Public Utilities Commission

Joshua B. Epel, Chairman
James K. Tarpey, Commissioner
Matt Baker, Commissioner
Doug Dean, Director

John W. Hickenlooper
Governor

Barbara J.Kelley
Executive Director

November 22, 2011

Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 2026

Re: Colorado Documents for the November 29th and 30th
FERC Reliability Technical Conference
Docket No. AD12-1-000

On behalf of Chairman Joshua Epel of the Colorado Public Utilities Commission, I submit for the record the following documents:

- Colorado House Bill 10-1365, The Colorado Clean Air Clean Jobs Act
- Colorado PUC HB10-1365, Final Order Addressing Emission Reduction Plan
- Colorado PUC HB10-1365, Order Addressing Applications for Rehearing, Reargument, or Reconsideration
- Colorado Department of Public Health and Environment, Comments to the U.S. EPA on proposed Mercury and Air Toxics Rule
- Colorado Department of Public Health and Environment, Addendum to the Comments to the U.S. EPA on proposed Mercury and Air Toxics Rule – AQCC Regional Haze Sate Implementation Plan Revision Regulation 3, Part F.

Sincerely,

Rebecca Johnson, PhD
Research and Emerging Issues
Colorado Public Utilities Commission

STATE OF COLORADO

John W. Hickenlooper, Governor
Christopher E. Urbina, MD, MPH
Executive Director and Chief Medical Officer

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Colorado Department of Public Health and Environment

August 4, 2011

U.S. Environmental Protection Agency
EPA Docket Center (EPA/DC)
Mail Code: 2822T
1200 Pennsylvania Ave., N.W.
Washington, DC 20460

RE: State of Colorado Comments – Docket ID No. EPA-HQ-OAR-2009-0234 and Docket ID No. EPA-HQ-OAR-2011-0044

The State of Colorado ("the State") submits the following comments on the U.S. Environmental Protection Agency ("EPA") proposed Mercury and Air Toxics Rule (a.k.a. "MATR," *76FR24976*, May 3, 2011), which encompasses proposed changes to:

- National Emissions Standard for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units, 40 C.F.R. Part 63, Subpart UUUUU ("MACT UUUUU"); and
- Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 40 C.F.R. Part 60, Subparts D, Da, Db, and Dc ("NSPS D, Da, Db, Dc").

The State's comments focus on making use of temporal flexibility in obtaining MATR delegation. In addition, the state makes additional technical comments specific to opacity testing, monitoring plans, and stack test reporting. Please consider the following comments for review:

1. **MATR Delegation** – The State seeks to make use of temporal flexibility, authorized under Clean Air Act (CAA) Section 112(i)(3) in obtaining delegation of the MATR to preserve a hard negotiated comprehensive Colorado-specific program designed to yield greater emission reductions than the MATR alone. The State is concerned about existing sources subject to state-only rules for the reduction of mercury and other air toxic emissions. The State does not want the promulgation of the MATR to undermine the tremendous amount of work invested in creating a program to curb emissions within a reasonable timeframe, protecting both the economic viability of the State and the health of the public.

The State has taken three separate actions to reduce the emissions of criteria and hazardous air pollutants from coal-fired utility boilers:

1) the Colorado Air Quality Control Commission (AQCC) adopted state-only Standards of Performance for Coal-Fired Electric Steam Generating Units into Regulation No. 6, Part B, Section VIII on October 18, 2007; and
2) the Colorado Legislature passed House Bill 10-1365, the "Clean Air-Clean Jobs Act" ("CACJA"), on April 19, 2010; and
3) the AQCC adopted revisions to the Regional Haze State Implementation Plan ("RH SIP") in Regulation No. 3, Part F on January 7, 2011.

Under these rules, the State has successfully negotiated both emissions standards and shut down provisions with Colorado utilities to reduce the emission of criteria and hazardous air pollutants on a timetable that protects the public interest. The CACJA in particular resulted in extensive negotiations to ensure the reliability of the energy grid while encouraging the use of renewable and cleaner energy sources, taking into consideration cost impact to customers, necessary transmission system changes, unit outage schedules and outage contingencies, and construction timeframes. Ultimately, the CACJA will promote job growth and reduce air emissions within the State.

EPA offers three options for delegation of MACT UUUUU to state or local agencies: straight delegation, partial approval, or replacement of the rule with a state rule (40 C.F.R. Part 63, Subpart E, §63.91). For state or local agencies which pursue straight or partial delegation, EPA has proposed in the preamble to the MATR that it supports the offering of an additional one (1) year to existing sources which are unable to comply with the requirements within the usual three (3) year timeframe, on a case-by-case basis where the need can be confirmed by the Administrator.

Several of the Colorado units covered by CACJA will achieve emission reductions years earlier than MATR. However, for other existing units in the State, four (4) years will not be sufficient to comply with the requirements of the MATR through the straight or partial delegation options. Through the CACJA, many of these sources have entered into phase-out schedules with completion in 2017, after the approximate compliance date in late 2014 or 2015 for the MATR. See Table 1, below, for more information on the scheduled compliance dates for coal-fired utility boilers in Colorado.

Table 1[1]. Schedule of Emission Reductions from Coal-Fired Utility Boilers as required under AQCC Regulation No. 3, Part F.

Coal-Fired EGU	Compliance Date[2]	Emission Reductions			
		NOx[2] (tpy)	SO2[2] (tpy)	PM[2] (tpy)	Hg (lb/yr)
PSCo Cherokee[3] Unit 1	Shutdown no later than 7/1/2012	1,556	2,221	37	6.7[4]

Coal-Fired EGU	Compliance Date[2]	Emission Reductions			
		NOx[2] (tpy)	SO2[2] (tpy)	PM[2] (tpy)	Hg (lb/yr)
PSCo Cherokee[3] Unit 2	Shutdown no later than 12/31/2011	2,895	1,888	35	4.2[4]
PSCo Cameo Unit 1	Shutdown no later than 12/31/2011	516	849	225	15.8[5]
PSCo Cameo Unit 2		624	1,749		
Black Hills Clark[3] Units 1 & 2	Shutdown no later than 12/31/2013	861	1,457	72	
PSCo Arapahoe[3] Unit 3	Shutdown no later than 12/31/2013	1,770	925	56	15.7[5]
PSCo Arapahoe[3] Unit 4	Natural Gas operation by 12/31/2014	248	1,764	0	30.8[5]
PSCo Cherokee[3] Unit 3	Shutdown no later than 12/31/2016	1,866	743	65	4.4[4]
PSCo Cherokee[3] Unit 4	Natural Gas operation by 12/31/2017	2,211	2,127	0	30.4[5]
PSCo Valmont[3] Unit 5	Shutdown no later than 12/31/2017	2,314	758	42	8.7[4]

1. This table only includes those sources in Colorado which will cease to be subject to MACT UUUUU by 2017. There are an additional 17 coal-fired EGUs that may be subject to MACT UUUUU which also achieved substantial emission reductions through the CACJA and the RH SIP.
2. Compliance dates and emission reductions for NOx, SO2, and PM are outlined in Colorado's RH SIP submittal for revisions adopted by the AQCC on January, 7, 2011.
3. CACJA source.
4. Mercury emission reductions are based on actual emissions from 2010 as reported to the State. These values are based on data from stack tests and/or continuous emission monitors.
5. Mercury emission reductions are based on actual heat input for the data year 2010. Except for PSCo Cherokee Unit 4, the emissions were calculated with an assumed emission factor of 0.0174 lb Hg/GWhr, which is the state-only emission standard beginning in 2014. PSCo reported an Hg emission factor of 0.006 lb Hg/GWhr for Cherokee Unit 4.

However, for states seeking to replace MACT UUUUU with a state rule, EPA offers no specific recommendation in the preamble to the MATR, and instead requests comments on the integration of existing state rules with MACT UUUUU under the delegation provisions in CAA Section 112(l). The State requests that in the review of the delegation plan under CAA 112(l), EPA remain open to a plan calling for the continued operation of equipment which will not individually be in compliance with the emissions standards of

MACT UUUUU after 2015, but that will result emissions reductions that are equivalent to or exceed reductions required on a unit-by-unit basis under CAA Section 112(d).

As mentioned above, through the CACJA, there are units in the State which are scheduled to remain in operation after the effective date of the MATR. During that operation, those units will be subject to the mercury standards (80% inlet mercury reduction) for coal-fired steam generating units in Regulation No. 6, Part B by no later than January 1, 2014. While these emission standards are not as stringent as in those proposed in the MATR, the combination of these reductions with the reductions associated with CACJA's existing coal-fired unit phase out, the overall reduction in mercury, other air toxic and criteria pollutant emissions will by far exceed the emission reductions projected in the MATR. Overall, the State believes that the ultimate benefit to air quality of the State's rules will exceed that of the MATR, and will result in a State rule that is more stringent than MACT UUUUU.

Without some measure of temporal flexibility in compliance schedules, the carefully-devised structure of the comprehensive CACJA is placed in jeopardy, and the value of such comprehensive approaches for overall, cost-effective compliance with the new MATR requirements on both the State and national levels could be lost. Therefore the State requests EPA provide an option in obtaining MATR delegation that allows temporal flexibility regarding compliance schedules, as authorized under CAA Section 112(i)(3), to preserve Colorado's comprehensive program designed to yield greater emissions reductions than the MATR alone.

The State requests this temporal flexibility associated with MACT UUUUU delegation because it is interested in permanently exempting sources that would otherwise be subject to MACT UUUUU from having to comply with the MACT when they have committed to shutting down or are undergoing a fuel conversion proximate to MACT UUUUU compliance dates. Without this ability, sources may have to expend substantial resources to comply with the rule for a short time. Sources undergoing a fuel conversion may trigger MACT UUUUU requirements which would not otherwise apply after the fuel conversion, and thus have to maintain records, report necessary information, and possibly comply with other requirements associated with a fuel the source no longer burns based on EPA's "Once In Always In" MACT policy. With this in mind, the State suggests that EPA use the following criteria in developing the MACT UUUUU delegation option affording temporal flexibility. EPA could delegate authority to implement MACT UUUUU to the State with the provision that the State has the authority to exempt specific affected sources from the MACT UUUUU requirements, if the State can demonstrate to EPA's satisfaction that:

- The source or sources in question are subject to a federally enforceable permit condition or state regulatory requirement[1] to shut down or convert from coal

[1] While the EPA may prefer to rely upon incorporation of such requirement into a state implementation plan (SIP), the time necessary to submit the SIP to EPA alone may exceed three years, and does not account for the additional time necessary for EPA to act on that SIP submittal. Reliance upon an EPA approved SIP provision may not be

and/or oil to natural gas within a reasonable time frame compared to MACT UUUU compliance dates; and

- The source's emissions reduction or benefit to air quality is equivalent to or greater than the reductions required by MACT UUUUU.

2. **Opacity Testing Extension –** The State suggests EPA consider removing the requirement to complete subsequent Method 9 opacity performance tests after the initial performance test is completed, if the source is able to show in the initial reading that the opacity complies with the standard. It is the experience of the State that subsequent opacity readings for sources which have not exceeded the standard are onerous and may actually discourage good air pollution control practices.

   Alternately, the State suggests that EPA consider expanding the extension associated with the MATR proposed changes to 40 C.F.R. Part 60, Subpart Dc, §60.47c(a)(1)(i). EPA has proposed a change in the MATR to allow sources to extend the time frame to complete a Method 9 performance test from a minimum of every 12 months for sources where the initial performance test showed that there were no visible emissions. In the MATR, EPA proposes to allow those sources to either repeat the performance test every 12 months or within 45 days of using a fuel with an opacity standard. Without the latter option, sources which primarily combust natural gas are often required to undergo a special startup using diesel fuel solely to satisfy the current compliance requirement to complete a Method 9 performance test every 12 months. As proposed, those sources will now only be required to complete a Method 9 performance test within 45 days of using diesel fuel, which will be dependent on the sources' operational need and not a compliance requirement. The State is in agreement with EPA's proposed revision to 40 C.F.R. Part 60, Subpart Dc, §60.47c(a)(1)(i).

   However, this proposed extension is only available to facilities that have no visible emissions observed during the initial 60 minute Method 9 performance test. Pursuant to 40 C.F.R. Part 60, Subpart Dc §60.47c(a)(1)(ii-iv), sources which have *any* 6-minute opacity average greater than 0% must conduct another Method 9 performance test for compliance purposes in the near term (every 6 months, 3 months, or more frequently). It is the State's experience that all boilers running on diesel experience some degree of opacity during operation, which typically subsides quickly. At least one 6-minute opacity average is likely to exceed 0%. For many of the State's sources, the primary fuel used is natural gas, and diesel fuel is used only as a backup. Because these sources are very likely to have at least one 6-minute opacity average greater than 0% while using diesel fuel, they are required to repeat the Method 9 performance test even if they have ceased using diesel fuel in the interim. Repeating this performance test requires the source to shut down the boiler and restart using diesel fuel, only to shut down once again to restart using natural gas. It is the State's experience that, left to the operational needs of the

temporally feasible considering that MACT requirements for new units typically apply 30 days after promulgation of a MACT rule, and MACT requirements for existing sources subject to new MACT requirements have up to three years. Thus, the State suggests reliance upon federally enforceable permit conditions or state regulatory requirements.

source, a boiler may only utilize diesel fuel once every few years as opposed to the compliance requirement to use diesel fuel every few months.

It appears that the 45-day allowance, while intending to limit unnecessary opacity monitoring for sources with no visible emissions, was not extended to sources which may have some visible emissions during operation. Therefore, such sources are required to regularly shutdown their equipment and restart on diesel just to complete the necessary opacity readings. The State suggests that either EPA extend the 45-day allowance to §60.47c(a)(1)(ii-iv), or that a permitting agency may authorize an alternative opacity monitoring schedule by means of the site-specific monitoring plan as discussed in 40 C.F.R. Part 60, Subpart Dc,§60.47c(h).

3. **Site-specific Monitoring Plan –** The State requests that EPA provide further guidance on the "written site-specific monitoring plan approved by the permitting authority," as discussed in the MATR under 40 C.F.R. Part 60, Subpart Dc, §60.47c(h). Specifically, in the scenario discussed in comment 2 above, the State requests EPA allow permitting authorities to authorize less stringent opacity or other monitoring requirements than identified in the rule. For example, the State proposes that a permitting agency could require sources to conduct opacity testing only upon using a fuel for operational reasons rather than for compliance demonstrations. Further, a permitting agency could specify that each periodically required Method 9 does not have to adhere to the notification and reporting requirements for 40 C.F.R. Part 60, associated with performance tests found in 40 C.F.R. Part 60, Subpart A, §§60.8 and 60.11, but rather the source would be required to submit any deviations with the excess emissions report required under 40 C.F.R. Part 60, §60.48c(c).

4. **Written Stack Test Reporting –** The State intends to continue to request sources to submit hard copies of stack test reports to the State, in addition to EPA's collection of stack testing data via the Electronic Reporting Tool ("ERT"), and therefore supports EPA's preservation of related requirements in 40 C.F.R. Part 60, §§60.8 and 60.11, and Part 63, §§63.7 and 63.10. The State appreciates EPA's need to readily access stack test data and applauds efforts to improve emission factors. However, the State believes that the stack test data reported must be considered along with additional, specific information for each source's operations. This evaluation cannot be easily conducted with the limited data reported in the ERT. The State believes that the stack test data submitted in the ERT, taken at face value, may be misleading unless the context in which the testing was completed is understood. Until the number and degree of source configuration and operation variables can be adequately accounted for and reported in one reporting tool, allowing the associated test data to be wholly considered, the State relies heavily upon the submission of written stack test reports. Thus, the State supports EPA's preservation of the submittal of written performance testing reports to state agencies, and requests that EPA consider a way for states to report to EPA via the ERT that the test is not approvable or was not representative.

Thank you again for the opportunity to submit comments on the MATR.

Sincerely,

Martha E. Rudolph
Director, Environmental Programs
Colorado Department of Public Health and Environment

cc: Christopher E. Urbina, CDPHE
Garry Kaufman, CDPHE

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 3

STATIONARY SOURCE PERMITTING AND AIR POLLUTANT EMISSION NOTICE REQUIREMENTS

5 CCR 1001-5

Outline of Regulation

Regulation Number 3

Style Guide

Many provisions of this Regulation Number 3 have been approved by the U.S. EPA for incorporation into Colorado's State Implementation Plan (SIP). Some provisions are currently under review by the U.S. EPA. The following guide to the font styles used in this Regulation Number 3 can be used to identify those provisions that have been adopted by the Air Quality Control Commission and are currently under review by the U.S. EPA.

* *Italicized text* will become effective when the U.S. EPA approves that language for incorporation into the state implementation plan

* <u>Underlined text</u> will be effective until the U.S. EPA approves the italicized text for incorporation into the state implementation plan

PART A CONCERNING GENERAL PROVISIONS APPLICABLE TO REPORTING AND PERMITTING

I. Applicability

I.A. The provisions of this Part A shall apply statewide to all sources of air pollutants except as otherwise provided herein.

PART F REGIONAL HAZE LIMITS - BEST AVAILABLE RETROFIT TECHNOLOGY (BART) AND REASONABLE PROGRESS (RP)

The provisions of Section VI (Regional Haze Determinations) and VII (MRR) of Regulation 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan. All other Sections of Regulation 3, Part F are State-Only.

The provisions of Part 51, Appendix Y, Title 40, of the Code of Federal Regulations (CFR), promulgated by the U.S. Environmental Protection Agency listed in this Section are hereby incorporated by reference by the Air Quality Control Commission and made a part of the Colorado Air Quality Control Commission Regulations as modified by the following Regulation Number 3, Part F. Materials incorporated by reference are those in existence as July 6, 2005 and do not include later amendments. The material incorporated by reference is available for public inspection during regular business hours at the Office of the Commission, located at 4300 Cherry Creek Drive South, Denver, Colorado 80246, or may be examined at any state publications depository library. Parties wishing to inspect these materials should contact the Technical Secretary of the Commission, located at the Office of the Commission.

I. Applicability

The provisions of this regulation apply to existing stationary facilities (BARTeligible sources), as defined in Section II.I. of this regulation, as well as to Reasonable Progress (RP) sources.

II. Definitions

II.A. Adverse impact on visibility

Means visibility impairment that interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas.

II.B. Available Technology

Means that a technology is licensed and available through commercial sales.

II.C. Applicable Technology

Means a commercially available control option that has been or may soon be deployed on the same or a similar source type or a technology that has been used on a pollutant-bearing gas stream that is the same or similar to the gas stream characteristics of the source.

II.D. Average Cost Effectiveness

Means the total annualized costs of control divided by annual emissions reductions (the difference between baseline annual emissions and the estimate of emissions after controls). For the purposes of calculating average cost effectiveness, baseline annual emissions means a realistic depiction of anticipated annual emissions for the source. The source or the Division may use state or federally enforceable permit limits or estimate the anticipated annual emissions based upon actual emissions from a representative baseline period.

II.E. BART Alternative

Means an alternative measure to the installation, operation, and maintenance of BART that will achieve greater reasonable progress toward national visibility goals than would have resulted from the installation, operation, and maintenance of BART at BART-eligible sources within industry source categories subject to BART requirements.

II.F. BART-eligible source

Means an existing stationary facility as defined in Section II.I.

II.G. Best Available Retrofit Technology (BART)

Means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant that is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, the remaining useful life of the source or unit, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

II.H. Deciview

Means a measurement of visibility impairment. A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. The deciview haze index is calculated based on the following equation (for the purposes of calculating deciview, the atmospheric light extinction coefficient must be calculated from aerosol measurements):

Deciview haze index=10 $\ln_e (b_{ext}/10\ Mm^{-1})$

Where b_{ext}= the atmospheric light extinction coefficient, expressed in inverse

megameters (Mm^{-1}).

II.I. Existing stationary facility

Means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any visibility impairing air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted.

- II.I.1. Fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input that generate electricity for sale
  - II.I.1.a. Boiler capacities shall be aggregated to determine the heat input of a plant
  - II.I.1.b. Includes plants that co-generate steam and electricity and combined cycle turbines
- II.I.2. Coal cleaning plants (thermal dryers)
- II.I.3. Kraft pulp mills

II.I.4. Portland cement plants

II.I.5. Primary zinc smelters

II.I.6. Iron and steel mill plants

II.I.7. Primary aluminum ore reduction plants

II.I.8. Primary copper smelters

II.I.9. Municipal incinerators capable of charging more than 250 tons of refuse per day

II.I.10. Hydrofluoric, sulfuric, and nitric acid plants

II.I.11. Petroleum refineries

II.I.12. Lime plants

II.I.13. Phosphate rock processing plants

Includes all types of phosphate rock processing facilities, including elemental phosphorous plants as well as fertilizer production plants

II.I.14. Coke oven batteries

II.I.15. Sulfur recovery plants

II.I.16. Carbon black plants (furnace process)

II.I.17. Primary lead smelters

II.I.18. Fuel conversion plants

II.I.19. Sintering plants

II.I.20. Secondary metal production facilities

Includes nonferrous metal facilities included within Standard Industrial Classification code 3341, and secondary ferrous metal facilities in the category "iron and steel mill plants."

II.I.21. Chemical process plants

Includes those facilities within the 2-digit Standard Industrial Classification 28, including pharmaceutical manufacturing facilities

II.I.22. Fossil-fuel boilers of more than 250 million BTUs per hour heat input

- II.I.22.a. Individual boilers greater than 250 million BTU/hr, considering federally enforceable operational limits

- II.I.22.b. Includes multi-fuel boilers that burn at least fifty percent fossil fuels

II.I.23. Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels

II.I.23.a. 300,000 barrels refers to total facility-wide tank capacity for tanks put in place after August 7, 1962 and in existence on August 7, 1977

II.I.23.b. Includes gasoline and other petroleum-derived liquids.

II.I.24. Taconite ore processing facilities

II.I.25. Glass fiber processing plants

II.I.26. Charcoal production facilities

Includes charcoal briquette manufacturing and activated carbon production

II.J. Incremental Cost Effectiveness

Means the comparison of the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

Incremental Cost Effectiveness (dollars per incremental ton removed) = [(Total annualized costs of control option) - (Total annualized costs of next control option)] ÷ [(Next Control option annual emissions) - (control option annual emissions)]

II.K. In existence

Means that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time.

II.L. In operation

Means engaged in activity related to the primary design function of the source.

II.M. Integral vista

Means a view perceived from within the mandatory Class I Federal area of a specific landmark or panorama located outside the boundary of the mandatory Class I Federal area.

II.N. Natural conditions

Means naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration.

II.O Plant

Means all emissions units at a stationary source.

II.P. Visibility-Impairing Air Pollutant

Includes the following:

II.P.1. Sulfur dioxide (SO2),

II.P.2. Nitrogen oxides (NOx) and

II.P.3. Particulate matter. (PM10 will be used as the indicator for particulate matter. Emissions of PM10 include the components of PM2.5 as a subset.).

III. Sources required to Perform a BART Analysis

Each source that the Division determines is BART-eligible and subject to BART shall complete a BART analysis under Section IV. The Division shall provide written notice to each source determined to be subject to BART. Within twenty calendar days of the mailing of such notice a source may appeal such determination to the Commission by filing a petition for a hearing with the Commission. Any such hearing shall be subject to Section 1.6.0 of the Procedural Rules.

III.A. Determining Potential to Emit for a BART Source

For the purposes of determining whether the potential to emit of an existing stationary source is greater than 250 tpy the potential emissions of visibility impairing pollutants from the existing stationary source shall include the emissions from all BART-eligible units which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same Major Group (*i.e.*, which have the same two-digit code) as described in the Standard Industrial Classification Manual.

III.B. Identification of sources subject to BART

III.B.1. Identification of sources subject to BART shall be performed in accordance with EPA's guidelines for BART determinations under the regional haze rule 40 CFR Part 51, Appendix Y. A BART-eligible source described in Section III.A, above, is subject to BART unless valid air quality dispersion modeling demonstrates that the source will not cause or contribute to visibility impairment in any Class I area.

III.B.1.a. A single source that is responsible for a 1.0 deciview change or more is considered to "cause" visibility impairment in any Class I area.

III.B.1.b. A single source that is responsible for a 0.5 deciview change or more is considered to "contribute" visibility impairment in any Class I area.

III.B.1.c. A single source is exempt from BART if the 98th percentile daily change in visibility, as compared against natural background conditions, is less than 0.5 deciviews at all Class I federal areas for each year modeled and for the entire multi-year modeling period.

III.B.2. The Division will perform air quality dispersion modeling for each source identified as BART-eligible, for all visibility impairing pollutants, for class I areas. The modeling results will be provided to each source.

IV. BART Analysis

IV.A. Presumptive BART for Coal Fired Power Plants

IV.A.1. Plants with a Generating Capacity of 750 MW or Greater

BART-eligible coal fired power plants with a generating capacity of 750 MW or GREATER is presumed to be able to meet the presumptive limits. Regardless of whether or not a unit can meet the presumptive BART limits the source must complete a BART analysis.

IV.A.2. Other Coal Fired Power Plants

The Division shall use the presumptive BART limits of section IV.A.3. as guidelines and may establish a BART level for the unit either above or below the presumptive BART level based on the BART determination.

IV.A.3. Coal-Fired Electric Generating Units

IV.A.3.a. Sulfur Dioxide

Coal-Fired Electric Generating Units: 95 percent reduction or 0.15 lb SO_2/mmBTU.

IV.A.3.b. Nitrogen Oxides

Unit Type	Coal Type	NO_X limit (lb/mm BTU)
Dry bottom Wall fired	Bituminous	0.39
	Sub-bituminous	0.23
	Lignite	0.29
Tangential Fired	Bituminous	0.28
	Sub-bituminous	0.15
	Lignite	0.17
Cell Burners	Bituminous	0.40
	Sub-bituminous	0.45
Dry-turbo-fired	Bituminous	0.32
	Sub-bituminous	0.23
Wet-bottom tangential-fired	Bituminous	0.62

IV.B. Each source subject to BART pursuant to Section III shall submit a BART application for a construction permit, which shall include a BART analysis, a proposal for BART at the source and a justification for the BART proposal to the Division by August 1, 2006.

IV.B.1. The BART analysis must include, at a minimum:

IV.B.1.a. A list of the demonstrated and potentially applicable retrofit control options for the units subject to BART. Sources are not required to evaluate control options, which are less effective than the controls currently installed on the BART subject source or unit.

IV.B.1.b. A discussion of the technical feasibility of each of the technologies identified in Section IV.B.1.a. This discussion should include an analysis of whether the proposed technology is available and applicable. If the source determines that a technology is not technically feasible the discussion shall include a factual demonstration that the option is not commercially available or that unusual circumstances preclude its application to the emission unit.

IV.B.1.c. A ranking of all the technically feasible technologies identified in Section IV.B.1.b. The ranking shall take into account various emission performance characteristics of the technologies. The technologies should be ranked from lowest emissions to highest emissions for each pollutant and each emissions unit. The ranking should include a discussion of pollution control equipment in use at the unit, including upgrading existing equipment if technically feasible.

IV.B.1.d. An evaluation of the impacts of the technically feasible BART options. The impact evaluation shall include:

IV.B.1.d.(i). An estimate of the Average Cost Effectiveness of each of the control technologies identified as technically feasible in Section IV.B.1.b. This analysis shall specify the emissions unit being controlled, the design parameters for the emission controls and cost estimates based on those design parameters. The remaining useful life of the source or unit may be taken into account in the cost of the technologies. The remaining useful life is the difference between: (1) The date that controls will be put in place (capital and other construction costs incurred before controls are put in place can be rolled into the first year); and (2) The date the facility permanently stops operations. Where this affects the BART determination, this date should be assured by a federally- or State-enforceable restriction preventing further operation. The analysis must also include the energy and non-air quality environmental impacts of control options.

IV.B.1.d.(ii). An analysis of the incremental cost effectiveness. Before a control technology can be eliminated the source shall evaluate the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option.

IV.B.1.d.(iii). An evaluation of the visibility impacts for each BART option according to modeling guidance provided by the Division.

IV.B.1.d.(iv). An evaluation of non-air quality impacts. The non-air quality impacts may include water use increases, solid waste disposal, or other adverse environmental impacts.

IV.B.1.d.(v). An evaluation of the energy impacts. The energy impact analysis should look at the energy requirements of the control technology and any energy penalties or benefits associated with the control. The analysis should also consider direct energy consumption and may address concerns over the use of locally scarce fuels or the use of locally or regionally available coal.

IV.B.1.d.(v).(1). The energy impacts analysis may consider whether there are relative differences between alternatives regarding the use of locally or regionally available coal, and whether a given alternative would result in significant economic disruption or unemployment.

IV.B.1.e. An evaluation and justification of the proposed averaging time to evaluate compliance with the proposed emission limitations.

IV.B.1.f. Coal-fired power plants may, in their discretion, include in the BART analysis an evaluation of representative characteristics (including nitrogen content) of coal from sources they reasonably expect to use, to the extent such characteristics tend to result in higher NOx emissions than coals of the same classification from alternative sources. The analysis also may consider whether a particular BART limit might lead the power plant not to use coal from a particular mine due to such coal characteristics, and the extent to which such a decision might result in economic disruption or unemployment at the mine or in nearby communities.

IV.B.1.g. Sources subject to a MACT standard may limit the analysis for those pollutants covered by the MACT to a discussion of new technologies that have become available since the promulgation of the MACT.

IV.B.2. Sources with a potential to emit of less than 40 tons per year of SO2 and NOx and less than 15 tpy of PM10 may exclude those pollutants from the BART determination.

IV.B.3. Selecting a best alternative

The source shall submit a proposal for BART at the source or unit(s), including a justification for selecting the technology proposed. The justification shall be based on the following factors: (1) the technology available; (2) the costs of compliance; (3) the energy and non-air environmental impacts of compliance; (4) any pollution control equipment in use at the source or unit(s); (5) the remaining useful life of the source or unit(s) and; (6) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

IV.B.4. Schedules to comply with BART emissions limits

IV.B.4.a. The technology analysis shall include a schedule to comply with BART or a BART alternative as expeditiously as practicable following EPA approval of the state implementation plan for regional haze that incorporates such BART requirements. The source must comply with BART or BART alternative emissions limits no later than 5 years after approval of the state implementation plan by EPA for regional haze.IV.B.4.b. A source or unit subject to BART may implement a BART alternative in lieu of BART if such BART alternative is authorized by the Division.

IV.C. BART Alternative

As an alternative to BART for a source or sources, the Division may approve a BART Alternative. If the Division approves source grouping as a BART Alternative, only sources (including BART-eligible and non-BART eligible sources) within the same source category (as defined by SIC or NAICS code) within the same airshed may be grouped together.

IV.C.1. If a Source (s) proposes a BART Alternative, the resultant emissions reduction and visibility impacts must be compared with those that would result from the BART options evaluated for the source(s).

IV.C.2. Source (s) proposing a BART alternative shall include in the BART analysis an analysis and justification of the averaging period and method of evaluating compliance with the proposed emission limitation.

IV.D. Emission limits

IV.D.1. Coal-Fired Electric Generating Units

Compliance with the emission limitation is determined on a 30-day rolling average basis for SO2 and NOx, or may be determined by the Division based on the BART analysis submitted by the source. The emission limit shall be included in the facility's permit.

IV.D.2. Other Sources Subject to BART

The Division will establish emission limits with averaging times consistent with established reference methods and include the limit in the facility's permit.

IV.E. A source that has installed BART for regional haze or implemented a Division approved BART alternative for regional haze is exempted from the imposition of further controls pursuant to regional haze BART with respect to those pollutants that are controlled through BART or the BART alternative for Regional Haze and is exempted from the imposition of further controls necessary for reasonable progress during the first reasonable progress planning period. Sources may be subject to additional controls or emission reductions based on reasonable progress requirements in planning periods beyond the first planning period under the regional haze State Implementation Plan.

IV.F. Division Review and Approval

IV.F.1. The Division shall review and approve, disapprove or amend the proposed BART technology or BART alternative, including the emission limit, schedule for compliance for the facility, and averaging period. The Division shall consider additional information both submitted and not submitted by the source that is deemed relevant. The Division shall submit its BART determination to the Commission for review and approval.

IV.F.2. If two or more sources are grouped together pursuant to Section IV.C. the Division shall establish recordkeeping and reporting requirements sufficient to determine that the sources meet the BART alternative emission limits.

IV.F.3. Any source seeking to modify the BART determination for that facility must submit a new BART analysis for review by the Division.

V. Challenge of Division BART Determinations and Enforceable Agreements.

V.A. Persons affected or aggrieved by a BART determination may challenge the decision of the Commission pursuant to Article 4 of Title 24, C.R.S.

VI. Regional Haze Determinations

VI.A. BART Determinations

VI. A.1. The provisions of this Section VI.A of Regulation Number 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan.

VI.A.2. The sources listed below shall not emit or cause to be emitted nitrogen oxides (NOx), sulfur dioxide (SO2), or particulate in excess of the following limits:

BART Determinations for Colorado Sources			
Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate Emission Limit**
CENC Unit 4	0.37 lb/MMBtu (30-day rolling average) or 0.26 lb/MMBtu Combined Average for Units 4 and 5 (30-day rolling average)	1.0 lb/MMBtu (30-day rolling average)	0.07 lb/MMBtu
CENC Unit 5	0.19 lb/MMBtu (30-day rolling average) or 0.26 lb/MMBtu Combined Average for Units 4 and 5 (30-day rolling average)	1.0lb/MMBtu (30-day rolling average)	0.07 lb/MMBtu
Craig Unit 1	0.28 lb/MMBtu (30-day rolling average)	0.11 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Craig Unit 2	0.08 lb/MMBtu (30-day rolling average)*	0.11 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu

* The NOx emission limits for Craig Units 1 and 2 constitute a BART Alternative.

Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate Emission Limit**

Comanche Unit 1	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	0.12 lb/MMBtu (individual unit 30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	0.03 lb/MMBtu
Comanche Unit 2	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	0.12 lb/MMBtu (individual unit 30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	0.03 lb/MMBtu
Hayden Unit 1	0.08lb/MMBtu (30-day rolling average)	0.13 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Hayden Unit 2	0.07 lb/MMBtu (30-day rolling average)	0.13 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Martin Drake Unit 5	0.31 lb/MMBtu (30-day rolling average)	0.26 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Martin Drake Unit 6	0.31lb/MMBtu (30-day rolling average)	0.13lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Martin Drake Unit 7	0.29 lb/MMBtu (30-day rolling average)	0.13lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu

CEMEX – Lyons Kiln	255.3 lbs/hr (30-day rolling average) 901.0 tons/year (12-month rolling average)	25.3 lbs/hr (12-month rolling average) 95.0 tons/yr (12-month rolling average)	0.275 lb/ton of dry feed 20% opacity
CEMEX – Lyons Dryer	13.9 tons/yr	36.7 tons/yr	22.8 tons/yr 10% opacity

VI.A.3. Each source listed in the above tables must comply with the above limits and averaging times as expeditiously as practicable, but in no event later than five years after EPA approval of Colorado's state implementation plan for regional haze, or relevant component thereof. Each source listed in the above tables must maintain control equipment or operational practices required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained.

VI.A.4. The sources shall submit to the Division a proposed compliance schedule within sixty days after EPA approves the BART portion of the Regional Haze SIP. The Division shall publish these proposed schedules and provide for a thirty-day public comment period following publication. The Division shall publish its final determinations regarding the proposed schedules for compliance within sixty days after the close of the public comment period and will respond to all public comments received.

VI.B. Reasonable Progress Determinations

VI.B.1. The provisions of this Section VI.B of Regulation Number 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan.

VI.B.2. The sources listed below shall not emit or cause to be emitted nitrogen oxides (NOx), sulfur dioxide (SO2), or particulate in excess of the following limits:

RP Determinations for Colorado Sources

Emission Unit	NOx Emission Limit	SO2 Emission Limit	Particulate Emission Limit
Rawhide Unit 101	0.145 lb/MMBtu (30-day rolling average)	0.11 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
CENC Unit 3	246 tons per year (12-month rolling total)	1.2 lb/MMBtu	0.07 lb/MMBtu

RP Determinations for Colorado Sources			
Emission Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate Emission Limit**
Nixon	0.21 lb/MMBtu (30-day rolling average)	0.11 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Clark Units 1 & 2 Shutdown 12/31/2013	Shutdown 12/31/2013	Shutdown 12/31/2013	Shutdown 12/31/2013
Holcim - Florence Kiln	2.73 lbs/ton clinker (30-day rolling average) 2,086.8 tons/year	1.30 lbs/ton clinker (30-day rolling average) 721.4 tons/year	246.3 tons/year
Nucla	0.5 lb/MMBtu (30-day rolling average)	0.4 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu

RP Determinations for Colorado Sources			
Emission Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate Emission Limit**
Craig Unit 3	0.28 lb/MMBtu (30-day rolling average)	0.15 lb/MMBtu (30-day rolling average)	0.013 lb/MMBtu filterable PM 0.012 lb/MMBtu filterable PM10
Cameo Shutdown 12/31/2011	Shutdown 12/31/2011	Shutdown 12/31/2011	Shutdown 12/31/2011

VI.B.3. Each source listed in the above table must comply with the above limits and averaging times as expeditiously as practicable, but in no event later than December 31, 2017. Each source listed in the above table must maintain control equipment or operational practices required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained.

