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Colorado Department of Public Health and Environment

NOTICE OF FINAL ADOPTION

PURSUANT to the provisions of sections 25-7-105(1), 109, and 1002 C.R.S. of the Colorado Pollution Prevention and Control Act.

NOTICE IS HEREBY GIVEN that after a public rulemaking hearing was held on April 19, 2001, and in compliance with the requirements of sections 25-7-105(1), 109, and 1002 C.R.S., the Colorado Air Quality Control Commission made revisions to:

"Class I Visibility Protection Element of the State Implementation Plan".

The amendments adopted by the Commission incorporate the requirements of a federal consent decree that will limit the emissions of sulfur dioxide, oxides of nitrogen, and particulate matter – ten microns and less. The amendments adopted by the Commission represent reasonable progress toward achieving the goal of Section 169(a) of the federal Clean Air Act and resolve the Certification of Visibility Impairment asserted by the U.S. Forest Service for the Mount Zirkel Wilderness Area.

Dated this 20th day of June, 2001 at Denver, Colorado.

COLORADO AIR QUALITY CONTROL COMMISSION

Douglas A. Lempke

Douglas A. Lempke, Administrator

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LONG-TERM STRATEGY REVIEW AND REVISION OF COLORADO'S STATE IMPLEMENTATION PLAN FOR CLASS I VISIBILITY PROTECTION

PART I: HAYDEN STATION REQUIREMENTS

COLORADO DEPARTMENT OF
PUBLIC HEALTH AND ENVIRONMENT

AUGUST 15, 1996

PREPARED BY:

COLORADO AIR POLLUTION CONTROL DIVISION
TECHNICAL SERVICES PROGRAM
VISIBILITY, RESEARCH, AND QUALITY ASSURANCE UNIT

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ABBREVIATIONS AND ACRONYMS

1977 CAAA	1977 Clean Air Act Amendments
AQRVs	Air Quality Related Values. A feature or property of a Class I Federal area other than visibility that may be affected by air pollution. General categories of AQRVs include odor, flora, fauna, soil, water, geologic features, and cultural resources.
ARS	Air Resource Specialists, Inc.
BACM	Best Available Control Measure
BART	Best Available Retrofit Technology
Atmospheric Extinction	Atmospheric extinction is a measure of the level of light scattering and absorption by particulates and gases in the atmosphere.
BLCA	Black Canyon of the Gunnison National Monument
BLM	U.S.D.I. Bureau of Land Management
Class I	Class I Federal areas are congressionally designated large national parks and wilderness created as of August 7, 1977
Commission	Colorado Air Quality Control Commission
C.R.S.	Colorado Revised Statutes

Division	Colorado Air Pollution Control Division
EDF	Environmental Defense Fund
EPA	U.S. Environmental Protection Agency
FIP	Federal Implementation Plan
FLM	Federal Land Manager (USFS, NPS, BLM, USF&WS)
FPM	Fine Particle Mass or portion of the mass which is under 2.5 microns in diameter
GRSA	Great Sand Dunes National Monument
Hayden Settlement	A comprehensive "global settlement" between the owners of the Hayden Generating Station, the Sierra Club, the State of Colorado, and the EPA/Dept. Of Justice concerning Sierra Club's lawsuit against Hayden, the State's ongoing visibility regulatory process, and EPA's Notice of Violation against Hayden. The set of emission reductions (particulate, sulfur dioxide, and nitrogen oxides) are also intended to address acid deposition concerns. The Consent Decree was signed by all parties and filed with the federal district court on May 22, 1996.
IMPROVE	Interagency Monitoring of PROtected Visual Environments. A visibility monitoring program for national parks, wilderness', and wildlife refuges.
IMPROVE Protocol	Visibility monitoring sites operated according to IMPROVE protocols for data comparability
IWAQM	Interagency Workgroup on Air Quality Modeling
LTS	Long-Term Strategy
MEVE	Mesa Verde National Park
MOU	Memorandum of Understanding
MOU Study	Mt. Zirkel Visibility Study
Smoke MOU	Colorado Smoke Management Memorandum of Understanding
Zirkel MOU	Mount Zirkel Reasonable Attribution Study of Visibility Impairment, Memorandum of Understanding
MZVS	Mount Zirkel Visibility Study
MZWA	Mt. Zirkel Wilderness Area
NESCAUM	North Eastern States for Coordinated Air Use Management
NO_x	Nitrogen Oxides
NPCA	National Parks and Conservation Association
NPS	National Park Service
PM_{10}	Particulate matter under 10 microns in diameter
$PM_{2.5}$	Particulate matter under 2.5 microns in diameter
PSD	Prevention of Significant Deterioration
RACM	Reasonably Available Control Measure
ROMO	Rocky Mountain National Park
SNOW	Snowmass/Maroon Bells Wilderness
SIP and Visibility SIP	State Implementation Plan for Class I Visibility Protection

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STAPPA	State and Territorial Air Pollution Program Administrators
SVR	Standard Visual Range
TSC	Technical Steering Committee of the Mount Zirkel Visibility Study
TPY	Tons per year, (tpy)
USFS	U.S.D.A. Forest Service
USF&WS	U.S. Fish & Wildlife Service
USGS	U.S. Geological Survey
WESTAR	Western States Air Resources Council
WEMI	Weminuche Wilderness
WHRI	Snowmass/Maroon Bells Wilderness monitoring site in the White River National Forest
ZIRK	Mt. Zirkel Wilderness

VI. COLORADO'S CLASS I VISIBILITY PROTECTION PROGRAM STATE IMPLEMENTATION PLAN REVISIONS TO THE LONG-TERM STRATEGY, PART I: HAYDEN STATION REQUIREMENTS.

A. PREAMBLE.

The State is conducting its Long-Term Strategy (LTS) review and revision in two phases: the first deals solely with visibility impacts in the Mt. Zirkel Wilderness area (MZWA) from emissions from the Hayden generating station, and the second deals with all other visibility issues in Class I areas in Colorado including other visibility impacts in the Mt. Zirkel Wilderness. This phased approach will allow for an expedited consideration and adoption of Visibility Protection Program State Implementation Plan (SIP) amendments that affect the Hayden generating station only. Timely adoption of these SIP amendments and Environmental Protection Agency (EPA) approval will enable the owners of Hayden to begin activities that will lead to significant reductions at the generating station. Delays in the regulatory process may lead to corresponding delays in the schedule of activities for Hayden. In addition, recently enacted State law exempts specific visibility SIP amendments that implement and enforce control strategies agreed to in a consent decree from legislative review pursuant to Colorado Revised Statutes section 25-7-133. The SIP amendments contained herein that affect the Hayden generating station implement and enforce such a consent decree, and are, therefore, exempt from the provisions of section 25-7-133. At this time, no other potential visibility SIP amendments are exempt from this legislative review. Adopting the visibility SIP amendments for the Hayden generating station separately from the remaining visibility SIP amendments will help avoid confusion during the legislative review process. For these reasons, the State believes it is prudent to phase the LTS revision process. The second part of the revision will be completed by the end of 1996. This LTS SIP revision is Part I: Hayden Station Requirements and replaces the previous existing impairment portion of the LTS as it relates to the MZWA. Below is the SIP revision that contains:

- •An introduction (section VI.B.1.a);
- •Summary of the portions of the Hayden Consent Decree that will be included in the SIP amendment (section VI.B.1.b);
- •Discussion of regulatory tools (section VI.B.1.c);
- •Discussion of reasonable progress and the Hayden requirements (section VI.B.1.d);
- •Discussion of the 6 factors that EPA requires be in a LTS (section VI.B.1.e); and
- •Hayden's requirements including emission limitations and construction schedule (section VI.C).

Sections a through e below are provided for information, context, and explanation only and are not intended to be enforceable parts of the SIP. Section VI.C is intended to be the enforceable part of the SIP revision.

B. NON-ENFORCEABLE PARTS OF THE SIP REVISION.

1. Existing Impairment and the Mount Zirkel Wilderness. The following subsections provide information, context, background, and explanation of the State's positions regarding existing visibility impairment in the Mt. Zirkel Wilderness in relation to the Hayden generating station.

a. Introduction. In July 1993, the U.S.D.A. Forest Service (USFS) certified visibility impairment in the Mt. Zirkel Wilderness area (MZWA) and named the Craig and Hayden coal-fired generating stations as possible contributors to the problem. The State of Colorado has been engaged in a cooperative study (Mt. Zirkel Visibility Study) to provide

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additional information for the State to utilize in determining whether impairment can be reasonably attributed to one or both generating stations. The study was completed on July 15, 1996.

In December 1995, the State, Sierra Club, and the owners of the Hayden generating station entered into negotiations to attempt to resolve Hayden's potential contribution to visibility impairment in the MZWA, Hayden's contributions to acid deposition in MZWA, and a citizen suit brought by the Sierra Club against Hayden for violations of opacity standards. EPA joined these negotiations in January 1996 after issuing a Notice of Violation against Hayden alleging violations of the Clean Air Act. After many hours of negotiations in over 50 separate sessions, Sierra Club, State of Colorado, United States, Public Service Company of Colorado, Salt River Project Agricultural Improvement and Power District, and PacifiCorp reached settlement, and on May 22, 1996, lodged a consent decree with the U.S. District Court for the District of Colorado. This settlement is ground breaking in many respects and addresses additional pollutants on a faster schedule than the August 1991 visibility settlement reached for the Navajo Generating Station. Notice of the Consent Decree has been published in the Federal Register and the public has had an opportunity wholly independent of this SIP revision to comment on the terms of the settlement.

Among other things, the Consent Decree requires the owners of Hayden station to significantly reduce missions of particulates and SO_2. The State believes it is appropriate and necessary to adopt certain parts of the Consent Decree requirements as elements of the Long-Term Strategy component of the Visibility SIP and that the imposition of these requirements represents reasonable progress toward remedying Hayden station's likely contribution to visibility impairment in MZWA.

b. Summary of the Decree. The major provisions of the Hayden Consent Decree that are being incorporated into the Long-Term Strategy are summarized below for information purposes. The actual language from the Decree that is being incorporated as an enforceable element of the SIP is contained in section I.F of this SIP amendment.

(1). SO_2 Emission Limitations. The SO_2 emission limitations will result in at least an 82% reduction in SO_2 from Hayden station. These reductions will reduce visibility problems in the Mt. Zirkel Wilderness as well as in the Yampa Valley. Acid deposition in the area will also be reduced. The Hayden station owners must install a Lime Spray Dryer (LSD) system to meet the emission limitations or switch to natural gas. The following emission limitations shall apply regardless of the fuel used at Hayden:

•no more than .160 lbs SO_2 per million Btu heat input on a 30 boiler operating day rolling average basis (85% reduction from the historic higher values of sulfur in the coal);

•no more than .130 lbs SO_2 per million Btu heat input on a 90 boiler operating day rolling average basis (85% reduction from the historic average values of sulfur in the coal);

•at least an 82% reduction of SO_2 on a 30 boiler operating day rolling average basis (to make sure that substantial reductions occur and that control equipment is run optimally even if lower sulfur coal is used at Hayden Station); and

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•a unit cannot operate for more than 72 consecutive hours without any SO_2 emission reductions; that is, it must shut down if the control equipment is not working at all for 3 days (this is to prevent the build-up of SO_2 emissions that may lead to visibility events).

(ii). Particulate Emission Limitations. The Hayden owners must install and operate a Fabric Filter Dust Collector (known as an FFDC or baghouse) on each unit unless the owners switch to natural gas. Baghouses are extremely effective devices for removing particles from flue gas and should virtually eliminate particulate plumes from the plant.

The existing particulate controls, Electro-Static Precipitators (ESPs), are older systems that do not operate optimally during start-up and shut-down of the plant. Performance also tends to degrade during periods between semi-annual major maintenance. The result has been frequent excursions over the 20% opacity limit and particulate plumes in the Yampa Valley from the power plant. Opacity is a measure of the density of smoke.

The new equipment is intended to eliminate these problems which were largely responsible for the USFS certification of visibility impairment and the State's continuing regulatory process regarding visibility impairment in the Mt. Zirkel Wilderness. Particulate emission limitations for each unit are:

•0.03 lbs of primary particulate matter per million Btu heat input; and

•20.0 % opacity, as averaged over each separate 6-minute period within an hour as measured by continuous opacity monitors.

(iii). Compliance with Emission Limits. All controls required by the Decree shall be designed to meet enforceable emission limits. Compliance with the SO_2, NOx, and opacity emission limits shall be determined by continuous emission monitors.

(iv). Hayden's Decision on Coal vs Natural Gas. No later than 180 days after the Hayden owners signed the Decree, they must notify the other parties (Sierra Club, State of Colorado, EPA) regarding their decision as to whether to continue using coal as the primary fuel at Hayden station or switch to natural gas. This notification must occur no later than November 17, 1996.

