**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2003 LEAST-COST RESOURCE PLAN	))))	**Docket No. 04A-214E**
IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER APPROVING A REGULATORY PLAN TO SUPPORT THE COMPANY'S 2003 LEAST-COST RESOURCE PLAN	))))))	**Docket No. 04A-215E**
IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE COMANCHE UNIT 3 GENERATION FACILITY	)))))	**Docket No. 04A-216E**

COMPREHENSIVE SETTLEMENT AGREEMENT

December 3, 2004

TABLE OF CONTENTS

PARTIES TO THIS COMPREHENSIVE SETTLEMENT

Public Service Company of Colorado, the Staff of the Colorado Public Utilities Commission ("Staff"), the Colorado Office of Consumer Counsel ("OCC"), the Colorado Energy Consumers Group,[1] the Colorado Governor's Office of Energy Management and Conservation, Western Resource Advocates, Colorado Coalition for New Energy Technologies, Southwest Energy Efficiency Project, Environment Colorado, Colorado Renewable Energy Society, the City and County of Denver, and Tri-State Generation & Transmission Association, Inc. (collectively, the "Parties") hereby enter into this Comprehensive Settlement Agreement.[2]

INTRODUCTION

On April 30, 2004 Public Service Company of Colorado ("Public Service" or the "Company") filed with the Commission the Verified Application of Public Service Company of Colorado for Approval of its 2003 Least-Cost Resource Plan. With the application, the Company filed its Least-Cost Resource Plan ("LCP") in four volumes: Volume 1 – Plan Summary; Volume 2 – Renewable Energy Request for Proposals; Volume 3 – All-Source Requests for Proposals; and Volume 4 –Technical Appendix.

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[1] Although a part of the Colorado Energy Consumers Group, AARP does not join in this Comprehensive Settlement Agreement and takes no position with respect to whether it should be approved.

[2] The following intervenors have not signed this Comprehensive Settlement Agreement: Colorado Mining Association, Colorado Independent Energy Association; Calpine Corporation; CF&I Steel, LP; City of Boulder; Climax Molybdenum Company; North American Power Group, Ltd.; L S Power Associates, L.P.; Baca Green Energy; LLC, Prairie Wind Energy, LLC; Pacificorp; Sun Power, Inc.; Arkansas River Power Authority; Rocky Mountain Farmers Union; Aquila, Inc.; Yampa Valley Electric Association, Incorporated; Holy Cross Energy; and the Regents of the University of Colorado at Boulder. Some of these parties are still reviewing the Comprehensive Settlement Agreement and may join the settlement on or before the date of the evidentiary hearing scheduled for December 8, 2004.

The Company also filed the Motion of Public Service Company of Colorado for Waiver of the 250 MW Limit in LCP Rule 3610 (b) to Permit the Construction of Comanche Unit 3.

On April 30, 2004, Public Service also filed the Verified Application For an Order Granting to Public Service Company of Colorado a Certificate of Public Convenience and Necessity, with supporting testimony, to construct Comanche 3.[3] Further, on April 30, 2004, the Company filed a Verified Application, with supporting testimony, for an order approving a proposed regulatory plan to support the Company's 2003 Least-Cost Resource Plan. The Company filed motions to consolidate into one docket the three applications filed on April 30.

The Commission granted the Company's motions to consolidate the three applications, but severed consideration of the Renewable Energy Request for Proposals from this consolidated docket and addressed the Company's Renewable Energy RFP in Commission Docket No. 04A-325E.

On August 13, 2004, Public Service filed Supplemental Direct Testimony. On September 13, 2004, the Intervenors filed Answer Testimony. On October 18, 2004, Public Service filed Rebuttal Testimony and other parties filed Cross-Answer Testimony.

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[3] Comanche 3 shall be defined to mean a new coal-fired steam electric generating unit with a summer net dependable capacity of 750 MW, and a maximum gross heat input rate of approximately 7421 million Btu per hour as set forth in the preconstruction air permit application, and to be located at the existing Comanche Station near Pueblo, Colorado. Public Service shall operate Comanche 3 but may co-own the unit with other entities. "Comanche 1" shall mean an existing coal-fired steam generating unit with a summer net dependable capacity of 325 MW. "Comanche 2" shall mean an existing coal-fired steam generating unit with a summer net dependable capacity of 335 MW. "Comanche Station" shall mean Comanche 1, Comanche 2 and Comanche 3, collectively.

Hearings were held from November 1 through November 17, 2004. At the hearing on November 18, the Company requested suspension of hearings to afford time to negotiate settlement of the contested issues in this consolidated docket. By Decision No. C04-1409 the Commission agreed to continue the hearings until December 8, 2004.

SETTLEMENT WITH CONCERNED ENVIRONMENTAL AND COMMUNITY PARTIES

Public Service conducted two separate sets of settlement discussions. The first set of discussions was among Public Service and national, regional, and local environmental and community groups who had expressed concerns about the public health and environmental impacts that will result from Comanche 3. These groups are collectively referred to as the "Concerned Environmental and Community Parties" or "CECP". Some of the CECP groups are intervening parties in this consolidated Commission docket; others spoke at the Commission's public statement hearings; others have not presented their views directly to the Commission.

Public Service reached settlement with CECP. The "CECP Settlement" is attached to this Comprehensive Settlement Agreement as Attachment A.[4] In consideration for the emission reductions and other provisions of the CECP Settlement, the Concerned Environmental and Community Parties agreed not to initiate, fund or participate in any formal administrative or legal action to oppose or knowingly impede the permitting or approval of those activities necessary for the construction and

[4] This Comprehensive Settlement Agreement generally describes the obligations of CECP. To the extent there are any inconsistencies between the general descriptions of CECP obligations in this Comprehensive Settlement Agreement and the CECP Settlement, the CECP Settlement shall control.

operation of Comanche 3 that are listed in Section 16 of the CECP Settlement. The CECP Settlement should mitigate but may not eliminate the risk of delay in the air permitting and construction of Comanche 3. Delay in obtaining the air permit for Comanche 3 would erode the economic benefits provided by Comanche 3 to Public Service's customers.

