Decree, if and only if:

(1) such change is commenced after Tampa Electric is implementing the plan, or the first phase of the plan if applicable, approved by EPA under Paragraph 31 (Optimizing Availability of Scrubbers),

(2) such change is commenced, within the meaning of 40 C.F.R. Section

52.21(b)(9), during the time this Consent Decree applies to the Unit at which this change has been made ;

(3) Tampa Electric is otherwise in compliance with this Consent Decree;

(4) hourly Emission Rates of NO_x, SO_2, or PM at the changed Unit(s) do not exceed their respective hourly Emission Rates prior to the change, as measured by 40 C.F.R. § 60.14(h); and

(5) in any calendar year following the change, emissions of no pollutant within the scope of Total Baseline Emissions exceed the emissions of that pollutant in the Total Baseline Emissions.

45. Separate Limitation on Resolution of Claims. Notwithstanding the provisions of Section XIII (Termination), the provisions of Paragraph 44 (Resolution of Future Claims - Covenant Not to Sue) shall terminate at Gannon and Big Bend, as follows. On December 31, 2006, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Gannon. On December 31, 2012, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Big Bend. If Tampa Electric Re-Powers any Unit at Big Bend under the terms provided by this Consent Decree, then for each such Unit the provisions of Paragraph 44 shall terminate two years after each such Unit is Re-Powered or on December 31, 2012, whichever is earlier.

46. Exclusion of Certain Emission Allowances. For any and all actions taken by Tampa Electric pursuant to the terms of this Consent Decree, including but not limited to

upgrading of ESPs and scrubbers, installation of NO_x controls, Re-Powering, and Shutdown, Tampa Electric shall not use or sell any resulting NO_x or SO_2 emission allowances or credits in any emission trading or marketing program of any kind; provided, however, that:

A. SO_2 credits allocated to Tampa Electric by the Administrator of EPA under the Act, due to the Re-Powering or Shutdown of Gannon, may be retained by Tampa Electric during the year in which they are allocated, but only for Tampa Electric s own use in meeting any acid rain requirement imposed under the Act. For any such allowances not used by Tampa Electric for this purpose by June 30 of the following calendar year, Tampa Electric shall not use, sell, trade, or otherwise transfer these allowances for its benefit or the benefit of a third party unless such a transfer would result in the retiring of such allowances without their ever being used.

B. If Tampa Electric decides to Re-Power any Unit at Big Bend, then Tampa Electric shall be entitled to retain for any purpose under law the difference between the emission allowances that would have resulted from installing BACT-level NO_x and SO_2 controls at the existing coal-fired Unit and the emission allowances that result from Re-Powering that Unit. Before Tampa Electric uses any allowances within the scope of this Subparagraph, Tampa Electric shall submit the calculation of the net emission allowances for approval by the United States.

C. Nothing in this Consent Decree shall preclude Tampa Electric from using or selling emission allowances arising from Tampa Electric s activities occurring prior to December 31, 1999, or Tampa Electric s activities after that date that are not related to actions required of Tampa Electric under this Consent Decree. The United States and Tampa Electric agree that the operation of the SO_2 scrubber serving Big Bend Units 1 and 2 meets the requirements of this Subparagraph, and that emission allowances resulting from the operation of this scrubber shall not be treated as an activity related to or required under this Consent Decree.

V. REPORTING AND RECORD KEEPING

47. Beginning at the end of the first calendar quarter after entry of this Consent Decree, and in addition to any other express reporting requirement in this Consent Decree, Tampa Electric shall submit to EPA a quarterly report, consistent with the form attached to this Consent Decree as the Appendix, within thirty (30) days after the end of each calendar quarter until this Consent Decree is terminated.

48. Tampa Electric s report shall be signed by Tampa Electric s Vice President, Environmental and Fuels, or, in his or her absence, Vice President, Energy Supply, or higher ranking official, and shall contain the following certification:

> I certify under penalty of law that this information was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I understand that there are significant penalties for making misrepresentations to or misleading the United States.

VI. CIVIL PENALTY

49. Within thirty (30) calendar days of entry of this Consent Decree, Tampa Electric shall pay to the United States a civil penalty in the amount of $3.5 million. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing the USAO File Number and DOJ Case Number 90-5-2-1-06932 and the civil action case name and case number of this action. The costs of such EFT shall be Tampa Electric s responsibility. Payment shall be made in accordance with instructions provided by the Financial Litigation Unit of the U.S. Attorney's Office for the Middle District of Florida. Any funds received after 11:00 a.m. (EST) shall be credited on the next business day. Tampa Electric shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1- 06932, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Paragraph 82 (Notice). Failure to timely pay the civil penalty shall subject Tampa Electric to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Tampa Electric liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

VII. NO_x REDUCTION PROJECTS AND MITIGATION PROJECTS

50. Tampa Electric shall submit plans for and shall implement the NO_x Reduction and Other Mitigation Projects (referred to together as Projects) described in this Section, and in Paragraph 35 of this Consent Decree, in compliance with the schedules and terms of this

Consent Decree. In performing these Projects, Tampa Electric shall spend no less than \$10 million in Project Dollars, in total, unless the Additional NO_x Reduction Project(s) selected under Paragraph 52.C is estimated to cost more than \$5 million, in which case Tampa Electric shall spend no less than \$10 million but no more than \$11 million in Project Dollars, in total. Tampa Electric shall expend the full amount of the Project Dollars required by this Paragraph on or before May 1, 2010. Tampa Electric shall maintain for review by EPA, upon its request, all documents identifying Project Dollars spent by Tampa Electric.

51. All plans and reports prepared by Tampa Electric pursuant to the requirements of Paragraph 35 and this Section of the Consent Decree shall be publicly available without charge.

52. Tampa Electric shall submit the required plans for and complete the following Projects:

A. Early NO_x reductions through combustion optimization as described in Paragraph 35 of this Consent Decree.

B. <u>Performance of Air Chemistry Work in Tampa Bay Estuary</u>. Tampa Electric shall expend no more than \$2 million Project Dollars in conducting or financing stack tests, emissions estimation, ambient air monitoring, data acquisition and analysis, and any combination thereof that: (1) is not otherwise required by law, (2) will provide data or analysis that is not already available, (3) will complement work carried out by other persons examining the air chemistry of Tampa Bay Estuary, and (4) will help close gaps in current understanding of air chemistry in the Tampa Bay Estuary. Tampa Electric shall either conduct this work itself, fund other persons already conducting such work on a non-profit basis, or both. For work Tampa Electric intends to conduct itself, the company shall describe the proposed work and a schedule for completion to EPA, in writing, at least 90 days prior to the date on which Tampa Electric intends to start such work, including an explanation of why the proposed work meets all the requirements of this Subparagraph. Unless EPA objects to the proposed work on the grounds it does not comply with the requirements of this Subparagraph, Tampa Electric shall undertake and complete the work according to the proposed schedule. If Tampa Electric elects to spend some or all of the $2 million Project Dollars to finance work to be performed by other persons or organizations, the company shall provide to EPA for review and approval a plan that describes the work to be performed, the persons or organizations conducting the work, the schedule for its completion, the schedule for Tampa Electric s payments, and an explanation of why the proposed payment(s) meets all the requirements of this Subparagraph. The plan shall be provided to EPA at least 90 days prior to the date on which Tampa Electric will begin transferring the money to finance such work. All payments to persons or organizations under such a plan shall be completed by Tampa Electric no later than June 30, 2002. Before Tampa Electric makes such payments for the benefit of any person or organization carrying out work under this Paragraph, Tampa Electric shall secure a written, signed commitment from such person to provide Tampa Electric and EPA with the results of the work.

C. Additional NO_x Reductions Project(s)

(1) General Requirement. Tampa Electric shall expend the remainder of the Project Dollars required under this Consent Decree to: (i) demonstrate innovative NO_x control technologies on any of its Units or boilers at Gannon or Big Bend not Shutdown or on Reserve / Standby; and/or (ii) reduce the NO_x Emission Rate for any Big Bend coal-combusting Unit below the lowest rate otherwise applicable to it under this Consent Decree.

(2) For any Project(s) at Gannon. If Tampa Electric elects to undertake a project on an eligible Gannon Unit(s) to demonstrate any innovative NO_x control technology, within six months after entry of this Consent Decree Tampa Electric shall submit a plan to EPA, for review and approval, which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. . EPA shall complete its review of this plan within 60 days after receipt. If such project is approved, Tampa Electric shall complete installation of the technology no later than December 31, 2004 as part of the Re-Powering of such Units; provided, however, that nothing in this Paragraph

alters Tampa Electric s obligation under Paragraph 26 of this Consent Decree.

(3) For any Project(s) at Big Bend. At least three (3) years prior to the date on which the expenditure of any Project Dollars is to commence on Big Bend under this Subparagraph C, Tampa Electric shall submit a plan to EPA for review and approval which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. If EPA approves the projects contained in the plan, Tampa Electric shall implement the project(s). Projects that would demonstrate innovative NO_x control technology or reduce the NO_x Emission Rate for any Big Bend coal-fired or Re-Powered Unit shall be operating and achieving reductions or demonstrating the performance of the innovative technology, as applicable, not later than May 1, 2010.

(4) Follow-up Report(s). Within sixty (60) days following the implementation of each EPA-approved project, Tampa Electric shall submit to EPA a report that documents the date that all aspects of the project were implemented, Tampa Electric s results in implementing the project, including the emission reductions or other environmental benefits

achieved, and the Project Dollars expended by Tampa Electric in implementing the project.

VIII. STIPULATED PENALTIES

53. For purposes of this Consent Decree, within thirty days after written demand from the United States, and subject to the provisions of Sections X (Force Majeure) and XI (Dispute Resolution), Tampa Electric shall pay the following stipulated penalties to the United States for each failure by Tampa Electric to comply with the terms of this Consent Decree.

A. For failure to pay timely the civil penalty as specified in Section VI of this Consent Decree, $10,000 per day.

B. For all violations of a 24 hour Emission Rate (1) Less than 5% in excess of limit: $4,000 per day, per violation; (2) more than 5% but less than 10% in excess of limit: $9,000 per day per violation; (3) equal to or greater than 10% in excess of limit: $27,500 per day, per violation

C. For all violations of 30-day rolling average Emission Rates (1) Less than 5% in excess of limit: $150 per day per violation; (2) more than 5% but less than 10% in excess of limit: $300 per day per violation; (3) equal to or greater than 10% in excess of limit: $800 per day per violation. Violation of an Emission Rate that is based on a 30 day rolling average is a violation on every day of the 30 day period on which the average is based . Where a violation of a 30 day rolling monthly average Emission Rate (for the same pollutant and from the same source) recurs within periods less than 30 days, Tampa Electric shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

D. For all violations of a 95% removal efficiency requirement (1) For removal efficiency less than 95% but greater than or equal to 94%, $4,000 per day, per violation; (2) for removal efficiency less than 94% but greater than or equal to 91%, $9,000 per day, per violation; (3) for removal efficiency less than 91%, $27,500 per day, per violation. For all violations of a 93% removal efficiency requirement (1) For removal efficiency less than 93% but greater than or equal to 92%, $4,000 per day, per violation; (2) for removal efficiency less than 92% but greater than or equal to 90%, $9,000 per day, per violation; (3) for removal efficiency less than 90%, $27,500 per day, per violation;

E. Violation of deadlines for Shutdown of boilers or Units or megawatt capacity $27,500 per day, per violation.

F. Failure to apply for the permits required by Paragraphs 26, 27, 34, 38, and 42 $1,000 per day, per violation.

G. Failure to implement the recommendations of the PM BACT Analysis or the PM optimization study by May 1, 2004 $5,000 per day, per violation for first 30 days; $15,000 per day, per violation, for next 30 days; $27,500 per day, per violation, thereafter.

H. Failure to commence combustion optimization at Big Bend Units 1, 2, or 3 on or before May 30, 2003 as required by Paragraph 35, $10,000 per day, per violation.

I. Failure to operate the scrubbers at Big Bend Units 1, 2, or 3 on any day except as permitted by Paragraphs 29, 30, or 31, $27,500 per day, per violation.

J. Failure to submit quarterly progress and monitoring report $100 per day, per violation, for first ten days late, and $500 per day for each day thereafter.

K. Failure to complete timely any action or payment required by or established under Subparagraph 52(B) (Performance of Air Chemistry Work in Tampa Bay Estuary), $5,000 per day, per violation

L. Failure to perform NO_x reduction or demonstration project(s), by the deadline(s) established in Subparagraph 52.C (Additional NO_x Reductions Project(s)), $10,000 per day, per violation;

M. For failure to spend at least the number of Project Dollars required by this Consent Decree by date specified in Paragraph 50, $5,000 per day, per violation;

N. Violation of any Consent Decree prohibition on use of allowances as provided in Paragraph 46 three times the market value of the improperly used allowance as measured at the time of the improper use.

54. Should Tampa Electric dispute its obligation to pay part or all of a stipulated penalty demanded by the United States, it may avoid the imposition of a separate stipulated penalty for the failure to pay the disputed penalty by depositing the disputed amount in a commercial escrow account pending resolution of the matter and by invoking the Dispute Resolution provisions of this Consent Decree within the time provided in this Section VIII of the Consent Decree for payment of the disputed penalty. If the dispute is thereafter resolved in Tampa Electric's favor, the escrowed amount plus accrued interest

shall be returned to Tampa Electric. If the dispute is resolved in favor of the United States, it shall be entitled to the escrowed amount determined to be due by the Court, plus accrued interest. The balance in the escrow account, if any, shall be returned to Tampa Electric.

55. The United States reserves the right to pursue any other remedies to which it is entitled, including, but not limited to, a new civil enforcement action and additional injunctive relief for Tampa Electric's violations of this Consent Decree. If the United States elects to seek civil or contempt penalties after having collected stipulated penalties for the same violation, any further penalty awarded shall be reduced by the amount of the stipulated penalty timely paid or escrowed by Tampa Electric. Tampa Electric shall not be required to remit any stipulated penalty to the United States that is disputed in compliance with Part XI of this Consent Decree until the dispute is resolved in favor of the United States. However, nothing in this Paragraph shall be construed to cease the accrual of the stipulated penalties until the dispute is resolved.

IX. RIGHT OF ENTRY

56. Any authorized representative of EPA or an appropriate state agency, including independent contractors, upon presentation of credentials, shall have a right of entry upon the premises of Tampa Electric's plants identified herein at any reasonable time for the purpose of monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment and inspecting and copying all records maintained by Tampa Electric required by this Consent Decree. Tampa Electric shall retain such records for a

period of twelve (12) years from the date of entry of this Consent Decree. Nothing in this Consent Decree shall limit the authority of EPA to conduct tests and inspections at Tampa Electric s facilities under Section 114 of the Act, 42 U.S.C. § 7414.

X. FORCE MAJEURE

57. If any event occurs which causes or may cause a delay in complying with any provision of this Consent Decree, Tampa Electric shall notify the United States in writing as soon as practicable, but in no event later than seven (7) business days following the date Tampa Electric first knew, or within ten (10) business days following the date Tampa Electric should have known by the exercise of due diligence, that the event caused or may cause such delay. In this notice Tampa Electric shall reference this Paragraph of this Consent Decree and describe the anticipated length of time the delay may persist, the cause or causes of the delay, the measures taken or to be taken by Tampa Electric to prevent or minimize the delay, and the schedule by which those measures will be implemented. Tampa Electric shall adopt all reasonable measures to avoid or minimize such delays.

58. Failure by Tampa Electric to comply with the notice requirements of Paragraph 57 shall render this Section X voidable by the United States as to the specific event for which Tampa Electric has failed to comply with such notice requirement. If voided, the provisions of this Section shall have no effect as to the particular event involved.

59. The United States shall notify Tampa Electric in writing regarding Tampa Electric's claim of a delay in performance within (15) fifteen business days of receipt of the Force

Majeure notice provided under Paragraph 57. If the United States agrees that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay through the exercise of due diligence, the parties shall stipulate to an extension of the required deadline(s) for all requirement(s) affected by the delay for a period equivalent to the delay actually caused by such circumstances. Such stipulation shall be filed as a modification to this Consent Decree in order to be effective. Tampa Electric shall not be liable for stipulated penalties for the period of any such delay.

60. If the United States does not accept Tampa Electric's claim of a delay in performance, to avoid the imposition of stipulated penalties Tampa Electric must submit the matter to this Court for resolution by filing a petition for determination. Once Tampa Electric has submitted the matter, the United States shall have fifteen business days to file its response. If Tampa Electric submits the matter to this Court for resolution, and the Court determines that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay by the exercise of due diligence, Tampa Electric shall be excused as to that event(s) and delay (including stipulated penalties otherwise applicable), but only for the period of time equivalent to the delay caused by such circumstances.

61. Tampa Electric shall bear the burden of proving that any delay in performance of any requirement of this Consent Decree was caused by or will be caused by circumstances

beyond its control, including any entity controlled by it, and that Tampa Electric could not have prevented the delay by the exercise of due diligence. Tampa Electric shall also bear the burden of proving the duration and extent of any delay(s) attributable to such circumstances. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

62. Unanticipated or increased costs or expenses associated with the performance of Tampa Electric's obligations under this Consent Decree shall not constitute circumstances beyond the control of Tampa Electric or serve as a basis for an extension of time under this Section. However, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure event where the failure of the permitting authority to act is beyond the control of Tampa Electric and Tampa Electric has taken all steps available to it to obtain the necessary permit, including, but not limited to, submitting a complete permit application, responding to requests for additional information by the permitting authority in a timely fashion, accepting lawful permit terms and conditions, and prosecuting appeals of any allegedly unlawful terms and conditions imposed by the permitting authority in an expeditious fashion.

63. The parties agree that, depending upon the circumstances related to an event and Tampa Electric s response to such circumstances, the kinds of events listed below could also qualify as Force Majeure events within the meaning of this Section X of the Consent Decree: Construction, labor, or equipment delays; natural gas and gas transportation availability delays;acts of God; and the failure of an innovative technology approved under Paragraph 26.B and 52.C.

64. Notwithstanding any other provision of this Consent Decree, this Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of Tampa Electric delivering a notice pursuant to this Section or the parties' inability to reach agreement on a dispute under this Part.

65. As part of the resolution of any matter submitted to this Court under this Section, the parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States or approved by this Court. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XI. DISPUTE RESOLUTION

66. The dispute resolution procedure provided by this Section XI shall be available to resolve all disputes arising under this Consent Decree, except as provided in Section X regarding Force Majeure, or in this Section XI, provided that the party making such application has made a good faith attempt to resolve the matter with the other party.

67. The dispute resolution procedure required herein shall be invoked by one party to this Consent Decree giving written notice to another advising of a dispute pursuant to this Section XI. The notice shall describe the nature of the dispute and shall state the noticing party's position with regard to such dispute. The party receiving such a notice shall acknowledge receipt of the notice, and the parties shall expeditiously schedule a meeting

to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

68. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations between the parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting between representatives of the United States and Tampa Electric unless the parties' representatives agree to shorten or extend this period.

69. If the parties are unable to reach agreement during the informal negotiation period, the United States shall provide Tampa Electric with a written summary of its position regarding the dispute. The written position provided by the United States shall be considered binding unless, within thirty (30) calendar days thereafter, Tampa Electric files with this Court a petition which describes the nature of the dispute and seeks resolution. The United States may respond to the petition within forty-five (45) calendar days of filing.

70. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the parties to the dispute.

71. This Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of invocation of this Section or the parties' inability to reach agreement.

72. As part of the resolution of any dispute under this Section, in appropriate circumstances the parties may agree, or this Court may order, an extension or modification of the schedule for completion of work under this Consent Decree to account for the delay that

occurred as a result of dispute resolution. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

73. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes; provided, however, that the United States and Tampa Electric reserve their rights to argue for what the applicable standard of law should be for resolving any particular dispute. Notwithstanding the preceding sentence of this Paragraph, as to disputes arising under Paragraph 32, the Court shall sustain the position of the United States as to the BACT Analysis recommendations and the optimization study measures that should be installed and implemented, unless Tampa Electric demonstrates that the position of the United States is arbitrary or capricious.

XII. GENERAL PROVISIONS

74. Effect of Settlement. This Consent Decree is not a permit; compliance with its terms does not guarantee compliance with all applicable Federal, State or Local laws or regulations.

75. Satisfaction of all of the requirements of this Consent Decree constitutes full settlement of and shall resolve and release Tampa Electric from all civil liability of Tampa Electric to the United States for the claims referred to in Paragraphs 43 and 44 of this Consent Decree. This Consent Decree does not apply to any claim(s) of alleged criminal liability, which are reserved.

76. In any subsequent administrative or judicial action initiated by the United States for

injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Tampa Electric shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim splitting, or other defense based upon any contention that the claims raised by the United States in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the enforceability of the Resolution of Claims provisions of Paragraphs 43 and 44 of this Consent Decree..

77. Other Laws. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Tampa Electric of its obligation to comply with all applicable Federal, State and Local laws and regulations. Subject to Paragraph 43 and 44, nothing contained in this Consent Decree shall be construed to prevent or limit the United States' rights to obtain penalties or injunctive relief under the Clean Air Act or other federal, state or local statutes or regulations.

78. Third Parties. This Consent Decree does not limit, enlarge or affect the rights of any party to this Consent Decree as against any third parties.

79. Costs. Each party to this action shall bear its own costs and attorneys' fees.

80. Public Documents. All information and documents submitted by Tampa Electric to the United States pursuant to this Consent Decree shall be subject to public inspection, unless subject to legal privileges or protection or identified and supported as business confidential by Tampa Electric in accordance with 40 C.F.R. Part 2.

81. Public Comments. The parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the requirements of 28 C.F.R. §

50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate.

82. Notice. Unless otherwise provided herein, notifications to or communications with the United States or Tampa Electric shall be deemed submitted on the date they are postmarked and sent either by overnight mail, return receipt requested, or by certified or registered mail, return receipt requested. Except as otherwise provided herein, when written notification to or communication with the United States, EPA, or Tampa Electric is required by the terms of this Consent Decree, it shall be addressed as follows:

As to the United States of America:

For U.S. DOJ

Chief
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-06932

Whitney L. Schmidt
Coordinator, Affirmative Civil Enforcement Program
Office of the United States Attorney
Middle District of Florida
400 N. Tampa Street
Tampa, FL 33602

For U.S. EPA

Director, Air Enforcement Division

Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Regional Administrator
U.S. EPA Region IV
61 Forsyth Street, S.E.
Atlanta, GA 30303

As to Tampa Electric:

Sheila M. McDevitt
General Counsel
Tampa Electric Company
P.O. Box 111
Tampa, FL 333601-0111

83. Any party may change either the notice recipient or the address for providing notices to it by serving all other parties with a notice setting forth such new notice recipient or address.

84. Modification. Except as otherwise allowed by law, there shall be no modification of this Consent Decree without written approval by the United States and Tampa Electric, and approval of such modification by the Court.

85. Continuing Jurisdiction. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, or modification. During the term of this Consent Decree, any party may apply

to the Court for any relief necessary to construe or effectuate this Consent Decree.

86. Complete Agreement. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the parties with respect to the settlement embodied in this Consent Decree. The parties acknowledge that there are no representations, agreements or understandings relating to the settlement other than those expressly contained in this Consent Decree. An Appendix is attached to and incorporated into this Consent Decree by this reference.

XIII. TERMINATION

87. Except as provided in Paragraphs 43, 44, and 45 (involving resolution of claims), this Consent Decree shall be subject to termination upon motion by either party after Tampa Electric satisfies all requirements of this Consent Decree, including payment of all stipulated penalties that may be due, installation of control technology systems as specified herein, the receipt of all permits specified herein, securing valid Title V Permits for Gannon and Big Bend that incorporate all emission and fuel limits from this Consent Decree as well as all operational limits established under this Consent Decree, and the submission of all final reports indicating satisfaction of the requirements for implementation of all acts called for under Part VII of this Consent Decree.

88. If Tampa Electric believes it has achieved compliance with the requirements of this Consent Decree, then Tampa Electric shall so certify to the United States. Unless the United States objects in writing with specific reasons within 60 days of receipt of Tampa Electric s certification, the Court shall order that this Consent Decree be terminated on

Tampa Electric's motion. If the United States objects to Tampa Electric's certification, then the matter shall be submitted to the Court for resolution under Section XI of this Consent Decree. In such case, Tampa Electric shall bear the burden of proving that this Consent Decree should be terminated.

SO ORDERED, THIS _____ DAY OF _______________ 2000.

____

UNITED STATES DISTRICT JUDGE

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

THROUGH ITS UNDERSIGNED REPRESENTATIVES, THE UNITED STATES AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE:

FOR PLAINTIFF
UNITED STATES OF AMERICA:

______________________________ Date: ____________

Lois J. Schiffer
Assistant Attorney General
Environment and Natural Resources
Division
United States Department of Justice

____

W. Benjamin Fisherow
Assistant Chief
Thomas A. Mariani, Jr.
Jon A. Mueller
Senior Attorneys
Environmental Enforcement Section
United States Department of Justice
P.O. Box 7611
Washington, D.C. 20044
(202) 514-4620

Donna A. Bucella
United States Attorney for the
Middle District of Florida

By:______________________________
Whitney L. Schmidt
Affirmative Civil Enforcement Coordinator
Assistant United States Attorney
United States Attorney s Office
Middle District of Florida
Florida Bar No. 0337129
Tampa, Florida 33602
(813) 274-6000
(813) 274-6198 (facsimile)

Signature Page for Consent Decree in United States v. Tampa Electric Company, Civ. No. 99-2524 CIV-T-23F

____

Steven A. Herman
Assistant Administrator for Office of Enforcement
and Compliance Assurance
U.S. Environmental Protection Agency
Washington, D.C.

____

Bruce Buckheit
Director

Gregory Jaffe
Senior Enforcement Counsel

Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Washington, D.C.

Signature Page for Consent Decree in United States v. Tampa Electric Company, Civ. No. 99-2524 CIV-T-23F

John H. Hankinson
Regional Administrator
U.S. Environmental Protection Agency (Region IV)
Atlanta, Georgia

Signature Page for Consent Decree in United States v. Tampa Electric Company,
Civ. No. 99-2524 CIV-T-23F

THROUGH ITS UNDERSIGNED REPRESENTATIVES, TAMPA ELECTRIC COMPANY AGREES AND CONSENTS TO ENTRY OF THE FOREGOING CONSENT DECREE

FOR TAMPA ELECTRIC COMPANY

______________________________ Date: ____________

John B. Ramil
President
Tampa Electric Company

____

Sheila M. McDevitt
General Counsel
Tampa Electric Company

Exhibit 8 to Title V Petition

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF NORTH DAKOTA

UNITED STATES OF AMERICA and STATE OF NORTH DAKOTA,	)	
Plaintiffs,	)	
v.	)	Civil Action No:
MINNKOTA POWER COOPERATIVE, Inc. and SQUARE BUTTE ELECTRIC COOPERATIVE,	)	
Defendants.	)	

CONSENT DECREE

TABLE OF CONTENTS

WHEREAS, Plaintiffs, the United States of America ("the United States"), on behalf of the United States Environmental Protection Agency ("EPA"), and the State of North Dakota ("State"), have filed a Complaint for injunctive relief and civil penalties pursuant to Sections 113(b)(2) and 167 of the Clean Air Act (the "Act"), 42 U.S.C. §§ 7413(b)(2) and 7477, alleging that Defendants, Minnkota Power Cooperative ("Minnkota") and Square Butte Electric Cooperative ("Square Butte") have undertaken construction projects at major emitting facilities in violation of the Prevention of Significant Deterioration provisions of Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-7492, and in violation of the federally approved and enforceable North Dakota State Implementation Plan;

WHEREAS, in their Complaint, the United States and the State (collectively, "the Plaintiffs") allege, *inter alia,* that Minnkota and Square Butte (collectively, the "Settling Defendants") failed to obtain the necessary permits and install the controls necessary under the Act to reduce their sulfur dioxide (SO_2), nitrogen oxide (NO_x), and/or particulate matter (PM) emissions;

WHEREAS, the Complaint alleges claims upon which relief can be granted against the Settling Defendants under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477;

WHEREAS, the United States provided the Settling Defendants and the State with actual notice of alleged violations in accordance with Section 113(a)(1) of the Act, 42 U.S.C. § 7413(a)(1);

WHEREAS, the Settling Defendants assert that there may be difficulty associated with the continuous operation of Flue Gas Desulfurization Systems at the Milton R. Young Station during the extremely cold ambient air temperatures at the plant in the winter months, and the

Parties have considered these circumstances in reaching this agreement;

WHEREAS, the Settling Defendants assert that it would be very difficult to install and continuously operate certain NO_x emission controls at the cyclone-fired, lignite-burning Units at the Milton R. Young Station;

WHEREAS, NDDH contemplates that, upon full implementation of the controls and other requirements of this Consent Decree, the Settling Defendants will have installed BACT-level SO_2 controls for purposes of netting under this Decree;

WHEREAS, the Parties have agreed that settlement of this action is in the best interest of the Parties and in the public interest, and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

WHEREAS, the Parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm's length and that this Consent Decree is fair, reasonable, consistent with the goals of the Act, and in the public interest;

WHEREAS, the Settling Defendants have cooperated in the resolution of this matter;

WHEREAS, the Settling Defendants have denied and continue to deny the violations alleged in the Complaint, and nothing herein shall constitute an admission of liability; and

WHEREAS, the Parties have consented to entry of this Consent Decree without trial of any issues;

NOW, THEREFORE, without any admission of fact or law, it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367, and pursuant to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying Complaint, the Settling Defendants waive all objections and defenses that they may have to the Court's jurisdiction over this action, to the Court's jurisdiction over the Settling Defendants, and to venue in this District. The Settling Defendants shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. For purposes of the Complaint filed by the Plaintiffs in this matter and resolved by the Consent Decree, and for purposes of entry and enforcement of this Consent Decree, the Settling Defendants waive any defense or objection based on standing. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the Parties to this Consent Decree. Except as provided in Section XXV (Public Comment) of this Consent Decree, the Parties consent to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. Except as set forth in Paragraph 3, the provisions of this Consent Decree shall, upon entry, apply to and be binding upon the Settling Defendants and their successors and assigns, and upon the Settling Defendants' officers, employees and agents solely in their capacities as such.

3. Upon entry, the provisions of this Consent Decree that relate exclusively to Unit 1 at the Milton R. Young Station shall only apply to and be binding upon Minnkota, and its

successors and assigns, and upon Minnkota's officers, employees and agents solely in their capacities as such.

4. The Settling Defendants shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization retained to perform any of the work required by this Consent Decree. Notwithstanding any retention of contractors, subcontractors, or agents to perform any work required under this Consent Decree, the Settling Defendants shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, the Settling Defendants shall not assert as a defense the failure of their officers, directors, employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless it is determined to be a Force Majeure Event and satisfies the Force Majeure provisions of this Consent Decree.

III. DEFINITIONS

5. A "30-day Rolling Average Emission Rate" shall be determined by calculating an arithmetic average of all hourly emission rates in lbs/MMBtu for the current Operating Day and the previous 29 Operating Days. A new 30-day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-day Rolling Average Emission Rate shall include all start-up, shutdown and Malfunction periods within each Operating Day. A Malfunction shall be excluded from this Emission Rate, however, if it is determined to be a Force Majeure Event and satisfies the Force Majeure provisions of this Consent Decree. The reference methods for determining SO_2 and NO_x Emission Rates shall be those specified in 40 C.F.R. Part 75, Appendix F.

6. A "30-day Rolling Average Removal Efficiency" means the percent reduction in the mass of a pollutant achieved by a Unit's pollution control device over a 30-Operating Day period. This percentage shall be calculated by subtracting the Unit's outlet 30-day Rolling Average Emission Rate from the Unit's inlet 30-day Rolling Average Emission Rate, dividing that difference by the Unit's inlet 30-day Rolling Average Emission Rate, and then multiplying by 100. A new 30-day Rolling Average Removal Efficiency shall be calculated for each new Operating Day, and shall include all start-up, shutdown and Malfunction periods with each Operating Day. A Malfunction shall be excluded from this Removal Efficiency, however, if it is determined to be a Force Majeure Event and satisfies the Force Majeure provisions of this Consent Decree. The reference method for determining both the inlet and outlet 30-day Rolling Average Emission Rate, for the purposes of calculating the SO_2 30-day Rolling Average Removal Efficiency, shall be that specified in 40 C.F.R. Part 75, Appendix F.

7. "CEMS" or "Continuous Emission Monitoring System," means, for obligations involving NO_x and SO_2 under this Consent Decree, the devices defined in 40 C.F.R. § 72.2, and installed and maintained as required by 40 C.F.R. Part 75.

8. "Clean Air Act" or "Act" means the federal Clean Air Act, 42 U.S.C. §§7401-7671q, and its implementing regulations.

9. "Consent Decree" means this Consent Decree.

10. "Emission Rate" for a given pollutant means the number of pounds of that pollutant emitted per million British thermal units of heat input (lb/MMBtu), measured in accordance with this Consent Decree.

11. "EPA" means the United States Environmental Protection Agency.

12. "ESP" means electrostatic precipitator, a pollution control device for the reduction of PM.

13. "Flue Gas Desulfurization System" or "FGD" means a pollution control device that employs flue gas desulfurization technology, including an absorber utilizing lime, flyash, or limestone slurry, for the reduction of sulfur dioxide emissions.

14. "Fossil Fuel" means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, or natural gas.

15. "lb/MMBtu" means one pound of a pollutant per million British thermal units of heat input.

16. "Malfunction" means malfunction as that term is defined under 40 C.F.R. § 60.2 (July 1, 2004).

17. "MW" means a megawatt or one million Watts.

18. "Milton R. Young Station" means, for purposes of this Consent Decree only, the Settling Defendants' electric generating Units near Center, North Dakota, which currently consist of two lignite-fired cyclone units. Unit 1 has a nominal net rating of 235 MW. Unit 2 has a nominal net rating of 440 MW. "Milton R. Young Station" also includes the Settling Defendants' proposed Unit 3, with a proposed net rating of 600 MW. The Settling Defendants anticipate submitting a permit to construct application on or before June 1, 2009. Subject to NDDH's permit to construct review process, the Unit 3 permit is anticipated to be issued by December 31, 2010, construction is expected to commence on or before December 31, 2012, and operation is expected to commence on or before December 31, 2015.

19. "NDDH" shall mean the North Dakota Department of Health.

20. "Netting" shall mean the process of determining whether a particular physical change or change in the method of operation of a major stationary source results in a net emissions increase, as that term is defined at 40 C.F.R. § 52.21(b)(3)(i) and Chapter 33-15-15 of the North Dakota Administrative Code (Feb. 1, 2005).

21. "NO_x" means oxides of nitrogen, measured in accordance with the provisions of this Consent Decree.

22. "NO_x Allowance" means an authorization or credit to emit a specified amount of NO_x that is allocated or issued under an emissions trading or marketable permit program of any kind established under the Act or a State Implementation Plan. The Parties acknowledge that at the time of lodging of this Consent Decree that no NO_x Allowance program is applicable to Milton R. Young Station.

23. "NO_x BACT Determination" shall mean the conclusions made by the NDDH as a result of reviewing the NO_x Top-Down BACT Analysis. Such determination shall be carried out in accordance with the applicable federal and state statutes, regulations, and guidance cited in the definition of "NO_x Top-Down BACT Analysis," below, and shall include the selection of control technology to be installed on Units 1 and 2 and 30-day Rolling Average Emission Rates applicable to Units 1 and 2 and to be continuously complied with by the Settling Defendants.

24. "NO_x Top-Down BACT Analysis" shall mean a study prepared by the Settling Defendants to identify the emission limits required by 42 U.S.C. § 7475(a)(4) and 40 C.F.R. § 52.21(j)(3), defined by 42 U.S.C. § 7479(3) and 40 C.F.R. §52.21(b)(12), and expressed as a 30-Day Rolling Average NO_x Emission Rate. The study shall be carried out in accordance with the provisions of Chapter B of EPA's "New Source Review Workshop Manual—Prevention of

Significant Deterioration and Nonattainment Area Permitting," (Draft October 1990) ("EPA's NSR Manual"). The study shall not include any other elements of PSD permitting required by other chapters of EPA's NSR Manual (notwithstanding any cross-reference in Chapter B to such other chapters), 40 C.F.R. § 52.21, or N.D. ADMIN. CODE § 33-15-15-01.2.

25. "Over-fire Air" means a technology to reduce NO_x formation in a Unit boiler by directing a portion of the air to be combusted through ports above the level of the cyclones in the furnace.

26. "Operating Day" means any calendar day on which a Unit fires fossil fuel.

27. "Parties" means the United States of America, the State of North Dakota, and the Settling Defendants. "Party" means one of the four named "Parties."