(v). Schedule --Coal as Primary Fuel. Should the owners of Hayden elect to continue to burn coal, the schedule for constructing control equipment and meeting the emission limitation deadlines is very rapid for a power plant retrofit. The Consent Decree contains force majeure provisions. If a force majeure event is determined to occur under terms of the Decree, this could affect the schedule and compliance dates.

Schedule for Unit 1:

-Commencement of physical, on-site construction of control equipment by 6/30/97.

-Commence start-up testing of FFDC and SO_2 control equipment by 12/31/98.

Schedule for Unit 2:

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-Commencement of physical, on-site construction of control equipment by 6/30/98.

-Commence start-up testing of FFDC and SO_2 control equipment by 12/31/99.

Emission Limitation Compliance Dates for SO_2:

-For Unit 1, within 180 days after flue gas is passed through the SO_2 control equipment, or by July 1, 1999, whichever date is earlier.

-For Unit 2, within 180 days after flue gas is passed through the SO_2 control equipment, or by July 1, 2000, whichever date is earlier.

Emission Limitation Compliance Dates for Particulates:

-For Unit 1, within 90 days after flue gas is passed through the FFDC control equipment, or by April 1, 1999, whichever date is earlier.

-For Unit 2, within 90 days after flue gas is passed through the FFDC control equipment, or by April 1, 2000, whichever date is earlier.

(vi). Schedule –Natural Gas as Primary Fuel. Should the owners of Hayden elect to switch to natural gas, the following schedule and emission limitation compliance dates apply:

Schedule for Unit 1 & Unit 2:

-Initiate permitting activities for construction of natural gas pipeline by 10/30/96

-Complete construction of pipeline and Hayden boiler modifications and commence use of natural gas as primary fuel source by 12/31/98

Emission Limitation Compliance Date for SO_2 and Particulate:

-February 1, 1999 or 30 days after the owners of Hayden commence use of natural gas as the primary fuel source.

(vii). Force Majeure. The Consent Decree contains force majeure provisions. A "force majeure event" is narrowly defined, and can only be the basis for an excused delay in meeting construction deadlines or emission limitation compliance deadlines in limited circumstances. In this SIP, the force majeure provisions of the Consent Decree referred to may impact the construction schedule and emission limitation compliance deadlines. A determination that the SIP revisions that incorporate the relevant provisions of the Consent Decree demonstrate reasonable progress toward the national visibility goal is not compromised, however, by the inclusion of the force majeure provisions into the SIP. The Division believes that the parties to the Consent Decree do not anticipate nor intend that a force majeure event will be used to significantly delay the construction and compliance deadlines in the Consent Decree and in this SIP. The Consent Decree provides that if a force majeure event may delay compliance by the owners of Hayden with the terms of the Consent Decree for more than six months, then the Division, EPA or the Sierra Club may seek further relief from the Court to fulfill the purposes of the Consent Decree. To help ensure that reasonable progress continues to be made, the Division and the Commission commit to reopen the SIP as soon as possible after it is determined that a construction schedule or an emission limitation schedule has been or will be, delayed by 12 months as a result of a force majeure determination. The SIP will be reevaluated at that time to determine whether revisions are necessary to continue to demonstrate reasonable progress, including revisions that adopt new construction or compliance deadlines. In addition,

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the SIP also contains a clarification that the force majeure provisions referred to in the SIP are not to be construed to authorize or create any preemption or waiver of the requirements of State or federal air quality laws, or of the requirements contained in the SIP or the Consent Decree.

c. Regulatory Tools. Federal and state law provide the air quality regulator with specific tools for addressing an existing stationary facility's emissions in the context of a specific certification of visibility impairment of a Class I area. The Division may reasonably attribute (RA) visibility impairment to the Hayden and/or Craig power stations if there is evidence that either one contributes to any visibility impairment in the Mt. Zirkel Wilderness. If impairment is attributed to an existing stationary facility the Division must analyze for BART and determine what, if any, are appropriate emission reductions. The facility(s) must then reduce their emissions accordingly. The State has worked collaboratively with stakeholders in the Mt. Zirkel Visibility Study to assemble additional information that could be used for regulatory decision-making and laid out a time-table for the decisions. However, the Hayden settlement has changed the State's approach (RA/BART approach) toward resolving the USFS certification as it affects Hayden station.

The owners of Hayden station have voluntarily agreed, through a court enforceable Consent Decree, to reduce emissions to such a degree that, in the Division's technical judgment, any possible contributions to visibility impairment in MZWA by Hayden will be reduced to below humanly perceptible levels. The State believes this level of improvement represents the overarching requirement of reasonable progress toward the national visibility goal as it relates to Hayden and MZWA. Continuation of the regulatory process to make a reasonable attribution decision and to conduct BART analyses has therefore become moot and would result in an inefficient use of state, federal, and private resources. In this circumstance, the need to use the RA/BART approach no longer exists. However, it is appropriate and necessary to adopt the relevant requirements of the Consent Decree into the LTS portion of the Visibility SIP.

d. Reasonable Progress and the Hayden Requirements. Section 169(A) of the federal Clean Air Act establishes a national visibility goal, not an air quality standard or specific emission standard. While the objective, over time, is to achieve the goal, the mandate is to make reasonable progress. In determining reasonable progress, the State must consider 1) the costs of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts of compliance; and 4) the remaining useful life of the source. The State also believes that inherent in the concept of reasonable progress is a demonstration that the steps taken are anticipated to result in visibility benefits. Each of the reasonable progress considerations and visibility benefits from the Hayden requirements, as embodied in this SIP revision, are briefly discussed below.

(I). Cost of Compliance. By signing the Consent Decree, the Hayden owners have demonstrated their willingness to bear the cost to retrofit the power station or convert it to natural gas. The Division concludes that the cost of the equipment or conversion will increase the cost of production of kilowatts at Hayden generating station and appears to be within the range of costs compared to retrofits at other facilities. However, the Division had difficulty finding studies that contained information that was completely comparable to the Hayden situation. It is also important to recognize that neither the Consent Decree, nor the State through this SIP revision, dictates that the source continue to burn coal or switch to natural gas. The Hayden owners retain the discretion to make this choice and presumably will evaluate cost as one factor in making their choice. Instead of dictating fuel choice, the Consent Decree and this SIP revision establish emission limits which are expected to resolve Hayden's likely contribution to visibility impairment in the MZWA. For the coal option, lime spray dryer technology was selected to address SO_2 emissions because it could achieve the emission limits, is compatible with baghouses, and has reasonable costs. Thus, the State believes that the selection of this specific technology is appropriate to ensure emission limitations will be met if coal continues to be burned at Hayden station. The Division presents the following additional points and information regarding cost:

•*Hayden is willing to pay.*

Through voluntarily signing the Consent Decree, the owners of the Hayden station have demonstrated that they are willing to bear the cost to retrofit the power plant or convert it to natural gas. The retrofit or conversion is not contingent on Public Utility Commission approval of Hayden being able to pass the cost into its rate base, therefore, whether or not the owners of Hayden are able to get approvals from the Public Utility Commission to pass the costs along to the owners' customers, the retrofit or conversion will proceed.

•*Cost of a retrofit estimated by Public Service Company of Colorado.*

The operators of Hayden station (Public Service Company of Colorado) have indicated in a letter to the Division dated June 14, 1996[1] that the estimated capital cost in 1996 dollars of installing baghouses to control particulate and lime spray dryers to control SO_2 would be approximately $121 million. (This does not include the NOx equipment because NOx emissions are not believed to influence visibility in the MZWA. NOx controls are designed to reduce acid deposition in the area). Total levelized annual cost of a retrofit, in 1996 dollars, would be approximately $22.8 million (includes the cost of capital, operating, maintenance, parts, personnel, energy use, water, and waste disposal). Capital cost for the LSDs (both units) is estimated at $41.4 million. The capital cost of the FFDCs (both units) is estimated to be $79.5 million. Division staff have reviewed these cost estimates and have not found any reason to question their validity.

•*Cost of a conversion to natural gas unknown at this time – retrofit costs will serve as upper boundary of cost.*

The cost of switching the plant to natural gas is not known at present and is the subject of study by the owners of Hayden who must determine, within 180 days of signing the Consent Decree, whether to continue with coal or switch to natural gas. The Division does not currently have information about the cost of a natural gas conversion and operation of the plant on this fuel. However, in terms of evaluating the agreement's cost, the Division feels comfortable using available information for a coal retrofit. The rationale is that if natural gas is more expensive, it is unlikely that the Hayden owners will switch fuels, in which case the use of retrofit data in this context is appropriate. If natural gas is less expensive and Hayden switches, then this analysis serves as an upper bound of the cost of the requirements. Hayden station will be able to meet the emission limitations with either fuel.

•*Division estimate of cost to the average customer of PSCo is less than that resulting from a recent visibility protection settlement.*

If Public Service Company were allowed by the Public Utilities Commission to pass the cost of this investment into its rate base, the Division estimates that an investment by Public Service Company of Colorado in pollution control equipment of $120 million would result in a rate increase of approximately 1.42% or an increase to the average household electric bill of $0.58/month[2]. As a comparison, the EPA estimated that the cost of SO_2

[1] Letter from Steve Dayney, Public Service Company of Colorado, to Dan Ely, Colorado Department of Public Health and Environment, Air Pollution Control Division, June 14, 1996.

[2] Memorandum from Stacie Nutt, Colorado Air Pollution Control Division, to Dan Ely, Air Pollution Control Division, June 6, 1996.

control for visibility protection purposes at the Navajo Generating Station (SO_2 only) would increase by $1.72/month the electric bill of the average Salt River Power customer in 1992 dollars[3]. Thus, the potential rate-based cost to customers of PSCo for the Hayden station retrofit, which includes both SO_2 and particulate controls, is expected to be far less per customer than that of the Navajo Generating Station retrofit.

•*Cost of a retrofit in $/yr, $/ton, and $/MWh (megawatt-hour) as estimated by Public Service Company of Colorado.*

Public Service Company (PSCo) has indicated (in a letter previously cited) that the retrofit cost in $/year, $/ton, and $/MWh are as follows:

	$/yr	$/ton	$/MWh
Unit 1 FFDC	$5,130,022	$102	$3.96
Unit 2 FFDC	$6,720,779	$99	$3.76
Unit 1 SO_2	$10,137,216	$2083	$7.82
Unit 2 SO_2	$12,723,188	$1930	$7.12

PSCo notes that the SO_2 removal costs include both the FFDC and the LSD as both are required to obtain SO_2 control. The Division believes it is valid to look at the baghouse and lime spray dryer together for the purpose of an integrated pollution control system that reduces particulate and SO_2. However, fully adding in the cost of the FFDC to the cost of the lime spray dryer to estimate SO_2 removal costs appears to the Division to double-count the cost of the FFDC. The FFDC is necessary to meet particulate and opacity limits and the Division does not believe its full cost should be included in the cost of SO_2 control at Hayden but acknowledges that there are varying approaches to analyze costs.

•*Division's estimate of cost per ton removal of SO_2 at Hayden.*

The Division believes a levelized annual cost of $11.255 million/year for SO_2 removal for Hayden is reasonable, recognizing that there is no one method for factoring in the role of the particulate removal system as it relates to costs of SO_2 removal. The Division's estimate includes the levelized annual cost of the LSDs ($10.07 million[4]) plus 10% of the cost of the FFDC ($1.185 million). The Division believes this 10% represents a reasonable apportionment to SO_2 reductions from the FFDC. Under this assumption, the cost per ton of SO_2 removed is approximately $799/ton/year in 1996 dollars ($11.255 million/(16,000 tpy x 88% removal =14,080 tpy) = $799/ton/year). Not included in these costs is the portion of the control costs that the owners of Hayden will be able to recoup by the sale of marketable allowances of SO_2 which it will receive as part of the allowance trading program under the Clean Air Act's acid rain provisions.

•*EPA study of SO_2 retrofit costs (both capital and $/ton) and comparisons to Hayden.*

A 1991 EPA modeling study[5] estimated the retrofit costs for SO_2 control at 200 coal-fired electric utilities (630 boilers) and specifically evaluated the cost of lime spray drying. The 50th percentile capital cost was estimated (in 1988 dollars) to be $150/kW. Adjusted for a plant of Hayden's size, this translates into $67.5 million capital cost ($150 x 440,000 kW) in 1988 dollars. PSCo has estimated the capital cost of SO_2 equipment for

3 "Approval and Promulgation of Implementation Plans: Revision of the Visibility FIP for Arizona," October 3, 1991, 56 Federal Register, 50178.