VI.B.4. The sources shall submit to the Division a proposed compliance schedule within sixty days after EPA approves the RP portion of the Regional Haze SIP. The Division shall publish these proposed schedules and provide for a thirty-day public comment period following publication. The Division shall publish its final determinations regarding the proposed schedules for compliance within sixty days after the close of the public comment period and will respond to all public comments received.

VI.C. Public Service Company of Colorado (PSCo) BART Alternative Program

VI.C.1. The provisions of this Section VI.C of Regulation Number 3, Part F (with the exception of the SO2 cap of subsection VI.C.4) shall be incorporated into Colorado's Regional Haze State Implementation Plan.

VI.C.2. The sources listed below shall not emit or cause to be emitted nitrogen oxides (NOx), sulfur dioxide (SO2), or particulate in excess of the following limits, after the following compliance dates:

BART Alternative Program Determinations for PSCo Sources			
Emission Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate Emission Limit**
Cherokee * Unit 1 Shutdown No later than 7/1/2012	0 Shutdown No later than 7/1/2012	0 Shutdown No later than 7/1/2012	0 Shutdown No later than 7/1/2012
Cherokee Unit 2 Shutdown 12/31/2011	0 Shutdown 12/31/2011	0 Shutdown 12/31/2011	0 Shutdown 12/31/2011
Cherokee Unit 3 Shutdown No later than 12/31/2016	0 Shutdown No later than 12/31/2016	0 Shutdown No later than 12/31/2016	0 Shutdown No later than 12/31/2016

Cherokee Unit 4	0.12 lb/MMBTU (30-day rolling average) by 12/31/2017 Natural Gas Operation 12/31/2017	7.81 tpy (rolling 12 month average) Natural Gas Operation 12/31/2017	0.03 lbs/MMBtu Natural Gas Operation 12/31/2017
Valmont Unit 5 Shutdown 12/31/2017	0 Shutdown 12/31/2017	0 Shutdown 12/31/2017	0 Shutdown 12/31/2017
Pawnee	0.07 lb/MMBTU (30-day rolling average) by 12/31/2014	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	0.03 lbs/MMBtu
Arapahoe** Unit 3 Shutdown 12/31/2013	0 Shutdown 12/31/2013	0 Shutdown 12/31/2013	0 Shutdown 12/31/2013
Arapahoe Unit 4	600 tpy on (rolling 12 month average) Natural Gas operation12/31/2014	1.28 tpy (rolling 12 month average) Natural Gas operation 12/31/2014	0.03 lbs/MMBtu Natural Gas operation 12/31/2014

* 500 tpy NOx will be reserved from Cherokee Station for netting or offsets

** 300 tpy NOx will be reserved from Arapahoe Station for netting or offsets for additional natural gas generation

VI.C.3. Each source listed in the above table must either shut down or comply with the above limits and averaging times no later than the compliance date set forth in the above table. Each source listed in the above table must maintain any applicable control equipment required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment is properly operated and maintained.

VI.C.4. In addition to the above listed emission limits and compliance dates, between 1/1/2013 and 12/31/2015, Cherokee Units 3 and 4 and Valmont, considered as a whole, shall not emit in excess of 4,200 tons of SO2 per year as determined on a calendar year annual basis. Between 1/1/2016 and 12/31/2017 Cherokee Unit 4 and Valmont considered as a whole, shall not emit in excess of 3,450 tons of SO2 per year as determined on a calendar year annual basis.

VII. Monitoring, Recordkeeping, and Reporting for Regional Haze Limits

The provisions of this Section VII of Regulation 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan.

Federal Regulations Adopted by Reference

The following regulations promulgated by the United States Environmental Protection Agency (EPA) were previously adopted by the Colorado Air Quality Control Commission and are thereby already incorporated by reference:

40 CFR Part 60 and Appendices (As incorporated by reference within Commission Regulation Number 6, 5 CCR 1001-8)

40 CFR Part 63, Subpart A - National Emission Standards for Hazardous Air Pollutants General Provisions and Subpart LLL - National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry (As incorporated by reference within Commission Regulation Number 8, Part A, 5 CCR 1001-10).

40 CFR Part 64 (As incorporated by reference within Commission Regulation Number 3, Part C Section XIV., 5 CCR 1001-5)

40 CFR Part 75 including Performance Specifications and Appendices (As incorporated by reference within Commission Regulation Number 6, 5 CCR 1001-8)

VII.A. Definitions

VII.A.1. "BART alternative program unit" means any unit subject to a Regional Haze emission limit contained in the Table in Regulation Number 3, Part F, Section VI.C.

VII.A.2. "BART unit" means any unit subject to a Regional Haze emission limit contained in the Table in Regulation Number 3, Part F, Section VI.A.

VII.A.3. "Continuous emission monitoring system" or "CEMS" means the equipment required by Regulation Number 3, Part F, Section VII, to sample, analyze, measure, and provide (using an automated data acquisition and handling system (DAHS)), a permanent record of SO2 or NOx emissions, other pollutant emissions, diluent, or stack gas volumetric flow rate.

VII.A.4. "Operating day" means any twenty-four-hour period between midnight and the following midnight during which any fuel is combusted at any time in a BART unit, BART alternative program unit, or Reasonable Progress unit.

VII.A.5. "Reasonable Progress unit" or "RP unit" means any unit subject to a Regional Haze emission limit contained in the Table in Regulation Number 3, Part F, Section VI.B.

VII.A.6. "Regional Haze emission limit" means any of the emission limits specified in the Tables contained in Regulation Number 3, Part F, Section VI.

VII.B. Monitoring/Compliance Determination: SO2 and NOx Regional Haze Limits

VII.B.1. BART, RP, and BART alternative program units with SO2 and NOx CEMS.

VII.B.1.a. All Boilers, except CENC and Clark boilers.

The owner or operator of a boiler subject to this section shall comply with the Part 75 monitoring and recordkeeping requirements as incorporated by reference into this regulation with the exception of the continuous emission monitoring system (CEMS) data substitution and bias adjustment requirements.

At all times after the compliance deadline specified in Regulation Number 3, Part F, Section VI.A.3., VI.B.3. or VI.C.3., the owner/operator of each BART, RP, or BART alternative program unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR Part 75 not excluded above, to accurately measure from such unit SO2, NOx, diluent, and stack gas volumetric flow rate as such parameters are relevant to the applicable emission limit. The CEMS shall be used to determine compliance with the SO2 and NOx Regional Haze emission limits for each such unit. Such limits are expressed in units of pounds per million Btu. The owner/operator shall calculate emissions in the applicable units.

In determining compliance with the SO2 and NOx Regional Haze limits, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions.

VII.B.1.a.(i). Pounds Per Million Btu Regional Haze Limits

For any hour in which fuel is combusted in the BART, RP, or BART alternative program unit, owner/operator shall calculate hourly average SO2 and NOx concentrations in pounds per million Btu at the CEMS in accordance with the requirements of 40 CFR Part 75 except for Part 75 requirements excluded by Section VII. B.1.a. These hourly averages shall then be used to determine compliance in accordance with the particular limit's averaging period, as follows:

VII.B.1.a.(i).(1). Regional Haze limits with a 3-hour averaging period: Emissions shall be calculated on a 3-hour rolling average basis. At the end of each operating hour, the owner/operator shall calculate and record a new 3-hour average emission rate in lb/MMBtu from the arithmetic average of the valid hourly emission rates from the CEMS for the previous three operating hours. (An operating hour is any hour in which fuel is combusted for any time in the unit.)

VII.B.1.a.(i).(2). Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the owner/operator shall calculate and record the 30-day rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 30 operating days.

VII.B.1.a.(i).(3). Regional Haze limits with a 90-day averaging period: Before the end of each operating day, the owner/operator shall calculate and record the 90-day rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 90 operating days.

VII.B.1.a.(i).(4). Regional Haze limits with a 12-month averaging period: Before the end of each month, the owner/operator shall calculate and record the 12-month rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 12 months.

VII.B.1.a.(i).(5). Regional Haze limits with an annual calendar averaging period: Emissions shall be calculated on a calendar year basis.

Within 30 days after the end of each calendar year, the owner/operator shall calculate and record a new emission rate in lb/MMBtu from the arithmetic average of all valid hourly emission rates from the CEMS for the preceding year.

VII.B.1.a.(i).(6). Comanche Units 1 and 2 Regional Haze combined annual average limits. The combined annual limitations for NOX and SO2 are on a 365-operating day rolling average. Before the end of each operating day, the owner/operator shall calculate and record an annual rolling average using data from the previous 365 operating days in accordance with the following equation.

Combined emission rate (lb/MMBtu) = [(ER1)(HI1) + (ER2)(HI2)]/(HI1 + HI2)

Where: ER1 = average emission rate over the 365 operating day period. This is an average of all valid hours within the 365 operating day period for Unit 1.

HI1 = total heat input over the 365 operating day period for Unit 1.

ER2 = average emission rate over the 365 operating day period. This is an average of all valid hours within the 365 operating day period for Unit 2.

HI2 = total heat input over the 365 operating day period for Unit 2.

VII.B.1.b. Portland Cement Kilns and CENC and Clark Boilers: At all times after the compliance deadline specified in Regulation Number 3, Part F, Section VI.A.3., or VI.B.3., the owner/operator of each BART or RP unit shall maintain, calibrate and operate a CEMS in full compliance with the requirements in 40 CFR Part 60 Section 60.13 and Part 60 Appendices A, B and F to accurately measure SO2, NOX and diluent, if diluent is required. The CEMS shall be used to determine compliance with the SO2 and NOX Regional Haze emission limits for each such unit. For particular units, such limits are expressed in units of pounds per hour, tons per year, pounds per ton clinker or pounds per million Btu. The owner/operator shall calculate emissions in the applicable units. In determining compliance with the SO2 and NOX Regional Haze limits, all periods of emissions shall be included, including startups, shutdowns, emergencies and malfunctions.

VII.B.1.b.(i). Pounds per Hour and Tons per Year Regional Haze Limits and Pounds per Million Btu Regional Haze Limits.

For any hour in which fuel is combusted in the BART or RP unit, the owner/operator shall calculate hourly NOx and SO2 emissions in the appropriate units (lbs/hr) or (lbs/MMbtu) in accordance with the provisions in 40 CFR Part 60. These hourly values shall be used to determine compliance in accordance with the particular limits averaging time, as follows:

VII.B.1.b.(i).(1). Pounds per Hour or Pounds per Million Btu Regional Haze Limits on a 30-day rolling average, Before the end of each operating day, the owner/operator shall calculate and record the 30-day rolling average emission rate in lb/MMBtu or lb/hr from all valid hourly emission values from the CEMS for the previous 30 operating days.

VII.B.1.b.i.(2). Pounds per Hour on a 12-month rolling average. Before the end of each month, the owner/operator shall calculate and record the 12-month rolling average emission rate in lb/hr from all valid hourly emission values from the CEMS for the previous 12 months.

VII.B.1.b.i.(3). Tons per year Regional Haze Limits on a 12-month rolling average. Before the end of each month, the owner/operator shall calculate and record the total emissions in tons/yr from all valid hourly emission values from the CEMS for the previous 12 months.

VII.B.1.b.(ii). 30-Day Rolling Average Pounds per Ton Clinker Regional Haze Limits . Hourly clinker production shall be determined in accordance with the requirements in 40 CFR Part 60 Subpart F Section 60.63(b). An operating day includes all valid data obtained in any daily 24-hour period during which the kiln operates and excludes any measurements made during the daily 24-hour period when the kiln was not operating. The 30-operating day rolling emission rate of NOX and SOx shall be calculated and recorded as the total of all hourly emissions data for a cement kiln in the preceding 30 operating days, divided by the total tons of clinker produced in that kiln during the same 30-day operating period in accordance with the equation in 40 CFR Part 60 Subpart F Section 60.64(c).

VII.B.1.b.(iii). CENC Units 4 and 5 NOX Regional Haze limits:

For any hour in which fuel is combusted in CENC Unit 4 or Unit 5, the owner/operator shall calculate hourly NOX emissions in the appropriate units (lbs/MMbtu) in accordance with the provisions in 40 CFR Part 60. These hourly values shall be used to determine compliance with the Regional Haze limits, as follows:

VII.B.1.b.(iii).(1). Individual unit pound per Million Btu on a 30-day rolling average Regional Haze Limit: Before the end of each operating day, the owner/operator shall calculate and record the 30-day rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 30 operating days, OR

VII.B.1.b.(iii).(2). Combined units 4 and 5 lbs/MMbtu 30-day rolling average Regional Haze Limit: Before the end of each operating day, the owner/operator shall calculate and record a 30-day rolling average using data from the previous 30 operating days in accordance with the following equation:

Average ER = [(ER4)(HI4)+(ER5)(HI5)] / [(HI4)+(HI5)]

Where:

ER4 = average NOX emission rate, in pounds per MMbtu over the 30 day period. This is an average of all valid hours within the 30 operating day period for Unit 4.

ER5 = average NOX emission rate, in pounds per MMbtu over the 30 day period. This is an average of all valid hours within the 30 operating day period for Unit 5.

HI4 = Total heat input over the 30 operating day period for Unit 4.

HI5 = Total heat input over the 30 operating day period for Unit 5.

VII.B.1.b.(iii).(3). The owner or operator shall indicate in the excess emission reports required by Section VII.E of this Part F, which compliance demonstration method has been followed for the reporting period.

VII.B.2. BART and RP Units without NOX and SO2 CEMS.

VII.B.2.a. CENC Unit 3. Compliance with the SO2 limitations shall be determined by sampling and analyzing each shipment of coal for the sulfur and heat content using the appropriate ASTM Methods. In lieu of sampling, vendor receipts may be used provided the sampling and analysis was conducted in accordance with the appropriate ASTM Method. Each sample or vendor receipt must indicate compliance with the SO2 limitation. Compliance with the annual NOx limits shall be monitored by recording fuel consumption and calculating emissions monthly using the appropriate AP-42 emission factor. Monthly emissions shall be calculated by the end of the subsequent month and shall be used in a rolling twelve month total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous 12 months data. [*Note: CENC Unit 3 is not subject to annual SO2 limits.]

VII.B.2.b. CEMEX Dryer. Unless performance tests were completed within the previous 6 months, within 60 days of the compliance deadline specified in Regulation Number3, Part F Section VI.A.3, the owner/operator shall conduct a stack test to measure NOX and SO2 emissions in accordance with the appropriate EPA test methods. Frequency of testing thereafter shall be every five years. Each test shall consist of three test runs, with each run at least 60 minutes in duration.

In addition to the stack tests described above, compliance with the annual NOx and SO2 limits shall be monitored by calculating emissions monthly using the emission factors (in lb/hr) determined from the most recent Division-approved stack test and hours of operation for the month. Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous 12 months' data.

VII.C. Monitoring/Compliance Determination: Particulate Regional Haze Limits

VII.C.1. Particulate Regional Haze Limits for all boilers except CENC and Clark boilers

Unless particulate compliance testing was completed within the previous 6 months, within 60 days of the compliance deadline specified in Regulation Number 3, Part F, Section VI.A.3., VI.B.3., or VI.C.3., the owner/operator shall conduct a stack test to measure particulate emissions in accordance with the requirements and procedures set forth in EPA Test Method 5 as set forth in 40 CFR Part 60, Appendix A. Stack testing for particulate matter shall be performed annually, except that: (1) if any test results indicate emissions are less than or equal to 50% of the emission limit, another test is required within five years; (2) if any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, another test is required within three years; and (3) if any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until the provisions of (1) or (2) are met. A test run shall consist of three test runs, with each run at least 120 minutes in duration. Test results shall be converted to the applicable units and compliance will the based on the average of the three test runs.

In addition, to the stack tests described above, the owner/operator shall monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring plan developed and approved in accordance with 40 CFR Part 64.

VII.C.2. Portland Cement Plant Particulate Regional Haze Limits.

VII.C.2.a. Kilns. Compliance with the particulate matter limitations shall be monitored using a PM CEMS that meets the requirements in 40 CFR Part 63 Subpart LLL. The owner or operator shall calculate emissions in the applicable units. If a PM CEMS is used to monitor compliance with the PM limits, the opacity limits specified in this Part F do not apply.

In the event that the provisions in 40 CFR Part 63 Subpart LLL are revised, stayed or vacated, such that a PM CEMS is not required, compliance with the PM limitations shall be monitored by conducting stack tests in accordance with the requirements of Section VII.C.3. except that the results of the test shall be converted to the appropriate units (lb/ton clinker or lb/ton dry feed) and compliance will be based on the average of three test runs.

In addition, if no PM CEMS is required, as discussed in the above paragraph, the opacity limits specified in this Part F do apply. In order to monitor compliance with the opacity limit, the owner or operator shall install, calibrate, maintain, and continuously operate a COM located at the outlet of the PM control device to continuously monitor opacity. The COM shall be installed, maintained, calibrated, and operated as required by 40 CFR Part 63, Subpart A, and according to PS-1 of 40 CFR Part 60, Appendix B

VII.C.2.b. Dryers. Performance tests shall be conducted in accordance with the requirements in Section VII.C.3. Opacity monitoring shall be conducted in accordance with the requirements in 40 CFR Part 63 Subpart LLL.

VII.C.3. Particulate Regional Haze Limits for the CENC and Clark boilers and the CEMEX dryer. Within 60 days of the compliance deadline specified in Regulation Number 3, Part F, Section VI.A.3. or VI.B.3., the owner/operator shall conduct a stack test to measure particulate emissions in accordance with the requirements and procedures set forth in EPA Test Method 5, 5B, 5D or 17, as appropriate, as set forth in 40 CFR Part 60, Appendix A. Stack testing for particulate matter shall be performed annually, except that: (1) if any test results indicate emissions are less than or equal to 50% of the emission limit, another test is required within five years; (2) if any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, another test is required within three years; and (3) if any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until the provisions of (1) or (2) are met. Each test shall consist of three test runs, with each run at least 60 minutes in duration.

In addition, to the stack tests described above, compliance with the annual limitations (ton/yr limits) applicable to the Clark boilers and CEMEX dryer shall be monitored by calculating emissions monthly using the emission factors (in lb/hr) determined from the most recent Division-approved stack test and hours of operation for the month. Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous 12 months' data.

In addition to the stack tests described above, the owner/operator shall monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring plan developed and approved in accordance with 40 CFR Part 64.

VII.D. Recordkeeping

Owner/operator shall maintain the following records for at least five years:

VII.D.1. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable; and any field data sheets from testing.

VII.D.2. Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Part 60, 63, or 75.

VII.D.3. Any other records required by 40 CFR parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75.

VII.E. Reporting requirements

The owner/operator of a BART, RP or BART alternative program unit shall submit semi-annual excess emissions reports no later than the 30th day following the end of each semi-annual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, Section 60.7(c).

The owner/operator of a BART, RP or BART alternative program unit shall submit reports of any required performance stack tests for particulate matter, to the Division within 60 calendar days after completion of the test.

The owner/operator shall also submit semi-annual reports of any excursions under the approved compliance assurance monitoring plan in accordance with the schedule specified in the source's Title V permit.

NOTE: This bill has been prepared for the signature of the appropriate legislative officers and the Governor. To determine whether the Governor has signed the bill or taken other action on it, please consult the legislative status sheet, the legislative history, or the Session Laws.

An Act

HOUSE BILL 10-1365

BY REPRESENTATIVE(S) Solano and Roberts, Benefield, Carroll T., Court, Fischer, Frangas, Gerou, Hullinghorst, Kagan, Kerr A., Kerr J., King S., Levy, Liston, Massey, May, McFadyen, McNulty, Merrifield, Middleton, Miklosi, Peniston, Pommer, Primavera, Rice, Ryden, Scanlan, Schafer S., Stephens, Todd, Tyler, Vaad, Vigil, Ferrandino, Kefalas, Labuda, McCann, Nikkel, Riesberg, Summers;
also SENATOR(S) Whitehead and Penry, Bacon, Boyd, Brophy, Carroll M., Foster, Heath, Johnston, Morse, Romer, Shaffer B., Steadman, Williams.

CONCERNING INCENTIVES FOR ELECTRIC UTILITIES TO REDUCE AIR EMISSIONS, AND, IN CONNECTION THEREWITH, REQUIRING PLANS TO ACHIEVE SUCH REDUCTIONS THAT GIVE PRIMARY CONSIDERATION TO REPLACING OR REPOWERING COAL GENERATION WITH NATURAL GAS AND ALSO CONSIDERING OTHER LOW-EMITTING RESOURCES, AND MAKING AN APPROPRIATION.

Be it enacted by the General Assembly of the State of Colorado:

SECTION 1. Article 3.2 of title 40, Colorado Revised Statutes, is amended BY THE ADDITION OF A NEW PART to read:

PART 2

Capital letters indicate new material added to existing statutes; dashes through words indicate deletions from existing statutes and such material not part of act.

COORDINATED UTILITY PLAN
TO REDUCE AIR EMISSIONS

40-3.2-201. Short title. THIS PART 2 SHALL BE KNOWN AND MAY BE CITED AS THE "CLEAN AIR - CLEAN JOBS ACT".

40-3.2-202. Legislative declaration. (1) THE GENERAL ASSEMBLY HEREBY FINDS, DETERMINES, AND DECLARES THAT THE FEDERAL "CLEAN AIR ACT", 42 U.S.C. SEC. 7401 ET SEQ., WILL LIKELY REQUIRE REDUCTIONS IN EMISSIONS FROM COAL-FIRED POWER PLANTS OPERATED BY RATE-REGULATED UTILITIES IN COLORADO. A COORDINATED PLAN OF EMISSION REDUCTIONS FROM THESE COAL-FIRED POWER PLANTS WILL ENABLE COLORADO RATE-REGULATED UTILITIES TO MEET THE REQUIREMENTS OF THE FEDERAL ACT AND PROTECT PUBLIC HEALTH AND THE ENVIRONMENT AT A LOWER COST THAN A PIECEMEAL APPROACH. A COORDINATED PLAN OF REDUCTION OF EMISSIONS FOR COLORADO'S RATE-REGULATED UTILITIES WILL ALSO RESULT IN REDUCTIONS IN MANY AIR POLLUTANTS AND PROMOTE THE USE OF NATURAL GAS AND OTHER LOW-EMITTING RESOURCES TO MEET COLORADO'S ELECTRICITY NEEDS, WHICH WILL IN TURN PROMOTE DEVELOPMENT OF COLORADO'S ECONOMY AND INDUSTRY.

(2) THE GENERAL ASSEMBLY FURTHER FINDS THAT THE USE OF NATURAL GAS TO REDUCE COAL-FIRED EMISSIONS MAY REQUIRE RATE-REGULATED UTILITIES TO ENTER INTO LONG-TERM CONTRACTS FOR NATURAL GAS IN A MANNER THAT PROTECTS ELECTRICITY CONSUMERS. EVEN THOUGH SUCH LONG-TERM CONTRACTS MIGHT BE BENEFICIAL TO CONSUMERS, FINANCIAL RATING AGENCIES COULD FIND THAT SUCH LONG-TERM CONTRACTS INCREASE THE FINANCIAL RISK TO RATE-REGULATED UTILITIES, WHICH IN TURN COULD INCREASE THE COST OF CAPITAL TO THESE UTILITIES. THE GENERAL ASSEMBLY FINDS THAT IT IS IMPORTANT TO GIVE FINANCIAL MARKETS CONFIDENCE THAT UTILITIES WILL BE ABLE TO RECOVER THE COSTS OF LONG-TERM GAS CONTRACTS WITHOUT THE RISK OF FUTURE REGULATORS DISALLOWING CONTRACTS.

(3) THE GENERAL ASSEMBLY FURTHER FINDS AND DECLARES THAT COLORADO RATE-REGULATED UTILITIES REQUIRE TIMELY AND FORWARD-LOOKING REVIEWS OF THEIR COSTS OF PROVIDING UTILITY SERVICE IN ORDER TO UNDERTAKE THE COMPREHENSIVE AND EXTENSIVE PLANNING AND CHANGES TO THEIR BUSINESS OPERATIONS CONTEMPLATED

BY THIS PART 2. IN ORDER TO ALLOW THESE UTILITIES TO CONTINUE TO PROVIDE RELIABLE ELECTRIC SERVICE, ALTER THEIR OPERATIONS IN THE MANNER DESCRIBED BY THIS PART 2, AND MEET OTHER STATE PUBLIC POLICY GOALS, IT IS IMPERATIVE THAT COLORADO RATE-REGULATED UTILITIES CONTINUE IN SOUND FINANCIAL CONDITION AND REMAIN ATTRACTIVE INVESTMENTS SO THAT SUFFICIENT CAPITAL IS PROVIDED TO ACHIEVE THE STATE'S GOALS. TO THAT END, THE GENERAL ASSEMBLY FINDS THAT THE COMMISSION SHOULD HAVE ADDITIONAL TOOLS AND MORE FLEXIBILITY IN ITS REGULATORY AUTHORITY TO ENSURE THE CONTINUED FINANCIAL HEALTH OF THESE UTILITIES. THE GENERAL ASSEMBLY ALSO FINDS AND DECLARES THAT THE ACTIONS PROVIDED FOR IN THIS PART 2 BE IMPLEMENTED IN A MANNER TO ADDRESS THE SOUND ECONOMIC, HEALTH, AND ENVIRONMENTAL CONDITIONS OF ENERGY PRODUCING COMMUNITIES.

40-3.2-203. Definitions. AS USED IN THIS PART 2, UNLESS THE CONTEXT OTHERWISE REQUIRES:

(1) "AIR QUALITY CONTROL COMMISSION" MEANS THE COMMISSION CREATED IN SECTION 25-7-104, C.R.S.

(2) "DEPARTMENT" MEANS THE DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT.

(3) "FEDERAL ACT" MEANS THE FEDERAL "CLEAN AIR ACT", 42 U.S.C. SEC. 7401 ET SEQ., AS AMENDED.

(4) "STATE ACT" MEANS THE "COLORADO AIR POLLUTION PREVENTION AND CONTROL ACT", ARTICLE 7 OF TITLE 25, C.R.S.

(5) "STATE IMPLEMENTATION PLAN" MEANS THE PLAN REQUIRED BY AND DESCRIBED IN SECTION 110 (a) AND OTHER PROVISIONS OF THE FEDERAL ACT.

40-3.2-204. Emission control plans - role of the department of public health and environment - timing of emission reductions - approval. (1) ON OR BEFORE AUGUST 15, 2010, AND IN COORDINATION WITH CURRENT OR EXPECTED REQUIREMENTS OF THE FEDERAL ACT AND THE STATE ACT, ALL RATE-REGULATED UTILITIES THAT OWN OR OPERATE COAL-FIRED ELECTRIC GENERATING UNITS LOCATED IN COLORADO SHALL SUBMIT TO THE COMMISSION AN EMISSION REDUCTION PLAN FOR EMISSIONS

FROM THOSE UNITS.

(2) (a) THE PLAN FILED UNDER THIS SECTION SHALL COVER A MINIMUM OF NINE HUNDRED MEGAWATTS OR FIFTY PERCENT OF THE UTILITY'S COAL-FIRED ELECTRIC GENERATING UNITS IN COLORADO, WHICHEVER IS SMALLER. EXCEPT AS SET FORTH IN SECTION 40-3.2-206, THE COAL-FIRED CAPACITY COVERED UNDER THE PLAN FILED UNDER THIS SECTION SHALL NOT INCLUDE ANY COAL-FIRED CAPACITY THAT THE UTILITY HAS ALREADY ANNOUNCED THAT IT PLANS TO RETIRE PRIOR TO JANUARY 1, 2015. AT THE UTILITY'S DISCRETION, THE PLAN MAY INCLUDE SOME OR ALL OF THE FOLLOWING ELEMENTS:

(I) NEW EMISSION CONTROL EQUIPMENT FOR OXIDES OF NITROGEN AND OTHER POLLUTANTS;

(II) RETIREMENT OF COAL-FIRED UNITS, IF THE RETIRED COAL-FIRED UNITS ARE REPLACED BY NATURAL GAS-FIRED ELECTRIC GENERATION OR OTHER LOW-EMITTING RESOURCES AS DEFINED IN SECTION 40-3.2-206, INCLUDING ENERGY EFFICIENCY;

(III) CONVERSION OF COAL-FIRED GENERATION TO RUN ON NATURAL GAS;

(IV) LONG-TERM FUEL SUPPLY AGREEMENTS;

(V) NEW NATURAL GAS PIPELINES AND OTHER SUPPORTING GAS INFRASTRUCTURE;

(VI) INCREASED UTILIZATION OF EXISTING GAS-FIRED GENERATING CAPACITY;

(VII) NEW TRANSMISSION LINES AND OTHER SUPPORTING TRANSMISSION INFRASTRUCTURE;

(VIII) EMISSION CONTROL EQUIPMENT THAT IS REQUIRED TO BE INSTALLED AT AFFECTED UNITS PRIOR TO OR IN CONJUNCTION WITH ANY RETIREMENT, CONVERSION, OR EMISSION CONTROL EQUIPMENT RETROFIT SET FORTH UNDER THE PLAN IN ORDER TO LIMIT ANY POLLUTANT OTHER THAN OXIDES OF NITROGEN; AND

(IX) ANY OTHER CAPITAL, FUEL, AND OPERATIONS AND MAINTENANCE EXPENDITURES APPROPRIATE TO SUPPORT THE IMPLEMENTATION OF THE PLAN.

(b) (I) PRIOR TO FILING THE PLAN, THE UTILITY SHALL CONSULT WITH THE DEPARTMENT AND SHALL WORK WITH THE DEPARTMENT IN GOOD FAITH TO DESIGN A PLAN TO MEET THE CURRENT AND REASONABLY FORESEEABLE REQUIREMENTS OF THE FEDERAL ACT AND STATE LAW IN A COST-EFFECTIVE AND FLEXIBLE MANNER.

(II) THE COMMISSION SHALL PROVIDE THE DEPARTMENT AN OPPORTUNITY TO:

(A) COMMENT ON THE AIR QUALITY, ALL OTHER AIR POLLUTANTS, AND OTHER EMISSION REDUCTIONS OF THE PLAN; AND

(B) EVALUATE AND DETERMINE WHETHER THE PLAN IS CONSISTENT WITH THE CURRENT AND REASONABLY FORESEEABLE REQUIREMENTS OF THE FEDERAL ACT.

(III) IN COMMENTING UPON THE UTILITY'S PLAN, THE DEPARTMENT SHALL DETERMINE WHETHER ANY NEW OR REPOWERED ELECTRIC GENERATING UNIT PROPOSED UNDER THE PLAN, OTHER THAN A PEAKING FACILITY UTILIZED LESS THAN TWENTY PERCENT ON AN ANNUAL BASIS OR A FACILITY THAT CAPTURES AND SEQUESTERS MORE THAN SEVENTY PERCENT OF EMISSIONS NOT SUBJECT TO A NATIONAL AMBIENT AIR QUALITY STANDARD OR A HAZARDOUS AIR POLLUTANT STANDARD, WILL ACHIEVE EMISSION RATES EQUIVALENT TO OR LESS THAN A COMBINED-CYCLE NATURAL GAS GENERATING UNIT.

(IV) THE COMMISSION SHALL NOT APPROVE A PLAN EXCEPT AFTER AN EVIDENTIARY HEARING AND UNLESS THE DEPARTMENT HAS DETERMINED THAT THE PLAN IS CONSISTENT WITH THE CURRENT AND REASONABLY FORESEEABLE REQUIREMENTS OF THE FEDERAL ACT.

(c) THE PLAN SHALL INCLUDE A SCHEDULE THAT WOULD RESULT IN FULL IMPLEMENTATION OF THE PLAN ON OR BEFORE DECEMBER 31, 2017. THE SCHEDULE MAY INCLUDE INTERIM MILESTONES. THE UTILITY SHALL DESIGN THE SCHEDULE TO PROTECT SYSTEM RELIABILITY, CONTROL OVERALL COST, AND ASSURE CONSISTENCY WITH THE REQUIREMENTS OF THE FEDERAL

ACT.

(d) THE PLAN SHALL SET FORTH THE COSTS ASSOCIATED WITH ACTIVITIES IDENTIFIED IN THE PLAN, INCLUDING THE PLANNING, DEVELOPMENT, CONSTRUCTION, AND OPERATION OF ELEMENTS IDENTIFIED PURSUANT TO SUBPARAGRAPHS (I) TO (IX) OF PARAGRAPH (a) OF SUBSECTION (2) OF THIS SECTION, AS WELL AS THE COSTS OF ANY SHUTDOWN, DECOMMISSIONING, OR REPOWERING OF EXISTING COAL-FIRED ELECTRIC GENERATING UNITS THAT ARE SET FORTH IN THE PLAN.

40-3.2-205. Review - approval. (1) IN EVALUATING THE PLAN, THE COMMISSION SHALL CONSIDER THE FOLLOWING FACTORS:

(a) WHETHER THE DEPARTMENT REPORTS THAT THE PLAN IS LIKELY TO ACHIEVE AT LEAST A SEVENTY TO EIGHTY PERCENT REDUCTION, OR GREATER, IN ANNUAL EMISSIONS OF OXIDES OF NITROGEN AS NECESSARY TO COMPLY WITH CURRENT AND REASONABLY FORESEEABLE REQUIREMENTS OF THE FEDERAL ACT AND THE STATE ACT. THE REDUCTION IN EMISSIONS UNDER THIS PARAGRAPH (a) SHALL BE MEASURED FROM 2008 LEVELS AT COAL-FIRED POWER PLANTS IDENTIFIED IN THE PLAN. IN DETERMINING THE REDUCTION IN EMISSIONS UNDER THIS PARAGRAPH (a), THE DEPARTMENT SHALL INCLUDE:

(I) EMISSIONS FROM COAL-FIRED POWER PLANTS IDENTIFIED IN THE PLAN AND CONTINUING TO OPERATE AFTER RETROFIT WITH EMISSION CONTROL EQUIPMENT; AND

(II) EMISSIONS FROM ANY FACILITIES CONSTRUCTED TO REPLACE ANY RETIRED COAL-FIRED POWER PLANTS IDENTIFIED IN THE PLAN.

(b) WHETHER THE DEPARTMENT HAS MADE THE DETERMINATION UNDER SECTION 40-3.2-204 (2) (b) (III);

(c) THE DEGREE TO WHICH THE PLAN WILL RESULT IN REDUCTIONS IN OTHER AIR POLLUTANT EMISSIONS;

(d) THE DEGREE TO WHICH THE PLAN WILL INCREASE UTILIZATION OF EXISTING NATURAL GAS-FIRED GENERATING CAPACITY;

(e) THE DEGREE TO WHICH THE PLAN ENHANCES THE ABILITY OF THE

UTILITY TO MEET STATE OR FEDERAL CLEAN ENERGY REQUIREMENTS, RELIES ON ENERGY EFFICIENCY, OR RELIES ON OTHER LOW-EMITTING RESOURCES;

(f) WHETHER THE PLAN PROMOTES COLORADO ECONOMIC DEVELOPMENT;

(g) WHETHER THE PLAN PRESERVES RELIABLE ELECTRIC SERVICE FOR COLORADO CONSUMERS;

(h) WHETHER THE PLAN IS LIKELY TO HELP PROTECT COLORADO CUSTOMERS FROM FUTURE COST INCREASES, INCLUDING COSTS ASSOCIATED WITH REASONABLY FORESEEABLE EMISSION REDUCTION REQUIREMENTS; AND

(i) WHETHER THE COST OF THE PLAN RESULTS IN REASONABLE RATE IMPACTS. IN EVALUATING THE RATE IMPACTS OF THE PLAN, THE COMMISSION SHALL EXAMINE THE IMPACT OF THE RATES ON LOW-INCOME CUSTOMERS.

(2) THE COMMISSION SHALL REVIEW THE PLAN AND ENTER AN ORDER APPROVING, DENYING, OR MODIFYING THE PLAN BY DECEMBER 15, 2010. ANY MODIFICATIONS REQUIRED BY THE COMMISSION SHALL RESULT IN A PLAN THAT THE DEPARTMENT DETERMINES IS LIKELY TO MEET CURRENT AND REASONABLY FORESEEABLE FEDERAL AND STATE CLEAN AIR ACT REQUIREMENTS.