28. "Plant-Wide 12-Month Rolling Average Tonnage" means the sum of the tons of the pollutant in question emitted from the Milton R. Young Station in the most recent complete month and the previous eleven (11) months. A new Plant-Wide 12-Month Rolling Average Tonnage shall be calculated for each new complete month in accordance with the provisions of this Consent Decree. The calculation of each Plant-Wide 12-Month Rolling Average Tonnage shall include the pollutants emitted during periods of startup, shutdown, and Malfunction within each calendar month, unless the Malfunction event is also deemed a "Force Majeure Event" as defined in Section XIV of this Consent Decree (Force Majeure), in which case such emissions shall be excluded.

29. "Plant-Wide Tonnage for One Calendar Year" means the sum of the tons of the pollutant in question emitted from the Milton R. Young Station in any 12-Month calendar year. A new Plant-Wide Tonnage for One Calendar Year shall be calculated for each new calendar

year. The calculation of each Plant-Wide Tonnage for One Calendar Year shall include the pollutants emitted during periods of startup, shutdown, and Malfunction within each 12-Month calendar year, unless the Malfunction event is also deemed a "Force Majeure Event" as defined in Section XIV of this Consent Decree (Force Majeure), in which case such emissions shall be excluded.

30. "Plant-Wide Tonnage for the Annual Average of Two Calendar Years" means the sum of the tons of the pollutant in question emitted from the Milton R. Young Station in any two consecutive 12-month calendar years, divided by two. A new Plant-Wide Tonnage for the Annual Average of Two Calendar Years shall be calculated for each new complete 12-month calendar year. The calculation of each Plant-Wide Tonnage for the Annual Average of Two Calendar Years shall include the pollutants emitted during periods of startup, shutdown, and Malfunction within each 12-Month calendar year, unless the Malfunction event is also deemed a "Force Majeure Event" as defined in Section XIV of this Consent Decree (Force Majeure), in which case such emissions shall be excluded.

31. "PM" means total particulate matter, measured in accordance with the provisions of this Consent Decree.

32. "PM CEMS" or "PM Continuous Emission Monitoring System" means, as specified in Section VI (PM Emission Reduction and Controls) of this Consent Decree, the equipment that samples, analyzes, measures, and provides, by readings taken at frequent intervals, an electronic or paper record of PM emissions.

33. "PM Emission Rate" means the average number of pounds of PM emitted per million British thermal units of heat input ("lbs/MMBtu") from the Unit stack, as measured in an annual

stack test from the Unit stack, in accordance with the reference method set forth in 40 C.F.R. Part 60, Appendix A, Method 5 (filterable portion only) or Method 17 (filterable portion only).

34. "Prevention of Significant Deterioration" or "PSD" means the prevention of significant deterioration of air quality program under Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470 - 7492, and 40 C.F.R. Part 52.

35. "Project Dollars" means the Settling Defendants' expenditures and payments incurred or made in carrying out the Projects identified in Section VIII (Additional Injunctive Relief) of this Consent Decree to the extent that such expenditures or payments both: (a) comply with the requirements set forth in Section VIII (Additional Injunctive Relief) of this Consent Decree; and (b) constitute (i) the Settling Defendants' direct payments for such projects, (ii) the Settling Defendants' external costs for contractors, vendors, and equipment, (iii) the Settling Defendants' internal costs consisting of employee time, travel, or out-of-pocket expenses specifically attributable to these particular projects and documented in accordance with Generally Accepted Accounting Principles ("GAAP"), or (iv) the discounted present value of the cash payments made by the Settling Defendants under a contract with another entity to carry out the project.

36. "Rich Reagent Injection" means a technology that injects reagent, such as ammonia or urea, into a Unit boiler to react with and reduce NO_x emissions.

37. "Selective Catalytic Reduction" means a pollution control device for reducing NO_x emissions through the use of selective catalytic reduction technology.

38. "Selective Non-Catalytic Reduction" means a pollution control device for reducing NO_x emissions through the use of selective non-catalytic reduction technology.

39. "Settling Defendants" means Minnkota Power Cooperative, Inc., and Square Butte Electric Cooperative.

40. "SO_2" means sulfur dioxide, measured in accordance with the provisions of this Consent Decree.

41. "SO_2 Allowance" means "allowance" of SO_2 as defined at 42 U.S.C. § 7651a(3): "an authorization, allocated to an affected Unit by the Administrator of EPA under Subchapter IV of the Act, to emit, during or after a specified calendar year, one ton of sulfur dioxide."

42. "Title V Permit" means the permit required of the Settling Defendants' major sources under Subchapter V of the Act, 42 U.S.C. §§ 7661-7661e.

43. "Unit" means, for the purposes of this Consent Decree, collectively, the coal crusher, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine and boiler, and all ancillary equipment, including pollution control equipment and systems necessary for the production of electricity. An electric utility steam generating station may comprise one or more Units.

IV. SO_2 EMISSION REDUCTIONS AND CONTROLS

A. SO_2 Emission Controls

1. New FGD Installations at Milton R. Young Station Unit 1

44. No later than December 31, 2010, the Settling Defendants shall elect to install either a wet FGD or a dry FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 46) at Unit 1, and shall notify the Plaintiffs in writing as to which option the Settling Defendants have elected for this Unit.

45. Beginning no later than December 31, 2011, the Settling Defendants shall install and commence continuous operation of the FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 46) elected above on Unit 1, and shall achieve and thereafter maintain:

a. If the Settling Defendants elect to install a wet FGD, a 30-Day Rolling Average Removal Efficiency for SO_2 at Unit 1 of at least ninety-five percent (95%), subject to the provisions of Paragraph 49;

b. If the Settling Defendants elect to install a dry FGD, a 30-Day Rolling Average Removal Efficiency for SO_2 at Unit 1 of at least ninety percent (90%).

46. With prior written notice to and written approval from EPA and the State, the Settling Defendants may, in lieu of installing and operating an FGD at Unit 1, install and operate an alternative SO_2 control technology at this Unit that achieves and maintains a 30-Day Rolling Average Removal Efficiency for SO_2 of at least ninety five percent (95%), unless Defendants demonstrate, and Plaintiffs agree, that the alternative control technology will provide significant additional multi-pollutant reductions, in which case Settling Defendant shall achieve and maintain a 30-Day Rolling Average Removal Efficiency for SO_2 of at least ninety percent (90%).

2. <u>FGD Upgrades for Milton R. Young Station Unit 2</u>

47. No later than December 31, 2010, the Settling Defendants shall design and upgrade the FGD on Unit 2. Beginning no later than this same date, the Settling Defendants shall also achieve and thereafter maintain a 30-Day Rolling Average Removal Efficiency for SO_2 at Unit 2 of at least ninety percent (90%), subject to the provisions of Paragraph 49.

3. **Continuous Operation of SO_2 Controls**

48. The Settling Defendants shall continuously operate each FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 46) covered under this Consent Decree at all times that the Unit it serves is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the FGDs, or equivalent technology, for minimizing emissions to the extent practicable. The Settling Defendants need not operate an FGD system during periods of Malfunction of the FGD, or during periods of Malfunction of the Unit that have a significant adverse impact on the operation of the FGD, provided that the Settling Defendants satisfy the requirements for a Malfunction as set forth in Paragraph 138 (Malfunctions). As set forth in Paragraph 138, a Malfunction may also constitute a Force Majeure Event if it meets the requirements for a Force Majeure Event in Section XIV (Force Majeure) of this Consent Decree.

4. **Maximizing SO_2 Emission Reductions while Minimizing Ice Formation During Wintertime Operations of FGDs**

49. In light of the potential for substantial and dangerous ice formation on emission stacks utilizing wet FGDs as a result of the particularly severe winter weather conditions in North Dakota, the Settling Defendants shall, by December 31, 2006, submit to EPA and NDDH for review and approval an evaluation of technologies and best management practices for minimizing and eliminating ice formation on the stacks while minimizing any effect on emission reductions at any Units served or to be served by a wet FGD. Such evaluation shall be performed by an independent contractor, and shall include an analysis of the feasibility, effectiveness, reliability, energy impacts, and economic costs of such technologies and best management practices. In their submittal, the Settling Defendants shall evaluate such

technologies and best management practices, and shall propose either available technologies, best management practices, or both.

a. Upon EPA's and NDDH's approval of the Settling Defendants' evaluation, EPA and NDDH shall provide the Settling Defendants with a written determination regarding an available technology and best management practices. Within 90 days after the installation or upgrade of a wet FGD pursuant to this Consent Decree, the Settling Defendants shall commence implementation of EPA's and NDDH's determination, subject to the Dispute Resolution procedures set forth in Paragraphs 139 through 146 of this Consent Decree.

b. The Settling Defendants shall include in the periodic compliance reports required pursuant to Section XI (Periodic Reporting) of this Consent Decree, a summary of the effectiveness of any technologies and best management practices in minimizing and eliminating ice formation on the stacks while minimizing any effect on emission reductions at any Units served by a wet FGD at the Milton R. Young Unit 2.

B. Tonnage Limits for SO_2 Emissions

50. The Settling Defendants shall comply with the following SO_2 emission limitations for the Milton R. Young Station:

a. Beginning January 1, 2006, the Settling Defendants shall not emit more than 31,000 tons of SO_2 per year based on a Plant-Wide Tonnage for the Annual Average of Two Calendar Years;

b. Beginning January 1, 2011, the Settling Defendants shall not emit more than 26,000 tons of SO_2 per year based on a Plant-Wide Tonnage for One Calendar Year;

c. Beginning January 1, 2012, and each year thereafter, the Settling Defendants shall not emit more than 11,500 tons of SO_2 per year based on a Plant-Wide Tonnage for the Annual Average of Two Calendar Years; and

d. In the event that Milton R. Young Unit 3 is not operational by December 31, 2015, then beginning January 1, 2014, and each year thereafter, the Settling Defendants shall not emit more than 8,500 tons of SO_2 per year based on a Plant-Wide Tonnage for the Annual Average of Two Calendar Years.

51. Beginning on the date of entry of this Consent Decree, and prior to the Settling Defendants' implementation of EPA's and NDDH's determination pursuant to Paragraph 49, above, the Settling Defendants shall continue to implement practices, to the extent practicable, to minimize and eliminate ice formation on the stacks while minimizing any effect on emission reductions at Milton R. Young Unit 2.

52. Notwithstanding the foregoing, the Settling Defendants may submit to EPA and NDDH a petition for a higher SO_2 emissions limitation than the 31,000 ton and 26,000 ton limits noted in Subparagraphs 50(a) and (b), above, if the Settling Defendants can demonstrate that they are unable to comply with such limitation given the energy demands of their cooperative, and despite utilization of best management practices and operation of the Milton R. Young Unit

2 FGD to minimize SO_2 emissions to the maximum extent practicable. EPA's and NDDH's disapproval of any such petition shall be subject to the dispute resolution provisions in Section XV (Dispute Resolution) of this Consent Decree.

53. The Settling Defendants shall not use SO_2 Allowances or credits to comply with the SO_2 emissions limitations set forth in Paragraph 50.

C. Surrender of SO_2 Allowances

54. For purposes of this Subsection, the "surrender of allowances" means permanently surrendering allowances from the accounts administered by EPA for Units 1 and 2—and from Unit 3 to the extent that SO_2 Allowances are allocated by EPA to that Unit – so that such SO_2 Allowances can never be used to meet any compliance requirement under the Clean Air Act, the North Dakota State Implementation Plan, or this Consent Decree.

55. For each year specified below, the Settling Defendants shall surrender to EPA, or transfer to a non-profit third party selected by the Settling Defendants for surrender, SO_2 Allowances that have been allocated to the Milton R. Young Station for the specified calendar year:

Calendar Year	**Amount**
2012-2015	4,346 Allowances
2016-2018	8,693 Allowances
2019	12,170 Allowances
2020 and thereafter	14,886 Allowances if Milton R. Young Units 1, 2, and 3 (as proposed) are operational by December 31, 2015, and 17,886 Allowances if only Milton R. Young Units 1 and 2 are operational by December 31, 2015

The Settling Defendants shall make such surrender annually, within forty-five (45) days of their receipt from EPA of the Annual Deduction Reports for SO_2. Any surrender need not include the specific SO_2 Allowances that were allocated to the Settling Defendants, so long as the Settling Defendants surrender SO_2 Allowances that are from the same year or an earlier year and that are equal to the number required to be surrendered under this Paragraph. The requirements in this Subsection (IV(C)) of the Consent Decree pertaining to the Settling Defendants' use and retirement of SO_2 Allowances are permanent injunctions not subject to any termination provision of this Decree.

56. If any SO_2 Allowances are transferred directly to a non-profit third party, the Settling Defendants shall include a description of such transfer in the next report submitted to EPA and NDDH pursuant to Section XI (Periodic Reporting) of this Consent Decree. Such report shall: (i) provide the identity of the non-profit third-party recipient(s) of the SO_2 Allowances and a listing of the serial numbers of the transferred SO_2 Allowances; and (ii) include a certification by the third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the SO_2 Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any SO_2 Allowances, the Settling Defendants shall include a statement that the third-party recipient(s) surrendered the SO_2 Allowances for permanent surrender to EPA in accordance with the provisions of Paragraphs 54 and 55 within one (1) year after the Settling Defendants transferred the SO_2 Allowances to them. The Settling Defendants shall not have complied with the SO_2 Allowance surrender requirements of this Paragraph until all third-party recipient(s) shall have actually surrendered the transferred SO_2 Allowances to EPA.

57. For all SO_2 Allowances surrendered to EPA, the Settling Defendants or the third-party recipient(s) (as the case may be) shall first submit an SO_2 Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such SO_2 Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, the Settling Defendants or the third-party recipient(s) shall irrevocably authorize the transfer of these SO_2 Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the SO_2 Allowances being surrendered.

D. <u>General SO_2 Provisions</u>

58. In determining Emission Rates for SO_2, the Settling Defendants shall use CEMS in accordance with those reference methods specified in 40 C.F.R. Part 75.

59. For the purpose of calculating the 30-Day Rolling Average Removal Efficiency, the outlet SO_2 Emission Rate and the inlet SO_2 Emission Rate shall be determined based on the data generated in accordance with 40 C.F.R. Part 75 (using SO_2 CEMS data from both the inlet and outlet of the control device).

60. If any Unit subject to this Consent Decree is constructed to allow any flue gas to by-pass the SO_2 pollution control equipment, the outlet 30-Day Rolling Average Emission Rate shall be determined from SO_2 CEMS located after the by-pass return, and the inlet 30-Day Rolling Average Emission Rate shall be determined from SO_2 CEMS located before the by-pass.

V. NOx EMISSION REDUCTIONS AND CONTROLS

A. Phase I NO_x Emissions Reductions and Controls

61. No later than December 31, 2007, the Settling Defendants shall install and commence continuous operation of Over-fire Air on Unit 2 at the Milton R. Young Station.

62. No later than December 31, 2009, the Settling Defendants shall install and commence continuous operation of Over-fire Air on Unit 1 at the Milton R. Young Station.

63. With prior written notice to and written approval from EPA and NDDH, the Settling Defendants may, in lieu of installing and operating the NO_x controls required by Paragraphs 61 or 62, install and operate equivalent technology that will achieve a NO_x emission rate of no greater than 0.36 lb/MMBtu based on a 30-Day Rolling Average Emission Rate.

B. Phase II NO_x Emissions Reductions and Controls

64. The Phase II 30-Day Rolling Average NO_x Emission Rates shall be determined in accordance with the procedures set forth in this subsection.

65. Within six months after entry of this Consent Decree, the Settling Defendants shall submit to NDDH for review and approval, and to EPA for review, a NO_x Top-Down BACT Analysis for each existing coal-fired Unit at the Milton R. Young Station. The Settling Defendants' NO_x Top-Down BACT Analysis shall include all information necessary for NDDH to make a BACT Determination, and any additional information requested by EPA and NDDH. The Settling Defendants' NO_x Top-Down BACT Analysis shall include an evaluation of Selective Catalytic Reduction, Selective Non-Catalytic Reduction, Over-fire Air, and Rich Reagent Injection, as well as other NO_x control technologies. This NO_x Top-Down BACT Analysis is independent and separate from the Settling Defendants' plans to install one or more

technologies pursuant to Paragraphs 61 and 62. The Settling Defendants shall retain a qualified contractor to assist in the performance and completion of each NO_x Top-Down BACT Analysis

66. NDDH shall review the Settling Defendants' NO_x Top-Down BACT Analysis, and shall develop its BACT Determination, in accordance with applicable federal and state statues, regulations, and guidance, including those cited in the definition of a NO_x Top-Down BACT Analysis under this Consent Decree. After consultation with EPA, NDDH shall provide to the Parties its BACT Determination for NO_x emissions from each existing coal-fired Unit at the Milton R. Young Station. NDDH's BACT Determination shall include for each Unit the specific control technologies to be installed and a specific Phase II 30-Day Rolling Average NO_x Emission Rate limitation (lbs/MMBtu). NDDH's BACT Determination shall also address specific NO_x emission limitations during Unit startups. NDDH's BACT Determination shall be subject to the Dispute Resolution procedures set forth in Paragraph 147 of this Consent Decree.

67. Beginning no later than December 31, 2010, the Settling Defendants shall achieve and maintain the Phase II 30-Day Rolling Average NO_x Emission Rates established by NDDH through its NO_x BACT Determination for Unit 2. Beginning no later than December 31, 2011, the Settling Defendants shall achieve and maintain the Phase II 30-Day Rolling Average NO_x Emission Rates established by NDDH through its NO_x BACT Determination for Unit 1. Such Phase II 30-Day Rolling Average NO_x Emission Rates shall not affect the Settling Defendants' obligation to also comply with the Phase I 30-Day Rolling Average NO_x Emission Rates set forth herein.

C. <u>Use of NO_x Allowances</u>

68. Except as provided in this Consent Decree, the Settling Defendants shall not sell or

trade any surplus NO_x Allowances allocated to Units 1, 2, and 3 at the Milton R. Young Station that would otherwise be available for sale or trade as a result of the actions taken by the Settling Defendants to comply with the requirements of this Consent Decree.

69. The number of NO_x Allowances that are surplus to the Settling Defendants' NO_x Allowance-holding requirements shall be equal to the amount by which the NO_x Allowances allocated to the Settling Defendants' Units 1, 2, and 3 at the Milton R. Young Station for a particular year are greater than the total amount of NO_x emissions from those same Units for the same year.

70. Provided that the Settling Defendants are in compliance with the NO_x emission limitations of this Consent Decree, nothing in this Consent Decree shall preclude the Settling Defendants from selling or transferring NO_x Allowances allocated to the Milton R. Young Station that become available for sale or trade as a result of:

a. activities that reduce NO_x emissions from any Unit at the Milton R. Young Station prior to the date of entry of this Consent Decree;

b. the installation and operation of any NO_x pollution control technology or technique that is not otherwise required under this Consent Decree;

c. achievement and maintenance of NO_x emission rates below the emission limits required by Section V (NO_x Emissions Reductions and Controls);

d. permanent shutdown of any Unit at the Milton R. Young Stations not otherwise required by this Consent Decree; and

e. other emission reduction measures that are agreed to by the Parties and made enforceable through modifications of this Consent Decree;

so long as the Settling Defendants timely report the generation of such surplus NO_x Allowances in accordance with Section XI (Periodic Reporting) of this Consent Decree. The Settling Defendants shall be allowed to sell or transfer NO_x Allowances equal to the NO_x emissions reductions achieved for any given year by any of the actions specified in Subparagraphs (b) through (e) only to the extent that the total NO_x emissions from all Units at the Milton R. Young Station are below the emissions limits required by this Consent Decree.

71. The Settling Defendants may not purchase or otherwise obtain NO_x Allowances from another source for purposes of complying with the requirements of this Consent Decree. However, nothing in this Consent Decree shall prevent the Settling Defendants from purchasing or otherwise obtaining NO_x Allowances from another source for purposes of complying with state or federal Clean Air Act requirements to the extent otherwise allowed by law.

D. <u>General NO_x Provisions</u>

72. In determining Emission Rates for NO_x, the Settling Defendants shall use CEMS in accordance with the reference methods specified in 40 C.F.R., Part 75.

73. At any time following the commencement of operation of the specific NO_x control technologies required by the NDDH's NO_x BACT Determination, the Settling Defendants may petition the Plaintiffs to revise the applicable Phase II 30-Day Rolling Average Emission Rate for NO_x. In their petition, the Settling Defendants shall demonstrate and explain why they cannot consistently achieve and maintain the 30-Day Rolling Average Emission NO_x Rate required by the NDDH's NO_x BACT Determination for the Unit in question, considering all relevant information. The Settling Defendants shall include in such petition a proposed

alternative 30-Day Rolling Average Emission Rate for NO_x. The Settling Defendants shall also retain a qualified contractor to assist in the preparation and completion of the petition for an alternative 30-Day Rolling Average Emission Rate for NO_x. The Settling Defendants shall provide with each petition all pertinent documents and data. If the Plaintiffs disapprove the alternative 30-Day Rolling Average Emission Rate for NO_x proposed by the Settling Defendants, such disapproval shall be subject to the provisions of Section XV (Dispute Resolution) of this Consent Decree. The Settling Defendants shall submit any petition for any Unit under this Paragraph no later than six (6) months after the final compliance date specified for that Unit in Paragraph 67.

74. The Settling Defendants shall continuously operate all NO_x control technology installed on the Milton R. Young Units at all times that the Unit served is in operation, consistent with the technological limitations, manufacturers' specifications to the extent practicable, and good engineering and maintenance practices for the NO_x control technology. The Settling Defendants need not operate NO_x control technology during periods of Malfunction of the NO_x control technology, or during periods of Malfunction of the Unit that have a significant adverse impact on the operation of the NO_x control technology, provided that the Settling Defendants satisfy the requirements for Malfunction Events as set forth in Paragraph 138 (Malfunction Events). As set forth in Paragraph 138, a Malfunction may also constitute a Force Majeure Event if it meets the requirements for a Force Majeure Event in Section XIV (Force Majeure) of this Consent Decree.

VI. PM EMISSION REDUCTIONS AND CONTROLS

A. Optimization of PM Emission Controls

75. Within ninety (90) days after entry of this Consent Decree and continuing thereafter, the Settling Defendants shall continuously operate each PM Control Device on the Milton R. Young Station Units to maximize PM emission reductions, consistent with the operational and maintenance limitations of the units. Specifically, the Settling Defendants shall, at a minimum: (a) energize each section of the ESP for each Unit, regardless of whether that action is needed to comply with opacity limits; (b) maintain the energy or power levels delivered to the ESP for each Unit to achieve the greatest possible removal of PM; (c) make best efforts to expeditiously repair and return to service transformer-rectifier sets when they fail; (d) inspect for, and schedule for repair, any openings in ESP casings and ductwork to minimize air leakage; (e) optimize for Unit 1 the plate-cleaning and discharge-electrode cleaning systems for the ESP by varying the cycle time, cycle frequency, rapper-vibrator intensity, and number of strikes per cleaning event; and (f) optimize for Unit 2 the plate-cleaning system for the ESP by varying the cycle time and frequency of the cycle.

B. <u>Compliance with PM Emission Limits</u>

76. Within one year of entry of the Consent Decree, and continuing annually thereafter, the Settling Defendants shall demonstrate, in accordance with Paragraphs 80 and 81, that Unit 2 at the Milton R. Young Station can achieve and thereafter maintain a PM Emission Rate of no greater than 0.030 lb/MMBtu.

77. No later than one-hundred-eighty (180) days after the Settling Defendants install and commence continuous operation of the FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 46) on Unit 1 at the Milton R. Young Station, and continuing annually thereafter, the Settling Defendants shall demonstrate, in accordance with Paragraphs 80 and 81,

that Unit 1 at the Milton R. Young Station can achieve and thereafter maintain a PM Emission Rate of:

a. No greater than 0.030 lb/MMBtu if the Settling Defendants install a wet FGD; and

b. No greater than 0.015 lb/MMBtu if the Settling Defendants install a dry FGD.

78. The Settling Defendants shall continuously operate each ESP or baghouse at the Milton R. Young Station at all times that each Unit the ESP or baghouse serves is combusting Fossil Fuel, consistent with good engineering practices for PM control, to minimize PM emissions to the extent practicable. The Settling Defendants need not operate an ESP or baghouse during periods of Malfunction of the ESP or baghouse, or during periods of Malfunction of the Unit that have a significant adverse impact on the operation of the ESP or baghouse, provided that the Settling Defendants satisfy the requirements for Malfunction Events as set forth in Paragraph 138 (Malfunction Events). As set forth in Paragraph 138, a Malfunction may also constitute a Force Majeure Event if it meets the requirements for a Force Majeure Event in Section XIV (Force Majeure) of this Consent Decree.

79. Within 180 days after the Settling Defendants complete the installation of any equipment required by Paragraphs 76 and 77, the Settling Defendants shall conduct a performance test demonstration to ensure that the PM emission limitation set forth in Paragraphs 76 and 77 can be consistently achieved in practice, including all requirements pertaining to proper operation and maintenance of control equipment. If the performance demonstration shows that the control equipment cannot consistently meet the required PM emission limitation, the Settling Defendants shall submit a report to EPA and NDDH proposing alternative emission

limits.

C. PM Monitoring

1. PM Stack Tests

80. Beginning in calendar year 2006, and continuing annually thereafter, the Settling Defendants shall conduct PM performance testing on Milton R. Young Station Units 1 and 2. Such annual performance tests may be satisfied by stack tests conducted in a given year, in accordance with the Settling Defendants' permit from the State of North Dakota.

81. In determining the PM Emission Rate, the Settling Defendants shall use the reference methods specified in 40 C.F.R. Part 60, App. A, Method 5 (filterable portion only) or 40 C.F.R. Part 60, App. A, Method 17 (filterable portion only), using stack tests, or alternative methods that are requested by the Settling Defendants and approved by EPA. The Settling Defendants shall also calculate the PM Emission Rates from annual stack tests in accordance with 40 C.F.R. § 60.8(f). In addition, the Settling Defendants shall submit the results of each PM stack test to NDDH and EPA within forty-five (45) days of completion of each test.

2. PM CEMS

82. The Settling Defendants shall install and operate PM CEMS in accordance with Paragraphs 82 through 88 on Unit 2 at the Milton R. Young Station. The PM CEMS shall comprise a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert the concentration to units of lb/MMBtu. The Settling Defendants shall maintain, in an electronic database, the hourly average emission values of all PM CEMS in lb/MMBtu. The Settling Defendants shall use reasonable efforts to keep the PM CEMS running and producing data whenever Unit 2 is

operating.

83. No later than six (6) months after entry of this Consent Decree, the Settling Defendants shall submit to EPA and NDDH for review and approval pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree a plan for the installation and certification of the PM CEMS for Milton R. Young Unit 2.

84. No later than one hundred twenty (120) days prior to the deadline to commence operation of the PM CEMS, the Settling Defendants shall submit to EPA and NDDH for review and approval pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree a proposed Quality Assurance/Quality Control ("QA/QC") protocol that shall be followed in calibrating such PM CEMS. Following EPA and NDDH's approval of the protocol, the Settling Defendants shall thereafter operate the PM CEMS in accordance with the approved protocol.

85. In developing both the plan for installation and certification of the PM CEMS and the QA/QC protocol, the Settling Defendants shall use the criteria set forth in EPA's Amendments to Standards of Performance for New Stationary Sources: Monitoring Requirements, 69 Fed. Reg. 1786 (January 12, 2004).

86. The Settling Defendants shall install and commence operation of PM CEMS on or before June 30, 2008.

87. By December 31, 2008, the Settling Defendants shall conduct tests and demonstrate compliance with the PM CEMS installation and certification plan submitted to and approved by EPA and NDDH in accordance with Paragraphs 83 and 84.

88. The Settling Defendants shall operate continuous opacity monitors on Unit 1 and

Unit 2 of the Milton R. Young Station at all times those units are in operation. However, if the Settling Defendants demonstrate that either one of these continuous opacity monitors cannot provide accurate opacity measurement due to the formation of liquid water droplets in the flue gas of a stack with a wet FGD, in accordance with Question 5.6, Part 75 of EPA's Emission Monitoring Policy Manual, then the Settling Defendants may submit to EPA and NDDH for review and approval alternative opacity procedures and requirements pursuant to the provisions of 40 C.F.R. § 60.13(i)(1).

VII. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

89. Emission reductions generated by the Settling Defendants to comply with the requirements of this Consent Decree shall not be considered as a creditable emission decrease for the purpose of obtaining a netting credit under the Clean Air Act's Nonattainment NSR and PSD programs. Notwithstanding the preceding sentence, the Settling Defendants may use any emission decreases of NO_x, SO_2, and PM generated under this Consent Decree at Units 1 and 2 as creditable decreases for the purpose of obtaining netting credit for these pollutants at Unit 3 under the Clean Air Act's Nonattainment NSR and PSD programs, if:

a. The Settling Defendants submit, as and addendum to its construction permit application for Unit 3, an analysis that proposes emissions limits for NO_x, SO_2, and PM that are equivalent to BACT as defined in the 42 U.S.C. § 7479(3), and NDDH issues a federally enforceable permit for Unit 3 that includes emissions limits that reflect BACT-equivalent level controls at the time of construction of the Unit, and that are at least as stringent as a 30-Day Rolling Average SO_2

Removal Efficiency of at least ninety-five percent 95% (if the Settling Defendants install a wet FGD on Unit 3) or 90% (if the Settling Defendants install a dry FGD on Unit 3), a 30-Day Rolling Average NO_x Emission Rate not greater than 0.100 lb/MMBtu, and an Emission Rate for PM of no greater than 0.015 lbs/MMBtu, provided that, at any time following the commencement of operation of this new Unit, the Settling Defendants may submit to EPA and NDDH a written petition for a higher 30-Day Rolling Average NO_x Emission Rate if the Settling Defendants can demonstrate that it cannot achieve such an emission rate on this new Unit;

b. The Settling Defendants have been and remain in full compliance with the plant-wide SO_2 tonnage limitation set forth in Paragraph 50 of this Consent Decree and NDDH has issued a federally-enforceable permit for Units 1, 2, and 3 that will limit the Plant-Wide Annual Average of the Tonnage for Two Calendar Years for SO_2 at those units to 11,500 tons per year commencing January 1, 2012; and

c. NDDH determines through air quality modeling submitted by the Settling Defendants in accordance with NDDH modeling protocols that the impact on either a PSD increment or on visibility in Class I Areas from the combined emissions at Units 1, 2 and 3, after the pollution control upgrades and installations required by this Consent Decree are operational, will be less than the impact from the combined emissions at Units 1 and 2 before such controls are operational.

90. Decreases in actual emissions of NO_x, SO_2, and PM generated under this Consent Decree at Units 1 and 2 qualify as contemporaneous decreases under 40 C.F.R. § 52.21(b)(3)(ii)

(July 1, 2005) for the purpose of obtaining netting credits for these pollutants at Unit 3, as long as the Settling Defendants commence construction of Unit 3 on or before December 31, 2012.

91. Nothing in this Consent Decree is intended to affect the application of Section 33-15-15-01.2 of the North Dakota Administrative Code regarding the availability of extensions on the commencement of construction for newly permitted facilities.

92. Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Consent Decree from being considered by NDDH and EPA as creditable emission decreases for the purpose of attainment demonstrations submitted pursuant to Section 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS or PSD increment.

VIII. ADDITIONAL INJUNCTIVE RELIEF

93. The Settling Defendants shall implement the wind turbine project ("Project") described in this Section in compliance with the approved plans and schedules for such Project and other terms of this Consent Decree. The Settling Defendants shall submit plans for the Project to the United States for review and approval pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree in accordance with the schedules set forth in this Section. In implementing the Project, the Settling Defendants shall spend no less than $5.0 million in funds ("Project Dollars") pursuant to the schedule set forth in Paragraph 103. The Settling Defendants shall maintain, and present to the United States, upon request, all documents to substantiate the Project Dollars expended and shall provide these documents to the United States and NDDH within thirty (30) days of a request by the United States or NDDH for the documents.

94. The Settling Defendants shall make all plans and reports prepared by the Settling

Defendants pursuant to the requirements of this Section of the Consent Decree publicly available without charge.

95. The Settling Defendants shall certify, as part of the plan submitted to the United States for the Project that, as of the date of this Consent Decree, the Settling Defendants are not otherwise required by law to perform the Project described in the plan, that the Settling Defendants are unaware of any other person who is required by law to perform the Project, and that the Settling Defendants will not use the Project, or portion thereof, to satisfy any obligations that it may have under other applicable requirements of law.

96. The Settling Defendants shall use good faith efforts to secure as much benefit as possible for the Project Dollars expended, consistent with the applicable requirements and limits of this Consent Decree.

97. Regardless of whether the Settling Defendants elected (where such election is allowed) to undertake the Project by itself or to do so by contributing funds to another person or instrumentality that will carry out the Project, the Settling Defendants acknowledge that they will receive credit for the expenditure of such funds as Project Dollars only if the Settling Defendants demonstrate that the funds have been actually spent by either the Settling Defendants or by the person or instrumentality receiving them (or, in the case of internal costs, have actually been incurred by the Settling Defendants), and that such expenditures met all requirements of this Consent Decree.

98. The Settling Defendants shall receive full credit for their expenditures only to the extent that they do not receive an offsetting financial or economic benefit from such expenditures; in determining how many Project Dollars have been spent by the Settling

Defendants, the Settling Defendants shall debit any such offsetting financial or economic benefit received against any of the Settling Defendants' expenditures for the Project.

99. Within sixty (60) days following the completion of the Project required under this Consent Decree, the Settling Defendants shall submit to the United States a report that documents the date that the Project was completed, the Settling Defendants' results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by the Settling Defendants in implementing the Project.

100. The Settling Defendants shall not financially benefit to a greater extent than any other member of the general public from the sale or transfer of technology obtained in the course of implementing any Project.

101. Project Dollar credit given for the Project shall reflect the Settling Defendants' net cost in implementing the Project, and any economic benefit or income resulting from the Project shall be deducted from the Project Dollar credit given to the Project.

102. Beginning one (1) year after entry of this Consent Decree, the Settling Defendants shall provide the United States with semi-annual updates concerning the progress of the Project.

103. Within 180 days after entry of this Consent Decree, the Settling Defendants shall submit a plan to EPA and the State for a Project to provide their members with electricity generated from wind turbines. The Project shall require the Settling Defendants to either (a) by December 31, 2012, spend no less than $5,000,000 in Project Dollars to purchase and install its own wind turbines, or (b) by December 31, 2009, enter into a power purchase agreement with a provider of wind energy that requires the provider of wind energy to build new wind turbines by

this same date in the Settling Defendants' service territory with a capacity of approximately 5 MW, and that obligates the Settling Defendants to purchase the entire electric output from the turbines for a period of no less than 15 years. The power purchase agreement shall have a discounted present value of cash outflows of no less than $5,000,000, based on a discount rate of 6.25%.

IX. CIVIL PENALTY

104. Within thirty (30) calendar days after entry of this Consent Decree, the Settling Defendants shall pay to the United States a civil penalty in the amount of $425,000. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing USAO File Number 2006V0009 and DOJ Case Number 90-5-2-1-07717 and the civil action case name and case number of this action. The costs of such EFT shall be the Settling Defendants' responsibility. Payment shall be made in accordance with instructions provided to the Settling Defendants by the Financial Litigation Unit of the U.S. Attorney's Office for the District of North Dakota. Any funds received after 2:00 p.m. EDT shall be credited on the next business day. At the time of payment, the Settling Defendants shall provide notice of payment, referencing the USAO File Number, the DOJ Case Number, and the civil action case name and case number, to the Department of Justice and to EPA in accordance with Section XVIII (Notices) of this Consent Decree.

105. Within thirty (30) calendar days after entry of this Consent Decree, the Settling Defendants shall pay to the State a civil penalty in the amount of $425,000. Payment shall be made in the form of a certified check or cashier's check, and be payable to "North Dakota Department of Health" Payment shall be sent to the Director, Air Quality Division, North

Dakota Department of Health, Bismark, North Dakota 58506-5520. To ensure proper credit, the check must reference *United States, et al. v. Minnkota Power Cooperative, et al.*, and the civil action case number

106. Failure to timely pay the civil penalty shall subject the Settling Defendants to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render the Settling Defendants liable for all charges. costs, fees. and penalties established by law for the benefit of a creditor or of the United States in securing payment.

107. Payments made pursuant to this Section are penalties within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and are not tax-deductible expenditures for purposes of federal law.

X. RESOLUTION OF CLAIMS

A. Resolution of Plaintiffs' Civil Claims

108. **Claims Based on Modifications Occurring Before the Lodging of Consent Decree.** Entry of this Consent Decree shall resolve all civil claims of the Plaintiffs under;

a. Parts C and D of Subchapter I of the Clean Air Act;

b. Section 111 of the Clean Air Act and 40 C.F.R. Part 60;

c. Sections 502(a) and 504(a) of the Clean Air Act, but only to the extent that such claims are based on the Settling Defendants' failure to obtain an operating permit that reflects applicable requirements imposed under Part C of Subchapter I of the Clean Air Act; and

d. Chapters 33-15-12 and 33-15-15 of the North Dakota Administrative Code, as well as Chapters 33-15-01 and 33-15-14 as they relate to Chapters 33-15-12 and 33-15-15, and all relevant prior versions of these regulations;

that arose from any modification that commenced at the Milton R. Young Station prior to the date of lodging of this Consent Decree, including but not limited to modifications alleged in the Complaint filed by the Plaintiffs in this civil action.