4 E-mail from Steve Dayney, Public Service Company of Colorado, to Dan Ely, Colorado Department of Public Health and Environment, Air Pollution Control Division, "Hayden SO2 Costs LSD only," June 24, 1996.

5 "Project Summary: Retrofit Costs for SO_2 and NOx Control Options at 200 Coal-Fired Plants," EPA/600/S7-90-021, March 1991.

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Hayden will be $41.4 million in 1996 dollars. The EPA study also estimated the $/ton removed of SO_2. The 50th percentile cost (in 1988 dollars) was approximately $700/ton. The estimate included the cost of capital, operating, maintenance, personnel, land, waste disposal, and energy. The Division's estimate for Hayden is $799/ton in 1996 dollars. Assuming a 3% inflation rate applied to the EPA number to make it more comparable to 1996 costs, yields a value of $887/ton -- more than the estimate for Hayden. However, the Division believes the EPA estimate to be high because EPA evidently included all or part of the cost of FFDC units on particular boilers for estimating the cost of SO_2 control with lime spray dryers if reuse of ESPs was not considered feasible (168 out of 630 boilers). Therefore, 50th percentile costs from the EPA study presented above include some particulate device control cost as well.

•*EPA's draft BART analysis of the cost of Navajo Generating Station's SO_2 control.*

EPA's draft BART analysis for the Navajo Generating Station[6], in Table 4 of the analysis, provides estimates of the $/ton removal of SO_2 from various control options (e.g., wet scrubbing, lime spray dryer, dry sorbent injection). The $/ton range from $1626 to $3611/ton/year depending on the assumptions, level of removal, and type of control system. This is much higher than the Division's estimates of $799/tpy for Hayden, although similar to PSCo's estimates of SO_2 removal (approximately $2000/tpy) that include the full cost of the FFDC. EPA's analysis does include FFDCs in costing the LSD option for Navajo Generating Station because the station would need to build baghouses to utilize a LSD. EPA's cost estimate is between $2402/tpy and $3611/tpy for a LSD/FFDC combination.

•*PSCo's estimate of cost per ton removal of particulate at Hayden station.*

In evaluating the cost element, it is important to recognize that baghouses, in addition to addressing Hayden station's contribution of particulates to visibility impairment in the MZWA, also will rectify Hayden's difficulty complying with State and Federal opacity limits. In the Sierra Club's lawsuit against Hayden station for opacity violations, the Sierra Club was seeking an injunction to require the Hayden owners to install baghouses. One could argue that if baghouses were already necessary to address opacity issues, the cost of the settlement for visibility purposes should only consider the cost of the LSDs. However, the Division believes it is appropriate to consider the cost of baghouses in the context of making reasonable progress because of the near certainty these controls bring to eliminating particulate plumes from Hayden station that may enter the MZWA. Hayden station, with a baghouse on each unit, is expected by PSCo to remove greater than 99% of particulate. PSCo estimates the cost (in a letter cited earlier) per ton of particulate removed at approximately $100/ton/year.

•*Division estimates of FFDC cost using EPA spreadsheets.*

EPA has developed a set of spreadsheets (COST-AIR) for estimating the cost of various air pollution control options. The Division attained the spreadsheet for fabric filters and estimated the cost of FFDCs at Hayden. The Division's estimate of capital costs of $29.6 million for Unit 1 and $42.9 million for Unit 2 are within about 10% of PSCo's estimates above[7]. The spreadsheet also outputs the cost per ton removed. The Division's estimates for Hayden Unit 1 are $92/tpy (compared to PSCo's estimate of $102/tpy) and $81/tpy for Unit 2 (PSCo's estimate is $99/tpy).

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[6] "Best Available Retrofit (BART) Analysis for the Navajo Generating Station in Page, Arizona," EPA Contract No. 68-02-4400, William R. Barnard, E.H. Pechan and Associates, Inc., prepared for the U.S. EPA, January 31, 1990.

[7] Memorandum from Gary Kenniston, Colorado Air Pollution Control Division, to Dan Ely, Air Pollution Control Division, Cost estimates for FFDC and spray dryer installation at Hayden SEGS, July 22, 1996.

The Division's and PSCo's estimated cost of SO_2 and particulate emission reductions appear to be lower or similar to estimates for other projects or for this project using alternative methods. The State concludes, therefore, that the cost of SO_2 and particulate emission reductions is reasonable.

(ii). Time Necessary for Compliance. If the owners of Hayden elect to continue using coal as their primary fuel, start-up testing of the FFDC and SO_2 control equipment would occur by 12/31/98 for Unit 1 and by 12/31/99 for Unit 2. If the owners elect to burn natural gas as their primary fuel, they will begin doing so by 12/31/98. Under the terms of the Consent Decree, approximately 2½ to 3½ years would elapse between the filing of the Decree and conversion to natural gas or operation of the control equipment, respectively. In comparison, assuming the Division went through a complete RA/BART process with the Hayden facility, which would take at least an additional 6 months, and further assuming there are no challenges to the decision, BART regulations (AQCC Regulation #3, Part B, XI.D.2) require that a facility that has received a BART permit from the Division "shall install and operate BART as expeditiously as practicable but in no case later than 5 years after permit issuance." Under this scenario the Division estimates that the time until installation of control equipment could be up to 5½ years -- longer if there were administrative and/or court appeals of agency decision-making. The State believes that the Hayden settlement offers particulate and SO_2 reductions on a more rapid timetable than would likely be achievable through a possibly controversial RA/BART process. The terms of the Hayden settlement, as embodied in this SIP revision, will also result in emission reductions much more rapidly than in the Navajo Generating Station visibility settlement and Visibility Protection Program Federal Implementation Plan (FIP). The FIP, which was promulgated on October 3, 1991, allowed until November 1997, November 1998, and August 1999 for installation of SO_2 controls on the three Navajo units.

(iii). Energy and Non-Air Quality Environmental Impacts.

•Natural gas.

If natural gas is chosen by the owners of Hayden as the primary fuel, the owners will have to initiate permitting, design, and construction activities for a natural gas pipeline. It is unknown at this time what the scale (i.e., number of miles, need for development of new gas fields) of this would be. However, in a generic sense, the construction of a pipeline will always cause disturbances. These disturbances and other issues would have to be addressed during permitting. The Division is aware of controversy over oil and gas leasing and proposed development on BLM lands in southwestern Wyoming and parts of northwestern Colorado ("South Baggs") and is uncertain as to whether and how ongoing delivery of natural gas to Hayden would be affected by this controversy. The Division also has no definitive information that would indicate that there are impacts to the nation's or region's energy supply associated with the use of natural gas at Hayden station. Compared to coal, there are fewer non-air quality impacts from the burning of natural gas as a fuel. For example, there is no ash or other solid waste for disposal.

•Coal.

Assuming coal is continued as the primary fuel, the impacts include:

•Energy. PSCo estimates that the use of baghouses and lime spray dryers, due to energy needs to run these systems, will decrease the plant output by 1.1%. In the Division's judgment this is a reasonable estimate and similar to those found in EPA's BART analysis for the Navajo Generating Station (cited earlier).

•Water. A lime spray dryer system requires water in order to operate. EPA's BART Guidelines[8] indicate the requirements for a lime spray dryer to be approximately .8 gallons per minute per megawatt. Assuming the Hayden facility was running at full capacity year-round, an additional 185 million gallons/year would be required. Similarly, PSCo estimates that at 80% capacity, the water use would be 544 acre feet to run the lime spray dryer (177 million gallons/year). Of that amount, 477 acre feet will come from reusing water in evaporation ponds. The Division understands that the additional water (67 acre feet) will be from existing water rights currently owned by Hayden. This additional water use would represent a commitment of water rights from the Yampa River.

•Ash and Sludge. In a spray-drying system, a fine spray of alkaline solution is injected into the flue gas stream as it passes through a contact chamber, where the reaction with the SO_2 occurs. The heat from the flue gas evaporates the liquid from the absorbent solution, leaving a dry powder, which is then collected by the particulate control device (baghouse). In addition to coal ash in the baghouse, the lime spray dryer will add spent reagent plus unreacted absorbent. Typically these have a low solubility and are not considered an environmental disposal problem[9]. Two additional studies indicate that the residuals from lime spray dryers are considered to be safe and that the toxicity of the residues are well below the Extraction Procedure (EP) toxicity limits[10] [11]. EP limits are established under the current Resource Conservation and Recovery Act regulations (40 CFR 261.24). Finally, Public Service Company (in a previously cited letter of June 14, 1996) states,

> Hayden is a zero discharge unit and thus does not have a river water discharge. The LSD will not affect the zero discharge and will not have off-site disposal of a new liquid waste.
>
> A LSD changes the solid waste stream that will be collected from the FFDC. The SO_2 in the flue gas reacts with the hydrated lime to form calcium/sulfur compounds. The calcium/sulfur compounds, unreacted reagent, and flyash will be collected from the FFDC and disposed of in the current landfill located near the plant. It is not expected that any major changes to the current solid waste disposal practices will be required. While no changes to the disposal method are planned, the quantities of waste generated will be increased. Without LSD operation approximately 118,000 tons per year of solid waste is generated from both units. After the LSD installation is in operation, it is estimated that 160,500 tons of solid waste will be generated resulting in a 36% increase in solids requiring disposal.

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[8] "Guidelines for Determining Best Available Retrofit Technology for Coal-Fired Power Plants and Other Existing Stationary Sources," United States Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711, EPA-450/3-80-009b, November 1980.

[9] Report to Congress: Wastes from the Combustion of Coal by Electric Utility Power Plants, EPA/530-SW-88-022A, Feb., 1988.

[10] "Evaluation of a 2.5-MW Spray Dryer/Fabric Filter SO2 Removal System," EPRI/65-7449, Project 1870-3, August 1991, p. 9-61.

[11] "Physical-Chemical Characteristics of Utility Solid Wastes," Tetra Tech Inc., EPRI EA-3236, September 1983.

Overall, it is the Division's judgment that either natural gas or coal and associated control systems will produce some non-air quality environmental impacts yet either choice would result in an overall acceptable level of environmental quality. Also, the USFS believes that because the Hayden settlement will lead to reductions of both SO_2 and NOx emissions, positive environmental impacts to the aquatic ecosystems in the MZWA will result[12].

(iv). Remaining Useful Life of the Source. An official with PSCo stated[13], "The remaining useful life of Hayden is contingent on its continued economic competitiveness in a deregulated marketplace in addition to technical and operational considerations. Given that the investments are made in pollution controls or natural gas conversion and the plant remains competitive in the market place, Public Service Company anticipates a useful life of Hayden station on the order of 20 years." It is the Division's technical judgment that given the overall competitive position of Public Service Company in the region[1], the typical current projected life of electric generating stations[14], and past representations of the remaining life of Hayden station made by PSCo[15], an estimate of at least 20 years remaining useful life of the Hayden station is reasonable regardless of the fuel chosen. Given the expected remaining useful life of the station, a retrofit or conversion of this magnitude is reasonable.

(v). Visibility Benefits and Level of Emission Reduction.

•Visibility Benefits. Any contributions to visibility impairment in the Mt. Zirkel Wilderness caused by or contributed to by the Hayden power station would come from 1) primary particulate plumes; and/or 2) a locally generated sulfate haze. Based on the Division's technical judgment, experience with information generated regarding the operation of Hayden station, and findings of the Mt. Zirkel Visibility Study[16] (e.g., pages 5-57, 5-61, 5-62 and Table 5.5.1) there is close correspondence between occasions when particulate plumes are clearly visible from the Hayden station and malfunctions with its existing Electro-Static Precipitators. The conversion of the station to natural gas or use of baghouses will virtually eliminate particulate plumes coming from Hayden that may enter the Mt. Zirkel Wilderness. With regard to locally generated sulfate hazes, the Division's technical judgment is that removing at least 82% of the 1995 inventory of 16,000 tons/year of SO_2 will effectively address visibility problems in the MZWA caused by SO_2 from Hayden and will lower the threshold of SO_2 emissions from the plant to below perceptible levels in the Wilderness. There is also evidence in the Mt. Zirkel Visibility Study that eliminating Hayden's SO_2 emissions (which the settlement, as embodied in this SIP revision, nearly accomplishes) would result

12 Letter from Elizabeth Estill, Regional Forester, Rocky Mountain Region, U.S.D.A. Forest Service, to Margie Perkins, Director, Colorado Air Pollution Control Division, July 10, 1996.

13 Personal communication between Steve Dayney, Public Service Company of Colorado, and Dan Ely, Colorado Department of Public Health and Environment, July 17, 1996.

14 Personal communication with Jim Geier, Colorado Air Pollution Control Division, and Dan Ely, Colorado Air Pollution Control Division, July 18, 1996.