(3) ALL ACTIONS TAKEN BY THE UTILITY IN FURTHERANCE OF, AND IN COMPLIANCE WITH, AN APPROVED PLAN ARE PRESUMED TO BE PRUDENT ACTIONS, THE COSTS OF WHICH ARE RECOVERABLE IN RATES AS PROVIDED IN SECTION 40-3.2-207.

(4) IF THE UTILITY DISAGREES WITH THE COMMISSION'S MODIFICATIONS TO ITS PROPOSED PLAN WITH RESPECT TO RESOURCE SELECTION, THE UTILITY MAY WITHDRAW ITS APPLICATION.

40-3.2-206. Coal plant retirements - replacement resources. (1) (a) THE GENERAL ASSEMBLY FINDS THAT, IN DESIGNING A COORDINATED EMISSION REDUCTION PLAN AS DESCRIBED IN SECTION 40-3.2-204 AND TO EXPEDITIOUSLY ACCELERATE COAL PLANT RETIREMENTS, IT IS IN THE PUBLIC INTEREST FOR UTILITIES TO GIVE PRIMARY CONSIDERATION TO REPLACING OR REPOWERING THEIR COAL GENERATION WITH NATURAL GAS GENERATION

AND THAT UTILITIES SHALL ALSO CONSIDER OTHER LOW-EMITTING RESOURCES, INCLUDING ENERGY EFFICIENCY, IF THIS REPLACEMENT OR REPOWERING CAN BE ACCOMPLISHED PRUDENTLY AND FOR REASONABLE RATE IMPACTS COMPARED WITH PLACING ADDITIONAL EMISSION CONTROLS ON COAL-FIRED GENERATING UNITS, AND IF ELECTRIC SYSTEM RELIABILITY CAN BE PRESERVED. TO THAT END, IN THE PLAN REQUIRED UNDER SECTION 40-3.2-204, EACH UTILITY SHALL INCLUDE AN EVALUATION OF THE FOLLOWING PROPOSALS:

(I) THE COST AND SYSTEM RELIABILITY IMPACTS OF RETIRING A MINIMUM OF NINE HUNDRED MEGAWATTS OF COAL-FIRED ELECTRIC GENERATING CAPACITY, OR FIFTY PERCENT OF THE UTILITY'S COAL-FIRED GENERATING UNITS IN COLORADO, WHICHEVER IS LESS, BY JANUARY 1, 2015, AND REPOWERING THE AFFECTED COAL-FIRED FACILITIES WITH NATURAL GAS OR REPLACING THEM WITH NATURAL GAS-FIRED GENERATION OR OTHER LOW-EMITTING RESOURCES, INCLUDING ENERGY EFFICIENCY. THE COAL-FIRED CAPACITY EVALUATED UNDER THIS SUBPARAGRAPH (I) SHALL NOT INCLUDE ANY COAL-FIRED CAPACITY THAT THE UTILITY HAS ALREADY ANNOUNCED THAT IT PLANS TO RETIRE PRIOR TO JANUARY 1, 2015. THE UTILITY MAY ALSO PREPARE EVALUATIONS OF ADDITIONAL SCENARIOS, INCLUDING SCENARIOS THAT RESULT IN THE RETIREMENT OF LESS THAN NINE HUNDRED MEGAWATTS OF COAL-FIRED ELECTRIC GENERATING CAPACITY OR THE RETIREMENT OF SOME PORTION OF THE NINE HUNDRED MEGAWATTS OF CAPACITY AFTER JANUARY 1, 2015, BUT BEFORE JANUARY 1, 2018.

(II) RETIREMENTS OF A PORTION OF ITS COAL-FIRED GENERATING CAPACITY IN THE PERIOD AFTER THE EFFECTIVE DATE OF THIS PART 2 BUT PRIOR TO JANUARY 1, 2015. AT A MINIMUM, THE UTILITY SHALL EVALUATE WHETHER TO RETIRE A PORTION OF ITS COAL-FIRED CAPACITY ON OR BEFORE JANUARY 1, 2013, OR WHETHER THE RETIREMENTS OF COAL-FIRED GENERATING FACILITIES THAT HAVE ALREADY BEEN ANNOUNCED COULD BE ADVANCED TO AN EARLIER RETIREMENT DATE.

(b) (I) FOR ALL EVALUATIONS REQUIRED BY THIS SUBSECTION (1), THE UTILITY SHALL REPORT:

(A) THE ESTIMATED OVERALL IMPACTS ON THE UTILITY'S EMISSIONS OF OXIDES OF NITROGEN AND OTHER POLLUTANTS;

(B) THE FEASIBILITY OF THE RETIREMENT, REPOWERING, OR

REPLACEMENT ON THE SCHEDULE PROPOSED IN THE EVALUATION;

(C) THE COSTS AND IMPACT ON ELECTRIC RATES FROM THESE PROPOSALS; AND

(D) THE IMPACT OF THE RETIREMENTS ON THE RELIABILITY OF THE UTILITY'S ELECTRIC SERVICE.

(II) ALL EVALUATIONS REQUIRED BY THIS SUBSECTION (1) SHALL CONTRAST THE COSTS OF REPLACING COAL GENERATION WITH NATURAL GAS GENERATION AND OTHER LOW-EMITTING RESOURCES, INCLUDING ENERGY EFFICIENCY, WITH THE COSTS OF INSTALLING ADDITIONAL EMISSION CONTROLS ON THE COAL PLANTS.

(2) THE UTILITY SHALL SET FORTH IN ITS PLAN THE UTILITY'S PROPOSAL FOR THE BEST WAY OF TIMELY MEETING THE EMISSION REDUCTION REQUIREMENTS REQUIRED BY FEDERAL AND STATE LAW, GIVEN THE NEED TO PRESERVE ELECTRIC SYSTEM RELIABILITY, TO AVOID UNREASONABLE RATE INCREASES, AND THE ECONOMIC AND ENVIRONMENTAL BENEFITS OF COORDINATED EMISSION REDUCTIONS.

(3) IN REVIEWING THE REASONABLENESS OF THE UTILITY'S PROPOSED PLAN, THE COMMISSION SHALL:

(a) COMPARE THE RELATIVE COSTS OF REPOWERING OR REPLACING COAL FACILITIES WITH NATURAL GAS GENERATION OR OTHER LOW-EMITTING RESOURCES, INCLUDING ENERGY EFFICIENCY, TO AN ALTERNATIVE THAT INCORPORATES EMISSION CONTROLS ON THE EXISTING COAL-FIRED UNITS;

(b) USE REASONABLE PROJECTIONS OF FUTURE COAL AND NATURAL GAS COSTS;

(c) INCORPORATE A REASONABLE ESTIMATE FOR THE COST OF REASONABLY FORESEEABLE EMISSION REGULATION CONSISTENT WITH THE COMMISSION'S EXISTING PRACTICE;

(d) CONSIDER THE DEGREE TO WHICH THE PLAN WILL INCREASE UTILIZATION OF EXISTING NATURAL GAS-FIRED GENERATING RESOURCES AVAILABLE TO THE UTILITY, TOGETHER WITH INCREASED UTILIZATION OF OTHER LOW-EMITTING RESOURCES INCLUDING ENERGY EFFICIENCY; AND

(e) CONSIDER THE ECONOMIC AND ENVIRONMENTAL BENEFITS OF A COORDINATED EMISSIONS REDUCTION STRATEGY.

(4) THE UTILITY MAY ENTER INTO LONG-TERM GAS SUPPLY AGREEMENTS TO IMPLEMENT THE REQUIREMENTS OF THIS PART 2. A LONG-TERM GAS SUPPLY AGREEMENT IS AN AGREEMENT WITH A TERM OF NOT LESS THAN THREE YEARS OR MORE THAN TWENTY YEARS. ALL LONG-TERM GAS SUPPLY AGREEMENTS MAY BE FILED WITH THE COMMISSION FOR REVIEW AND APPROVAL. THE COMMISSION SHALL DETERMINE WHETHER THE UTILITY ACTED PRUDENTLY BY ENTERING INTO THE SPECIFIC AGREEMENT, WHETHER THE PROPOSED AGREEMENT APPEARS TO BE BENEFICIAL TO CONSUMERS, AND WHETHER THE AGREEMENT IS IN THE PUBLIC INTEREST. IF AN AGREEMENT IS APPROVED, THE UTILITY IS ENTITLED TO RECOVER THROUGH RATES THE COSTS IT INCURS UNDER THE APPROVED AGREEMENT, AND ANY APPROVED AMENDMENTS TO THE AGREEMENT, NOTWITHSTANDING ANY CHANGE IN THE MARKET PRICE OF NATURAL GAS DURING THE TERM OF THE AGREEMENT. THE COMMISSION SHALL NOT REVERSE ITS APPROVAL OF THE LONG-TERM GAS AGREEMENT EVEN IF THE AGREEMENT PRICE IS HIGHER THAN A FUTURE MARKET PRICE OF NATURAL GAS.

40-3.2-207. Cost recovery - legislative declaration. (1) (a) A UTILITY IS ENTITLED TO FULLY RECOVER THE COSTS THAT IT PRUDENTLY INCURS IN EXECUTING AN APPROVED EMISSION REDUCTION PLAN, INCLUDING THE COSTS OF PLANNING, DEVELOPING, CONSTRUCTING, OPERATING, AND MAINTAINING ANY EMISSION CONTROL OR REPLACEMENT CAPACITY CONSTRUCTED PURSUANT TO THE PLAN, AS WELL AS ANY INTERIM AIR QUALITY EMISSION CONTROL COSTS THE UTILITY INCURS WHILE THE PLAN IS BEING IMPLEMENTED.

(b) THE GENERAL ASSEMBLY FINDS THAT THE EMISSIONS REDUCTIONS UNDER THIS PART 2 ARE BEING MADE TO ASSIST THE STATE OF COLORADO TO COMPLY WITH CURRENT AND REASONABLY FORESEEABLE EMISSION RESTRICTIONS UNDER FEDERAL LAW. TO PROVIDE THIS ASSISTANCE, THE UTILITY IS BEING ASKED TO MAKE SUBSTANTIAL CAPITAL INVESTMENTS AND TO ENTER INTO SUBSTANTIAL CONTRACTUAL COMMITMENTS IN AN EXPEDITED TIME PERIOD OUTSIDE OF THE NORMAL RESOURCE PLANNING PROCESS.

(2) (a) IF A PUBLIC UTILITY'S WHOLESALE SALES ARE SUBJECT TO

REGULATION BY THE FEDERAL ENERGY REGULATORY COMMISSION, AND IF THE PUBLIC UTILITY SELLS POWER ON THE WHOLESALE MARKET FROM A PROJECT DEVELOPED PURSUANT TO THE PLAN, THE COMMISSION SHALL DETERMINE WHETHER TO ASSIGN A PORTION OF THE PLAN COST TO BE RECOVERED FROM THE PUBLIC UTILITY'S WHOLESALE CUSTOMERS. THE COMMISSION MAY MAKE SUCH ASSIGNMENT TO THE EXTENT THAT IT DOES NOT CONFLICT WITH THE PUBLIC UTILITY'S WHOLESALE CONTRACTS ENTERED INTO BEFORE THE EFFECTIVE DATE OF THIS PART 2.

(b) EXCEPT AS SPECIFIED IN PARAGRAPH (c) OF THIS SUBSECTION (2), IF THE COMMISSION MAKES AN ASSIGNMENT OF COSTS PURSUANT TO PARAGRAPH (a) OF THIS SUBSECTION (2) AND IF THE UTILITY APPLIES TO THE FEDERAL ENERGY REGULATORY COMMISSION FOR RECOVERY AND PURSUES THAT APPLICATION IN GOOD FAITH, THEN:

(I) TO THE EXTENT THAT THE FEDERAL ENERGY REGULATORY COMMISSION DOES NOT PERMIT RECOVERY OF THE ALLOCATED WHOLESALE PORTION OF PLAN-RELATED INVESTMENT, THE COMMISSION SHALL APPROVE RETAIL RATES SUFFICIENT TO RECOVER SUCH DISALLOWED WHOLESALE PORTION OF THE INVESTMENT THROUGH THE RECOVERY MECHANISM DETAILED IN THIS SECTION; AND

(II) THE PUBLIC UTILITY MAY NOT RECOVER ANY REVENUE SHORTFALL CAUSED BY A DELAY IN MAKING ANY FILING WITH THE FEDERAL ENERGY REGULATORY COMMISSION OR DUE TO ANY RATE SUSPENSION PERIOD EMPLOYED BY THE FEDERAL ENERGY REGULATORY COMMISSION OR BECAUSE THE PUBLIC UTILITY FAILED TO PURSUE RECOVERY OF THE AMOUNTS AT THE FEDERAL ENERGY REGULATORY COMMISSION IN GOOD FAITH.

(c) IF THE PUBLIC UTILITY FAILS TO APPLY TO THE FEDERAL ENERGY REGULATORY COMMISSION WITHIN SIX MONTHS AFTER THE COMMISSION'S FINAL ORDER ASSIGNING A PORTION OF THE PLAN'S COSTS TO THE PUBLIC UTILITY'S WHOLESALE CUSTOMERS, THE PUBLIC UTILITY IS NOT ENTITLED TO RECOVER THE ASSIGNED PORTION OF THE COSTS FROM ITS RETAIL CUSTOMERS.

(3) CURRENT RECOVERY SHALL BE ALLOWED ON CONSTRUCTION WORK IN PROGRESS AT THE UTILITY'S WEIGHTED AVERAGE COST OF CAPITAL, INCLUDING ITS MOST RECENTLY AUTHORIZED RATE OF RETURN ON EQUITY,

FOR EXPENDITURES ON PROJECTS ASSOCIATED WITH THE PLAN DURING THE CONSTRUCTION, STARTUP, AND PRE-SERVICE IMPLEMENTATION PHASES OF THE PROJECTS.

(4) TO THE EXTENT THAT AN APPROVED PLAN INCLUDES THE EARLY CONVERSION OR CLOSURE OF COAL-BASED GENERATION CAPACITY BY JANUARY 1, 2015, AND TO THE EXTENT THAT THE UTILITY DEMONSTRATES THAT A LAG IN THE RECOVERY OF THE COSTS OF THE PLAN RELATED TO THE INVESTMENT REQUIRED BY SUCH PLAN CONTRIBUTES TO A UTILITY EARNING LESS THAN ITS AUTHORIZED RETURN ON EQUITY, THE COMMISSION SHALL EMPLOY RATE-MAKING MECHANISMS, IN ADDITION TO ALLOWING A CURRENT RETURN ON CONSTRUCTION WORK IN PROGRESS, THAT PERMIT RATE ADJUSTMENTS, NO LESS FREQUENTLY THAN ONCE PER YEAR, WITHOUT REQUIRING THE UTILITY TO FILE A GENERAL RATE CASE TO ALLOW RECOVERY OF THE APPROVED PLAN'S COSTS. SUCH RATE-MAKING MECHANISMS MAY INCLUDE A SEPARATE RATE ADJUSTMENT CLAUSE, REGULAR MAKE-WHOLE RATE INCREASES, OR OTHER APPROPRIATE MECHANISMS AS DETERMINED BY THE COMMISSION.

(5) DURING THE TIME ANY SPECIAL REGULATORY PRACTICE IS IN EFFECT, THE UTILITY SHALL FILE A NEW RATE CASE AT LEAST EVERY TWO YEARS OR FILE A BASE RATE RECOVERY PLAN THAT SPANS MORE THAN ONE YEAR.

(6) THE COMMISSION SHALL ALLOW, BUT NOT REQUIRE, THE UTILITY TO DEVELOP AND OWN AS UTILITY RATE-BASED PROPERTY ANY NEW ELECTRIC GENERATING PLANT CONSTRUCTED PRIMARILY TO REPLACE ANY COAL-FIRED ELECTRIC GENERATING UNIT RETIRED PURSUANT TO THE PLAN FILED UNDER THIS PART 2.

40-3.2-208. Air quality planning. (1) THE AIR QUALITY PROVISIONS OF THE EMISSION REDUCTION PLAN FILED UNDER THIS PART 2 ARE INTENDED TO FULFILL THE REQUIREMENTS OF THE STATE AND FEDERAL ACTS AND SHALL BE PROPOSED BY THE DEPARTMENT TO THE AIR QUALITY CONTROL COMMISSION AFTER THE UTILITY FILES THE PLAN WITH THE COMMISSION TO BE CONSIDERED FOR INCORPORATION INTO THE REGIONAL HAZE ELEMENT OF THE STATE IMPLEMENTATION PLAN.

(2) (a) UPON THE UTILITY'S FILING OF THE UTILITY PLAN WITH THE COMMISSION PURSUANT TO SECTION 40-3.2-204, THE AIR QUALITY CONTROL

COMMISSION, IN RESPONSE TO THE PROPOSAL BY THE DEPARTMENT, SHALL INITIATE A PROCEEDING TO INCORPORATE THE AIR QUALITY PROVISIONS OF THE UTILITY PLAN INTO THE REGIONAL HAZE ELEMENT OF THE STATE IMPLEMENTATION PLAN. EXCEPT AS SET FORTH IN THIS SUBSECTION (2), THE AIR QUALITY CONTROL COMMISSION SHALL NOT ACT ON THE UTILITY PLAN OR THE PROVISIONS OF THE REGIONAL HAZE ELEMENT OF THE STATE IMPLEMENTATION PLAN THAT WOULD ESTABLISH CONTROLS FOR THOSE UNITS COVERED BY THE UTILITY PLAN UNTIL AFTER THE COMMISSION'S APPROVAL OF THE UTILITY PLAN.

(b) THE AIR QUALITY CONTROL COMMISSION SHALL VACATE THE ENTIRE PROCEEDING RELATED TO THE UTILITY PLAN AND SHALL INITIATE A NEW PROCEEDING FOR THE CONSIDERATION OF ALTERNATIVE PROPOSALS FOR THE APPROPRIATE CONTROLS FOR THOSE UNITS COVERED BY THE UTILITY PLAN FOR INCLUSION IN THE REGIONAL HAZE ELEMENT OF THE STATE IMPLEMENTATION PLAN IF:

(I) THE COMMISSION DOES NOT APPROVE THE UTILITY PLAN BY DECEMBER 15, 2010;

(II) THE UTILITY WITHDRAWS ITS APPLICATION PURSUANT TO SECTION 40-3.2-205 (4); OR

(III) THE AIR QUALITY CONTROL COMMISSION REJECTS ANY PORTION OF THE UTILITY PLAN AS APPROVED BY THE COMMISSION.

(c) THE AIR QUALITY CONTROL COMMISSION SHALL CONDUCT THE PROCEEDINGS SPECIFIED IN THIS SUBSECTION (2) AFTER PUBLIC NOTICE AND AN OPPORTUNITY FOR THE PUBLIC TO PARTICIPATE IN ACCORDANCE WITH THE AIR QUALITY CONTROL COMMISSION'S PROCEDURES.

(3) IF THE FINAL APPROVED PROVISIONS OF THE STATE IMPLEMENTATION PLAN ARE NOT CONSISTENT WITH THE AIR QUALITY PROVISIONS OF THE UTILITY PLAN, THE UTILITY MAY FILE A REVISED UTILITY PLAN WITH THE COMMISSION THAT MODIFIES THE ORIGINAL PLAN TO BE CONSISTENT WITH THE FINAL APPROVED STATE IMPLEMENTATION PLAN. THE REVISED UTILITY PLAN IS SUBJECT TO ALL OF THE REVIEW AND COST RECOVERY PROVISIONS CONTAINED IN THIS PART 2. NOTWITHSTANDING ANY REVISION REQUIRED TO THE UTILITY PLAN, THE UTILITY IS ENTITLED TO FULLY RECOVER ANY COSTS IT PRUDENTLY INCURRED OR CONTRACTED TO

INCUR UNDER THE ORIGINALLY APPROVED PLAN PRIOR TO THE PLAN'S REVISION AND ANY COSTS INCURRED AS A RESULT OF ANY ENFORCEABLE STATE IMPLEMENTATION PLAN OR OTHER AIR QUALITY REQUIREMENTS.

40-3.2-209. Early reductions. REDUCTIONS IN EMISSIONS ACHIEVED PURSUANT TO THIS PART 2 THROUGH A COMPLIANCE STRATEGY BEFORE SUCH REDUCTIONS ARE MANDATED UNDER FEDERAL LAW ARE VOLUNTARY FOR PURPOSES OF DETERMINING EARLY REDUCTION CREDITS UNDER FEDERAL LAW.

40-3.2-210. Exemption from limits on voluntary emission reductions. THE LIMITS ON UTILITY EXPENDITURES ON VOLUNTARY EMISSION REDUCTIONS IN SECTION 40-3.2-102 DO NOT APPLY TO UTILITY EXPENDITURES UNDER A PLAN APPROVED BY THE COMMISSION UNDER THIS PART 2.

SECTION 2. 40-6-111 (1), Colorado Revised Statutes, is amended BY THE ADDITION OF A NEW PARAGRAPH to read:

40-6-111. Hearing on schedules - suspension - new rates - rejection of tariffs. (1) (d) NOTWITHSTANDING ANY ORDER OF SUSPENSION OF A PROPOSED INCREASE IN ELECTRIC, GAS, OR STEAM RATES UNDER THIS SUBSECTION (1), AFTER JANUARY 1, 2012, THE COMMISSION MAY ORDER, WITHOUT HEARING, INTERIM RATES, AT ANY LEVEL UP TO THE PROPOSED NEW RATES, TO TAKE EFFECT NOT LATER THAN SIXTY DAYS AFTER THE FILING FOR THE PROPOSED RATE INCREASE. IN MAKING A DETERMINATION AS TO WHETHER TO ALLOW INTERIM RATES, THE COMMISSION SHALL CONSIDER THE AMOUNT OF THE REVENUE DEFICIENCY PRESENTED BY THE UTILITY AND THE EXTENT TO WHICH THIS DEFICIENCY WOULD ADVERSELY AFFECT THE UTILITY DURING THE TIME PERIOD REQUIRED TO HOLD HEARINGS ON THE SUSPENDED RATES.

SECTION 3. 40-6-111 (2) (a), Colorado Revised Statutes, is amended to read:

40-6-111. Hearing on schedules - suspension - new rates - rejection of tariffs. (2) (a) (I) If a hearing is held thereon, whether completed before or after the expiration of the period of suspension, the commission shall establish the rates, fares, tolls, rentals, charges, classifications, contracts, practices, OR rules ~~or regulations~~ proposed, in whole or in part, or others in lieu thereof, ~~which~~ THAT it finds just and reasonable. In making such finding in the case of a public utility other than a rail carrier, the commission may consider current, future, or past test periods or any reasonable combination thereof and any other factors ~~which~~ THAT may affect the sufficiency or insufficiency of such rates, fares, tolls, rentals, charges, or classifications during the period the same may be in effect and may consider any factors ~~which~~ THAT influence an adequate supply of energy, encourage energy conservation, or encourage renewable energy development. THE COMMISSION SHALL CONSIDER THE REASONABLENESS OF THE TEST PERIOD REVENUE REQUIREMENTS PRESENTED BY THE UTILITY.

(II) IF THE RATES ESTABLISHED BY THE COMMISSION AFTER HEARING ARE LOWER THAN ANY INTERIM RATES ESTABLISHED UNDER PARAGRAPH (d) OF SUBSECTION (1) OF THIS SECTION, THEN THE COMMISSION SHALL ORDER THE UTILITY TO RETURN TO CUSTOMERS ON THEIR UTILITY BILLS THROUGH A NEGATIVE RATE RIDER THE DIFFERENCE BETWEEN THE TOTAL AMOUNT THAT WOULD HAVE BEEN COLLECTED UNDER THE FINAL APPROVED RATES AND THE AMOUNT COLLECTED UNDER THE INTERIM RATES FOR THE PERIOD THAT THE INTERIM RATES WERE IN EFFECT, WITH INTEREST AT A RATE ESTABLISHED BY THE COMMISSION.

(III) All such rates, fares, tolls, rentals, charges, classifications, contracts, practices, OR rules ~~or regulations~~ not so suspended, on the effective date thereof, which, in the case of a public utility other than a rail carrier, shall not be less than thirty days ~~from~~ AFTER the time of filing the same with the commission, or of such lesser time as the commission may grant, shall go into effect and be the established and effective rates, fares, tolls, rentals, charges, classifications, contracts, practices, AND rules ~~and regulations~~ subject to the power of the commission, after a hearing on its own motion or upon complaint, as provided in this article, to alter or modify the same.

SECTION 4. Appropriation. (1) In addition to any other appropriation, there is hereby appropriated, out of any moneys in the public utilities commission fixed utility fund created in section 40-2-114, Colorado Revised Statutes, not otherwise appropriated, to the department of regulatory agencies, for allocation to the public utilities commission, for the fiscal year beginning July 1, 2010, the sum of seventy-four thousand one hundred fifteen dollars ($74,115) cash funds and 0.6 FTE, or so much thereof as may be necessary, for the implementation of this act.

(2) In addition to any other appropriation, there is hereby appropriated to the department of law, for the fiscal year beginning July 1, 2010, the sum of thirteen thousand forty-one dollars ($13,041) and 0.1 FTE, or so much thereof as may be necessary, for the provision of legal services to the department of regulatory agencies related to the implementation of this act. Said sum shall be from reappropriated funds received from the department of regulatory agencies out of the appropriation made in subsection (1) of this section.

SECTION 5. Applicability. This act shall apply to conduct occurring on or after the effective date of this act.

SECTION 6. Safety clause. The general assembly hereby finds, determines, and declares that this act is necessary for the immediate preservation of the public peace, health, and safety.

Terrance D. Carroll SPEAKER OF THE HOUSE OF REPRESENTATIVES	Brandon C. Shaffer PRESIDENT OF THE SENATE
Marilyn Eddins CHIEF CLERK OF THE HOUSE OF REPRESENTATIVES	Karen Goldman SECRETARY OF THE SENATE

APPROVED____

Bill Ritter, Jr.
GOVERNOR OF THE STATE OF COLORADO

Decision No. C10-1328

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 10M-245E

IN THE MATTER OF COMMISSION CONSIDERATION OF PUBLIC SERVICE COMPANY OF COLORADO'S PLAN IN COMPLIANCE WITH HOUSE BILL 10-1365, "CLEAN AIR-CLEAN JOBS ACT."

FINAL ORDER ADDRESSING EMISSION REDUCTION PLAN

Mailed Date: December 15, 2010
Adopted Date: December 9, 2010

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I. BY THE COMMISSION

A. Statement

1. This matter comes before the Commission for consideration of an emission reduction plan filed by Public Service Company of Colorado (Public Service or Company) pursuant to House Bill (HB) 10-1365.

2. At the highest level, HB 10-1365 reflects the General Assembly's belief that Colorado will realize significant economic and public health benefits by addressing emissions from front-range coal-fired power plants in a coordinated fashion. Having made this determination that a comprehensive emission reduction strategy is in the public interest, the legislature tasked the Commission and other state agencies with vetting and shaping the plans proposed by regulated electric utilities.

3. Public Service filed its proposed emission reduction plan on August 13, 2010. HB 10-1365 requires the Commission to "review the plan and enter an order approving, denying, or modifying the plan by December 15, 2010." § 40-3.2-205(2), C.R.S. Having conducted a hearing on the plan and fully considered the facts and arguments before us, the Commission hereby modifies and approves Public Service's plan.

B. House Bill 10-1365 and Docket No. 10M-245E

1. The Clean Air – Clean Jobs Act

4. On April 19, 2010, Governor Ritter signed into law HB 10-1365, commonly known as the "Clean Air – Clean Jobs Act." To assist in achieving the state's air quality goals, HB 10-1365 requires Public Service to submit an emission reduction plan addressing a minimum of 900 megawatts of its coal-fired generation no later than August 15, 2010. § 40-3.2-204(1), C.R.S. This plan must "include a schedule that would result in full implementation of the plan on or before December 31, 2017." § 40-3.2-204(2)(c), C.R.S. The Commission must then

undertake an evidentiary hearing before entering an order "approving, denying, or modifying the plan by December 15, 2010." § 40-3.2-205(2), C.R.S. If the plan or some modified version of the plan is approved by the Commission, the plan is subject to further review by the Colorado Department of Public Health and Environment (CDPHE). The Air Quality Control Commission (AQCC), a division of the CDPHE, undertakes a proceeding to incorporate the air quality provisions of the approved plan into the regional haze element of the State Implementation Plan (SIP) Colorado will soon be filing with the Federal Environmental Protection Agency (EPA) pursuant to the Federal Clean Air Act (CAA).

5. HB 10-1365 therefore sets forth independent and complementary roles for the CDPHE and this Commission. Because the relationship between the CDPHE and this Commission has been subject to some debate in these proceedings, we will briefly address this issue as a preliminary matter.

2. Role of the CDPHE

6. The CDPHE plays an integral role in both the implementation of HB 10-1365 and in this Docket. First, prior to submitting its proposed plan, Public Service is required to consult and work in good faith with the CDPHE to design a plan that meets the current and reasonably foreseeable emission reduction requirements in a cost-effective and flexible manner. § 40-3.2-204(2)(b)(I), C.R.S.

7. Then, after the proposed plan is submitted, the CDPHE is required to offer its perspective on the plan to the Commission. The Commission is directed to provide an opportunity for the CDPHE to comment on the air quality and emission reductions of the plan, and to evaluate whether the plan is consistent with reasonably foreseeable requirements of the CAA. § 40-3.2-204(2)(b)(II), C.R.S. This determination is critical because the Commission

shall not approve a plan unless the CDPHE has determined that the plan is consistent with the reasonably foreseeable requirements of the CAA. § 40-3.2-204(2)(b)(IV), C.R.S. In preparing these comments, the CDPHE is also required to make a determination as to "whether any new or repowered electric generating unit proposed under the plan, other than a peaking facility utilized less than twenty percent on an annual basis or a facility that captures and sequesters more than seventy percent of emissions not subject to a national ambient air quality standard or a hazardous air pollutant standard, will achieve emission rates equivalent to or less than a combined-cycle natural gas generating unit." § 40-3.2-204(2)(b)(III), C.R.S.

8. Further, when evaluating the plan, the Commission is required to consider whether the CDPHE believes the plan is likely to achieve at least a 70 percent reduction in oxides of nitrogen (NOx). § 40-3.2-205(1)(a), C.R.S. In making a determination as to achievable emissions reductions, the CDPHE is required to consider emissions from coal-fired power plants identified in the plan that will continue to operate with emission control equipment, as well as emissions from any facilities constructed as replacement capacity. *Id.*

9. Finally, the CDPHE's opinion regarding what emission reduction requirements are reasonably foreseeable limits the modifications the Commission may adopt in approving the final plan. Section 40-3.2-205(2), C.R.S., provides "[a]ny modifications required by the commission shall result in a plan that the [CDPHE] determines is likely to meet current and reasonably foreseeable federal and state clean air act requirements."

3. Role of the Commission

10. After preparing its proposed plan in coordination with the CDPHE, Public Service is required to file the plan with this Commission for approval. At a high level, the Commission's role is to ensure the Company's plan achieves the necessary emissions reductions in a reasonable

and cost-effective manner. Additionally, the Commission is tasked with ensuring the plan meets the minimum standards of HB 10-1365, such as satisfaction of the full implementation deadline of December 31, 2017, as set forth in § 40-3.2-204(2)(c), C.R.S. In order to make these determinations, the Commission is required to conduct an evidentiary hearing. § 40-3.2-204(2)(b)(IV), C.R.S.

11. HB 10-1365 identifies nine specific factors the Commission must consider in evaluating the plan: (1) whether the CDPHE has determined the plan is likely to achieve at least a 70 percent reduction in NOx; (2) whether the CDPHE made a determination under § 40-3.2-204(2)(b)(III); (3) the degree to which the plan will result in reductions in other air pollutant emissions; (4) the degree to which the plan will increase utilization of existing natural gas-fired generation; (5) the degree to which the plan enhances the utility's ability to meet state or federal clean energy requirements, relies on energy efficiency, or relies on other low-emitting resources; (6) whether the plan promotes Colorado economic development; (7) whether the plan preserves reliable electric service; (8) whether the plan is likely to protect Colorado customers from future cost increases, including costs associated with reasonably foreseeable emission reduction requirements; and (9) whether the cost of the plan results in reasonable rate impacts, particularly on low-income customers. § 40-3.2-205(1)(a), C.R.S.

12. The plan must also set forth associated costs. § 40-3.2-204(2)(d), C.R.S. The Company is "entitled to fully recover the costs that it prudently incurs in executing an approved emission reduction plan, including the costs of planning, developing, constructing, operating, and maintaining any emission control or replacement capacity constructed pursuant to the plan, as well as any interim air quality emission control costs the utility incurs while the plan is being implemented." § 40-3.2-207(1)(a), C.R.S. The Commission is tasked with evaluating the

reasonableness of costs associated with the plan, as well as the mechanisms by which costs will be recovered.

13. Additionally, HB 10-1365 permits the Company to enter into long-term gas supply agreements to implement the plan. § 40-3.2-206(4), C.R.S. The Commission must review any proposed agreement, and determine "whether the utility acted prudently by entering into the specific agreement, whether the proposed agreement appears to be beneficial to consumers, and whether the agreement is in the public interest." *Id.*

14. The Commission is required to issue a final order addressing these elements and approving, denying, or modifying the plan no later than December 15, 2010. § 40-3.2-205(2), C.R.S.

4. Role of the AQCC

15. The AQCC is required to initiate a proceeding "to incorporate the air quality provisions of the utility plan into the regional haze element of the [SIP]." § 40-3.2-208(2)(a), C.R.S. This proceeding can only occur after notice and an opportunity for public participation. § 40-3.2-208(2)(c), C.R.S. The AQCC may act on the plan only after the Commission has approved it. § 40-3.2-208(2)(a), C.R.S.

16. If the Commission does not timely approve a plan, if the Company withdraws its plan, or if the final approved plan is rejected by the AQCC, HB 10-1365 establishes an alternative procedure: the AQCC is required to vacate the entire proceeding related to the Company's plan and initiate a new proceeding for the consideration of alternative proposals for

the appropriate controls of those units covered by the Company's plan. § 40-3.2-208(2)(b), C.R.S.

5. Further Action Under HB 10-1365

17. After the Company's plan has been approved by the Commission and further approved by the AQCC, it proceeds to the General Assembly for consideration as part of the Colorado SIP related to regional haze, which is then submitted to the EPA. If the final approved provisions of the SIP are not consistent with the air quality provisions of the plan the Commission approved, the Company may file a revised plan with the Commission that modifies the original plan to obtain consistency with the SIP. § 40-3.2-208(3), C.R.S.

C. Procedural Summary

1. Procedural Milestones

18. The Commission opened this Docket by Decision No. C10-0452, mailed on May 7, 2010. Decision No. C10-0452 served as the initial notice, provided an opportunity for interested parties to file petitions for leave to intervene, and established a preliminary procedural schedule. Decision No. C10-0452 also identified a unique role for Staff of the Commission (Staff) in this proceeding, characterizing their expected participation as "relatively neutral yet active, providing the Commission with an analysis of the proffered Plan, alternative plans, and responses." ¶ 24. Additionally, Decision No. C10-0452 ordered Public Service to produce certain documents and records that would be helpful in developing the record in this case. *Id.* at ¶ 28. Further, in paragraph 38 of that decision, we permitted "[i]nterested persons, including non-parties," to "file written requests with the Commission asking that the Commission order

Public Service to produce additional documents" pursuant to the Commission's statutory audit power. *See* § 40-6-106, C.R.S. These requests became known as "paragraph 38 data requests."[1] *See, e.g.*, Decision Nos. C10-0596, C10-0639, C10-0678, C10-0850. In establishing this data request process, the Commission intended to accommodate the short timelines of this Docket by permitting intervenors to begin developing their cases prior to the August 15, 2010 filing deadline.

19. By Decision No. C10-0545, mailed on June 3, 2010, the Commission noted interventions by right and found good cause to grant petitions to intervene by permission filed by the following entities:

- American Coalition for Clean Coal Electricity (ACCCE);
- Anadarko Energy Services Company (Anadarko);
- Associated Governments of Northwest Colorado (AGNC);
- Blanca Ranch Holdings, LLC and Trinchera Ranch Holdings, LLC, jointly;
- Board of County Commissioners of Weld County, Colorado;
- Boulder County and the City of Boulder, jointly[2] (collectively, Boulder);
- City and County of Denver (Denver);
- Climax Molybdenum Company and CF&I Steel, L.P., jointly (collectively, CF&I/Climax);
- CDPHE;
- Colorado Energy Consumers;
- Colorado Governor's Energy Office (GEO);
- Colorado Independent Energy Association (CIEA);
- Colorado Interstate Gas Company (CIG) and Wyoming Interstate Company, LLC, jointly;

[1] Public Service sought an alteration of this data production procedure in its Motion for Reconsideration and/or Clarification of Commission Decision No. C10-0452, filed on May 18, 2010. The paragraph 38 procedure was upheld in Decision No. C10-0638, at ¶ 77.