109. **Claims Based on Modifications After the Lodging of Consent Decree.** Entry of this Decree also shall resolve all civil claims of the Plaintiffs for pollutants regulated under:

a. Parts C and D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder as of the date of lodging of this Decree; and

b. Chapter 33-15-15 of the North Dakota Administrative Code, as well as Chapter 33-15-01 and 33-15-14 as they relate to Chapter 33-15-15;

where such claims are based on a modification completed before December 31, 2015 and: i) commenced at either Unit 1 or Unit 2 at the Milton R. Young Station after lodging of this Decree; or ii) that this Consent Decree expressly directs the Settling Defendants to undertake. The term "modification" as used in this Paragraph shall have the meaning that term is given under the Clean Air Act statute as it existed on the date of lodging of this Decree.

110. Reopener. The resolution of the civil claims of the United States provided by this Subsection is subject to the provisions of Section B of this Section.

B. Pursuit of Plaintiffs' Civil Claims Otherwise Resolved

111. **Bases for Pursuing Resolved Claims.** If the Settling Defendants:

a. fail by more than ninety (90) days (which may be extended by written agreement of the Parties) to complete installation or upgrade, and commence operation, of any emission control device, unless that failure is excused under the Force Majeure provisions of this Consent Decree; or

b. emit more SO_2 than allowed by the following tonnage limitations:

1. 31,000 tons of SO_2 based on a Plant-Wide 12-Month Rolling Average Tonnage beginning January 1, 2006;

2. 26,000 tons of SO_2 based on a Plant-Wide 12-Month Rolling Average Tonnage beginning January 1, 2011;

3. 11,500 tons of SO_2 based on a Plant-Wide 12-Month Rolling Average Tonnage beginning January 1, 2012; and

4. 8,500 tons of SO_2 per year based on a Plant-Wide 12-Month Rolling Average Tonnage beginning January 1, 2014, in the event that Milton R. Young Unit 3 is not operational by December 31, 2015;

then the Plaintiffs may pursue any claim that is otherwise covered by the covenant not to sue or to bring administrative action under Subsection A of this Section for any claims based on modifications undertaken at a Unit where the modification(s) on which such claim is based was commenced after lodging of the Consent Decree and within the five years preceding the violation or failure specified in this Paragraph.

112. **Additional Bases for Pursuing Resolved Claims for Modifications.** The Plaintiffs may also pursue claims arising from a modification (or collection of modifications) at a Unit that is otherwise covered by the covenant not to sue or to bring administrative action under Subsection A of this Section, if the modification (or collection of modifications) at the Unit on

which such claims are based (a) was commenced after lodging of this Consent Decree, and (b) individually (or collectively) increased the maximum hourly emission rate of that Unit for NO_x or SO_2 (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%).

XI. PERIODIC REPORTING

113. Beginning thirty (30) days after the end of the first full calendar quarter following the entry of this Consent Decree, continuing on a semi-annual basis until December 31, 2020, and in addition to any other express reporting requirement in this Consent Decree, the Settling Defendants shall submit to EPA and the State a progress report, containing

a. all information necessary to determine compliance with this Consent Decree, including but not limited to information required to be included in the reports pursuant to Paragraphs 49, 55, 56, 70, and 99; and

b. all information indicating that the installation and commencement of operation for a pollution control device may be delayed, including the nature and cause of the delay, and any steps taken by the Settling Defendants to mitigate such delay.

114. In any periodic progress report submitted pursuant to this Section, the Settling Defendants may incorporate by reference information previously submitted under their Title V permitting requirements, provided that the Settling Defendants attach the Title V permit report (or pertinent portions of such report) and provide a specific reference to the provisions of the Title V permit report that are responsive to the information required in the periodic progress report.

115. In addition to the progress reports required pursuant to this Section, the Settling Defendants shall provide a written report to Plaintiffs of any violation of the requirements of this

Consent Decree, including exceedances of the 30-Day Rolling Average Removal Efficiencies, 30-day Rolling Average Emission Rates, PM Emission Rates, and Plant-Wide Tonnage limits within ten (10) business days of when the Settling Defendants knew or should have known of any such violation. In this report, the Settling Defendants shall explain the cause or causes of the violation and all measures taken or to be taken by the Settling Defendants to prevent such violations in the future. Exceedances of the PM Emission Rates shall be reported within forty-five (45) days of the completion of the stack test that demonstrates such non-compliance. In this report, the Settling Defendants shall explain the cause or causes of the violation and all measures taken or to be taken by the Settling Defendants to prevent such violations in the future.

116. Each Settling Defendant's report shall be signed by each of the Settling Defendant's Environmental Manager or, in his or her absence, the Settling Defendant's Vice President of Generation, or higher ranking official, and shall contain the following certification:

> This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the direction and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

XII. REVIEW AND APPROVAL OF SUBMITTALS

117. The Settling Defendants shall submit each plan, report, or other submission to EPA and the State whenever such a document is required to be submitted for review or approval pursuant to this Consent Decree. EPA and the State, to the extent that this Consent Decree provides for joint approval with the State, may approve the submittal or decline to approve it and provide written comments. Within sixty (60) days of receiving written comments from EPA, the Settling Defendants shall either: (a) revise the submittal consistent with the written comments and provide the revised submittal for final approval to EPA and, if applicable, to the State; or (b) submit the matter for dispute resolution, including the period of informal negotiations, under Section XV (Dispute Resolution) of this Consent Decree.

118. Upon receipt of EPA's final approval of the submittal, and the State's final approval, if applicable, or upon completion of the submittal pursuant to dispute resolution, the Settling Defendants shall implement the approved submittal in accordance with the schedule specified therein.

XIII. STIPULATED PENALTIES

119. For any failure by the Settling Defendants to comply with the terms of this Consent Decree, and subject to the provisions of Sections XIV (Force Majeure) and XV (Dispute Resolution) of this Consent Decree, the Settling Defendants shall pay, within thirty (30) days after receipt of written demand to the Settling Defendants by the United States, the following stipulated penalties to the United States:

Consent Decree Violation	Stipulated Penalty (Per day per violation, unless otherwise specified)

a. Failure to pay the civil penalty as specified in Section IX (Civil Penalty) of this Consent Decree	\$10,000
b. Failure to comply with any applicable NO_x emission rate resulting from the State's BACT determination, 30-Day Rolling Average Removal Efficiency for SO_2, or Emission Rate for PM, where the violation is less than 5% in excess of the limits set forth in this Consent Decree	\$2,500
c. Failure to comply with any applicable NO_x emission rate or removal efficiency resulting from the State's BACT determination, 30-Day Rolling Average Removal Efficiency for SO_2, or Emission Rate for PM, where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree	\$5,000
d. Failure to comply with any applicable NO_x emission rate or removal efficiency resulting from the State's BACT determination, 30-Day Rolling Average Removal Efficiency for SO_2, or Emission Rate for PM, where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree	\$10,000
e. Failure to comply with the Plant-Wide Tonnage Limitations for One Calendar Year or the Plant-Wide Tonnage Limitations for the Annual Average of Two Calendar Years	\$60,000 per ton per year for the first 100 tons over the limit, and \$120,000 per ton per year for each additional ton over the limit
f. Failure to install, upgrade, commence operation, or continue operation of the NO_x, SO_2, and PM pollution control devices on any Unit	\$10,000 during the first 30 days, \$27,000 thereafter
g. Failure to install or operate CEMS as required in Paragraphs 82 through 88	\$1,000
h. Failure to conduct annual performance tests of PM emissions, as required by Paragraphs 80 and 81	\$1,000
i. Failure to apply for any permit required by this Consent Decree	\$1,000

j. Failure to timely submit, modify, or implement, as approved, the reports, plans, studies, analyses, protocols, or other submittals required by this Consent Decree	$750 during the first ten days, $1,000 thereafter
k. Using, selling, or transferring SO_2 Allowances, except as permitted in this Consent Decree	the surrender, pursuant to the procedures set forth in Paragraphs 55 through 57 of this Consent Decree, of SO_2 Allowances in an amount equal to four times the number of SO_2 Allowances used, sold, or transferred in violation of this Consent Decree
l. Using, selling or transferring NO_x Allowances except as permitted in Paragraphs 68 through 71	the surrender of NO_x Allowances in an amount equal to four times the number of NO_x Allowances used, sold, or transferred in violation of this Consent Decree
m. Failure to surrender an SO_2 Allowance as required by Subsection B (Surrender of SO_2 Allowances) of Section IV (SO_2 Emission Reductions and Controls)	(a) $27,500 plus (b) $1,000 per SO_2 Allowance
n. Failure to undertake and complete any of the Projects in compliance with Section VIII (Additional Injunctive Relief) of this Consent Decree	$1,000 during the first 30 days, $5,000 thereafter
o. Any other violation of this Consent Decree	$1,000

120. Notwithstanding the foregoing, the Settling Defendants shall not be liable for failure to comply with a 30-Day Rolling Average Removal Efficiency for SO_2 if the Settling Defendants are in full compliance with the requirements of Paragraph 49 of this Consent Decree, such exceedance is due to the Settling Defendants' efforts to reduce ice formation on a wet FGD stack by resorting to a partial bypass of their FGD, and the Settling Defendants maintain a 30-Day Rolling Average Removal Efficiency for SO_2 of no less than 83% during such periods of

partial bypass.

121. Violation of an Emission Rate or removal efficiency that is based on a 30-Day Rolling Average is a violation on every day on which the average is based.

122. Where a violation of a 30-Day Rolling Average Removal Efficiency (from the same source) recurs within periods of less than thirty (30) days, the Settling Defendants shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

123. All stipulated penalties shall begin to accrue on the day after the performance is due or on the day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases. Nothing in this Consent Decree shall prevent the simultaneous accrual of separate stipulated penalties for separate violations of this Consent Decree.

124. The Settling Defendants shall pay all stipulated penalties to the Plaintiffs within thirty (30) days of receipt of written demand to the Settling Defendants from the United States, and shall continue to make such payments every thirty (30) days thereafter until the violation(s) no longer continues, unless the Settling Defendants elects within 20 days of receipt of written demand to the Settling Defendants from the United States to dispute the accrual of stipulated penalties in accordance with the provisions in Section XV (Dispute Resolution) of this Consent Decree.

125. Stipulated penalties shall continue to accrue as provided in Paragraph 119 during any dispute, with interest on accrued stipulated penalties payable and calculated at the rate established by the Secretary of the Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid

until the following:

a. If the dispute is resolved by agreement, or by a decision of Plaintiffs pursuant to Section XV (Dispute Resolution) of this Consent Decree that is not appealed to the Court, accrued stipulated penalties agreed or determined to be owing, together with accrued interest, shall be paid within thirty (30) days of the effective date of the agreement or of the receipt of Plaintiffs' decision;

b. If the dispute is appealed to the Court and Plaintiffs prevail in whole or in part, the Settling Defendants shall, within sixty (60) days of receipt of the Court's decision or order, pay all accrued stipulated penalties determined by the Court to be owing, together with accrued interest, except as provided in Subparagraph (c);

c. If the Court's decision is appealed by any Party, the Settling Defendants shall, within fifteen (15) days of receipt of the final appellate court decision, pay all accrued stipulated penalties determined to be owing, together with accrued interest.

For purposes of this Paragraph, the accrued stipulated penalties agreed by the Parties, or determined by the Plaintiffs through Dispute Resolution, to be owing may be less than the stipulated penalty amounts set forth in Paragraph 119. The Settling Defendants need not pay any stipulated penalties based on violations which they dispute and ultimately prevail under the Dispute Resolution provisions of this Consent Decree.

126. All stipulated penalties shall be paid in the manner set forth in Section IX (Civil Penalty) of this Consent Decree.

127. Should the Settling Defendants fail to pay stipulated penalties in compliance with

the terms of this Consent Decree, the Plaintiffs shall be entitled to collect interest on such penalties, as provided for in 28 U.S.C. § 1961.

128. The stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to any Plaintiff by reason of the Settling Defendants' failure to comply with any requirement of this Consent Decree or applicable law, except that for any violation of the Act for which this Consent Decree provides for payment of a stipulated penalty, the Settling Defendants shall be allowed a credit for stipulated penalties paid against any statutory penalties also imposed for such violation.

XIV. FORCE MAJEURE

129. For purposes of this Consent Decree, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of the Settling Defendants, their contractors, or any entity controlled by the Settling Defendants that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite the Settling Defendants' best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay or violation is minimized to the greatest extent possible.

130. **Notice of Force Majeure Events.** If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which the Settling Defendants intends to assert a claim of Force Majeure, the Settling Defendants shall notify the United States and the State in writing as soon as practicable, but in no event later than fourteen (14) business days following the date the Settling Defendants

first knew, or by the exercise of due diligence should have known, that the event caused or may cause such delay or violation. In this notice, the Settling Defendants shall reference this Paragraph of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by the Settling Defendants to prevent or minimize the delay or violation, the schedule by which the Settling Defendants proposes to implement those measures, and the Settling Defendants' rationale for attributing a delay or violation to a Force Majeure Event. The Settling Defendants shall adopt all reasonable measures to avoid or minimize such delays or violations. The Settling Defendants shall be deemed to know of any circumstance which the Settling Defendants, their contractors, or any entity controlled by the Settling Defendants knew or should have known.

131. **Failure to Give Notice**. If the Settling Defendants fails to comply with the notice requirements in the preceding Paragraph, the Plaintiffs may void the Settling Defendants' claim for Force Majeure as to the specific event for which the Settling Defendants have failed to comply with such notice requirement.

132. **Plaintiffs' Response.** The Plaintiffs shall notify the Settling Defendants in writing regarding the Settling Defendants' claim of Force Majeure within twenty (20) business days of receipt of the notice provided under Paragraph 130. If the Plaintiffs agree that a delay in performance has been or will be caused by a Force Majeure Event, the Parties shall stipulate to an extension of deadline(s) for performance of the affected compliance requirement(s) by a period equal to the delay actually caused by the event. In such circumstances, an appropriate modification shall be made pursuant to Section XXII (Modification) of this Consent Decree.

133. **Disagreement.** If the Plaintiffs do not accept the Settling Defendants' claim of Force Majeure, or if the Parties cannot agree on the length of the delay actually caused by the Force Majeure Event, the matter shall be resolved in accordance with Section XV (Dispute Resolution) of this Consent Decree.

134. **Burden of Proof.** In any dispute regarding Force Majeure, the Settling Defendants shall bear the burden of proving that any delay in performance or any other violation of any requirement of this Consent Decree was caused by or will be caused by a Force Majeure Event. The Settling Defendants shall also bear the burden of proving that the Settling Defendants gave the notice required by Paragraph 130 and the burden of proving the anticipated duration and extent of any delay(s) attributable to a Force Majeure Event. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

135. **Events Excluded.** Unanticipated or increased costs or expenses associated with the performance of the Settling Defendants' obligations under this Consent Decree shall not constitute a Force Majeure Event.

136. **Potential Force Majeure Events**. The Parties agree that, depending upon the circumstances related to an event and the Settling Defendants' response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Section: construction, labor, or equipment delays; Malfunction of a Unit or emission control device; acts of God; acts of war or terrorism; and orders by a government official, government agency, or other regulatory body acting under and authorized by applicable law that directs the Settling Defendants to supply electricity in response to a

system-wide (state-wide or regional) emergency. Depending upon the circumstances and the Settling Defendants' response to such circumstances, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure Event where the failure of the permitting authority to act is beyond the control of the Settling Defendants and the Settling Defendants have taken all steps available to it to obtain the necessary permit, including, but not limited to: submitting a complete permit application; responding to requests for additional information by the permitting authority in a timely fashion; and accepting lawful permit terms and conditions after expeditiously exhausting any legal rights to appeal terms and conditions imposed by the permitting authority, provided that the Settling Defendants shall not be precluded from asserting that a new Force Majeure Event has caused or may cause a new or additional delay in complying with the extended or modified schedule.

137. As part of the resolution of any matter submitted to this Court under Section XV (Dispute Resolution) of this Consent Decree regarding a claim of Force Majeure, the Parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States and the State or approved by the Court. The Settling Defendants shall be liable for stipulated penalties for their failure thereafter to complete the work in accordance with the extended or modified schedule.

138. **Malfunctions.** The Settling Defendants shall notify EPA and NDDH in writing of each Malfunction impacting a pollution control technology required by this Consent Decree as soon as practicable, but in no event later than fourteen (14) business days following the date that the Settling Defendants first knew, or by the exercise of due diligence should have known, of the

Malfunction. The Settling Defendants shall be deemed to know of any circumstance which the Settling Defendants, their contractors, or any entity controlled by the Settling Defendants knew or should have known. In this notice, the Settling Defendants shall describe the anticipated length of time that the Malfunction may persist, the cause or causes of the Malfunction, all measures taken or to be taken by the Settling Defendants to minimize the duration of the Malfunction, and the schedule by which the Settling Defendants proposes to implement those measures. The Settling Defendants shall adopt all reasonable measures to minimize the duration of such Malfunctions and, consistent with 40 C.F.R. § 60.11(d), shall, to the extent practicable, maintain and operate any affected Unit and associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. A Malfunction, as defined in Paragraph 16 of this Consent Decree, does not constitute a Force Majeure Event unless the Malfunction also meets the definition of a Force Majeure Event, as provided in this Section. Conversely, a period of Malfunction may be excluded by the Settling Defendants from the calculations of emission rates and removal efficiencies, as allowed under this Paragraph, if the Malfunction constitutes a Force Majeure event.

XV. <u>DISPUTE RESOLUTION</u>

139. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, provided that the Party invoking such procedure has first made a good faith attempt to resolve the matter with the other Parties.

140. The dispute resolution procedure required herein shall be invoked by one Party giving written notice to the other Parties advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party's position with

regard to such dispute. The Parties receiving such a notice shall acknowledge receipt of the notice, and the Parties in dispute shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

141. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations among the disputing Parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting among the disputing Parties' representatives unless they agree in writing to shorten or extend this period. During the informal negotiations period, the disputing Parties may also submit their dispute to a mutually-agreed-upon alternative dispute resolution ("ADR") forum if the Parties agree that the ADR activities can be completed within the 30-day informal negotiations period (or such longer period as the Parties may agree to in writing).

142. If the disputing Parties are unable to reach agreement during the informal negotiation period, the Plaintiffs shall provide the Settling Defendants with a written summary of their position regarding the dispute. The written position provided by the Plaintiffs shall be considered binding unless, within forty-five (45) calendar days thereafter, the Settling Defendants seeks judicial resolution of the dispute by filing a petition with this Court. The Plaintiffs may respond to the petition within forty-five (45) calendar days of filing.

143. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the Parties to the dispute.

144. This Court shall not draw any inferences nor establish any presumptions adverse to any disputing Party as a result of invocation of this Section or the disputing Parties' inability to

reach agreement.

145. As part of the resolution of any dispute under this Section, in appropriate circumstances the disputing Parties may agree, or this Court may order, an extension or modification of the schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution. The Settling Defendants shall be liable for stipulated penalties for their failure thereafter to complete the work in accordance with the extended or modified schedule, provided that the Settling Defendants shall not be precluded from asserting that a Force Majeure Event has caused or may cause a delay in complying with the extended or modified schedule.

146. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes. In their initial filings with the Court under Paragraph 142, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

147. This Paragraph shall govern all disputes under this Consent Decree between any Party regarding the BACT Determination provided by NDDH under Section V(B) of this Consent Decree. The Settling Defendants hereby waive their rights to challenge or dispute NDDH's BACT Determination other than through this Paragraph, which shall constitute the sole means by which the Settling Defendants may dispute such determination.

a. If any Party does not agree, in whole or in part, with NDDH's BACT Determination or with the 30-Day Rolling Average NO_x Emission Rate established by NDDH as part of its BACT Determination, it shall notify the other Parties within thirty (30) days of receipt of the BACT Determination. The notice shall describe the particular reason(s) for disagreeing with NDDH's BACT Determination. The disputing Party shall bear the burden of proof throughout the dispute resolution process. The Parties to the dispute shall endeavor to resolve the dispute informally for up to thirty (30) days following issuance of such notice.

b. If the Parties to the dispute do not reach an agreement during this informal dispute resolution process, each disputing Party shall provide the other Parties with a written summary of its position within thirty (30) calendar days after the end of the informal process. The written position(s) provided by the State shall be considered binding unless, within forty-five (45) calendar days thereafter, a Party files with this Court a petition which describes the nature of the dispute and seeks judicial resolution. The other Parties to the dispute shall respond to the petition(s) within forty-five (45) calendar days of each such filing.

c. The Court shall sustain the decision by NDDH unless the Party disputing the BACT Determination demonstrates that it is not supported by the state administrative record and not reasonable in light of applicable statutory and regulatory provisions.

XVI. PERMITS

148. Unless expressly stated otherwise in this Consent Decree (e.g. Paragraph 109), in any instance where otherwise applicable law or this Consent Decree requires the Settling Defendants to secure a permit to authorize construction or operation of any device, including all preconstruction, construction, and operating permits required under state law, the Settling

Defendants shall make such application in a timely manner. The United States and NDDH will use their best efforts to expeditiously review all permit applications submitted by the Settling Defendants in order to meet the requirements of this Consent Decree.

149. When permits are required, the Settling Defendants shall complete and submit applications for such permits to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request, including requests for additional information by the permitting authorities. Any failure by the Settling Defendants to submit a timely permit application for any Unit at the Milton R. Young Station shall bar any use by the Settling Defendants of Section XIV (Force Majeure) of this Consent Decree, where a Force Majeure claim is based on permitting delays.

150. Notwithstanding the reference to the Title V permit in this Consent Decree, the enforcement of the permit shall be in accordance with its own terms and the Act. The Title V permit shall not be enforceable under this Consent Decree, although any term or limit established by or under this Consent Decree shall be enforceable under this Consent Decree regardless of whether such term has or will become part of a Title V permit, subject to the terms of Section XXVI (Conditional Termination of Enforcement Under Consent Decree) of this Consent Decree.

151. Within ninety (90) days after entry of this Consent Decree, the Settling Defendants shall amend any applicable Title V permit application, or apply for amendments of their Title V permit, to include a schedule for all unit-specific and plant-specific performance, operational, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, emission rates, removal efficiencies, tonnage limitations, and the requirements pertaining to the surrender of SO_2 Allowances.

152. Within one (1) year from the commencement of operation of each pollution control device to be installed or upgraded on a Unit under this Consent Decree, the Settling Defendants shall apply to include the requirements and limitations enumerated in this Consent Decree in either a federally enforceable permit (other than a Title V permit) or amendments to the North Dakota State Implementations Plan ("SIP"). The permit or SIP amendment shall require compliance with the following: (a) any applicable 30-Day Rolling Average Emission Rate or 30-Day Rolling Average Removal Efficiency, (b) the allowance surrender requirements set forth in this Consent Decree, and (c) any applicable Tonnage limitations set forth in this Consent Decree.

153. The Settling Defendants shall provide the United States with a copy of each application for a federally enforceable permit or SIP amendment, as well as a copy of any permit proposed as a result of such application, to allow for timely participation in any public comment opportunity. The Settling Defendants and the NDDH agree to incorporate the SO_2 limitations in Subparagraphs 50(c) (and Subparagraph 50(d), if applicable) as federally-enforceable limits for the Settling Defendants in future permitting proceedings.

154. If the Settling Defendants sell or transfer to an entity unrelated to the Settling Defendants ("Third Party Purchaser") part or all of an ownership interest in a Unit ("Ownership Interest") covered under this Consent Decree, the Settling Defendants shall comply with the requirements of Paragraphs 148 through 153 with regard to that Unit prior to any such sale or transfer unless, following any such sale or transfer, the Settling Defendants remains the holder of the permit for such facility.

XVII. INFORMATION COLLECTION AND RETENTION

155. Any authorized representative of the Plaintiffs, including their attorneys, contractors, and consultants, upon presentation of credentials, shall have a right of entry upon the premises of any facility covered under this Consent Decree at any reasonable time for the purpose of:

a. monitoring the progress of activities required under this Consent Decree;

b. verifying any data or information submitted to the Plaintiffs in accordance with the terms of this Consent Decree;

c. obtaining samples and, upon request, splits of any samples taken by the Settling Defendants or their representatives, contractors, or consultants; and

d. assessing the Settling Defendants' compliance with this Consent Decree.

156. The Settling Defendants shall retain, and instruct their contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in their or their contractors' or agents' possession or control, and that directly relate to the Settling Defendants' performance of their obligations under this Consent Decree, until December 31, 2020. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

157. All information and documents submitted by the Settling Defendants pursuant to this Consent Decree shall be subject to public disclosure based on requests under applicable law providing for such disclosure unless (a) the information and documents are subject to legal privileges or protection or (b) the Settling Defendants claim and substantiate in accordance with 40 C.F.R. Part 2 that the information and documents contain confidential business information.

158. Nothing in this Consent Decree shall limit the authority of the Plaintiffs to conduct tests and inspections at facilities covered under this Consent Decree under Section 114 of the Act, 42 U.S.C. § 7414, or any other applicable federal or state laws, regulations or permits.

XVIII. NOTICES

159. Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

As to the United States of America:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DOJ# 90-5-2-1-07717

and

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

U. S. EPA, Region 8
Director, Office of Enforcement, Compliance, and Environmental Justice
999 18th Street, Suite 300
Denver, Colorado 80202-2466

As to the State of North Dakota:

Director, Air Quality Division
North Dakota Department of Health

Bismark, North Dakota 58506-5520

As to the Settling Defendants:

David Sogard, General Counsel
John Graves, Environmental Manager
1822 State Mill Road
P.O. Box 13200
Grand Forks, ND 58208-3200

160. All notifications, communications or submissions made pursuant to this Section shall be sent either by: (a) overnight mail or delivery service; (b) certified or registered mail, return receipt requested; or (c) electronic transmission, unless the recipient is not able to review the transmission in electronic form. All notifications, communications and transmissions (a) sent by overnight, certified or registered mail shall be deemed submitted on the date they are postmarked, or (b) sent by overnight delivery service shall be deemed submitted on the date they are delivered to the delivery service. All notifications, communications, and submissions made by electronic means shall be electronically signed and certified, and shall be deemed submitted on the date that the Settling Defendants receive written acknowledgment of receipt of such transmission.

161. Any Party may change either the notice recipient or the address for providing notices to it by serving the other Parties with a notice setting forth such new notice recipient or address.

XIX. SALES OR TRANSFERS OF OWNERSHIP INTERESTS

162. If the Settling Defendants propose to sell or transfer part or all of their ownership interest in any of their real property or operations subject to this Consent Decree ("Ownership Interest") to an entity unrelated to the Settling Defendants ("Third Party Purchaser"), they shall

advise the Third Party Purchaser in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to the Plaintiffs pursuant to Section XVIII (Notices) at least sixty (60) days before such proposed sale or transfer.

163. No sale or transfer of an Ownership Interest shall take place before the Third Party Purchaser and the Plaintiffs have executed, and the Court has approved, a modification pursuant to Section XXII (Modification) of this Consent Decree making the Third Party Purchaser a party defendant to this Consent Decree and jointly and severally liable with the Settling Defendants for all the requirements of this Consent Decree that may be applicable to the transferred or purchased Ownership Interests, except as provided in Paragraph 165, below.

164. This Consent Decree shall not be construed to impede the transfer of any Ownership Interests between the Settling Defendants and any Third Party Purchaser as long the requirements of this Consent Decree are met. In addition, this Consent Decree shall not be construed to prohibit a contractual allocation–as between the Settling Defendants and any Third Party Purchaser of Ownership Interests–of the burdens of compliance with this Decree, provided that both the Settling Defendants and such Third Party Purchaser shall remain jointly and severally liable to the Plaintiffs for the obligations of the Decree applicable to the transferred or purchased Ownership Interests, except as provided in Paragraph 165.

165. If the Plaintiffs agree, the United States, the State, the Settling Defendants and the Third Party Purchaser that has become a party defendant to this Consent Decree pursuant to Paragraph 163 may execute a modification that relieves Minnkota and/or Square Butte of their liability under this Consent Decree for, and makes the Third Party Purchaser liable for, all obligations and liabilities applicable to the purchased or transferred Ownership Interests.

Notwithstanding the foregoing, however, the Settling Defendants may not assign, and may not be released from, any obligation under this Consent Decree that is not specific to the purchased or transferred Ownership Interests, including the obligations set forth in Sections VIII (Additional Injunctive Relief) and IX (Civil Penalty). The Settling Defendants may propose and the Plaintiffs may agree to restrict the scope of joint and several liability of any purchaser or transferee for any obligations of this Consent Decree that are not specific to the purchased or transferred Ownership Interests to the extent such obligations may be adequately separated in an enforceable manner.

XX. EFFECTIVE DATE

166. The effective date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court.

XXI. RETENTION OF JURISDICTION

167. **Continuing Jurisdiction.** The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, modification, or adjudication of disputes. During the term of this Consent Decree, any Party to this Consent Decree may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

XXII. MODIFICATION

168. The terms of this Consent Decree may be modified only by a subsequent written agreement signed by all Parties. Where the modification constitutes a material change to any term of this Consent Decree, it shall be effective only upon approval by the Court.

XXIII. GENERAL PROVISIONS

169. This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations. The removal efficiencies and emission rates set forth herein do not relieve the Settling Defendants from any obligation to comply with other state and federal requirements under the Clean Air Act, including the Settling Defendants' obligations to satisfy any state modeling requirements set forth in the North Dakota State Implementation Plan. Unless otherwise indicated herein, citations to statutes or regulations herein shall mean the version of the statutes or regulations in force as of July 1, 2005.

170. This Consent Decree does not apply to any claim(s) of alleged criminal liability.

171. In any subsequent administrative or judicial action initiated by the Plaintiffs for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, the Settling Defendants shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, or claim splitting, or any other defense based upon the contention that the claims raised by the Plaintiffs in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to, or shall, affect the validity of Section X (Resolution of Claims) of this Consent Decree.

172. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve the Settling Defendants of their obligations to comply with all applicable federal, state, and local laws and regulations. Nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the Plaintiffs to obtain penalties, injunctive relief or other relief under the Act or other federal, state, or local statutes, regulations, or permits.

173. Every term expressly defined by this Consent Decree shall have the meaning given to that term by this Consent Decree and, except as otherwise provided in this Consent Decree, every other term used in this Consent Decree that is also a term under the Act or the regulations implementing the Act shall mean in this Consent Decree what such term means under the Act or those implementing regulations.

174. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including but not limited to any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8315 (Feb. 27, 1997)) concerning the use of data for any purpose under the Act, generated either by the reference methods specified herein or otherwise.

175. Each limit and/or other requirement established by or under this Consent Decree is a separate, independent requirement.

176. Performance standards, emissions limits, and other quantitative standards set by or under this Consent Decree must be met to the number of significant digits in which the standard or limit is expressed. For example, an Emission Rate of 0.100 is not met if the actual Emission Rate is 0.101. The Settling Defendants shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the nearest second significant digit, depending

upon whether the limit is expressed to three or two significant digits. For example, if an actual Emission Rate is 0.1004, that shall be reported as 0.100, and shall be in compliance with an Emission Rate of 0.100, and if an actual Emission Rate is 0.1005, that shall be reported as 0.101, and shall not be in compliance with an Emission Rate of 0.100. The Settling Defendants shall report data to the number of significant digits in which the standard or limit is expressed.

177. This Consent Decree does not limit, enlarge or affect the rights of any Party to this Consent Decree as against any third parties.

178. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the Parties with respect to the settlement embodied in this Consent Decree, and supersedes all prior agreements and understandings among the Parties related to the subject matter herein. No document, representation, inducement, agreement, understanding, or promise constitutes any part of this Consent Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

179. The United States and the Settling Defendants shall bear their own costs and attorneys' fees.

XXIV. SIGNATORIES AND SERVICE

180. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind to this document the Party he or she represents.

181. This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

182. Each Party hereby agrees to accept service of process by mail with respect to all

matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to. service of a summons.

XXV. PUBLIC COMMENT

183. The Parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the procedures of 28 C.F.R. § 50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper or inadequate. The Settling Defendants shall not oppose entry of this Consent Decree by this Court or challenge any provision of this Consent Decree unless the United States has notified the Settling Defendants, in writing, that the United States no longer supports entry of the Consent Decree.

XXVI. CONDITIONAL TERMINATION OF ENFORCEMENT UNDER CONSENT DECREE

184. **Termination as to Completed Tasks.** As soon as the Settling Defendants complete a construction project or any other requirement of this Consent Decree that is not ongoing or recurring, the Settling Defendants may, by motion to this Court, seek termination of the provision or provisions of this Consent Decree that imposed the requirement.

185. **Conditional Termination of Enforcement Through the Consent Decree.** After the Settling Defendants:

a. have successfully completed construction, and have maintained operation, of all pollution controls as required by this Consent Decree;

b. have obtained a final Title V permit (I) as required by the terms of this Consent Decree; (ii) that cover all units in this Consent Decree; and (iii) that include as enforceable permit terms all of the Unit performance and other requirements specified in Section XVI (Permits) of this Consent Decree; and

c. certified that the date is later than December 31, 2015;

then the Settling Defendants may so certify these facts to the Plaintiffs and this Court. If the Plaintiffs do not object in writing with specific reasons within forty-five (45) days of receipt of the Settling Defendants' certification, then, for any Consent Decree violations that occur after the filing of notice, the Plaintiffs shall pursue enforcement of the requirements contained in the Title V permit through the applicable Title V permit and not through this Consent Decree.

186. **Resort to Enforcement under this Consent Decree.** Notwithstanding Paragraph 187, if enforcement of a provision in this Consent Decree cannot be pursued by a Party under the applicable Title V permit, or if a Consent Decree requirement was intended to be part of a Title V Permit and did not become or remain part of such permit, then such requirement may be enforced under the terms of this Consent Decree at any time, unless and until the Settling Defendants have secured a source-specific revision to the North Dakota State Implementation Plan to reflect the emission limitations, emissions monitoring, and allowance surrender requirements set forth in this Consent Decree.

XXVII. <u>FINAL JUDGMENT</u>

187. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment in the above-captioned matter between the Plaintiffs and the Settling Defendants.

SO ORDERED, THIS _____ DAY OF ________________, 2006.