15 See Public Service Company of Colorado, *1994 Annual Report*, regarding the Hayden power plant the Company indicates that Unit 1 has a remaining life of 20 years and Unit 2 has a remaining life of 31 years.

16 Watson, John G., Blumenthal, Donald L., et. al., *Mt. Zirkel Wilderness Area Reasonable Attribution Study of Visibility Impairment, Volume II: Results of Data Analysis and Modeling, Final Report*, prepared for Technical Steering Committee, c/o Colorado Department of Public Health and Environment, Air Pollution Control Division, Denver, CO, July 1, 1996.

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in a change in visibility in the MZWA that would be perceptible (e.g., pages 6-74, 6-106, 6-147, 6-148, 6-167, 6-168, 6-171, 7-4, 7-9, 7-10, 7-15, 7-16, 7-17). The Division recognizes that regional haze from outside Colorado and emissions from other sources within Colorado may also be contributing to visibility impairment at MZWA.

•Level of Emission Reductions. The Division believes the level of particulate reduction at Hayden is appropriate and bases this conclusion in part on an examination of levels of control required of the most recently permitted coal-fired utilities in Colorado. For example, unit #3 of the Craig station (Craig, CO) and the Rawhide station (Fort Collins, CO) underwent PSD permit reviews and BACT determinations for particulate. The emission limit for each station is 0.03 lbs per million Btu heat input -- the same as required for the Hayden retrofit/conversion. The Division believes the SO_2 emission limits for unit #3 of Craig and Rawhide also show that Hayden's emission limits are what is generally required for new sources. Craig's requirement is a 70% reduction, while Rawhide's is 80%. Hayden's emission limits were established by reducing by 85% the sulfur content in its coal.

(vi). Reasonable Progress. The State believes that the terms of this SIP revision represent reasonable progress toward the national visibility goal with respect to Hayden station. The requirements will produce significant emission reductions that are expected to effectively eliminate the visibility impairment in the MZWA that could be associated with the Hayden station. The associated costs, non-air quality environmental impacts, and energy impacts appear to be reasonable given the remaining useful life on the facility. The SIP will produce reductions of visibility impairing pollutants at Hayden Station at a reasonable cost, years before similar reductions would likely occur through reasonable attribution and BART determinations. The emission limitations for Hayden for SO_2 and particulate, reached through a negotiation process involving a number of parties, are similar to or more stringent than those imposed on units subject to PSD regulations (e.g., Craig Unit 3 and Rawhide Energy Station). The State believes that the Hayden settlement, as embodied in this SIP revision, by remedying Hayden's contribution to visibility impairment in the MZWA expeditiously, at a reasonable cost, and without undue non-air environmental or energy impacts, brings more "reasonable progress" to the Mt. Zirkel Wilderness than could be achieved through other means. The Division recognizes that regional haze from outside Colorado, emissions from sources outside Colorado, and emissions from other Colorado sources could also be contributing to visibility impairment in the MZWA.

The State believes the Hayden settlement effectively closes-out and resolves the certification of impairment brought by the USFS in relation to Hayden station. The State is joined in this conclusion by the USFS -- the manager of the Mt. Zirkel Wilderness. The Division on June 24, 1996 received a letter from the USFS Regional Forester, Elizabeth Estill. The USFS formally certified visibility impairment at MZWA in 1993 and now concludes:

> The Consent Decree recently developed by the State, EPA, Sierra Club, and Public Service company (sic) will result in significant emissions reductions at the Hayden Station. It is our opinion that the magnitude of the emission reductions for particulates and sulfur dioxide contained in the Consent Decree should effectively address the concerns of visibility impairment we had with this facility. The

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emission reductions should eliminate Hayden's contribution to visibility impairment to below a perceptible threshold[17].

e. The Six Factors. EPA regulations (C.F.R. 51.302(c)(2)) require the State to consider, at a minimum, six factors when developing a LTS. Because part I of this LTS SIP revision process is focused entirely on the Hayden requirements that resulted from the negotiated settlement, some of the six factors are not applicable. Each factor is discussed individually below:

(i). Ongoing Air Pollution Programs. This factor is not applicable in the context of requirements for Hayden station. It will be considered in part II of the LTS review/revision process.

(ii). Smoke Management Practices. This factor is not applicable in the context of requirements for Hayden station. It will be considered in part II of the LTS review/revision process.

(iii). Additional Emission Limitations and Schedules for Compliance. The Division was on-track to determine reasonable attribution and perhaps BART for the Hayden station. Because a settlement, embodied in a Consent Decree, was reached that established limits that are expected to eliminate Hayden station's contribution to visibility impairment in MZWA, the need to proceed with a RA/BART approach is obviated. In order to insure that reasonable progress is demonstrated in the SIP context, the State has determined it is necessary and appropriate to include certain requirements from the Consent Decree in this SIP. The specific emission limitations and specific controls (if Hayden continues to burn coal as its primary fuel) to achieve the limitations are contained in the language included from the Consent Decree (Consent Decree section V. Emission Controls and Limitations). The construction schedule and schedule for compliance with emission limitations for Hayden station are also in the excerpted Consent Decree in sections VII. Construction Schedule and VIII. Emission Limitations and Compliance Deadlines, respectively. The schedules are subject to force majeure determinations pursuant to the Consent Decree.

(iv). Source Retirement and Replacement Schedules. This factor is not applicable in the context of requirements for Hayden station as the source is neither being retired nor replaced.

(v). Measures to Mitigate the Impacts of Construction Activities. In the technical judgment of the Division, it is not believed that construction activities at Hayden station or in the construction of a natural gas pipeline will contribute to impairment to the Mt. Zirkel Wilderness or other Class I areas. The distance between the construction and the Class I area is at least 20 miles and it is very unlikely that fugitive emissions from the site would influence visibility. The size of particles that escape a construction site are also usually relatively large (e.g., fugitive dust) and would rapidly deposit out. The marginal increase in emissions from these Hayden-specific activities would not be measurable against the background of current existing area emissions. Thus, no mitigation measures are necessary in this context.

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17 Letter from Elizabeth Estill, Regional Forester, Rocky Mountain Region of the U.S.D.A. Forest Service, to Margie Perkins, Director, Air Pollution Control Division, Colorado Department of Public Health and Environment, June 24, 1996.

(vi). Enforceability of Emission Limitations. By adopting the emission limitations for Hayden into Colorado's SIP, such limitations become enforceable by the State, and when approved by EPA, the limits are also federally enforceable by EPA. The Consent Decree's emission limitations, during the term of its existence, are enforceable through a petition by any of the parties to the Consent Decree to the United States District Court for the District of Colorado. A provision of the Consent Decree states that it cannot be terminated until certain requirements including emission limitations have been incorporated into the State's Title V permit for Hayden station. Once in the Title V permit, the requirements would be enforceable by the State and/or EPA. A provision of the Decree also stipulates monetary penalties to be paid by the owners of Hayden should the station fail to meet emission limits. Enforceability of emission limitations is also related to how one determines compliance, the reliability and validity of measurements to determine compliance, and reporting of data. For these reasons, Consent Decree sections VI. Continuous Emission Monitors (for SO_2 and opacity) and IX. Reporting are included from the Hayden Consent Decree in this SIP amendment.

C. ENFORCEABLE PARTS OF THE SIP REVISION: HAYDEN STATION REQUIREMENTS.

The following provisions, which are taken from the Hayden Consent Decree, are being adopted as part of this revision to the Long-Term Strategy portion of the Colorado Visibility SIP, shall be met by the Hayden owners, and are intended to be enforceable. The Consent Decree numbering scheme has been retained to avoid confusion between the Consent Decree and the SIP, but only those sections pertinent to visibility, necessary to ensure the enforceability of the requirements related to visibility, and to demonstrate reasonable progress are being adopted in this SIP revision. Also, some changes have been made to the Consent Decree language to conform the Consent Decree requirements to the SIP regulatory framework. Changes have been made to language which refers to the force majeure provisions of the Consent Decree to ensure that a demonstration of reasonable progress can be made at this time. Changes are highlighted in bold.

II. DEFINITIONS

1. Unless otherwise expressly provided herein, terms used in this **SIP component [Defined below. "SIP component" replaces Decree wherever it appears]** that are defined in the Clean Air Act, 42 U.S.C. § 7401 et seq., or regulations implementing the Clean Air Act, shall have the meaning set forth in the Act or regulations.

2. Whenever the terms set forth below are used in this SIP component, the following definitions shall apply:

a. "Act" shall mean the Clean Air Act, 42 U.S.C. § 7401, et seq.

b. "Boiler operating day" for coal shall mean any calendar day in which coal is combusted in the boiler of a unit for more than 12 hours. If coal is combusted for more than 12 but less than 24 hours during a calendar day, the calculation of that day's SO_2 emissions for the unit shall be based solely upon the average of hourly CEMS data collected during hours in which coal was combusted in the unit, and shall not include any time in which coal was not combusted. "Boiler operating day" for natural gas shall mean any calendar day in which natural gas was combusted in a boiler of a unit for 24 hours.

c. "Business day" shall mean all work days of the week except Saturday, Sunday and all Colorado and federal holidays.

d. "Calendar day" shall mean any 24 hour period between 12:00 midnight and the following midnight in Colorado.

e. "CEMS" shall mean continuous emissions monitoring system, which consists of all equipment used to sample, analyze, and record on a continuous basis, opacity, SO_2, NO_x, or any other emissions-related parameters that may be required.

f. "Coal" shall mean all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials, Designation
D388-77.

g. "Co-fire" shall mean when a unit at the Hayden Station is combusting coal and natural gas simultaneously, other than during periods of startup.

h. "Colorado" shall mean the State of Colorado and the Colorado Department of Public Health and Environment, Air Pollution Control Division;

i. "Day" shall mean a calendar day. In computing any period of time under this SIP component, except in computing compliance with emission limitations, where the last day would fall on a Saturday, Sunday or federal or Colorado holiday, the period shall run until the close of the next business day.

j. "SIP component" shall mean the language from the Hayden Consent Decree (Civil Action 93-B-1749, United States District Court for the District of Colorado), as modified herein, included in paragraph [illegible] of the August 8, 1996 revision of the Long-Term Strategy portion of Colorado's Class I Visibility Protection Program State Implementation Plan.

k. **"Hayden Owners"[replace "Defendants" throughout]** shall mean Public Service Company of Colorado, Inc., Salt River Project Agricultural Improvement and Power District, and PacifiCorp, and successor owners of Hayden Station.

l. "Division" shall mean the Colorado Air Pollution Control Division.

m. "EPA" shall mean the United States Environmental Protection Agency.

n. "Excess opacity reading" shall mean each six-minute period of time during which the opacity of emissions from Unit 1 or Unit 2 at Hayden Station exceeds 20.0%, as determined by the opacity CEMS.

o. "FFDC" shall mean Fabric Filter Dust Collector.

p. "Fossil-fuel" shall mean natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

q. "Hayden Station" shall mean the fossil-fuel fired steam generating plant located near the town of Hayden, Colorado, consisting of two boilers and related electric generators and all ancillary process and air pollution emission control equipment known as Unit 1 and Unit 2.

r. "NO_x" shall mean nitrogen oxides.

s. "Paragraph" shall mean a portion of this SIP component identified by an arabic numeral.

t. **[Not applicable to this SIP component.]**

u. **[Not applicable to this SIP component.]**

v. "QA/QC" shall mean the quality assurance and quality control measures to ensure the accuracy of CEMS required by this SIP component.

w. "Quarter" shall mean a calendar quarter consisting of three full months, beginning on the first day of either January, April, July or October.

x. "Rolling average basis" shall mean an average over a period of time consisting of the last 30 or 90 boiler operating days, with a new daily average generated each successive boiler operating day, based on the sum of the daily averages for the last 30 or 90 boiler operating days.

y. "Section" shall mean a portion of this SIP component identified by a capital roman numeral.

z. "Shutdown" shall mean the cessation of operation of Unit 1 or Unit 2 at Hayden Station for any purpose or reason.

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aa. **[Not applicable to this SIP component.]**

bb. "Startup" shall mean the setting in operation of Unit 1 or Unit 2 at Hayden Station for any purpose or reason.

cc. "SO_2" shall mean sulfur dioxide.

dd. "Title V" shall mean Title V of the Clean Air Act, 42 U.S.C. § 7661 through § 7661f.

ee. "Unit 1" shall mean the 180 megawatt steam generating unit and related electric generating and air pollution emission control equipment for which construction was completed at the Hayden Station in 1965, including all changes made, and to be made, to such equipment thereafter.

ff. "Unit 2" shall mean the 260 megawatt steam generating unit and related electric generating and air pollution emission control equipment for which construction was completed at the Hayden Station in 1976, including all changes made, and to be made, to such equipment thereafter.

gg. "Consent Decree" or "Hayden Consent Decree" shall mean the Consent Decree entered in <u>Sierra Club v. Public Service Company of Colorado, Inc., et al.</u>, Civil Action No. 93-B-1749.