Pursuant to Section 17(A) of the CECP Settlement, Public Service agreed to seek Commission approval for the commitments in Sections 3, 4, 5, 6, 7, 8, 12, 14 and 15 of the CECP Settlement, as part of the Commission order on the Company's 2003 Least Cost Plan. Section 17(A) states that, if the Commission does not approve in full the Company undertaking the commitments in these sections of the CECP Settlement, or if a Commission order significantly impedes implementation of any of the commitments under the CECP Settlement, or if the Commission Order approving such commitments is reversed on judicial appeal in any significant respect, Public Service's and CECP's obligations under the CECP Settlement are terminated.

Since Public Service and its customers derive significant benefits from the CECP Settlement, termination of the CECP Settlement should be avoided. Public Service and the Parties to this Comprehensive Settlement Agreement agree that it is in the public interest for the Commission to approve Public Service undertaking the commitments set forth in Sections 3, 4, 5, 6, 7, 8, 12, 14 and 15 of the CECP Settlement. These provisions are referenced in this Comprehensive Settlement Agreement. Public Service and the Parties to this Comprehensive Settlement Agreement further request that the Commission not issue an order that would significantly impede the implementation of any of the commitments set forth in the CECP Settlement. Notwithstanding the foregoing, unless a Party to this Comprehensive Settlement Agreement is also a signatory to the CECP Settlement, a Party to this Comprehensive Settlement Agreement is not bound by the provisions in the CECP Settlement. The Parties to this Comprehensive Settlement Agreement have attempted to make the Comprehensive Settlement Agreement and the CECP Settlement consistent with each other in all material respects, and it is the Parties' intent and recommendation that the two agreements should be interpreted as consistent with each other. However, Public Service is not asking for the Commission to agree to the CECP Settlement in its entirety because it addresses some issues that are beyond the scope of this proceeding. Public Service and the Parties to this Comprehensive Settlement Agreement are requesting only that the Commission approve this Comprehensive Settlement Agreement.

COMPREHENSIVE SETTLEMENT WITH PARTIES TO CONSOLIDATED COMMISSION DOCKET

The second set of settlement discussions was held among Public Service and some of the intervening parties in this consolidated docket. These settlement negotiations have resulted in this Comprehensive Settlement Agreement.

COMPREHENSIVE SETTLEMENT

The Parties to this Comprehensive Settlement Agreement hereby agree to the following resolution of the contested issues in this consolidated docket.

CPCN for Comanche 3

1. The Commission should grant the Company a Certificate of Public Convenience and Necessity ("CPCN") to construct Comanche 3 as a supercritical pulverized coal-fired steam electric generating unit. The description of Comanche 3 is set forth in the testimony and exhibits filed by the Company with its Application for a CPCN. The CPCN granted by the Commission should also grant the Company permission to install both the new emission controls to the existing generating units Comanche 1 and Comanche 2 that are discussed in the Company's LCP and testimony and exhibits and the additional environmental controls that are discussed below in this Comprehensive Settlement Agreement. The construction authorized by this CPCN for Comanche 3 and the additional environmental controls for Comanche 1 and Comanche 2 shall be referred to collectively in this Comprehensive Settlement Agreement as the "Comanche Project."

2. Public Service has preexisting contractual commitments that require it to offer ownership shares in Comanche 3 to Intermountain Rural Electric Association and Holy Cross Energy. If both of these Colorado utilities agree to participate with Public Service in Comanche 3, Public Service's share of Comanche 3 would be approximately 500 MW. In its CPCN Application, Public Service requested a CPCN to construct a 750 MW Comanche 3 and to own 500 MW of Comanche 3. Negotiations between Public Service and Intermountain Rural Electric Association, and between Public Service and Holy Cross Energy, for participation in Comanche 3 have not yet been completed.

3. Due to the expected benefits from Comanche 3, the Parties agree that the Commission should grant Public Service a CPCN that will allow Public Service to

construct and own 750 MW of Comanche 3. Given Public Service's pre-existing contractual commitments to Intermountain Rural Electric Association and Holy Cross Energy, the Parties further agree that the Commission should approve, as part of the CPCN, a transfer by Public Service to Intermountain Rural Electric Association and to Holy Cross Energy of an ownership share of up to approximately 250 MW, but these transfer approvals shall be subject to the limitations set forth in Highly Confidential Attachment B to this Comprehensive Settlement Agreement. Should Public Service not be able to reach joint ownership terms and conditions with either Intermountain Rural Electric Association or Holy Cross Energy or both that comply with the limitations set forth in Highly Confidential Attachment B, then Public Service must file a separate application with the Commission under C.R.S. §40-5-105 if Public Service desires to transfer an ownership interest in Comanche 3 to the utility who refused to agree to ownership terms and conditions that comply with the limitations set forth in Highly Confidential Attachment B. Should Public Service desire to sell an ownership share in Comanche 3 to any entity other than Intermountain Rural Electric Association or Holy Cross Energy, Public Service must obtain Commission approval under C.R.S. §40-5-105.

4. In order to grant Public Service the CPCN set forth in this Comprehensive Settlement Agreement, the Parties recommend that the Commission grant Public Service's motion for a waiver of the 250 MW limit in Rule 3610 (b) of the Commission's Least-Cost Resource Planning Rules.

Additional Environmental Controls

5. The Company shall install lime spray dryers on both Comanche 1 and Comanche 2 as required by section 3 of the CECP Settlement. The cost of the lime spray dryer for Comanche 2 was already included within the cost estimates set forth in the Company's testimony and exhibits. The additional lime spray dryer for Comanche 1 is estimated to cost approximately $48 million ($2003).