____

UNITED STATES DISTRICT COURT JUDGE

FOR THE UNITED STATES OF AMERICA:

SUE ELLEN WOOLDRIDGE
Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice

MATTHEW W. MORRISON
Senior Counsel
Environmental Enforcement Section
Environmental and Natural Resources Division
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GRANTA Y. NAKAYAMA
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ADAM M. KUSHNER
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United States Environmental Protection Agency

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CAROL RUSHIN
Assistant Regional Administrator
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and Environmental Justice

BRENDA MORRIS
Enforcement Attorney
U.S. Environmental Protection Agency
Region 8

FOR THE STATE OF NORTH DAKOTA:

TERRY L. DWELLE, MD, MPHTM
State Health Officer
North Dakota Dep't of Health

WAYNE STENEHJEM
Attorney General
Attorney for North Dakota

FOR DEFENDANT MINNKOTA POWER COOPERATIVE, INC.:

____

DAVID LOER
President & CEO

FOR DEFENDANT SQUARE BUTTE ELECTRIC COOPERATIVE:

____

DAVID LOER
General Manager

Exhibit 9 to Title V Petition

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF WISCONSIN

UNITED STATES OF AMERICA	)	
	)	
Plaintiff,	)	
	)	
v.	)	Civil Action No. __________
	)	
WISCONSIN ELECTRIC POWER COMPANY,	)	
	)	
Defendant.	)	
	)	
______________________________	)	

CONSENT DECREE

TABLE OF CONTENTS

WHEREAS, the United States of America ("the United States"), on behalf of the United States Environmental Protection Agency ("EPA") has filed a Complaint with this Consent Decree, against Wisconsin Electric pursuant to Sections 113(b) and 167 of the Clean Air Act (the "Act"), 42 U.S.C. §§ 7413(b) and 7477, for injunctive relief and the assessment of civil penalties for alleged violations of:

(a) the Prevention of Significant Deterioration provisions in Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-92;

(b) the nonattainment New Source Review provisions in Part D of Subchapter I of the Act, 42 U.S.C. §§ 7501-7515;

(c) the federally-enforceable State Implementation Plan developed by the State of Michigan (the "Michigan SIP");

(d) the federally-enforceable State Implementation Plan developed by the State of Wisconsin (the "Wisconsin SIP"); and

WHEREAS, in its Complaint, Plaintiff alleges, *inter alia,* that Wisconsin Electric failed to obtain the necessary permits and install the controls necessary under the Act to reduce its sulfur dioxide, nitrogen oxides, and/or particulate matter emissions, and that such emissions can damage human health and the environment;

WHEREAS, the Plaintiff alleges that its Complaint states claims upon which relief can be granted against Wisconsin Electric under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, Wisconsin Electric has not answered or otherwise responded to the Complaint filed by the United States in light of the settlement memorialized in this Consent Decree;

WHEREAS, Wisconsin Electric has denied and continues to deny the violations alleged in the Complaint, maintains that it has been and remains in compliance with the Act and is not liable for civil penalties or injunctive relief, and states that it is agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation, and to reduce its emissions;

WHEREAS, EPA provided Wisconsin Electric and the States of Michigan and Wisconsin with actual notice of violations pertaining to Wisconsin Electric's alleged violations, in accordance with Section 113(a)(1)of the Act, 42 U.S.C. § 7413(a)(1);

WHEREAS, the Parties anticipate that the States of Michigan and Wisconsin may seek to intervene in this case, and the Parties anticipate that they will consent to such intervention;

WHEREAS, Wisconsin Electric, consistent with its environmental, health and safety policy, met with the United States in February 2003, to resolve the Parties' respective goals for achieving emission reductions of certain emissions at the electric generating stations covered under this Consent Decree;

WHEREAS, the Parties anticipate that the installation and operation of pollution control equipment pursuant to this Consent Decree will achieve significant reductions in SO_2, NO_x and PM emissions and thereby improve air quality and that certain actions that Wisconsin Electric has agreed to undertake are expected to advance technologies and methodologies for reducing certain air emissions, including mercury;

WHEREAS, nothing in this Consent Decree is intended to prohibit the use of emission reductions under this Consent Decree to demonstrate attainment with §110 of the Act (42 U.S.C. § 7410);

WHEREAS, Wisconsin Electric has begun the process of retiring the coal-fired units at the Port Washington Generating Station and has applied for and received permits to construct two new combined cycle natural gas units at that facility;

WHEREAS, Wisconsin Electric is seeking approval, including air emissions permits, to construct three new coal-fired units in Wisconsin at a site adjacent to the South Oak Creek Generating Station, designated as the Elm Road Generating Station;

WHEREAS, EPA supports the construction of cleaner power plants to meet growing energy demands;

WHEREAS, the United States and Wisconsin Electric have agreed, and the Court by entering this Consent Decree finds: that this Consent Decree has been negotiated in good faith and at arms length; that this settlement is fair, reasonable, in the best interest of the Parties and in the public interest; consistent with the goals of the Act; and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

and

WHEREAS, the United States and Wisconsin Electric have consented to entry of this Consent Decree without trial of any issue;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaint it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367, Sections 113(b) and 167 of the Act, 42 U.S.C. §§ 7413(b) and 7477, the Michigan SIP, 40 C.F.R. § 52.1180(b); 45 Fed. Reg. 8348 (February 7, 1980), and the Wisconsin SIP, 40 C.F.R. § 52.2570; Wis. Admin. Code, NR § 405. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the Plaintiff's underlying Complaint, Wisconsin Electric waives all objections and defenses that it may have to the claims set forth in the underlying Complaints, and to the jurisdiction of the Court over Wisconsin Electric and this action, and to venue in this District. Wisconsin Electric shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. For purposes of the Complaint filed by the United States in this matter and resolved by the Consent Decree, and for purposes of entry and enforcement of this Decree, Wisconsin Electric waives any defense or objection based on standing. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the United States and Wisconsin Electric. Except as provided by Section XXVII (Public Comment), the Parties consent to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. Upon entry, the provisions of this Consent Decree shall apply to and be binding upon the United States and Wisconsin Electric, its successors and assigns, and Wisconsin Electric's officers, employees, and agents solely in their capacities as such.

3. Wisconsin Electric shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or organization retained to perform any of the work required by this Consent Decree. Notwithstanding any retention of contractors, subcontractors, or agents to perform any work required under this Consent Decree, Wisconsin Electric shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, Wisconsin Electric shall not assert as a defense the failure of its officers, directors, employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless Wisconsin Electric establishes that such failure resulted from a Force Majeure Event, as defined in Paragraph 143 of this Consent Decree.

III. DEFINITIONS

4. A "30-day Rolling Average Emission Rate" shall be determined by calculating an arithmetic average of all hourly emission rates in lb/mmBTU for the current day and the previous 29 Operating Days. A new 30-day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-Day Rolling Average Emission Rate shall include all start-up, shut down and Malfunction periods within each Operating Day. A Malfunction shall be excluded from this Emission Rate, however, if it is determined to be a Force Majeure Event and satisfies the Force Majeure provisions of this Consent Decree.

5. "30-Day Rolling Average Removal Efficiency" means the percent reduction in the mass of a pollutant achieved by a Unit's pollution control device over a 30-day period. This percentage shall be calculated by subtracting the Unit's outlet 30-Day Rolling Average Emission Rate from the Unit's inlet 30-Day Rolling Average Emission Rate, dividing that difference by

the Unit's inlet 30-Day Rolling Average Emission Rate, and then multiplying by 100. A new 30-Day Rolling Average Removal Efficiency shall be calculated for each new Operating Day, and shall include all periods of startup, shutdown and Malfunction within an Operating Day. A Malfunction shall be excluded from this removal efficiency, however, if it is determined to be a Force Majeure Event and satisfies the Force Majeure provisions of this Consent Decree.

6. "Air Quality Control Region" means a geographic area designated under Section 107(c) of the Act, 42 U.S.C. § 7407(c).

7. "Baseline" means the annual average emissions of SO_2 and NO_x of the Plants in the Wisconsin Electric System for calendar years 2000 and 2001, as measured under 40 C.F.R. Part 75.

8. "Boiler Island" means a Unit's (A) fuel combustion system (including bunker, coal pulverizers, crusher, stoker, and fuel burners); (B) combustion air system; (C) steam generating system (i.e., firebox, boiler tubes and walls); and (D) draft system (excluding the stack), as further described in "Interpretation of Reconstruction," by John B. Rasnick, U.S. EPA (November 25, 1986) and the attachments thereto.

9. "BH" means baghouse, a pollution control device for the reduction of particulate matter ("PM").

10. "Capital Expenditure" means all capital expenditures, as defined by Generally Accepted Accounting Principles ("GAAP"), excluding the cost of installing or upgrading pollution control devices.

11. "CEMS" or "Continuous Emission Monitoring System" means, for obligations involving NO_x and SO_2 under this Decree, the devices defined in 40 C.F.R. § 72.2 and installed and maintained as required by 40 C.F.R. Part 75.

12. "Clean Air Act" or "Act" means the federal Clean Air Act, 42 U.S.C. §§7401-7671q, and its implementing regulations.

13. "Consent Decree" or "Decree" means this Consent Decree.

14. "Elm Road Generating Station" means the proposed coal-fired electric generating units, for which Wisconsin Electric is seeking regulatory approval to construct at a site adjacent to the South Oak Creek Generating Station.

15. "Emission Rate" means the number of pounds of pollutant emitted per million BTU of heat input ("lb/mmBTU"), measured in accordance with this Consent Decree.

16. "EPA" means the United States Environmental Protection Agency.

17. "ESP" means electrostatic precipitator, a pollution control device for the reduction of particulate matter ("PM").

18. "Existing Units" means those Units included in the Wisconsin Electric System.

19. "Flue gas desulfurization system," or "FGD," means a pollution control device that employs flue gas desulfurization technology for the reduction of sulfur dioxide.

20. "Fossil fuel" means any hydrocarbon fuel, including coal, petroleum oil, or natural gas.

21. "Improved Unit" means, in the case of NO_x, a Wisconsin Electric System Unit scheduled under this Decree to be equipped with SCR (or equivalent NOx control technology approved pursuant to Paragraph 56) or to be retired, and, in the case of SO_2, a Wisconsin Electric

System Unit scheduled under this Decree to be equipped with an FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 71) or to be retired. A Unit may be an Improved Unit for one pollutant without being an Improved Unit for the other.

22. "lb/mmBTU" mean one pound of a pollutant per million British Thermal Units of heat input.

23. "Malfunction" means malfunction as that term is defined under 40 C.F.R.§ 60.2.

24. "MW" means a megawatt, or one million Watts.

25. "National Ambient Air Quality Standards" means national air quality standards promulgated pursuant to Section 109 of the Act, 42 U.S.C. § 7409.

26. "New Units" means any coal-fired or natural gas fired units that commence operation after entry of this Consent Decree, including but not limited to the re-powered natural gas units at the Port Washington Generating Station.

27. "NO_x" means oxides of nitrogen, as measured in accordance with the provisions of this Consent Decree.

28. "Nonattainment NSR" means the nonattainment area New Source Review program within the meaning of Part D of Subchapter I of the Act, 42 U.S.C. §§ 7510-7515, 40 C.F.R. Part 51.

29. "NSPS" means New Source Performance Standards within the meaning of Part A of Subchapter I, of the Clean Air Act, 42 U.S.C. § 7411, 40 C.F.R. Part 60.

30. "Operating Day" means any calendar day on which a Unit fires fossil fuel.

31. "Other Unit" means any Unit of the Wisconsin Electric System that is not an Improved Unit for the pollutant in question. A Unit may be an Improved Unit for NOx and an Other Unit for SO_2 and vice versa.

32. "PM Control Device" means an electrostatic precipitator ("ESP") or a baghouse ("BH"), devices which reduce emissions of particulate matter (PM).

33. "Parties" means Wisconsin Electric and the United States.

34. "Permitting State" means the state in which a particular Unit is located from which Wisconsin Electric is required to obtain permits, licenses, or approvals in order to install or operate a source of air pollution.

35. "Plaintiff" means the United States.

36. "PM" means particulate matter, as measured in accordance with the provisions of this Consent Decree.

37. "PM CEMS" or "PM continuous emission monitoring system" means equipment that samples, analyzes, measures, and provides PM emissions data -- by readings taken at frequent intervals – and makes an electronic or paper record of the PM emissions measured.

38. "PM Emission Rate" shall mean the average number of pounds of PM emitted per million BTU of heat input ("lb/mmBTU"), as measured in annual stack tests, in accordance with the reference methods set forth in 40 C.F.R. Part 60, Appendix A, Method 5 or Method 17.

39. "Project Dollars" means Wisconsin Electric's expenditures and payments incurred or made in carrying out the projects identified in Section IX of this Consent Decree (Environmental Projects) to the extent that such expenditures or payments both: (a) comply with the Project Dollar and other requirements set by this Consent Decree in Section IX of this

Consent Decree (Environmental Projects); and (b) constitute Wisconsin Electric's external costs for contractors, vendors, and equipment, and its internal costs consisting of employee time, travel, and other out-of-pocket expenses specifically attributable to these particular projects and documented in accordance with "GAAP".

40. "PSD" means Prevention of Significant Deterioration within the meaning of Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470 - 7492 and 40 C.F.R. Part 52.

41. "SCR" means a device that employs selective catalytic reduction technology for the reduction of nitrogen oxides.

42. "SO_2" means sulfur dioxide, as measured in accordance with this Consent Decree.

43. "SO_2 Allowance" means an "allowance," as defined at 42 U.S.C. § 7651a(3): an authorization, allocated to an affected unit, by the Administrator of EPA under Subchapter IV of the Act, to emit, during or after a specified calendar year, one ton of sulfur dioxide.

44. [RESERVED.]

45. "System-wide 12-Month Rolling Average Emission Rate" means (a) summing the pounds of pollutant in question emitted from the Wisconsin Electric System during the most recent complete month and the previous eleven (11) months, (b) summing the heat input to the Wisconsin Electric System in mmBTU during the most recent complete month and the previous eleven (11) months, and (c) dividing the total number of pounds of pollutants emitted during the twelve (12) months by the total heat input during the twelve (12) months, and expressing the resulting figure in lbs/mmBTU. A new System-wide 12-Month Rolling Average Emission Rate shall be calculated for each new complete month. Each "System-wide 12-Month Rolling

Average Emission Rate" shall include all start-up, shut down and Malfunction periods within each complete month.

46. "System-wide 12-Month Rolling Tonnage" means the sum of the tons of pollutant in question emitted from the Wisconsin Electric System in the most recent month and the previous eleven (11) months. A new System-wide 12-Month Rolling Tonnage will be calculated for each new complete month.

47. "Title V Permit" means the permit required of Wisconsin Electric's major sources under Subchapter V of the Clean Air Act, 42 U.S.C. §§ 7661-7661e.

48. "Unit" means, for the purpose of this Consent Decree, collectively, the coal pulverizer, the stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine and boiler, and all ancillary equipment, including pollution control equipment, or systems necessary for the production of electricity. An electric utility steam generating station may be comprised of one or more Units.

49. "Unit-Specific 12-Month Rolling Tonnage" means the sum of the tons of pollutant in question emitted from the applicable Unit in the most recent month and the previous eleven (11) months. A new Unit-Specific 12-Month Rolling Tonnage will be calculated for each new complete month.

50. "WEC" means Wisconsin Energy Corporation, the parent company of Wisconsin Electric and W.E. Power.

51. "W.E. Power" means W.E. Power LLC, a subsidiary of WEC and an affiliate of Wisconsin Electric.

52. "Wisconsin Electric" means the Wisconsin Electric Power Company.

53. "Wisconsin Electric System" means, solely for purposes of this Consent Decree, the following twenty-three (23) coal-fired, electric utility steam generating Units (with the rated $MW_{(net)}$ capacity of each Unit noted in parentheses):

- Presque Isle Generating Station in Marquette, Michigan - Unit 1 (25 MW), 2 (37.5 MW), 3 (54.4 MW), 4 (57.8 MW), 5 (90 MW), 6 (90 MW), 7 (90 MW), 8 (90 MW), and 9 (90 MW);
- Pleasant Prairie Generating Station in Kenosha, Wisconsin - Units 1 (616.6 MW) and 2 (616.6 MW);
- South Oak Creek Generating Station in Oak Creek, Wisconsin - Units 5 (275 MW), 6 (275 MW), 7 (317.6 MW), and 8 (324 MW);
- Port Washington Generating Station in Port Washington, Wisconsin - Units 1 (80 MW), 2 (80 MW), 3 (80 MW), and 4 (80 MW);
- Valley Generating Station in Milwaukee, Wisconsin - Units 1 (80 MW), 2 (80 MW), 3 (80 MW), and 4 (80 MW).

IV. UNITS TO BE CONTROLLED OR RETIRED

54. Wisconsin Electric shall either satisfy the emission control requirements of Paragraphs 55 and 70 with regard to the following Units or retire and permanently cease to operate the following Units within the Wisconsin Electric System by the following dates:

Unit	**Date by which Wisconsin Electric Must Control or Cease to Operate Unit**
Port Washington Unit 4	Upon Entry of this Consent Decree
Port Washington Unit 1	December 31, 2004
Port Washington Unit 2	December 31, 2004
Port Washington Unit 3	December 31, 2004
Oak Creek Unit 5	December 31, 2012
Oak Creek Unit 6	December 31, 2012
Presque Isle Unit 1	December 31, 2012
Presque Isle Unit 2	December 31, 2012
Presque Isle Unit 3	December 31, 2012
Presque Isle Unit 4	December 31, 2012

V. NO_x EMISSION REDUCTIONS AND CONTROLS

A. NO_x Emission Controls

55. Wisconsin Electric shall install and commence continuous operation of Selective Catalytic Reduction technology ("SCR") (or equivalent NO_x control technology approved pursuant to Paragraph 56) so as to achieve a 30-Day Rolling Average Emission Rate not greater than 0.100 lb/mmBTU NO_x on the following Units within the Wisconsin Electric System by the following dates:

Unit	**Date by Which Wisconsin Electric Must Complete Installation and Continuously Operate SCR**
Pleasant Prairie Unit 2	December 31, 2003
Pleasant Prairie Unit 1	December 31, 2006
Oak Creek Unit 7	December 31, 2012
Oak Creek Unit 8	December 31, 2012

56. With prior written notice to and approval from EPA, Wisconsin Electric may, in lieu of installing and operating any such SCR, install and operate equivalent NO_x control technology so long as such equivalent NO_x control technology achieves a 30-Day Rolling Average Emission Rate not greater than 0.100 lb/mmBTU NO_x.

57. Wisconsin Electric shall continuously operate SCR (or equivalent NOx control technology approved pursuant to Paragraph 56) at all times that the Unit it serves is in operation consistent with the technological limitations, manufacturers' specifications, and good operating practices, for the SCR or equivalent technology.

58. Wisconsin Electric shall also operate either low NO_x burners ("LNB") or combustion control technology on the following Units within the Wisconsin Electric System. Such low-NO_x burner or combustion control technology shall be operational in accordance with the following schedule:

Units to be Controlled	NO_x Control	Deadline for Commencement of Operation
Valley Boiler 1	LNB and Combustion Optimization Software (Existing LNB and Combustion Optimization Software)	30 days after the date of lodging of this Consent Decree
Valley Boiler 2	LNB and Combustion Optimization Software (Existing LNB and Combustion Optimization Software)	30 days after the date of lodging of this Consent Decree
Valley Boiler 3	LNB and Combustion Optimization Software (Existing LNB and Combustion Optimization Software)	30 days after the date of lodging of this Consent Decree
Valley Boiler 4	LNB and Combustion Optimization Software (Existing LNB and Combustion Optimization Software)	30 days after the date of lodging of this Consent Decree
Presque Isle Unit 5	LNB and Combustion Optimization Software	December 31, 2003
Presque Isle Unit 6	LNB and Combustion Optimization Software	December 31, 2003
Presque Isle Unit 7	LNB and Combustion Optimization Software (Existing LNB)	December 31, 2005
Presque Isle Unit 8	LNB and Combustion Optimization Software (Existing LNB)	December 31, 2005
Presque Isle Unit 9	LNB and Combustion Optimization Software (Existing LNB)	December 31, 2006

B. System-Wide NO_x Emission Limits

59. Wisconsin Electric shall not exceed the Wisconsin Electric System-wide 12-Month Rolling Average Emission Rates for NO_x as specified below:

Beginning on	System-wide 12-Month Rolling Average Emission Rate for NO_x
January 1, 2005	0.270 lbs/mmBTU
January 1, 2007	0.190 lbs/mmBTU
January 1, 2013	0.170 lbs/mmBTU

60. In addition to meeting the system-wide emission limit set forth in the preceding Paragraph, Wisconsin Electric shall not emit NO_x on a System-wide 12-Month Rolling Tonnage basis from the Wisconsin Electric System in an amount greater than the following number of tons:

Beginning on	System-wide 12-Month Rolling Tonnage Limitation for NO_x
January 1, 2005	31,500 tons
January 1, 2007	23,400 tons
January 1, 2013	17,400 tons

Wisconsin Electric shall meet the above NO_x tonnage limitations exclusively through the operation of all control equipment required to be installed and operated by this Decree, Unit retirements, and any additional control equipment that Wisconsin Electric installs and operates. Wisconsin Electric shall not use NO_x allowances or credits to comply with these limitations.

C. <u>NOx Emission Limitations at Presque Isle Units 1 and 2</u>

61. In addition to meeting the System-wide 12-Month Rolling Tonnage limitations for NO_x set forth in Paragraph 60, after December 31, 2003, Wisconsin Electric shall not emit NO_x from the Units 1 and 2 at the Presque Isle Generating Plant in an amount greater than 130 and 194 tons per year, respectively, based upon a Unit-Specific 12-Month Rolling Tonnage. If a Unit exceeds the applicable Unit-Specific 12-Month Rolling Tonnage limitation specified in this Paragraph, Wisconsin Electric shall install and operate LNB technologies on that Unit no later than December 31 of the calendar year following such exceedance.

62. So long as Units 1 through 4 at the Presque Isle Generating Station discharge through a common stack, are of the same design and combust the same fuel, Wisconsin Electric shall determine monthly mass emissions of NO_x by apportioning NO_x emissions from the common stack to Units 1 and 2. To apportion emissions, Wisconsin Electric shall utilize the load based apportionment protocol used in the Acid Rain Program to apportion heat rates to units that share a common stack. Each month, Wisconsin Electric shall calculate the Unit-Specific 12-month Rolling Tonnage of NO_x mass (tons/year) attributed to Units 1 and 2.

D. <u>Use of NO_x Emission Allowances</u>

63. For any and all actions taken by Wisconsin Electric to conform to the requirements of this Consent Decree, Wisconsin Electric shall not use, sell, or trade any resulting NO_x emission allowances or credits in any emission trading or marketing program of any kind, except as provided in this Consent Decree.

64. NO_x emission allowances or credits allocated to the Wisconsin Electric System by the Administrator of EPA under the Act, or by any State under its State Implementation Plan,

may be used by Wisconsin Electric to meet its own federal and/or state Clean Air Act regulatory requirements for any Existing Unit or New Unit owned or operated, in whole or in part, by Wisconsin Electric.

65. Nothing in this Consent Decree shall preclude Wisconsin Electric from using, selling, or transferring NO_x emission reductions below the emission requirements of Wi. Admin. Code NR 428 among the units in the Wisconsin Electric System in order to demonstrate compliance with either Wi. Admin. Code NR 428 or Mich. Admin. Code Rule 801. Use of emission reductions generated from the Wisconsin Electric System to comply with the requirements of Mich. Admin. Code Rule 801 will conform to the Memorandum of Understanding ("MOU") among the State of Wisconsin, the State of Michigan and Wisconsin Electric, dated November 8, 2002, as that MOU may be amended from time to time.

66. Nothing in this Consent Decree shall preclude Wisconsin Electric from using, selling or transferring excess NO_x emission allowances or credits that may arise as a result of:

a. activities which occur prior to the date of entry of this Consent Decree;

b. achieving NO_x emission reductions at an Improved Unit that are below both the 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU NO_x and the System-wide 12-Month Rolling Tonnage limitations set forth in this Consent Decree; or

c. the NO_x emission reductions achieved by virtue of Wisconsin Electric's installation and operation any NO_x pollution controls prior to the dates required under Section V (NO_x Emission Reductions and Controls) of this Consent Decree, so long as Wisconsin Electric timely reports the creation of such allowances or credits in accordance with Section XII of this Consent Decree. For purposes of this Paragraph, excess NO_x emission allowances or credits equal the number of tons of NO_x that Wisconsin Electric removed from its emissions that are in excess of the NO_x reductions required by this Decree.

67. Wisconsin Electric may not purchase or otherwise obtain NO_x allowances or credits from another source for purposes of complying with the requirements of this Consent Decree. However, nothing in this Consent Decree shall prevent Wisconsin Electric from purchasing or otherwise obtaining NO_x allowances or credits from another source for purposes of complying with state or federal Clean Air Act requirements to the extent otherwise allowed by law.

E. General NO_x Provisions

68. In determining Emission Rates for NO_x, Wisconsin Electric shall use CEMs in accordance with those reference methods specified in 40 C.F.R. Part 75.

69. In calculating the 30-day Rolling Average Emission Rate or System-wide 12-Month Rolling Average Emission Rate for NO_x for a given Unit or group of Units, Wisconsin Electric shall not exclude any period of time that the Unit(s) is/are in operation, including periods in which any NO_x emission control technology for the Unit(s) is not in operation.

VI. SO_2 EMISSION REDUCTIONS AND CONTROLS

A. SO_2 Emission Controls

1. New FGD Installations

70. Wisconsin Electric shall install and commence continuous operation of Flue Gas Desulfurization technology ("FGD") (or equivalent SO_2 control technology approved pursuant to Paragraph 71) so as to achieve either a 30-Day Rolling Average Emission Rate of not greater than 0.100 lb/mmBTU SO_2 or a 30-day Rolling Average SO_2 Removal Efficiency of at least 95 percent on the following Units within the Wisconsin Electric System by the dates specified below:

Unit	Date by which Wisconsin Electric Must Complete Installation and Continuously Operate FGD
Pleasant Prairie Unit 1	December 31, 2006
Pleasant Prairie Unit 2	December 31, 2007
Oak Creek Unit 7	December 31, 2012
Oak Creek Unit 8	December 31, 2012

71. In lieu of installing and operating such FGDs, Wisconsin Electric may, with prior written notice to and approval from EPA, install and operate equivalent SO_2 control technology, so long as such equivalent SO_2 control technology achieves a 30-Day Rolling Average Emission Rate of not greater than 0.100 lb/mmBTU SO_2 or a 30-day Rolling Average Removal Efficiency of at least 95 percent.

72. Wisconsin Electric shall continuously operate each FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 71) in the Wisconsin Electric System at all

times that the Unit it serves is in operation, except that, following startup of the Unit, Wisconsin Electric need not operate such control technology until the Unit is fired with any coal. Wisconsin Electric shall use good operating practices at all times that the Unit is in operation.

B. System-Wide SO_2 Emission Limits

73. Wisconsin Electric shall not exceed the Wisconsin Electric System-Wide 12-Month Rolling Average Emission Rates for SO_2 as specified below:

Beginning on	System-wide 12-Month Rolling Average Emission Rate for SO_2
January 1, 2005	0.76 lbs/mmBTU
January 1, 2007	0.61 lbs/mmBTU
January 1, 2008	0.45 lbs/mmBTU
January 1, 2013	0.32 lbs/mmBTU

74. In addition to installing the controls, retiring Units, achieving the SO_2 Emission Rates or Removal Efficiencies described in Paragraph 70, and surrendering the SO_2 Allowances required in this Consent Decree, Wisconsin Electric shall not emit SO_2 on a System-wide 12-Month Rolling Tonnage basis from the Wisconsin Electric System in an amount greater than the following number of tons:

Beginning on	System-wide 12-Month Rolling Tonnage Limit for SO_2
January 1, 2005	86,900 tons
January 1, 2007	74,400 tons
January 1, 2008	55,400 tons
January 1, 2013	33,300 tons

Wisconsin Electric shall meet the above SO_2 tonnage limitations exclusively through the operation of all control equipment required to be installed and operated by this Decree, Unit retirements, and any additional control equipment that Wisconsin Electric installs and operates. Wisconsin Electric shall not use SO_2 allowances or credits to comply with these limitations.

C. Surrender of SO_2 Allowances

75. For purposes of this Subsection, the "surrender of allowances" means permanently surrendering allowances from the accounts administered by EPA for all units in the Wisconsin Electric System, so that such allowances can never be used to meet any compliance requirement under the Clean Air Act, the Michigan or Wisconsin State Implementation Plans, or this Consent Decree.

76. Beginning on January 1, 2004, Wisconsin Electric may use any SO_2 Allowances allocated by EPA to the Wisconsin Electric System only to satisfy the operational needs of Existing Units or New Units. Wisconsin Electric shall not sell or transfer any allocated SO_2 Allowances to a third party, except as provided in Paragraphs 77, 78 and 81 below. However, for the calendar years 2004 through 2007, Wisconsin Electric may bank SO_2 allowances allocated by EPA to the Units in the Wisconsin Electric System for use at the Existing Units or New Units during the years 2004 through 2007.

77. For each calendar year, beginning with calendar year 2007, Wisconsin Electric shall surrender to EPA, or transfer to a non-profit third party selected by Wisconsin Electric for surrender, any SO_2 Allowances that exceed the operational needs of the Existing Units and New Units for SO_2 Allowances, collectively. Surrender shall occur annually thereafter and within 45 days of Wisconsin Electric's receipt from EPA of the Annual Deduction Reports for SO_2. In

addition, in calendar year 2008, Wisconsin Electric shall surrender any allowances allocated by EPA to the Units in the Wisconsin Electric System that were banked and not used during the years 2004 through 2007. Wisconsin Electric shall surrender SO_2 Allowances by the use of applicable United States Environmental Protection Agency Acid Rain Program Allowance Transfer Form.

78. If any allowances are transferred directly to a third party, Wisconsin Electric shall include a description of such transfer in the next report submitted to the Plaintiffs pursuant to Section XII (Periodic Reporting) of this Consent Decree. Such report shall: (i) provide the identity of the non-profit third-party recipient(s) of the SO_2 Allowances and a listing of the serial numbers of the transferred SO_2 Allowances; and (ii) include a certification by the third-party recipient(s) stating that the recipient will not sell, trade, or otherwise exchange any of the allowances and will not use any of the SO_2 Allowances to meet any obligation imposed by any environmental law. No later than the next Section XII periodic report due 12 months after the first report due after the transfer, Wisconsin Electric shall include in a statement that the third-party recipient(s) surrendered the SO_2 Allowances for permanent surrender to EPA within one year after Wisconsin Electric transferred the SO_2 Allowances to them. Wisconsin Electric shall not have complied with the SO_2 Allowance surrender requirements of this Paragraph until all third-party recipient(s) shall have actually surrendered the transferred SO_2 Allowances to EPA.

79. For all SO_2 Allowances surrendered to EPA, Wisconsin Electric shall first submit an SO_2 Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of the SO_2 Allowances held or controlled by Wisconsin Electric to the EPA Enforcement Surrender Account or to any other EPA account that EPA may

direct. As part of submitting these transfer requests, Wisconsin Electric shall irrevocably authorize the transfer of these SO_2 Allowances and identify -- by name of account and any applicable serial or other identification numbers or station names -- the source and location of the SO_2 Allowances being surrendered.

80. The requirements in Paragraphs 76 and 77 of this Decree pertaining to Wisconsin Electric's use and retirement of SO_2 Allowances are permanent injunctions not subject to any termination provision of this Decree. These provisions shall survive any termination of this Decree in whole or in part.

81. Notwithstanding the provisions in Paragraph 76 and 77, nothing in this Consent Decree shall preclude Wisconsin Electric from using, banking, selling or transferring excess emission SO_2 allowances that may arise as a result of:

a. activities which occur prior to the date of entry of this Consent Decree;

b. achieving SO_2 emissions at an Improved Unit that are below both the 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU SO_2 and the System-wide 12-Month Rolling Tonnage limitations set forth in this Consent Decree;

c. achieving a 30-Day Rolling Average Removal Efficiency at an Improved Unit greater than 95 percent and achieving emissions below the System-wide 12-Month Rolling Tonnage limitations set forth in this Consent Decree; or

d. the installation and operation of any SO_2 pollution controls prior to the dates required under Section VI (SO_2 Emission Reductions and Controls) of this Consent Decree so long as Wisconsin Electric timely reports such use under Section XII. For purposes of this paragraph, excess SO_2 emission allowances equal the number of tons of SO_2 that Wisconsin Electric removed from its emissions that are in excess of the SO_2 reductions required by this Decree.

D. Fuel Limitations

82. Wisconsin Electric shall not burn coal having a sulfur content greater than any amount authorized by regulation or state permit at any Wisconsin Electric System Unit. Upon entry of the Consent Decree, Wisconsin Electric shall not receive petroleum coke at any Unit that is not controlled by an FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 71), except that Wisconsin Electric may continue to receive petroleum coke at Presque Isle Units 1 through 6 until June 30, 2006.

E. General SO_2 Provisions

83. In determining Emission Rates for SO_2, Wisconsin Electric shall use CEMs in accordance with those reference methods specified in 40 C.F.R. Part 75 and 40 C.F.R. Part 60.

84. For Units that are required to be equipped with SO_2 control equipment and that are subject to the 95% removal provisions, the outlet SO_2 Emission Rate and the inlet SO_2 Emission Rate shall be determined in accordance with 40 C.F.R. § 75.15 (using SO_2 CEMS data from both the inlet and outlet of the control device). For Units that are required to meet a 0.100 lb/mmBTU limitation, the SO_2 Emission Rate shall be determined only at the outlet of the control equipment in accordance with 40 C.F.R. § 75.15 (using SO_2 CEMS data from only the outlet of the control device).

VII. PM EMISSION REDUCTIONS AND CONTROLS

A. Optimization of PM Controls

85. Within 45 days of lodging of this Consent Decree and continuing thereafter, Wisconsin Electric shall continuously operate each Particulate Matter Control Device on its Existing Units to maximize PM emission reductions, consistent with the operational and maintenance limitations of the Units. Specifically, Wisconsin Electric shall, at a minimum: (a) energize each section of the ESP for each Unit, regardless of whether that action is needed to comply with opacity limits; (b) maintain the energy or power levels delivered to the ESPs for each Unit to achieve the greatest possible removal of PM; (c) make best efforts to expeditiously repair and return to service transformer-rectifier sets when they fail; and (d) maintain an ongoing bag leak detection and replacement program to assure optimal operation of each BH.

B. Upgrade of PM Controls

86. Within 365 days of lodging of this Consent Decree, Wisconsin Electric shall operate each of the ESPs and BHs within the Wisconsin Electric System, except Units 5 and 6 at the Presque Isle Generating Station, to achieve and maintain a PM Emission Rate of 0.030 lb/mmBTU. Presque Isle Unit 5 shall achieve and maintain a PM Emission Rate of 0.030 lb/mmBTU by June 30, 2005 and Presque Isle Unit 6 shall achieve and maintain a PM Emission Rate of 0.030 lb/mmBTU by June 30, 2006.

87. Wisconsin Electric shall continuously operate each ESP and BH in the Wisconsin Electric System at all times that the Unit it serves is combusting coal. Wisconsin Electric shall use good operating practices at all times that the Unit is combusting coal.

C. PM Monitoring

1. PM Stack Tests

88. Beginning in calendar year 2004, and continuing annually thereafter, Wisconsin Electric shall conduct a performance test on each Wisconsin Electric System Unit. The annual stack test requirement imposed on each Wisconsin Electric System Unit by this Paragraph may be satisfied by Wisconsin Electric's stack tests conducted as required by its permits from the States of Michigan and Wisconsin for any year that such stack tests are required under the permits. Wisconsin Electric may perform biannual rather than annual testing provided that (a) two of the most recently completed test results from tests conducted in accordance with Method 5 or Method 17 demonstrate that the particulate matter emissions are equal to or less than a 0.015 lb/mmBTU emission limitation, or (b) the Unit is equipped with a PM CEMS in accordance with Paragraph 93. Wisconsin Electric shall perform annual rather that biannual testing the year immediately following any test result demonstrating that the particulate matter emissions are greater than a 0.015 lb/mmBTU emission limitation.

89. The reference and monitoring methods and procedures for determining compliance with Emission Rates for PM shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5 or Method 17. Use of any particular method shall conform to the EPA requirements specified in 40 C.F.R. Part 60, Appendix A and 40 C.F.R. § 60.48a (b) and (e), or any federally approved SIP method. Wisconsin Electric shall calculate the PM Emission Rates from the stack test results in accordance with 40 C.F.R. § 60.8(f), and 40 C.F.R. § 60.46a(c). The results of each PM stack test shall be submitted to EPA within 45 days of completion of each test.

90. The PM Emission Rates established under Paragraph 86 of this Section shall not apply during periods of startup and shutdown or during periods of control equipment or Unit Malfunction, if the Malfunction meets the requirements of the Force Majeure section of this Consent Decree. Periods of startup shall not exceed two hours after any amount of coal is combusted. Periods of shutdown shall only commence when the Unit ceases burning any amount of coal.

2. PM CEMS

91. Wisconsin Electric shall undertake a program to install and operate Continuous Emission Monitoring System for Particulate Matter ("PM CEMS"). Each PM CEMS shall be comprised of a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert results to units of lb/mmBTU. Wisconsin Electric shall maintain, in an electronic database, the hourly average emission values of all PM CEMS in lb/mmBTU. Wisconsin Electric shall use reasonable efforts to keep each PM CEMS running and producing data whenever any Unit served by the PM CEMS is operating.

92. No later than one year prior to the deadline to commence operation as set forth in Paragraph 93, Wisconsin Electric shall submit to EPA for review and approval a plan for the installation and certification of each PM CEMS.

93. Wisconsin Electric shall install, certify, and operate PM CEMS on 10 Units, stacks or common stacks in accordance with the following schedule:

Unit	Deadline to Commence Operation	Location
Presque Isle Units 1-4	April 1, 2006	Common Outlet Flue at Stack
Presque Isle Unit 5	April 1, 2006	Stack
Presque Isle Unit 6	April 1, 2006	Stack
Presque Isle Units 7-9	April 1, 2006	Common Outlet Duct of TOXECON
Oak Creek Units 5&6	April 1, 2005	Common Stack
Oak Creek Unit 7	April 1, 2005	Precipitator Outlet Duct
Oak Creek Unit 8	April 1, 2005	Precipitator Outlet Duct
Pleasant Prairie Units 1&2	April 1, 2005	Common Stack
Valley Unit 1	April 1, 2006	Common Stack
Valley Unit 2	April 1, 2006	Common Stack

94. Notwithstanding the requirements of Paragraph 93, by April 1, 2005, Wisconsin Electric may install two mercury CEMS, one of which will be installed at Pleasant Prairie Unit 1 or Unit 2, and one of which will be installed at Oak Creek Unit 7 or Unit 8, in lieu of a PM CEMS on Presque Isle Units 1 through 4 and one of the units at Valley.