V. EMISSION CONTROLS AND LIMITATIONS

7. Hayden Owners shall, at all times, maintain and optimally operate the boilers and all pollution control equipment installed at the Hayden Station consistent with good air pollution control practices for minimizing emissions. Without limitation, this shall include returning the control equipment to optimum efficiency as soon as practicable during boiler startup or following control equipment outage or impairment, and maintaining the control equipment at optimum efficiency as long as possible while shutting down the boiler.

8. Hayden Owners shall install the following control equipment, and shall achieve the following emission limitations for each Unit at the Hayden Station, in accordance with the deadlines set forth in Sections VII and VIII:

a. Sulfur Dioxide (SO_2)

i. Unless Hayden Owners elect to switch to natural gas pursuant to paragraph 24, Hayden Owners shall install and operate lime spray dryer technology on Unit 1 and Unit 2 at the Hayden Station. Hayden Owners shall design and construct such lime spray dryer technology to meet the emission limitations, including the percentage reduction requirement, set forth below.

ii. The sulfur dioxide mass emission limitations for each unit at the Hayden Station shall be as follows:

(1) 0.160 pounds per million Btu heat input on a 30 boiler operating day rolling average basis;

(2) 0.130 pounds per million Btu heat input on a 90 boiler operating day rolling average basis.

iii. Compliance with the SO_2 mass emission limitations in subparagraphs (a)(ii)(1) and (2) herein shall be determined using data from the SO_2 CEMS that Hayden Owners are required to maintain, calibrate and operate pursuant to Section VI.

iv. Sulfur dioxide controls on each unit at the Hayden Station shall achieve at least an 82% reduction of sulfur dioxide on a 30 boiler operating day rolling average basis.

v. Compliance with the SO_2 percentage reduction requirement in subparagraph (a)(iv) above shall be determined using data from the SO_2 CEMS that Hayden Owners are required to maintain, calibrate and operate pursuant to Section VI. Continuous emission monitor data taken from the inlet flue gas stream to the lime spray dryer shall be compared to continuous emission monitor data taken from the outlet flue gas stream at the stack to determine the percentage reduction in sulfur dioxide concentrations (based on pounds per million Btu at the inlet continuous emission monitor versus pounds per million Btu at the outlet continuous emission monitor). If the Hayden Owners elect to switch to or co-fire with natural gas, an adjustment shall be made in the calculation of this percentage reduction requirement to provide Hayden Owners credit for the decrease in the SO_2 concentrations in the inlet stream resulting from the introduction of the natural gas component of the fuel, provided that Hayden Owners first submit, and obtain **State and EPA** approval of, a detailed protocol setting forth the method by which such adjustments will be made. Upon approval by **the State and EPA**, such protocol shall become an enforceable part of this SIP component.

vi. The first two hours after the first coal feeder on a unit has started during startup shall be excluded from the calculation of that day's SO_2 emissions for such unit.

vii. Regardless of Hayden Owners' compliance with (and without relieving Hayden Owners of the obligation to comply with) the emission limitations and other requirements set forth in this Section, in no event shall Hayden Owners operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this subparagraph, Hayden Owners shall only restart the boiler on a unit when any malfunctioning control equipment has been repaired.

viii. During any boiler operating day, as defined in this SIP component, all emissions of SO_2 from the stack of any unit shall be included in the determination of Hayden Owners' compliance with the SO_2 emission limitations set forth in this paragraph, unless excluded as the first two hours during startup, excluded pursuant to paragraph 29 during the first six months after the compliance date established in Section VIII, or as a result of a "catastrophic failure" as defined below.

ix. Catastrophic Failure.

(1) A "catastrophic failure," for purposes of this paragraph, shall mean a complete failure of the SO_2 emission control equipment at a Hayden Station unit that is directly caused by a force that Hayden Owners could neither have controlled nor reasonably anticipated, and that could not have been prevented through the exercise of good air pollution control practices for minimizing emissions.

(2) Without limitation, a catastrophic failure shall not include SO_2 emissions that are related to unit startup or shutdown; load fluctuations; operator failure; upsets; design, construction, or equipment defects that Hayden Owners could have controlled or reasonably anticipated; or the failure of any SO_2 emission control equipment components due to ordinary wear and tear, irrespective of Hayden Owners' efforts to maintain and/or replace such components.

(3) For purposes of determining Hayden Owners' compliance with the SO_2 emission limitations set forth in this paragraph, no more than 24 hours of SO_2 data shall be excluded for any single "catastrophic failure".

(4) For any boiler operating day for which data is excluded due to a catastrophic failure, the calculation of that day's average SO_2 emissions for the unit shall be based solely upon hours of nonexcluded CEMS data that would otherwise be counted under this SIP component. Days in which all such hours are excluded as a result of a catastrophic failure pursuant to this paragraph shall not be counted in calculating compliance with the SO_2 emission limitations.

(5) If Hayden Owners wish to invoke the catastrophic failure exception, they first must notify the Division by phone immediately, but no later than two hours after the start of the next business day following such failure. Second, within 30 days of such failure, Hayden Owners must provide a written report to **the Division** that contains: (a) all hourly SO_2 CEMS data Hayden Owners wish to have excluded, (b) evidence of Hayden Owners' notification to the Division, and (c) all evidence that demonstrates the failure is a "catastrophic failure" as defined above. **[Language deleted].** If Hayden Owners fail to follow the notice and/or reporting requirements of this paragraph, the catastrophic failure exception shall not apply.

c. Particulates

i. Unless Hayden Owners elect to switch to natural gas pursuant to paragraph 24, Hayden Owners shall install and operate Fabric Filter Dust Collectors (also known as FFDCs or baghouses) on Unit 1 and Unit 2 at the Hayden station. Hayden Owners shall design and construct such FFDCs to meet the emission limitations set forth below.

ii. The particulate matter limitations for each unit at the Hayden Station shall be as follows:

(1) 0.03 pounds of primary particulate matter per million Btu heat input, as averaged over six (6) hours of EPA's reference method for particulate testing; and

(2) opacity of 20.0 percent, as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. Notwithstanding the foregoing, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, Hayden Owners shall not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

iii. Any opacity reading in excess of the limitations set forth in subparagraph (ii)(2) above may be excused if **[deletion]** Hayden Owners have demonstrated such reading was the result of an unpredictable failure of air pollution control or process equipment that was not due to poor maintenance, improper or careless operations, or otherwise could not have been prevented through the exercise of reasonable care. If Hayden Owners seek to excuse any such excess opacity reading, they must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in Hayden Owners' next quarterly report following such condition, and must describe: (a) the date and time telephone notification was given to the Division, and the person to whom notification was given, (b) the cause of the condition, (c) all actions Hayden Owners took to correct the condition, and (d) all actions Hayden Owners will take to prevent the condition from recurring.

iv. Compliance with the primary particulate emission limitation in subparagraph (c)(ii)(1) herein shall be determined according to EPA Method 5, 40 C.F.R. Part 60, Appendix A, or in accordance with a compliance assurance monitoring plan as may be set forth in Hayden Owners' Title V operating permit. Hayden Owners shall conduct a Method 5 test on each unit at the Hayden Station within 100 days after flue gas is first passed through the FFDC, and thereafter as directed by Colorado or EPA, and submit all results and a complete description of the tests to **the Division** in the next quarterly report following Hayden Owners' receipt of the results.

v. Compliance with the opacity emission limitation in subparagraph (c)(ii)(2) herein shall be determined on a continuous basis using data from the opacity CEMS that Hayden Owners are required to maintain, calibrate and operate pursuant to Section VI of this SIP component, and may be verified on an intermittent basis by EPA Method 9, 40 C.F.R. Part 60, Appendix A.

vi. **[Not applicable to this SIP component].**

VI. CONTINUOUS EMISSION MONITORS

9. At all times after **the Colorado Air Quality Control Commission's adoption** of this SIP component, Hayden Owners shall maintain, calibrate and operate CEMS for each unit of the Hayden Station to measure accurately SO_2 emissions from each such unit, as well as flow and carbon dioxide, in full compliance with the requirements found at 40 C.F.R. Part 75. Nothing herein shall preclude Hayden Owners from installing, certifying and operating integrated CEMS equipment to measure SO_2, NO_x or opacity, or any combination thereof.

10. At all times after **the Colorado Air Quality Control Commission's adoption** of this SIP component, Hayden Owners shall maintain, calibrate and operate CEMS to measure accurately the opacity of emissions from each unit at the Hayden Station in full compliance with the requirements found at 40 C.F.R. Part 60, Appendix B, Specification 1, and 5 C.C.R. 1001-3, IV.A and B.

11. **[Not applicable to this SIP component.]**

12. Prior to initial startup of the SO_2 control equipment at each unit as required by this SIP component, Hayden Owners shall, in addition to other CEMS required by this SIP component: (a) install and thereafter maintain, calibrate and operate an accurate CEMS at the inlet flue gas stream to the lime spray dryer on each unit to measure accurately SO_2 concentrations in pounds per million Btu heat input, and (b) tie the coal feeders on each unit into the SO_2 CEMS such that the CEMS accurately reflect the date and time when the first coal feeder on each unit has started during each startup.

13. **[Not applicable to this SIP component].**

14. **[Not applicable to this SIP component].**

15. **[Not applicable to this SIP component].**

16. Beginning within 30 boiler operating days from the date flue gas is first passed through the SO_2 control equipment for each unit, Hayden Owners shall calculate hourly average SO_2 concentrations in pounds per million Btu at the inlet and outlet continuous emission monitors for each unit, in accordance with the requirements of 40 C.F.R. Part 75.

a. For each boiler operating day, Hayden Owners shall use the inlet and outlet hourly averages to calculate the following at each unit: hourly SO_2 average percentage removal, daily SO_2 average percentage removal based on the hourly averages, and 30 day rolling SO_2 average percentage removal based on the daily averages.

b. For each boiler operating day, Hayden Owners shall use the outlet hourly averages to calculate the following at each unit: daily average SO_2 emissions based on the hourly averages, and 30 day and 90 day rolling averages based on the daily averages.

c. As provided in paragraph 8(a)(vi), during startup of the unit, the first two hours after the first coal feeder has started shall be excluded from the calculation of that boiler operating day's SO_2 emissions for the unit.

d. Notwithstanding the foregoing, if Hayden Owners elect to switch to natural gas as the primary fuel source, beginning within 30 days of the date Hayden Owners commence use of natural gas as the primary fuel source, Hayden Owners shall calculate hourly average SO_2 concentrations in pounds per million Btu at the outlet continuous emission monitor at each unit, in accordance with the requirements of 40 C.F.R. Part 75, and shall calculate the averages required by paragraph 16(b).

17. Hayden Owners shall report to the **Division** on a quarterly basis each 30 day rolling average and each 90 day rolling average during the prior quarter that exceeded or failed to comply with the SO_2 emission limitations contained in this SIP component. Each quarterly report shall include all times the coal feeders have started during startup as reported through the CEMS. This report shall also include a list of the days and hours excluded for any reason from the determination of Hayden Owners' compliance with the SO_2 limits.

18. **[Not applicable to this SIP component.]**

19. **[Not applicable to this SIP component.]**

20. For any hour that valid, quality-assured continuous emission monitor data for a unit is unavailable, SO_2 **[deletion]** emissions shall be calculated in accordance with the missing data substitution procedures contained in 40 C.F.R. Part 75.

21. Hayden Owners shall calculate opacity based on CEMS data for each six-minute period of time any boiler is operating, in the manner, frequency and interval as prescribed in the applicable regulations.

22. Hayden Owners shall report to **the Division** on a quarterly basis all excess opacity readings from each unit, and shall state the cause of each excess opacity reading and Hayden Owners' efforts to minimize such readings.

23. Hayden Owners shall ensure that the opacity CEMS on Unit 1 and Unit 2 are properly recording data at least 98.0% of each unit's operating time each quarter; provided, however, that if final federally-enforceable regulations are promulgated that impose new CEMS QA/QC requirements that have the effect of increasing the proportion of CEMS QA/QC activity time in relation to unit operating time, then **Hayden Owners may seek a revision to** this SIP component to amend the 98.0% CEMS availability requirement accordingly.

VII. CONSTRUCTION SCHEDULE

24. No later than **[deletion] November 17, 1996**, Hayden Owners shall notify **the Division** of Hayden Owners' decision concerning the primary fuel source for the Hayden Station. If Hayden Owners decide to continue using coal as the primary fuel source, the schedule in paragraph 25(a) shall apply. If Hayden Owners decide to switch to natural gas as the primary fuel source, the schedule in paragraph 25(b) shall apply.