6. Public Service shall comply with the monitoring, testing and emission limits for mercury set forth in section 7 of the CECP Settlement. The CECP Settlement establishes a process by which the Company will test mercury emissions at Comanche Station no later than 180 days after the initial startup of Comanche 3 and will provide its test results to the Colorado Department of Public Health and Environment ("CDPHE") and CECP. The CDPHE shall use the test results provided by the Company to determine the maximum level of mercury control for the Comanche Station that CDPHE considers to be cost-effective based on a dollar per pound of mercury removed. The mercury control limits determined by CDPHE to maximize cost-effective reductions for Comanche Station will be incorporated into the Title V operating permit. The mercury control technology is likely to be sorbent injection, unless a better control technology emerges. It is anticipated that Public Service will need to install, as it constructs the Comanche Project, mercury emission controls with an estimated capital cost of approximately $3 million ($2003). Public Service anticipates that the mercury emissions testing that it will perform for CDPHE will cost approximately $500,000 ($2004). Finally, Public Service anticipates that the mercury control level determined by CDPHE, as described above, will require Public Service to spend initially from $2 million to $5

million per year in the first year's operation and maintenance costs associated with the control technology, beginning no later than two years after the initial startup of Comanche 3. This annual operation and maintenance expense may increase with the escalation in the variable costs of the control technology or due to the establishment of laws or regulations that provide for more stringent mercury emissions limits than those determined by CDPHE as a result of the process set forth in the CECP Settlement.

7. All emission control equipment installed on Comanche 1, Comanche 2 and Comanche 3 shall be designed to comply with the specific emission limits, installation and compliance schedules, and other permit requirements set forth in sections 3, 4 ,5, 6, 7 and 8 of the CECP Settlement.

8. In addition to the specific additional environmental controls set forth in this Comprehensive Settlement Agreement, Public Service may be required by either CDPHE or the United States Environmental Protection Agency to incur additional expenditures in order to receive an air permit for Comanche 3.

9. The Parties agree that, except as provided later in this Comprehensive Settlement Agreement with respect to the Construction Cost Cap, the investments in environmental controls associated with the Comanche Project set forth in paragraphs 5 through 8 above are deemed prudent and are recoverable in rates. The Parties further agree that operation and maintenance expenses associated with the environmental controls set forth in paragraphs 5 through 8 above are recoverable in rates by Public Service to the extent the operation and maintenance expenses are prudently incurred.

10. Section 9 of the CECP Settlement sets forth additional covenants that address environmental mitigation in the Pueblo area. Public Service agrees that the

environmental mitigation covenants in section 9 of the CECP Settlement with respect to shredded car bodies at the Rocky Mountain Steel plant in Pueblo and the diesel school buses in the Pueblo area shall not be recoverable in rates.

11. The CECP Settlement also addresses in section 10 sustainable development activities for the Pueblo region, and in section 13 the consideration of innovative technologies. The Parties to this Comprehensive Settlement Agreement who are not signatories to the CECP Settlement are taking no position with respect to these covenants in the CECP Settlement. Further, the Parties to this Comprehensive Settlement Agreement request that the Commission take no action at this time as to the rate treatment that should be afforded in future rate proceedings to any costs incurred by the Company to comply with the sustainable development activities and with the consideration of innovative technologies required under the CECP Settlement.

Construction Cost Cap

12. In exchange for the compromises reflected in this Comprehensive Settlement Agreement, Public Service agrees that the construction costs for the Comanche Project that may be placed into its rate base shall be subject to a cap. Public Service shall be limited to placing into utility rate base the actual capital expenditures[5] for the Comanche Project that are equal to or below the Construction Cost Cap determined in accord with Highly Confidential Attachment C. The Parties agree that actual capital expenditures incurred by Public Service, up to and including the level set by this Construction Cost Cap, represent reasonable and prudent

[5] By "actual capital expenditures" the Parties mean the capital expenditures that are recorded in the Company's books and records under the FERC Uniform System of Accounts. Separate sub-accounts shall be established for the Comanche Project.

expenditures by Public Service that shall not be subject to challenge at the time that the Company seeks to place the Comanche Project into rate base, except to the extent a Party could establish that an expenditure resulted from fraud or deceit on the part of Public Service, its affiliates, or its contractors.

13. In addition to actual construction cost up to the Construction Cost Cap, Public Service shall be entitled to include in rate base, when a commercially-operational Comanche 3 is reflected in the test year of a Phase 1 rate proceeding, the Company's accumulated AFUDC[6] associated with the capital expenditures for the Comanche Project that are at or below the Construction Cost Cap.

14. By agreeing to the recovery of Comanche 3 construction costs that are at or below the Construction Cost Cap determined in accord with Highly Confidential Attachment C, Parties to this Comprehensive Settlement Agreement do not waive the right to challenge the recovery of replacement power costs that result from material delays in the commercial operation date of Comanche 3 due to imprudence.

15. The Company shall file progress reports with the Commission semi-annually, beginning June 1, 2005 and ending with the first report after Comanche 3 reaches commercial operation, regarding the progress of construction and the expected commercial operation date of Comanche 3. The progress reports shall contain the status of each vendor contract (including updated information on contracts under negotiation) and a narrative which summarizes bids received and the selection process employed for each vendor contract. The progress reports shall also set forth the force majeure clauses in each vendor contract and in any subcontract let by Utility

[6] The accumulated AFUDC must be set forth in the Company's books and records in a Comanche Project sub-account in accord with FERC Uniform System of Accounts.

Engineering Corporation or by Public Service. The progress reports shall provide the account balances for all Comanche Project expenditures.[7] The progress reports also shall include budgeted versus actual status with respect to the milestone payment schedule, differences in status between the projected and actual overall construction schedule and the status of on-going permit applications. Any material departure from the milestone payment schedule or the construction schedule will be accompanied by a narrative explaining the departure. Continuing property records shall be timely maintained and available for inspection. Finally, the progress reports shall list any material design or scope change orders. Public Service reserves the right to file bid and financial information under seal and to seek highly confidential protection for this information.