[2] In Decision No. C10-0545, we encouraged the City of Boulder and Boulder County to voluntarily withdraw their virtually identical petitions to intervene and to re-file as a joint party. ¶ 6. Boulder County and the City of Boulder filed a Petition to Join the Approved Interventions on June 16, 2010, which was granted in Decision No. C10-0659.

- Colorado Mining Association (CMA);
- Colorado Office of Consumer Counsel (OCC);
- Colorado Oil & Gas Association (COGA);
- Colorado Solar Energy Industries Association (CoSEIA);
- Colorado Springs Utilities and Tri-State Generation and Transmission Association, Inc., jointly (collectively, CSU/Tri-State);
- Federal Executive Agencies;
- Ms. Leslie Glustrom, *pro se*;
- Holy Cross Electric Association, Inc. (Holy Cross);
- Intermountain Rural Electric Association;
- Interwest Energy Alliance;
- Mr. Ronal Larson, *pro se*;
- Noble Energy, Inc., Chesapeake Energy, Inc., and Encana Corporation[3] (collectively, Gas Intervenors);
- Peabody Energy Corporation (Peabody);
- School District No. 1, in the City and County of Denver, State of Colorado;
- Southwest Generation (Southwest);
- Staff;
- Suncor Energy (U.S.A.), Inc. (Suncor);
- Thermo Power & Electric LLC (Thermo);
- Wal-Mart Stores, Inc. and Sam's West Inc., jointly (collectively, Wal-Mart);
- Western Fuels – Colorado and Colorado Rural Electric Association, jointly; and
- Western Resource Advocates (WRA).

20. Further, we found good cause to grant the following petitions to participate in this Docket as *amici curiae*:

- Colorado Renewable Energy Society;
- Energy Outreach Colorado;
- Independence Institute;
- Industrial Energy Consumers of America; and
- Luca Technologies.

[3] Although the Gas Intervenors intervened jointly, we treated them as three distinct parties to this proceeding for purposes of discovery. Decision No. C10-0969, at Ordering ¶ 2.

21. The Commission held a pre-hearing conference on May 27, 2010, which was memorialized in Decision No. C10-0638 mailed on June 23, 2010. In that Decision, we further clarified Staff's role in this proceeding and discussed the terms under which Staff would be permitted to utilize a consultant to aid in its analysis of the complex issues in this Docket.[4] In Decision No. C10-0638 we set limits on the amount and timing of acceptable discovery in this Docket and established additional hearing dates. Decision No. C10-0638 also addressed the process by which Public Service was to develop its August 13, 2010 filing, which is discussed in more detail below.

22. In Decision No. C10-0808, mailed July 30, 2010, the Commission established a process by which motions for extraordinary protection would be resolved by an Administrative Law Judge. We also altered the procedural schedule by, among other things, establishing a date and time for a public comment hearing to be held in Denver, Colorado.

23. Further, Decision No. C10-0808 denied a Notice for Withdrawal of Petition for Intervention filed by the CDPHE. In making that determination, the Commission found the CDPHE was a necessary party in this docket, and that its absence would render the Commission unable to resolve the matters before it. However, in order to accommodate the CDPHE's unique role, the Commission delayed the date after which the CDPHE would be subject to discovery. *See* Decision No. C10-0808, at ¶¶ 48-57.

24. By Decision No. C10-0858, mailed on August 9, 2010, we held the CDPHE would be permitted to file its official report analyzing Public Service's plan no later than

[4] Staff utilized two consultants in this proceeding. The Harris Group, Inc., provided testimony regarding retrofit feasibility, constructability, retrofit cost estimates, and replacement generation cost estimates. Dr. Harvey Cutler, a professor of Economics at Colorado State University, assessed the statewide economic impacts of the proposed plan.

September 17, 2010, the deadline for answer testimony. However, we requested the CDPHE to submit a filing on August 13, 2010 concerning the criteria it was using to assess the plan's compliance with reasonably foreseeable emissions reductions requirements. We further addressed the contents of the CDPHE's September 17, 2010 report in Decision No. C10-0874, mailed on August 11, 2010, by ordering the CDPHE to address, in part, the scenario identified as "Benchmark 1.1."[5]

25. In Decision No. C10-0874, we also established a public comment hearing to be held in Grand Junction, Colorado.

26. Public Service filed its proposed emission reduction plan on August 13, 2010. The plan contained nine potential emissions reduction scenarios (Benchmark 1.0, Benchmark 1.1, and Scenarios 2, 3, 4, 5, 6, 6.1, and 7) as well as nine replacement generation portfolios (A through I), and a variety of "bolt-on" analyses. In its August 13, 2010 filing, Public Service identified its preferred scenario as scenario 6.1, with replacement portfolio E. *See* § 40-3.2-206(2), C.R.S. (requiring the utility to identify what it believes is the "best way of timely meeting the emission reduction requirements" under the circumstances). This scenario was commonly referred to as "scenario 6.1E" or the Company's "preferred plan."

27. The Commission re-noticed these proceedings on August 18, 2010 in a "Notice of Filing," in order to specifically notice the proposed plan as filed by Public Service. The Notice of Filing referred to a request "for approval of an emission reduction plan, for approval of a long term gas contract, and for approval of a new rate adjustment clause, called the Emissions Reduction Adjustment (ERA)" and specifically referenced that the proposed emission reduction

[5] Benchmark 1.1 is an alternative all-controls scenario, which excludes Pawnee. *See* Decision No. C10-0808 at ¶ 27.

plan was being filed in accordance with HB 10-1365. The Notice of Filing further established a second period for interventions. No additional petitions for intervention were filed during this second period.

28. On August 30, 2010, the Commission held a public comment hearing in Grand Junction, Colorado.

29. By Decision Nos. R10-0872-I, R10-0897-I, C10-0910, C10-0944, C10-0957, C10-0976, and C10-1021, the Commission addressed the treatment of confidential and highly confidential information in this Docket. *See also* Decisions No. C10-1040 and C10-1079. We determined that Staff and the OCC would be permitted access to the long-term gas contract between Public Service and Anadarko.[6] Additionally, we held natural gas and coal suppliers would not have access to bids for long-term gas supplies submitted in response to Public Service's May Request for Proposals (RFP). All other parties, excluding Staff and the OCC, were permitted access by outside counsel and outside consultants on an *in camera* basis. We held COGA, CIEA, Southwest, and Thermo would not have access to detailed cost estimates concerning Public Service's proposed replacement generation. However, Staff and the OCC would have unlimited access to this material, and all other parties were permitted access on an *in camera* basis. We also held COGA, Southwest, and Thermo would not have access to offers from Independent Power Producers (IPPs) to sell their facilities and any related letters of intent or other agreements. We further supplemented this Decision to prevent CSU/Tristate, Holy Cross, CoSEIA, Suncor, Boulder, and AGNC from accessing this information. *See* Decision No. C10-1021. For other parties, excluding Staff, the OCC, and WRA, outside counsel and

[6] This holding was upheld in Decision No. C10-1009.

outside consultants or experts were allowed access to this material on an *in camera* basis. Finally, we held the Company's STRATEGIST[7] input files were highly confidential, and that access to those files would be limited to Staff and the OCC. However, we did allow discovery concerning the STRATEGIST inputs.

30. Parties submitted answer testimony on September 17, 2010. The CDPHE also submitted its report in the form of answer testimony on September 17, 2010.

31. By Decision No. C10-1036, mailed on September 23, 2010, we permitted Public Service to file supplemental direct testimony in support of its long-term gas contract with Anadarko. As part of that Decision, we altered the procedural schedule to allow Staff and the OCC to file supplemental answer testimony and for Public Service to file supplemental rebuttal. Further, by Decision No. C10-1098, mailed on October 8, 2010, we granted Anadarko and any other party leave to file supplemental cross-answer testimony regarding the long-term gas contract no later than October 15, 2010.

32. On September 23, 2010, the Commission held a public comment hearing in Denver, Colorado.

33. On September 29, 2010, the Commission addressed a Motion for Partial Summary Judgment in Decision No. C10-1067,[8] concerning whether the Company's preferred scenario, scenario 6.1E, was in compliance with HB 10-1365. Scenario 6.1E included some actions to be taken after 2017, which the moving parties argued was in violation of the

[7] STRATEGIST is an electric utility planning model that simulates the economic dispatch of the generating resources in Public Service's system in the lowest cost manner. STRATEGIST can assist in the selection of new resources, either to replace retired units or to meet future load growth. STRATEGIST can also be used to simulate power plant emissions, as well as changes in utility rates and revenue requirements over time.

[8] This Motion for Partial Summary Judgment was filed by CIEA, Thermo, and Southwest on August 31, 2010.

December 31, 2017 implementation deadline set forth in § 40-3.2-204(2)(c). In Decision No. C10-1067, we interpreted the phrase "full implementation by December 31, 2017" as requiring that all activities necessary to comply with current and reasonably foreseeable emissions requirements be completed prior to January 1, 2018. Decision No. C10-1067 at ¶ 20. We therefore accepted the Company's representations that its preferred scenario would meet reasonably foreseeable emissions reduction requirements if only those actions scheduled to occur prior to December 31, 2017 were completed. *Id.* at ¶ 22. In other words, we opted to consider only those activities scheduled to occur before 2018 as part of Public Service's preferred scenario, which we referred to as "truncated." In Decision No. C10-1067, we asked the CDPHE to file a statement concerning whether, in its opinion, this truncated scenario would be sufficient from an emissions reduction standpoint.

34. On October 4, 2010, the CDPHE filed a responsive pleading, in which it stated the truncated scenario would not meet reasonably foreseeable emissions reduction requirements. This pleading, when combined with the rationale in Decision No. C10-1067, essentially eliminated Scenario 6.1E from the Commission's consideration. The Commission later upheld this ruling in Decision No. C10-1164, mailed on October 27, 2010. In Decision No. C10-1164, we further held that we would generally defer to the CDPHE in matters pertaining to determining which emissions reduction requirements are reasonably foreseeable, as well as how far into the future such requirements can reasonably be foreseen. *See* ¶ 41.

35. On October 8, 2010, parties submitted cross-answer and rebuttal testimony. Also on October 8, 2010, parties filed supplemental answer testimony regarding the long-term gas contract.

36. On October 15, 2010, parties filed supplemental cross-answer and rebuttal related to the long-term gas contract.

37. At a Pre-Hearing Conference on October 19, 2010, Public Service made an oral motion seeking leave to file supplemental direct testimony that would set forth what it characterized as a cost-effective alternative to scenario 6.1E (scenario 6.2J), that would include the retirement and replacement of Cherokee 4 by 2017, to comply with the requirements we set forth in Decision No. C10-1067. We received a written motion later that same day, which also contained proposed modifications to the procedural schedule to accommodate this supplemental testimony. We granted Public Service's Motion for Leave to File Supplemental Testimony in Decision No. C10-1135, mailed on October 22, 2010, but we declined to actually consider that testimony until we heard from parties regarding the procedural burden it could create.

38. On October 25, 2010, Public Service filed supplemental direct testimony in accordance with its October 19, 2010 motion. That supplemental direct testimony identified some modified scenarios for the Commission's consideration, and identified Scenario 5B as the Company's new recommended scenario.[9]

39. In Decision No. C10-1193, mailed November 4, 2010, we granted Public Service's Motion for Acceptance of Supplemental Testimony. In that Decision, we found that the goals of HB 10-1365 would be best served by the development of a full and complete evidentiary record. We therefore accepted the supplemental testimony and adopted an alteration to the procedural schedule, including additional discovery deadlines and hearing dates, to accommodate the supplemental testimony.

[9] As its nomenclature suggests, scenario 5B was one of the scenarios originally presented in the Company's August 13, 2010 filing.

40. On October 21, 2010, the Commission undertook consideration of a Motion for Disqualification concerning Chairman Binz and Commissioner Baker filed by CMA on October 12, 2010. We denied the Motion for Disqualification in Decision No. C10-1326 mailed on December 10, 2010.

41. On October 21, 2010, the Commission began hearings in this matter. The first round of hearings was conducted on October 21, 22, 25, 26, 28, 29 and 30, 2010, as well as November 1, 2, and 3, 2010. The Commission instructed parties that the first round of hearings should focus on those elements of the plan, as originally filed, that were not impacted by Public Service's supplemental direct testimony.[10] Parties were instructed they would have an additional opportunity to cross-examine witnesses on the supplemental testimony, as well as on the Company's new recommended scenario.

42. Parties filed supplemental answer testimony on November 9, 2010.

43. Parties filed supplemental rebuttal and cross-answer testimony on November 15, 2010.

44. On November 18, 2010, the Commission began the second round of hearings in this matter. The second round of hearings was conducted on November 18, 19, and 20, 2010.

45. The Commission undertook deliberations in this Docket on December 6, 8, and 9, 2010.

[10] Some of the issues parties covered in these days of hearings were: fuel costs, foreseeable emission costs, existing scenarios, the long-term gas contract, and cost recovery.

2. Due Process

46. Throughout these proceedings, a number of parties have raised broad due process arguments.[11] Although no party has directly stated as much, many of these pleadings appear to assert constitutional procedural due process arguments, by either invoking the United States Constitution, or by citing to cases concerning constitutional procedural due process.[12]

47. Both the federal and Colorado constitutions prohibit governmental actions that deprive individuals of liberty or property without "due process of law." U.S. CONST. amend. V and XIV; Colo. CONST. Art. II §25. To raise a successful due process claim, a party must first identify the protected liberty or property interest at stake. *See Goss v. Lopez*, 419 U.S. 565, 572-76 (1975). Once a party has established that procedural due process applies, a court must determine what process is due. *Morrissey v. Brewer*, 408 U.S. 471, 480 (1972). Standards of due process are flexible and will depend on the situation. *Cafeteria Workers v. McElroy*, 367 U.S. 886 (1961). At a minimum, procedural due process requires "notice and an opportunity to be heard in a meaningful manner." *Nichols ex. rel. Nichols v. DeStefano*, 70 P.3d 505, 507 (Colo. App. 2002) (citing *Goss*, 419 U.S. 565).

48. At no point in these proceedings did any party articulate a liberty or property interest of which it would be deprived. Therefore, the standards of procedural due process, as set

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[11] *See, e.g.*, Peabody Motion to Vacate Procedural Schedule and Set a Status Conference, filed October 18, 2010; Response of CIEA and Thermo to the Motion of Public Service for Leave to File Additional Testimony, filed October 27, 2010; Gas Intervenors Response to "Motion of Public Service Company of Colorado for Acceptance of Supplemental Testimony" and Response Pursuant to Commission Decision C10-1135, filed October 27, 2010; and Peabody Motion for Summary Judgment, filed October 29, 2010.

[12] *See, e.g.*, Peabody Motion for Summary Judgment, at 21 (citing U.S. CONST. amend. V and XIV); Response of CIEA and Thermo to the Motion of Public Service for Leave to File Additional Testimony, filed October 27, 2010, at 7 (citing *Denver Welfare Rights Org. v. Pub. Utils. Comm'n*, 190 Colo. 329, 547 P.2d 239 (1976); and *In re Marriage of Salby*, 126 P.3d 291 (Colo. App. 2005)).

forth in U.S. CONST. amend. V and XIV, and Colo. Const. Art. II, § 25, are inapplicable here. *See Public Service Co. of Colo. v. Public Util. Comm'n*, 653 P.2d 1117, 1121 (Colo. 1982).

49. However, the Commission is cognizant of the statutory due process to which parties are entitled. Generally, the Commission is required to "conduct its proceedings in such a manner as will best conduce the proper dispatch of business and the ends of justice." § 40-6-101(1), C.R.S. Specifically, § 40-3.2-204(2)(b)(IV), C.R.S, provides "[t]he commission shall not approve a plan except after an evidentiary hearing." The Commission held an evidentiary hearing in this Docket on October 21, 22, 25, 26, 28, 29, 30, 2010, as well as November 1, 2, 3, 18, 19, and 20, 2010. Further, § 40-6-109(1), C.R.S., provides that all intervenors "interested in or affected by any order that may be made" are entitled "to be heard, examine and cross-examine witnesses, and introduce evidence." The Commission believes that, over the course of these proceedings, all parties have been afforded ample opportunity to present their cases, examine and cross-examine witnesses, and introduce evidence. *See* Decision No. C10-0545 (granting Petitions for Intervention); Decision Nos. C10-0452, C10-0638, and C10-1193 (establishing procedural schedules and hearing dates).

50. In short, the Commission has done everything possible to provide parties the maximum process possible, while still complying with the December 15, 2010 deadline for a final decision, as required by § 40-3.2-205(2), C.R.S. These proceedings have necessarily been time constrained. However, the Commission is permitted to fashion procedural mechanisms, including abbreviated procedures, where necessary to carry out its regulatory function.

51. For example, in *Public Service Co. of Colo. v. Public Util. Comm'n*, intervenors challenged the emergency procedures fashioned by the Commission as violating standards of statutory due process. In that case, Public Service filed advice letters arguing that the Company

was facing a financial emergency that warranted an increase in rates. The Commission suspended the tariffs, conducted three days of limited hearings, and issued a decision approximately a month and a half later. 653 P.2d at 1118. Intervenors in the case argued that the abbreviated nature of the proceeding and the limitation of issues to be considered created a hearing that was not granted at a meaningful time or in a meaningful manner. *Id.* at 1121. Intervenors argued they did not have adequate time to conduct discovery and to procure the expert witnesses they needed, because the hearing began only 16 days after the Commission's order of suspension. *Id.* The Colorado Supreme Court disagreed, finding the Commission struck an appropriate balance between offering procedural protections and ensuring the health of the regulated utility. *Id.* at 1122. The Court further agreed with the Commission that it "would be derelict in its responsibility if it did not fashion the procedural mechanisms available to it so as to minimize, to the extent possible, harmful economic results." *Id.* As the Court concluded, "[p]articipatory values are better served by allowing the commission to conform its procedures to the exigencies of the case before it." *Id.*

52. We believe the reasoning of *Public Service Co. of Colo. v. Public Util. Comm'n* supports the procedural mechanisms the Commission has fashioned in this case.

D. Public Service's Plan and Modification Scenarios

1. Pre-Filing Requirements and Plan Development

53. In Decision No. C10-0638, we discussed the process by which Public Service was to develop the scenarios contained in its August 13, 2010 filing. In that Decision, we declined to adopt any limitations on our authority to consider alternative scenarios and to modify any proffered plan. Decision No. C10-0638, at ¶ 28. To that end, we encouraged Public Service to meet with the parties in a workshop setting to discuss development of the scenarios to be

contained in the Company's proposed emission reduction plan. *Id.* at ¶ 26. We further ordered Public Service to submit a filing outlining the contents of the proposed emission reduction plan, including any alternative scenarios and major modeling assumptions, on July 1, 2010. *Id.* at ¶ 31. Following submission of this filing, we permitted comment from parties regarding the sufficiency of Public Service's plan to date, as well as the extent to which the Company was responsive in accommodating and modeling their suggested alternatives in STRATEGIST.[13] *Id.* at ¶ 33. In so doing, we sought to provide additional process to parties, by providing them with substantial information prior to the August 15, 2010 filing deadline and allowing an opportunity to assist in the development in Public Service's proposed plan.

54. We conducted a status conference to discuss the Company's July 1, 2010 filing and relevant comments on July 9, 2010. In Decision No. C10-0808, we requested that the Company model in STRATEGIST two additional scenarios: (1) an alternative baseline that excluded the installation of a selective catalytic reduction (SCR) at Pawnee station (Benchmark 1.1); and (2) a variation of one of the Company's proposed scenarios that would contain higher levels of renewable resources, while still maintaining transmission stability (scenario 6H). ¶¶ 27-29. While we declined to order the Company to develop any of the other intervenor-suggested alternatives, we stated, "we will in no way preclude the parties from raising arguments in the course of this proceeding concerning the merits of Public Service's emission reduction plan and the alternatives that the Company may not have fully developed for our consideration." *Id.* at ¶ 30. *See also* Decision No. C10-0874 (addressing motions seeking clarification or alteration of Decision No. C10-0808).

[13] *See* footnote 7.

2. Public Service's August 13, 2010 Filing

55. On August 13, 2010, the Company filed its proposed emission reduction plan and supporting direct testimony. *See* Public Service Emissions Reduction Plan (Hrg. Ex. 2). Public Service represented that it developed its plan by: (1) identifying the coal units for consideration in the plan and the actions (retirement, fuel switch, or emissions controls) feasible for each unit; (2) constructing combinations of actions, referred to as scenarios; (3) identifying feasible replacement capacity for retired coal facilities; and (4) estimating costs. *Id.* at 25. The Company also stated it consulted with the CDPHE throughout this process. *Id.*

56. The result was a proposed plan that identified nine scenarios (Benchmark 1.0, Benchmark 1.1, and Scenarios 2, 3, 4, 5, 6, 6.1, and 7) and set forth nine potential portfolios of replacement capacity (A through I). *See Id.* at 44, fig. 5.5. Of the combinations of these options, the Company identified scenario 6.1E as its preference.

57. Scenario 6.1E would retire all of the coal-fired electric generating units at Cherokee Station (Cherokee 1-4) and Valmont 5. Cherokee 1 and 2 would be retired before the end of 2011. Selective Non-Catalytic Reduction (SNCR) controls would be installed at Cherokee 4 in 2012. Before Cherokee 3 would be retired, a new 2X1 combined cycle (CC) natural gas-fired plant would be installed at Cherokee Station. Then, Cherokee 3 would be retired in 2017. A second new 1X1 CC gas plant would come into service in 2022, at which time Cherokee 4 would be retired. Valmont 5 would be retired in 2017. Also, Arapahoe 3 and Cherokee 2 would be converted to synchronous condensers in 2014 and 2012, respectively, and 90 MVAR of capacitor banks would be installed at Arapahoe and Cherokee for reactive voltage support. Arapahoe 4 would be fuel switched to run on gas at the end of 2013.

58. Under scenario 6.1E, 213 MW of coal would be retired by 2013; 551 MW of coal would be retired by 2018;[14] and 903 MW of coal would be retired by 2022.

59. With respect to controls, scenario 6.1E would include SCR controls at the Pawnee Station and at Hayden Station on units 1 and 2. The SCR installation at Pawnee would be completed before the end of 2014 and would be coordinated with the installation of a lime spray dryer (LSD) for reductions in the emissions of SO_2. The SCR installation on Hayden 1 and 2 would be complete by the end of 2015 and 2016, respectively.

3. Partial Summary Judgment and Elimination of Scenario 6.1E

60. On August 31, 2010, CIEA, Thermo, and Southwest (collectively, the IPP Intervenors), filed a Motion for Partial Summary Judgment, arguing the two post-2017 elements of Public Service's plan (construction of the new 1X1 CC unit and retirement of Cherokee 4) rendered it fatally flawed under HB 10-1365. Assuming these post-2017 actions were necessary to meet reasonably foreseeable emission requirements, the IPP Intervenors argued the Commission could not approve scenario 6.1E because it would not meet all reasonably foreseeable emissions reduction requirements by December 31, 2017. *See* §§ 40-3.2-204(2)(b)(IV), -204(2)(c), C.R.S.

61. The Commission agreed with the IPP Intervenors that scenario 6.1E did not satisfy the implementation deadline set forth at § 40-3.2-204(2)(c), C.R.S., in Decision No. C10-1067. We therefore stated we would only consider a truncated version of scenario 6.1E, and asked the CDPHE to opine on whether such a truncated scenario would satisfy reasonably foreseeable emissions requirements. The CDPHE stated it would not. *See* Response of the

[14] The Commission had already approved the early retirement of Arapahoe 3 and 4 by Decision No. C08-0929 in Docket No. 07A-447E mailed on September 19, 2008.

CDPHE to the PUC's September 29, 2010 Order Denying Motion for Summary Judgment, filed Oct. 4, 2010.

62. The Company sought modification of Decision No. C10-1067 on October 5, 2010. The Commission denied Public Service's Motion to Modify Decision No. C10-1067 in Decision No. C10-1164. In that decision, we further stated that we generally deferred to the CDPHE with regard to what emissions reduction requirements were reasonably foreseeable, and stated that we declined to utilize our existing organic authority in any way that would circumvent the December 31, 2017 implementation deadline.

63. As a result of these Decisions, Public Service sought leave to file supplemental direct testimony on October 19, 2010. After fully considering the procedural implications of supplemental testimony, we granted the Company leave to file and accepted the supplemental direct testimony in Decision No. C10-1193.

4. Public Service's October 25 Supplemental Direct Testimony

64. Public Service filed its supplemental direct testimony on October 25, 2010. The supplemental testimony set forth an alternative scenario that achieves retirement of Cherokee 4 by 2017, but also analyzes cost associated with fuel-switching Cherokee 4 to run on natural gas by the end of 2017. Public Service identified these scenarios as scenario 6.2J (retires Cherokee 4 by the end of 2017 and constructs both a 1X1 and a 2X1 CC plant at Cherokee Station before the end of 2017); scenario 6E FS (modifies scenario 6E by fuel switching Cherokee 4 at the end of 2017 and completing the retirement of Cherokee 4 and the construction of a new 1X1 CC plant at Cherokee Station by the end of 2018); and scenario 6.1E FS (modifies scenario 6.1E by fuel switching Cherokee 4 at the end of 2017 and completing the retirement of Cherokee 4 and the construction of a 1X1 CC plant at Cherokee Station by the end of 2022).

65. In addition to identifying these proposed scenario modifications, the Company further stated that scenario 5B was now the Company's recommended scenario.

66. In response to this supplemental direct testimony, the CDPHE filed supplemental answer testimony of Mr. Paul Tourangeau, in which he stated the CDPHE believes the fuel switching scenarios are consistent with current and reasonably foreseeable emissions requirements while achieving the necessary levels of NOx reductions. *See* Tourangeau Fuel Switching Testimony (Hrg. Ex. 200). The CDPHE believes Scenario 6.2J is similarly consistent with HB 10-1365's air quality provisions. *See* Tourangeau Supplemental Answer Testimony (Hrg. Ex. 201).

5. Public Service's Recommended Scenario

67. Scenario 5B was contained in the Company's August 13, 2010 filing, and was elevated to the status of "recommended" by the Company in its October 25, 2010 supplemental direct testimony. Scenario 5B would retire Cherokee 1 and 2 before the end of 2011 and retire Cherokee 3 and Valmont 5 before the end of 2017. A new 2X1 CC would be installed at Cherokee Station before the end of 2015. Arapahoe 3 and Cherokee 2 would be converted to synchronous condensers in 2014 and 2012, respectively. Further, 90 MVAR of capacitor banks are installed at Arapahoe and Cherokee for reactive voltage support. Arapahoe 4 would be fuel switched to run on gas before the end of 2013.

68. Scenario 5B retires 213 MW of coal by January 1, 2013, and retires a total of 551 MW of coal by January 1, 2018.

69. As originally presented, scenario 5B also included the installation of SCR controls on Cherokee 4 in 2016. However, in its October 25, 2010 supplemental direct testimony, Public Service requested this installation date be changed to 2017. As with all other primary scenarios,

scenario 5B also included SCR and LSD controls at the Pawnee Station and SCR controls on Hayden 1 and 2.

6. Intervenor Presented Alternative Scenarios

70. Certain intervenors prepared alternative scenarios or advocated for specific scenarios modeled in STRATEGIST by Public Service.

71. Those intervenors generally representing coal interests advocated for the adoption of Benchmark 1.0. Benchmark 1.0 is the all controls scenario that the Company must prepare for cost comparison purposes, pursuant to § 40-3.2-206(3)(a), C.R.S. Benchmark 1.0 includes installation of SNCR on Cherokee 1 and 2 and SCRs on Cherokee 3 and 4, Hayden 1 and 2, and Valmont 5. Primarily because of the SNCR installations on Cherokee 1 and 2, which are among the oldest coal-fired units in the Company's generation fleet, and because of the installation of SCR on Cherokee 3, Public Service opposes Benchmark 1.0 and stated it would withdraw its plan under § 40-32-205(4), C.R.S., should the Commission adopt those modifications to the Company's recommended scenario. *See* Public Service Statement of Position (SOP) at 27.

72. By contrast, the Gas Intervenors advocated for a modified version of scenario 7E. As modeled by the Company, scenario 7E would retire all of the Cherokee units and Valmont 5. Cherokee 1 and 2 would be retired at the end of 2011. Cherokee 3 and 4 would be fuel switched from coal to gas in 2014. Cherokee 3 would be retired in 2015 when a new 2X1 CC gas plant would go into operation. Cherokee 4 would be retired in 2018 when a new 1X1 CC gas plant would go into operation. Valmont 5 would be switched to gas in 2013 prior to being retired in 2017. Arapahoe 3 and Cherokee 2 would be converted to synchronous condensers in 2014 and 2012, respectively, and 90 MVAR of capacitor banks would be installed at Arapahoe and

Cherokee for reactive voltage support. Arapahoe 4 would be fuel switched to run on gas at the end of 2013.

73. By way of modifications to the Company's modeled scenario 7E, the Gas Intervenors recommend delaying the decision to build any 1X1 CC to replace Cherokee 4 until either the Company's 2011 Electric Resource Plan (ERP) filing,[15] or until additional transmission studies could be completed. According to the Gas Intervenors, scenario 7E would result in earlier emission reduction benefits with no significant differences in near-term ratepayer impacts as compared to the Company's proposed scenario. *See* Cavicchi Answer Testimony (Hrg. Ex. 73), at 32.

74. The IPP Intervenors support a scenario known as IPP2. Late in these proceedings, the IPP Intervenors reached an understanding with Public Service regarding the development of a STRATEGIST analysis of certain modifications to the Company's emission reduction plan,[16] involving various combinations of re-contracting long-term purchased power agreements (PPAs) with existing natural gas electricity generation units owned by Thermo and Southwest. Based on these STRATEGIST runs, the IPP Intervenors presented and advocated for scenario IPP2. The CDPHE evaluated scenario IPP2 and concluded it was consistent with reasonably foreseeable emissions reduction requirements and achieved the necessary levels of NOx reductions. *See* Tourangeau Testimony Regarding IPP2 (Hrg. Ex. 202).

75. Scenario IPP2 would retire Cherokee 1 and 2 in 2011 and replace Cherokee 2 with a synchronous condenser in 2012. Arapahoe 3 would similarly be retired in 2013 and

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[15] The Commission's ERP Rules, set forth at Rule 3600, 4 *Code of Colorado Regulations* (CCR) 723-3, *et seq.*, require Public Service to file an ERP on or before October 31, 2011.

[16] The Commission expects the timing of STRATEGIST runs may be an issue in the Company's next ERP proceeding. As a result, we are interested on gathering information on the timing of STRATEGIST modeling in advance of the Company's next ERP filing.

transformed into a synchronous condenser in 2014, while Arapahoe 4 would be retired in 2013. The Company would renew contracts for 199 MW of replacement power from Southwest and 69 MW from Thermo for service beginning in the 2012 to 2013 timeframe. SCR would be installed on Hayden 1 and 2, and SCR and LSD would be installed on Pawnee. Cherokee 3 and 4 and Valmont 5 would all be retired in 2017, when a new single-cycle combustion turbine (CT) peaker unit at the Cherokee Station would come online. *See* Response to Discovery Request No. CIEA5-1 (Hrg. Ex. 181).

76. In support of scenario IPP2, the IPP Intervenors stressed the lower levels of construction risk associated with the relatively less complicated installation of a CT at Cherokee Station in combination with the use of already built gas-fired generation through PPAs. The IPP Intervenors further argue that the STRATEGIST results likely underestimate the costs of the new Company-built generation facilities and that, from a reliability perspective, it would be preferable to have multiple load-service centers at the Valmont and Arapahoe Stations in addition to Cherokee Station. The IPP Intervenors also suggest that their existing CT facilities are better than the proposed new CC units for system operations. *See, e.g.*, Southwest SOP; Thermo SOP.

77. WRA also presented an alternative scenario in answer testimony. This modified scenario 6H would retire Cherokee 1, 2, 3, and 4 and Valmont 5, all before 2017. A new 2X1 CC gas plant at the Cherokee site would go into operation before the end of 2015, and, only if necessary as a backstop measure, additional replacement capacity would be installed at the Company's Fort Saint Vrain Station. Unlike the other principal scenarios, only Arapahoe 3 would be converted into a synchronous condenser. Voltage support and reactive power needs at Cherokee Station would instead be satisfied with MVAR static VAR compensators (SVCS) or

static synchronous compensators (STATCOMMS). *See* Nielsen Answer Testimony (Hrg. Ex. 92), at 19.

78. WRA supported its modified scenario 6H due to its lower emissions of NOx, SO_2, CO_2, and mercury, as well as its relatively lower exposure to high coal costs due to earlier coal plant retirements. If monetized health benefits were associated with these incremental emissions benefits, WRA claimed the cost effectiveness of its preferred scenario relative to the Company's recommended scenario would improve. Although WRA supported this modified scenario 6H at the beginning of hearings, its position eventually changed in support of scenario 6.2J. *See* WRA SOP, at 1.

79. Therefore, the Commission's consideration was focused on an evaluation and comparison of its proposed scenario 5B to scenarios Benchmark 1.0, as required by the statute, and scenarios 6E FS, 6.1E FS, 6.2J, 7E, and IPP2.

7. Requested Approvals

80. Public Service sought the following approvals and/or findings in this Docket:

- approval of Scenario 5B as the Company's "recommended" emission reduction plan under HB 10-1365;
- findings that the emissions controls, retirements, and replacements associated with the Company's recommended plan are needed and in the public interest;
- findings that the Company has the flexibility to install the SCR on Cherokee 4 until the end of 2017, if controls are approved for Cherokee 4;
- approval of the fuel switching of Arapahoe 4 so that no challenge to this fuel switching can be made in subsequent adjustment clause reviews;
- approval of the long-term gas purchase agreement with Anadarko[17] under § 40-3.2-206, C.R.S., including findings that the Company acted prudently by entering into this agreement, that the agreement appears to be beneficial to consumers, and that the agreement is in the public interest;

[17] Carter Direct Testimony (Hrg. Ex. 14), Exhibits TJC 3 and TJC 3A.

- a finding that under certain defaults, under the long-term gas contract, replacement gas costs would be recoverable through the fuel clause given prudent contract management;

- recognition by the Commission that the new gas-fired 2X1 CC units at Cherokee Station and any additional natural gas-fired generation located at Cherokee Station will need adequate gas transportation infrastructure and the pipeline will eventually be included in gas rate base with charges to the Company's electric department for service rendered;

- a finding of need for a 2X1 CC at Cherokee Station in order to accelerate a required subsequent proceeding regarding a Certificate of Public Convenience and Necessity (CPCN) for this new generation facility;

- a finding that the Company does not need a CPCN for emissions controls at Pawnee, Hayden, and Cherokee 4, as well as clarification that Rule 3205(b)(II) applies to these projects, deeming them to be in the ordinary course of business;

- a finding that the Company does not need to file a separate application, either for a CPCN or otherwise, to retire units ahead of their useful lives;

- approval in this docket of the early retirements of all existing units affected by the plan scenarios selected by the Commission;

- approval of a specific rate rider, the ERA and associated tariff sheets to allow: (1) current return on capitalized construction work in progress (CWIP) at Public Service's weighted average cost of capital (WACC), including the Company's most recently authorized rate of return on equity (ROE); and (2) recovery of incremental 2011 plant-related costs (for example, accelerated depreciation and removal expenses offset by reduced rate base during 2011) starting January 1, 2011;

- a finding that the Company's plan satisfies the requirement of "early conversion or closure of coal-based generation capacity by January 1, 2015" required by CRS § 40-3.2-207 (4);

- a finding that the Company has demonstrated "that a lag in recovery of the costs of the plan related to the investment required by such plan contributes to a utility earning less than its authorized return on equity" under § 40-3.2-207(4), C.R.S.;[18] and

- a finding that the appropriate share of costs of these plants to seek recovery from wholesale customers is the jurisdictional allocator as it changes over time under § 40-3.2-207(2)(a), so long as the allocator does not conflict with the Company's wholesale contracts executed prior to HB 10-1365.

[18] The Company requests this finding regardless of whether the ERA or deferred accounting is approved for accelerated depreciation and removal costs.