25. The schedules are as follows, subject to a force majeure **determination pursuant to the Hayden Consent Decree, including a decision by the Court to limit force majeure pursuant to paragraph 59 of the Hayden Consent Decree. However, if any schedule has been extended or will be extended pursuant to such a force majeure determination or determinations by more than 12 months beyond the particular deadline, the Division shall request that the Commission reopen (with public notice and hearing) the Long-Term Strategy element of Colorado's Class I Visibility Protection Program State Implementation Plan to reevaluate the demonstration of reasonable progress, and to revise the State Implementation Plan as may be necessary to ensure that the emission limitations are met. In no event shall these force majeure provisions be construed to authorize or create any preemption or waiver of any State or federal air quality law, or of any requirement contained in the Consent Decree and incorporated into this SIP.**

a. Schedule - Coal as Primary Fuel. If Hayden Owners continue to operate Hayden Station using coal, Hayden Owners shall meet the following deadlines for **[deletion]** construction, and startup testing of the emission control equipment required by Section V of this SIP component:

UNIT 1.

Activity	Deadline
(i - vii) Not applicable to this SIP component	
(viii) **Complete construction and** commence startup testing of the FFDC **and** SO_2 **[deletion]** control equipment	12/31/98

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UNIT 2.

Activity	Deadline
(i - vii) Not applicable to this SIP component	
(viii) **Complete construction and** commence startup testing of the FFDC **and** SO_2 **[deletion]** control equipment	12/31/99

b. Schedule - Natural Gas as Primary Fuel. If Hayden Owners elect to convert Hayden Station to natural gas, Hayden Owners shall meet the following deadlines for conversion of the Hayden Station to natural gas:

Activity	Deadline
(i - iii) Not applicable to this SIP component	
(iv) Complete construction of pipeline and boiler modifications, and commence use of natural gas as primary fuel source	12/31/98

26. Upon initiation of startup of the Hayden Station using natural gas as the fuel source, Hayden Owners shall thereafter monitor on a quarterly basis the quality of the natural gas being burned. Results of such monitoring shall be sent to **the Division** on a quarterly basis.

a. The natural gas burned at the Hayden Station shall be of the following quality: no more than 5 grains of total sulfur per 100 cubic feet at 14.73 p.s.i. and 60 degrees F.

b. The natural gas quality shall be determined by the following method: ASTM D-5504-94, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, or equivalent method.

27. **[Not applicable to this SIP component].**

VIII. EMISSION LIMITATION COMPLIANCE DEADLINES

28. Hayden Owners' obligation to meet the SO_2 **[deletion]** and particulate emission limitations set forth in Section V shall commence on the dates listed below, subject to a force majeure [deletion] **determination pursuant to the Hayden Consent Decree (including a decision by the Court to limit force majeure pursuant to paragraph 59 of the Hayden Consent Decree). However, if any schedule has been extended or will be extended pursuant to such a force majeure determination or determinations by more than 12 months beyond the particular deadline, the Division shall request that the Commission reopen (with public notice and hearing) the Long-Term Strategy element of Colorado's Class I Visibility Protection Program State Implementation Plan to reevaluate the demonstration of reasonable progress, and to revise the State Implementation Plan as may be necessary to ensure that the emission limitations are met. In no event shall these force majeure provisions be construed to authorize**

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or create any preemption or waiver of any State or federal air quality law, or of any requirement contained in the Consent Decree and incorporated into this SIP.

a. <u>SO_2</u>:

i. For Unit 1, within 180 days after flue gas is passed through the SO_2 control equipment, or by July 1, 1999, whichever date is earlier; and

ii. For Unit 2, within 180 days after flue gas is passed through the SO_2 control equipment, or by July 1, 2000, whichever date is earlier.

b. **[deletion]**

i. **[deletion]**

ii. **[deletion]**

c. <u>Particulates</u>:

i. For Unit 1, within 90 days after flue gas is passed through the FFDC control equipment, or by April 1, 1999, whichever date is earlier; and

ii. For Unit 2, within 90 days after flue gas is passed through the FFDC control equipment, or by April 1, 2000, whichever date is earlier.

29. During the first six months following the dates listed in paragraphs 28(a)(i) and (ii) above, **for purposes of [deletion]** determining compliance with the SO_2 emission limitations set forth in Section V, **[deletion]** periods during which the control equipment fails to meet an SO_2 emission limitation **may be excluded if Hayden Owners are able to demonstrate that such failure was** due to a design or construction defect beyond Hayden Owners' control. During the first four months following the dates listed in paragraphs 28(c)(i) and (ii) above, **for purposes of [deletion]** determining compliance with the particulate emission limitations set forth in Section V, **[deletion]** periods during which the control equipment fails to meet a particulate emission limitation **may be excluded if Hayden Owners are able to demonstrate that such failure was** due to a design or construction defect beyond Hayden Owners' control.

a. **If Hayden Owners wish to seek an exclusion under this paragraph, Hayden Owners shall submit a written report to the Division that [deletion]** identifies the times proposed for exclusion and provides the reasons for the failure to meet the limitation, including all evidence that demonstrates the failure was caused by a design or construction defect beyond Hayden Owners' control. The **report** shall also describe all actions taken and to be taken to correct the failure, and a schedule to complete such actions.

b. **[Not applicable to this SIP component.]**

30. Notwithstanding the foregoing, if Hayden Owners elect to convert the Hayden Station to natural gas, Hayden Owners' obligation to meet the SO_2 **[deletion]** and particulate emission limitations set forth in Section V shall commence on the earlier of February 1, 1999 or 30 days after the date Hayden Owners commence use of natural gas as the primary fuel source, subject to a force majeure **[deletion] determination pursuant to the Hayden Consent Decree (including a decision by the Court to limit force majeure pursuant to paragraph 59 of the Hayden Consent Decree). However, if any schedule has been extended or will be extended pursuant to such a force majeure determination or determinations by more than 12 months beyond the particular deadline, the Division shall request that the Commission reopen (with public notice and hearing) the Long-Term Strategy element of Colorado's Class I Visibility Protection Program State Implementation Plan to reevaluate the demonstration of reasonable progress, and to revise the State Implementation Plan as may be necessary to ensure that the emission limitations are met. In no event shall these force majeure provisions be construed to authorize or create any**

preemption or waiver of any State or federal air quality law, or of any requirement contained in the Consent Decree and incorporated into this SIP.

IX. REPORTING

31. Within 30 days after the end of each quarter, **[deletion]**, Hayden Owners shall provide a quarterly report to **the Division** regarding the immediately preceding quarter that contains all of the information this SIP component requires Hayden Owners to report on a quarterly basis.

32. **[Not applicable to this SIP component].**

33. In specific, each quarterly report shall include:

a. A description of construction deadlines achieved, progress made toward meeting future deadlines, and any actual, expected or reasonably likely delays;

b. All elements of the excess opacity quarterly report;

c. After installation of the SO_2 control equipment, the required quarterly reports for SO_2 emissions (including information regarding excluded periods) **[deletion]** and CEMS quality assurance reports;

d. **[deletion]**

e. If Hayden Owners elect to convert Hayden Station to natural gas, all information required to be included in the natural gas quarterly reports; and,

f. **[Not applicable to this SIP component].**

34. **[Not applicable to this SIP component].**

35. **[Not applicable to this SIP component].**

REVISION OF

COLORADO'S STATE IMPLEMENTATION PLAN

FOR CLASS I VISIBILITY PROTECTION

CRAIG STATION UNITS 1 AND 2 REQUIREMENTS

CRAIG STATION
SECTION
SUBMITTED 6/7/01
BY STATE
FR. VOL 66 #129
7/5/01 Pg 35374

COLORADO DEPARTMENT OF
PUBLIC HEALTH AND ENVIRONMENT

APRIL 19, 2001

PREPARED BY:

COLORADO AIR POLLUTION CONTROL DIVISION

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III. ENFORCEABLE PORTION OF THE SIP REVISION: CRAIG STATION UNITS 1 AND 2 REQUIREMENTS

The following provisions, which are taken from the Craig Consent Decree, are being adopted as part of this revision to the Long-Term Strategy portion of the Colorado Visibility SIP, shall be met by the Craig Owners, and are intended to be enforceable. The Craig Consent Decree numbering scheme has been retained to avoid confusion between the Craig Consent Decree and the SIP, but only those sections pertinent to visibility, necessary to ensure the enforceability of the requirements related to visibility, and to demonstrate reasonable progress are being adopted in this SIP revision. Also, some changes have been made to the Craig Consent Decree language to conform the Craig Consent Decree requirements to the SIP regulatory framework. All changes are highlighted in bold. The changes that have been made to language in paragraphs 24 and 25 below which refer to the force majeure provisions of the Craig Consent Decree have been inserted to ensure that a demonstration of reasonable progress can be made at this time.

II. DEFINITIONS

1. Unless otherwise expressly provided herein, terms used in this **SIP component [Defined below. "SIP component" replaces Decree wherever it appears]** that are defined in the Clean Air Act, 42 U.S.C. §§ 7401, *et seq.*, or regulations implementing the Clean Air Act, shall have the meaning set forth in the Act or regulations.

2. Whenever the terms set forth below are used in this **SIP component**, the following definitions shall apply:

(a) "Act" shall mean the Clean Air Act, 42 U.S.C. §§ 7401, *et seq.*

(b) "Allowance" shall mean an authorization, under Title IV of the Act, allowing Craig Units 1 and 2 to emit one ton of SO_2 in one year.

(c) "Boiler operating day" shall mean any calendar day in which coal is combusted in the boiler of a unit for more than 12 hours. If coal is combusted for more than 12 but less than 24 hours during a calendar day, the calculation of that day's SO_2 emissions for the unit shall be based upon the average of coal sampling and hourly CEMS data collected during hours in which coal was combusted in the unit, and shall not include any time in which coal was not combusted.

(d) "Business day" shall mean all work days of the week except Saturday, Sunday and all Colorado and federal holidays.

(e) "Calendar day" shall mean any 24 hour period between 12:00 midnight and the following midnight in Colorado.

(f) "CEMS" shall mean continuous emissions monitoring system, which consists of the total equipment used to sample, analyze, and record on a continuous basis SO_2, NO_x, or any other emissions-related parameters that may be required.

(g) "COMS" shall mean continuous opacity monitoring system, which consists of the total equipment used to sample, analyze, and record opacity on a continuous basis.

(h) "Coal" shall mean all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials, Designation D388-77.

(i) "Colorado" shall mean the State of Colorado and the Colorado Department of Public Health and Environment, Air Pollution Control Division.

(j) "Craig Units 1 and 2" shall mean the fossil-fuel fired steam generating plant located near the town of Craig, Colorado, including the two boilers and related electric generators and all ancillary process and air pollution emission control equipment known as Unit 1 and Unit 2. Craig Station also includes Unit 3 that is not subject to this **SIP component**.

(k) "Day" shall mean a calendar day. In computing any period of time under this **SIP component**, except in computing compliance with emission limitations, where the last day would fall on a Saturday, Sunday or federal or Colorado holiday, the period shall run until the close of the next business day.

(l) "Decree" shall mean Consent Decree, and any written modifications of such Consent Decree.

(m) **"Craig Owners" [replaces "Defendants" throughout]** shall mean Tri-State Generation and Transmission Association, Inc., Public Service Company of Colorado, Salt River Project Agricultural Improvement and Power District, PacifiCorp and Platte River Power Authority **and successor owners of the Craig Station Units 1 and 2**.

(n) "EPA" shall mean the United States Environmental Protection Agency.

(o) "Excess opacity reading" shall mean each six-minute period of time during which the opacity of emissions from Unit 1 or Unit 2 at the Craig Station exceeds 20 percent, regardless of cause or any regulatory exception, as determined by the existing or any EPA and Colorado-approved alternative COMS.

(p) "FGD" shall mean flue gas desulfurization system.

(q) "Fossil-fuel" shall mean natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

(r) "Malfunction" shall mean any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or of 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.

(s) "NO_x" shall mean all oxides of nitrogen, except nitrous oxide.

(t) "Opacity" shall mean the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

(u) "Paragraph" shall mean a portion of this **SIP component** identified by an arabic numeral.

(v) **[Not applicable to this SIP component]**

(w) **[Not applicable to this SIP component]**

(x) "Quarter" shall mean a calendar quarter consisting of three full months, beginning on the first day of either January, April, July or October.

(y) "Rolling average basis" shall mean an average over a period of time consisting of the last 30 or 90 boiler operating days, with a new average generated each successive boiler operating day, based on the sum of the averages for the last 30 or 90 boiler operating days.