2003 Least-Cost Resource Plan and 2005 All-Source Solicitation

16. The Parties agree that the Company should use a planning reserve margin of 16%[8] for the 2003 LCP.[9]

17. For purposes of the 2003 LCP, Public Service agrees not to apply a balance sheet equalization factor or other imputed debt adjustment mechanism to the bids received.

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[7] The Comanche Project expenditures shall be set forth in the Company's books and records in Comanche Project sub-accounts in accord with FERC Uniform System of Accounts.

[8] The 16% is applied to the Company's "base" demand forecast (i.e. normal weather).

[9] When the term "2003 LCP" is used in covenants set forth in this Comprehensive Settlement Agreement, the Parties intend that the term shall include the Company's 2003 LCP as approved by the Commission in this docket, all resource solicitations that are conducted under the Company's approved 2003 LCP, the implementation of any contingency plan that may be required under the 2003 LCP, and any amendments to the 2003 LCP that the Company may file.

18. As required by section 12 of the CECP Settlement and in consideration of the potential incurrence of future costs due to greenhouse gas regulation (e.g., carbon dioxide taxes or allowance costs) during the 30 year Planning Period of the 2003 LCP, the Parties agree that all evaluations of resources acquired under the 2003 LCP should include imputation of CO_2 costs of $9/ton beginning in 2010 and escalating at 2.5% per year beginning in 2011 and continuing over the planning life of the resource. The imputed cost of CO_2 shall be included in both the initial economic screening and in the dynamic portfolio optimization steps of the bid evaluation processes. In evaluating bids during the initial economic screening, Public Service shall reflect the costs associated with the CO_2 proxy cost as a dollar per MWh variable operating cost. In the dynamic portfolio optimization modeling, the CO_2 proxy cost shall be applied to all existing and new resources as a $/MWh variable operating cost affecting resource dispatch. For any CO_2 emitting resource, the variable $/MWh CO_2 cost of a resource shall be calculated using the formula set forth in Section 12(C) of the CECP Settlement, which is hereby incorporated by reference.

19. In accord with section 15(E) of the CECP Settlement and in recognition of the potential future value of renewable energy credits ("RECs") provided to Public Service, particularly after the passage of 2004 Colorado Ballot Initiative Amendment 37, the Company shall include a REC value of $8.75/MWh for all renewable resources bid into solicitations under the 2003 LCP, with the exception of the Renewable Energy RFP issued August 17, 2004. To qualify for the REC value, the renewable energy bid must meet the definition of "Eligible Renewable Energy Resource" under Amendment 37, as that definition may be updated by the Colorado Legislature by the time the bids are due

in response to the 2005 All-Source RFP or by the time the bids are due in response to any other solicitation conducted under the 2003 LCP. The REC value shall be included in both the initial economic screening and in the dynamic portfolio optimization steps of the bid evaluation process. Public Service shall apply the REC value to renewable resource bids for all operating years of the renewable energy project from 2006 onward. The Renewable Energy Credit will not escalate in value over the Planning Period used in the 2003 LCP.

20. As required by CECP Settlement sections 15(A) and 15(B), Public Service shall accelerate and complete those components of the wind ancillary service cost study required by the Commission in Docket No. 04A-325E that are necessary to obtain projections of ancillary service costs for nameplate wind penetration levels of 15% of Public Service's system peak demand. For purposes of the study, the 15% wind penetration level shall be based on Public Service's 2007 peak demand forecast or Public Service's best available peak demand forecast for 2007 at the commencement of the study. These necessary components of the study shall be completed in time to evaluate wind resource bids submitted in response to the 2005 All Source RFP. Public Service shall accept wind bids in response to solicitations under the 2003 LCP up to a 15% penetration level, so long as the wind bids are part of Public Service's least cost resource portfolio. In the 2003 LCP, due to concerns over potential operational impacts, the Company will not be required to select resources that would result in a greater than 15% penetration level of intermittent resources on the Public Service system. For this purpose, the 15% wind penetration level shall be based on Public Service's peak demand forecast used to determine resource need and acquisition at the time of the bid

evaluations and shall be calculated based on the year in which the wind resource would be projected to come on-line. Nothing in this paragraph shall alter the $2.50/MWh ancillary service costs to be ascribed to intermittent resources that are bid in response to the Company's Renewable Energy RFP issued on August 17, 2004; the ancillary service costs ascribed to the Renewable Energy RFP bids shall be governed by the Commission's orders in Docket No. 04A-325E.

21. Public Service shall use a capacity value of wind generation resources equal to 10% of nameplate capacity for existing wind generation and in evaluating the wind bids submitted in response to solicitations conducted under the 2003 LCP.

22. Public Service shall remove from the Model Power Purchase Agreement provided with the 2005 All-Source RFPs and other solicitations under the 2003 LCP an opportunity for bidders to sell up to ten megawatts of Excess Capacity to Public Service beyond the level of capacity specified in the bid.

23. The Parties agree that, when assessing supplier concentration and parent company financial strength of bidders in the 2003 LCP, the evaluation will focus on an assessment of the bidder's ability to perform the obligations of the project under a potential purchase power agreement.

Additional Resource Planning Studies

24. Public Service, Staff and OCC shall jointly work to develop a study scope and study methodology, and to identify appropriate study model(s), to perform a probabilistic assessment of the appropriate reserve margin for the Public Service system that includes consideration of the following:

a. Resources acquired in the Renewable Energy RFP, the 2005 All-Source RFP, plus Comanche 3;

b. Weather related load variability; and

c. Planned and unplanned generation and transmission outages.