95. No later than 120 days prior to the deadline to commence operation of each PM CEMS, Wisconsin Electric shall submit to EPA for approval pursuant to Section XIII (Review and Approval of Submittals) a proposed Quality Assurance/Quality Control ("QA/QC") protocol that shall be followed in calibrating such PM CEMS. Following EPA's approval of the protocol, Wisconsin Electric shall thereafter operate each PM CEMS in accordance with the approved protocol.

96. In developing both the plan for installation and certification of the PM CEMS and the QA/QC protocol, Wisconsin Electric may use the criteria set forth in EPA's proposed revisions to Performance Specification 11: Specification and Test Procedures for PM CEMS and Procedure 2: PM CEMS at Stationary Sources (PS 11), as published at 66 Fed. Reg 64176 (December 12, 2001) or other available PM CEMS guidance.

97. No later than 90 days after Wisconsin Electric begins operation of the PM CEMS, Wisconsin Electric shall conduct tests of each PM CEMS to demonstrate compliance with the PM CEMS plan submitted to and approved by EPA in accordance with Paragraph 92.

98. If after Wisconsin Electric operates the PM CEMS for at least two years, and if the Parties then agree that it is infeasible to continue operating PM CEMS, Wisconsin Electric shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall include an explanation of the basis for stopping operation of the PM CEMS and a proposal for an alternative monitoring protocol. Until EPA approves such plan, Wisconsin Electric shall continue to operate the PM CEMS.

99. Operation of a PM CEMS shall be considered "infeasible" if (a) the PM CEMS cannot be kept in proper condition for sufficient periods of time to produce reliable, adequate, or useful data consistent with the QA/QC protocol; or (b) Wisconsin Electric demonstrates that recurring, chronic, or unusual equipment adjustment or servicing needs in relation to other types of continuous emission monitors cannot be resolved through reasonable expenditures of resources. If the United States determines that Wisconsin Electric has demonstrated infeasibility pursuant to this Paragraph, Wisconsin Electric shall be entitled to discontinue operation of and remove the PM CEMS.

3. PM Reporting

100. Following the installation of each PM CEMS, Wisconsin Electric shall begin and continue to report to EPA, pursuant to Section XII, the data recorded by the PM CEMS, expressed in lb/mmBTU on a 3-hour, 24-hour, 30-day, and 365-day rolling average basis in electronic format, as required in Paragraph 91.

D. General PM Provisions

101. In determining the PM Emission Rate, Wisconsin Electric shall use the reference methods specified in 40 C.F.R. Part 60, Appendix A, Method 5 or Method 17, using stack tests, or alternative methods that are either promulgated by EPA or requested by Wisconsin Electric and approved by EPA. Wisconsin Electric shall also calculate the PM Emission Rates from annual (or biannual) stack tests in accordance with 40 C.F.R. § 60.8(f). Wisconsin Electric shall also determine PM Emission Rates using PM CEMS consistent with the approved QA/QC protocol.

102. Data from the PM CEMS shall be used by Wisconsin Electric, at a minimum, to monitor progress in reducing PM emissions. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8315 (Feb. 27, 1997)) concerning the use of data for any purpose under the Act, generated either by the reference methods specified herein or otherwise.

VIII. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

103. For any and all actions taken by Wisconsin Electric to comply with the requirements of this Consent Decree, including but not limited to the upgrade of ESPs and BHs, the installation of FGDs, SCRs, or equivalent control devices approved under this Consent Decree, the re-powering of certain units, the retirement of certain units, and the reduction of emissions to satisfy annual emission tonnage limitations, any emission reductions generated shall not be considered as a creditable contemporaneous emission decrease for the purpose of obtaining a netting credit under the Clean Air Act's Nonattainment NSR and PSD programs. Notwithstanding the preceding sentence, Wisconsin Electric may use any creditable contemporaneous emission decreases of Volatile Organic Compounds ("VOCs") generated under this Consent Decree for the purpose of obtaining a netting credit for VOCs under the Clean Air Act's Nonattainment NSR and PSD programs.

104. Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Decree from being considered as creditable contemporaneous emission decreases for the purpose of attainment demonstrations submitted pursuant to § 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS and PSD increment consumption.

IX. ENVIRONMENTAL PROJECTS

105. Wisconsin Electric, in cooperation with the United States Department of Energy ("DOE") and potentially other parties, shall design, construct, operate and analyze the first full scale TOXECON with activated carbon injection with the goal of achieving a 90% removal of all species of mercury ("the TOXECON Project"). The TOXECON Project will be implemented at Units 7, 8, and 9 of Wisconsin Electric's Presque Isle Generating Station.

106. At least six months before it plans to commence implementation of the TOXECON Project, Wisconsin Electric shall submit to the Plaintiff for review and approval pursuant to Section XIII of this Consent Decree a plan for the implementation of the TOXECON Project, including the date by which Wisconsin Electric will commence design and construction of the Project, and the date by which Wisconsin Electric will complete the Project. To the extent that any change to the TOXECON Project may be required, Wisconsin Electric shall notify the Plaintiff of such change within 60 days of becoming aware a change is necessary. Wisconsin Electric shall implement the TOXECON Project in compliance with the schedules and terms of this Consent Decree and the plans for such Project approved under this Decree.

107. For purposes of this Consent Decree, in performing the TOXECON Project, Wisconsin Electric shall, prior to December 31, 2006, spend no less than $20 million, and shall not be required to spend more than $25 million, in Project Dollars (measured in calendar year 2003 constant dollars). Wisconsin Electric shall maintain all documents required by Generally Accepted Accounting Principles to substantiate the Project Dollars spent by Wisconsin Electric, and shall provide copies of these documents to the Plaintiff within 30 days of a request by the Plaintiff for these documents.

108. All plans and reports prepared by Wisconsin Electric pursuant to the requirements of this Section in this Consent Decree shall be publicly available without charge, subject to the limitations contained in Paragraph 172.

109. Wisconsin Electric shall certify, as part of each plan submitted to the United States for any Project, that it is unaware of any person required by law, other than this Consent Decree, to perform the Project described in the plan.

110. Wisconsin Electric shall use good faith efforts to secure as much benefit as possible for the Project Dollars expended, consistent with the applicable requirements and limits of this Consent Decree.

111. Within 60 days following the completion of the TOXECON Project, Wisconsin Electric shall submit to the EPA a report that documents the date that the Project was completed, Wisconsin Electric's results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by Wisconsin Electric in implementing the Project.

112. Following completion of the TOXECON Project, Wisconsin Electric shall maintain the baghouse component of the TOXECON in the flue gas stream regardless of the results of the demonstration project. If Wisconsin Electric determines that the demonstration project has removed reasonable levels of mercury and is operationally viable, Wisconsin Electric shall also continue sorbent injection for mercury control.

113. Wisconsin Electric shall not financially benefit from the sale or transfer of the TOXECON technology or the collection or distribution of information collected during this demonstration project.

114. Wisconsin Electric shall provide the United States with semi-annual updates concerning the progress of the TOXECON Project. Wisconsin Electric also shall make information concerning the performance of the TOXECON Project available to the public in an expeditious matter, consistent with DOE's requirements concerning the disclosure of project information and subject to the limitations contained in Paragraph 172. Such information disclosure shall include, but not be limited to, release of periodic progress reports, clearly

identifying demonstrated removal efficiencies of mercury and other pollutants, sorbent injection rates and cost effectiveness. In addition, periodic technology transfer open houses and plant tours shall be scheduled, consistent with DOE's requirements for disclosure of project information and subject to the limitations contained in Paragraph 172.

X. CIVIL PENALTY

115. Within thirty (30) calendar days of entry of this Consent Decree, Wisconsin Electric shall pay to the United States a civil penalty in the amount of $ 3.2 million. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing USAO File Number 2003V00451 and DOJ Case Number 90-5-2-1-07493 and the civil action case name and case number of this action, with notice given to the Plaintiff, in accordance with Section XX (Notices) of this Consent Decree. The costs of such EFT shall be Wisconsin Electric's responsibility. Payment shall be made in accordance with instructions provided to Wisconsin Electric by the Financial Litigation Unit of the U.S. Attorney's Office for the Eastern District of Wisconsin. Any funds received after 2:00 p.m. EDT shall be credited on the next business day. At the time of payment, Wisconsin Electric shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1-07493, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Paragraph 174 (Notice) of this Consent Decree.

116. Failure to timely pay the civil penalty shall subject Wisconsin Electric to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Wisconsin Electric liable for all charges, costs, fees, and

penalties established by law for the benefit of a creditor or of the United States in securing payment.

117. Payments made pursuant to this Section are penalties within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and are not tax-deductible expenditures for purposes of federal law.

XI. RESOLUTION OF CLAIMS

A. RESOLUTION OF U.S. CIVIL CLAIMS

118. Claims Based on Modifications Occurring Before the Lodging of Decree. Entry of this Decree shall resolve all civil claims of the United States under either: (i) Parts C or D of Subchapter I of the Clean Air Act or (ii) 40 C.F.R. Section 60.14, that arose from any modifications that commenced at any Wisconsin Electric System Unit prior to the date of lodging of this Decree, including but not limited to those modifications alleged in the Complaint in this civil action.

119. Claims Based on Modifications After the Lodging of Decree. Entry of this Decree also shall resolve all civil claims of the United States for pollutants regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated as of the date of lodging of this Decree, where such claims are based on a modification completed before December 31, 2015 and:

(a) commenced at any Wisconsin Electric System Unit after lodging of this Decree; or

(b) that this Consent Decree expressly directs Wisconsin Electric to undertake.

The term "modification" as used in this Paragraph shall have the meaning that term is given under the Clean Air Act statute as it existed on the date of lodging of this Decree.

120. Reopener. The resolution of the civil claims of the United States provided by this Subsection is subject to the provisions of Section B of this Section.

B. PURSUIT OF U.S. CIVIL CLAIMS OTHERWISE RESOLVED

121. Bases for Pursuing Resolved Claims Across Wisconsin Electric System. If Wisconsin Electric violates Paragraph 60 (System-wide NO_x Rolling Tonnage Limits), Paragraph 59 (System-wide NO_x Rolling Average Emission Rate), Paragraph 74 (System-wide Rolling SO_2 Tonnage Limits), Paragraph 73 (System-wide SO_2 Emission Rates), or Paragraph 82 (Fuel Limitation), or fails by more than ninety days to complete installation and commence operation of any emission control device required pursuant to Paragraphs 55 or 70; or fails by more than ninety days to control or retire and permanently cease to operate Wisconsin Electric System Units pursuant to Paragraph 54, then the United States may pursue any claim at any Wisconsin Electric System Unit that has otherwise been resolved under Subsection A of this Section, subject to (A) and (B) below.

(A) For any claims based on modifications undertaken at an Other Unit, claims may be pursued only where the modification(s) on which such claim is based was commenced within the five years preceding the violation or failure specified in this Paragraph.

(B) For any claims based on modifications undertaken at an Improved Unit, claims may be pursued only where the modification(s) on which such claim is based was commenced (i) after lodging of the Consent Decree and (ii) within the five years preceding the violation or failure specified in this Paragraph.

122. Additional Bases for Pursuing Resolved Claims for Modifications at an Improved Unit. Solely with respect to Improved Units, the United States may also pursue claims arising

from a modification (or collection of modifications) at an Improved Unit that has otherwise been resolved under Section A if the modification (or collection of modifications) at the Improved Unit on which such claim is based (i) was commenced after lodging of this Consent Decree, and (ii) individually (or collectively) increased the maximum hourly emission rate of that Unit for NO_x or SO_2 (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%).

123. Additional Bases for Pursuing Resolved Claims for Modifications at an Other Unit. Solely with respect to Other Units, the United States may also pursue claims arising from a modification (or collection of modifications) at an Other Unit that has otherwise been resolved under Section XI. A if the modification (or collection of modifications) on which the claim is based was commenced within the five years preceding any of the following events:

(A) a modification (or collection of modifications) at such Other Unit commenced after lodging of this Consent Decree increases the maximum hourly emission rate for such Other Unit for the relevant pollutant (NO_x or SO_2) as measured by 40 C.F.R. § 60.14(b) and (h);

(B) the aggregate of all Capital Expenditures made at such Other Unit exceed $125/KW on the Unit's Boiler Island (based on the capacity numbers included in Paragraph 53) during any of the following five year periods: January 1, 2006 through December 31, 2010; January 1, 2011 through December 31, 2015. For the period from the date of lodging of this Decree through December 31, 2005, the $125/KW limit shall be pro-rated to include only that portion of the five-year period (January 1, 2000 through December 31, 2005) following the date of lodging of this Decree. (Capital Expenditures shall be measured in calendar year 2002 constant dollars, as adjusted by the McGraw-Hill Engineering News-Record Construction Cost Index); or

(C) a modification (or collection of modifications) at such Other Unit commenced after lodging of this Consent Decree results in an emissions increase of NO_x and/or SO_2 at such Other Unit, and such increase:

(1) presents, by itself, or in combination with other emissions or sources, "an imminent and substantial endangerment" within the meaning of Section 303 of the Act, 42 U.S.C. §7603;

(2) causes or contributes to violation of a National Ambient Air Quality Standard ("NAAQS") in any Air Quality Control Area that is in attainment with that NAAQS;

(3) causes or contributes to violation of a PSD increment; or

(4) causes or contributes to any adverse impact on any formally-recognized air quality and related values in any Class I area.

(D) Solely for purposes of Paragraph 123, Subparagraph (C), the determination of whether there was an emissions increase must take into account any emissions changes relevant to the modeling domain that have occurred or will occur under this Decree at other Wisconsin Electric System Units. In addition, an emissions increase shall be deemed to have occurred at an Other Unit if the annual emissions of the relevant pollutant (NO_x or SO_2) from the plant at which such modification(s) occurred exceed the Baseline for that plant.

(E) The introduction of any new or changed National Ambient Air Quality Standard shall not, standing alone, provide the showing needed under Paragraph 123, Subparagraphs

(C)(2) or (C)(3), to pursue any claim for a modification at an Other Unit resolved under Subsection A of this Section.

124. [RESERVED.]

XII. PERIODIC REPORTING

125. Within 180 days after each date established by this Consent Decree for Wisconsin Electric to achieve and maintain a certain Emission Rate or Removal Efficiency at any Wisconsin Electric System Unit, Wisconsin Electric shall conduct performance tests that demonstrate compliance with the Emission Rate or Removal Efficiency required by this Consent Decree. Within 45 days of each such performance test, Wisconsin Electric shall submit the results of the performance test to EPA at the addresses specified in Section XX (Notices) of this Consent Decree.

126. Beginning thirty days after the end of the first full calendar quarter following the entry of this Consent Decree or December 31, 2003, whichever is later, continuing on a semi-annual basis until December 31, 2015, and in addition to any other express reporting requirement in this Consent Decree, Wisconsin Electric shall submit to EPA a progress report.

127. The progress report shall contain the following information:

a. all information necessary to determine compliance with this Consent Decree;

b. all information relating to emission allowances and credits that Wisconsin Electric claims to have generated in accordance with Paragraphs 66 and 81 by compliance beyond the requirements of this Consent Decree; and

c. all information indicating that the installation and commencement of operation for a pollution control device may be delayed, including the nature and cause of the delay, and any steps taken by Wisconsin Electric to mitigate such delay.

128. In any periodic progress report submitted pursuant to this Section, Wisconsin Electric may incorporate by reference information previously submitted under its Title V permitting requirements, provided that Wisconsin Electric attaches the Title V permit report and provides a specific reference to the provisions of the Title V permit report that are responsive to the information sought in the periodic progress report.

129. In addition to the progress reports required pursuant to this Section, Wisconsin Electric shall provide a written report to EPA of any violation of the requirements of this Consent Decree, including exceedances of required Emission Rates, removal efficiencies, and Unit-Specific and System-wide Rolling Average Emission Rate and Rolling Tonnage limits, within 10 business days of when Wisconsin Electric knew or should have known of any such violation. In this report, Wisconsin Electric shall explain the cause or causes of the violation and all measures taken or to be taken by Wisconsin Electric to prevent such violations in the future.

130. Each Wisconsin Electric report shall be signed by Wisconsin Electric's Vice President Environmental, or, in his or her absence, General Counsel, or higher ranking official, and shall contain the following certification:

> This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is

true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

131. If any allowances are surrendered to any third party pursuant to Section VI.C of this Consent Decree, the third party's certification shall be signed by a managing officer of the third party and shall contain the following language:

> I certify under penalty of law that,____________ [name of third party] will not sell, trade, or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any environmental law. I understand that there are significant penalties for making false, inaccurate, or incomplete information to the United States.

XIII. REVIEW AND APPROVAL OF SUBMITTALS

132. Wisconsin Electric shall submit and complete each plan, report, or other item to the Plaintiff whenever such a document is required to be submitted for review or approval pursuant to this Consent Decree. EPA may approve the submittal or decline to approve it and provide written comments. Within 60 days of receiving written comments from EPA, Wisconsin Electric shall either: (i) alter the submittal consistent with the written comments and provide the revised submittal for final approval to EPA if called for in this Consent Decree; or (ii) submit the matter for dispute resolution, including the period of informal negotiations, under Section XVI (Dispute Resolution) of this Consent Decree.

133. Upon receipt of EPA's final approval of the submittal, or upon completion of the submittal pursuant to dispute resolution, Wisconsin Electric shall implement the submittal in accordance with the approved submittal.

XIV. STIPULATED PENALTIES

134. For any failure by Wisconsin Electric to comply with the terms of this Consent Decree, and subject to the provisions of Sections XV (Force Majeure) and XVI (Dispute

Resolution), Wisconsin Electric shall pay, within 30 days after written demand to Wisconsin Electric by the United States the following stipulated penalties to EPA:

Consent Decree Violation	**Stipulated Penalty (Per day per violation, unless otherwise specified)**
a. Failure to pay the civil penalty as specified in Section X (Civil Penalty) of this Consent Decree	$10,000
b. Failure to meet any 30-Day Rolling Average Emission Rate, any 30-Day Rolling Average Removal Efficiency, or any other Emission Rate or emission limitation (other than the System-wide 12-month Rolling Average Emission Rates, System-wide 12-month Rolling Tonnage limitations or any other 12-month rolling limitation), where the violation is less than 5% in excess of the limits set forth in this Consent Decree	$2,500
c. Failure to meet any 30-Day Rolling Average Emission Rate, any 30-Day Rolling Average Removal Efficiency, or any other Emission Rate or emission limitation (other than the System-wide 12-month Rolling Average Emission Rates, System-wide 12-month Rolling Tonnage limitations or any other 12-month rolling limitation), where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree	$5,000
d. Failure to meet any 30-Day Rolling Average Emission Rate, any 30-Day Rolling Average Removal Efficiency, or any other Emission Rate or emission limitation (other than the System-wide 12-month Rolling Average Emission Rates, System-wide 12-month Rolling Tonnage limitations or any other 12-month rolling limitation), where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree	$10,000
e. Failure to meet any System-wide 12-month Rolling Average Emission Rate, where the violation is less than 5% in excess of the limits set forth in this Consent Decree	$2,500 per month

f. Failure to meet any System-wide 12-month Rolling Average Emission Rate, where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree	$5,000 per month
g. Failure to meet any System-wide 12-month Rolling Average Emission Rate, where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree	$10,000 per month
h. Failure to meet the System-wide 12-month Rolling SO_2 and NO_x Tonnage Limits as set out in Paragraphs 60 and 74 or any other the 12-month rolling tonnage limitation	$5,000 per ton per month for the first 100 tons over the limit, and $10,000 per ton per month for each additional ton over the limit
i. Failure to install, commence operation, or continue operation of the NO_x, SO_2, and PM pollution control devices on any Unit, or failure to retire a Unit	$10,000 during the first 30 days, $27,500 thereafter
j. Failure to meet the fuel use limitations at a Unit, as required by Paragraph 82	$10,000
k. Failure to install or operate CEMS as required in Paragraph 93, subject to Paragraph 99	$1,000
l. Failure to conduct annual or biannual performance tests of PM emissions, as required in Paragraph 88	$1,000
m. Failure to apply for the permits required by Paragraphs 165-167	$1,000
n. Failure to timely submit, modify, or implement, as approved, the reports, plans, studies, analyses, protocols, or other submittals required by this Consent Decree	$750 for the first ten days, $1,000 thereafter.

o. Using, selling, or transferring SO_2 Allowances, except as permitted by Paragraphs 76, 77 and 81	(a) three times the market value of the improperly used allowance, as measured at the time of the improper use, plus (b) the surrender, pursuant to the procedures set forth in Paragraphs 77 through 79 of this Decree, of SO_2 Allowances in an amount equal to the SO_2 Allowances used, sold, or transferred in violation of the Decree
p. Using, selling or transferring NOx allowances or credits except as permitted under Paragraph 64-66	(a) three times the market value of the improperly used allowance, as measured at the time of the improper use, plus (b) the surrender, pursuant to the procedures set forth in Section XII (Periodic Reporting) of this Decree, of NO_x allowances or credits in an amount equal to the NO_x allowances or credits used, sold, or transferred in violation of the Decree
q. Failure to surrender an SO_2 Allowance in accordance with Paragraph 77	(a) \$27,500 plus (b) \$1,000 per SO_2 Allowance
r. Failure to demonstrate the third-party surrender of an SO_2 Allowance in accordance with Paragraph 78	\$2,500
s. Failure to undertake and complete any of the Environmental Projects in compliance with Section IX (Environmental Projects)	\$1,000 for the first 30 days, \$5,000 thereafter
t. Any other violation of this Consent Decree	\$1,000

135. Violation of an Emission Rate or Removal Efficiency that is based on a 30-Day Rolling Average is a violation on every day on which the average is based. Violation of System-wide 12-Month Rolling Average Emission Rates, System-wide 12-Month Rolling Tonnage

Limitations or any other 12-month rolling limitation is a violation each month on which the average is based.

136. Where a violation of a 30-Day Rolling Average Emission Rate or Removal Efficiency (for the same pollutant and from the same source) recurs within periods less than 30 days, Wisconsin Electric shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

137. All stipulated penalties shall begin to accrue on the day after the performance is due or on the day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases. Nothing herein shall prevent the simultaneous accrual of separate penalties for separate violations of this Consent Decree.

138. Wisconsin Electric shall pay all stipulated penalties to the United States, in the manner set forth below in Paragraph 140, within 30 days of any violation of this Consent Decree, and shall continue to make such payments every 30 days thereafter until the violation(s) no longer continues, unless Wisconsin Electric elects within 20 days of the violation to dispute the accrual of stipulated penalties in accordance with the provisions in Section XVI (Dispute Resolution) of this Consent Decree.

139. Penalties shall continue to accrue as provided in accordance with Paragraph 137 during any dispute, with interest on accrued penalties payable and calculated at the rate established by the Secretary of the Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid until the following:

a. If the dispute is resolved by agreement or by a decision of the Plaintiff that is not appealed to the Court, accrued penalties determined to be owing, together with accrued interest, shall be paid to the United States within thirty (30) days of the effective date of the agreement or the receipt of EPA's decision or order;

b. If the dispute is appealed to the Court and the Plaintiff prevails in whole or in part, Wisconsin Electric shall, within sixty (60) days of receipt of the Court's decision or order, pay all accrued penalties determined by the Court to be owing, together with accrued interest, except as provided in Subparagraph c, below;

c. If the District Court's decision is appealed by any Party, Wisconsin Electric shall, within fifteen (15) days of receipt of the final appellate court decision, pay all accrued penalties determined to be owing to the United States, together with accrued interest.

140. All stipulated penalties must be paid within thirty (30) days of the date payable, and payment shall be made in the manner set forth in Section X of this Consent Decree (Civil Penalty).

141. Should Wisconsin Electric fail to pay stipulated penalties in compliance with the terms of this Consent Decree, the United States shall be entitled to collect interest on such penalties, as provided for in 28 U.S.C. § 1961.

142. The stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to the United States by reason of Wisconsin Electric's failure to comply with any requirement of this Consent Decree or applicable law, except that for any violation of the Act for which this Consent Decree also provides for payment

of a stipulated penalty, Wisconsin Electric shall be allowed a credit for stipulated penalties paid against any statutory penalties imposed for such violation.

XV. FORCE MAJEURE

143. For purposes of this Consent Decree, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of Wisconsin Electric, its contractors, or any entity controlled by Wisconsin Electric that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite Wisconsin Electric's best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay or violation is minimized to the greatest extent possible.

144. Notice. If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which Wisconsin Electric intends to assert a claim of Force Majeure, Wisconsin Electric shall notify the Plaintiffs in writing as soon as practicable, but in no event later than fourteen (14) business days following the date Wisconsin Electric first knew, or by the exercise of due diligence should have known, that the Force Majeure Event caused or may cause such delay or violation. In this notice, Wisconsin Electric shall reference this Paragraph of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by Wisconsin Electric to prevent or minimize the delay or violation, the schedule by which Wisconsin Electric proposes to implement those measures, and Wisconsin Electric's rationale for attributing a delay or violation to a Force

Majeure Event. Wisconsin Electric shall adopt all reasonable measures to avoid or minimize such delays or violations. Wisconsin Electric shall be deemed to know of any circumstance of which Wisconsin Electric, its contractors, or any entity controlled by Wisconsin Electric knew or should have known.

145. Failure to Give Notice. If Wisconsin Electric fails to comply with the notice requirements of this Section, the EPA may void Wisconsin Electric's claim for Force Majeure as to the specific event for which Wisconsin Electric has failed to comply with such notice requirement.

146. Plaintiff's Response. The EPA shall notify Wisconsin Electric in writing regarding Wisconsin Electric's claim of Force Majeure within (20) twenty business days of receipt of the notice provided under Paragraph 144. If EPA agrees that a delay in performance has been or will be caused by a Force Majeure Event, the Parties shall stipulate to an extension of deadline(s) for performance of the affected compliance requirement by a period not to exceed the delay actually caused by the event. In such circumstances, an appropriate modification shall be made pursuant to Section XXIV of this Consent Decree (Modification).

147. Disagreement. If EPA does not accept Wisconsin Electric's claim of Force Majeure, the matter shall be resolved in accordance with Section XVI of this Consent Decree (Dispute Resolution).

148. Burden of Proof. In any dispute regarding Force Majeure, Wisconsin Electric shall bear the burden of proving that any delay in performance or any other violation of any requirement of this Consent Decree was caused by or will be caused by a Force Majeure Event. Wisconsin Electric shall also bear the burden of proving that Wisconsin Electric gave the notice

required by this Section and the anticipated duration and extent of any delay(s) attributable to a Force Majeure Event. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

149. Events Excluded. Unanticipated or increased costs or expenses associated with the performance of Wisconsin Electric's obligations under this Consent Decree shall not constitute a Force Majeure Event.

150. Potential Force Majeure Events. The Parties agree that, depending upon the circumstances related to an event and Wisconsin Electric's response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Section: construction, labor, or equipment delays; Malfunction of a Unit or emission control device; natural gas and gas transportation availability delay; acts of God; acts of war or terrorism; and orders by a government official, government agency, or other regulatory body acting under and authorized by applicable law that directs Wisconsin Electric to supply electricity in response to a system-wide (state-wide or regional) emergency. Depending upon the circumstances and Wisconsin Electric's response to such circumstances, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure Event where the failure of the permitting authority to act is beyond the control of Wisconsin Electric and Wisconsin Electric has taken all steps available to it to obtain the necessary permit, including, but not limited to, submitting a complete permit application, responding to requests for additional information by the permitting authority in a timely fashion, accepting lawful permit terms and conditions, and prosecuting in an expeditious fashion appeals of any allegedly unlawful terms and conditions imposed by the permitting authority.

151. As part of the resolution of any matter submitted to this Court under this Section, the Parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by EPA or approved by this Court. Wisconsin Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XVI. DISPUTE RESOLUTION

152. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, except as provided in either this Section (Dispute Resolution) or Section XV (Force Majeure) of this Consent Decree, provided that the Party making such application has first made a good faith attempt to resolve the matter with the other Party.

153. The dispute resolution procedure required herein shall be invoked by one Party to this Consent Decree giving written notice to the other party to this Consent Decree advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party's position with regard to such dispute. The Party receiving such a notice shall acknowledge receipt of the notice, and the Parties in dispute shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

154. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations between the disputing Parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first

meeting among the disputing Parties' representatives unless they agree to shorten or extend this period. During the informal negotiations period, the disputing Parties may also submit their dispute to a mutually-agreed-upon alternative dispute resolution (ADR) forum if the Parties agree that the ADR activities can be completed within the 30-day informal negotiations period.

155. If the disputing Parties are unable to reach agreement during the informal negotiation period, the EPA shall provide Wisconsin Electric with a written summary of their position regarding the dispute. The written position provided by EPA shall be considered binding unless, within forty-five (45) calendar days thereafter, Wisconsin Electric seeks judicial resolution of the dispute by filing with this Court a petition. The EPA may respond to the petition within forty-five (45) calendar days of filing.

156. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the Parties to the dispute.

157. This Court shall not draw any inferences nor establish any presumptions adverse to any disputing Party as a result of invocation of this Section or the disputing Parties' inability to reach agreement.

158. As part of the resolution of any dispute under this Section, in appropriate circumstances the disputing Parties may agree, or this Court may order, an extension or modification of the schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution. Wisconsin Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

159. As to disputes arising under Section VII of this Consent Decree (PM Emission Reductions and Controls), the Court shall sustain the position of the EPA as to the feasibility of obtaining accurate and reliable data from the PM CEMS that Wisconsin Electric is to install pursuant to Paragraph 93, unless Wisconsin Electric demonstrates that the position of the EPA is arbitrary or capricious. The Court shall decide all other disputes pursuant to applicable principles of law for resolving such disputes. In their initial filings with the Court under Paragraph 155, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

XVII. EMISSIONS LIMITATIONS ON THE SOUTH OAK CREEK AND ELM ROAD GENERATING STATIONS

160. Wisconsin Electric has submitted an application for a PSD Permit for the construction of proposed new coal-fired generating Units, which if approved will be known as the Elm Road Generating Station. If, at any time after the date of lodging of this Consent Decree, one or more of the new units at the proposed Elm Road Generating Station is approved and constructed, Wisconsin Electric shall limit the combined emissions of SO_2, NO_x, PM, mercury, VOCs, hydrochloric acid, hydrofluoric acid, and sulfuric acid from both its South Oak Creek Generating Station and its Elm Road Generating Station to 38,400 tons per year, collectively. This emission limitation is based on actual or calculated emissions of SO_2, NO_x, PM, mercury, VOCs, hydrochloric acid, hydrofluoric acid, and sulfuric acid from the existing units at South Oak Creek Generating Station in calendar year 2000. Compliance with this emission limitation shall be demonstrated on a 12-month rolling average. The emission limitation shall be included in the Title V operating permit issued to the South Oak Creek Generating Station and the Elm Road Generating Station, if approved and constructed.

XVIII. PERMITS

161. Unless expressly stated otherwise in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Wisconsin Electric to secure a permit to authorize construction or operation of any device, including all preconstruction, construction, and operating permits required under state law, Wisconsin Electric shall make such application in a timely manner. EPA will use its best efforts to expeditiously review all permit applications submitted pursuant to this Consent Decree.

162. Notwithstanding the previous paragraph, nothing in this Consent Decree shall be construed to require Wisconsin Electric to apply for or obtain a PSD or Nonattainment NSR permit for physical changes or changes in the method of operation that would give rise to claims resolved by Section XI (Resolution of Claims) of this Consent Decree.

163. When permits are required by the Paragraph 161, Wisconsin Electric shall complete and submit applications for such permits to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request. Any failure by Wisconsin Electric to submit a timely permit application for any Unit in the Wisconsin Electric System shall bar any use by Wisconsin Electric of Section XV (Force Majeure), where a Force Majeure claim is based on permitting delays.

164. Notwithstanding the reference to Title V permits in this Consent Decree, the enforcement of such permits shall be in accordance with their own terms and the Act. The Title V permits shall not be directly enforceable under this Decree, although any term or limit established by or under this Decree shall be enforceable under this Decree regardless of whether

such term has or will become part of a Title V permit, subject to the terms of Section XXVIII (Conditional Termination of Enforcement Under Decree).

165. Within ninety (90) days of entry of this Consent Decree, Wisconsin Electric shall amend any applicable Title V permit application, or apply for amendments of its Title V permits, to include a schedule for all performance, operational, maintenance, and control technology requirements established by this Consent Decree, including, but not limited to, Emission Rates, removal efficiencies, limits on fuel use, and the requirement in Paragraph 77 pertaining to surrender of SO_2 allowances.

166. Within one year from the commencement of operation of each pollution control device to be installed or upgraded on an Improved Unit under this Consent Decree, Wisconsin Electric shall apply to modify its Title V permit for the generating plant where such device is installed to reflect all new requirements applicable to that plant, including, but not limited to any applicable 30-Day Rolling Average Emission Rate or Removal Efficiency.

167. Prior to January 1, 2015, Wisconsin Electric shall apply to amend the Title V permit for each plant in the Wisconsin Electric System to include specific Emission Rates or tonnage limitations as described below. Wisconsin Electric shall be in compliance with this requirement if, by January 1, 2015, it has applied to amend each such Title V permit to include Emissions Rate limitations applicable to Improved Units and tonnage limitations applicable to plants with Other Units. Improved Units shall not exceed a 12-Month Rolling Average Emission Rate for NOx of 0.080 lb/mmBTU and a 12-Month Rolling Average Emission Rate for SO_2 of 0.080 lb/mmBTU or a Removal Efficiency of 96% for SO_2. The plants with Other Units shall meet the following Unit-specific 12-Month Rolling Tonnage:

Plant	NO_x	SO_2
Valley	3, 989	9,973
Presque Isle	7,376	17, 257

168. Wisconsin Electric shall provide the EPA with a copy of each application to amend its Title V permit, as well as a copy of any permit proposed as a result of such application, to allow for timely participation in any public comment opportunity.

169. If Wisconsin Electric sells or transfers to a Third Party Purchaser part or all of its ownership interest in a Unit in the Wisconsin Electric System, Wisconsin Electric shall comply with the requirements of Paragraph 167 with regard to that Unit, prior to any such sale or transfer unless, following any such sale or transfer, Wisconsin Electric remains the holder of the Title V permit for such facility. For purposes of this Paragraph and Section XXI, "Third Party Purchaser" refers to an entity unrelated to Wisconsin Electric, WEC or W.E. Power that may acquire an ownership interest in one or more of the Units in the Wisconsin Electric System.

XIX. INFORMATION COLLECTION AND RETENTION

170. Any authorized representative of the United States or Permitting State Agency, including their attorneys, contractors, and consultants, upon presentation of credentials, shall have a right of entry upon the premises of any facility in the Wisconsin Electric System at any reasonable time for the purpose of:

a. monitoring the progress of activities required under this Consent Decree;

b. verifying any data or information submitted to the United States in accordance with the terms of this Consent Decree;

c. obtaining samples and, upon request, splits of any samples taken by Wisconsin Electric or its representatives, contractors, or consultants; and

d. assessing Wisconsin Electric's compliance with this Consent Decree.

171. Wisconsin Electric shall retain, and instruct its contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in its or its contractors' or agents' possession or control, and that directly relate to Wisconsin Electric's performance of its obligations under this Consent Decree for the following periods: (a) until December 31, 2020 for records concerning physical or operational changes undertaken in accordance with Paragraph 119 (Resolution of U.S. Claims Based On Modifications after Lodging of the Decree) of this Consent Decree; and (b) until December 31, 2017 for all other records. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

172. All information and documents submitted by Wisconsin Electric pursuant to this Consent Decree shall be subject to any requests under applicable law providing public disclosure of documents unless (a) the information and documents are subject to legal privileges or protection or (b) Wisconsin Electric claims and substantiates that the information and documents contain confidential business information in accordance with 40 C.F.R. Part 2.

173. Nothing in this Consent Decree shall limit the authority of the EPA to conduct tests and inspections at Wisconsin Electric's facilities under Section 114 of the Act, 42 U.S.C. § 7414, or any other applicable federal or state laws, regulations or permits.

XX. NOTICES

174. Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

As to the United States of America:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-06965

and

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Regional Administrator
U.S. EPA Region V
77 West Jackson Blvd.
Chicago, Illinois 60604-3590

As to Wisconsin Electric:

Vice President Environmental
Wisconsin Electric Power Company
231 W. Michigan Street
Milwaukee, Wisconsin 53203

and

General Counsel
Wisconsin Electric Power Company
231 W. Michigan Street
Milwaukee, Wisconsin 53203

175. All notifications, communications or submissions made pursuant to this Section shall be sent either by: (a) overnight mail or by certified or registered mail, return receipt requested; (b) electronic transmission, unless the recipient is not able to review the transmission in electronic form. All notifications, communications and transmissions sent by overnight, certified or registered mail shall be deemed submitted on the date they are postmarked. All notifications, communications, and submissions made by electronic means shall be electronically signed and certified, and shall be deemed submitted on the date that Wisconsin Electric receives written acknowledgment of receipt of such transmission.