(z) "Section" shall mean a portion of this **SIP component** identified by a capital roman numeral.

(aa) "Shutdown" shall mean the cessation of operation of Unit 1 or Unit 2 at Craig Station for any purpose or reason.

(ab) **[Not applicable to this SIP component]**

(ac) "Startup" shall mean the setting in operation of Unit 1 or Unit 2 at Craig Station for any purpose or reason.

(ad) "SO_2" shall mean sulfur dioxide.

(ae) "Title V" shall mean Title V of the Clean Air Act, 42 U.S.C. § 7661 through § 7661f.

(af) "Unit 1" shall mean the steam generating unit and related electric generating and air pollution emission control equipment that commenced commercial operation at the Craig Station in 1980, including all changes made, and to be made, to such equipment thereafter.

(ag) "Unit 2" shall mean the steam generating unit and related electric generating and air pollution emission control equipment that commenced commercial operation at the Craig Station in 1979, including all changes made, and to be made, to such equipment thereafter.

(ah) "Upset condition" shall mean an unpredictable failure of air pollution control or process equipment which results in the violation of an emission limit in this **SIP component** and which is not due to poor maintenance, improper or careless operations, or is otherwise preventable through exercise of reasonable care.

(ai) "Consent Decree" or "Craig Station Consent Decree" shall mean the Consent Decree entered in <u>Sierra Club v. Tri-State Generation & Transmission Association, Inc., et al.</u>, Civil Action No. 96-N-2368, U.S. District Court for the District of Colorado.

(aj) "SIP Component" shall mean the language from the Craig Station Consent Decree, as modified herein, and included in this section III of this April 2001 revision of the Long-Term Strategy portion of Colorado's Class I Visibility Protection Program State Implementation Plan.

III. <u>JURISDICTION AND VENUE</u>

3. [Not applicable to this SIP component.]

4. [Not applicable to this SIP component.]

IV. <u>APPLICABILITY</u>

5. **[Not applicable to this SIP component.]**

6. **[Not applicable to this SIP component.]**

V. EMISSION CONTROLS AND LIMITATIONS

7. **Craig Owners** shall, at all times including periods of startup, shutdown, and malfunction, maintain and operate Craig Units 1 and 2 in a manner consistent with good air pollution control practices for minimizing emissions.

8. **Craig Owners** shall install the following control equipment, and shall achieve the following emission limitations for Craig Units 1 and 2 in accordance with the deadlines set forth in Sections VII and VIII:

(a) Particulate Matter

(i) **Craig Owners** shall install and operate fabric filter baghouses ("baghouses") on Craig Units 1 and 2, and make any other capital and operational modifications necessary to meet, by the deadlines in Section VIII, the final particulate matter standards and limitations described below.

(ii) The particulate matter limitations for Craig Units 1 and 2 shall be as follows:

(A) 0.03 pounds of particulate matter per million Btu heat input. Compliance shall be established by EPA test methods;

(B) opacity not in excess of 20 percent, as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, **Craig Owners** shall not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (SIP limit from 5 C.C.R. 1001-3, Section II.A.1. and 5 C.C.R. § 1001-3, II.A.4, approved by EPA on December 3, 1986);

(1) **Craig Owners** shall not cause or allow the emission of air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition, however, an upset condition can occur after initiation of a startup in which case only excess emissions caused by such upset condition may be excused.

(2) **Craig Owners** shall not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

(C) opacity no greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. Emissions during startup, shutdown and malfunction are excused under this opacity limit. The SIP exceptions at 5 C.C.R. § 1001-3, II.A.4 (approved by EPA on December 3, 1986), including "cleaning of new fire boxes," "soot blowing," and "any process modification or adjustment or occasional cleaning of control equipment," are not excused. (NSPS limit from 40 C.F.R. § 60.42(a)(2) and 40 C.F.R. § 60.11(c)).

(iii) An opacity reading in excess of the limitations in subparagraph

8(a)(ii)(B) may be excused by an upset condition, and an opacity reading in excess of the limitations in subparagraph 8(a)(ii)(C) may be excused by a malfunction, **[deletion] if Craig Owners demonstrate [deletion]** such reading was the result of an upset condition or malfunction. **[Deletion].** If **Craig Owners** seek to excuse any opacity reading in excess of the limitations above, they must notify Colorado as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this **SIP component**, any claim of excuse must be made in writing in **Craig Owners'** next quarterly report following such condition, and must describe: (1) the date and time telephone notification was given to Colorado, including the person to whom notification was given either directly or through a voice mailbox, (2) the cause of the condition, (3) all actions **Craig Owners** took to correct the condition, and (4) all actions **Craig Owners** will take to prevent the condition from recurring.

(iv) **Craig Owners** shall file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. **Craig Owners** shall indicate in their EERs the specific times in which the fans that move flue gas are on and off. At **Craig Owners'** election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction shall be provided at the time the EER is filed.

(v) **Craig Owners** shall perform particulate matter stack tests at Craig Units 1 and 2 within 100 calendar days after flue gas is first passed through the baghouses and thereafter as directed by Colorado or EPA, and shall submit all results and a complete description of the tests to **Colorado** in the next quarterly report following **Craig Owners'** receipt of the

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results.

(vi) Compliance with the opacity emission limitations in Section V, subparagraph 8(a), shall be determined on a continuous basis using data from the current COMS or an EPA and Colorado-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, 40 C.F.R. Part 60, Appendix A.

(vii) Until such time as **Craig Owners** install baghouses, **Craig Owners** shall, at all times, optimally operate the existing electrostatic precipitators and all other ESP-related equipment at Craig Units 1 and 2 consistent with good air pollution control practices for minimizing opacity and particulate matter emissions.

(b) Sulfur Dioxide (SO_2)

(i) **Craig Owners** shall treat one hundred percent (100%) of the flue gas from Craig Units 1 and 2 in the respective FGDs during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this Section and emissions of SO_2 during any such period shall not be excluded from the determination of **Craig Owners'** compliance with the SO_2 emission limitations.

(ii) **Craig Owners** shall enhance the current FGDs for Craig Units 1 and 2 by designing, evaluating, and installing upgrades which will reliably treat 100% of the flue gas. **Craig Owners** shall be generally guided by those enhancements described as "Option 3" in the *Craig Station FGD System Modifications - Analyses of Potential Alternatives; Project Design Basis and Cost Estimates*, dated August 31, 1999. Craig Units 1 and 2 shall be designed to meet at least a 93.7% removal rate as was calculated in the FGD study. In the event that **Craig**

Owners intend to deviate from Option 3, prior to implementation **Craig Owners** shall submit their complete design plans and required implementation time to **[deletion]** Colorado and EPA for review.

(iii) **Craig Owners** shall have the right to evaluate the reliability and efficiency of the enhancements described as Option 3 and may, in **Craig Owners'** sole discretion, replace such upgrades with technology and operations which may better integrate with the current operations of Craig Units 1 and 2, including the existing FGD and other systems, while still designing the upgrades to meet at least the 93.7% removal rate and reliably treat 100% of the flue gas for SO_2 removal. **[Deletion].**

(iv) **Craig Owners** shall design, construct and operate its FGD upgrades and related equipment to meet the emission limitations, including the percentage reduction requirement, set forth below.

(v) The sulfur dioxide mass emission limitations for Craig Units 1 and 2 shall be as follows:

(1) 0.160 pounds per million Btu heat input on a 30 boiler operating day rolling average basis;

(2) 0.130 pounds per million Btu heat input on a 90 boiler operating day rolling average basis.

(vi) Compliance with the SO_2 mass emission limitations in subparagraphs (b)(v)(1) and (2) herein shall be determined using data from the SO_2 CEMS that **Craig Owners** are required to operate and maintain pursuant to Section VI. The SO_2 CEMs shall be placed in a location to accurately monitor 100% of the flue gas, including any periods of by-pass.

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(vii) Sulfur dioxide controls at Craig Units 1 and 2 shall achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler operating day rolling average basis measured from coal to stack as described in subparagraph (viii) below, unless **Craig Owners** show, for any unit, that the SO_2 reduction equipment was designed and constructed to meet such limit but that for reasons beyond **Craig Owners'** control, despite the fact that **Craig Owners** had designed and constructed the SO_2 reduction equipment to meet the 90 percent limit, they could not meet such limit (hereinafter "Showing"). As part of their Showing **Craig Owners** must establish the maximum SO_2 reduction attainable, and such maximum amount (minus 2 percentage points if **Craig Owners** elect a 90 day rolling average or minus 3 percentage points if **Craig Owners** elect a 30 day rolling average) shall constitute **Craig Owners'** final SO_2 reduction limit. If **Craig Owners** make this Showing, in no event shall the final limit be less than eighty five percent (85%) reduction of SO_2 on a 30 boiler operating day rolling average basis, or less than eighty six percent (86%) reduction of SO_2 on a 90 boiler operating day rolling average basis, measured from coal to stack. **Craig Owners** must make such Showing on or before the dates by which the 90 percent limit must be achieved pursuant to paragraph 25(b). In the event **Craig Owners** present a Showing that is disputed in accordance with the Consent Decree, the 90% limit shall be stayed and the issue shall be decided as set forth in the Consent Decree. During the pendency of any such stay, the limit shall be **Craig Owners'** final SO_2 reduction limit derived from their Showing as described above. **[Deletion].**

(viii) Compliance with the SO_2 percentage reduction requirement shall be determined as follows:

(1) Based on the coal sampling analysis, a daily potential SO_2

emission rate for coal, expressed in lbs/mmBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day an arithmetic average of the potential SO_2 emission rates for the last 30 or 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in paragraph 28(c);

(2) The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lbs/mmBtu, for the last 30 or 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_o in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under paragraph 28(c);

(3) The 30 or 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100\ (\ 1.0 - E_o/E_i)$$

Coal sampling will follow the most current version of ASTM D2234, *Standard Practice for Collection of a Gross Sample of Coal.* Sample preparation will follow the most current version of ASTM 2013, *Standard Method of Preparing Coal Samples for Analysis.* Sulfur analysis will follow the most recent version of ASTM D4239, *Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion*

Methods.

(ix) Regardless of **Craig Owners'** compliance with (and without relieving **Craig Owners** of the obligation to comply with) the emission limitations and other requirements set forth in this Section, in no event shall **Craig Owners** operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this subparagraph, **Craig Owners** shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

(c) Nitrogen Oxides

(i) **Craig Owners** shall select, install and operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air on Craig Units 1 and 2. **Craig Owners** shall design and construct such control equipment to meet the emission limitations set forth below.

(ii) Craig Units 1 and 2 shall meet a NO_x limit of 0.30 pounds per million Btu heat input on a calendar year annual average basis. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of **Craig Owners'** compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that **Craig Owners** are required to maintain, calibrate and operate.

9. **Craig Owners** have the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

VI. CONTINUOUS EMISSION MONITORS

10. At all times **[deletion] Craig Owners** shall maintain, calibrate and operate COMS to measure accurately the opacity of emissions at Craig Units 1 and 2 in full compliance with the requirements found at 40 C.F.R. Part 60, Appendix B, Specification 1, and 5 C.C.R. 1001-3, IV.A and B.

11. **Craig Owners** are currently monitoring opacity with COMS located at the 300 foot level in the stacks of Craig Units 1 and 2. **Craig Owners** intend to change the current location of the COMS to a location after the baghouses and before the FGDs. **Craig Owners** shall seek approval from EPA and Colorado for any such alternative COMS location, and approval from EPA and Colorado to install and thereafter operate a continuous monitoring system to measure pressure differential across the mist eliminator that indicates whether FGD generated particulate matter emissions are minimized. Any request for approval described above shall be submitted to EPA and Colorado no later than 60 days after completion of the FGD design activities set forth at paragraphs 24(a)(iii) and 24(b)(iii). **[Deletion].** Until EPA and Colorado grant final approval for an alternative location, the current COMS will be used for compliance purposes with all opacity standards, and at no time shall Craig Units 1 and 2 be operated without an approved method of continuous opacity monitoring.

In addition to any other requirements that may apply to an alternative location of opacity monitoring, **Craig Owners** shall ensure after installation of the baghouse and FGD upgrades that the new system is reading comparable opacity to what is read by the current COMS under dry stack conditions. Flue gas may be by-passed around the FGD as necessary during the test in order to achieve dry stack conditions. Comparability will be determined based on simultaneous readings from the COMS at the current and new locations during the COMS recertification process required at paragraphs 16 and 17. This comparability analysis may take into account the allowable variation associated with the measurements of opacity by each COM after each COM is calibrated to minimize any such variation. **[Deletion].**

In any request for approval of an alternative COMS location and FGD monitoring system, **Craig Owners** shall provide the manufacturer's specified normal operating pressure drop range across the mist eliminator at given operating gas flow rates and supporting documentation that demonstrates that such range will most effectively minimize particulate matter emissions from the FGD. The pressure drop range submitted by **Craig Owners** shall be shown to be consistent with the normal range established for other similar mist eliminator systems. Within 180 days after flue gas first passes through the upgraded FGDs, **Craig Owners** may submit to EPA and Colorado for approval **[deletion]** a revised pressure drop range based on actual testing data from the applicable unit that will more effectively minimize particulate matter emissions compared to the manufacturer's specified range.