Public Service shall use its best efforts to collect information from all electric systems within the TOT-constrained area of Eastern Colorado and to obtain commercially-available Loss of Load Probability (LOLP) models that have the capability to properly represent both 1) the transmission limitations of the TOT-constrained area and 2) the reliability support that the different electric systems provide to each other. If Public Service is able to obtain the data and software necessary to conduct this study, Public Service shall study the full TOT-constrained area of Eastern Colorado. If Public Service, Staff and OCC reach consensus on the study scope, methodology, and appropriate computer models, then Public Service, Staff and OCC shall rely on the study results to develop their individual recommendations for the reserve margin in Pubic Service's next resource plan. If Public Service, Staff and OCC are unable to reach consensus on the study scope, methodology, or appropriate computer models that would produce a meaningful study of the TOT-constrained area of Eastern Colorado, within the limitations of available data and modeling software, all Parties are free to advocate any position in the next Public Service resource plan.

25. In accord with section 15(D) of the CECP Settlement, Public Service shall perform an Effective Load Carrying Capability study on its system as a means for determining the capacity value of wind generation resources. The study shall consider the uncertainty or variability of hourly wind generation patterns from year-to-year and

the combined effects of diverse wind farm locations. Public Service shall file the study with the Commission and provide copies to the Parties by November 1, 2006. Public Service agrees to advocate in future Commission proceedings that the reliability contribution or capacity value of wind generation resources should be based upon a method that incorporates consideration of reliability contribution in all hours of the year and to propose recommendations for ascribing capacity value to existing and new wind generation resources. Public Service shall solicit participation of industry experts, Staff, OCC and other interested parties with Public Service personnel on a technical review committee with the intent of incorporating their specific interest and knowledge base into the study. If Public Service claims the information in such report is confidential, any member of the technical review committee or any organization listed in Section 1 to the CECP Settlement shall be allowed to review such information after signing a reasonable confidentiality agreement that ensures that commercially sensitive or trade secret information is protected. Members of the technical review committee shall be afforded access to confidential information of entities other than Public Service only upon the execution of non-disclosure agreements acceptable to the owner of the Confidential Information. The Parties to this Comprehensive Settlement Agreement, other than Public Service, reserve their rights to advocate for a different method for determining wind capacity value.

26. In accord with section 15(C) of the CECP Settlement, if Public Service selects cost-effective wind generation resources in response to the Renewable Energy RFP and All-Source Solicitations of the 2003 LCP that increase nameplate wind generation on its system above 720 MW, Public Service agrees to perform an

additional ancillary service cost study to obtain projections of ancillary service costs at a 20% penetration level. This 20% wind penetration study shall be used to inform resource solicitations subsequent to the solicitations conducted under the 2003 LCP.

27. Public Service agrees to conduct and present with its CPCN application for the transmission facilities required by Comanche 3 the following two studies. Public Service will evaluate the specific 230 kV alternative for the Comanche 3 transmission system outlined by Mr. Dominguez in his Answer Testimony in this consolidated docket. Further, as requested by Staff witness Mr. Dominguez, Public Service will evaluate methods to reduce transmission noise levels to 50 db(A) for the 345 kV double circuit Comanche-Midway-Daniels Park facility proposed in Volume 4 of the Company's LCP. By agreeing to conduct these studies, Public Service is not agreeing that these alternatives will be the transmission facilities that Public Service proposes to construct or for which Public Service requests a CPCN. The Parties reserve their rights to comment upon Mr. Dominguez's alternatives to protect their respective interests.

28. Under the Stipulation Between the Staff of the Colorado Public Utilities Commission and Public Service Company of Colorado with Respect to Wind Studies, as modified by the Commission in Docket No. 04A-325E by Decision No. C04-0994 (August 24, 2004), Public Service is obligated to perform power flow and stability analyses, using 2007 power flow cases, of the portfolio of resources selected by the Company in response to the Renewable Energy RFP. Public Service shall invite neighboring transmission owners, through the auspices of the Colorado Coordinated Planning Group, to participate in these studies.

29. In order to increase public information about wind generation facility operations, Public Service agrees to request permission from wind energy sellers to publicly disclose historic production data on a 2-minute interval basis. To the degree that such permission is obtained, Public Service agrees to make such information available upon request. Such information will be provided on a historic basis only.

Demand-Side Management

30. In order to achieve energy efficiency to provide a hedge against volatile gas prices and against uncertain future emission regulation, in order to reduce total system costs, and in accord with section 14 of the CECP Settlement, Public Service shall use its best efforts to acquire, on average, 40 MW of demand reduction and 100 GWh of energy savings per year from cost-effective Demand-Side Management ("DSM") programs over the period beginning January 1, 2006 and ending December 31, 2013, so that by January 1, 2014 the Company will have achieved a cumulative level of 320 MW of total demand reduction and 800 GWh of annual energy savings. Notwithstanding the foregoing, Public Service's actual annual demand reductions and energy savings during this period may vary from these annual averages. The Company shall expend $196 million (2005 dollars) to meet such demand reductions and energy savings unless these demand reductions and energy savings are achieved with a lower level of expenditures. The DSM demand reductions and energy savings required by this paragraph shall include the demand reductions and energy savings achieved by Public Service through bidding under the 2003 LCP. The Company shall strive to develop and implement a set of DSM programs that give all classes of customers an opportunity to participate. As part of this effort, the Company will attempt to develop for

residential and commercial customers some programs that concentrate on reduction in peak demand and some programs that concentrate on reduction of energy usage. All DSM programs implemented under this Comprehensive Settlement Agreement, outside of bidding under the 2003 LCP, shall be required to pass the Total Resource Cost test. All DSM programs selected in the 2005 All-Source Evaluation will be part of the portfolio that minimizes the net present value of rate impacts.