176. Any Party may change either the notice recipient or the address for providing notices to it by serving the other Party with a notice setting forth such new notice recipient or address.

177. [RESERVED.]

XXI. SALES OR TRANSFERS OF OWNERSHIP INTERESTS

178. If Wisconsin Electric proposes to sell or transfer part or all of its ownership interest in any Existing Unit ("Ownership Interest") to an entity unrelated to Wisconsin Electric, WEC or W.E. Power (Third Party Purchaser), it shall advise the Third Party Purchaser in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to EPA pursuant to Section XX (Notices) at least sixty (60) days before such proposed sale or transfer.

179. No sale or transfer of an Ownership Interest shall take place before the Third Party Purchaser and EPA have executed, and the Court has approved, a modification pursuant to Section XXIV (Modification) of this Consent Decree making the Third Party Purchaser a party defendant to this Consent Decree and jointly and severally liable with Wisconsin Electric for all the requirements of this Decree that may be applicable to the transferred or purchased Ownership Interests, including joint and several liability with Wisconsin Electric for all requirements specific to the Existing Unit, as well as all requirements in this Consent Decree that are not specific to these Existing Units, except as provided in Paragraph 181.

180. This Consent Decree shall not be construed to impede the transfer of any Ownership Interests between Wisconsin Electric and any Third Party Purchaser as long the requirements of this Consent Decree are met. This Consent Decree shall not be construed to prohibit a contractual allocation – as between Wisconsin Electric and any Third Party Purchaser of Ownership Interests – of the burdens of compliance with this Decree, provided that both Wisconsin Electric and such Third Party Purchaser shall remain jointly and severally liable to EPA for the obligations of the Decree applicable to the transferred or purchased Ownership Interests, except as provided in Paragraph 181.

181. If EPA agrees, EPA, Wisconsin Electric, and the Third Party Purchaser that has become a party defendant to this Consent Decree pursuant to Paragraph 179, may execute a modification that relieves Wisconsin Electric of its liability under this Consent Decree for, and makes the Third Party Purchaser liable for, all obligations and liabilities applicable to the purchased or transferred Ownership Interests. Notwithstanding the foregoing, however, Wisconsin Electric may not assign, and may not be released from, any obligation under this

Consent Decree that is not specific to the purchased or transferred Ownership Interests, including the obligations set forth in Sections IX (Environmental Projects) and X (Civil Penalty). Wisconsin Electric may propose and the EPA may agree to restrict the scope of joint and several liability of any purchaser or transferee for any obligations of this Consent Decree that are not specific to the Unit, to the extent such obligations may be adequately separated in an enforceable manner.

XXII. EFFECTIVE DATE

182. The effective date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court.

XXIII. RETENTION OF JURISDICTION

183. Continuing Jurisdiction. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, modification, or adjudication of disputes. During the term of this Consent Decree, either Party to this Consent Decree may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

XXIV. MODIFICATION

184. The terms of this Consent Decree may be modified only by a subsequent written agreement signed by both Parties. Where the modification constitutes a material change to any term of this Decree, it shall be effective only upon approval by the Court.

XXV. GENERAL PROVISIONS

185. This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations.

186. This Consent Decree does not apply to any claim(s) of alleged criminal liability.

187. In any subsequent administrative or judicial action initiated by the United States for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Wisconsin Electric shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, or claim splitting, or any other defense based upon the contention that the claims raised by the United States in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the validity of Section XI (Resolution of Claims).

188. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Wisconsin Electric of its obligation to comply with all applicable federal, state, and local laws and regulations. Subject to the provisions in Section XI (Resolution of Claims) of this Consent Decree, nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the United States to obtain penalties or injunctive relief under the Act or other federal, state, or local statutes, regulations, or permits.

189. Every term expressly defined by this Consent Decree shall have the meaning given to that term by this Consent Decree, and, except as otherwise provided in this Decree,

every other term used in this Decree that is also a term under the Act or the regulations implementing the Act shall mean in this Decree what such term means under the Act or those implementing regulations.

190. Nothing in this Consent Decree alters or waives any applicable law (including but not limited to, any defenses, entitlements, or clarifications related to the Credible Evidence Rule (62 Fed. Reg. 8314 (Feb. 27, 1997))), concerning the use of data for any purpose under the Act, generated by the reference methods specified herein or otherwise.

191. Each limit and/or other requirement established by or under this Decree is a separate, independent requirement.

192. Performance standards, emissions limits, and other quantitative standards set by or under this Decree must be met to the number of significant digits in which the standard or limit is expressed. Thus, for example, an Emission Rate of 0.100 is not met if the actual Emission Rate is 0.101. Wisconsin Electric shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the second significant digit, depending upon whether the limit is expressed to two or three significant digits. Thus, for example, if an actual Emission Rate is 0.1004, that shall be reported as 0.100, and shall be in compliance with an Emission Rate of 0.100, and if an actual Emission Rate is 0.1005, that shall be reported as 0.101, and shall not be in compliance with an Emission Rate of 0.100. Wisconsin Electric shall collect and report data to the number of significant digits in which the standard or limit is expressed. As otherwise applicable and unless this Decree expressly directs otherwise, the calculation and measurement procedures established under 40 C.F.R. Parts 75 and 76 apply to the measurement and calculation of NO_x and SO_2 under this Decree.

193. This Consent Decree does not limit, enlarge or affect the rights of any Party to this Consent Decree as against any third parties.

194. This Consent Decree constitutes the final, complete and exclusive agreement and understanding between the Parties with respect to the settlement embodied in this Consent Decree, and supercedes all prior agreements and understandings between the Parties related to the subject matter herein. No document, representation, inducement, agreement, or understanding, or promise constitutes any part of this Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

195. Each Party to this action shall bear its own costs and attorneys' fees.

XXVI. SIGNATORIES AND SERVICE

196. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind the Party he or she represents to this document.

197. This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

198. Each Party hereby agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

XXVII. PUBLIC COMMENT

199. The Parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the procedures of 28 C.F.R. § 50.7, which provides for

notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper or inadequate. Wisconsin Electric shall not oppose entry of this Consent Decree by this Court or challenge any provision of this Consent Decree unless the United States has notified Wisconsin Electric, in writing, that the United States no longer supports entry of the Consent Decree.

XXVIII. CONDITIONAL TERMINATION OF ENFORCEMENT UNDER DECREE

200. Termination as to Completed Tasks. As soon as Wisconsin Electric completes a construction project or any other requirement of this Consent Decree that is not ongoing or recurring, Wisconsin Electric may seek termination of the provision or provisions of this Consent Decree that imposed the requirement.

201. Conditional Termination of Enforcement Through the Consent Decree. Once Wisconsin Electric:

(A) believes that it has successfully completed and commences successful operation of all pollution controls required by this Decree;

(B) has obtained final Title V permits (a) as required by the terms of this Consent Decree; (b) that cover all Units in this Consent Decree; and (c) that include as enforceable permit terms all of the Unit performance and other requirements required by Section XVIII (Permits); and

(C) certifies that the date is later than December 31, 2015;

then Wisconsin Electric may so certify these facts to the EPA and this Court. If EPA does not object in writing with specific reasons within forty-five (45) days of receipt of Wisconsin Electric's certification, then, for any violations that occur after the filing of notice, the United States shall pursue enforcement of the requirements contained in the Title V permit through the applicable Title V permit and not through this Consent Decree.

202. Resort to Enforcement under this Consent Decree. Notwithstanding Paragraph 201, if enforcement of a provision in this Decree cannot be pursued by a party under the applicable Title V permit, or if a Decree requirement was intended to be part of a Title V Permit and did not become or remain part of such permit, then such requirement may be enforced under the terms of this Decree at any time.

XXIX. FINAL JUDGMENT

203. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment between the United States and Wisconsin Electric.

SO ORDERED, THIS _____ DAY OF _______________, 2003.

____

UNITED STATES DISTRICT COURT JUDGE

FOR THE UNITED STATES OF AMERICA:

THOMAS L. SANSONETTI
Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice

NICOLE VEILLEUX
ARNOLD ROSENTHAL
Trial Attorneys
Environmental Enforcement Section
Environmental and Natural Resources Division
United States Department of Justice

STEVEN M. BISKUPIC
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United States Department of Justice

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Office of Enforcement and Compliance Assurance
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BRUCE C. BUCKHEIT
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United States Environmental Protection Agency

EDWARD MESSINA
Attorney Advisor
Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

THOMAS SKINNER
Regional Administrator
Region 5
United States Environmental Protection Agency

FOR WISCONSIN ELECTRIC:

____

RICHARD R. GRIGG
President and Chief Operating Officer
Wisconsin Electric Power Company

Exhibit 10 to Title V Petition

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF ILLINOIS

UNITED STATES OF AMERICA)
)
Plaintiff,)
)
and)
)
THE STATE OF ILLINOIS, AMERICAN)
BOTTOM CONSERVANCY, HEALTH)
AND ENVIRONMENTAL JUSTICE –)
ST. LOUIS, INC., ILLINOIS)
STEWARDSHIP ALLIANCE, and)
PRAIRIE RIVERS NETWORK)
)
Plaintiff - Intervenors,)
)
v.) Civil Action No. 99-833-MJR
)
ILLINOIS POWER COMPANY and)
DYNEGY MIDWEST GENERATION,)
INC.,)
)
Defendants.)
)

CONSENT DECREE

TABLE OF CONTENTS

WHEREAS, the United States of America ("the United States"), on behalf of the United States Environmental Protection Agency ("EPA") filed a Complaint against Illinois Power Company ("Illinois Power") on November 3, 1999, and Amended Complaints against Illinois Power Company and Dynegy Midwest Generation, Inc. ("DMG") on January 19, 2000, March 14, 2001, and March 7, 2003, pursuant to Sections 113(b) and 167 of the Clean Air Act (the "Act"), 42 U.S.C. §§ 7413(b) and 7477, for injunctive relief and the assessment of civil penalties for alleged violations at the Baldwin Generating Station of:

(a) the Prevention of Significant Deterioration provisions in Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-92;

(b) the federally enforceable State Implementation Plan developed by the State of Illinois (the "Illinois SIP"); and

(c) the New Source Performance Standard provisions in Part A of Subchapter I of the Act, 42 U.S.C. § 7411.

WHEREAS, EPA issued Notices of Violation with respect to such allegations to Illinois Power on November 3, 1999 and November 26, 2000;

WHEREAS, EPA provided Illinois Power, DMG, and the State of Illinois actual notice of violations pertaining to its alleged violations, in accordance with Section 113(a)(1) and (b) of the Act, 42 U.S.C. § 7413(a)(1) and (b);

WHEREAS, Illinois Power was the owner and operator of the Baldwin Facility from 1970 to October 1999. On October 1, 1999, Illinois Power transferred the Baldwin Facility to Illinova Corporation. Illinova Corporation then contributed the Baldwin Facility to Illinova

Power Marketing, Inc., after which time Illinois Power no longer owned or operated the Baldwin Facility.

WHEREAS, beginning on October 1, 1999 and continuing through the date of lodging of this Consent Decree, Illinois Power has been neither the owner nor the operator of the Baldwin Facility or of any of the Units in the DMG System which are affected by this Consent Decree;

WHEREAS, in February 2000, Illinova Corporation merged with Dynegy Holdings Inc. and became a wholly owned subsidiary of Dynegy Inc. (referred to herein as "Dynegy"). Thereafter, Illinova Power Marketing, Inc., the owner of the Baldwin Facility, changed its name to Dynegy Midwest Generation, Inc. (referred to herein as "DMG"). On September 30, 2004, Dynegy, through Illinova, sold Illinois Power to Ameren Corporation.

WHEREAS, Ameren and Illinova Corporation, a subsidiary of Dynegy, have entered into an agreement which provides for the escrow of certain funds, the release of which funds is related to the resolution of certain contingent environmental liabilities that were alleged in the above-referenced Amended Complaints against Illinois Power and DMG.

WHEREAS, Plaintiff-Intervenors – the American Bottom Conservancy, Health and Environmental Justice - St. Louis, Inc., Illinois Stewardship Alliance, the Prairie Rivers Network, and the State of Illinois – moved to intervene on September 25, 2003 and filed Complaints in Intervention. The Court granted intervention to all movants on October 23, 2003.

WHEREAS, in their Complaints, Plaintiff United States and Plaintiff Intervenors (collectively "Plaintiffs") allege, *inter alia,* that Illinois Power and DMG failed to obtain the necessary permits and install the controls necessary under the Act to reduce sulfur dioxide, nitrogen oxides, and/or particulate matter emissions, and that such emissions can damage human health and the environment;

WHEREAS, the Plaintiffs' Complaints state claims upon which relief can be granted against Illinois Power and DMG under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, DMG and Illinois Power have denied and continue to deny the violations alleged in the Complaints, maintain that they have been and remain in compliance with the Act and are not liable for civil penalties or injunctive relief, and DMG is agreeing to the obligations imposed by this Consent Decree solely to avoid further costs and uncertainty;

WHEREAS, DMG has installed equipment for the control of nitrogen oxides emissions at the Baldwin Facility, including Overfire Air systems on Baldwin Units 1, 2, and 3, Low NO_X Burners on Baldwin Unit 3 and Selective Catalytic Reduction ("SCR") Systems on Baldwin Units 1 and 2, resulting in a reduction in emissions of nitrogen oxides from the Baldwin Plant of approximately 65% below 1999 levels from 55,026 tons in 1999 to 19,061 tons in 2003;

WHEREAS, DMG switched from use of high sulfur coal to low sulfur Powder River Basin coal at Baldwin Units 1, 2 and 3 in 1999 and 2000, resulting in a reduction in emissions of sulfur dioxide from the Baldwin Plant of approximately 90% below 1999 levels from 245,243 tons in 1999 to 26,311 tons in 2003;

WHEREAS, the Parties anticipate that the installation and operation of pollution control equipment pursuant to this Consent Decree will achieve significant additional reductions of SO_2, NO_x, and PM emissions and thereby further improve air quality;

WHEREAS, in June of 2003, the liability stage of the litigation resulting from the United States' claims was tried to the Court and no decision has yet been rendered; and

WHEREAS, the Plaintiffs, DMG and Illinois Power have agreed, and the Court by entering this Consent Decree finds: that this Consent Decree has been negotiated in good faith and at arms length; that this settlement is fair, reasonable, in the best interest of the Parties and in the public interest, and consistent with the goals of the Act; and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

NOW, THEREFORE, without any admission by the Defendants, and without adjudication of the violations alleged in the Complaints or the NOVs, it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367, Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and Section 42(e) of the Illinois Environmental Protection Act, 415 ILCS 5/42(e). Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying Complaints, and for no other purpose, Defendants waive all objections and defenses that they may have to the Court's jurisdiction over this action, to the Court's jurisdiction over the Defendants, and to venue in this District. Defendants shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. Solely for purposes of the Complaints filed by the Plaintiffs in this matter and resolved by the Consent Decree, for purposes of entry and enforcement of this Consent Decree,

and for no other purpose, Defendants waive any defense or objection based on standing. Except as expressly provided for herein, this Consent Decree shall not create any rights in or obligations of any party other than the Plaintiffs and the Defendants. Except as provided in Section XXVI (Public Comment) of this Consent Decree, the Parties consent to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. Upon entry, the provisions of the Consent Decree shall apply to and be binding upon and inure to the benefit of the Citizen Plaintiffs and DMG, and their respective successors and assigns, officers, employees and agents, solely in their capacities as such, and the State of Illinois and the United States. Illinois Power is a Party to this Consent Decree, is the beneficiary of Section X of this Consent Decree (Release and Covenant Not to Sue for Illinois Power Company), and is subject to Paragraph 171 and the other applicable provisions of the Consent Decree as specified in such Paragraph in the event it acquires an Ownership Interest in, or becomes an operator (as that term is used and interpreted under the Clean Air Act) of, any DMG System Unit, but otherwise has no other obligations under this Consent Decree except as expressly specified herein.

3. DMG shall be responsible for providing a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization retained to perform any of the work required by this Consent Decree. Notwithstanding any retention of contractors, subcontractors, or agents to perform any work required under this Consent Decree, DMG shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree,

DMG shall not assert as a defense the failure of its officers, directors, employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless DMG establishes that such failure resulted from a Force Majeure Event, as defined in Paragraph 137 of this Consent Decree.

III. DEFINITIONS

4. A "30-Day Rolling Average Emission Rate" for a Unit shall be expressed as lb/mmBTU and calculated in accordance with the following procedure: first, sum the total pounds of the pollutant in question emitted from the Unit during an Operating Day and the previous twenty-nine (29) Operating Days; second, sum the total heat input to the Unit in mmBTU during the Operating Day and the previous twenty-nine (29) Operating Days; and third, divide the total number of pounds of the pollutant emitted during the thirty (30) Operating Days by the total heat input during the thirty (30) Operating Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of startup, shutdown and Malfunction within an Operating Day, except as follows:

a. Emissions and BTU inputs that occur during a period of Malfunction shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if DMG provides notice of the Malfunction to EPA and the State in accordance with Paragraph 138 in Section XV (Force Majeure) of this Consent Decree;

b. Emissions of NO_x and BTU inputs that occur during the fifth and subsequent Cold Start Up Period(s) that occur at a given Unit during any 30-day period shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if inclusion of such emissions would result in a violation of any applicable 30-Day Rolling Average Emission Rate and DMG has installed, operated and maintained the SCR in question in accordance with manufacturers' specifications and good engineering practices. A "Cold Start Up Period" occurs whenever there has been no fire in the boiler of a Unit (no combustion of any Fossil Fuel) for a period of six (6) hours or more. The NO_x emissions to be excluded during the fifth and subsequent Cold Start Up Period(s) shall be the lesser of (i) those NO_x emissions emitted during the eight (8) hour period commencing when the Unit is synchronized with a utility electric transmission system and concluding eight (8) hours later, or (ii) those NO_x emissions emitted prior to the time that the flue gas has achieved the minimum SCR operational temperature specified by the catalyst manufacturer; and

c. For a Unit that has ceased firing Fossil Fuel, emissions of SO_2 and Btu inputs that occur during any period, not to exceed two (2) hours, from the restart of the Unit to the time the Unit is fired with any coal, shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate.

5. "Baghouse" means a fullstream (fabric filter) particulate emission control device.

6. "Boiler Island" means a Unit's (A) fuel combustion system (including bunker, coal pulverizers, crusher, stoker, and fuel burners); (B) combustion air system; (C) steam generating system (firebox, boiler tubes, and walls); and (D) draft system (excluding the stack), all as further described in "Interpretation of Reconstruction," by John B. Rasnic U.S. EPA (November 25, 1986) and attachments thereto.

7. "Capital Expenditure" means all capital expenditures, as defined by Generally Accepted Accounting Principles ("GAAP"), as those principles exist at the date of entry of this Consent Decree, excluding the cost of installing or upgrading pollution control devices.

8. "CEMS" or "Continuous Emission Monitoring System" means, for obligations involving NO_x and SO_2 under this Consent Decree, the devices defined in 40 C.F.R. § 72.2 and installed and maintained as required by 40 C.F.R. Part 75.

9. "Citizen Plaintiffs" means, collectively, the American Bottom Conservancy, Health and Environmental Justice - St. Louis, Inc., Illinois Stewardship Alliance, and the Prairie Rivers Network.

10. "Clean Air Act" or "Act" means the federal Clean Air Act, 42 U.S.C. §§7401-7671q, and its implementing regulations.

11. "Consent Decree" or "Decree" means this Consent Decree and the Appendix hereto, which is incorporated into this Consent Decree.

12. "Defendants" means Dynegy Midwest Generation, Inc. and Illinois Power Company.

13. "DMG" means Dynegy Midwest Generation, Inc.

14. "DMG System" means, solely for purposes of this Consent Decree, the following ten (10) listed coal-fired, electric steam generating Units (with the rated gross MW capacity of each Unit, reported to Mid-America Interconnected Network ("MAIN") in 2003, noted in parentheses), located at the following plants:

- Baldwin Generating Station in Baldwin, Illinois: Unit 1 (624 MW), 2 (629 MW), 3 (629 MW);

- Havana Generating Station in Havana, Illinois: Unit 6 (487 MW);
- Hennepin Generating Station in Hennepin, Illinois: Unit 1 (81 MW), Unit 2 (240 MW);
- Vermilion Generating Station in Oakwood, Illinois: Unit1 (84 MW), Unit 2 (113 MW);
- Wood River Generating Station in Alton, Illinois: Unit 4 (105 MW), Unit 5 (383 MW).

15. "Emission Rate" means the number of pounds of pollutant emitted per million BTU of heat input ("lb/mmBTU"), measured in accordance with this Consent Decree.

16. "EPA" means the United States Environmental Protection Agency.

17. "ESP" means electrostatic precipitator, a pollution control device for the reduction of PM.

18. "Existing Units" means those Units included in the DMG System.

19. "Flue Gas Desulfurization System," or "FGD," means a pollution control device with one or more absorber vessels that employs flue gas desulfurization technology for the reduction of sulfur dioxide.

20. "Fossil Fuel" means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, or natural gas.

21. "Illinois Environmental Protection Act" means the Illinois Environmental Protection Act, 415 ILCS 5/1 et. seq., and its implementing regulations.

22. "Illinois Power" means the Illinois Power Company.

23. "Improved Unit" means, in the case of NO_x, a DMG System Unit equipped with or scheduled under this Consent Decree to be equipped with an SCR, or, in the case of SO_2, a DMG System Unit scheduled under this Consent Decree to be equipped with an FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 68). A Unit may be an Improved Unit for one pollutant without being an Improved Unit for the other. Any Other Unit can become an Improved Unit if (a) in the case of NO_x, it is equipped with an SCR (or equivalent NOx control technology approved pursuant to Paragraph 64) and has become subject to a federally enforceable 0.100 lb/mmBTU NO_x 30-Day Rolling Average Emission Rate, or (b) in the case of SO_2, it is equipped with an FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 68) and has become subject to a federally enforceable 0.100 lb/mmBTU SO_2 30-Day Rolling Average Emission Rate, and (c) in the case of NO_x or SO_2, the requirement to achieve and maintain a 0.100 lb/mmBTU 30-Day Rolling Average Emission Rate is incorporated into the Title V Permit applicable to that Unit or, if no Title V Permit exists, a modification to this Consent Decree that is agreed to by the Plaintiffs and DMG and approved by this Court.

24. "lb/mmBTU" means one pound per million British thermal units.

25. "Malfunction" means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not Malfunctions.

26. "MW" means a megawatt or one million Watts.

27. "National Ambient Air Quality Standards" or "NAAQS" means national ambient air quality standards that are promulgated pursuant to Section 109 of the Act, 42 U.S.C. § 7409.

28. "Nonattainment NSR" means the nonattainment area New Source Review program within the meaning of Part D of Subchapter I of the Act, 42 U.S.C. §§ 7501-7515, 40 C.F.R. Part 51.

29. "NO_x" means oxides of nitrogen.

30. "NO_x Allowance" means an authorization or credit to emit a specified amount of NO_x that is allocated or issued under an emissions trading or marketable permit program of any kind that has been established under the Clean Air Act or a State Implementation Plan.

31. "Operating Day" means any calendar day on which a Unit fires Fossil Fuel; provided, however, that exclusively for purposes of Paragraph 36, "Operating Day" means any calendar day on which both Baldwin Unit 1 and Baldwin Unit 2 fire Fossil Fuel.

32. "Other Unit" means any Unit of the DMG System that is not an Improved Unit for the pollutant in question.

33. "Ownership Interest" means part or all of DMG's legal or equitable ownership interest in any Unit in the DMG System.

34. "Parties" means the United States, the State of Illinois, the Citizen Plaintiffs, DMG, and Illinois Power.

35. "Plaintiffs" means the United States, the State of Illinois, and the Citizen Plaintiffs.

36. A "Plant-Wide 30-Day Rolling Average Emission Rate" shall be expressed as lb/mmBTU and calculated in accordance with the following procedure: first, sum the total

pounds of the pollutant in question emitted from all three Units at the Baldwin Plant during an Operating Day and the previous twenty-nine (29) Operating Days; second, sum the total heat input to all three Units at the Baldwin Plant in mmBTU during the Operating Day and the previous twenty-nine (29) Operating Days; and third, divide the total number of pounds of the pollutant emitted from all three Baldwin Units during the thirty (30) Operating Days by the total heat input to all three Baldwin Units during the thirty (30) Operating Days. A new Plant-Wide 30-Day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each Plant-Wide 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of startup, shutdown and Malfunction within an Operating Day. A Malfunction shall be excluded from this Emission Rate, however, if DMG satisfies the Force Majeure provisions of this Consent Decree.

37. A "Plant-Wide Annual Tonnage Emission Level" means, for the purposes of Section XI of this Decree, the number of tons of the pollutant in question that may be emitted from the plant at issue during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of the pollutant emitted during periods of startup, shutdown, and Malfunction.

38. "Pollution Control Equipment Upgrade Analysis" means the technical study, analysis, review, and selection of control technology recommendations (including an emission rate or removal efficiency) required to be performed in connection with an application for a federal PSD permit, taking into account the characteristics of the existing facility. Except as otherwise provided in this Consent Decree, such study, analysis, review, and selection of recommendations shall be carried out in accordance with applicable federal and state regulations

and guidance describing the process and analysis for determining Best Available Control Technology (BACT), as that term is defined in 40 C.F.R. §52.21(b)(12), including, without limitation, the December 1, 1987 EPA Memorandum from J. Craig Potter, Assistant Administrator for Air and Radiation, regarding Improving New Source Review (NSR) Implementation. Nothing in this Decree shall be construed either to: (a) alter the force and effect of statements known as or characterized as "guidance" or (b) permit the process or result of a "Pollution Control Equipment Upgrade Analysis" to be considered BACT for any purpose under the Act.

39. "PM Control Device" means any device, including an ESP or a Baghouse, that reduces emissions of particulate matter (PM).

40. "PM" means particulate matter.

41. "PM CEMS" or "PM Continuous Emission Monitoring System" means the equipment that samples, analyzes, measures, and provides, by readings taken at frequent intervals, an electronic or paper record of PM emissions.

42. "PM Emission Rate" means the number of pounds of PM emitted per million BTU of heat input (lb/mmBTU), as measured in annual stack tests in accordance with EPA Method 5, 40 C.F.R. Part 60, including Appendix A.

43. "Project Dollars" means DMG's expenditures and payments incurred or made in carrying out the Environmental Mitigation Projects identified in Section VIII (Environmental Mitigation Projects) of this Consent Decree to the extent that such expenditures or payments both: (a) comply with the requirements set forth in Section VIII (Environmental Mitigation Projects) and Appendix A of this Consent Decree, and (b) constitute DMG's direct payments for

such projects, DMG's external costs for contractors, vendors, and equipment, or DMG's internal costs consisting of employee time, travel, or out-of-pocket expenses specifically attributable to these particular projects and documented in accordance with GAAP.

44. "PSD" means Prevention of Significant Deterioration within the meaning of Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470 - 7492 and 40 C.F.R. Part 52.

45. "Selective Catalytic Reduction System" or "SCR" means a pollution control device that employs selective catalytic reduction technology for the reduction of NO_x emissions.

46. "SO_2" means sulfur dioxide.

47. "SO_2 Allowance" means "allowance" as defined at 42 U.S.C. § 7651a(3): "an authorization, allocated to an affected unit by the Administrator of EPA under Subchapter IV of the Act, to emit, during or after a specified calendar year, one ton of sulfur dioxide."

48. "System-Wide Annual Tonnage Limitation" means the limitation on the number of tons of the pollutant in question that may be emitted from the DMG System during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of the pollutant emitted during periods of startup, shutdown, and Malfunction.

49. "Title V Permit" means the permit required of DMG's major sources under Subchapter V of the Act, 42 U.S.C. §§ 7661-7661e.

50. "Unit" means collectively, the coal pulverizer, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine and boiler, and all ancillary equipment, including pollution control equipment. An electric steam generating station may comprise one or more Units.

IV. NO_x EMISSION REDUCTIONS AND CONTROLS

A. NO_x Emission Controls

51. Beginning 45 days after entry of this Consent Decree, and continuing thereafter, DMG shall commence operation of the SCRs installed at Baldwin Unit 1, Unit 2, and Havana Unit 6 so as to achieve and maintain a 30-Day Rolling Average Emission Rate from each such Unit of not greater than 0.100 lb/mmBTU NO_x.

52. Beginning 45 days after entry of this Consent Decree, and continuing thereafter, DMG shall achieve and maintain a Plant-Wide 30-Day Rolling Average Emission Rate of not greater than 0.100 lb/mmBTU NO_x at the Baldwin Plant.

53. Beginning 45 days after entry of this Consent Decree, and continuing thereafter, subject to paragraph 54 below, DMG shall achieve and maintain a 30-Day Rolling Average Emission Rate of not greater than 0.120 lb/mmBTU NO_x at Baldwin Unit 3.

54. Beginning on December 31, 2012, and continuing thereafter, DMG shall maintain a 30-Day Rolling Average Emission Rate of not greater than 0.100 lb/mmBTU NO_x at Baldwin Unit 3.

55. Beginning 30 days after entry of this Consent Decree, and continuing thereafter, DMG shall operate each SCR in the DMG System at all times when the Unit it serves is in operation, provided that such operation of the SCR is consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the SCR. During any such period in which the SCR is not operational, DMG will minimize emissions to the extent reasonably practicable.

56. Beginning 45 days from entry of this Consent Decree, DMG shall operate low NO_x burners ("LNB") and/or Overfire Air Technology ("OFA") on the DMG System Units listed in the table below at all times that the Units are in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the LNB and/or the Overfire Air Technology, so as to minimize emissions to the extent reasonably practicable.

DMG System Unit	**NOx Control Technology**
Baldwin Unit 1	OFA
Baldwin Unit 2	OFA
Baldwin Unit 3	LNB, OFA
Havana Unit 6	LNB, OFA
Hennepin Unit 1	LNB, OFA
Hennepin Unit 2	LNB, OFA
Vermilion Unit 2	LNB, OFA
Wood River Unit 4	LNB, OFA
Wood River Unit 5	LNB, OFA

B. System-Wide Annual Tonnage Limitations for NO_x

57. During each calendar year specified in the Table below, all Units in the DMG System, collectively, shall not emit NO_x in excess of the following System-Wide Annual Tonnage Limitations:

Applicable Calendar Year	System-Wide Annual Tonnage Limitations for NO_x
2005	15,000 tons
2006	14,000 tons
2007 and each year thereafter	13,800 tons

C. Use of NO_x Allowances

58. Except as provided in this Consent Decree, DMG shall not sell or trade any NO_x Allowances allocated to the DMG System that would otherwise be available for sale or trade as a result of the actions taken by DMG to comply with the requirements of this Consent Decree.

59. Except as may be necessary to comply with Section XIV (Stipulated Penalties), DMG may not use NO_x Allowances to comply with any requirement of this Consent Decree, including by claiming compliance with any emission limitation required by this Decree by using, tendering, or otherwise applying NO_x Allowances to offset any excess emissions (i.e., emissions above the limits specified in Paragraph 57).

60. NO_x Allowances allocated to the DMG System may be used by DMG only to meet its own federal and/or state Clean Air Act regulatory requirements, except as provided in Paragraph 61.

61. Provided that DMG is in compliance with the System-Wide Annual Tonnage Limitations for NO_x set forth in this Consent Decree, nothing in this Consent Decree shall preclude DMG from selling or transferring NO_x Allowances allocated to the DMG System that become available for sale or trade solely as a result of:

a. activities that reduced NO_x emissions at any Unit within the DMG System prior to the date of entry of this Consent Decree;

b. the installation and operation of any NO_x pollution control technology or technique that is not otherwise required by this Consent Decree; or

c. achievement and maintenance of NO_x emission rates below a 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU at Baldwin Units 1, 2 or 3, or at Havana Unit 6,

so long as DMG timely reports the generation of such surplus NO_x Allowances in accordance with Section XII (Periodic Reporting) of this Consent Decree. DMG shall be allowed to sell or transfer NO_x Allowances equal to the NO_x emissions reductions achieved for any given year by any of the actions specified in Subparagraphs 61.b or 61.c. only to the extent that, and in the amount that, the total NO_x emissions from all Units within the DMG System are below the System-Wide Annual Tonnage Limitation specified in Paragraph 57 for that year.

62. Nothing in this Consent Decree shall prevent DMG from purchasing or otherwise obtaining NO_x Allowances from another source for purposes of complying with state or federal Clean Air Act requirements to the extent otherwise allowed by law.

D. <u>NO_x Provisions - Improving Other Units</u>

63. Any Other Unit can become an Improved Unit for NO_x if (a) it is equipped with an SCR (or equivalent NOx control technology approved pursuant to Paragraph 64), and (b) has become subject to a federally enforceable 0.100 lb/mmBTU NO_x 30-Day Rolling Average Emission Rate.

64. With prior written notice to the Plaintiffs and written approval from EPA (after consultation with the State of Illinois and the Citizen Plaintiffs), an Other Unit in the DMG System may be considered an Improved Unit under this Consent Decree if DMG installs and

operates NO_x control technology, other than an SCR, that has been demonstrated to be capable of achieving and maintaining a 30-Day Rolling Average Emission Rate not greater than 0.100 lb/mmBTU NO_x and if such unit has become subject to a federally enforceable 0.100 lb/mmBTU NO_x 30-Day Rolling Average Emission Rate.

E. General NO_x Provisions

65. In determining Emission Rates for NO_x, DMG shall use CEMS in accordance with the reference methods specified in 40 C.F.R. Part 75.

V. SO_2 EMISSION REDUCTIONS AND CONTROLS

A. SO_2 Emission Limitations and Control Requirements

66. No later than the dates set forth in the Table below for each of the three Units at Baldwin and Havana Unit 6, and continuing thereafter, DMG shall not operate the specified Unit unless and until it has installed and commenced operation of, on a year-round basis, an FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 68) on each such Unit, so as to achieve and maintain a 30-Day Rolling Average Emission Rate of not greater than 0.100 lb/mmBTU SO_2.

UNIT	**DATE**
First Baldwin Unit (i.e., any of the Baldwin Units 1, 2 or 3)	December 31, 2010
Second Baldwin Unit (i.e., either of the 2 remaining Baldwin Units)	December 31, 2011
Third Baldwin Unit (i.e., the remaining Baldwin Unit)	December 31, 2012
Havana Unit 6	December 31, 2012

67. Any FGD required to be installed under this Consent Decree may be a wet FGD or a dry FGD at DMG's option.

68. With prior written notice to the Plaintiffs and written approval from EPA (after consultation by EPA with the State of Illinois and the Citizen Plaintiffs), DMG may, in lieu of installing and operating an FGD at any of the Units specified in Paragraph 66, install and operate equivalent SO_2 control technology so long as such equivalent SO_2 control technology has been demonstrated to be capable of achieving and maintaining a 30-Day Rolling Average Emission Rate of not greater than 0.100 lb/mmBTU SO_2.

69. Beginning on the later of the date specified in Paragraph 66 or the first Operating Day of each Unit thereafter, and continuing thereafter, DMG shall operate each FGD (or equivalent SO_2 control technology approved pursuant to Paragraph 68) required by this Consent Decree at all times that the Unit it serves is in operation, provided that such operation of the FGD or equivalent technology is consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the FGD or equivalent technology. During any such period in which the FGD or equivalent technology is not operational, DMG will minimize emissions to the extent reasonably practicable.

70. No later than 30 Operating Days after entry of this Consent Decree, and continuing thereafter, DMG shall operate Hennepin Units 1 and 2 and Wood River Units 4 and 5 so as to achieve and maintain a 30-Day Rolling Average Emission Rate from each of the stacks serving such Units of not greater than 1.200 lb/mmBtu SO_2.

71. DMG shall operate Vermilion Units 1 and 2 so that no later than 30 Operating Days after January 1, 2007, DMG shall achieve and maintain a 30-Day Rolling Average Emission Rate from the stack serving such Units of not greater than 1.200 lb/mmBtu SO_2.

72. No later than 30 Operating Days after entry of this Consent Decree and continuing until December 31, 2012, DMG shall operate Havana Unit 6 so as to achieve and maintain a 30-Day Rolling Average Emission Rate from the stack serving such Unit of not greater than 1.200 lb/mmBtu SO_2.

B. System-Wide Annual Tonnage Limitations for SO_2

73. During each calendar year specified in the Table below, all Units in the DMG System, collectively, shall not emit SO_2 in excess of the following System-Wide Annual Tonnage Limitations:

Applicable Calendar Year	**System-Wide Annual Tonnage Limitations for SO_2**
2005	66,300 tons
2006	66,300 tons
2007	65,000 tons
2008	62,000 tons
2009	62,000 tons
2010	62,000 tons
2011	57,000 tons
2012	49,500 tons
2013 and each year thereafter	29,000 tons

74. Except as may be necessary to comply with Section XIV (Stipulated Penalties), DMG may not use SO_2 Allowances to comply with any requirement of this Consent Decree,

including by claiming compliance with any emission limitation required by this Decree by using, tendering, or otherwise applying SO_2 Allowances to offset any excess emissions (i.e., emissions above the limits specified in Paragraph 73).