E. Considerations in Evaluating the Plan

1. Reasonable Fuel Cost Forecasts

81. Section 40-3.2-206(3)(b), C.R.S., requires us to "use reasonable projections of future coal and natural gas costs." As part of its STRATEGIST modeling, Public Service adopted certain fuel cost assumptions. These modeling assumptions and conventions are based on those the Commission approved in the Company's most recent ERP. *See* Docket No. 07A-447E.[19] While the methodology for deriving the forecasts is the same, the values have been updated to reflect current data.

a. Gas Price Forecasts

82. In developing its forecast for gas prices, Public Service blends three industry forecasts and a quote of the current market using the closing price on the New York Mercantile Exchange and an adder for estimating gas price volatility. *See* Hrg. Ex. 2, at 16-17. *See also* Public Service SOP, at 51-53. The Company believes this method represents a prudent range of possible future prices. Further, in developing its forecast, the Company incorporated projected savings from the Anadarko long-term gas contract. However, these savings were not credited to the Benchmark 1.0 scenario. *See* Montgomery Cross-Answer Testimony (Hrg. Ex. 45), at 22-23.

83. A number of parties suggest the Commission use a different natural gas price forecast in evaluating the proposed scenarios. *See* Peabody SOP, at 38-39 (contending Public

[19] We took administrative notice of Decision No. C08-0929 in Docket No. 07A-447E. Tr. Oct. 21, 2010, at 146.

Service's forecasted natural gas price is too low); Fishman Answer Testimony (Hrg. Ex. 181) (contending Public Service's forecasted natural gas price is too high).

84. The Commission finds Public Service's method of forecasting natural gas prices is reasonable. However, we do not believe this finding of reasonableness requires us to explicitly adopt Public Service's gas forecasts in evaluating the scenarios before us. Rather, we are mindful of each scenario's relative sensitivity to fluctuations in gas prices, and take this into consideration in determining which scenario is the most reasonable from a cost perspective. We do, however, accept Public Service's predictions regarding gas transportation costs, as we think the Company is in the best position to estimate those costs.

85. Furthermore, we decline to assume any estimated savings as a result of the Anadarko long-term gas contract. As a preliminary matter, we believe any predicted savings that may result from the contract should be applied to all scenarios, including Benchmark 1.0, as Public Service could, under any scenario, benefit from a contract covering a portion of its gas burn. Additionally, the predicted savings associated with the contract are a function of differences in various forecasts and therefore are not likely to be precise. In other words, while we believe the long-term contract offers benefits (which we will discuss further below), we do not believe the Company's projected savings should affect our evaluation of the relative benefits of the scenarios.

b. Coal Price Forecasts

86. Public Service obtains its coal supplies through a combination of term and spot contracts, as well as over-the-counter transactions. The Company developed coal price forecasts based on forecasts from third-party experts combined with known prices from existing contracts. Hrg. Ex. 2, at 16-18. This is similar to the assumptions Public Service made in its 2007 ERP.

However, Public Service did adjust coal prices downward slightly for purposes of its emission reduction plan, as a result of the Wood Mackenzie modeling of the impact the plan itself would have on coal prices. *See* Hrg. Ex. 2, at 140.

87. Some parties suggest the Commission use a different coal price forecast in evaluating the proposed scenarios. *See* Peabody SOP, at 42-43 (contending Public Service's coal price forecasts are biased); Glustrom SOP, at 12-16 (contending Public Service's coal price forecasts are too low).

88. The Commission finds Public Service's method of forecasting coal prices is reasonable. However, again, we do not believe this finding of reasonableness requires us to explicitly adopt Public Service's coal price forecasts in evaluating the scenarios before us. While coal prices are historically less volatile than natural gas prices, we nonetheless believe coal prices may change significantly. Therefore, as with natural gas, we are mindful of each scenario's relative sensitivity to fluctuations in coal prices, and take this into consideration in determining which scenario is the most reasonable from a cost perspective.

2. Reasonable Cost Forecasts for Reasonably Foreseeable Emission Regulation

89. Section 40-3.2-206(3)(c), C.R.S., requires us to "incorporate a reasonable estimate for the cost of reasonably foreseeable emission regulation consistent with the Commission's existing practice." To implement this provision of HB 10-1365, parties have focused exclusively on costs associated with carbon dioxide and other greenhouse gasses.

90. In Docket No. 07A-447E, the Commission approved a carbon proxy cost of $20 per ton, escalating at 7 percent per year, beginning in 2010. Decision No. C08-0929, at ¶ 270. In this Docket, Public Service recommends the Commission adopt a $20 per ton price of

carbon, escalating at 7 percent per year but beginning in 2014. Parties in support of the $20 per ton proxy price argue it is a price the EPA may reasonably adopt if it chooses to regulate greenhouse gases under § 111(d) of the Clean Air Act. *See* Public Service SOP, at 49. Others argue $20 per ton represents an internalization of the social costs of carbon emissions that are typically experienced as externalities. *See* WRA SOP, at 25-27. Still others support adopting a $20 per ton price because the alternative of $0 per ton is unreasonable. *See* GEO SOP, at 6. Finally, parties argue the Commission should adopt the $20 per ton prices because it is the price the Commission used in Docket No. 07A-447E and thus, any other price would not be "consistent with the Commission's existing practice." *See* Gas Intervenors SOP, at 17.

91. However, a number of parties oppose a $20 per ton cost of carbon. Peabody presented testimony that the EPA's imminent regulation of greenhouse gases under the New Source Review provisions of the Clean Air Act would not impose a price per ton of carbon emissions, and that it is unlikely a policy to address climate change will be adopted that includes a price per ton of carbon emitted. Smith Answer Testimony (Hrg. Ex. 50), at 22-24; Tr. Nov. 19, 2010, at 59-62. Further, some parties argue the Commission should adopt a $0 per ton cost of carbon, because Public Service failed to meet its burden of proof in justifying a $20 per ton price. *See* Peabody SOP, at 44-49; AGNC SOP, at 14; ACCCE SOP, at 16-18.

92. The Commission has applied a cost to carbon emissions in the Company's two previous ERPs. *See* Docket Nos. 04A-214E, 04A-215E, 04A-216E, and 07A-447E. Carbon "adders" in this context served as proxies for the expected costs that carbon regulation would impose on various resources over the course of their lifetimes. Modeling a presumed cost of carbon is justified when considering the relative benefits of new utility resources, some of which have useful lives in excess of 40 years. However, the compressed timeframe required by this

Docket, coupled with the uncertainty over how carbon regulation will be manifest, leads us not to adopt a specific "dollars per ton" benchmark for this proceeding. That being said, the Commission observes that EPA regulation of greenhouse gasses is currently underway, future regulation in some form is highly likely, and that those regulations will eventually impose costs on a utility's greenhouse gas emissions. Therefore, while we do not adopt a specific future cost per ton in evaluating the proposed scenarios, we consider each scenario's carbon emissions reductions, as well as its sensitivity to carbon prices, as modeled by the Company.

3. Benefits of a Coordinated Emissions Reduction Strategy

93. Section 40-3.2-206(3)(e), C.R.S., requires the Commission to "consider the economic and environmental benefits of a coordinated emissions reduction strategy."

94. We agree with Public Service that the primary purpose of HB 10-1365 is to encourage the Company to address current and reasonably foreseeable emissions reductions in a coordinated fashion to reduce the overall cost of compliance. *See* Public Service. SOP, at 92. We have therefore considered not only the pattern of estimated costs during the implementation period of the plan, 2011 to 2017, but also the likely occurrence of base rate proceedings by which Public Service would begin to recover the substantial investments associated with emission reduction when these investments go into service.

95. In other words, we have examined the sequencing and level of capital spending over the next seven years in addition to the predicted changes in overall rates from the STRATEGIST model runs in the near term (2011 to 2020) as well as the long term (2011 to 2046). By considering such impacts in a coordinated fashion, we help to ensure the benefits of a coordinated emission reduction strategy consistent with HB 10-1365.

F. Modifications and Approvals

1. Basis for Findings

96. With the exception of Benchmark 1.0, the scenarios presented by Public Service and the intervening parties share many common elements. All include early retirement of Cherokee 1, 2, and 3; early retirement of Valmont 5; fuel conversion of Arapahoe 4; conversion of Cherokee 2 and Arapahoe 3 into synchronous condensers; controls on Pawnee and Hayden; and replacement generation for Cherokee 1, 2, and 3 plus Valmont 5 in the form of a new 2X1 CC at Cherokee Station.

97. The principal differences between the scenarios involve the disposition of Cherokee 4 (scenarios 5B, 6E FS, 6.1E FS, 6.2J), whether and when to apply fuel conversion of certain coal units to natural gas (scenario 7E), and whether to renew PPAs with certain plants owned by Southwest and Thermo (scenario IPP2).

98. From a cost perspective, the STRATEGIST model runs clearly indicate that the cost of capital construction, the cost of natural gas, and the cost of carbon emissions all significantly contribute to the overall cost of each scenario. *See* Hill Supplemental Rebuttal Testimony (Hrg. Ex. 188), at 9. Even so, the STRATEGIST results for expected rates and revenue requirements, even supplemented with monetized health benefits, do not reveal an easily apparent advantage of one scenario over another. *See* Dirmeier Supplemental Answer Testimony (Hrg. Ex. 239), at 6. In addition, uncertainty surrounding the preliminary estimates of the capital construction costs of the proposed projects, including both controls and new natural gas-fired generation facilities, suggests that during the period between 2011 and 2022, all scenarios could result in roughly the same level of investment costs.

99. According to Staff, the Company's projected costs for a new 2x1 CC at Cherokee Station appear to be low based on other similar facilities with similar equipment, potentially causing an understatement of the total capital costs of the scenarios that include this new facility. Staff also generally concludes that the Company's capital cost estimates may be less accurate than the plus or minus 20 percent that the Company has attached to them. *See* Camp Supplemental Answer Testimony (Hrg. Ex. 203), at 8-9.

100. Public Service acknowledges that the Company has not presented cost estimates as Certificate of Public Convenience and Necessity (CPCN) quality numbers, given the time available and the number of scenarios under consideration. Nevertheless, the Company believes the cost estimates that it presented in this Docket are sufficient for valid comparisons of the scenarios against each other. *See* Public Service SOP, at 61.

101. From an emission reduction perspective, all of the scenarios meet the standard that NOx emissions will be reduced by 70 to 80 percent. CDPHE SOP, at 9-11. Likewise, the CDPHE has determined that these scenarios will meet reasonably foreseeable requirements of the CAA. *Id.* at 11-12.

102. It is also undisputed that early emission reductions offer potential health benefits to the residents in the Denver metro area. The emission reduction profiles of the various scenarios as developed by STRATEGIST reveal significant differences among the scenarios in NOx, SO_2, and mercury emissions between 2011 and 2018. Scenarios with relatively more coal burn tend to have higher emissions of NOx, SO_2, mercury, and CO_2.

103. Largely due to such emission reductions, several parties support the adoption of scenario 6.2J, including WRA, the GEO, Boulder, and, notably, the CDPHE.

104. Finally, from a feasibility perspective, Public Service affirms that all of the scenarios that we are considering can be implemented successfully. *See* Public Service SOP, at 62. However, the only practical options for Cherokee 4, according to the Company, are the installation of SCR at Cherokee 4 by 2017 (scenario 5B), fuel switching Cherokee 4 by 2017 (scenarios 6E FS or 7E), or retiring Cherokee 4 and replacing it with a 1X1 CC or CT (scenario 6.2J or IPP2). Public Service claims that the alternatives to scenario 5B could result in higher rates for customers, but the Company also acknowledges that the balance between short-run price impacts and long-run benefits, including emission reductions, is a close call among these scenarios. *See* Hyde Supplemental Rebuttal Testimony (Hrg. Ex. 184), at 7. Public Service concludes that this Docket is, in essence, a public policy debate over how much to raise electric rates to achieve various levels of emissions reductions. *See* Public Service SOP, at 94.

2. Cherokee 1, 2, and 3

105. Unit 1 at Cherokee Station is a 107 MW coal-fired electric generating facility that began operations in 1957 and whose expected useful life ends in 2017. Unit 2 at Cherokee Station is a 106 MW coal-fired electric generating facility that began operations in 1959 and whose expected useful life ends in 2019. Unit 3 at Cherokee Station is a 152 MW coal-fired electric generating facility that began operations in 1962 and whose expected useful life ends in 2022.

106. Both Cherokee 1 and 2 would be retired in 2011 under Public Service's recommended scenario. SNCR controls would be installed at each unit before the end of 2014 under the Benchmark 1.0 scenario at an estimated cost of approximately $21.3 million, plus or minus 20 percent. Ford Direct Testimony (Hrg. Ex. 10), at 7-8.

107. With respect to Cherokee 3, Public Service proposes to retire the facility in 2017. SCR controls on the unit would be installed under the Benchmark 1.0 scenario at an approximate cost of $163 million, plus or minus 20 percent. *Id.* at 9.

108. Because both Cherokee 1 and 2 are more than 50 years old and are approaching the end of their useful life, we conclude that retirement is a superior solution to controls on these units in order to meet reasonably foreseeable emission reduction requirements. Therefore, the Commission finds it necessary and in the public interest to retire Cherokee units 1 and 2 before the end of 2011 for emission reduction purposes.

109. Public Service proposes to convert the retired Cherokee 2 unit into a synchronous condenser before the end of 2012 to provide dynamic VAR support upon the retirement of the coal-fired units at Cherokee Station. The Company estimates that the capital costs associated with this conversion, plus the addition of a 90 MVAR capacitor bank for static VAR support, will be approximately $4 million, plus or minus 20 percent. *Id.* at 17.

110. We find that the re-use of Cherokee 2 as a synchronous condenser and the additional 90 MVAR capacitor bank to be the most cost effective solution for providing both dynamic and static VAR support at Cherokee Station. In light of the criticism that synchronous condensers may result in higher than expected operating costs in the future, and given the extensive testimony offered in this Docket regarding alternative VAR support technologies such as SVCs, STATCOMMS, and D-VAR systems, we direct Public Service to carefully monitor the use of the synchronous condenser at Cherokee 2 during the implementation period of the plan. As part of future transmission planning activities, the Company should ensure that the synchronous condenser provides the appropriate level of cost-effective VAR support relative to these alternative technologies.

111. We also find retirement of Cherokee 3 to be a better outcome than SCR controls for meeting reasonably foreseeable emission reduction requirements. We recognize that under the Company's proposed scenario (scenario 5B), this unit would be retired in 2017. Public Service explains that retirement in 2017 would allow a period of time for a 2X1 CC to be tested and tuned, for fuel cost savings to be available to ratepayers in 2016 and 2017, and for minimizing the impact of accelerated depreciation in years 2011 through 2017. *See* Hrg. Ex. 184, at 15. However, we are not aware of any operating or construction-related impediments to retirement in 2015 and note that a 2015 retirement for Cherokee 3 was modeled in STRATEGIST for scenarios 6E FS and 7E. The Commission therefore finds it necessary and in the public interest to retire Cherokee 3 before the end of 2015 for emission reduction purposes.

3. Arapahoe 3 and 4

112. Arapahoe 3 is a 45 MW coal-fired electric generation facility that began operations in 1951. Arapahoe 4 is a 111 MW coal-fired electric generation facility that began operations in 1955.

113. By Decision No. C08-0929, the Commission approved the early retirement of both Arapahoe 3 and 4 for emission reduction purposes. Consistent with that previous Decision, Public Service proposes in this Docket to retire Arapahoe 3 before the end of 2013 and to convert the unit into a synchronous condenser. The Company estimates that the capital costs associated with this conversion, plus the addition of a 90 MVAR capacity bank for static VAR support, will be approximately $4.9 million, plus or minus 20 percent. Hrg. Ex. 10, at 17. The Company no longer plans to retire Arapahoe 4 but instead proposes that it be converted from coal-fired generation to run on natural gas before the end of 2014.

114. The Commission determines that because Arapahoe 3 is approaching the end of its useful life, retirement is necessary and in the public interest consistent with our previous determination in Docket No. 07A-447E. Also, consistent with our findings regarding the conversion of Cherokee 2, we find the re-use of Arapahoe 3 as a synchronous condenser plus the installation of 90 MVARs of new shunt capacitors, will together offer a cost effective solution for providing both dynamic and static VAR support at Arapahoe Station.

115. We also find the conversion of Arapahoe 4 from coal-fired generation to natural gas generation to be needed and in the public interest for emission reduction purposes. Although the Commission previously approved early retirement of Arapahoe 4 in Docket No. 07A-447E, its conversion into a natural gas-fired facility will allow the plant to operate during peak loading and other adverse system conditions with no or inexpensive capital investments. Therefore, we find fuel conversion at Arapahoe 4 in 2014 to be the proper implementation of HB 10-1365 for this coal-fired electric generation unit.

116. We recognize that under certain conditions it is less costly and better for the environment to burn gas in higher efficiency natural gas-fired units than using natural gas in coal units such as Arapahoe 4. Alternative replacement capacity solutions in the future, including new or reconfigured transmission resources or IPP-provided generation, may also prove to be relatively more cost effective than fuel conversion under different circumstances, particularly with respect to projected costs for natural gas. We therefore require Public Service to present alternatives to running Arapahoe 4 on natural gas in its ERP filing due October 31, 2011, so long as these potential alternatives meet or exceed the emission reductions achieved by the fuel conversion we adopt here.

4. Valmont 5

117. Valmont 5 is a 187 MW coal-fired electric generation facility that began operations in 1964 and whose expected useful life ends in 2024.

118. Valmont 5 would be retired before the end of 2017 under Public Service's proposed scenario. In the Benchmark 1.0 scenario, SCR controls would be installed on Valmont 5 before the end of 2015 at a cost of approximately $86.7 million, plus or minus 20 percent. Hrg. Ex. 10, at 12.

119. Although Valmont 5 is not quite as old as the Cherokee 1, 2 and 3, we find early retirement after a few more years of operation as a coal-fired unit to be a cost-effective approach for meeting current and reasonably foreseeable emission reduction requirements. We therefore find the retirement of Valmont 5 in 2017 to be needed and in the public interest for emission reduction purposes.

5. Pawnee

120. Pawnee is a 505 MW coal-fired electric generation facility that began operations in 1981 and whose expected useful life ends in 2041.

121. Under the Company's proposed scenario, both SCR and LSD would be retrofitted on the unit for NOx and SO_2 emission reductions beginning in 2014. In addition, the unit would receive a sorbent injection system for mercury emissions. These installations would have the most impact on overall emissions from the Company's plan. *Id.* at 14. The capital cost of these projects would be $236.5 million, plus or minus 20 percent. *Id.* at 15.

122. The CDPHE states that Pawnee must be included in Public Service's plan because it is a Best Available Retrofit Technology (BART) source that must be addressed under EPA's Regional Haze Rule. *See* Tourangeau Answer Testimony (Hrg. Ex. 33), at 6. Public Service

explains that retiring Pawnee for emission reduction purposes would result in approximately $600 million in increased costs to ratepayers. Public Service SOP, at 27.

123. We agree that emission controls on Pawnee are preferable to early retirement given the relatively young age of the plant and its cost effectiveness as a coal-fired electric generation unit. We further find that including the emission control projects at Pawnee in the Company's plan allows us to consider a coordinated approach for emission reduction as contemplated by HB 10-1365. We therefore approve the installation of SCR, LSD, and sorbent injection controls at Pawnee as needed and in the public interest for emission reduction purposes.

6. Hayden

124. Hayden 1 is a coal-fired electric generation facility that began operations in 1965 and whose expected useful life ends in 2025. Hayden 2 is a coal-fired electric generation facility that began operations in 1976 and whose expected useful life ends in 2036. Public Service is a partial owner of both Hayden 1 and 2 such that the Company obtains 139 MW from Hayden 1 (75.5 percent) and 98 MW from Hayden 2 (37.4 percent).[20]

125. Hayden 1 and 2 were included in the Company's proposed scenario contingent upon the outcome of the AQCC's regional haze BART determinations for those units. The CDPHE reported that the AQCC made a preliminary final determination on November 19, 2010 that BART for Hayden Station is SCR for NOx reduction. The AQCC therefore has adopted a BART equivalent emissions rate for the regional haze SIP. *See* Tr. Nov. 20, 2010, at 81.

[20] Hayden 1 is owned in partnership with PacifiCorp. Hayden 2 is owned in partnership with PacifiCorp and the Salt River Project.

126. As a result of the AQCC's actions concerning Hayden Station, Public Service requests that the units be included in the Company's plan and for the costs of the SCR controls to be eligible for the recovery under the provisions of § 40-3.2-207, C.R.S., as applicable.

127. Under the Company's proposed scenario, Hayden 1 would receive SCR controls in 2015 at an approximate capital cost to Public Service of $67.1 million, plus or minus 20 percent. Hrg. Ex. 10 at 13. Hayden 2 would receive SCR controls in 2016 at an approximate capital cost to Public Service of $80.7 million, plus or minus 20 percent. *Id.* at 14.

128. In light of the AQCC's BART determination, we find that SCR controls on Hayden 1 and 2 are needed and in the public interest for emission reduction purposes. We further find that the including of the emission control projects at Hayden in the Company's plan allows for a coordinated approach for emission reduction to be adopted on a cost-effective basis as contemplated by HB 10-1365. Public Service can therefore avail itself of the cost recovery provisions in § 40-3.2-207, C.R.S., consistent with the discussion below.

7. Cherokee 4

129. Cherokee 4 is a 352 MW coal-fired electric generation facility that began operations in 1968 and whose expected useful life ends in 2028. Cherokee 4 is the largest coal unit in the Denver metro area.

130. Whether Cherokee 4 should be retired and its capacity replaced, whether it should instead be retrofitted with SCR controls, or whether it should be converted from coal to natural gas was the most controversial issue concerning resource selection in this Docket. Under scenario 5B, the plant continues to operate burning coal with SCR controls installed in 2016. The plant is retired and replaced with a 314 MW 1X1 CC at Cherokee Station in scenarios 6.2J

(2017), 7E (2018), and 6E FS (2018). Under scenario IPP2, Cherokee 4 is retired in 2017 and is replaced with a 147 MW CT.

131. Public Service estimates that SCR controls would cost $174.9 million, plus or minus 20 percent. *See* Hrg. Ex. 10, at 11. Staff argues that these costs can be substantially reduced by the re-sequencing of the various construction projects at Cherokee Station. *See* Staff SOP, at 9.

132. Public Service estimates that a new 1X1 installed at Cherokee Station would cost $346.5 million, plus or minus 20 percent, if the Company procures a new steam turbine for the facility. *See* Ford Supplemental Direct Testimony (Hrg. Ex. 158), at 3. The Company estimates that a new CT at Cherokee Station would cost $107.4 million, plus or minus 20 percent. *See* Hrg. Ex. 10, at 28.

133. The STRATEGIST model runs do not clearly demonstrate which of the three alternatives for Cherokee 4 is superior in terms of costs and rate impacts. Operating the unit on coal with SCR would meet reasonable foreseeable emission reduction requirements under the CAA, but this option, as represented under scenario 5B, would nevertheless result in relatively higher levels of NOx, SO_2, mercury, and CO_2 emissions, as compared to certain other alternatives. Plant retirement and replacement under scenario 6.2J would improve emission reductions relative to scenario 5B, but these emission reductions would be achieved as a result of relatively higher capital spending between 2011 and 2017, but not necessarily higher overall revenue requirements.

134. Converting Cherokee 4 from coal to natural gas in 2017, similar to the proposed conversion of Arapahoe 4, would preserve an additional source of real power at Cherokee Station with little or no additional capital investment. Under a reasonable range of projected natural gas

costs, and given the long-term gas contract offered by Anadarko and the potential for more such contracts in the future, we conclude that fuel switching is the superior option for Cherokee 4. We therefore find that conversion of Cherokee 4 from coal to natural gas before the end of 2017 is needed and in the public interest for emission reduction purposes.

135. As with Arapahoe 4, circumstances may change such that it becomes less expensive and more effective from an emission reduction perspective to no longer burn natural gas at Cherokee 4. New or reconfigured transmission resources, IPP-provided generation, and new alternative proposals for replacement generation at Cherokee Station might become more attractive vis-à-vis fuel conversion under different circumstances in the future. We therefore require Public Service to present alternatives to running Cherokee 4 on natural gas in its ERP filing due October 31, 2011, so long as these potential alternatives meet or exceed the emission reductions achieved by the fuel conversion we adopt here. Along those lines, we encourage Public Service to continue to explore the early retirement of Cherokee 4 such that the unit no longer operates after 2022.

8. Replacement Capacity

136. Section 40-3.2-207(6), C.R.S., states, "the commission shall allow, but not require, the utility to develop and own as utility rate-based property any new electric generating plant constructed primarily to replace any coal-fired electric generating unit retired pursuant to the plan."

137. Public Service proposes to replace the retired capacity of Cherokee 1, 2, and 3 as well as Valmont 5 (a combined 551 MW of retired capacity) with a new 2X1 CC at Cherokee Station (569 MW). The Company estimates that the cost of the new 2X1 CC would be approximately $487.5 million, plus or minus 20 percent. *See* Hrg. Ex. 158 at 3.

138. Public Service explains that in addition to providing real power from the Cherokee Station after these coal units are retired, the new 2X1 CC will better position the Company to acquire more intermittent renewable resources in the future. *See* Public Service SOP, at 12.

139. Because we have found the retirement of Cherokee 1, 2, and 3, as well as Valmont 5 as needed and in the public interest for emission reduction purposes, we agree that Public Service should be allowed to build replacement capacity in the form of a new 2X1 CC of approximately 569 MW at Cherokee Station. By locating the new plant at Cherokee Station, Public Service will be able to continue to locally satisfy real power needs in the Denver area. We will therefore grant Public Service a presumption of need for 2X1 CC at Cherokee Station with respect to a future application for a CPCN for that facility.

9. Gas Infrastructure

140. Public Service requests that the Commission recognize that the new gas-fired 2X1 CC units at Cherokee will need adequate gas transportation infrastructure and that a new pipeline will eventually be included in gas rate base with charges to the electric department for service rendered. Public Service SOP, at 29. We agree, and find that our decision in this matter creates an incremental need for gas service at the Cherokee generation plant. Though this Docket does not address the specific gas-department distribution system capacities, needs, or alternative methods of providing such incremental gas service, we agree with Public Service that a 24-inch pipeline extending approximately 32 miles from CIG's Fort Lupton compressor facility to the Cherokee plant can be constructed in the ordinary course of business.

10. Future Filing Requirements

141. In its STRATEGIST modeling, Public Service used the decommissioning and removal costs developed for its last general rate case, Docket No. 09AL-299E. *See* Hrg. Ex. 2, at 142. These costs, developed by the Company's consultants in 2007 and labeled the "TLG Services Study," were proposed for the establishment of base rates but were ultimately not adopted by the Commission by virtue of our approval of a settlement agreement in which Public Service consented to apply removal costs approved in an earlier rate case proceeding.

142. Rule 3103 of the Commission's Rules Regulating Electric Utilities requires an electric utility to file applications for authority from the Commission to amend a CPCN in the event that the utility seeks to "discontinue without equivalent replacement" any facility not in the ordinary course of business. *See* Rule 3103, 4 *Code of Colorado Regulations* (CCR) 723-3.

143. We find that it is necessary under Rule 3103, 4 CCR 723-3, for Public Service to amend its CPCNs for the coal-fired generation units whose retirement we have just approved. The early retirement of generation plants does not constitute the Company's "ordinary course of business." Moreover, we are concerned that the decommissioning and removal costs set forth in the TLG Services Study are too limited and may not have been sufficiently reviewed by the Commission in Docket No. 09AL-299E.

144. Because we have decided in this Docket that the retirement of these plants is necessary and in the public interest, and in order to move ahead with the plant closures in a timely fashion, we will not require Public Service to satisfy all of the usual CPCN filing requirements set forth in Rule 3103, 4 CCR 723-3. A modified application proceeding limited to Commission review and approval of detailed cost estimates and schedules associated with the closure and decommissioning of the Cherokee and Valmont units will instead suffice. We will

therefore waive certain provisions under Rule 3103, 4 CCR 723-3, such that Public Service will be required to provide in the application only the following elements:

- the information required in Commission Rules 3002(b) and 3002(c), consistent with conventional application filings;
- a description of the proposed facilities to be decommissioned and/or removed;
- estimated costs of the decommissioning and/or removal of these facilities; and
- anticipated start date of the decommissioning and/or removal work, a schedule for these activities, and a completion date.

145. Public Service may file an application as described above for each unit to be retired, or the Company may file a single application addressing all of the units to be retired pursuant to this Decision. Such applications shall be submitted three months prior to the commencement of the Company's next electric base rate proceeding.

146. Rule 3102 requires an electric utility to file applications for a CPCN for all new electric generation facilities. *See* Rule 3102, 4 CCR 723-3. Accordingly, Public Service recognizes that it must file an application for a CPCN for the 2X1 CC to be constructed at Cherokee Station. *See* Public Service SOP, at 28-29.

147. Public Service also acknowledges that the cost information for new facilities it provided in this Docket is not CPCN quality. *See* Public Service SOP, at 61. We agree, but we are nonetheless satisfied that the cost information the Company has presented is sufficient for the purpose of approving a plan under HB 10-1365 and determining whether the costs of the plan result in reasonable rate impacts under § 40-3.2-205(1)(g), C.R.S. For actual ratemaking purposes, however, Public Service's cost estimates as presented in this Docket are too high-level and preliminary to be relied upon.

148. We recognize that by this Decision the Commission has already determined a need for the new 2X1 CC at Cherokee Station. Therefore, we will not require Public Service to

submit all of the information typically required under Rule 3102, 4 CCR 723-3, for a new generation facility. Our intent is for the CPCN proceeding to focus narrowly on the Commission review and approval of detailed cost estimates and project schedules associated with the construction of the new generation plant. We thus direct Public Service to file the following elements under Rule 3102; 4 CCR 723-3,

- the information required in Commission Rules 3002(b) and 3002(c), consistent with conventional application filings;
- a description of the proposed facilities to be constructed;
- estimated costs of the proposed facilities to be constructed;
- anticipated construction start date, construction period, and in-service date;
- a map showing the general area or actual location where facilities will be constructed at Cherokee Station; and
- electric one-line diagrams, as applicable.

149. Public Service has also requested that the Commission enter a finding that applications for CPCNs for the emission controls at Pawnee and Hayden not be required. We decline to grant this request because the cost estimates presented in this Docket are not CPCN quality. Moreover, the costs of these projects are substantial, and, as evidenced by HB 10-1365 itself, these projects are not in the Company's ordinary course of business. Accordingly, we also waive Rule 3205(b)(II), 4 CCR 723-3, which concerns pollution control system retrofits.

150. Notwithstanding our concerns about the lack of detailed cost estimates, the Commission has determined that the proposed controls at Pawnee and Hayden are needed and in the public interest by this Decision. Public Service shall therefore file a modified application for a CPCN for the proposed controls, consistent with the discussion above for the application for a CPCN for the proposed 2X1 CC at Cherokee Station.

151. Finally, we expect that the applications for CPCNs required by this Decision will allow us to consider the establishment of a not-to-exceed maximum level of expenditures for

these projects. In conjunction with the cost recovery mechanisms we address later in this Decision, we find that the future application filings outlined above are necessary to ensure that the costs and rate impacts associated with the plan remain reasonable over the course of its implementation.

11. Overview of Emission Reduction Plan, as Modified

152. The Commission has approved by this Decision, an emission reduction plan that entails the early retirement of five coal-fired electric generating units, emission controls for three additional units, and the fuel conversion of two units from coal to natural gas. The emission reduction plan we adopt pursuant to HB 10-1365 is thus summarized in the table below:

Unit	Size	Action	Date
Cherokee 1	107 MW	Retirement	2011
Cherokee 2	106 MW	Retirement	2011
Cherokee 3	152 MW	Retirement	2015
Cherokee 4	352 MW	Conversion	2017
Arapahoe 3	45 MW	Retirement	2013
Arapahoe 4	111 MW	Conversion	2014
Valmont 5	186 MW	Retirement	2017
Hayden 1	139 MW	Controls	2015
Hayden 2	98 MW	Controls	2016
Pawnee	505 MW	Controls	2014

153. Under the approved emission reduction plan, 551 MW of coal-fired electric generation will be retired, 742 MW of coal-fired electric generation will be controlled with emission reducing retrofits, and 463 MW of coal-fired electric generation will be fuel switched from coal to natural gas.

154. The capital costs associated with this coordinated approach to emission reductions, including the costs of a new 2X1 natural gas-fired CC plant (569 MW) at Cherokee

Station to serve as replacement capacity for the retired units, are presently estimated to be approximately $890 million through 2017, within an error band of plus or minus 20 percent.

155. Consistent with the discussion above concerning the projections of future coal, natural gas, and carbon costs, we believe the potential range of overall rate impacts of this plan and the corresponding range of emission reductions have been properly developed by the Company's STRATEGIST model runs. *See* Hrg. Exs. 189, 251, and 256.

156. Based on these modeled results, we conclude that the modified emission reduction plan established by this Decision can be implemented at a reasonable cost and rate impact. Moreover, we find that the modified plan will result in significantly more emission reductions than the minimums required by HB 10-1365, to benefit the public health.

G. Analysis of the Modified Plan

157. HB 10-1365 sets forth the General Assembly's belief that a coordinated plan of emission reductions from coal-fired power plants will enable Public Service to meet the requirements of the CAA and protect the public health and the environment at a lower cost than a piecemeal approach. § 40-3.2-202(1), C.R.S. In order to accomplish the important objectives of HB 10-1365, we have taken the following statutory factors into consideration in approving this modified version of Public Service's preferred scenario.

1. Satisfaction of the August 15 Filing Deadline

158. Section 40-3.2-204(1), C.R.S., requires the Company to file its emission reduction plan on or before August 15, 2010. Public Service filed its plan on August 13, 2010.

159. A number of parties claim that, because the Commission rejected scenario 6.1E, the entirety of the plan was rejected by Decision No. C10-1067. As a result, these parties claim the alternative scenarios the Company presented in its supplemental direct testimony of

October 25, 2010 must be rejected as untimely filed. *See* Peabody's Motion for Summary Judgment and for Shortened Response Time, filed October 29, 2010; AGNC SOP, at 3-5; CMA SOP, at 3-6; Peabody SOP, at 14-19.

160. The Commission does not agree. Scenario 6.1E was one of many scenarios contained in the Company's August 13, 2010 plan. After we rejected scenario 6.1E, a number of those scenarios remained viable for the Commission's consideration including, for example, scenario 5B. In addition, the scenarios identified in the October 25, 2010 supplemental direct testimony constitute modifications of scenarios originally presented in the August 13, 2010 filing. The Commission has the authority to modify the Company's plan. § 40-3.2-205(2), C.R.S. As a result, the Commission could have modified the plan to create any of the scenarios the Company presented on October 25, 2010, even if the supplemental testimony had not been allowed. The Commission's ability to modify the Company's plan would be rendered meaningless if we were limited to adopting only those scenarios set forth in the Company's August 13, 2010 filing. *See* Decision No. C10-1265 at ¶¶ 21-25.

161. We therefore find the Company satisfied the August 15, 2010 filing deadline.

2. Scope of the Plan

162. Section 40-3.2-204(2)(a), C.R.S., requires that the emission reduction plan address "a minimum of nine hundred megawatts of fifty percent of the utility's coal-fired electric generating units in Colorado, whichever is smaller." In evaluating compliance with this requirement, the calculation "shall not include any coal-fired capacity that the utility has already announced it has plans to retire, prior to January 1, 2015." *Id.*

163. Public Service's emission reduction plan addresses 1,801 MW of its coal-fired electric generation in Colorado. Excluding the MW associated with Arapahoe 3 and 4, both of

which were slated to be retired, the plan addresses 1,645 MW. Therefore, the Commission finds the plan satisfies this requirement.

3. CDPHE Determination Regarding Consistency with Reasonably Foreseeable Emission Reduction Requirements

164. Section 40-3.2-204(2)(b)(IV), C.R.S., states, "the Commission shall not approve a plan . . . unless the Department has determined that the plan is consistent with the current and reasonably foreseeable requirements of the federal [Clean Air] act." The Commission has interpreted HB 10-1365 as recognizing the CDPHE is the state agency with the authority and expertise to determine what requirements of the federal CAA are reasonably foreseeable. *See* Decision Nos. C10-1067 and C10-1164. Therefore, the Commission has generally deferred to the CDPHE in matters pertaining to determining which emission reduction requirements are reasonably foreseeable, as well as how far into the future such requirements can reasonably be foreseen. In other words, while the Commission is permitted to opine on the costs associated with reasonably foreseeable emissions reduction requirements, HB 10-1365 does not permit the Commission to assess what those requirements will be, as a general matter.

165. The CDPHE determined scenario 6E FS, which, from an air quality standpoint, closely resembles the plan we approve today, is consistent with reasonably foreseeable requirements of the CAA. CDPHE SOP, at 12. *See also* Hrg. Ex. 200, at 4.