31. The Company shall perform a market study to determine, generally, levels of efficiency available for various customer classes and the costs associated with such measures, and whether such levels of DSM are cost-effective and available in Colorado. Public Service agrees to involve other stakeholders in the design of the market study and the review of the contractor summary results. The market study shall not exceed $2 million in cost. Public Service shall complete the market study as expeditiously as practicable, but no later than March 31, 2006.

32. Public Service further commits to conduct program-specific market and load research and ongoing measurement and verification for each DSM measure as appropriate, ranging from random audits to project-based reviews for the more customized measures. Public Service will conduct an impact and process evaluation that assesses the amount of energy and demand savings from each program and evaluates the functional efficiency and customer satisfaction with each program. Public Service will spend up to an additional $2 million on these evaluation efforts. The $4 million spent on the market study and the evaluation efforts shall be included in the $196 million cap and shall be recoverable through the Demand Side Management Cost Adjustment ("DSMCA") clause.

33. Public Service shall be entitled to continue to fully recover its expenses and investment associated with existing DSM programs under the Company's 1999 Integrated Resource Plan under the terms and conditions of the Company's current DSMCA, which include a five year amortization period for DSM investment.

34. For the DSM programs contemplated by this Comprehensive Settlement Agreement, Public Service shall be entitled to fully recover its expenses and investment associated with these new programs under the terms and conditions of the Company's current DSMCA, except that the Company's investment in DSM measures shall be amortized over an 8 year period instead of a 5 year period. All DSM investments associated with contracts signed after December 31, 2005 shall be considered to be investments subject to the 8 year amortization period. Further, the Company shall be entitled to make an out-of-period adjustment in its 2006 rate case filing to capture the annualized effect of incremental increases in internal labor, benefits and other employee-related costs associated with implementing this expanded DSM program through 2006. The Company shall include no more than 18 full-time-equivalent employees in this out-of-period adjustment. These incremental labor and employee-related costs shall be included in the $196 million cap discussed in prior paragraphs.

35. Within three months of completing the market study described in paragraph 31 above, but no later than July 1, 2006, the Company shall file an application with the Commission to open a docket to address the provision of DSM by Public Service above and beyond the levels provided by existing programs and by this

Comprehensive Settlement Agreement.[10] The Company acknowledges that in the DSM docket initiated pursuant to this paragraph, the Commission may examine for future DSM programs beyond the levels set forth in this Comprehensive Settlement Agreement, among other issues, 1) whether the Company's expenses should be recovered through a rider and 2) the appropriate amortization period for recovery of DSM investment.

36. Public Service shall file with the Commission with its annual DSMCA filing a report on the DSM expenditures, energy savings, and peak demand reduction achieved by the programs for the past year. Public Service shall also file with the Commission with its annual DSMCA filing the results of the impact and process evaluations[11] that were conducted in the past year.

37. Public Service shall establish and maintain a DSM working group that shall meet at least twice a year. The DSM working group shall be open to all interested persons and shall provide input to Public Service in DSM program design, analysis and other issues relevant to helping the Company meet or exceed the minimum energy savings and peak demand reduction levels. Public Service shall provide to the members of the DSM working group copies of all DSM filings it makes with the Commission.

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[10] The Company has agreed in section 14(D) of the CECP Settlement to advocate in the subsequent Commission DSM proceedings, among other things, for use of the Total Resource Cost test and for financial incentives for Company acquisition of DSM. The Parties to this Comprehensive Settlement Agreement who are not signatories to the CECP Settlement are not bound by these terms of the CECP Settlement and fully reserve their rights to advocate for their interests in the subsequent DSM docket.

[11] Public Service shall conduct impact and process evaluations at the conclusion of each program.

38. The Parties do not agree among themselves as to whether the Commission must grant the Company a waiver from the Commission's Least-Cost Resource Planning Rules to accomplish the DSM commitments set forth in this Comprehensive Settlement Agreement. The Parties are not asking the Commission for a specific ruling on whether a waiver is required. However, to the extent that a waiver is required, the Parties agree that the public interest would be served by the Commission granting such a waiver.

Impact of Settlement on Public Service's 2003 LCP

39. Public Service represents that it has modeled the economic impact of the provisions of this Comprehensive Settlement Agreement on the Company's screening analyses presented in the Company's filed 2003 Least-Cost Resource Plan, with a variety of updated modeling assumptions including the use of the price for natural gas used in the Renewable Energy RFP bid evaluation.[12] Public Service's report discussing the assumptions used for each model run and the results of these model runs is attached as Attachment D. Public Service represents that the model runs show the impact of this Comprehensive Settlement Agreement, referred to as the "Settlement Case" in comparison to both the case proposed in the Company's October 18, 2004 rebuttal testimony and to updated generic screening analyses.[13] In general, Public Service represents that these runs demonstrate the following aspects of the Settlement Case:

[12] The gas price used in the Renewable Energy RFP bid evaluation is based upon on combination of four different long-term gas price forecasts: CERA, PIRA, EIA, and NYMEX.

[13] A description of the updates made to the Company's screening analyses is set forth in Attachment D.

a. Even with the additional environmental controls, the inclusion of higher CO_2 proxy costs, and increased DSM required by this Comprehensive Settlement Agreement, Comanche 3 is still chosen as part of the Least- Cost Resource Plan.

b. An additional coal resource could be selected in the 2005 All-Source RFP Evaluation as part of the Least-Cost Resource Plan.

c. Additional gas-fired resources could be selected in the 2005 All-Source RFP Evaluation as part of the Least-Cost Resource Plan.

d. Additional wind resources priced without the benefit of the federal production tax credit could be selected in the 2005 All-Source RFP Evaluation as part of the Least-Cost Resource Plan.

e. The Comprehensive Settlement Agreement, including DSM, produces a net present value reduction of revenue requirements of approximately $90 million compared to the Company's October 18, 2004 rebuttal case and between $500 million to $1.3 billion compared to the revised generic screening analyses. The Comprehensive Settlement Agreement, including DSM, results in a slight increase in the net present value of average rate impacts of approximately $0.05/MWh ($0.00005/kWh) compared to the Company's rebuttal case and a reduction in the net present value of average rate impacts of between $.58/MWh and $2.14/MWh compared to the revised generic screening analyses.