Craig Owners shall continuously and accurately monitor **and report to Colorado**, pursuant to Section IX, the hourly average pressure drop across the mist eliminator and the hourly average flow rate for each unit at Craig Units 1 and 2. **Craig Owners'** pressure monitoring system shall be of sufficient sensitivity and reliability to enable consistent, continuous and effective monitoring of the pressure drop range. **Craig Owners** shall take all necessary corrective actions to maintain the pressure drop within the applicable range. **[Deletion].**

12. **Craig Owners** shall provide to **Colorado** on a quarterly basis all excess emission reports (EERs) for Craig Units 1 and 2 that describe in the form required by this **SIP component** all excess readings, all claimed exceptions, and all other information required by law.

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13. At all times **[deletion] Craig Owners** shall maintain, calibrate and operate CEMS at Craig Units 1 and 2 to measure accurately SO_2 and NO_x emissions from each unit, as well as flow and CO_2, in full compliance with the requirements found at 40 C.F.R. Parts 60 and 75. Nothing herein shall preclude **Craig Owners** from installing, certifying and operating integrated CEMS equipment to measure SO_2, NO_x, CO_2 or opacity, or any combination thereof.

14. **Craig Owners** shall maintain, calibrate and operate a method of coal sampling and analysis to determine accurately, pursuant to methods identified in paragraph 8(b)(viii), the potential emissions from sulfur in the coal entering the boiler reported in pounds of SO_2 per million Btu heat input.

15. **Craig Owners** shall ensure that any modifications to any COMS or CEMS necessitated by **Craig Owners'** actions under or in furtherance of this **SIP component** shall be completed prior to the completion of construction of the SO_2, NO_x, and particulate control systems for Unit 1 and Unit 2, respectively.

16. **Craig Owners** shall recertify all COMS and CEMS on Craig Units 1 and 2 by the following dates:

Opacity COMS: Within 60 boiler operating days after passing flue gas through the baghouses for each unit, and within 60 boiler operating days after passing flue gas through the upgraded scrubber and NO_x control systems for each unit.

SO_2 CEMS: Within 60 boiler operating days after passing flue gas through the upgraded scrubber system for each unit.

NO_x CEMS: Within 60 boiler operating days after the NO_x burner and overfire air upgrades become operational on each unit.

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17. In recertifying such COMS and CEMS, **Craig Owners** shall meet all requirements in 40 C.F.R. Parts 60 and 75 for initial certification. In particular, **Craig Owners** shall demonstrate that the SO_2 and NO_x CEMS are accurately monitoring 100 percent of the flue gas, including any periods of by-pass, and are accurately reflecting SO_2 and NO_x concentrations exiting the stack, that the COMS are accurately monitoring the opacity of emissions, and that **Craig Owners** have resolved any problems with laminar or cyclonic flow, uncombined water droplets, or any other problem that may be affecting the performance of the CEMS or COMS. On at least a quarterly basis during the first year after recertification of the SO_2 CEMS, **Craig Owners** shall contract with a private laboratory to analyze a split sample from a composite coal sample to ensure that **Craig Owners'** coal analysis system is accurately reporting Btu, sulfur and potential SO_2 emissions. **Craig Owners** shall report the results of such analyses in their quarterly reports. **Craig Owners** shall provide at least 30 days prior written notice to **Colorado and EPA** of the date(s) **Craig Owners** intend to perform the recertification tests required by this paragraph and shall allow **Colorado and EPA** to be present for such tests.

18. Beginning within 30 and 90 boiler operating days (depending on the applicable SO_2 limit in Section V) from the date flue gas is first passed through the upgraded SO_2 control equipment for each unit, **Craig Owners** shall calculate the following:

(a) For each boiler operating day, the percentage of SO_2 removal consistent with paragraph 8(b)(viii), and

(b) For each boiler operating day, the SO_2 mass emission rate for 30 and 90 boiler operating days calculated consistent with paragraph 8(b)(viii)(2).

19. **Craig Owners** shall report to **Colorado** on a quarterly basis each 30 day rolling

average and each 90 day rolling average during the prior quarter that exceeded or failed to comply with the SO_2 emission limitations contained in this **SIP component**. Each quarterly report shall include a list of the hours excluded for any reason from the determination of **Craig Owners'** compliance with the SO_2 limits, and a list of times in which flue gas is by-passed around the FGD.

20. Beginning within 30 boiler operating days of the date of the first startup of a unit following installation of the upgrades to the NO_x reduction systems for each unit, **Craig Owners** shall calculate hourly average NO_x concentrations in pounds per million Btu, in accordance with the requirements of 40 C.F.R. Part 75. **Craig Owners** shall use the hourly averages to calculate calendar year averages in accordance with the requirements of 40 C.F.R. Part 75.

21. **Craig Owners** shall report to **Colorado** on a quarterly basis **Craig Owners'** year-to-date average NO_x emission rate for that calendar year.

22. For any hour that valid, quality-assured continuous emission monitor data for a unit is unavailable, SO_2, NO_x and CO_2 emissions shall be calculated in accordance with the missing data substitution procedures contained in 40 C.F.R. Part 75. For any day in which daily coal sample data are not available, the average potential SO_2 emission rate of coal from the previous 30 days as calculated in paragraph 8(b)(viii) shall be substituted.

23. **Craig Owners** shall be bound by the data from their COMS, SO_2 CEMs and coal sampling data, and NO_x CEMS. **Craig Owners** may not challenge the accuracy or credibility of their COMS, SO_2 CEMs and coal sampling data, and NO_x CEMS in any enforcement action unless otherwise expressly allowed by statute or regulation.

VII. CONSTRUCTION SCHEDULE

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24. **Craig Owners** shall design, contract, construct and complete all particulate matter, SO_2, and NO_x control systems required by this **SIP component** according to the following schedule, subject to a force majeure **determination pursuant to the Craig Station Consent Decree, including a decision by the Court to limit** **force majeure** **pursuant to paragraph 50 of the Craig Station Consent Decree. However, if any schedule has been extended or will be extended pursuant to such a** **force majeure** **determination or determinations by more than 12 months beyond the particular deadline, the Division shall request the Commission reopen (with public notice and hearing) the Long-Term Strategy element of Colorado's Class I Visibility Protection Program State Implementation Plan to reevaluate the demonstration of reasonable progress, and to revise the State Implementation Plan as may be necessary to ensure that the emission limitations are met. In no event shall these** **force majeure** **provisions be construed to authorize or create any preemption or waiver of any State or federal air quality law, or of any requirement contained in the Consent Decree and incorporated into this SIP.**

(a) **UNIT 1**

	Activity	Deadline
(i)	Initiate design activities for baghouses, FGD and NO_x upgrades	1/01/01
(ii)	Issuance of binding contract to construct, or contracts to design and construct:	
	For baghouses	7/31/01
	For FGD upgrades	3/31/02
	For NO_x upgrades	1/31/03
(iii)	Substantial completion of design activities	1/01/03

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required for commencement of
construction of baghouses, FGD and NO_x
control equipment

(iv) Commencement of physical, on-site construction of baghouse, FGD and NO_x upgrades. Dates from contracts described at (ii) above to be provided by **Craig Owners** to **Colorado.** within 15 days of execution of each contract, and shall become enforceable deadlines under this **SIP Component**.

(v) Completion of construction and initiation of startup of all upgrades — 12/31/03

(vi) Provide an opportunity for on-site inspection by **Colorado and EPA** of control equipment installation — 12/31/03 – 6/30/04

(b) **UNIT 2**

	Activity	Deadline
(i)	Initiate design activities for baghouses, FGD and NO_x upgrades	1/01/01
(ii)	Issuance of binding contract to construct, or contracts to design and construct:	
	For baghouses	7/31/01
	For FGD upgrades	3/31/02
	For NO_x upgrades	1/31/03
(iii)	Substantial completion of design activities required for commencement of construction of baghouses, FGD and NO_x control equipment	1/01/03
(iv)	Commencement of physical, on-site construction of baghouse, FGD and NO_x upgrades. Dates from contracts described at (ii) above to be provided by **Craig Owners** to **Colorado** within 15 days of execution of each contract, and shall become enforceable deadlines under this **SIP component**.	
(v)	Completion of construction and initiation of startup of all upgrades	6/30/04

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(vi) Provide an opportunity for on-site inspection by **Colorado and EPA** of control equipment installation — 6/30/04 – 12/31/04

VIII. EMISSION LIMITATION COMPLIANCE DEADLINES

25. **Craig Owners'** obligation to meet the particulate matter, SO_2, and NO_x emission limitations set forth in Section V shall commence on the dates listed below, subject to a force majeure **determination pursuant to the Craig Station Consent Decree, including a decision by the Court to limit force majeure pursuant to paragraph 50 of the Craig Station Consent Decree. However, if any schedule has been extended or will be extended pursuant to such a force majeure determination or determinations by more than 12 months beyond the particular deadline, the Division shall request the Commission reopen (with public notice and hearing) the Long-Term Strategy element of Colorado's Class I Visibility Protection Program State Implementation Plan to reevaluate the demonstration of reasonable progress, and to revise the State Implementation Plan as may be necessary to ensure that the emission limitations are met. In no event shall these force majeure provisions be construed to authorize or create any preemption or waiver of any State or federal air quality law, or of any requirement contained in the Consent Decree and incorporated into this SIP.**

(a) Particulate Matter:

(i) For Unit 1, within 180 days after completion of construction of baghouse system, or by April 30, 2004, whichever date is earlier.

(ii) For Unit 2, within 180 days after completion of construction of baghouse system, or by October 31, 2004, whichever date is earlier.

(b) <u>SO_2</u>:

(i) For Unit 1, within 180 days after completion of construction of the additional SO_2 control equipment, or by June 30, 2004, whichever date is earlier, **Craig Owners** shall achieve the SO_2 mass emission limits at paragraph 8(b)(v), and shall achieve an 85 percent reduction of SO_2 emissions on a 30 boiler operating day rolling average basis measured from coal to stack. Within 270 days of the initial compliance date above, but no later than March 31, 2005, **Craig Owners** shall achieve the 90 percent SO_2 reduction limit, subject to the provisions of subparagraph 8(b)(vii); and

(ii) For Unit 2, within 180 days after completion of construction of the additional SO_2 control equipment, or by December 31, 2004, whichever date is earlier, **Craig Owners** shall achieve the SO_2 mass emission limits at paragraph 8(b)(v), and shall achieve an 85 percent reduction of SO_2 emissions on a 30 boiler operating day rolling average basis measured from coal to stack. Within 270 days of the initial compliance date above, but no later than September 30, 2005, **Craig Owners** shall achieve the 90 percent SO_2 reduction limit, subject to the provisions of subparagraph 8(b)(vii).

(c) <u>NO_x</u>: Design, construction, installation, and testing of overfire upgrades must be completed by June 30, 2004 for Unit 1 and December 31, 2004 for Unit 2.

IX. REPORTING

26. Within thirty days after the end of each quarter, beginning with the report for the first quarter of 2001 **[deletion]**, **Craig Owners** shall provide a quarterly report to **Colorado** regarding the immediately preceding quarter that contains all of the information this **SIP**

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component requires **Craig Owners** to report on a quarterly basis.

27. **[Not applicable to this SIP component.]**

28. In specific, each quarterly report shall include:

(a) A description of construction deadlines achieved, progress made toward meeting future deadlines, and any actual, expected or reasonably likely delays;

(b) All elements of the opacity, SO_2 and NO_x quarterly excess emission and monitoring report **[deletion]**;

(c) After installation of the SO_2 control equipment upgrades, the required quarterly reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 C.F.R. Part 60 containing CEMS quality assurance information;

(d) After installation of the NO_x control equipment upgrades, the required year-to-date quarterly reports for NO_x emissions; and,

(e) **[Not applicable to this SIP component.]**

29. **[Not applicable to this SIP component.]**

30. **Craig Owners'** requirement to provide quarterly reports is in addition to any other notification or report required by this **SIP component**, unless such notification or report is required on a quarterly basis. Furthermore, nothing in this **SIP component** shall be interpreted to either excuse or diminish **Craig Owners'** obligation to provide any other reports, notices or other documents to the public, or local, state or federal officials.

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