C. Surrender of SO_2 Allowances

75. For each year specified below, DMG shall surrender to EPA, or transfer to a non-profit third party selected by DMG for surrender, SO_2 Allowances that have been allocated to DMG for the specified calendar year by the Administrator of EPA under the Act or by any State under its State Implementation Plan, in the amounts specified below, subject to Paragraph 76:

Calendar Year	**Amount**
2008	12,000 Allowances
2009	18,000 Allowances
2010	24,000 Allowances
2011, and each year thereafter	30,000 Allowances

DMG shall make the surrender of SO_2 Allowances required by this Paragraph by December 31 of each specified calendar year.

76. If the surrender of SO_2 allowances required by Paragraph 75 would result in an insufficient number of allowances being available from those allocated to the Units comprising the DMG System to meet the requirements of any Federal and/or State requirements for any DMG System unit, DMG must provide notice to the Plaintiffs of such insufficiency, including documentation of the number of SO_2 allowances so required and the Federal and/or State requirement involved. Unless EPA objects, in writing, to the amounts surrendered or to be

surrendered, the basis of the amounts surrendered or to be surrendered, or the adequacy of the documentation, DMG may reduce the number of SO_2 allowances to be surrendered under Paragraph 75 to the extent necessary to allow such DMG System Unit to satisfy the specified Federal and/or State requirement(s). If DMG has sold or traded SO_2 allowances allocated by the Administrator of EPA or a State for the year in which the surrender of allowances under Paragraph 75 would result in an insufficient number of allowances, all sold or traded allowances must be restored to DMG's account through DMG's purchase or transfer of allowances before DMG may reduce the surrender requirements of Paragraph 75 as described above.

77. Nothing in this Consent Decree is intended to preclude DMG from using SO_2 Allowances allocated to the DMG System by the Administrator of EPA under the Act, or by any State under its State Implementation Plan, to meet its own Federal and/or State Clean Air Act regulatory requirements for any Unit in the DMG System.

78. For purposes of this Subsection, the "surrender of allowances" means permanently surrendering allowances from the accounts administered by EPA for all Units in the DMG System, so that such allowances can never be used thereafter to meet any compliance requirement under the Clean Air Act, the Illinois State Implementation Plan, or this Consent Decree.

79. If any allowances required to be surrendered under this Consent Decree are transferred directly to a non-profit third party, DMG shall include a description of such transfer in the next report submitted to EPA pursuant to Section XII (Periodic Reporting) of this Consent Decree. Such report shall: (i) identify the non-profit third-party recipient(s) of the SO_2 Allowances and list the serial numbers of the transferred SO_2 Allowances; and (ii) include a

certification by the third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the SO_2 Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any SO_2 Allowances, DMG shall include a statement that the third-party recipient(s) surrendered the SO_2 Allowances for permanent surrender to EPA in accordance with the provisions of Paragraph 80 within one (1) year after DMG transferred the SO_2 Allowances to them. DMG shall not have complied with the SO_2 Allowance surrender requirements of this Paragraph until all third-party recipient(s) shall have actually surrendered the transferred SO_2 Allowances to EPA.

80. For all SO_2 Allowances surrendered to EPA, DMG or the third-party recipient(s) (as the case may be) shall first submit an SO_2 Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such SO_2 Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, DMG or the third-party recipient(s) shall irrevocably authorize the transfer of these SO_2 Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the SO_2 Allowances being surrendered.

81. The requirements in Paragraphs 75 and 76 of this Decree pertaining to DMG's surrender of SO_2 Allowances are permanent injunctions not subject to any termination provision of this Decree.

E. General SO_2 Provisions

82. In determining Emission Rates for SO_2, DMG shall use CEMS in accordance with those reference methods specified in 40 C.F.R. Part 75.

VI. PM EMISSION REDUCTIONS AND CONTROLS

A. Optimization of PM Emission Controls

83. Beginning ninety (90) days after entry of this Consent Decree, and continuing thereafter, DMG shall operate each PM Control Device on each Unit within the DMG System to maximize PM emission reductions at all times when the Unit is in operation, provided that such operation of the PM Control Device is consistent with the technological limitations, manufacturer's specifications and good engineering and maintenance practices for the PM Control Device. During any periods when any section or compartment of the PM control device is not operational, DMG will minimize emissions to the extent reasonably practicable. Specifically, DMG shall, at a minimum, to the extent reasonably practicable: (a) energize each section of the ESP for each unit, where applicable, operate each compartment of the Baghouse for each unit, where applicable (regardless of whether those actions are needed to comply with opacity limits), and repair any failed ESP section or Baghouse compartment at the next planned Unit outage (or unplanned outage of sufficient length); (b) operate automatic control systems on each ESP to maximize PM collection efficiency, where applicable; (c) maintain and replace bags on each Baghouse as needed to maximize collection efficiency, where applicable; and (d) inspect for and repair during the next planned Unit outage (or unplanned outage of sufficient length) any openings in ESP casings, ductwork and expansion joints to minimize air leakage.

84. Within two hundred seventy (270) days after entry of this Consent Decree, for each DMG System Unit served by an ESP or Baghouse, DMG shall complete a PM emission control optimization study which shall recommend: the best available maintenance, repair, and operating practices and a schedule for implementation of such to optimize ESP or Baghouse availability and performance in accordance with manufacturers' specifications, the operational design of the Unit, and good engineering practices. DMG shall retain a qualified contractor to assist in the performance and completion of each study and shall implement the study's recommendations in accordance with the schedule provided for in the study, but in no event later than the next planned Unit outage or 180 days of completion of the optimization study, whichever is later. Thereafter, DMG shall maintain each ESP and Baghouse as required by the study's recommendations or other alternative actions as approved by EPA. These requirements of this Paragraph shall also apply, and these activities shall be repeated, whenever DMG makes a major change to a Unit's ESP, installs a new PM Control Device, or changes the fuel used by a Unit.

B. Installation of New PM Emission Controls

85. No later than the dates set forth in the Table below for Baldwin Units 1, 2 and 3 and Havana Unit 6, and continuing thereafter, DMG shall not operate the specified Unit unless and until it has installed and commenced operation of a Baghouse on each such Unit so as to achieve and maintain a PM emissions rate of not greater than 0.015 lb/mmBTU.

Unit	Date
First Baldwin Unit (i.e., any of Baldwin Units 1, 2 or 3)	December 31, 2010
Second Baldwin Unit (i.e., either of the 2 remaining Baldwin Units)	December 31, 2011
Third Baldwin Unit (i.e., the remaining Baldwin Unit)	December 31, 2012
Havana Unit 6	December 31, 2012

C. <u>Upgrade of Existing PM Emission Controls</u>

86. At each Unit listed below, no later than the dates specified, and continuing thereafter, DMG shall operate ESPs or alternative PM control equipment at the following Units to achieve and maintain a PM emissions rate of not greater than 0.030 lb/mmBTU:

Unit	Date
Havana Unit 6	December 31, 2005
1st Wood River Unit (i.e., either of Wood River Units 4 or 5)	December 31, 2005
1st Hennepin Unit (i.e., either of Hennepin Units 1 or 2)	December 31, 2006
2nd Wood River Unit (i.e., the remaining Wood River Unit)	December 31, 2007
2nd Hennepin Unit (i.e., the remaining Hennepin Unit)	December 31, 2010
1st Vermilion Unit (i.e., either of Vermilion Units 1 or 2)	December 31, 2010
2nd Vermilion Unit (i.e., the remaining Vermilion Unit)	December 31, 2010

In the alternative and in lieu of demonstrating compliance with the PM emission rate applicable under this Paragraph, DMG may elect to undertake an upgrade of the existing PM emissions control equipment for any such Unit based on a Pollution Control Equipment Upgrade Analysis for that Unit. The preparation, submission, and implementation of such Pollution Control Equipment Upgrade Analysis shall be undertaken and completed in accordance with the compliance schedules and procedures as specified in Paragraph 88.

87. DMG shall operate each ESP (on Units without a Baghouse) and each Baghouse in the DMG System at all times when the Unit it serves is in operation, provided that such operation of the ESP or Baghouse is consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the ESP or Baghouse. During any such period in which the ESP or Baghouse is not operational, DMG will minimize emissions to the extent reasonably practicable. Notwithstanding the foregoing sentence, DMG shall not be required to operate an ESP on any Unit on which a Baghouse is installed and operating, unless DMG operated the ESP during the immediately preceding stack test required by Paragraph 89.

88. For each Unit in the DMG System for which DMG does not elect to meet a PM Emission Rate of 0.030 lb/mmBTU as required by Paragraph 86, DMG shall prepare, submit, and implement a Pollution Control Equipment Upgrade Analysis in accordance with this Paragraph. Such Pollution Control Equipment Upgrade Analysis shall include proposed upgrades to the Unit's existing PM Control Devices and a proposed alternate PM Emission Rate that the Unit shall meet upon completion of such upgrade. DMG shall deliver such Pollution Control Equipment Upgrade Analysis to EPA and the State of Illinois for approval pursuant to

Section XIII (Review and Approval of Submittals) of this Consent Decree at least 24 months prior to the deadlines set forth in Paragraph 86 for each such Unit, unless those deadlines are less than 24 months after the date of entry of this Decree. In those cases only, (a) the Analysis shall be delivered within 180 days of entry of this Decree, and (b) so long as DMG timely submits the Analysis, any deadline for implementing a PM Emission Control Equipment Upgrade may be extended in accordance with the provisions of subparagraph (c) below.

a. In conducting the Pollution Control Equipment Upgrade Analysis for any Unit, DMG shall consider all commercially available control technologies, except that DMG need not consider any of the following PM control measures:

   1. the complete replacement of the existing ESP with a new ESP, FGD, or Baghouse, or

   2. the upgrade of the existing ESP controls through the installation of any supplemental PM pollution control device if the costs of such upgrade are equal to or greater than the costs of a replacement ESP, FGD, or Baghouse (on a total dollar-per-ton-of-pollutant-removed basis).

b. With each Pollution Control Equipment Upgrade Analysis delivered to EPA and the State of Illinois, DMG shall simultaneously deliver all documents that were considered in preparing such Pollution Control Equipment Upgrade Analysis. DMG shall retain a qualified contractor to assist in the performance and completion of each Pollution Control Equipment Upgrade Analysis.

c. Beginning one (1) year after EPA and the State of Illinois approve the recommendation(s) made in a Pollution Control Equipment Upgrade Analysis for a Unit, DMG shall not operate that Unit unless all equipment called for in the recommendation(s) of the Pollution Control Equipment Upgrade Analysis has been installed. An installation period longer than one year may be allowed if DMG makes such a request in the Pollution Control Equipment Upgrade Analysis and EPA and the State of Illinois determine such additional time is necessary due to factors including but not limited to the magnitude of the PM control project or the need to address reliability concerns that could result from multiple Unit outages within the DMG System. Upon installation of all equipment recommended under an approved Pollution Control Equipment Upgrade Analysis, DMG shall operate such equipment in compliance with the recommendation(s) of the approved Pollution Control Equipment Upgrade Analysis, including compliance with the PM Emission Rate specified by the recommendation(s).

D. PM Emissions Monitoring

1. PM Stack Tests.

89. Beginning in calendar year 2005, and continuing in each calendar year thereafter, DMG shall conduct a PM performance test on each DMG System Unit. The annual stack test requirement imposed on each DMG System Unit by this Paragraph may be satisfied by stack tests conducted by DMG as required by its permits from the State of Illinois for any year that such stack tests are required under the permits. DMG may perform testing every other year, rather than every year, provided that two of the most recently completed test results from tests conducted in accordance with the methods and procedures specified in Paragraph 90 demonstrate that the particulate matter emissions are equal to or less than 0.015 lb/mmBTU. DMG shall

perform testing every year, rather than every other year, beginning in the year immediately following any test result demonstrating that the particulate matter emissions are greater than 0.015 lb/mmBTU.

90. The reference methods and procedures for determining compliance with PM Emission Rates shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, or an alternative method that is promulgated by EPA, requested for use herein by DMG, and approved for use herein by EPA and the State of Illinois. Use of any particular method shall conform to the EPA requirements specified in 40 C.F.R. Part 60, Appendix A and 40 C.F.R. § 60.48a (b) and (e), or any federally approved method contained in the Illinois State Implementation Plan. DMG shall calculate the PM Emission Rates from the stack test results in accordance with 40 C.F.R. § 60.8(f). The results of each PM stack test shall be submitted to EPA and the State of Illinois within 45 days of completion of each test.

2. <u>PM CEMS</u>

91. DMG shall install and operate PM CEMS in accordance with Paragraphs 92 through 96. Each PM CEMS shall comprise a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert the concentration to units of lb/mmBTU. DMG shall maintain, in an electronic database, the hourly average emission values produced by all PM CEMS in lb/mmBTU. DMG shall use reasonable efforts to keep each PM CEMS running and producing data whenever any Unit served by the PM CEMS is operating.

92. Within nine (9) months after entry of this Consent Decree, but in any case no later than June 30, 2006, DMG shall submit to EPA and the State of Illinois for review and

approval pursuant to Section XIII (Review and Approval of Submittals) of this Consent Decree (a) a plan for the installation and certification of each PM CEMS; and (b) a proposed Quality Assurance/Quality Control ("QA/QC") protocol that shall be followed in calibrating such PM CEMS. In developing both the plan for installation and certification of the PM CEMS and the QA/QC protocol, DMG shall use the criteria set forth in EPA's Amendments to Standards of Performance for New Stationary Sources: Monitoring Requirements, 69 Fed. Reg. 1786 (January 12, 2004) ("P.S. 11"). EPA and the State of Illinois shall expeditiously review such submissions. Following approval by EPA and the State of Illinois of the protocol, DMG shall thereafter operate each PM CEMS in accordance with the approved protocol.

93. No later than the dates specified below, DMG shall install, certify, and operate PM CEMS on four (4) Units, stacks or common stacks in accordance with the following schedule:

STACK	**DATE TO COMMENCE OPERATION OF PM CEMS**
1st CEM on any DMG System Unit not scheduled to receive an FGD	December 31, 2006
2nd CEM on any DMG System Unit not scheduled to receive an FGD	December 31, 2007
3rd CEM on any DMG System Unit scheduled to receive an FGD	December 31, 2011
4th CEM on any DMG System Unit scheduled to receive an FGD	December 31, 2012

94. No later than ninety (90) days after DMG begins operation of the PM CEMS, DMG shall conduct tests of each PM CEMS to demonstrate compliance with the PM CEMS installation and certification plan submitted to and approved by EPA and the State of Illinois in accordance with Paragraph 92.

95. DMG shall operate the PM CEMS for at least two (2) years on each of the Units specified in Paragraph 93. After two (2) years of operation, DMG shall not be required to continue operating the PM CEMS on any such Units if EPA determines that operation of the PM CEMS is no longer feasible. Operation of a PM CEMS shall be considered no longer feasible if (a) the PM CEMS cannot be kept in proper condition for sufficient periods of time to produce reliable, adequate, or useful data consistent with the QA/QC protocol; or (b) DMG demonstrates that recurring, chronic, or unusual equipment adjustment or servicing needs in relation to other types of continuous emission monitors cannot be resolved through reasonable expenditures of resources. If EPA determines that DMG has demonstrated pursuant to this Paragraph that operation is no longer feasible, DMG shall be entitled to discontinue operation of and remove the PM CEMS.

3. PM Reporting

96. Following the installation of each PM CEMS, DMG shall begin and continue to report to EPA, the State of Illinois, and the Citizen Plaintiffs, pursuant to Section XII (Periodic Reporting), the data recorded by the PM CEMS, expressed in lb/mmBTU on a 3-hour rolling average basis in electronic format, as required by Paragraph 91.

E. General PM Provisions

97. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8315 (Feb. 27, 1997)) concerning the use of data for any purpose under the Act.

VII. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

98. Emission reductions that result from actions to be taken by DMG after entry of this Consent Decree to comply with the requirements of this Consent Decree shall not be considered as a creditable contemporaneous emission decrease for the purpose of obtaining a netting credit under the Clean Air Act's Nonattainment NSR and PSD programs.

99. The limitations on the generation and use of netting credits or offsets set forth in the previous Paragraph 98 do not apply to emission reductions achieved by DMG System Units that are greater than those required under this Consent Decree. For purposes of this Paragraph, emission reductions from a DMG System Unit are greater than those required under this Consent Decree if, for example, they result from DMG compliance with federally enforceable emission limits that are more stringent than those limits imposed on DMG System Units under this Consent Decree and under applicable provisions of the Clean Air Act or the Illinois State Implementation Plan.

100. Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Consent Decree from being considered by the State of Illinois or EPA as creditable contemporaneous emission decreases for the purpose of attainment demonstrations

submitted pursuant to § 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS, PSD increment, or air quality related values, including visibility, in a Class I area.

VIII. ENVIRONMENTAL MITIGATION PROJECTS

101. DMG shall implement the Environmental Mitigation Projects ("Projects") described in Appendix A to this Decree in compliance with the approved plans and schedules for such Projects and other terms of this Consent Decree. DMG shall submit plans for the Projects to the Plaintiffs for review and approval pursuant to Section XIII (Review and Approval of Submittals) of this Consent Decree in accordance with the schedules set forth in Appendix A. In implementing the Projects, DMG shall spend no less than $15 million in Project Dollars on or before December 31, 2007. DMG shall maintain, and present to the Plaintiffs upon request, all documents to substantiate the Project Dollars expended and shall provide these documents to the Plaintiffs within thirty (30) days of a request by any of the Plaintiffs for the documents.

102. All plans and reports prepared by DMG pursuant to the requirements of this Section of the Consent Decree and required to be submitted to EPA shall be publicly available from DMG without charge.

103. DMG shall certify, as part of each plan submitted to the Plaintiffs for any Project, that DMG is not otherwise required by law to perform the Project described in the plan, that DMG is unaware of any other person who is required by law to perform the Project, and that DMG will not use any Project, or portion thereof, to satisfy any obligations that it may have under other applicable requirements of law, including any applicable renewable portfolio standards.

104. DMG shall use good faith efforts to secure as much benefit as possible for the Project Dollars expended, consistent with the applicable requirements and limits of this Consent Decree.

105. If DMG elects (where such an election is allowed) to undertake a Project by contributing funds to another person or entity that will carry out the Project in lieu of DMG, but not including DMG's agents or contractors, that person or instrumentality must, in writing: (a) identify its legal authority for accepting such funding; and (b) identify its legal authority to conduct the Project for which DMG contributes the funds. Regardless of whether DMG elected (where such election is allowed) to undertake a Project by itself or to do so by contributing funds to another person or instrumentality that will carry out the Project, DMG acknowledges that it will receive credit for the expenditure of such funds as Project Dollars only if DMG demonstrates that the funds have been actually spent by either DMG or by the person or instrumentality receiving them (or, in the case of internal costs, have actually been incurred by DMG), and that such expenditures met all requirements of this Consent Decree.

106. Beginning six (6) months after entry of this Consent Decree, and continuing until completion of each Project (including any applicable periods of demonstration or testing), DMG shall provide the Plaintiffs with semi-annual updates concerning the progress of each Project.

107. Within sixty (60) days following the completion of each Project required under this Consent Decree (including any applicable periods of demonstration or testing), DMG shall submit to the Plaintiffs a report that documents the date that the Project was completed, DMG's results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by DMG in implementing the Project.

IX. CIVIL PENALTY

108. Within thirty (30) calendar days after entry of this Consent Decree, DMG shall pay to the United States a civil penalty in the amount of $9,000,000. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing USAO File Number 1999V00379 and DOJ Case Number 90-5-2-1-06837 and the civil action case name and case number of this action. The costs of such EFT shall be DMG's responsibility. Payment shall be made in accordance with instructions provided to DMG by the Financial Litigation Unit of the U.S. Attorney's Office for the Southern District of Illinois. Any funds received after 2:00 p.m. EDT shall be credited on the next business day. At the time of payment, DMG shall provide notice of payment, referencing the USAO File Number, the DOJ Case Number, and the civil action case name and case number, to the Department of Justice and to EPA in accordance with Section XIX (Notices) of this Consent Decree.

109. Failure to timely pay the civil penalty shall subject DMG to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render DMG liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

110. Payments made pursuant to this Section are penalties within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and are not tax-deductible expenditures for purposes of federal law.

X. RELEASE AND COVENANT NOT TO SUE FOR ILLINOIS POWER COMPANY

111. Upon entry of this Decree, each of the Plaintiffs hereby forever releases Illinois Power Company from, and covenants not to sue Illinois Power Company for, any and all civil claims, causes of action, and liability under the Clean Air Act and/or the Illinois Environmental Protection Act that such Plaintiffs could assert (whether such claims, causes of action, and liability are, were, or ever will be characterized as known or unknown, asserted or unasserted, liquidated or contingent, accrued or unaccrued), where such claims, causes of action, and liability are based on any modification, within the meaning of the Clean Air Act and/or the Illinois Environmental Protection Act, undertaken at any time before lodging of this Decree at any DMG System Unit, including and without limitation all such claims, causes of action, and liability asserted, or that could have been asserted, against Illinois Power Company by the United States, the State of Illinois and/or the Citizen Plaintiffs in the lawsuit styled United States of America, et al. v. Illinois Power Company and Dynegy Midwest Generation, Inc., Civil Action No. 99-833-MJR and all such civil claims, causes of action, and liability asserted or that could have been or could be asserted under any or all of the following statutory and/or regulatory provisions:

a. Parts C or D of Subchapter I of the Clean Air Act,

b. Section 111 of the Clean Air Act and 40 C.F.R. Section 60.14,

c. The federally approved and enforceable Illinois State Implementation Plan, but only insofar as such claims were alleged in the third amended complaint filed in the lawsuit so styled,

d. Sections 502(a) and 504(a) of the Clean Air Act, but only to the extent that such claims are based on Illinois Power's failure to obtain an operating permit that reflects applicable requirements imposed under Parts C or D of Subchapter I, or Section 111, of the Clean Air Act,

e. Sections 9 and 9.1 of the Illinois Environmental Protection Act, 415 ILCS 5/9 and 9.1, all applicable regulations promulgated thereunder, and all relevant prior versions of such statute and regulations, and

f. Section 39.5 of the Illinois Environmental Protection Act, 415 ILCS 5/39.5, and all applicable regulations promulgated thereunder, and all relevant prior versions of such statutes and regulations, but only to the extent that such claims are based on Illinois Power's failure to obtain an operating permit that reflects applicable requirements imposed under Sections 9 and 9.1 of the Illinois Environmental Protection Act, 415 ILCS 5/9 and 9.1,

where such claims, causes of actions and liability are based on any modification, within the meaning of the Clean Air Act and/or the Illinois Environmental Protection Act, undertaken at any time before lodging of this Decree at any DMG System Unit. As to Illinois Power Company, such resolved claims shall not be subject to the Bases for Pursuing Resolved Claims set forth in Section XI, Subsection B, of this Consent Decree.

112. In accordance with Paragraph 171 of this Decree, in the event that Illinois Power acquires an Ownership Interest in, or becomes an operator (as that term is used and interpreted under the Clean Air Act) of, any DMG System Unit, this release shall become void with respect

to the Unit(s) to which the Ownership Interest applies when and to the extent specified in Paragraph 171.

XI. RESOLUTION OF PLAINTIFFS' CIVIL CLAIMS AGAINST DMG

A. RESOLUTION OF PLAINTIFFS' CIVIL CLAIMS

113. Claims Based on Modifications Occurring Before the Lodging of Decree. Entry of this Decree shall resolve all civil claims of the Plaintiffs against DMG under any or all of:

a. Parts C or D of Subchapter I of the Clean Air Act,

b. Section 111 of the Clean Air Act and 40 C.F.R. Section 60.14,

c. The federally approved and enforceable Illinois State Implementation Plan, but only insofar as such claims were alleged in the third amended complaint filed in the lawsuit styled United States of America, et al. v. Illinois Power Company and Dynegy Midwest Generation, Inc., Civil Action No. 99-833-MJR,

d. Sections 502(a) and 504(a) of the Clean Air Act, but only to the extent that such claims are based on DMG's or Illinois Power's failure to obtain an operating permit that reflects applicable requirements imposed under Parts C or D of Subchapter I, or Section 111, of the Clean Air Act,

e. Sections 9 and 9.1 of the Illinois Environmental Protection Act, 415 ILCS 5/9 and 9.1, all applicable regulations promulgated thereunder, and all relevant prior versions of such statute and regulations, and

f. Section 39.5 of the Illinois Environmental Protection Act, 415 ILCS 5/39.5, and all applicable regulations promulgated thereunder, and all relevant prior versions of such statutes and regulations, but only to the extent that such claims are based on Illinois Power's failure to obtain an operating permit that reflects applicable requirements imposed under Sections 9 and 9.1 of the Illinois Environmental Protection Act, 415 ILCS 5/9 and 9.1,

that arose from any modifications commenced at any DMG System Unit prior to the date of lodging of this Decree, including but not limited to those modifications alleged in the Complaints filed in this civil action.

114. Claims Based on Modifications After the Lodging of Decree. As to DMG, entry of this Decree also shall resolve all civil claims of the Plaintiffs against DMG for pollutants regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder as of the date of lodging of this Decree, where such claims are based on a modification completed before December 31, 2015 and:

a. commenced at any DMG System unit after lodging of this Decree; or

b. that this Consent Decree expressly directs DMG to undertake.

The term "modification" as used in this Paragraph 114 shall have the meaning that term is given under the Clean Air Act and under the regulations promulgated thereunder as of July 31, 2003.

115. Reopeners. The Resolution of the Plaintiffs' Civil Claims against DMG, as provided by this Subsection A, is subject to the provisions of Subsection B of this Section.

B. PURSUIT OF PLAINTIFFS' CIVIL CLAIMS OTHERWISE RESOLVED

116. Bases for Pursuing Resolved Claims Across DMG System. If DMG violates System-Wide Annual Tonnage Limitations for NO_x required pursuant to Paragraph 57, the System-Wide Annual Tonnage Limitations for SO_2 required pursuant to Paragraph 73, or

operates a Unit more than ninety days past an installation date without completing the required installation or upgrade and commencing operation of any emission control device required pursuant to Paragraphs 51, 54, 66, or 85, then the Plaintiffs may pursue any claim at any DMG System Unit that is otherwise resolved under Subsection A (Resolution of Plaintiffs' Civil Claims), subject to (a) and (b) below.

a. For any claims based on modifications undertaken at an Other Unit (i.e., any Unit of the DMG System that is not an Improved Unit for the pollutant in question), claims may be pursued only where the modification(s) on which such claim is based was commenced within the five (5) years preceding the violation or failure specified in this Paragraph.

b. For any claims based on modifications undertaken at an Improved Unit, claims may be pursued only where the modification(s) on which such claim is based was commenced (1) after lodging of the Consent Decree and (2) within the five years preceding the violation or failure specified in this Paragraph.

117. Additional Bases for Pursuing Resolved Claims for Modifications at an Improved Unit. Solely with respect to Improved Units, the Plaintiffs may also pursue claims arising from a modification (or collection of modifications) at an Improved Unit that have otherwise been resolved under Subsection A (Resolution of Plaintiffs' Civil Claims), if the modification (or collection of modifications) at the Improved Unit on which such claims are based (a) was commenced after lodging of this Consent Decree, and (b) individually (or collectively) increased the maximum hourly emission rate of that Unit for NO_x or SO_2 (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%).

118. Additional Bases for Pursuing Resolved Claims for Modifications at an Other Unit.

a. Solely with respect to Other Units, the Plaintiffs may also pursue claims arising from a modification (or collection of modifications) at an Other Unit that have otherwise been resolved under Subsection A (Resolution of Plaintiffs' Civil Claims), if the modification (or collection of modifications) at the Other Unit on which the claim is based was commenced within the five (5) years preceding any of the following events:

1. a modification (or collection of modifications) at such Other Unit commenced after lodging of this Consent Decree increases the maximum hourly emission rate for such Other Unit for the relevant pollutant (NO_x or SO_2) (as measured by 40 C.F.R. § 60.14(b) and (h));

2. the aggregate of all Capital Expenditures made at such Other Unit (a) exceed $150/KW on the Unit's Boiler Island (based on the generating capacities identified in Paragraph 14) during the period from the date of lodging of this Decree through December 31, 2010, provided that Capital Expenditures made solely for the conversion of Vermilion Units 1 and 2 to low sulfur coal through the earlier of entry of this Consent Decree or September 30, 2005, shall be excluded; or (b) exceed $125/KW on the Unit's Boiler Island (based on the generating capacities identified in Paragraph 14) during the period from January 1, 2011 through December 31, 2015. (Capital Expenditures shall be measured in calendar year 2004

constant dollars, as adjusted by the McGraw-Hill Engineering News-Record Construction Cost Index); or

3. a modification (or collection of modifications) at such Other Unit commenced after lodging of this Consent Decree results in an emissions increase of NO_x and/or SO_2 at such Other Unit, and such increase:

(i) presents, by itself, or in combination with other emissions or sources, "an imminent and substantial endangerment" within the meaning of Section 303 of the Act, 42 U.S.C. §7603;

(ii) causes or contributes to violation of a NAAQS in any Air Quality Control Area that is in attainment with that NAAQS;

(iii) causes or contributes to violation of a PSD increment; or

(iv) causes or contributes to any adverse impact on any formally-recognized air quality and related values in any Class I area.

4. The introduction of any new or changed NAAQS shall not, standing alone, provide the showing needed under Paragraph 113, Subparagraphs (3)(ii) or (3)(iii), to pursue any claim for a modification at an Other Unit resolved under Subsection B of this Section.

b. Solely with respect to Other Units at the plants listed below, the Plaintiffs may also pursue claims arising from a modification (or collection of modifications) at such Other Unit commenced after lodging of this Consent Decree if such modification (or collection of modifications) results in an emissions increase of

NO_x and/or SO_2 at such Other Unit, and such increase causes the emissions at the Plant at issue to exceed the Plant-Wide Annual Tonnage Emission Levels listed below:

Unit	**SO_2 Tons Limit**	**NO_X Tons Limit**
Hennepin	9,050	2,650
Vermillion	17,370 (in 2005) 5,650 (in 2006 and thereafter)	3,360
Wood River	13,700	3,100

XII. PERIODIC REPORTING

119. Within one hundred eighty (180) days after each date established by this Consent Decree for DMG to achieve and maintain a certain PM Emission Rate at any DMG System Unit, DMG shall conduct a performance test for PM that demonstrates compliance with the Emission Rate required by this Consent Decree. Within forty-five (45) days of each such performance test, DMG shall submit the results of the performance test to EPA, the State of Illinois, and the Citizen Plaintiffs at the addresses specified in Section XIX (Notices) of this Consent Decree.

120. Beginning thirty (30) days after the end of the second full calendar quarter following the entry of this Consent Decree, and continuing on a semi-annual basis until December 31, 2015, and in addition to any other express reporting requirement in this Consent Decree, DMG shall submit to EPA, the State of Illinois, and the Citizen Plaintiffs a progress report.

121. The progress report shall contain the following information:

a. all information necessary to determine compliance with the requirements of the following Paragraphs of this Consent Decree: Paragraphs 51, 52, 53, 54, and 57 concerning NO_x emissions; Paragraphs 66, 70, 71, 72 and 73 concerning SO_2 emissions; Paragraphs 83, 84, 85, 86, 88 (if applicable), 89, 91, 93, and 94 concerning PM emissions;

b. documentation of any Capital Expenditures made, during the period covered by the progress report, solely for the conversion of Vermilion Units 1 and 2 to low sulfur coal, but excluded from the aggregate of Capital Expenditures pursuant to Paragraph 118(a)(2);

c. all information relating to emission allowances and credits that DMG claims to have generated in accordance with Paragraph 61 through compliance beyond the requirements of this Consent Decree; and

d. all information indicating that the installation and commencement of operation for a pollution control device may be delayed, including the nature and cause of the delay, and any steps taken by DMG to mitigate such delay.

122. In any periodic progress report submitted pursuant to this Section, DMG may incorporate by reference information previously submitted under its Title V permitting requirements, provided that DMG attaches the Title V permit report, or the relevant portion thereof, and provides a specific reference to the provisions of the Title V permit report that are responsive to the information required in the periodic progress report.

123. In addition to the progress reports required pursuant to this Section, DMG shall provide a written report to EPA, the State of Illinois, and the Citizen Plaintiffs of any violation of

the requirements of this Consent Decree within fifteen (15) calendar days of when DMG knew or should have known of any such violation. In this report, DMG shall explain the cause or causes of the violation and all measures taken or to be taken by DMG to prevent such violations in the future.

124. Each DMG report shall be signed by DMG's Vice President of Environmental Services or his or her equivalent or designee of at least the rank of Vice President, and shall contain the following certification:

> This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the direction and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

125. If any SO_2 Allowances are surrendered to any third party pursuant to this Consent Decree, the third party's certification pursuant to Paragraph 79 shall be signed by a managing officer of the third party and shall contain the following language:

> I certify under penalty of law that,_____________ [name of third party] will not sell, trade, or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any environmental law. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

XIII. REVIEW AND APPROVAL OF SUBMITTALS

126. DMG shall submit each plan, report, or other submission required by this Decree to the Plaintiff(s) specified whenever such a document is required to be submitted for review or approval pursuant to this Consent Decree. The Plaintiff(s) to whom the report is submitted, as required, may approve the submittal or decline to approve it and provide written comments

explaining the bases for declining such approval. Such Plaintiff(s) will endeavor to coordinate their comments into one document when explaining their bases for declining such approval. Within sixty (60) days of receiving written comments from any of the Plaintiffs, DMG shall either: (a) revise the submittal consistent with the written comments and provide the revised submittal to the Plaintiffs; or (b) submit the matter for dispute resolution, including the period of informal negotiations, under Section XVI (Dispute Resolution) of this Consent Decree.

127. Upon receipt of EPA's final approval of the submittal, or upon completion of the submittal pursuant to dispute resolution, DMG shall implement the approved submittal in accordance with the schedule specified therein or another EPA-approved schedule.

XIV. STIPULATED PENALTIES

128. For any failure by DMG to comply with the terms of this Consent Decree, and subject to the provisions of Sections XV (Force Majeure) and XVI (Dispute Resolution), DMG shall pay, within thirty (30) days after receipt of written demand to DMG by the United States, the following stipulated penalties to the United States:

Consent Decree Violation	**Stipulated Penalty**
a. Failure to pay the civil penalty as specified in Section IX (Civil Penalty) of this Consent Decree	$10,000 per day
b. Failure to comply with any applicable 30-Day Rolling Average Emission Rate for NO_x or SO_2 or Emission Rate for PM, where the violation is less than 5% in excess of the limits set forth in this Consent Decree	$2,500 per day per violation
c. Failure to comply with any applicable 30-Day Rolling Average Emission Rate for NO_x or SO_2 or Emission Rate for PM, where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree	$5,000 per day per violation

d. Failure to comply with any applicable 30-Day Rolling Average Emission Rate for NO_x or SO_2 or Emission Rate for PM, where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree	$10,000 per day per violation
e. Failure to comply with the System-Wide Annual Tonnage Limits for SO_2, where the violation is less than 100 tons in excess of the limits set forth in this Consent Decree	$60,000 per calendar year, plus the surrender, pursuant to the procedures set forth in Paragraphs 79 and 80 of this Consent Decree, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
f. Failure to comply with the System-Wide Annual Tonnage Limits for SO_2, where the violation is equal to or greater than 100 tons in excess of the limits set forth in this Consent Decree	$120,000 per calendar year, plus the surrender, pursuant to the procedures set forth in Paragraphs 79 and 80 of this Consent Decree, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
g. Failure to comply with the System-Wide Annual Tonnage Limits for NO_x, where the violation is less than 100 tons in excess of the limits set forth in this Consent Decree	$60,000 per calendar year, plus the surrender of NO_x Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
h. Failure to comply with the System-Wide Annual Tonnage Limits for NO_x, where the violation is equal to or greater than 100 tons in excess of the limits set forth in this Consent Decree	$120,000 per calendar year, plus the surrender of NO_x Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
i. Operation of a Unit required under this Consent Decree to be equipped with any NO_x, SO_2, or PM control device without the operation of such device, as required under this Consent Decree	$10,000 per day per violation during the first 30 days, $27,500 per day per violation thereafter
j. Failure to install or operate CEMS as required in this Consent Decree	$1,000 per day per violation

k. Failure to conduct performance tests of PM emissions, as required in this Consent Decree	$1,000 per day per violation
l. Failure to apply for any permit required by Section XVII	$1,000 per day per violation
m. Failure to timely submit, modify, or implement, as approved, the reports, plans, studies, analyses, protocols, or other submittals required by this Consent Decree	$750 per day per violation during the first ten days, $1,000 per day per violation thereafter
n. Using, selling or transferring NO_x Allowances except as permitted by Paragraphs 60 and 61	the surrender of NO_x Allowances in an amount equal to four times the number of NO_x Allowances used, sold, or transferred in violation of this Consent Decree
o. Failure to surrender SO_2 Allowances as required by Paragraph 75	(a) $27,500 per day plus (b) $1,000 per SO_2 Allowance not surrendered
p. Failure to demonstrate the third-party surrender of an SO_2 Allowance in accordance with Paragraph 79 and 80	$2,500 per day per violation
q. Failure to undertake and complete any of the Environmental Mitigation Projects in compliance with Section VIII (Environmental Mitigation Projects) of this Consent Decree	$1,000 per day per violation during the first 30 days, $5,000 per day per violation thereafter
r. Any other violation of this Consent Decree	$1,000 per day per violation

129. Violation of an Emission Rate that is based on a 30-Day Rolling Average is a violation on every day on which the average is based. Where a violation of a 30-Day Rolling Average Emission Rate (for the same pollutant and from the same source) recurs within periods of less than thirty (30) days, DMG shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

130. In any case in which the payment of a stipulated penalty includes the surrender of SO_2 Allowances, the provisions of Paragraph 76 shall not apply.