4. Full Implementation by 2017

166. Section 40-3.2-204(2)(c), C.R.S., requires that the plan "include a schedule that would result in full implementation of the plan on or before December 31, 2017." Further, this schedule must be designed "to protect system reliability, control overall cost, and assure consistency with the requirements of the [CAA]." *Id.* Each element of the plan we approve

today that is necessary to satisfy reasonably foreseeable emissions reduction requirements is scheduled to occur on or before December 31, 2017. Therefore, we find the implementation deadline is satisfied.

5. Identification of Associated Costs

167. Section 40-3.2-204(2)(d), C.R.S., states "[t]he plan shall set forth the costs associated with the activities identified in the plan," including "planning, development, construction, and operation of elements." Public Service did provide estimates of planning, development, construction, operation, shutdown, decommissioning, and repowering costs for each of its scenarios. Though we will order additional review of these costs through the application procedures described above, we find they are sufficient to satisfy the requirements of HB 10-1365.

6. Relative Cost Differences

168. Section 40-3.2-206(3)(a), C.R.S., requires us to "compare the relative costs of repowering or replacing coal facilities with natural gas generation or other low-emitting resources, including energy efficiency, to an alternative that incorporates emission controls on the existing coal-fired units." Public Service did present an all-controls alternative, known as Benchmark 1.0. Based on our review of the STRATEGIST model results for the various scenarios, we believe the plan we approve today comes at a lower cost to ratepayers than an all-controls option. *See* Hrg. Ex. 251. Therefore, we believe this factor weighs in support of the approved plan.

7. CDPHE Report Concerning Reduction in Emissions of Oxides of Nitrogen

169. The Commission must consider whether the CDPHE "reports that the plan is likely to achieve at least a seventy to eighty percent reduction, or greater, in annual emissions of oxides of nitrogen." § 40-3.2-205(1)(a), C.R.S. In making this determination, the CDPHE is required to consider "emissions from coal-fired power plants identified in the plan and continuing to operate after retrofit with emission control equipment," as well as "emissions from any facilities constructed to replace any retired coal-fired power plants identified in the plan." *Id.*

170. The CDPHE determined scenario 6E FS, which has an emissions profile very similar to the plan we approve today, meets and exceeds the minimum standard for NOx reduction. CDPHE witness Mr. Tourangeau testified that the plan we approve here today will reduce NOx from 18,147 tpy to 3,095 tpy, which constitutes an 83 percent reduction. Hrg. Ex. 200, at 2. These emission reductions will be further improved if Public Service opts to run Cherokee 4 at a lower capacity. For example, if the Company operates Cherokee 4 on natural gas at a 50 percent capacity factor, as it represented to the CDPHE it would, NOx emissions would be further reduced to 2,434 tpy, for an overall reduction of 87 percent. *Id.* at 3.

171. Because the plan we approve today is predicted to reduce NOx emissions by more than 80 percent, we believe this factor supports the approved plan.

8. CDPHE Determination Pursuant to § 40-3.2-204(2)(b)(III), C.R.S.

172. Section 40-3.2-204(2)(b)(III), C.R.S, requires the CDPHE to "determine whether any new or repowered electric generating unit proposed under the plan, other than a peaking facility utilized less than twenty percent on an annual basis or a facility that captures and sequesters more than seventy percent of emissions not subject to a national ambient air quality

standard or a hazardous air pollutant standard, will achieve emission rates equivalent to or less than a combined-cycle natural gas generating unit."

173. Section 40-3.2-205(1)(b), C.R.S., requires us to consider whether the CDPHE made this determination. The new gas-fired replacement unit we approve as part of the plan is a CC natural gas generating unit. Therefore, this section is inapplicable to the new replacement generation. However, we note that the CDPHE does not seem to have made a specific finding as to the repowered units, Arapahoe 4 and Cherokee 4, which will be converted to run on natural gas. Nonetheless, this is only one factor among many the Commission must consider. Given that the CDPHE has determined the plan we approve today is consistent with current and reasonably foreseeable emissions reduction requirements, we believe the plan satisfies the air quality goals embodied in HB 10-1365.

9. The Degree to Which the Plan Will Result in Reductions in Other Air Pollutant Emissions

174. Section 40-3.2-205(1)(c), C.R.S., requires us to consider "the degree to which the plan will result in reductions in other air pollutant emissions." In addition to achieving significant reductions in NOx emissions, the plan we approve today will also reduce emissions of SO_2, particulate matter, greenhouse gasses, and mercury. *See* Hrg. Ex. 200, at 2-3. We believe the approved plan meets and exceeds the air quality improvements that motivated the legislature to pass HB 10-1365. As a result, we believe this factor weighs in favor of approving the plan.

10. The Degree to Which the Plan Will Increase Utilization of Existing Natural Gas-Fired Generating Capacity

175. Section 40-3.2-205(1)(d), C.R.S., requires us to consider "the degree to which the plan will increase utilization of existing natural gas-fired generating capacity." *See also* § 40-3.2-206(3)(d), C.R.S. The STRATEGIST model runs prepared by the Company present

increased gas burn from existing facilities for all proposed scenarios. For scenario 6E FS, which closely resembles the plan we have approved, increased usage of existing natural gas units was clearly demonstrated. *See* Hrg. Exs. 188 and 189. We believe the approved plan significantly increases the utilization of existing facilities that are capable of running on natural gas. Therefore, we believe this factor weighs in favor of the approved plan.

11. Satisfaction of Clean Energy Requirements, and Utilization of Energy Efficiency or Other Low-Emitting Resources

176. Section 40-3.2-205(1)(e), C.R.S., requires us to consider "the degree to which the plan enhances the ability of the utility to meet state or federal clean energy requirements, relies on energy efficiency, or relies on other low-emitting resources." The CDPHE has stated the emissions profile of the plan we approve today will satisfy reasonably foreseeable emission reduction requirements and, as a result, the Commission believes it is likely to help the Company meet clean energy requirements. Further, we find the plan does rely on resources that are lower emitting than existing coal-fired plants, such as natural gas-fired facilities. We therefore find this factor supports approval of the plan.

12. Promotion of Colorado Economic Development

177. Section 40-3.2-205(1)(f), C.R.S., requires us to consider "whether the plan promotes Colorado economic development." Public Service's economic impact analyses suggest that the plan we adopt will positively impact Colorado's economy. *See* Sheesley Supplemental Direct Testimony (Hrg. Ex. 159). Similarly, Anadarko testified that more gas generation in Colorado would support more gas-industry jobs in the state. *See* Anadarko SOP, at 37. Additionally, the plan we approve here today will most certainly create new construction jobs as the Company's facilities are replaced or retrofitted. By contrast, the evidence on impacts to the Colorado coal industry is somewhat ambiguous. Much of the impact depends on whether

Peabody and other coal-producing companies will open new mines to replace the mines that are going to close in the near term, such as the Twentymile Mine.

178. On balance, the Commission is convinced that the overall economic impact of the plan we approve here today will be positive. While predicting the movement of the economy is always inexact, we believe adopting this coordinated approach to achieving emissions reductions will put Colorado at a competitive advantage with regard to utility rates in the near future. As such, we find this factor supports approving the plan.

13. Preservation of Reliable Electric Service

179. Section 40-3.2-205(1)(g), C.R.S., requires us to consider whether the plan preserves reliable electric service for Colorado customers. Public Service has consistently stated that system reliability is dependent on maintaining two sources of real power and three sources of reactive power support at the Cherokee site. *See* Mogensen Direct Testimony (Hrg. Ex. 6), at 12. We find the approved plan meets this requirement. The new 2x1 CC facility and the fuel switched Cherokee 4 will serve as two sources of real power. These same facilities, together with Cherokee unit 2 converted to a synchronous condenser, will also serve as three sources of reactive power support. Further, the approved retirement dates of the existing coal-fired units leave adequate time for conversion of Cherokee unit 2 and the construction of the 2x1 CC unit to ensure that three sources of generation are available during the implementation of the plan.

180. Further, while testimony on reliability was mainly focused at the Cherokee site, there are obvious requirements for reactive power support at Arapahoe. To address this need, Public Service recommended and we approved, the conversion of Arapahoe 3 to a synchronous condenser by 2014.

181. We find the foregoing is sufficient to preserve reliable electric service for Colorado customers. As such, we believe this factor supports approval of the plan.

14. Protection from Future Cost Increases

182. Section 40-3.2-205(1)(h), C.R.S., requires us to consider "whether the plan is likely to help protect Colorado customers from future cost increases, including costs associated with reasonably foreseeable emission reduction requirements." As stated above, the Commission agrees with the General Assembly's finding that the coordinated approach we approve today will, in the long term, be less costly to consumers than a piecemeal approach to compliance with the CAA and other reasonably foreseeable emissions reduction requirements. As a result, we find this factor weighs in favor of approving the plan.

15. Reasonable Rate Impacts

183. Section 40-3.2-205(1)(i), C.R.S., requires us to consider "whether the cost of the plan results in reasonable rate impacts." In making this determination, we are directed to "examine the impact of the rates on low-income customers." *Id.* We find the projected percentage change in customers' bills that will result from implementation of the plan is reasonable, particularly when the plan's health benefits and air quality improvements are considered. Further, we find this coordinated approach will ultimately provide a benefit to all customers, including the low-income. As a result, we find this factor supports approval of the plan.

184. Related to this consideration, the Gas Intervenors suggest implementation of a surcharge on the plan-related costs recovered from ratepayers, the funds from which would be transferred to Colorado's Low Income Energy Assistance Program, known as LEAP. Gas Intervenors SOP, at 65. The Commission finds the Gas Intervenors' suggestion, which was

raised in its SOP, is not sufficiently developed to warrant adoption in this Order. However, the Commission is currently exploring a potential rulemaking on low-income energy assistance programs. *See* Docket Nos. 10M-473E and 10M-475G. The Commission encourages all interested intervenors in this Docket to participate in those Miscellaneous Dockets if they wish to further address rate impacts on low-income customers.

16. Conclusions Regarding the Modified Plan

185. The plan we approve today satisfies the minimum requirements related to timeliness, § 40-3.2-204(1), C.R.S.; scope, § 40-3.2-204(2)(a), C.R.S.; CDPHE approval, § 40-3.2-204(2)(b)(IV), C.R.S.; scheduled implementation, § 40-3.2-204(2)(c), C.R.S.; and identification of costs, § 40-3.2-204(2)(d), C.R.S. Further, we find the nine factors set forth at § 40-3.2-205(1), C.R.S., when considered as a whole, support our approval of the plan, as modified.

H. Cost Recovery

1. Cost Recovery Provisions of HB 10-1365

186. HB 10-1365's introductory legislative declaration contains the following:

> The General Assembly further finds and declares that Colorado rate-regulated utilities require timely and forward-looking reviews of their costs of providing utility service in order to undertake the comprehensive and extensive planning and changes to their business operations contemplated by [HB 10-1365]. . . . To that end, the General Assembly finds that the commission should have additional tools and more flexibility in its regulatory authority to ensure the continued financial health of these utilities.

§ 40-3.2-202(3), C.R.S. The substantive cost recovery provisions of HB 10-1365 are then set forth in §§ 40-3.2-205(3), C.R.S. and 40-3.2-207, C.R.S., *et seq*. Section 40-3.2-205(3), C.R.S., is contained in the "Review – Approval" section of HB 10-1365 and provides that "[a]ll actions taken by the utility in furtherance of, and in compliance with, an approved plan are presumed to be prudent actions, the costs of which are recoverable in rates as provided in section 40-3.2-207."

187. Section 40-3.2-207, C.R.S., commences with its own legislative declaration. This legislative declaration echoes § 40-3.2-205(3), C.R.S., and states that Public Service is "entitled to fully recover the costs that it prudently incurs in executing an approved emission reduction plan." § 40-3.2-207(1)(a), C.R.S. Subsection 207(1)(a), C.R.S., goes on to broadly define costs as activities in the "planning, developing, constructing, operating, and maintaining" any emission control or replacement capacity constructed pursuant to the plan. The second half of the legislative declaration acknowledges that the activities Public Service will undergo pursuant to its approved emission reduction plan will be conducted "outside of the normal resource planning process." § 40-3.2-207(1)(b), C.R.S. Section 40-3.2-207, C.R.S., then sets forth four provisions addressing various aspects of cost recovery.

188. Section 40-3.2-207(2), C.R.S., permits the Commission to assign a portion of the cost of the emission reduction plan to Public Service's wholesale customers and expects Public Service to pursue a good faith application with the Federal Energy Regulatory Commission (FERC) for recovery of these dollars from its wholesale customers. Section 40-3.2-207(2), C.R.S., contains a "make-whole" provision in the event the FERC does not permit recovery of the entire plan-related rate increase Public Service requests.

189. Section 40-3.2-207(3), C.R.S., permits "current recovery" of "construction work in progress at the utility's weighted average cost of capital, including its most recently authorized rate or return on equity, for expenditures on projects associated with the plan during the construction, startup, and pre-service implementation phases of the projects."

190. Section 40-3.2-207(4), C.R.S., states the Commission shall employ rate-making mechanisms that allow for adjustments not less than once per year, without requiring Public Service to file a general rate case, "to the extent that" Public Service can show: (1) the "approved plan includes the early conversion or closure of coal-based generation capacity by January 1, 2015;" and (2) the plan contributes to "a lag in the recovery of the costs of the plan related to the investment required," which contributes to Public Service "earning less than its authorized return on equity." This paragraph contains no requirement that the special regulatory mechanism be implemented on a forward looking basis versus a historical basis; however, the Commission's review of the costs to be recovered through the special rate-making mechanism may not amount to a full blown rate case.

191. Finally, § 40-3.2-207(5), C.R.S., provides that "during the time any special regulatory practice is in effect, the utility shall file a new rate case at least every two years or file a base rate recovery plan that spans more than one year."

2. Public Service's Request Concerning Cost Recovery and the Opposition Thereto

192. Public Service took the position from the very outset of this proceeding that a fully-projected cost recovery approach would be required to carry out the requirements of HB 10-1365. To this end, Public Service proposed to recover both its CWIP and its accelerated depreciation and removal costs through an automatic adjustment clause, which it proposed go into effect on January 1, 2011. This rider would be known as the ERA and would have a true-up mechanism. The ERA would not be used to recover the costs of plan-related assets once they are placed in service. Public Service included an illustrative advice letter with its August 13, 2010 filing. However, during the course of the proceedings it became apparent that Public Service could not finalize this advice letter until after December 15, 2010 when it knew the

Commission's rulings on both resource selection and the permissibility of the implementation of the ERA. During the first round of hearings, Public Service stated the 2011 ERA would be in the range of $14.1 million; however, this amount was later corrected in the second round of hearings to the range of $16.8 million.[21]

193. Public Service contends that ratepayers will best benefit from an approach to cost recovery that spreads out the rate increases over the greatest number of months. For this reason, Public Service proposed a rider that collects projected cost and expenses from ratepayers in advance of the actual date in which some of those costs would in fact be incurred. Public Service takes the position that an automatic adjustment clause based on projected pre-CPCN approval CWIP expenditures is required by HB 10-1365 and that it met both of the "to the extent" triggers contained in § 40-3.2-207(4), C.R.S., such that it may use the ERA also to recover its accelerated depreciation and removal costs.[22]

194. Public Service requests the Commission approve the ERA and associated tariff sheets to allow current return on capitalized CWIP at the Company's weighted average cost of capital including its most recently authorized rate of return on equity[23] and to allow, using a two- or four-year amortization period, recovery of incremental 2011 plant related costs (accelerated

[21] The 19 percent increase must be put into perspective as the estimates associated with the ERA's two components moved in opposite directions. The projected CWIP portion of the ERA decreased by 77 percent (from $4.7 million to $1.1 million) and the projected accelerated depreciation and removal cost portion increased by 67 percent (from $9.4 million to $15.7 million).

[22] Public Service contends that the first trigger – early action – is met for the entire emission reduction plan because Cherokee 1 and 2 are retired before January 1, 2015. As to the second trigger, Public Service contends the accelerated depreciation associated with early retirement of its plants will clearly contribute to earning less than authorized. Public Service argues: "[t]he Company cannot accelerate plant lives by several years and invest a billion in new plant without such a plan contributing to underearnings. . . . Public Service has adequately demonstrated that the plan costs, including accelerated depreciation, will contribute to under earnings." Public Service SOP, at 85.

[23] Public Service contends that § 40-3.2-207(3), C.R.S., is intended to address the expenditures associated with incremental investments – such as scrubbers, catalytic converters, and plant conversions prior to the rate base inclusion date.

depreciation and removal expenses offset by reduced rate base during 2011) associated with the shortened useful lives of any coal plant whose early retirement is within the scope of the approved emission reduction plan.[24] Alternatively, in its November 15, 2010 supplemental rebuttal testimony, Public Service proposed deferred accounting for the accelerated depreciation and removal costs as follows:

> i. Public Service shall create and/or adjust a regulatory asset or liability for each plant by an amount equal to the difference between:
>   1. The level of depreciation expenses using the removal cost and depreciation currently recovered through base rates for each retired plant; and
>   2. The level of depreciation and removal costs estimated to be recognized by the Company in accordance with Generally Accepted Accounting Principles ("GAAP"); and
>
> ii. Public Service shall recover a return of and a return on such regulatory asset or refund of any regulatory liability balance through base rates in the next general rate case.

Public Service SOP, at 31. Public Service argues these special regulatory approvals are necessary for it to timely execute the approved emission reduction plan and its associated expenditure of approximately $1 billion dollars over the next seven years. Similarly, Public Service argues that financial harm justifying a special regulatory mechanism is both inevitable and has been proven not only for 2011, but for the term of any approved emission reduction plan. *See* Public Service SOP, at 85.

195. Finally, Public Service seeks a finding that the appropriate share of the costs of the FERC-approved emission reduction plan to be assigned to its wholesale customers is the jurisdictional allocator as it changes over time, so long as the allocator does not conflict with the

[24] These plants include Cherokee 1, significant portions of Cherokee 2, Cherokee 3, and Valmont 5.

Company's wholesale contracts that were executed prior to the effective date of HB 10-1365. *See* Public Service SOP, at 32.

196. Several intervenors took issue with Public Service's proposed ERA. At a policy level, these intervenors disagreed that the statutory triggers in § 40-3.2-207(4), C.R.S., had been met. For example, Staff pointed out that Public Service's approach is nothing more than a demonstration that a lag in recovery of the investment costs will reduce "revenues" and therefore does not meet the requirement of HB 10-1365 because the Company's demonstration must be with respect to earnings. *See* Staff SOP, at 14. Intervenors also argued that the demonstration of underearnings needed to justify the use of a special regulatory mechanism should not include the effect of accelerated depreciation and removal costs. They argue that the demonstration should be made more than once during the duration of the approved emission reduction plan, contrary to what is requested by Public Service. Further, several parties took the position that Public Service needed to make more of a demonstration of the contribution to earning less than the authorized return on equity and suggested reliance upon some type of modified Appendix A or monthly surveillance reports. Several intervenors also argued that the recovery of costs under § 40-3.2-207(4), C.R.S., should only be allowed to the level of what would make Public Service "whole" from an earnings perspective, and not guarantee Public Service cost recovery of all costs without regard to the level of underearnings. The general effect of these arguments is that Public Service needs to make a more robust demonstration of underearnings prior to taking advantage of the special regulatory treatment outlined at § 40-3.2-207(4), C.R.S.

197. At the mechanical level, the intervenors addressed such topics as the timing of recovery of a return on CWIP in relation to the timing of an award of a CPCN for a project eligible for current recovery of a return on CWIP, the inclusion of "project development costs" in

the CWIP calculation, the number of months to be used in the calculation of an average CWIP balance, whether to recognize short term debt in the capital structure used to calculate the weighted average cost of capital applied to CWIP, the appropriate use of projected versus historical figures, the confidence with the proposed early retirement date, the proper amortization period for various categories of costs, the levelizing of the revenue requirement, the details of any true-up feature, and clarifications to the proposed tariff text.

198. As noted by the OCC, the cost recovery provisions of HB 10-1365 do not require the Commission to approve a cost recovery plan in this docket on or before December 15, 2010. OCC SOP, at 14. The OCC argues that the Commission defer all cost recovery issues to a future application proceeding in which the guidelines and documents required can be vetted. *Id.* at 15. However, because Public Service will take actions in 2011 pursuant to the plan we are adopting here, we find it is efficient and advisable to make as many determinations as possible based on the evidentiary record that has been developed. The OCC and other interested persons will likely have additional opportunities to opine on the cost recovery issues implicated by HB 10-1365 and the plan we are adopting here.

3. Decision on Wholesale Rates

199. Taken together, the provisions at § 40-3.2-207(2), C.R.S., recognize that Public Service provides both retail and wholesale services. This section then sets forth the basis by which an appropriate proportion of the costs of the approved emission reduction plan can be assigned to Public Service's wholesale customers via a rate proceeding at the FERC. Such a FERC rate proceeding must be commenced within six months of the Commission's final order assigning costs to the wholesale jurisdiction and must be pursued in good faith. HB 10-1365, however, further allows Public Service to recover all costs of the approved Plan from the retail

customers in the event that the FERC disapproves of all or a portion of the wholesale's sectors responsibility for HB 10-1365 costs. Public Service recognizes all of its responsibilities under Subsection 207(2) and, for our purposes in this proceeding, has satisfied all of its obligations.

200. Public Service's request on this issue was unopposed. Public Service is entitled to the finding it seeks on this issue.

201. Specifically, we find when seeking cost recovery from wholesale customers for their appropriate share of the costs of the approved emission reduction plan, Public Service shall use the jurisdictional allocator as it changes over time, so long as the allocator does not conflict with Public Service's wholesale contracts that were executed prior to the effective date of HB 10-1365.

4. Decision on Cost Recovery Related to Construction Work in Progress

202. Public Service seeks an automatic cost adjustment in its proposed ERA. However, Public Service concedes that the dollar amounts it presented as the basis for such a mechanism have not been through the rigors associated with an application for a CPCN. *See* Public Service SOP, at 61. Because we have found that all significant capital investments associated with the approved emission reduction plan require a CPCN, we find that cost recovery of CWIP earnings should not begin until CPCNs for these projects have been issued.

203. Moreover, we disagree with Public Service that § 40-3.2-207(3), C.R.S., requires us to construe "current recovery" as eliminating rate proceedings as the vehicle by which investment in a new plant under construction is included in rate base.

204. Thus, for all investments on projects associated with the approved emission reduction plan (including the non-plant specific "project development costs" identified by Public Service witness Mr. Brockett), Public Service is authorized to recover a return on rate base on a

CWIP amount prior to a plant coming into service. Public Service shall do this by accumulating Allowance for Funds Used During Construction (AFUDC) and requesting the actual recovery of CWIP in a general rate case along with the AFUDC that has accumulated.[25] The result is that there will be no AFUDC offset.[26] As explained below, this conclusion does not preclude the use of a special regulatory mechanism, such as an automatic adjustment clause, in the event the triggers of § 40-3.2-207(4), C.R.S., are met.

205. We further find that expenditures eligible for current earnings on CWIP must occur between the date of this Commission's decision and December 31, 2017. No party has opposed this position as a general matter.

5. Decision on Cost Recovery Related to Accelerated Depreciation and Removal Costs

206. The Commission recognizes that this Order approving the early retirement of coal-fired electricity generation plants will have immediate consequences for Public Service under generally accepted accounting principles and may negatively impacting the Company's potential to earn its authorized level of return on equity. As explained by Public Service, these immediate consequences can be isolated.

207. We accept Public Service's approach to using deferred accounting, as set forth above, to protect the Company against the possible financial harm associated with the early retirements of Cherokee 1, 2, and 3, as well as Valmont 5. By approving the use of deferred

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[25] Based on our prior ruling that the Hayden 1 and Hayden 2 SCR investments are within the scope of the approved emission reduction plan, these projects are eligible for the CWIP cost recovery treatment we have approved.

[26] Commissioner Matt Baker would have accepted an approach to the current recovery on CWIP that looked more like the Transmission Cost Adjustment rider, so long as the project received CPCN-like approval. Commissioner Baker prefers this result for policy reasons, including its likely positive impact of demonstrating the feasibility of accounting and forecasting concepts that Public Service would use when setting rates based on a future test year.

accounting, we avoid a future claim of retroactive ratemaking if these costs are included in a different test year that may be used in a future rate proceeding.

6. Decision on Special Rate Making Mechanism

208. Public Service is seeking at this time approval only of a mechanism to recover its current return on CWIP as well as accelerated depreciation and removal costs. *See* Brockett Direct Testimony (Hrg. Ex. 23), at 3. Public Service describes this as a modest approach that does not seek to recover all of the costs that Public Service will incur to implement the plan. *See* Tr. Oct. 22, 2010, at 53. Specifically, it does not include recovery of operations and maintenance costs, depreciation expense, insurance, taxes, etc., of new plants as they are brought into service. That being said, Public Service projects the 2011 level of costs (including current earnings on CWIP and accelerated depreciation and removal costs) that will flow through its proposed cost recovery mechanism will be greater than $30 million. *See* Brockett Supplemental Rebuttal Testimony (Hrg. Ex. 196), at 7.

209. Public Service has not convinced us that its 2011 expenditures on construction projects are so large as to require the adoption of an automatic adjustment mechanism at this time, especially in view of our approval of the Company's proposed deferred accounting for the accelerated depreciation and removal costs. Public Service's proposed tariff language was not thoroughly vetted in the case, and we believe that current recovery of earnings on CWIP can be accomplished in accordance with the Clean Air – Clean Jobs Act without resorting to an automatic adjustment mechanism.

210. Thus, we adopt deferred treatment accounting as the default approach for the CWIP dollars and the accelerated depreciation and removal costs for the duration of the approved emission reduction plan. If Public Service desires different cost recovery, it shall

commence a cost recovery proceeding at the Commission and can prevail only if it meets the two triggers set forth at § 40-3.2-207(4), C.R.S. Prior to commencing a proceeding to implement a different approach to cost recovery than that authorized here, Public Service shall obtain a final Commission order setting forth the theoretical parameters for the alternative approach. Such Commission order will determine the filing requirements and the standard required for Public Service to show how the early action and the lag in recovery contributing to earning less than the authorized return on equity.

211. It is clear from the controversy that Public Service's proposed ERA has attracted that processing and adopting a special regulatory mechanism will likely be contentious and time consuming. In preparing to make its filing to establish a rider or deferred accounting mechanism, Public Service should carefully review the procedural and technical criticisms of its illustrative advice letter and consider making changes to address the critiques. In that way, we hope that efficiencies will be gained in any future proceeding to establish an actual rate rider or deferred accounting procedure.

212. Examples of parameters that Public Service should consider including are whether rate changes can be designed so that they flow directly to base rates without the need for a separate rider and whether the mechanism should be designed so as to bring Public Service back up to only its authorized return on equity. As to this second parameter, it will be necessary to determine how to measure the requisite under-earnings without undertaking a full rate case.

7. Decision on Biennial Rate Cases and Multi-Year Rate Plans

213. Public Service has not put forth its proposed approach as to the form of rate cases and/or rate plans it desires. Rather, Public Service has offered to conduct discussions with interested stakeholders in 2011 to discuss the pros and cons of using multiyear rate plans rather

than riders and rate cases every two years. *See* Hyde Direct Testimony (Hrg. Ex. 1), at 56. We find Public Service's approach to use discussions with stakeholders to address this issue to be reasonable and we shall adopt it.

214. Additionally, we note, that, regardless of the approach taken by Public Service, the requirement from our order in Docket No. 10A-327E that the Company file a rate case no later than April 30, 2012) will meet the two-year requirement of § 40-3.2-207(5), C.R.S.

I. Long Term Gas Contract

215. Section 40-3.2-206(4), C.R.S., states the utility may enter into long-term gas supply agreements to implement the requirements of HB 10-1365. It goes on to state,

> A long-term gas supply agreement is an agreement with a term of not less than three years or more than twenty years. All long-term gas supply agreements may be filed with the Commission for review and approval. The Commission shall determine whether the utility acted prudently by entering into the specific agreement, whether the proposed agreement appears to be beneficial to consumers, and whether the agreement is in the public interest. If an agreement is approved, the utility is entitled to recover through rates the costs it incurs under the approved agreement, and any approved amendments to the agreement, notwithstanding any change in the market price of natural gas during the term of the agreement. The Commission shall not reverse its approval of the long-term gas agreement even if the agreement price is higher than a future market price of natural gas.

Id.

216. As a part of its August 13, 2010 proposed plan filing, Public Service requested approval of a long-term gas supply contract with Anadarko (Anadarko Contract).

217. By Decision Nos. C10-0957 and C10-0976, the Commission granted extraordinary protection of the contract and certain testimony, limiting full access to the Anadarko Contract to Staff and the OCC. Because of this confidentiality limitation, the

Commission directed Staff and the OCC to analyze the contract. Although Peabody did not have access to the Anadarko Contract, it nonetheless provides a detailed discussion about potential concerns with long-term contracting, generally, as well as an analysis and recommendations based on the information it reviewed. *See* Montgomery Answer, Cross-Answer, Supplemental Answer, and Supplemental Cross-Answer Testimony (Hrg. Exs. 44, 45, 220, 221, 222, 223, and 224).

1. The Anadarko Contract

218. Public Service implemented an RFP process for long-term gas contracts to complement the Company's proposed emissions reduction plan. Public Service solicited bids for either five- or ten-year terms with pricing that was: (a) fixed for the entire term; (b) collared with a price floor and ceiling; and/or (c) a fixed price with an annual adjustment or escalation. The RFP required the gas to be produced in Colorado, in order to maximize positive impacts on the Colorado economy, consistent with HB 10-1365.

219. Without divulging the confidential terms of the winning Anadarko Contract, Public Service states that it falls within the bidding category which contains "a fixed price offer with an annual adjustment or escalation." The contract is for a ten-year term, with the Cheyenne Hub specified as the delivery point.

220. To assist the Commission and parties in evaluating the Anadarko Contract, Public Service provides a public estimate of the average nominal cost of the associated gas supply of $5.48 per Dth over the ten years. *See* Hrg. Ex. 2 at 141. Public Service states that if an annual forecast cost of the Anadarko Contract volumes are applied to the STRATEGIST modeling, the Anadarko Contract could result in approximately $100 million savings in present value revenue requirements. *See* Public Service SOP, at 72.

221. Public Service asserts that the Anadarko Contract is prudent, as it was selected as the winning bidder through a robust competitive bidding process in which all potential bidders were pre-screened from a credit standpoint, and additional credit support or collateral requirements in the form of a corporate parental guaranty were required. The Company also requests a finding that under contract defaults, replacement gas costs would be recoverable through the fuel clause, assuming prudent contract management. *See* Public Service SOP, at 73.

222. In answer testimony, Staff provides a thorough discussion of the Anadarko Contract and addresses the various risks and benefits associated with the specific terms contained in the contract. Staff generally states that the contract is beneficial to customers and in the public interest. Despite the lack of production guarantee behind the gas supply, Staff states that Public Service has received a level of security and credit support from Anadarko's parent companies. Staff raises the notion that although the Anadarko Contract price has escalators and is not a purely a fixed price contract, it does provide a price that will likely be more stable than traditional index-based contracts. Further, the value of reducing volatility should be considered, which may be different from least cost. *See* Kwan Answer Testimony (Hrg. Ex. 41).

223. Staff further asserts it is premature to address a default situation that provides Public Service assurances that it will not be held responsible for any difference between the contract price of the gas and the ultimate replacement cost of such gas. According to Staff, the prudence of Public Service's action, or lack of action, would be determined at the time when a default happens. *See* Staff SOP, at 13.

224. The OCC states the Company conducted a well structured bid solicitation and evaluation process. The selected winning bid is expected to result in lower prices for the natural

gas than would result if the natural gas was purchased at the price forecast filed in this docket. The winning bid also provides some level of customer protection from the price volatility that would likely result from purchasing the natural gas at index prices. In the event of a contract default, the OCC suggests that the Commission should, at that time, evaluate whether the actions that the Company took over time have been prudent and that it has done everything possible to protect the ratepayers and the value of the long-term contract. Accordingly to the OCC, it is premature at this time to simply assume that the implementation of the contract terms will be prudent. *See* Senger Supplemental Answer Testimony (Hrg. Ex. 126).

2. Decisions on Anadarko Contract

225. HB 10-1365 provides that the Commission may approve the contract if it is prudent, of benefit to customers, and in the public interest. As discussed further in Highly Confidential Attachment A, the Commission finds the Company acted prudently in entering into the Anadarko Contract and that it will provide a benefit to consumers, because it will likely provide a lower cost of gas than conventional index-based pricing and greater price stability.[27] For these cost-benefit reasons, we similarly find approval of the Anadarko Contract is in the public interest.

226. Peabody recommends that the Commission require Anadarko to provide additional credit to cover the full amount that the Anadarko Contract could be under or over. Public Service asserts that such a requirement would increase the costs of the Anadarko Contract and that existing provisions in the agreement provide adequate protection. *See* Carter

[27] The Anadarko Contract is highly confidential, and party review was significantly limited. The confidential attachment to this Decision addresses and makes findings regarding: contract structure; gas produced in Colorado; contrast with current contracting practices; fixed-price aspects of the contract; contract price mechanism; production resource adequacy; transportation capacity; difference between projected contract price and base price forecast; risk of non-performance; and dispute resolution.

Supplemental Rebuttal Testimony (Hrg. Ex. 191), at 2. As discussed in Highly Confidential Attachment A, the terms of the contract lead the Commission to believe Anadarko will be able to meet its obligations. We accept Public Service's assertion that no appreciable benefit would be achieved by requiring additional credit requirements.

227. Peabody also recommends the Commission require an independent evaluator to oversee the management of the Anadarko Contract, if approved. Public Service argues that such a requirement would increase costs and that the Company regularly manages many gas contracts without the benefit of an independent evaluator. *See* Hrg. Ex. 191, at 3. We agree with Public Service that it is not necessary for an Independent Evaluator to oversee the Anadarko Contract, as such a requirement adds significant additional costs and is not warranted in this situation.

228. HB 10-1365 generally intends to provide assurance to the supplier that future Commissions will not prevent the utility from paying costs under the contract and receiving reimbursement from ratepayers for such costs, even if costs are higher than market. Similarly, we believe the utility should be protected from exposure to liability from non-performance of the contract, so long as the Company does not cause the contract breach and any replacement gas costs are prudently incurred. Therefore we grant Public Service a presumption of prudence for the procurement of replacement gas in the event Anadarko breaches the agreement. This presumption of prudence for replacement power assumes, of course, that the Company was prudent in its management of the contract leading up to the breach.

3. Additional Long-Term Contracts

229. Anadarko recommends that Public Service pursue additional long-term contracts, which, if undertaken at rates similar to the Anadarko Contract, will further reduce gas supply costs. *See* Moore Supplemental Answer Testimony (Hrg. Ex. 197).

230. Staff recommends that for another long-term contract in the future, given the volatility of natural gas prices and the long duration of the contract, Public Service should request bids in the RFP process with a one-time reset from the date of the bid to the date of the contract to ensure the chosen bid continues to be beneficial to its customers as the sole least cost bid option. Peabody concurs with such a price reset requirement, and suggests the Commission require approval of the RFP before it is issued by Public Service.

231. Public Service stated it would be open to additional contracts, although it should be within the Company's discretion to decide whether to pursue such additional contracting. *See* Tr. Oct. 28, 2010, at 204.

232. We find additional long-term gas contracts could provide value to the Company and its customers, particularly because the plan we approve today will likely lead to increased natural gas burn as compared to the Company's recommended scenario 5B. Therefore, we direct Public Service to investigate additional long-term natural gas supply contracts. However, we recognize that the decision to enter into additional long-term contracts is within the Company's management discretion.

J. Emissions Cap on New Resources

233. The GEO suggests the Commission rule that all future resources considered by the Company in its 2011 ERP achieve, at minimum, the emissions performance standards that are achieved by replacement resources in this plan. GEO SOP, at 14. In other words, the GEO argues the Company should only consider those resources that have an emissions profile equal to or better than a 2X1 CC natural gas plant. The Commission finds this suggestion is outside the scope of this Docket, which exists only to address the Company's emission reduction plan filed in accordance with HB 10-1365. As such, we decline to consider this proposal.

K. Transmission

234. In its SOP, Staff requests that Public Service develop a 10 to 12 year long-term study of the Denver-Boulder load serving network. Staff SOP, at 15. Staff believes the study should include, among other things, an evaluation of the severe overloads shown on Table 5 of Attachment TWG-1 of the rebuttal testimony of Company witness Tom Green. Hrg. Ex. 26, at 18. Staff asserts that the study should start immediately after a decision is entered in this Docket. Staff SOP, at 15.

235. We agree with Staff on this matter and require Public Service to develop a study of the Denver-Boulder area looking out 10 to 12 years. In addition, we request that Public Service solicit input from Staff about the scope of the study. This information will help inform the next resource plan proceeding and we direct Public Service submit the study as part of it next ERP filing.