New LCP Rules

40. Concerns were expressed by many Parties to this docket about various provisions in the Commission's Least-Cost Planning Rules. The Parties agree that Public Service shall file a petition no later than September 1, 2005 requesting the

Commission to open a rulemaking docket to reexamine the LCP rules. Among other things, the petition shall request that the rulemaking proceeding should examine the following topics: 1) the competitive solicitation processes that should be used to acquire various types of resources; 2) how a utility rate-based generation facility can be fairly evaluated and compared against purchased power options; 3) the effects of purchased power contracts on utility balance sheets and income statements and how those effects can reasonably be addressed; 4) how cost impacts and cost recovery can be integrated into the resource planning and acquisition cycle; 5) whether the net present value of revenue requirements instead of net present value of rate impacts should be the test employed to select the least cost resource portfolio; 6) how future environmental regulatory risks should be taken into account; 7) the adequacy of the current public participation process, and 8) the appropriate cost-effectiveness test for DSM. Public Service shall not ask the Commission to reopen Rules 3602 and 3605 dealing with the applicability of the Commission's LCP Rules to cooperative electric associations and cooperative generation and transmission associations[14]

Regulatory Plan

41. The Company acknowledges that the Intervenors' willingness to resolve the cost recovery issues as set forth below is based upon the particular factual circumstances that have been presented in this consolidated docket. The Parties agree that the following compromises and agreements with respect to the Regulatory Plan shall have no precedential effect or significance, except as may be necessary to enforce

[14] Other Parties reserve their rights to seek to expand the scope of the LCP Rulemaking.

this Comprehensive Settlement Agreement or Commission Order approving this agreement.

42. The Company agrees to withdraw its request for the Least Cost Plan Adjustment Rider.

43. Public Service agrees that it shall not file an electric Phase 1 rate case prior to January 1, 2006.

44. The Parties recognize the Company's need to begin increasing its equity ratio, as calculated for financial reporting purposes, to 56% to offset the debt equivalent value of existing purchased power agreements and to improve the Company's overall financial strength. The Parties agree that, for purposes of the 2006 Phase 1 rate case, the actual regulatory capital structure,[15] including pro forma adjustments but excluding short-term debt, as of the earlier of the date on which a settlement of the 2006 Phase 1 rate case is executed or the first day of evidentiary hearings, shall be deemed reasonable and shall be used to determine the Company's 2006 Phase 1 rate case revenue requirement. The Parties understand that, depending upon the level of short-term debt on the Company's balance sheet as of the date the regulatory capital structure is determined, the equity ratio could exceed 56%. Public Service stipulates that, for purposes of the 2006 Phase 1 rate case, its proposed regulatory capital structure shall not exceed 60% equity. Public Service reserves the right to seek higher levels of equity in its regulatory capital structure in Phase I rate proceedings subsequent to the 2006 rate case. The Parties reserve their rights to take a position that reflects their respective interests at such time.

[15] In calculating its actual regulatory capital structure, Public Service shall use its most recently available month-end financial statement as the starting point.

45. The Parties agree that in any one or more Phase 1 rate proceedings that the Company may file between January 1, 2006 and the later of January 1, 2011 or five and one-half years after the Company secures an administratively final air permit for Comanche 3,[16] provided that the Company's actual capital structure used for regulatory purposes equals or exceeds 56 percent equity, the Company shall be entitled to the following treatment of Construction Work in Progress associated with the construction of Comanche 3, the installation of environmental controls on Comanche 1, 2, and 3, and related transmission investment ("Comanche CWIP"):

a. If on the earlier of the date on which a settlement of the Phase 1 rate case is executed or the first day of evidentiary hearings, the Company's senior unsecured debt rating from either Standard & Poor's or Moody's is below A- or its Moody's equivalent, the Company shall be permitted to include Comanche CWIP in ratebase without an AFUDC offset, calculated as of the end of the applicable test year;[17] and

b. If on the earlier of the date on which a settlement of the Phase 1 rate case is executed or the first day of evidentiary hearings, the Company's senior unsecured debt rating from either Standard & Poor's or Moody's is below BBB+ or its Moody's equivalent, the Company shall be permitted to make an out-of-period adjustment to include Comanche CWIP in rate base without an AFUDC offset, accrued during the

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[16] If construction at Comanche 3 is halted due to a legal challenge to the air permit filed after issuance or other force majeure event, the five and one half year period referenced in this Paragraph shall be extended day for day for so long as the construction is halted.

[17] Based upon Public Service's current estimates, for illustrative purposes only, the annual revenue requirement impact of including the Comanche CWIP balance as of year-end 2005 in rate base without an AFDUC offset would be $ 4,747,150. This amount would be included in the revenue requirement used to establish rates that would take effect on January 1, 2007, assuming Public Service files an electric rate case in Spring 2006.

period ending twelve months following the end of the test year upon which the Phase 1 filing is based.[18] The Parties acknowledge that the Company's Phase 1 filing will include the Company's best estimate of the Comanche CWIP balance as of the end of the twelve month period following the end of the applicable test year, which estimate may be revised from time to time up until 30 days prior to the first day of scheduled evidentiary hearings in the Phase 1 rate case.[19]

c. If Public Service's actual capital structure used for regulatory purposes does not equal or exceed 56%, or if Public Service's senior unsecured debt rating from both Standard & Poor's and Moody's is at or above A- or its Moody's equivalent, then the Parties reserve their rights to take a position with respect to Comanche CWIP that reflects their respective interests at such time. If the Company's senior unsecured debt rating from both Standard & Poor's and Moody's is BBB+ or its Moody's equivalent, then the Parties reserve their rights to take a position with respect to the Comanche CWIP pro forma adjustment discussed in Paragraph b that reflects their respective interests at such time.