131. All stipulated penalties shall begin to accrue on the day after the performance is due or on the day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases, whichever is applicable. Nothing in this Consent Decree shall prevent the simultaneous accrual of separate stipulated penalties for separate violations of this Consent Decree.

132. DMG shall pay all stipulated penalties to the United States within thirty (30) days of receipt of written demand to DMG from the United States, and shall continue to make such payments every thirty (30) days thereafter until the violation(s) no longer continues, unless DMG elects within 20 days of receipt of written demand to DMG from the United States to dispute the accrual of stipulated penalties in accordance with the provisions in Section XVI (Dispute Resolution) of this Consent Decree.

133. Stipulated penalties shall continue to accrue as provided in accordance with Paragraph 128 during any dispute, with interest on accrued stipulated penalties payable and calculated at the rate established by the Secretary of the Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid until the following:

a. If the dispute is resolved by agreement, or by a decision of Plaintiffs pursuant to Section XVI (Dispute Resolution) of this Consent Decree that is not appealed to the Court, accrued stipulated penalties agreed or determined to be owing, together with accrued interest, shall be paid within thirty (30) days of the effective date of the agreement or of the receipt of Plaintiffs' decision;

b. If the dispute is appealed to the Court and Plaintiffs prevail in whole or in part, DMG shall, within sixty (60) days of receipt of the Court's decision or order, pay all accrued stipulated penalties determined by the Court to be owing, together with interest accrued on such penalties determined by the Court to be owing, except as provided in Subparagraph c, below;

c. If the Court's decision is appealed by any Party, DMG shall, within fifteen (15) days of receipt of the final appellate court decision, pay all accrued stipulated penalties determined to be owing, together with interest accrued on such stipulated penalties determined to be owing by the appellate court.

Notwithstanding any other provision of this Consent Decree, the accrued stipulated penalties agreed by the Plaintiffs and DMG, or determined by the Plaintiffs through Dispute Resolution, to be owing may be less than the stipulated penalty amounts set forth in Paragraph 128.

134. All stipulated penalties shall be paid in the manner set forth in Section IX (Civil Penalty) of this Consent Decree.

135. Should DMG fail to pay stipulated penalties in compliance with the terms of this Consent Decree, the United States shall be entitled to collect interest on such penalties, as provided for in 28 U.S.C. § 1961.

136. The stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to the United States by reason of DMG's failure to comply with any requirement of this Consent Decree or applicable law, except that for any violation of the Act for which this Consent Decree provides for payment of a stipulated penalty, DMG shall be allowed a credit for stipulated penalties paid against any statutory penalties also imposed for such violation.

XV. FORCE MAJEURE

137. For purposes of this Consent Decree, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of DMG, its contractors, or any entity controlled by DMG that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite DMG's best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay or violation is minimized to the greatest extent possible.

138. Notice of Force Majeure Events. If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which DMG intends to assert a claim of Force Majeure, DMG shall notify the Plaintiffs in writing as soon as practicable, but in no event later than fourteen (14) business days following the date DMG first knew, or by the exercise of due diligence should have known, that the event caused or may cause such delay or violation. In this notice, DMG shall reference this Paragraph of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by DMG to prevent or minimize the delay or violation, the schedule by which DMG proposes to implement those measures, and DMG's rationale for attributing a delay or violation to a Force Majeure Event. DMG shall adopt all reasonable measures to avoid or minimize such delays or violations. DMG shall be deemed to know of any circumstance which DMG, its contractors, or any entity controlled by DMG knew or should have known.

139. Failure to Give Notice. If DMG fails to comply with the notice requirements of this Section, EPA (after consultation with the State of Illinois and the Citizen Plaintiffs) may void DMG's claim for Force Majeure as to the specific event for which DMG has failed to comply with such notice requirement.

140. Plaintiffs' Response. EPA shall notify DMG in writing regarding DMG's claim of Force Majeure within twenty (20) business days of receipt of the notice provided under Paragraph 138. If EPA (after consultation with the State of Illinois and the Citizen Plaintiffs) agrees that a delay in performance has been or will be caused by a Force Majeure Event, EPA and DMG shall stipulate to an extension of deadline(s) for performance of the affected compliance requirement(s) by a period equal to the delay actually caused by the event. In such circumstances, an appropriate modification shall be made pursuant to Section XXIII (Modification) of this Consent Decree.

141. Disagreement. If EPA (after consultation with the State of Illinois and the Citizen Plaintiffs) does not accept DMG's claim of Force Majeure, or if EPA and DMG cannot agree on the length of the delay actually caused by the Force Majeure Event, the matter shall be resolved in accordance with Section XVI (Dispute Resolution) of this Consent Decree.

142. Burden of Proof. In any dispute regarding Force Majeure, DMG shall bear the burden of proving that any delay in performance or any other violation of any requirement of this Consent Decree was caused by or will be caused by a Force Majeure Event. DMG shall also bear the burden of proving that DMG gave the notice required by this Section and the burden of proving the anticipated duration and extent of any delay(s) attributable to a Force Majeure Event.

An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

143. Events Excluded. Unanticipated or increased costs or expenses associated with the performance of DMG's obligations under this Consent Decree shall not constitute a Force Majeure Event.

144. Potential Force Majeure Events. The Parties agree that, depending upon the circumstances related to an event and DMG's response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Section: construction, labor, or equipment delays; Malfunction of a Unit or emission control device; acts of God; acts of war or terrorism; and orders by a government official, government agency, other regulatory authority, or a regional transmission organization, acting under and authorized by applicable law, that directs DMG to supply electricity in response to a system-wide (state-wide or regional) emergency. Depending upon the circumstances and DMG's response to such circumstances, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure Event where the failure of the permitting authority to act is beyond the control of DMG and DMG has taken all steps available to it to obtain the necessary permit, including, but not limited to: submitting a complete permit application; responding to requests for additional information by the permitting authority in a timely fashion; and accepting lawful permit terms and conditions after expeditiously exhausting any legal rights to appeal terms and conditions imposed by the permitting authority.

145. As part of the resolution of any matter submitted to this Court under Section XVI (Dispute Resolution) of this Consent Decree regarding a claim of Force Majeure, the Plaintiffs

and DMG by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States and the States or approved by the Court. DMG shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule (provided that DMG shall not be precluded from making a further claim of Force Majeure with regard to meeting any such extended or modified schedule).

XVI. DISPUTE RESOLUTION

146. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, provided that the Party invoking such procedure has first made a good faith attempt to resolve the matter with the other Party.

147. The dispute resolution procedure required herein shall be invoked by one Party giving written notice to the other Party advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party's position with regard to such dispute. The Party receiving such a notice shall acknowledge receipt of the notice, and the Parties in dispute shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

148. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations among the disputing Parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting among the disputing Parties' representatives unless they agree in writing to shorten or extend this period. During the informal negotiations period, the disputing Parties may also

submit their dispute to a mutually agreed upon alternative dispute resolution (ADR) forum if the Parties agree that the ADR activities can be completed within the 30-day informal negotiations period (or such longer period as the Parties may agree to in writing).

149. If the disputing Parties are unable to reach agreement during the informal negotiation period, the Plaintiffs shall provide DMG with a written summary of their position regarding the dispute. The written position provided by Plaintiffs shall be considered binding unless, within forty-five (45) calendar days thereafter, DMG seeks judicial resolution of the dispute by filing a petition with this Court. The Plaintiffs may respond to the petition within forty-five (45) calendar days of filing. In their initial filings with the Court under this Paragraph, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

150. The time periods set out in this Section may be shortened or lengthened upon motion to the Court of one of the Parties to the dispute, explaining the party's basis for seeking such a scheduling modification.

151. This Court shall not draw any inferences nor establish any presumptions adverse to any disputing Party as a result of invocation of this Section or the disputing Parties' inability to reach agreement.

152. As part of the resolution of any dispute under this Section, in appropriate circumstances the disputing Parties may agree, or this Court may order, an extension or modification of the schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution. DMG shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with

the extended or modified schedule, provided that DMG shall not be precluded from asserting that a Force Majeure Event has caused or may cause a delay in complying with the extended or modified schedule.

153. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes. In their initial filings with the Court under Paragraph 149, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

XVII. PERMITS

154. Unless expressly stated otherwise in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires DMG to secure a permit to authorize construction or operation of any device contemplated herein, including all preconstruction, construction, and operating permits required under state law, DMG shall make such application in a timely manner. EPA and the State of Illinois shall use their best efforts to review expeditiously all permit applications submitted by DMG to meet the requirements of this Consent Decree.

155. Notwithstanding the previous Paragraph, nothing in this Consent Decree shall be construed to require DMG to apply for or obtain a PSD or Nonattainment NSR permit for physical changes in, or changes in the method of operation of, any DMG System Unit that would give rise to claims resolved by Section XI. A. (Resolution of Plaintiffs' Civil Claims) of this Consent Decree.

156. When permits are required as described in Paragraph 154, DMG shall complete and submit applications for such permits to the appropriate authorities to allow time for all

legally required processing and review of the permit request, including requests for additional information by the permitting authorities. Any failure by DMG to submit a timely permit application for any Unit in the DMG System shall bar any use by DMG of Section XV (Force Majeure) of this Consent Decree, where a Force Majeure claim is based on permitting delays.

157. Notwithstanding the reference to Title V permits in this Consent Decree, the enforcement of such permits shall be in accordance with their own terms and the Act. The Title V permits shall not be enforceable under this Consent Decree, although any term or limit established by or under this Consent Decree shall be enforceable under this Consent Decree regardless of whether such term has or will become part of a Title V permit, subject to the terms of Section XXVII (Conditional Termination of Enforcement Under Decree) of this Consent Decree.

158. Within one hundred eighty (180) days after entry of this Consent Decree, DMG shall amend any applicable Title V permit application, or apply for amendments of its Title V permits, to include a schedule for all Unit-specific performance, operational, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, required emission rates and the requirement in Paragraph 75 pertaining to the surrender of SO_2 Allowances.

159. Within one (1) year from the commencement of operation of each pollution control device to be installed, upgraded, or operated under this Consent Decree, DMG shall apply to amend its Title V permit for the generating plant where such device is installed to reflect all new requirements applicable to that plant, including, but not limited to, any applicable 30-Day Rolling Average Emission Rate.

160. Prior to January 1, 2015, DMG shall either: (a) apply to amend the Title V permit for each plant in the DMG System to include a provision, which shall be identical for each Title V permit, that contains the allowance surrender requirements and the System-Wide Annual Tonnage Limitations set forth in this Consent Decree; or (b) apply for amendments to the Illinois State Implementation Plan to include such requirements and limitations therein.

161. DMG shall provide the Plaintiffs with a copy of each application to amend its Title V permit for a plant within the DMG System, as well as a copy of any permit proposed as a result of such application, to allow for timely participation in any public comment opportunity.

162. If DMG sells or transfers to an entity unrelated to DMG ("Third Party Purchaser") part or all of its Ownership Interest in a Unit in the DMG System, DMG shall comply with the requirements of Section XX (Sales or Transfers of Ownership Interests) with regard to that Unit prior to any such sale or transfer unless, following any such sale or transfer, DMG remains the holder of the Title V permit for such facility.

XVIII. INFORMATION COLLECTION AND RETENTION

163. Any authorized representative of the United States or the State of Illinois, including their attorneys, contractors, and consultants, upon presentation of credentials, shall have a right of entry upon the premises of any facility in the DMG System at any reasonable time for the purpose of:

a. monitoring the progress of activities required under this Consent Decree;

b. verifying any data or information submitted to the United States in accordance with the terms of this Consent Decree;

c. obtaining samples and, upon request, splits of any samples taken by DMG or its representatives, contractors, or consultants; and

d. assessing DMG's compliance with this Consent Decree.

164. DMG shall retain, and instruct its contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in its or its contractors' or agents' possession or control, and that directly relate to DMG's performance of its obligations under this Consent Decree for the following periods: (a) until December 31, 2020 for records concerning physical or operational changes undertaken in accordance with Paragraph 114; and (b) until December 31, 2017 for all other records. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

165. All information and documents submitted by DMG pursuant to this Consent Decree shall be subject to any requests under applicable law providing public disclosure of documents unless (a) the information and documents are subject to legal privileges or protection or (b) DMG claims and substantiates in accordance with 40 C.F.R. Part 2 that the information and documents contain confidential business information.

166. Nothing in this Consent Decree shall limit the authority of the EPA or the State of Illinois to conduct tests and inspections at DMG's facilities under Section 114 of the Act, 42 U.S.C. § 7414, or any other applicable federal or state laws, regulations or permits.

XIX. NOTICES

167. Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

As to the United States of America:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-06837

and

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Regional Administrator
U.S. EPA- Region 5
77 W. Jackson St.
Chicago, IL 60604

and

George Czerniak, Chief, AECAB
U.S. EPA- Region 5
77 W. Jackson St. - AE-17J
Chicago, IL 60604

As to the State of Illinois:

Bureau Chief
Bureau of Air

Illinois Environmental Protection Agency
1021 North Grand Avenue East, P.O. Box 19276
Springfield, Illinois 62794-9276

and

Bureau Chief
Environmental Bureau
Illinois Attorney General's Office
500 South Second Street
Springfield, Illinois 62706

As to the Citizen Plaintiffs:

Executive Director
Environmental Law and Policy Center of the Midwest
35 East Wacker Dr. Suite 1300
Chicago, Illinois 60601-2110

As to DMG:

Vice President, Environmental Health & Safety
Dynegy Midwest Generation, Inc.
2828 North Monroe Street
Decatur, Illinois 62526

and

Executive Vice President and General Counsel
Dynegy Inc.
1000 Louisiana Street, Suite 5800
Houston, Texas 77002

As to Illinois Power Company:

Senior Vice President, General Counsel, and Secretary
Illinois Power Company
One Ameren Plaza
1901 Chouteau Avenue
St. Louis, Missouri 63166

168. All notifications, communications or submissions made pursuant to this Section shall be sent either by: (a) overnight mail or overnight delivery service, or (b) certified or registered mail, return receipt requested. All notifications, communications and transmissions (a) sent by overnight, certified or registered mail shall be deemed submitted on the date they are postmarked, or (b) sent by overnight delivery service shall be deemed submitted on the date they are delivered to the delivery service.

169. Any Party may change either the notice recipient or the address for providing notices to it by serving all other Parties with a notice setting forth such new notice recipient or address.

XX. SALES OR TRANSFERS OF OWNERSHIP INTERESTS

170. If DMG proposes to sell or transfer an Ownership Interest to an entity unrelated to DMG ("Third Party Purchaser"), it shall advise the Third Party Purchaser in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to the Plaintiffs pursuant to Section XIX (Notices) of this Consent Decree at least sixty (60) days before such proposed sale or transfer.

171. No sale or transfer of an Ownership Interest shall take place before the Third Party Purchaser and EPA have executed, and the Court has approved, a modification pursuant to Section XXIII (Modification) of this Consent Decree making the Third Party Purchaser a party to this Consent Decree and jointly and severally liable with DMG for all the requirements of this Decree that may be applicable to the transferred or purchased Ownership Interests. Should Illinois Power (or any successor thereof) become a Third Party Purchaser or an operator (as the term "operator" is used and interpreted under the Clean Air Act) of any DMG System Unit, then

the provisions in Section X of this Consent Decree (Release and Covenant Not to Sue for Illinois Power Company) that apply to Illinois Power shall no longer apply as to the DMG System Unit(s) associated with the transfer, and instead, the Resolution of Plaintiffs' Civil Claims provisions in Section XI that apply to DMG shall apply to Illinois Power with respect to such transferred Unit(s), and such changes shall be reflected in the modification to the Decree reflecting the sale or transfer of an Ownership Interest contemplated by this Paragraph.

172. This Consent Decree shall not be construed to impede the transfer of any Ownership Interests between DMG and any Third Party Purchaser so long as the requirements of this Consent Decree are met. This Consent Decree shall not be construed to prohibit a contractual allocation – as between DMG and any Third Party Purchaser of Ownership Interests – of the burdens of compliance with this Decree, provided that both DMG and such Third Party Purchaser shall remain jointly and severally liable to EPA for the obligations of the Decree applicable to the transferred or purchased Ownership Interests.

173. If EPA agrees, EPA, DMG, and the Third Party Purchaser that has become a party to this Consent Decree pursuant to Paragraph 171, may execute a modification that relieves DMG of its liability under this Consent Decree for, and makes the Third Party Purchaser liable for, all obligations and liabilities applicable to the purchased or transferred Ownership Interests. Notwithstanding the foregoing, however, DMG may not assign, and may not be released from, any obligation under this Consent Decree that is not specific to the purchased or transferred Ownership Interests, including the obligations set forth in Sections VIII (Environmental Mitigation Projects) and IX (Civil Penalty). DMG may propose and the EPA may agree to restrict the scope of the joint and several liability of any purchaser or transferee for any

obligations of this Consent Decree that are not specific to the transferred or purchased Ownership Interests, to the extent such obligations may be adequately separated in an enforceable manner.

174. Paragraphs 170 and 171 of this Consent Decree do not apply if an Ownership Interest is sold or transferred solely as collateral security in order to consummate a financing arrangement (not including a sale-leaseback), so long as DMG: a) remains the operator (as that term is used and interpreted under the Clean Air Act) of the subject DMG System Unit(s); b) remains subject to and liable for all obligations and liabilities of this Consent Decree; and c) supplies Plaintiffs with the following certification within 30 days of the sale or transfer:

> "Certification of Change in Ownership Interest Solely for Purpose of Consummating Financing. We, the Chief Executive Officer and General Counsel of Dynegy Midwest Generation, hereby jointly certify under Title 18 U.S.C. Section 1001, on our own behalf and on behalf of Dynegy Midwest Generation ("DMG"), that any change in DMG's Ownership Interest in any Unit that is caused by the sale or transfer as collateral security of such Ownership Interest in such Unit(s) pursuant to the financing agreement consummated on [insert applicable date] between DMG and [insert applicable entity]: a) is made solely for the purpose of providing collateral security in order to consummate a financing arrangement; b) does not impair DMG's ability, legally or otherwise, to comply timely with all terms and provisions of the Consent Decree entered in *United States of America, et al. v. Illinois Power Company and Dynegy Midwest Generation, Inc.*, Civil Action No. 99-833-MJR; c) does not affect DMG's operational control of any Unit covered by that Consent Decree in a manner that is inconsistent with DMG's performance of its obligations under the Consent Decree; and d) in no way affects the status of DMG's obligations or liabilities under that Consent Decree."

XXI. EFFECTIVE DATE

175. The effective date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court.

XXII. RETENTION OF JURISDICTION

176. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, modification, or adjudication of disputes. During the term of this Consent Decree, any Party to this Consent Decree may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

XXIII. MODIFICATION

177. The terms of this Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and DMG. Where the modification constitutes a material change to any term of this Decree, it shall be effective only upon approval by the Court.

XXIV. GENERAL PROVISIONS

178. This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations. The emission rates set forth herein do not relieve the Defendants from any obligation to comply with other state and federal requirements under the Clean Air Act, including the Defendants' obligation to satisfy any state modeling requirements set forth in the Illinois State Implementation Plan.

179. This Consent Decree does not apply to any claim(s) of alleged criminal liability.

180. In any subsequent administrative or judicial action initiated by any of the Plaintiffs for injunctive relief or civil penalties relating to the facilities covered by this Consent

Decree, the Defendants shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, or claim splitting, or any other defense based upon the contention that the claims raised by any of the Plaintiffs in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the validity of Sections X (Release and Covenant Not to Sue for Illinois Power Company) and XI (Resolution of Plaintiffs' Civil Claims Against DMG).

181. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve the Defendants of their obligation to comply with all applicable federal, state, and local laws and regulations. Subject to the provisions in Sections X (Release and Covenant Not to Sue for Illinois Power Company) and XI (Resolution of Plaintiffs' Civil Claims Against DMG), nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the Plaintiffs to obtain penalties or injunctive relief under the Act or other federal, state, or local statutes, regulations, or permits.

182. Every term expressly defined by this Consent Decree shall have the meaning given to that term by this Consent Decree and, except as otherwise provided in this Decree, every other term used in this Decree that is also a term under the Act or the regulations implementing the Act shall mean in this Decree what such term means under the Act or those implementing regulations.

183. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including but not limited to any defenses, entitlements, challenges, or

clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8314 (Feb. 24, 1997)) concerning the use of data for any purpose under the Act.

184. Each limit and/or other requirement established by or under this Decree is a separate, independent requirement.

185. Performance standards, emissions limits, and other quantitative standards set by or under this Consent Decree must be met to the number of significant digits in which the standard or limit is expressed. For example, an Emission Rate of 0.100 is not met if the actual Emission Rate is 0.101. DMG shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the nearest second significant digit, depending upon whether the limit is expressed to three or two significant digits. For example, if an actual Emission Rate is 0.1004, that shall be reported as 0.100, and shall be in compliance with an Emission Rate of 0.100, and if an actual Emission Rate is 0.1005, that shall be reported as 0.101, and shall not be in compliance with an Emission Rate of 0.100. DMG shall report data to the number of significant digits in which the standard or limit is expressed.

186. This Consent Decree does not limit, enlarge or affect the rights of any Party to this Consent Decree as against any third parties.

187. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the Parties with respect to the settlement embodied in this Consent Decree, and supercedes all prior agreements and understandings among the Parties related to the subject matter herein. No document, representation, inducement, agreement, understanding, or promise constitutes any part of this Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

188. Each Party to this action shall bear its own costs and attorneys' fees.

XXV. SIGNATORIES AND SERVICE

189. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind to this document the Party he or she represents.

190. This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

191. Each Party hereby agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

XXVI. PUBLIC COMMENT

192. The Parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the procedures of 28 C.F.R. § 50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper or inadequate. The Defendants shall not oppose entry of this Consent Decree by this Court or challenge any provision of this Consent Decree unless the United States has notified the Defendants, in writing, that the United States no longer supports entry of the Consent Decree.

XXVII. CONDITIONAL TERMINATION OF ENFORCEMENT UNDER DECREE

193. Termination as to Completed Tasks. As soon as DMG completes a construction project or any other requirement of this Consent Decree that is not ongoing or recurring, DMG may, by motion to this Court, seek termination of the provision or provisions of this Consent Decree that imposed the requirement.

194. Conditional Termination of Enforcement Through the Consent Decree. After DMG:

a. has successfully completed construction, and has maintained operation, of all pollution controls as required by this Consent Decree;

b. has obtained final Title V permits (i) as required by the terms of this Consent Decree; (ii) that cover all units in this Consent Decree; and (iii) that include as enforceable permit terms all of the Unit performance and other requirements specified in Section XVII (Permits) of this Consent Decree; and

c. certifies that the date is later than December 31, 2015;

then DMG may so certify these facts to the Plaintiffs and this Court. If the Plaintiffs do not object in writing with specific reasons within forty-five (45) days of receipt of DMG's certification, then, for any Consent Decree violations that occur after the filing of notice, the Plaintiffs shall pursue enforcement of the requirements contained in the Title V permit through the applicable Title V permit and not through this Consent Decree.

195. Resort to Enforcement under this Consent Decree. Notwithstanding Paragraph 194, if enforcement of a provision in this Decree cannot be pursued by a party under the

applicable Title V permit, or if a Decree requirement was intended to be part of a Title V Permit and did not become or remain part of such permit, then such requirement may be enforced under the terms of this Decree at any time.

XXVIII. FINAL JUDGMENT

196. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment among the Plaintiffs, DMG, and Illinois Power.

SO ORDERED, THIS _____ DAY OF _______________, 200_.

HONORABLE MICHAEL J. REAGAN
UNITED STATES DISTRICT COURT JUDGE

Signature Page for Consent Decree in:

United States of America
v.
Illinois Power and Dynegy Midwest Generation Inc.

FOR THE UNITED STATES OF AMERICA:

THOMAS L. SANSONETTI
Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice

Nicole Veilleux
Trial Attorney
Environmental Enforcement Section
Environmental and Natural Resources Division
United States Department of Justice

William Coonan
Assistant United States Attorney
Southern District of Illinois
United States Department of Justice

Signature Page for Consent Decree in:

United States of America
v.
Illinois Power Company and Dynegy Midwest Generation Inc.

THOMAS V. SKINNER
Acting Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

ADAM M. KUSHNER
Acting Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

Edward J. Messina
Attorney Advisor
Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

Signature Page for Consent Decree in:

United States of America
v.
Illinois Power Company and Dynegy Midwest Generation Inc.

____
Bharat Mathur
Acting Regional Administrator
U.S. Environmental Protection Agency
Region 5

____
Mark Palermo
Associate Regional Counsel
U.S. Environmental Protection Agency
Region 5

Signature Page for Consent Decree in:

United States of America
v.
Illinois Power Company and Dynegy Midwest Generation Inc.

FOR THE STATE OF ILLINOIS
PEOPLE OF THE STATE OF ILLINOIS ex rel:

LISA MADIGAN
Attorney General of the State of Illinois

MATTHEW J. DUNN, Chief
Environmental Enforcement/Asbestos
Litigation Division

____
by: Thomas Davis, Chief
Environmental Bureau
Assistant Attorney General

Signature Page for Consent Decree in:

United States of America
v.
Illinois Power Company and Dynegy Midwest Generation Inc.

FOR CITIZEN PLAINTIFFS:

____
Albert Ettinger
Senior Staff Attorney
Environmental Law and Policy Center of the Midwest

Signature Page for Consent Decree in:

United States of America
v.
Illinois Power Company and Dynegy Midwest Generation Inc.

FOR DYNEGY MIDWEST GENERATION:

____
Alec G. Dreyer
President
Dynegy Midwest Generation, Inc.

Signature Page for Consent Decree in:

United States of America
v.
Illinois Power Company and Dynegy Midwest Generation Inc.

FOR ILLINOIS POWER COMPANY:

____
Steven R. Sullivan
Senior Vice President, General Counsel and Secretary
Illinois Power Company

APPENDIX A - MITIGATION PROJECTS REQUIREMENTS

In compliance with and in addition to the requirements in Section VIII of the Consent Decree, DMG shall comply with the requirements of this Appendix to ensure that the benefits of the environmental mitigation projects are achieved.

I. Advanced Truck Stop Electrification Project

A. Within one hundred thirty five (135) days after entry of this Consent Decree, DMG shall submit a plan to the Plaintiffs for review and approval for the completion of the installation of Advanced Truck Stop Electrification, preferably at State of Illinois owned rest areas along Illinois interstate highways in the St. Louis Metro East area (comprised of Madison, St. Clair and Monroe Counties in Illinois) or as nearby as possible. Long-haul truck drivers typically idle their engines at night at rest areas to supply heat or cooling in their sleeper cab compartments, and to maintain vehicle battery charge while electrical appliances such as TVs, computers and microwaves are in use. Modifications to rest areas to provide parking spaces with electrical power, heat and air conditioning will allow truck drivers to turn their engines off. Truck driver utilization of the Advanced Truck Stop Electrification will result in reduced idling time and therefore reduced fuel usage, reduced emissions of PM, NOx, VOCs and toxics, and reduced noise. This Project shall include, where necessary, techniques and infrastructure needed to support such project. DMG shall spend no less than $1.5 million in Project Dollars in performing this Advanced Truck Stop Electrification Project.

B. The proposed plan shall satisfy the following criteria:

1. Describe how the work or project to be performed is consistent with requirements of Section I. A., above.
2. Involve rest areas located in areas that are either in the St. Louis Metro East area (comprised of Madison, St. Clair and Monroe Counties in Illinois) or as nearby as reasonably possible.
3. Provide for the construction of Advanced Truck Stop Electrification stations with established technologies and equipment designed to reduce emissions of particulates and/or ozone precursors.
4. Account for hardware procurement and installation costs at the recipient truck stops.
5. Include a schedule for completing each portion of the project.
6. Describe generally the expected environmental benefits of the project.
7. DMG shall not profit from this project for the first five years of implementation.

C. Performance - Upon approval of plan by the Plaintiffs, DMG shall complete the mitigation project according to the approved plan and schedule, but no later than December 31, 2007.

II. Middle Fork/Vermilion Land Donation

A. Within sixty (60) days after entry of the Consent Decree, DMG shall submit a plan to the Plaintiffs for review and approval for the transfer of ownership to the State of Illinois Department of Natural Resources (IDNR), of an approximately 1135 acre parcel of land along the Middle Fork Vermilion River in Vermilion County identified as the Middle Fork/Vermilion ("Property"). The value of the Property to be donated can be fairly valued at $2.25 million. Accordingly, DMG's full and final transfer of the Property in accordance with the plan shall satisfy its requirement to spend at least $2.25 million Project Dollars to implement this project.

B. The proposed plan shall satisfy the following criteria:

1. Describe how the work or project to be performed is consistent with requirements of Section II. A., above.
2. This project entails the donation of the entire parcel of land owned by DMG (an approximately 1135 acre parcel of land) as of lodging of the Consent Decree along the East side of the Middle Fork Vermilion River in Vermilion County. The Property is located between Kickapoo State Park and the Middle Fork State Fish and Wildlife Area and Kennekuk County Park on the East side of the Middle Fork of the Vermilion River. Ownership of the Property and management of the natural resources thereon shall be transferred to IDNR so as to ensure the continued preservation and public use of the Property.
3. The plan shall include DMG's agreement to convey to IDNR, the Property, the Ancillary Structures and the Personal Property, if any, to the extent located on the Property, and to the extent owned by DMG. The plan shall include steps for resolution of all past liens, payment of all outstanding taxes, title transfer, and other such information as would be necessary to convey the Property to IDNR. In all other respects, the Property will be conveyed subject to the easements, rights-of-way and similar rights of third parties existing as of the date of the conveyance.
4. DMG shall retain its existing right to take and use the water from a stripmine lake located in the NW ¼ of Section 28, T-20_N, R-12-W, 3 P.M. and in the NE ¼ of Section 29, T-20_N, R-12-W, 3rd P.M. of Vermillion County, and an easement to access this water and to provide electrical power to pump the water.
5. DMG agrees to furnish to IDNR a current Alta/ACSM Land Title Survey of the Property prepared and certified by an Illinois registered land surveyor.
6. Describe generally the expected environmental benefit for the project.

C. Performance - Upon approval of plan by the Plaintiffs, DMG shall complete the mitigation project according to the approved plan and schedule, and convey such Property prior to the date 180 days from entry of this Consent Decree or June 30, 2006, whichever is earlier.

III. <u>Metro East Land Acquisition and Preservation and Illinois River Projects</u>

A. Within sixty (60) days after entry of the Consent Decree, and following consultation with Plaintiffs, including on behalf of the State of Illinois, the Illinois Department of Natural Resources, DMG shall submit a plan to the Plaintiffs for review and approval for the transfer of $2.75 million to the Illinois Conservation Foundation, 20 ILCS 880/15 (2004). The funds transferred by DMG to the Illinois Conservation Foundation shall be used for the express purpose of acquiring natural lands and habitat in the St Louis Metro East area, for acquiring and/or restoring endangered habitat along the Illinois River, and for future funding of the Illinois River Sediment Removal and Beneficial Reuse Initiative, administered by the Waste Management Resource Center of IDNR. In addition, to the extent possible, the funding shall be utilized to enhance existing wetlands and create new wetlands restoration projects at sites along the Illinois River between DMG's Havana Station and the Hennepin Station, and provide for public use of acquired areas in a manner consistent with the ecology and historic uses of the area. Further, to the extent possible, the funding shall enable the removal and transport of high quality soil sediments from the Illinois River bottom to end users, including State fish and wildlife areas, a local environmental remediation project, and other projects deemed beneficial by plaintiffs. Any properties acquired through funding of this project shall be placed in the permanent ownership of the State of Illinois and preserved for public use by IDNR.

B. The proposed plan shall satisfy the following criteria:

1. Describe how the work or project to be performed is consistent with requirements of Section III. A., above.
2. Include a schedule for completing the funding of each portion of the project.
3. Describe generally the expected environmental benefit for the project.

C. Performance - Upon approval of plan by the Plaintiffs, DMG shall complete the mitigation project according to the approved plan and schedule, but no later than December 31, 2007.

IV. <u>Vermilion Power Station Mercury Control Project</u>

A. Within sixty (60) days of entry of the Consent Decree, DMG shall submit a plan to the Plaintiffs for review and approval for the performance of the Vermilion Power Station Mercury Control Project. The project will result in the installation of a baghouse, along with a sorbent injection system, to control mercury emissions from Vermilion Units 1 and 2, with a goal of achieving 90% mercury reduction. For purposes of the Consent Decree, of the approximately $26.0 million expected capital cost for construction and installation of the baghouse with a sorbent injection system, DMG shall be deemed to have expended $7.5 million Project Dollars upon commencement of operation of this control technology, provided that DMG continues to operate the control technology for five (5) years and surrenders any mercury allowances and/or mercury reduction credits, as applicable, during the five (5) year period. DMG shall complete construction and installation of the baghouse with a sorbent injection system, and commence operation of such control device, no later than June 30, 2007.

B. The proposed plan shall satisfy the following criteria:

1. Describe how the work or project to be performed is consistent with requirements of Section IV. A., above.
2. Include a general schedule and budget for completion of the construction of the baghouse and sorbent injection system, along with a plan for the submittal of periodic reports to the Plaintiffs on the progress of the work through completion of the construction and the commencement of operation of the baghouse and sorbent injection system.
3. The sorbent injection system shall be designed to inject sufficient amounts of sorbent to collect (and remove) mercury emissions from the coal-fired boilers and to promote the goal of achieving a total mercury reduction of 90%.
4. DMG shall not be permitted to benefit, under any federal or state mercury cap and trade program, from the operation of this project before June 30, 2012 (if such a cap and trade system is legally in effect at that time). Specifically, DMG shall not be permitted to sell, or use within its system, any mercury allowances and/or mercury reduction credits earned through resulting mercury reductions under any Mercury MACT rule or other state or federal mercury credit/allowance trading program, through June 30, 2012.
5. From July 1, 2007 through June 30, 2012, DMG shall surrender to EPA any and all mercury credits/allowances obtained through mercury reductions resulting from this project.
6. DMG shall provide the Plaintiffs, upon completion of the construction and continuing for five (5) years thereafter, with semi-annual updates documenting: a) the mercury reduction achieved, including summaries of all mercury testing and any available continuous emissions monitoring data; and b) any mercury allowances and/or mercury reduction credits earned through resulting mercury reductions under any Mercury MACT rule or other state or federal mercury credit/allowance trading program, and surrender thereof. DMG also shall make such semi-annual updates concerning the performance of the project available to the public. Such information disclosure shall include, but not be limited to, release of semi-annual progress reports clearly identifying demonstrated removal efficiencies of mercury, sorbent injection rates, and cost effectiveness.
7. Describe generally the expected environmental benefit for the project.

C. Performance - Upon approval of plan by the Plaintiffs, DMG shall complete the mitigation project according to the approved plan and schedule.

V. Municipal and Educational Building Energy Conservation & Energy Efficiency Projects

A. Within one hundred thirty five (135) days after entry of the Consent Decree, DMG shall submit a plan to Plaintiffs for review and approval for the completion of the Municipal and Educational Building Energy Conservation & Energy Efficiency Projects, as described herein. DMG shall spend no less than $1.0 million Project Dollars for the purchase and installation of environmentally beneficial energy technologies for municipal and public educational buildings in the Metro East area or the City of St. Louis.

B. The proposed plan shall satisfy the following criteria:

1. Describe how the work or project to be performed is consistent with requirements of Section V. A., above.
2. Include a general schedule and budget (for $1.0 million) for completion of the projects.
3. Describe generally the expected environmental benefit for the project.

C. Performance - Upon approval of plan by the Plaintiffs, DMG shall complete the mitigation project according to the approved plan and schedule, but no later than December 31, 2007.