236. Expanding this perspective, we further find it is important to begin developing a better understanding of how the transmission and generation system needs to develop over the next 20 to 30 years considering the projected growth and eastward expansion of the Colorado Front Range population center. In addition, the process going forward should not be limited to a dialog between the Commission and utilities but should also involve all stakeholders: developers, economic development organizations, local governments, etc. While we understand that Cherokee and Arapahoe will continue to play a key role, building a better understanding of how the system needs to develop as well as establishing the necessary communication channels will allow the Commission to better serve current and future ratepayers.

L. Classification of Information as Highly Confidential and Discovery Disputes

237. If a party believes information requires extraordinary protection, Rule 1100(a)(III) of the Commission's Rules of Practice and Procedure, 4 CCR 723-1, require the party to submit a motion to the Commission seeking such treatment. The Commission, upon viewing the information[28] and the motion *in camera*, may enter an order granting the motion and ordering the level of extraordinary protection which the Commission, in the exercise of its discretion, deems appropriate. Rule 1100(a)(I), 4 CCR 723-1. Requests for extraordinary protection are not routine, and we will grant them only if the moving party meets its high burden. *See* Decision No. C08-0237 at ¶ 15. *See also* Decision No. R07-0924 at ¶ 36.

238. The Commission's Rules regarding extraordinary protection are set forth to ensure the Commission is the final arbiter of what is and what is not deserving of extraordinary protection. This is not a determination parties may make without first obtaining an order from the Commission.

239. In the course of these proceedings, it came to the Commission's attention that the Company withheld certain reports prepared by its consultant from Staff, under the assertion that such documents were subject to extraordinary protection. *See* Tr. Oct. 25, 2010, at 94-104; Tr. Oct. 28, 2010, at 50-54. In this Docket, Staff was granted access to all highly confidential information, as it typically is. Nonetheless, Public Service undertook some delay in providing a highly confidential consultant's report to Staff, on the basis that the information was subject to a

[28] Parties seeking extraordinary protection may also provide a representative sample of the information or a description of the information. Rule 1100(a)(III), 4 CCR 723-1. However, the Commission may seek the actual information if it is necessary for the Commission to render a decision on the motion. Further, if the motion is granted, a complete version of the document shall be filed with the Commission. *Id.*

confidentiality agreement between the Company and its consultant. *See* Tr. Oct. 28, 2010, at 52-54.

240. The Commission wishes to remind the Company and other parties seeking extraordinary protection that a determination as to the level of protection afforded to a document is entirely within the Commission's discretion, and is not to be determined by any party. Further, where consistent with existing protective orders, such information should be provided to Staff without delay, and without regard to supplemental agreements the party seeking extraordinary protection may have.

241. An additional dispute came to the Commission's attention on November 19, 2010. Peabody raised concerns about the completeness of the Company's response to discovery requests propounded by itself, Climax/CF&I, and Staff.[29] The Commission has come to understand that, in responding to these discovery requests, Public Service narrowed the term "the Company" to include only certain departments that, in its opinion, were affected by the particular response. *See* Tr. Nov. 20, 2010, at 211-14. This occurred even though the Company was aware additional departments might be in possession of responsive information. *Id.* at 216. However, Public Service represented this type of narrowing is not the its typical practice in responding to discovery requests that seek information related to "the Company." *See Id.* at 212-14.

242. The Commission accepts Public Service's representation that this occurrence does not represent the Company's typical discovery practice. However, the Commission does not look favorably on parties attempting to impose artificial limitations on a particular request when

[29] *See* Statement of Known Facts and Circumstances, filed by Peabody on November 20, 2010. *See also* Tr. Nov. 19, 2010, at 301-35; Tr. Nov. 20, 2010, at 89-161; Tr. Nov. 20, 2010, at 209-234.

responding to discovery. The Company should take note and adopt appropriate precautions in the future to ensure its discovery responses are prompt and full.

M. Impacts on Coal-Producing Communities

243. At its highest level, HB 10-1365 is a major policy statement of the Colorado General Assembly. The legislation discusses the impact of the bill's implementation on the environment, the Colorado economy, resource development, Colorado's investor-owned utilities, and on utility rates. In its Legislative declaration, HB 10-1365 requires the Commission to address the impact of our decision on Colorado's energy-producing communities: "The general assembly also finds and declares that the actions provided for in this Part 2 be implemented in a manner to address the sound economic, health, and environmental conditions of energy producing communities." § 40-3.2-202(3), C.R.S.

244. In this Docket, we heard testimony from experts and citizens alike, expressing concern about the possible loss of jobs in the Colorado coal mining industry and the communities that support those workers. At the same time, we heard conflicting testimony that any lost sales of Colorado coal due to the plant closures ordered in this Docket will likely be made up with sales of Colorado coal into other markets.

245. The Commission is concerned about the impact of this Decision on the state's economy generally and any potential job losses in the coal industry in particular. We believe that the General Assembly intended for the Commission to be actively engaged with this issue. During the public hearing in Denver on September 23, 2010, we heard that the funding for worker retraining available to the Colorado Department of Labor is, at least at the moment, fairly depleted. Therefore, we begin a process with this Order that will lead, if it is needed, to

additional funding for the retraining of coal miners who may lose their jobs due to the Decision in this Docket.

246. We direct the Staff of the Commission to consult with the relevant entities, which may include the Colorado Department of Labor, CMA, AGNC, and the OCC, among others, to design an approach to the questions of how to ascertain the impact on mining employment of the Company's approved emission reduction plan and how to efficiently dedicate appropriate ratepayer funds to the effort of retraining eligible coal miners. Staff shall prepare and present a recommendation to the Commission before December 31, 2011.

II. ORDER

A. The Commission Orders That:

1. The emission reduction plan submitted by Public Service Company of Colorado (Public Service or Company) is modified and hereby approved.

2. Retirement of Cherokee 1 by 2011 is necessary and in the public interest for emission reduction purposes.

3. Within three months prior to the commencement of the Company's next electric base rate proceeding, Public Service shall file an application, consistent with the discussion above, to amend its Cherokee 1 Certificate of Public Convenience and Necessity (CPCN).

4. Retirement of Cherokee 2 by 2011 is necessary and in the public interest for emission reduction purposes.

5. Re-use of Cherokee 2 as a synchronous condenser and installation of a 90 MVAR capacitor bank is necessary and in the public interest for system stability and emission reduction purposes. Public Service shall carefully monitor the use of the synchronous condenser at Cherokee 2 during the implementation of the plan.

6. Within three months prior to the commencement of the Company's next electric base rate proceeding, Public Service shall file an application, consistent with the discussion above, to amend its Cherokee 2 CPCN.

7. Retirement of Cherokee 3 by 2015 is necessary and in the public interest for emission reduction purposes.

8. Within three months prior to the commencement of the Company's next electric base rate proceeding, Public Service shall file an application, consistent with the discussion above, to amend its Cherokee 3 CPCN.

9. Conversion of Cherokee 4 from coal-fired generation to natural gas-fired generation by the end of 2017 is necessary and in the public interest for emission reduction purposes.

10. Public Service is granted a presumption of need for a 2X1 combined cycle natural gas facility at Cherokee Station with respect to a future application for a CPCN.

11. Retirement of Arapahoe 3 by 2013 is necessary and in the public interest for emission reduction purposes.

12. Re-use of Arapahoe 3 as a synchronous condenser and installation of 90 MVAR of new shunt capacitors is necessary and in the public interest for system stability and emission reduction purposes.

13. Conversion of Arapahoe 4 from coal-fired generation to natural gas-fired generation by 2014 is necessary and in the public interest for emission reduction purposes.

14. Retirement of Valmont 5 by 2017 is necessary and in the public interest for emission reduction purposes.

15. Within three months prior to the commencement of the Commission's next electric base rate proceeding, Public Service shall file an application, consistent with the discussion above, to amend the Valmont 5 CPCN.

16. Installation of selective catalytic reduction (SCR), lime spray dryer, and sorbent injection controls at Pawnee by 2014 is necessary and in the public interest for emission reduction purposes.

17. Public Service shall file a modified application, consistent with the discussion above, for a CPCN for the controls to be installed at Pawnee. Public Service is granted a presumption of need for these controls with respect to this CPCN application.

18. Installation of SCR controls at Hayden 1 by 2015 is necessary and in the public interest for emission reduction purposes.

19. Public Service shall file a modified application, consistent with the discussion above, for a CPCN for the controls to be installed at Hayden 1. Public Service is granted a presumption of need for those controls with respect to this CPCN application.

20. Installation of SCR controls at Hayden 2 by 2016 is necessary and in the public interest for emission reduction purposes.

21. Public Service shall file a modified application, consistent with the discussion above, for approval of the controls to be installed at Hayden 2. Public Service is granted a presumption of need for those controls with respect to this CPCN application.

22. Public Service's request to adopt an Emissions Reduction Adjustment for Construction Work in Progress (CWIP) is rejected. Public Service shall be permitted to accumulate allowance for funds used during construction (AFUDC) and request actual recovery of the CWIP in a general rate case, consistent with the above discussion.

23. Public Service's request to use deferred accounting for accelerated depreciation and removal costs associated with the coal-fired electric generating units retired by this Order is adopted, consistent with the discussion above.

24. Public Service's request to use the jurisdictional allocator as it changes over time in the assignment to wholesale customers of their proportion share of House Bill 10-1365 costs is approved.

25. The long term natural gas contract between Public Service and Anadarko Energy Services Company (Anadarko) is approved. The Commission finds Public Service acted prudently in entering into the contract, the contract will provide a benefit to consumers, and approval of the contract is in the public interest.

26. Public Service is granted a presumption of prudence for the procurement of replacement gas in the event Anadarko breaches the long-term gas contract, so long as Public Service has prudently managed the contract.

27. Public Service shall develop a 10- to 12-year study of the Denver-Boulder load serving network, after soliciting input from Staff of the Commission regarding the scope of the study.

28. Consistent with the discussion herein, Staff of the Commission shall consult with appropriate entities and then inform the Commission of a recommended structure and funding of a program to assist in retraining Colorado mining industry employees if mining jobs are lost as a result of the implementation of the Company's modified and approved emission reduction plan.

29. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Order.

30. This Order is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING December 9, 2010.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

RONALD J. BINZ

JAMES K. TARPEY

MATT BAKER

Commissioners

Decision No. C11-0121

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 10M-245E

IN THE MATTER OF COMMISSION CONSIDERATION OF PUBLIC SERVICE COMPANY OF COLORADO'S PLAN IN COMPLIANCE WITH HOUSE BILL 10-1365, "CLEAN AIR-CLEAN JOBS ACT."

ORDER ADDRESSING APPLICATIONS FOR REHEARING, REARGUMENT, OR RECONSIDERATION

Mailed Date: February 3, 2011
Adopted Date: January 26, 2011

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I. BY THE COMMISSION

A. Statement

1. This matter comes before the Commission for consideration of Applications for Rehearing, Reargument, or Reconsideration (RRR) of Commission Decision No. C10-1328.

2. Decision No. C10-1328, issued on December 15, 2010, modifies and approves the emission reduction plan filed with the Commission by Public Service Company of Colorado (Public Service or Company) pursuant to House Bill (HB) 10-1365, commonly known as the "Clean Air – Clean Jobs Act."

3. Applications for RRR were timely filed under § 40-6-114, C.R.S., on January 4, 2011 by Public Service; Peabody Energy Corporation (Peabody); the Colorado Mining Association (CMA) and the Associated Governments of Northwest Colorado (AGNC), jointly; the Colorado Office of Consumer Counsel (OCC); Chesapeake Energy Corporation, Noble Energy, Inc., and EnCana Oil & Gas (USA) (collectively, Gas Intervenors); Ms. Leslie Glustrom; and the American Coalition for Clean Coal Electricity (ACCCE).

4. On January 5, 2011, the Colorado Independent Energy Association (CIEA) filed a Motion for Leave for Acceptance of Late Filed Application of Reargument, Rehearing, or Reconsideration of Commission Decision No. C10-1328 (Motion).

B. Motion for Acceptance of Late Filed RRR Application

5. Section 40-6-114, C.R.S., sets forth the Commission's RRR process. After the Commission issues a final decision, parties have 20 days within which to file applications for RRR. § 40-6-114(1), C.R.S. This RRR deadline may be extended by the Commission at its

discretion, so long as the motion for extension of time is received within that initial 20-day period. *Id.*

6. Decision No. C10-1328 was issued on December 15, 2010. Therefore, Applications for RRR were due on January 4, 2011.

7. On January 5, 2010, CIEA filed the Motion. In the Motion, CIEA claims that, due to the slowness of the Commission's e-filing system approaching 5 p.m. on January 4, 2011, there was confusion about whether its RRR was successfully filed. CIEA explains that it did not become aware its RRR was not successfully filed until January 5, 2011.

8. Rule 1211(d)(I) of the Commission's Rules of Practice and Procedure, 4 *Code of Colorado Regulations* (CCR) 723-1, allows users experiencing technical difficulty to file a statement attesting to that technical difficulty. If a compliant notice of technical difficulty is submitted to the Commission within one day, the corrected filing shall be accepted *nunc pro tunc* to the date it was first attempted to be filed electronically. Rule 1211(e), 4 CCR 723-1.

9. The Commission's e-filing records indicate CIEA's RRR Application was successfully uploaded to the system prior to 5 p.m. on January 4, 2011 for final review and submission, but that the file was never submitted.

10. The Commission will deny the Motion because motions for extension of time within which to file RRR must be received within the 20-day time period established by § 40-6-114, C.R.S. Further, the Commission does not believe the situation involves a technical difficulty that would trigger the exceptions established by Rule 1211, 4 CCR 723-1. This appears to be an instance of user error that occurred too close to the filing deadline to be timely

resolved, rather than a technical problem with the Commission's e-filing system. The Commission therefore will not consider CIEA's untimely filed Application for RRR.[1]

C. Due Process

11. Peabody, ACCCE, and AGNC/CMA allege they were not afforded due process. They raise eight arguments in support of their allegation, and ask that the case be dismissed.[2]

1. Reliance on *Public Service Co. of Colo. v. Colo. Pub. Utils. Comm'n*

12. In Decision No. C10-1328, the Commission discussed the due process arguments raised by parties over the course of these proceedings. ¶¶ 46-52. Specifically, the Commission discussed the Colorado Supreme Court case of *Public Service Co. of Colo. v. Colo. Pub. Utils. Comm'n*, 653 P.2d 1117 (Colo. 1982). In *Public Service*, the Colorado Supreme Court distinguished between procedural and statutory due process and went on to affirm the expedited procedures utilized by the Commission in an emergency rate proceeding. *Id.*

13. Peabody argues the Commission erred in relying on the reasoning of *Public Service* as support for the Commission's authority to "conform its procedures to the exigencies of the case before it." *Id.* at 1122. Peabody argues *Public Service* is inapplicable here, because the factual circumstances are distinguishable. In support of this contention, Peabody makes three arguments: (1) *Public Service* concerned an emergency rate proceeding, whereas this evidentiary hearing was mandated by a special purpose statute with a specific timetable, which is more significant and permanent than a rate proceeding, because rates may be subject to refund; (2) the

[1] Chairman Binz would have granted the Motion and considered CIEA's Application for RRR.

[2] Dismissal of the proceeding is the only specific form of relief requested by Peabody in its Application for RRR. The Applications for RRR filed by CMA and AGNC, jointly, and ACCE do not request any specific relief other than the granting of RRR. We presume that these parties seek reconsideration of the Commission's findings in favor of their arguments related to all components of the approved emission reduction plan except for emission controls on units that will continue to operate on coal.

hearing the Commission conducted was not "substantively complete and fair to all parties;" and (3) there are no emergency circumstances similar to those that existed in *Public Service* that would justify the procedural limitations that existed in this case. Peabody RRR, at 5-7. ACCCE and AGNC/CMA present a similar argument. ACCCE RRR, at 6-7; AGNC/CMA RRR, at 6-7.

14. Peabody, ACCCE, and AGNC/CMA are correct that there are factual differences between the HB 10-1365 proceedings and those of an emergency rate proceeding. However, *Public Service* stands for the principle, similarly applicable in all factual circumstances, that "[p]articipatory values are better served by allowing the commission to conform its procedures to the exigencies of the case before it." 653 P.2d at 1122.

15. The Commission agrees that this proceeding is distinguishable from an emergency rate proceeding. However, we disagree that, since we may not apply the exact procedural mechanisms utilized in that emergency rate proceeding, there may be no crafting of procedures. The Commission therefore will not dismiss these proceedings for improper reliance on *Public Service*. As such, RRR on this issue is denied.

2. Commission Authority to Modify the Plan

16. In Decision No. C10-1328, the Commission discussed its authority to modify any proffered plan, as provided by § 40-3.2-205(2), C.R.S. *See, e.g.*, ¶¶ 14, 160.

17. Peabody argues that the Commission overstates its authority to modify the Company's plan. Peabody reasons that "[i]f the Commission had the authority and all it needed to modify the August 13 plan when it was filed, there would have been no need for additional multiple rounds of testimony." Peabody RRR, at 8. Peabody concludes that "the Commission's discretion to modify is bounded by the Plan as timely submitted by August 15." *Id.*

18. The Commission disagrees. The language of § 40-3.2-205(2), C.R.S., is plain and clear. It states, "[t]he commission shall review the plan and enter an order approving, denying, or modifying the plan by December 15, 2010." *Id.* The only limitation on the Commission's authority to modify is that "[a]ny modifications required by the commission shall result in a plan that the [CDPHE] determines is likely to meet current and reasonably foreseeable federal and state clean air act requirements." *Id.* This provision of the statute indicates that, where the General Assembly intended to place limitations on the Commission's authority to modify the plan, *it explicitly did so*. It is inappropriate and contrary to canons of statutory interpretation to impose additional limitations on the Commission's authority to modify the plan in a way that conflicts with the statute's plain language.

19. Further, adopting Peabody's reasoning would lead to the untenable result of rendering the evidentiary hearing meaningless. If, as Peabody contends, the Commission's discretion to modify the plan is bounded by the August 13, 2010 filing, the Commission would effectively have been precluded from considering any of the intervenor-presented alternative scenarios introduced after August 15, 2010. Such an evidentiary procedure would have unfairly limited the rights of intervenor parties.

20. For these reasons, the Commission declines to dismiss these proceedings on the basis that the Commission overstated its authority to modify the plan. Therefore, RRR on this issue will be denied.

3. Discovery Irregularities

21. The Commission addressed discovery disputes occurring in these proceedings in Decision No. C10-1328, at ¶¶ 241-42. This was in addition to Decision No. C10-1282, issued November 24, 2010, which specifically addressed the discovery disputes and their resolution.

22. Peabody contends due process violations occurred as a result of discovery irregularities. Peabody states, "the withholding of information and the Commission's failure to respond to the withholding in anything but the most superficial terms is evidence of bias inherent in this proceeding." Peabody RRR, at 9-10.

23. The Commission undertook significant consideration of the alleged discovery irregularities and, after reviewing all of the relevant material, found the delay in producing that material did not necessitate additional hearings or dismissal of these proceedings. Decision No. C10-1282. The Commission strongly rejects Peabody's characterization of our consideration of this issue as "superficial," and finds dismissal of these proceedings on this basis is unwarranted. RRR on this issue therefore will be denied.

4. Procedural Schedule

24. ACCCE and AGNC/CMA argue the procedural schedule adopted by the Commission violated their constitutional procedural due process rights. ACCCE RRR, at 3-4; AGNC/CMA RRR, at 6. ACCCE and AGNC/CMA, in identical footnotes, both state they have "consistently asserted the legally-cognizable interest at stake" for each of their respective associations, but they do not explain what those interests are, or how they trigger the constitutional protections that ensure no deprivation of life, liberty, or property without due process of law. ACCCE RRR, at 6, n.4; AGNC/CMA RRR, at 8, n.6.

25. Because neither ACCCE nor AGNC/CMA has articulated a liberty or property interest at stake in this proceeding, they have not demonstrated the applicability of constitutional procedural due process standards. Rather, they are entitled to statutory due process, which the Commission finds has been afforded in this case. Therefore, the Commission finds it would be

inappropriate to dismiss these proceedings based on a violation of procedural due process. RRR on this issue will be denied.

5. Sufficiency of Additional Procedures

26. Public Service filed supplemental direct testimony on October 25, 2010. *See* Decision Nos. C10-1135, issued October 22, 2010, and C10-1193 issued November 4, 2010. ACCCE states the additional procedures the Commission adopted after the supplemental direct testimony were insufficient because parties were not afforded time necessary to conduct a detailed review of the new scenarios, to verify the Strategist® modeling runs for the new plans, or to conduct discovery. ACCCE RRR, at 6. However, ACCCE does not articulate how it would have better been able to present its case if it were afforded additional time.

27. The Commission satisfied and exceeded minimum standards of statutory due process. The Commission is required to "conduct its proceedings in such manner as will best conduce the proper dispatch of business and the ends of justice." § 40-6-101(1), C.R.S. To evaluate the Company's emission reduction plan, the Commission was required to conduct an evidentiary hearing, § 40-3.2-204(2)(b)(IV), C.R.S., at which it was required to permit all intervenors "to be heard, examine and cross-examine witnesses, and introduce evidence," § 40-6-109(1), C.R.S. The Commission does not believe the procedures utilized here were so restrictive as to violate ACCCE's statutory due process rights. *See* Decision Nos. C10-1265, issued November 23, 2010 at ¶¶ 26-32, and C10-1328, at ¶¶ 46-52 (describing the applicable standards of statutory due process); *see also Public Service*, 653 P.2d at 1120-21 (distinguishing between procedural due process and statutory due process). ACCCE was permitted an opportunity to heard, and was allowed to introduce written testimony and other evidence, s*ee,*

e.g., Ross Answer Testimony (Hearing Exhibit 62), as well as to cross-examine witnesses.[3] Because the procedures crafted by the Commission satisfied all relevant statutory due process requirements, RRR on this issue will be denied.

6. Effect of Supplemental Direct Testimony

28. ACCCE and AGNC/CMA claim that Public Service failed to satisfy the August 15, 2010 filing deadline established by § 40-3.2-204(1), C.R.S., because it filed supplemental direct testimony on October 25, 2010 and parties were not afforded sufficient time to respond to that testimony in a meaningful way. ACCCE RRR, at 4-5; AGNC/CMA RRR, at 4-5. ACCCE implies that no modifications or new alternatives should have been considered by the Commission after August 15, 2010 because that date was specifically chosen in order to provide the minimum amount of process necessary.

29. Again, the Commission believes the parties were in fact offered sufficient time to satisfy all applicable due process standards. ACCCE states, in a conclusory manner, that it was not afforded sufficient time to participate in a meaningful way. ACCCE RRR, at 5. AGNC/CMA rhetorically asks why, if the supplemental direct testimony was only a modification to existing scenarios, additional discovery, testimony, and hearing days were undertaken. AGNC/CMA RRR, at 5. Besides these very surface level representations, neither party introduces any new arguments with regard to this issue. The Commission therefore will deny RRR on this issue.

[3] Although ACCCE was afforded an opportunity to cross-examine any and all witnesses in this proceeding, it did not avail itself of that opportunity.

7. Satisfaction of the August 15, 2010 Filing Deadline

30. AGNC/CMA argue the Company's August 13, 2010 filing contained a single "plan" for which approval was sought: scenario 6.1E. AGNC/CMA RRR, at 5. AGNC/CMA argue the Company's supplemental direct testimony filed on October 25, 2010 contained "new plans" that were therefore untimely filed. *Id.* AGNC/CMA further contend the late filing of these additional scenarios deprived intervenors of sufficient time to engage in a meaningful review. *Id.*

31. The Commission considered these arguments in Decision No. C10-1265 and again in Decision No. C10-1328. The August 13, 2010 filing contained a number of scenarios that remained viable even after the Commission rejected the Company's original preferred scenario, 6.1E, because that scenario was determined to be inconsistent with the statutory requirements that the plan be fully implemented by December 31, 2017. AGNC/CMA present no new arguments as to why the August 15, 2010 deadline was not satisfied. The Commission therefore will deny RRR on this issue.

8. Access to the Long-Term Gas Contract

32. ACCCE and AGNC/CMA both argue the Commission violated the due process rights of coal interests by denying them access to the long-term gas contract between Public Service and Anadarko Energy Services Company. ACCCE RRR, at 8-10; AGNC/CMA RRR, at 7-10. ACCCE and AGNC/CMA both argue the Commission should have allowed coal intervenors *in camera* access by consultants and counsel, with no employees receiving access. *Id.*

33. We considered and rejected all of the arguments raised by ACCCE and AGNC/CMA in previous Decision Nos. C10-0957 issued August 30, 2010 and C10-1009 issued

September 13, 2010. Because ACCCE and AGNC/CMA present no new arguments on this issue, RRR on this issue will be denied.

D. Considerations in Evaluating the Plan

1. Cost of Fuel and Reasonably Foreseeable Emission Regulation

34. Peabody argues in its Application for RRR that the Commission ignored the evidence in this Docket that shows the approved emission reduction plan to be an inefficient, expensive, and unreliable solution for meeting reasonable foreseeable emission reduction requirements. Peabody RRR, at 15. Along these lines, Peabody argues that because the Commission made no assumptions about future natural gas prices and future costs of emissions, it could not reach any determination on the reasonableness of the potential costs of implementing the approved plan. *Id.*

35. For example, with respect to projected natural gas costs, Peabody argues that the Commission ignored substantial evidence that Public Service understated its gas transportation costs. Peabody further argues that the Commission failed to explicitly correct how the Company quantified expected savings from the long-term gas contract in the approved scenario vis-à-vis other scenarios including the all controls scenario (Benchmark 1.0). *Id.* at 16-17.

36. With respect to emissions costs, Peabody argues that the Commission erred by not using a cost of $0/ton for carbon emissions. Peabody further argues that the Commission failed to recognize the costs associated with other reasonably foreseeable emission regulations. Peabody alleges that the Commission considered only the Strategist® model runs including a cost of carbon of $20/ton. *Id.* at 17-18.

37. For these reasons, and others, Peabody asks the Commission to dismiss the proceeding. *Id.* at 21.

38. AGNC/CMA and ACCCE similarly argue that the Commission should have used different carbon prices and natural gas prices than what Public Service used in Strategist®. They argue that the cost information used by Public Service in its analyses is so flawed that it fails to satisfy the Company's obligations under HB 10-1365. AGNC/CMA RRR, at 15-17; ACCCE RRR, at 14-18.

39. AGNC/CMA and ACCCE allege that the Commission considered only Public Service's base case modeled costs, ignoring the Strategist® model runs in which alternative assumptions were used. They further imply that the Commission should have used more precise measures for fuel costs and emissions costs and been more specific regarding the Strategist® model outputs that are based on those other cost inputs. In sum, AGNC/CMA and ACCCE argue the Commission's conclusion that the approved emission reduction plan is less expensive than an all controls option is without merit. *Id.*

40. We deny RRR on these matters. Contrary to the allegations, the Commission carefully considered a range of potential fuel costs and emission costs based on the material evidence in the record. Moreover, HB 10-1365 requires the Commission to look decades into the future and, lacking a crystal ball, we must make judgment calls regarding different possible futures based on that evidence.

41. The Commission therefore rejected a formulaic approach to considering these costs that might have locked down single cost estimates for the future. Instead we considered a range of potential costs as well as the risk that these factors may deviate from base case projections. Using this approach, we identified the scenarios that appear to be robust in producing the required emission reductions at the best cost and least risk over the life of the projects included in the plan. We also sought scenarios that would result in a reasonable impact

on rates in the near term. In other words, we attempted to ascertain which scenario would perform best across a variety of plausible futures.

42. Ms. Glustrom requests that the Commission modify ¶ 86 of Decision No. C10-1328 to state that the coal price forecasts that Public Service used in its 2007 Electric Resource Plan (ERP) was incorrect. Glustrom RRR, at 27. Ms. Glustrom also requests that the Commission add an ordering paragraph to the Decision requiring Public Service to undertake "mine-specific analysis" of coal costs and supply issues for each of its coal-fired generation units, such that these studies are submitted to the Commission at least six months prior to the applications for Certificates of Public Convenience and Necessity (CPCNs) for controls at the Pawnee and Hayden facilities. *Id.* at 28.

43. We deny RRR on these matters. First, we find no need for the Commission to enter a finding in this Docket on the coal price forecast the Company used in Docket No. 07A-447E. Second, we find an assessment of future coal costs for Pawnee and Hayden is not required for the CPCN applications for emission controls on these plants. Paragraph 88 of Decision No. C10-1328 accurately describes how we addressed coal price forecasts in consideration of the proposed controls in the Company's emission reduction plan. We were well aware of Ms. Glustrom's views on future coal costs and supplies and fully considered her positions in reaching our decision to approve controls for Pawnee and Hayden.

2. Projected Costs and Rate Impacts

44. Peabody argues that the Commission cannot simultaneously conclude that certain information provided by the Company is sufficient for determining whether the costs of an emission reduction plan result in reasonable rate impacts while acknowledging that same cost

information is insufficient for purposes of ratemaking or the issuance of CPCNs. Peabody RRR, at 18-19. Peabody seeks that we dismiss the case on this basis.

45. We deny Peabody's request. We find that the record in this proceeding provides sufficient cost information for the Commission to make the determinations regarding future costs and rate impacts as required under HB 10-1365.

46. The type and quality of cost information the Commission considered in this Docket is akin to the data we consider when reviewing, modifying, and approving utility ERPs as well as utility plans for compliance with Colorado's Renewable Energy Standard (RES). Such information, including preliminary and generic cost estimates for new utility resources and modeled revenue requirements from Strategist®, is sufficient for comparing the relative cost profiles of various scenarios and for testing their sensitivities to changed assumptions. In the context of ERPs and RES compliance plans, we rely upon such information to reach findings regarding a reasonable course of action into the future (*i.e.*, a plan).

47. However, the Commission does not generally rely on that same source and type of information when it considers an application for a CPCN or approves utility rates. In those circumstances, we depend on more detailed and updated cost information based either on historic accounts and records or on near-term budgets and financial forecasts.

48. When the Commission considers competing resource portfolios, whether in the ERP or RES context, it is not feasible for the utility to negotiate the details of every potential project in each possible scenario in order to compare plans. Consistent cost estimates across the scenarios are sufficient for the purpose of comparing the portfolios to each other. On the other hand, when setting rates or issuing CPCNs, it is feasible and, in fact, it is our duty to require the utility to prepare more careful cost estimates that will be used to set consumer rates. At the

CPCN or the rate making stage, the focus has shifted to a single, well-defined generating plant or portfolio of assets. Therefore, we conclude it is entirely appropriate and consistent with our resource planning practices to approve utility plans based on cost information that is less refined and more uncertain than the cost information we use for other regulatory purposes, such as for the issuance of CPCNs or for the establishment of rates and charges.

3. Preservation of Reliable Electric Service

49. Peabody argues the Commission failed to meet the requirement in § 40-3.2-205(1)(g), C.R.S., that the emission reduction plan preserve the reliability of the Company's system. In support of its contention, Peabody points to the Company's concerns about the required sequencing of actions at the Cherokee site under the approved emission reduction plan as set forth in Public Service's Request for Clarification of Decision No. C10-1328 filed on December 17, 2010. Peabody also cites the Commission's requirement that Public Service submit a transmission study for the Denver-Boulder area as part of its next ERP filing. Peabody RRR, at 20.

50. We deny RRR on this point. Decision No. C10-1328 makes clear that we considered the potential reliability impacts of the approved emission reduction plan on the Company's system. In fact, the preservation of system reliability was a key factor in the determination of whether a plan was feasible, particularly with respect to the combinations of plant retirements and replacements. We also found that the approved plan would meet the service reliability criteria that Public Service proposed for Cherokee Station. The record further establishes that certain parties believe those reliability standards are especially cautious. *See e.g.*, Answer Testimony of Jeffrey Palermo (Hearing Exhibit 93); Answer Testimony of Keith Malmedal (Hearing Exhibit 106).

4. Identification of Associated Costs

51. Public Service acknowledges that the capital cost estimates for proposed emission controls projects or for new replacement generation as cited throughout Decision No. C10-1328 were derived from the testimony of the Company's witness Gregory Ford. The Company requests, however, that the Commission acknowledge in the Decision that these cost estimates are in 2010 dollars and exclude adjustments for the allowance of funds used during construction (Allowance for Funds Used During Construction (AFUDC)) or for "escalation to the time of expenditure." Public Service RRR, at 23-24.

52. We deny RRR on this matter. The Commission recognized that Mr. Ford's cost estimates were "overnight construction" estimates that were not seasoned enough for establishing revenue requirements for ratemaking purposes. Moreover, in reaching our findings regarding the approved emission reduction plan, we considered the revenue requirements of capital costs produced by Strategist®. It is our understanding that those revenue requirements account for the impacts that might not have been explicitly identified in Mr. Ford's testimony.

5. Economic Impacts

53. AGNC/CMA and ACCCE argue that there is substantial evidence in the record of the harm plant retirements and fuel conversion will cause to certain coal producing communities in Colorado. They further contend that Public Service's assumption that other demand for coal will replace the reduction in the Company's coal usage is pure speculation. AGNC/CMA and ACCCE also argue that an investigation into the potential funding of coal worker retraining is no substitute for meeting the Commission's obligations under HB 10-1365. In sum, they posit that the Commission erred in finding that the emission reduction plan will result in an overall positive net impact for Colorado. AGNC/CMA RRR, at 12-14; ACCCE RRR, at 11-14.

54. We decline to modify our finding in Decision No. C10-1328 that the overall economic impacts of the approved emission reduction plan will be positive for Colorado. As indicated in the Decision, our finding rests on the evidence in the record that the plan will result in construction related jobs as well as gas-industry jobs. The Decision also explains that by adopting a coordinated approach to emission reductions, Colorado will be at a competitive advantage vis-à-vis other states that address environmental requirements in a less cost effective manner.

55. As indicated at ¶ 245 of the Decision, we are concerned about the potential for job losses in the Colorado mining communities if sales of Colorado coal into other markets do not offset the sales that will decline as a result of plant retirements and fuel conversion. However, we reiterate our finding that the uncertainty surrounding future market demands for Colorado coal renders ambiguous the projected net economic impact of the approved plan on the state's mining communities at this time.

E. Plan Modifications and Approvals

1. Cherokee 1 and 2

56. Public Service suggests that the Commission may have overlooked the necessary sequencing of activities for the retirement of Cherokee 1 as set forth in the Company's testimony. The Company therefore seeks in its Application for RRR some flexibility in the retirement schedule and proposes an alternate retirement date for Cherokee 1. Public Service RRR, at 16-17.

57. Under the Company's proposed sequencing, Cherokee 2 would be retired no later than December 31, 2011 and Cherokee 1 would be retired no later than July 1, 2012. Public

Service states that these dates provide the Company with the flexibility needed to preserve system reliability.[4] *Id.*

58. We grant Public Service's request and modify the retirement dates. Cherokee 2 shall be retired no later than December 31, 2011, and Cherokee 1 shall be retired no later than July 1, 2012. This change to Decision No. C10-1328 is reasonable in that it provides the Company with some flexibility to ensure the successful conversion of Cherokee 2 into a synchronous condenser for providing dynamic VAR support.

59. Ms. Glustrom argues in her Application for RRR that the Commission has not devoted enough attention to the reasons why the Company's system needs dynamic reactive power support such as would be provided by Cherokee 2 when converted into a synchronous condenser. Ms. Glustrom requests that the Commission order Public Service to conduct an assessment of the causes of dynamic reactive power needs to ensure that customer loads with low power factors are not unduly subsidized by general ratepayers. Glustrom RRR, at 26-27.

60. Ms. Glustrom further suggests that the Commission include an ordering paragraph to Decision No. C10-1328 requiring Public Service to undertake a study into VAR support needs on the Company's system. The study would address possible corrections for reactive power needs on the customer side of the meter and would include a review of how other state regulators address reactive power in ratemaking. This suggested study would be due at least three months before the Company's next base rate proceeding. *Id.* at 30.

61. We find that the record in this proceeding does not support Ms. Glustrom's request and therefore deny RRR on this matter. It is our general understanding that reactive

[4] Public Service explains that the proposed retirement dates for Cherokee 1 and 2 are consistent with the dates in the Statement Implemental Plan (SIP) for regional haze adopted by the Air Quality Control Commission (AQCC).

power is required by the Company's transmission and distribution system and that customer power factors are well monitored and kept to a minimum by existing interconnection requirements. Therefore, we will not require Public Service to undertake a study into system reactive power needs along the lines suggested by Ms. Glustrom.

2. Cherokee 3

62. Public Service argues that by ordering the retirement of Cherokee 3 no later than December 31, 2015, the Commission will not afford Public Service the flexibility it needs to accommodate possible construction delays in the building of the natural gas-fired 2X1 CC replacement capacity or to address other "issues with early testing or tuning of the unit." The Company suggests that the Commission state in the Decision that Cherokee 3 shall be retired after the 2X1 CC is on-line and operating reliably, but in no case later than December 31, 2016.[5] Public Service RRR, at 17-18.

63. In reaching our decision to retire Cherokee 3 by the end of 2015, we relied upon the evidence provided by Public Service regarding the feasibility of that deadline. We also recognized the emission reduction benefits of retiring Cherokee 3 in 2015 as opposed to 2017.

64. We also understand Public Service's request for flexibility and conclude that affording the Company up to 12 additional months will help the Company ensure system reliability as the new natural gas plant comes online. We therefore grant Public Service's RRR on this matter and approve retirement of Cherokee 3 no later than December 31, 2016. However, we also encourage Public Service to strive to retire Cherokee 3 as close to December 31, 2015 as possible so the emissions profile of the approved plan remains consistent with that of

[5] Public Service explains that the proposed retirement date for Cherokee 3 is consistent with the date in the SIP for regional haze adopted by the AQCC.

scenario 6E FS. We therefore require Public Service to file notice in this Docket on or before July 1, 2015 indicating when the Company expects Cherokee 3 to cease operations.

3. Arapahoe 3 and 4

65. Ms. Glustrom makes the same arguments regarding the conversion of Arapahoe 3 into a synchronous condenser as she does for Cherokee 2. Glustrom RRR, at 30.

66. Consistent with our findings regarding Cherokee 2 above, we deny RRR on this matter. There is insufficient evidence in the record to support a finding that a study of dynamic reactive power needs is required before the filing of the Company's 2011 ERP.

67. Public Service states that Decision No. C10-1328 is unclear as to whether the Company is authorized to fuel switch Arapahoe 4 by the end of 2013 or if the Commission instead intends for the unit to operate on coal through 2014. Public Service RRR, at 18.

68. We clarify Decision No. C10-1328 by finding now that Arapahoe 4 shall no longer burn coal after December 31, 2013. The Company may begin using natural gas as the primary fuel at Arapahoe 4 before December 31, 2013, provided that the Company prudently manages the winding down of its coal transportation agreement at Arapahoe Station.

4. Valmont 5

69. In her application for RRR, Ms. Glustrom requests that the Commission explore additional options for the Valmont plant as part of Public Service's 2011 ERP proceeding. These options would include fuel conversion to natural gas prior to its approved retirement in 2017 or earlier retirement with or without fuel conversion. Ms. Glustrom argues such options received insufficient consideration during this proceeding. She further notes that Public Service may be in a position of having excess generation capacity on its system during some of the years when Valmont would continue to operate on coal. As a consequence of this excess capacity, she

contends that retirement or conversion of Valmont before 2017 may be a reasonable option. Glustrom RRR, at 25-26.

70. Accordingly, Ms. Glustrom requests that the Commission modify ¶ 119 of Decision No. C10-1328 to require Public Service to study alternatives for Valmont 5 in the Company's 2011 ERP filing such as earlier retirement or fuel switching before 2017. She also provides similar recommended language to the ordering paragraphs concerning Valmont. *Id.* at 28.

71. The Commission denies RRR on this matter. We were well-informed of Ms. Glustrom's recommendations for Valmont 5 when we reached our findings in Decision No. C10-1328. Ms. Glustrom makes no new argument in her Application for RRR on this issue.

5. Pawnee

72. Ms. Glustrom argues that the Commission should conduct more analysis of the costs and risks associated with the continued operation of Pawnee on coal. She argues that there was almost no testimony or analysis in the record regarding alternative options for Pawnee. She further disputes that ratepayers will experience savings from the continued operation of Pawnee on coal versus retirement for emission reduction purposes. She argues that rather than investing in Pawnee, the Company should instead invest in more renewable energy to drive system costs down. *Id.* at 20.

73. Consistent with Ms. Glustrom's testimony on the risk of much higher than expected coal costs, she posits that burning coal at Pawnee could add several hundred million dollars (if not billions) of costs to the future revenue requirements. For instance, she raises concerns about the environmental and cost impacts associated with the Eagle Butte Mine that supplies coal to Pawnee and similar concerns about potential replacement sources of coal if that

mine is closed. Ms. Glustrom also repeats her arguments in favor of using the pattern of significant coal price increases in recent years as a predictor of future coal price increases. She further raises general concerns about Public Service's ability to recover higher coal costs without risk through its Electric Commodity Adjustment rider and general concerns about carbon cost impacts on customer rates. *Id.*

74. Ms. Glustrom also argues that emission controls at Pawnee do not need to be part of the Commission's decision in this Docket, as consideration of this plant's emissions is not mandatory under HB 10-1365. *Id.*

75. Ms. Glustrom suggests additional language for ¶ 150 of Decision No. C10-1328 regarding the CPCN filing requirement for the controls at Pawnee. These changes would require Public Service to demonstrate that a reasonably priced supply of coal will be available for the plant and that continued operations of the plant with emissions controls is the "best alternative" as amounts of efficiency and renewable energy on the Company's system increase in the coming decades. Her suggested additional language would also require a "mine-specific analysis" of future coal supplies for the plant. *Id.* at 27-30.

76. The Commission denies RRR on this matter. When approving emission controls for Pawnee, the Commission considered both the economics associated with the continued use of coal at Pawnee and the overall fuel mix of Public Service's system resulting from this proceeding. In reaching our findings, we fully considered Ms. Glustrom's arguments regarding future coal costs and future coal supplies. We further conclude no additional studies regarding coal prices, coal supplies, or Pawnee's operations are necessary in any CPCN proceeding related to the emission controls.

77. We further note that the record in this Docket indicates all of the scenarios assessed by the Colorado Department of Health and Environment (CDPHE) include emission controls on Pawnee. The controls proposed for Pawnee are also identical to those that would be expected for the plant under a BART determination in the State Implementation Plan (SIP). Ms. Glustrom provides no new argument why the controls should not be part of the Company's coordinated approach for emission reduction. We therefore decline to modify Decision No. C10-1328, which approves controls at Pawnee as part of the Company's emission reduction plan under HB 10-1365.

6. Hayden

78. Ms. Glustrom posits the same types of arguments regarding the Commission's approval of emission controls at Hayden as for its approval of controls at Pawnee. *Id.* at 20-24. That is, she requests that the Commission require Public Service to demonstrate as part of the CPCN application for the controls at Hayden that a reasonably priced supply of coal would be available for the plant and that continued operations of the plant is the "best alternative." *Id.* at 27-30.

79. We deny RRR on this point consistent with our discussion above regarding Pawnee. We likewise conclude no additional studies regarding coal prices, coal supplies, or the units' operations are necessary in any CPCN proceeding related to emission controls at Hayden.

80. In addition, we note that Public Service does not fully own Hayden 1 and 2. Public Service explains in its Statement of Position (SOP) that the other owners of the Hayden plant did not agree with the Company concerning the appropriate BART determinations for the units. Given that there was no agreement on BART controls among the owners, we find that it is highly unlikely that other options for these units could have practically been considered in the

Company's BART Alternative Program. Although the SIP addresses Hayden outside of the Company's BART Alternative Program, we uphold our decision to include controls at Hayden in the Company's approved emission reduction plan under HB 10-1365, primarily because they are consistent with a coordinated approach to emissions reduction as contemplated by the statute.

81. In its Application for RRR, Public Service seeks explicit Commission approval of the installation of sorbent injection controls for mercury emissions at Hayden 1 and 2.

82. We correct this oversight and grant Public Service's request by modifying Decision No. C10-1328 to approve the sorbent injection controls at Hayden as part of its emission reduction plan.

7. Cherokee 4

83. Public Service argues the Commission found the "three-source principle must be observed at Cherokee" in Decision No. C10-1328. Public Service RRR, at 19. The Company requests that the Decision be further modified to state any change to running Cherokee 4 on natural gas, such as early plant retirement after 2017, also be required to meet the "three-source principle." *Id.*

84. We decline to modify Decision No. C10-1328 as requested by Public Service. The Commission recognized the centrality of Cherokee Station in the Company's transmission system serving the Denver-Metro area. The Decision thus acknowledges that the Company supported the "three source principle" for ensuring system reliability and explains that the approved plan satisfies the Company's standard for the Cherokee site. Decision No. C10-1328 does not include a finding that the "three source principle" is the minimum or optimal reliability standard for Cherokee Station. Rather, we are interested in learning more about alternative transmission system configurations, plant designs, and operational practices that also preserve

system reliability and have accordingly required the Company to complete a transmission study for the Denver-Metro area in ¶¶ 234-36 of the Decision.

85. Peabody argues the Commission violated a requirement of HB 10-1365 that an emission reduction plan approved by the Commission must avoid a "piecemeal approach." Specifically, Peabody argues that the Commission's intent to reexamine the fuel-switching at Cherokee 4 amounts to the undertaking of "further actions" in the long term in violation of the requirement that the plan be fully implemented by December 31, 2017. Peabody RRR, at 13-15.

86. We deny RRR on this point. Pursuant to the approved emissions reduction plan, fuel conversion at Cherokee 4 will be fully implemented by December 31, 2017 and will enable the unit to meet reasonably foreseeable emission reduction requirements consistent with HB 10-1365. We reiterate our finding that fuel switching at Cherokee 4 is the appropriate action for a coordinated approach to emission reduction consistent with HB 10-1365.

87. Contrary to Peabody's assertions, ¶ 135 of Decision No. C10-1328 does not run counter to a coordinated emission reduction approach. Rather, we recognize that fuel switching offers flexibility to address changed circumstances in the future. HB 10-1365 does not preclude the Commission from approving additional actions at Cherokee 4, particularly if the same or more emission reductions can be achieved at a reasonable cost.

F. Future Filing Requirements

1. Applications to Modify CPCNs for Early Retirement

88. Public Service requests that the Commission clarify the filing deadlines for the applications containing cost information for the approved plant retirements. Public Service recognizes that the Commission intends for these filings to be submitted sufficiently in advance of rate case filings. To remove any ambiguity as to when these filings should be made, however,

the Company requests that the Decision clarify that the filings are required "at least three months before the Company files the base rate case in which it will seek to recover the retirement costs." Public Service RRR, at 20-22.

89. Public Service is correct concerning our intent to review plant closure and decommissioning costs in advance of the relevant rate cases. We therefore grant Public Service's request and modify Decision No. C10-1328 so that the application filings associated with plant retirements are submitted at least three months before the Company files the base rate case in which it will seek to recover the retirement costs.

2. CPCNs for Emission Controls at Pawnee and Hayden

90. Public Service wants the Commission to reverse its decision requiring applications for CPCNs for the planned emission controls at Hayden and Pawnee. Public Service argues that the Commission should instead follow its rules and accept the proposed pollution control installations at Hayden and Pawnee to be in the ordinary course of business and thereby exempt them from a CPCN filing requirement. Public Service argues that the Commission has already found these projects to be in the public interest and the Commission can otherwise review the associated costs through different means, including the filing of a report, Staff audit, or a rate case proceeding. *Id.* at 22-23.

91. We deny Public Service's request on this issue. We find that the CPCN application proceedings contemplated by Decision No. C10-1328 are the best process for addressing the costs and other details of the projects at Pawnee and Hayden. We further note that these CPCN proceedings should not be lengthy affairs, given that the controls are included in the approved emission reduction plan and therefore the need for these controls has already been established.

3. Propriety of Cost Caps

92. In ¶ 151 of Decision No. C10-1328, the Commission states, "we expect that the applications for CPCNs required by this Decision will allow us to consider the establishment of a not-to-exceed maximum level of expenditures for these projects."

93. Public Service argues it is inappropriate for the Commission to even consider the future imposition of cost caps associated with implementation of the plan because § 40-3.2-205(3), C.R.S., precludes the Commission from capping the prudently incurred costs associated with implementing the approved plan. The Company therefore requests that the Commission remove the language from the decision that suggests "an artificial limit" can be set on the recovery of prudently-incurred costs in future CPCN proceedings related to plan implementation. Public Service RRR, at 14.

94. Section 40-3.2-205(3), C.R.S., states, "[a]ll actions taken by the utility in furtherance of, and in compliance with, an approved plan are presumed to be prudent actions, the costs of which are recoverable in rates as provided in section 40-3.2-207." Section 40-3.2-207(1)(a), C.R.S., goes on to state,

> A utility is entitled to fully recover the costs that it prudently incurs in executing an approved emission reduction plan, including the costs of planning, developing, constructing, operating, and maintaining any emission control or replacement capacity constructed pursuant to the plan, as well as any interim air quality emission control costs the utility incurs while the plan is being implemented.

In other words, § 40-3.2-205(3), C.R.S., creates a presumption of prudence, but § 40-3.2-207(1)(a), C.R.S., establishes that the presumption is rebuttable and, if successfully challenged, costs may not be recovered. Public Service acknowledges as much, but still believes it would violate § 40-3.2-205(3), C.R.S., to establish cost caps, whether hard or soft, for those actions undertaken to implement the approved plan.

95. The Commission does not believe HB 10-1365 prohibits the imposition of cost caps, and therefore will deny RRR on this issue. Reading §§ 40-3.2-205(3) and 40-3.2-207(1)(a), C.R.S., together indicates that HB 10-1365 allows full recovery of costs prudently incurred in implementing the approved plan. However, this not is synonymous with a prohibition against cost caps. At most, it addresses the permissible strength of those caps.

96. Decision No. C10-1328 does not state cost caps will be imposed, nor that they will be prohibitively hard. Rather, it states the Commission will "consider the establishment" of such caps in the future. The mere consideration of this issue in a future docket does not violate HB 10-1365. Therefore, RRR on this issue will be denied.

G. Satisfaction of Requirements Related to the CDPHE

97. Peabody, ACCCE and AGNC/CMA argue the Decision does not adequately address what they characterize as the CDPHE's failure to meet its obligations.

1. Consultations Pursuant to § 40-3.2-204(2)(b)(I), C.R.S.

98. Peabody contends the CDPHE did not consult with the Company as required by § 40-3.2-204(2)(b)(I), C.R.S. Peabody states "[t]here is no evidence in the record that such consultations took place or, if they took place, were anything more than superficial." Peabody RRR, at 10.

99. There are numerous representations in the record that such consultations occurred. *See, e.g.*, Public Service August 13, 2010 filing (Hearing Exhibit 2), at 25-26 (describing consultations with the CDPHE undertaken during plan development); Tourangeau Direct Testimony (Hearing Exhibit 33), at 2 (stating personal involvement in consultations with the

Company). The Commission believes Peabody has misrepresented the record and that dismissal of these proceedings on this basis is unwarranted. RRR on this issue will therefore be denied.

2. Sufficiency of CDPHE Findings

a. § 40-3.2-204(2)(b)(IV), C.R.S.

100. Peabody also argues the CDPHE did not make a finding that the plan is consistent with current and reasonably foreseeable emission reduction requirements as required by § 40-3.2-204(2)(b)(IV), C.R.S.

101. The CDPHE made a finding that scenario 6E FS, which is nearly identical to the approved plan from an air quality standpoint, is consistent with reasonably foreseeable emission reduction requirements. CDPHE SOP, at 12. *See also* Tourangeau Supplemental Testimony (Hearing Exhibit 200), at 4. Peabody acknowledges the CDPHE made this finding, but contends the Commission could not rely on the CDPHE's testimony regarding nearly identical emission reductions. Peabody RRR, at 11-12. Peabody implies that, by relying on the CDPHE's testimony concerning scenario 6E FS, the Commission improperly substituted its judgment for that of the CDPHE. Peabody RRR, at 12.

102. To accept Peabody's argument would lead to the unreasonable conclusion that the Commission's authority to modify the Company's plan is limited to approving only those specific scenarios which the CDPHE explicitly approved, even if the CDPHE testified the emissions reductions achieved by the modified plan would satisfy the statutory reductions. The Commission finds this is an attempt to impose artificial limitations on the Commission's authority to modify the Company's plan, as established in § 40-3.2-205(2), C.R.S. There is no question as to whether the CDPHE believes the approved plan is sufficient from an air quality standpoint. The CDPHE testified that the type of emissions reductions achieved by the approved

plan satisfy current and reasonably foreseeable emission reduction requirements. *See* Hearing Exhibit 200, at 4. In addition, the CDPHE, through the AQCC, has conducted its HB 10-1365 proceedings and integrated the plan into the SIP.

103. The Commission finds the CDPHE did determine the emissions reductions effectuated by the plan are sufficient, in accordance with § 40-3.2-204(2)(b)(IV), C.R.S. Further, we properly undertook consideration of this determination as one of the § 40-3.2-205(1), C.R.S., factors. Therefore, we believe dismissal of these proceedings is unwarranted and will deny RRR on this issue.

b. § 40-3.2-205(2), C.R.S.

104. Section 40-3.2-205(2), C.R.S., provides, "[a]ny modifications required by the commission shall result in a plan that the [CDPHE] determines is likely to meet current and reasonably foreseeable federal and state clean air act requirements."

105. The CDPHE stated that the earlier units are shut down or repowered, the better the plan is from an air quality perspective. Tr. Oct. 26, 2010, at 221 (testimony by Mr. Tourangeau agreeing that "if there is any other scenario other than 6.1E, that would achieve greater emissions reductions and in a more quick fashion, the department would not object to that as a possible scenario that could be accepted by the [CDPHE]"); CDPHE SOP, at 12 ("the greater and timelier emission reductions that are provided in a plan, the more readily that scenario will meet current and reasonably foreseeable requirements"). The plan approved by the Commission achieves greater emissions reductions faster than scenario 6.1E. Therefore, according to the CDPHE's own testimony, the Commission's modifications will meet current and reasonably foreseeable federal and state clean air act requirements.

106. Peabody nonetheless argues the CDPHE failed to make its § 40-3.2-205(2), C.R.S., determination, because it did not specifically approve the modifications adopted by the Commission in Decision No. C10-1328 prior to its issuance. Again, Peabody contends the Commission is not permitted to rely on the CDPHE's testimony regarding what emission reduction levels are satisfactory and that the Commission improperly substituted its judgment for that of the CDPHE. Peabody RRR, at 11-12.

107. As explained above, the Commission believes Peabody's reasoning would place the Commission in an untenable position by prohibiting it from relying on reasoning presented by the CDPHE in modifying the plan. The CDPHE has not stated the modified plan, as approved by the Commission, fails to achieve the necessary emission reductions. Therefore, we believe dismissal of these proceedings on this basis is unwarranted and we will deny Peabody's RRR on this issue.

3. Considerations Required Under § 40-3.2-205(1), C.R.S.

108. Section 40-3.2-205(1), C.R.S., establishes nine factors the Commission must consider in evaluating the Company's plan. Peabody contends the Commission failed to adequately consider two of those factors.

a. § 40-3.2-205(1)(a), C.R.S.

109. Section 40-3.2-205(1)(a), C.R.S., requires the Commission to consider whether the CDPHE reports the plan is likely to achieve at least a 70 percent reduction in annual reductions in NOx emissions.

110. The CDPHE determined scenario 6E FS, which has an emissions profile nearly identical to the plan we approved, meets and exceeds the minimum standard for NOx reduction. Hearing Exhibit 200, at 2.

111. Peabody contends the CDPHE did not make the report, because the testimony presented in Hearing Exhibit 200 did not concern the exact plan we approved in Decision No. C10-1328. Peabody RRR, at 11-12. However, scenario 6E FS and the approved plan are nearly identical from an emission reduction standpoint. The Commission believes the requirements of § 40-3.2-205(1)(a), C.R.S., have been satisfied. As stated above, the Commission believes it may reasonably rely on the CDPHE's testimony regarding what types of activities will achieve sufficient emission reductions. Further, the Commission declines to interpret HB 10-1365 in a way that unnecessarily and unreasonably curtails its authority to modify any plan proffered by the Company. The Commission finds this argument does not warrant dismissal of these proceedings and, therefore, RRR on this issue will be denied.

b. § 40-3.2-205(1)(b), C.R.S.

112. Section 40-3.2-205(1)(b), C.R.S., requires the Commission to consider whether the CDPHE made a determination regarding the emissions rates of new or repowered facilities. This consideration is one of nine factors the Commission must consider in evaluating the plan. § 40-3.2-205(1), C.R.S.

113. In the Decision, we noted "the CDPHE does not seem to have made a specific finding as to the repowered units, Arapahoe 4 and Cherokee 4, which will be converted to run on natural gas. Nonetheless, this is only one factor among many the Commission must consider." Decision No. C10-1328, at ¶ 173.

114. Peabody contends the CDPHE's failure to make this determination and the Commission's failure to take the lack of findings into consideration is a clear error. Peabody RRR, at 11.

115. Contrary to Peabody's arguments, the Commission did consider whether the CDPHE made this determination, as required by § 40-3.2-205(1), C.R.S. Decision No. C10-1328, at ¶ 173. Section 40-3.2-205(1), C.R.S., lists nine factors the Commission must "consider." The Commission did consider the CDPHE's determination by reviewing the record, finding the appropriate information, taking that information into account, and appropriately weighing that information as one of nine factors for the Commission's overall analysis.

116. Section § 40-3.2-205(1), C.R.S., does not state, as Peabody suggests, that failure to satisfy any one of those nine factors will render the plan fatally flawed. To accept Peabody's reasoning would impose this kind of harsh requirement, ignoring the plain language of this statutory subsection. There are other instances where the General Assembly places strong, explicit requirements on an approved plan, showing that, where such strict requirements were intended, they were explicitly included. Peabody's interpretation is contrary to the plain meaning of the statute and, as a result, does not require dismissal of these proceedings. Therefore, RRR on this issue will be denied.

4. Role of the CDPHE Under HB 10-1365

117. Peabody argues the Commission has decided the CDPHE's determination of current and reasonably foreseeable requirements is not subject to challenge and the Commission has no authority to review that determination. Peabody RRR, at 12. Peabody states that the Commission's decision is erroneous and, as a result, "parties in this proceeding have no recourse to address, to question or otherwise to challenge the CDPHE's reasonably foreseeable determinations." *Id.* Peabody characterizes the Commission's interpretation of the statute as "unreasonable," but does not offer an alternative statutory interpretation. *Id.*

118. As was fully explained in Decision No. C10-1164, issued October 27, 2010, the Commission reads HB 10-1365 as vesting the CDPHE with the discretion to determine which emission reduction requirements are reasonably foreseeable, as it is the state agency with technical and legal expertise in this area. *See* Decision No. C10-1164, at ¶ 39-40 (noting that, in HB 10-1365, all but one of the references to the phrase "reasonably foreseeable" specifically concern the CDPHE's opinion regarding what is reasonable foreseeable). Therefore, RRR on this issue will be denied.

5. New Legal Standard

119. Peabody states the Commission "appears" to create a "new legal standard" by stating retirement of certain plants is necessary "for emission reduction purposes." Peabody RRR, at 12-13.

120. HB 10-1365 requires certain emission reductions and identifies three ways a utility can achieve those reductions from coal fired power plants: installing controls, converting to an alternative fuel source, or early retirement. Using the phrase "for emission reduction purposes" does not create a new legal standard. Rather, it identifies the purpose behind the action. The Commission finds Peabody's argument does not warrant dismissal of these proceedings and therefore, RRR on this issue will be denied.

H. Cost Recovery

1. Construction Work in Progress (CWIP)

121. In its Application for RRR, Public Service argues that the Commission failed to adopt an approach for the timely cost recovery of the construction costs necessary to implement the approved emission reduction plan. Specifically, Public Service argues the Commission's rejection of CWIP recovery along the lines proposed by the Company runs counter to HB 10-

1365 and was done without explaining our reasoning. Public Service RRR, at 4. Public Service contends that the Commission improperly adopted a combination of traditional ratemaking with periodic roll-ins of CWIP and accumulated AFUDC contrary to the explicit language of the statute. *Id.* at 5. Public Service thus repeats its position that a rider mechanism is the method required under HB 10-1365 by which the Company is allowed to recover returns on CWIP, otherwise the recovery will not be "current" as required by § 40-3.2-207(3), C.R.S.[6] *Id.* at 5-6.

122. The Company further argues that the statutory basis for CWIP recovery is distinct from the basis for the recovery of other "non-CWIP" costs under § 40-3.2-207(4), C.R.S., but the Commission instead conflates the standards in § 40-3.2-207(4), C.R.S., with those in § 40-3.2-207(3), C.R.S., concerning CWIP *Id.* at 7. The Company thus argues that ¶ 210 of the Decision places an inappropriate and inefficient procedural burden on the Company with respect to CWIP recovery, because the two triggers set forth in § 40-3.2-207(4), C.R.S., do not apply to CWIP recovery. *Id.* at 9-10. Public Service argues that the record in this Docket is sufficient and further litigation in the form of a preliminary, theoretical proceeding is unnecessary for CWIP recovery. The Company instead suggests that the Commission adopt the Emissions Reduction Adjustment (ERA) to recover earnings on CWIP on a current basis. *Id.* at 11.

123. We are not persuaded by Public Service's arguments regarding § 40-3.2-207(3), C.R.S.,[7] and do not accept that "current recovery" can be accomplished only through the use of a

[6]Public Service does not specifically contest the requirement in ¶ 202 of the Decision that cost recovery of CWIP earnings for a project included in the approved emission reduction plan shall begin only after a CPCN for that project has been issued.

[7]Section 40-3.2-207(3), C.R.S., provides: "Current recovery shall be allowed on construction work in progress at the utility's weighted average cost of capital, including its most recently authorized rate of return on equity, for expenditures on projects associated with the plan during the construction, startup, and pre-implementation phases of the projects."

cost adjustment mechanism or rate rider. [8] The requirements of § 40-3.2-207(3), C.R.S., are satisfied by the approach adopted for CWIP recovery by Decision No. C10-1328, such that, in a rate proceeding, earnings on CWIP may be recovered from ratepayers for projects contained in the emission reduction plan before these investments go into service. This approach is consistent with the requirements of § 40-3.2-207(3), C.R.S., as it protects the Company from the financial harm this provision is designed to protect against. Moreover, we find that, the General Assembly, if it intended for current recovery on CWIP to be achieved only through an adjustment mechanism, § 40-3.2-207(3), C.R.S., would have explicitly prohibited other methods for CWIP recovery by mandating the adoption of a cost adjustment clause. *See, e.g.*, § 40-2-123(2)(f)(I), C.R.S. ("To provide additional encouragement to utilities to pursue the development of an IGCC project, the commission shall approve current recovery by the utility through the rate adjustment clause of the utility's weighted average cost of capital, including its most recently authorized rate of return on equity, for expenditures on an IGCC project during the construction, startup, and implementation phases of the IGCC project."). *See also* §§ 40-5-101(4), 40-2-124(1)(f), 40-3.2-103(2), and 40-3.2-104(5), C.R.S.

124. We also reject Public Service's position that a rider used to recover CWIP under § 40-3.2-207(3), C.R.S., may not be subject to the triggers set forth in § 40-3.2-207(4), C.R.S. Rather, we find that the meaning of the two provisions is best interpreted together, particularly in view of the level of costs expected to be incurred by the Company over the course of the implementation of the emission reduction plan, where CWIP costs in the future will eclipse the

[8] Commissioner Matt Baker stands by his position announced in Decision No. C10-1328 that he would have accepted an approach to the current recovery on CWIP that looked more like the Transmission Cost Adjustment rider, so long as the project received CPCN-like approval. Commissioner Baker prefers this result for policy reasons, including its likely positive impact of demonstrating the feasibility of accounting and forecasting concepts that Public Service would use when setting rates based on a future test year.

"non-CWIP" costs, such as accelerated depreciation and removal costs, and in light of the incentive to the Company to take early actions prior to January 1, 2015.

125. We therefore decline to approve the Company's proposed ERA, even if the ERA would be used only to recover CWIP after the required CPCNs have been issued. Accordingly, we shall not eliminate the requirement that the Company submit a future filing to address the mechanics of any special rate making mechanism or other approach to resolve the controversies indicated in this Docket. We also continue to find that it will be worthwhile for the Company to carefully review the procedural and technical criticisms of the proposed ERA along the lines suggested in Decision No. C10-1328. Public Service should consider rate making mechanisms other than a rate adjustment clause, including the use of a future test year, as outcomes that might be appropriate if it can be demonstrated that the triggers of § 40-3.2-207(4), C.R.S., have been met. However, while we still see many benefits to the application requirement set forth at ¶ 210 of the Decision, we will modify ¶ 210 of the Decision such that Public Service shall no longer be required to make this filing separately from a proceeding in which the result will be the recovery of actual costs from ratepayers.

126. Finally, in footnote 11 of its Application for RRR, Public Service takes issue with the statement in ¶ 210 in the Decision that adopts "deferred treatment accounting" as the default approach for CWIP dollars. We clarify here that the default approach for CWIP for Public Service is consistent with regulatory practice in Colorado when current earnings on CWIP are allowed: AFUDC will be allowed to accumulate on CWIP prior to the filing of a general rate proceeding. Further, when the Commission allows current earnings on CWIP to be included in rate setting prior to the facility entering into service, the CWIP balance and the accumulated AFUDC are placed into rate base without any offset to income.

2. Planning Costs Incurred Prior to December 15, 2010

127. Public Service argues it is entitled under HB 10-1365 to fully recover the planning costs it incurred prior to the issuance of Decision No. C10-1328. Public Service explains that these costs have been capitalized and, absent reconsideration by the Commission on this matter, these costs will need to be expensed. Public Service RRR, at 15.

128. We grant Public Service's request on this matter and allow for planning costs associated with the capital investments contemplated in the emission reduction plan to be capitalized as part of costs of the approved projects in the plan adopted by Decision No. C10-1328, even if these planning costs were incurred prior to December 15, 2010. For example, we find the plant design and engineering studies the Company commissioned in preparation of its August 13, 2010 filing were useful to our review of the expected costs and rate impacts of the emission reduction plan.

129. Before any such planning costs are recovered through rates, including returns on these capitalized costs as CWIP, we expect that stakeholders such as Commission Staff will have a sufficient opportunity to review them to ensure they are prudent and do not include resource planning costs or litigation costs incurred in the normal course of business, where such costs are recovered through base rates. We find the record in this Docket is not adequate to approve the $346,923 of "Plan Development Costs" set forth in Exhibit SBB-7 of Company witness Scott Brockett's Supplemental Rebuttal Testimony (Hearing Exhibit 196).

I. Additional Long-Term Gas Contracts

130. The Gas Intervenors point out that, while ¶ 232 of the Decision requires Public Service to investigate additional long-term natural gas supply contracts, there was no corresponding ordering paragraph. They request the Commission specifically include such a

directive in the ordering paragraphs of Decision No. C10-1328 and offer suggested language that entails a requirement for competitive bidding and prudence evaluation. Gas Intervenors RRR, at 3-4.

131. We agree with the Gas Intervenors that an ordering paragraph regarding the investigation of additional long-term supply contracts would be useful in Decision No. C10-1328. Therefore, we modify the Decision by adding an ordering paragraph directing Public Service to submit a report in this Docket describing the results of its investigation into additional long-term natural gas supply contracts as described in ¶ 232 of the Decision by December 31, 2011.

J. Impacts on Coal Producing Communities

132. In ¶ 246 of Decision No. C10-1328, the Commission directed

> relevant entities, which may include the Colorado Department of Labor, CMA, AGNC, and the OCC, among others, to design an approach to the questions of how to ascertain the impact on mining employment of the Company's approved emission reduction plan and how to efficiently dedicate appropriate ratepayer funds to the effort of retraining eligible coal miners.

To this end, Ordering paragraph 28 orders Staff of the Commission to consult with appropriate entities and then inform the Commission as to a recommended structure for such a plan.

133. The OCC argues that requiring ratepayers to pay for the retraining of mining workers is beyond the Commission's authority. The OCC argues the Commission is supposed to protect the right of customers to pay a rate that accurately reflects the cost of service rendered, and has a general responsibility to protect the public interest regarding utility rates. Because a charge related to retraining coal workers is not connected to the Company's cost of service, the OCC believes ordering such a charge is beyond the authority of the Commission. Nor does the OCC believe such authority was given to the Commission in HB 10-1365. OCC RRR, at 2-3

134. Ordering paragraph 28 does not require a worker retraining program, nor does it require ratepayer funds be used to support such a program. Rather, it directs Commission Staff to conduct an investigation and report to the Commission with recommendations as to the structure and funding of such a program. Therefore, the Commission finds the OCC's arguments concerning the Commission's authority are not yet ripe. No specific program or funding source has yet been proposed, let alone utilized.

135. However, we acknowledge the discussion in ¶ 246 makes specific reference to ratepayer funds, when a similar designation is not contained in the corresponding ordering paragraph. Therefore, we will grant RRR on this issue for the limited purpose of removing the word "ratepayer" from ¶ 246 of Decision No. C10-1328. This paragraph will therefore now read:

> 246. We direct the Staff of the Commission to consult with the relevant entities, which may include the Colorado Department of Labor, CMA, AGNC, and the OCC, among others, to design an approach to the questions of how to ascertain the impact on mining employment of the Company's approved emission reduction plan and how to efficiently dedicate appropriate funds to the effort of retraining eligible coal miners. Staff shall prepare and present a recommendation to the Commission before December 31, 2011.

K. Classification of Information as Highly Confidential

136. The Gas Intervenors request that the Commission amend its decision to include a determination that previous, specific determinations regarding highly confidential treatment of information in this Docket will not control in later proceedings or dockets. Gas Intervenors RRR, at 2.

137. Rules 1100-02, 4 CCR 723-1, address treatment of confidential and highly confidential information, as well as extraordinary protection of that information. Rule 1100(b)(IV), 4 CCR 723-1, states that resolution of a pleading asserting confidentiality or

requesting extraordinary protection will apply in all future proceedings as to the particular information for which confidentiality or extraordinary protection is asserted. As to categories of information—such as long term gas contracts, or Strategist® input files—nothing in the Commission's Rules creates a presumption that the provision of extraordinary protection in one docket relieves the moving party from asserting confidentiality or extraordinary protection in a subsequent docket. However, it is also reasonable that commissions look to past action and experience for guidance as to what information warrants extraordinary protection in a particular circumstance.

138. The Gas Intervenors have not presented a sufficient rationale for their request. The Commission does not find the proposed amendment to be necessary at this time. Therefore, RRR on this issue will be denied.

139. In the alternative, the Gas Intervenors ask the Commission to undertake a rulemaking to clarify its confidentiality rules. The Commission is indeed interested in undertaking an examination of its confidentiality rules in the near future. However, an Application for RRR is not the appropriate venue in which to petition the Commission to undertake a rulemaking. Therefore, RRR on this issue will be denied.

L. Other Matters

140. The Commission modifies ¶ 228 of Decision No. C10-1328 to correct a wording error by replacing the phrase "replacement power" with "replacement gas."

141. All other matters raised in Applications for RRR that are not expressly addressed by this decision are denied.

II. ORDER

A. The Commission Orders That:

1. The Motion for Leave for Acceptance of Late Filed Application of Reargument, Rehearing, or Reconsideration of Commission Decision No. C10-1328 filed by the Colorado Independent Energy Association on January 5, 2011 is denied.

2. The Application for Rehearing, Reargument, or Reconsideration filed by Public Service Company of Colorado on January 4, 2011 is granted, in part, and denied, in part, consistent with the discussion above.

3. The Application for Rehearing, Reargument, or Reconsideration filed by Peabody Energy Corporation on January 4, 2011 is denied, consistent with the discussion above.

4. The Application for Rehearing, Reargument, or Reconsideration filed jointly by the Colorado Mining Association and the Associated Governments of Northwest Colorado on January 4, 2011 is denied, consistent with the discussion above.

5. The Application for Rehearing, Reargument, or Reconsideration filed by the Colorado Office of Consumer Counsel on January 4, 2011 is denied, consistent with the discussion above.

6. The Application for Rehearing, Reargument, or Reconsideration filed by Chesapeake Energy Corporation, Noble Energy, Inc., and EnCana Oil & Gas (USA) on January 4, 2011 is granted, in part, and denied, in part, consistent with the discussion above.

7. The Application for Rehearing, Reargument, or Reconsideration filed by Ms. Leslie Glustrom on January 4, 2011 is denied, consistent with the discussion above.

8. The Application for Rehearing, Reargument, or Reconsideration filed by the American Coalition for Clean Coal Electricity on January 4, 2011 is denied, consistent with the discussion above.

9. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Order.

10. This Order is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING January 26, 2011.

(S E A L)

STATE OF COLORADO ★ THE PUBLIC UTILITIES COMMISSION ★ NIL SINE NUMINE

ATTEST: A TRUE COPY

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

RONALD J. BINZ

JAMES K. TARPEY

MATT BAKER

Commissioners