46. Public Service reserves the right to seek additional regulatory relief associated with the construction of the Comanche Project or the impact of purchased power at any time, except that the Company agrees that it shall not seek a rider specific

[18] Based upon Public Service's current estimates, for illustrative purposes only, the annual revenue requirement impact of including the Comanche CWIP balance as of year-end 2006 in rate base without an AFDUC offset would be $ 29,513,628. This amount would be included in the revenue requirement used to establish rates that would take effect on January 1, 2007, assuming Public Service files an electric rate case in Spring 2006.

[19] Any revised Comanche CWIP estimate shall be filed with the Commission and served on all parties with accompanying work papers with an attestation by an officer of the Company and the Company's contractors, including Utility Engineering Corporation.

to recovery of the financing costs of Comanche 3 and the Company shall not file an electric Phase 1 rate case prior to January 1, 2006. The Parties reserve their rights to take a position that reflects their respective interests with regard to such additional regulatory relief requests.

GENERAL TERMS AND CONDITIONS

This Comprehensive Settlement Agreement reflects compromise and settlement of all issues raised or that could have been raised in this consolidated docket. The Parties agree that Public Service's last stated position regarding its proposed 2003 Least Cost Resource Plan, whether presented by Public Service in the pre-filed Least Cost Plan volumes, its pre-filed direct, pre-filed supplemental direct, pre-filed rebuttal testimonies, or oral statements at the evidentiary hearing, should be approved by the Commission, subject to the provisions of this Comprehensive Settlement Agreement[20].

All Parties agree to support this Comprehensive Settlement Agreement. The Parties agree to join a motion that requests the Commission to approve this Comprehensive Settlement Agreement and to agree to all provisions of this Comprehensive Settlement Agreement that are binding upon the Parties of this agreement.

Unless otherwise specifically indicated, the provisions of this Comprehensive Settlement Agreement shall apply only to the Company's 2003 LCP. Unless otherwise specifically indicated, the provisions of this Comprehensive Settlement Agreement do not apply to any other Commission docket affecting Public Service or any other utility.

[20] The Intervenors' agreement in this regard should not be assumed to imply that the Intervenors necessarily support these positions or necessarily agree that such positions should be adopted in the future.

This Comprehensive Settlement Agreement is a negotiated compromise of issues and is broadly supported by Parties who include Public Service, independent energy providers, retail customers, other utilities, and public interest and environmental organizations. Nothing contained herein shall be deemed to constitute an admission or an acceptance by any party of any fact, principle, or position contained herein. Notwithstanding the foregoing, the Parties, by signing this Comprehensive Settlement Agreement and by joining the motion to approve this Comprehensive Settlement Agreement, acknowledge that they pledge support for Commission approval and subsequent implementation of these provisions.

This Comprehensive Settlement Agreement is to be treated as a complete package, not as a collection of separate agreements on discrete issues or proceedings. To accommodate the interests of different parties on diverse issues, the Parties acknowledge that changes, concessions, or compromises by a party or parties in one section of this Comprehensive Settlement Agreement necessitated changes, concessions, or compromises by other parties in other sections.

The Parties hereby agree that all pre-filed testimony and exhibits that have not already been admitted into evidence in this docket shall be admitted into evidence without cross-examination.

This Comprehensive Settlement Agreement shall not become effective until the issuance of a final Commission Order approving the Comprehensive Settlement Agreement, which Order does not contain any modification of the terms and conditions of this Comprehensive Settlement Agreement that is unacceptable to any of the Parties and which does not result in the termination of the CECP Settlement. In the event the

Commission modifies this Comprehensive Settlement Agreement in a manner unacceptable to any Party, that Party shall have the right to withdraw from this agreement and proceed to hearing on the issues that may be appropriately raised by that Party in this docket. The withdrawing Party shall notify the Commission and the Parties to this Comprehensive Settlement Agreement by e-mail within three business days of the Commission-ordered modification that the Party is withdrawing from the Comprehensive Settlement Agreement and that the Party is ready to proceed to hearing; the e-mail notice shall designate the precise issue or issues on which the Party desires to proceed to hearing (the "Hearing Notice").

The withdrawal of a Party shall not automatically terminate this Comprehensive Settlement Agreement as to the withdrawing Party or any other Party. However, within three business days of the date of the Hearing Notice from the first withdrawing Party, all Parties shall confer to arrive at a comprehensive list of issues that shall proceed to hearing and a list of issues that remain settled as a result of the first Party's withdrawal from this Comprehensive Settlement Agreement. Within five business days of the date of the Hearing Notice, the Parties shall file with the Commission a formal notice containing the list of issues that shall proceed to hearing and the list of issues that remain settled. The Parties who proceed to hearing shall have and be entitled to exercise all rights with respect to the issues that are heard that they would have had in the absence of this Comprehensive Settlement Agreement. Hearing shall be scheduled on all of the issues designated in the formal notice filed with the Commission as soon as practicable.

Due to the importance of the CECP Settlement to the timely implementation of the 2003 LCP, Public Service has agreed in the CECP Settlement that if the Commission order in this docket would result in the termination of the CECP Settlement, Public Service, and certain other Parties, shall jointly apply for rehearing, reargument and reconsideration of the Commission decision.[21] If Public Service applies for rehearing to comply with the CECP Settlement, the Parties agree that rehearing of the Commission decision and the hearing process contemplated in this Comprehensive Settlement Agreement by the withdrawal of a party, shall simultaneously go forward on parallel tracks so that the issues in this docket may be resolved at the earliest practicable time. The Parties agree that, if the Commission order on the Comprehensive Settlement Agreement could result in the termination of the CECP Settlement, Public Service immediately will request that the Commission stay the finality of the order pending resolution of the rehearing requests on this issue.

In the event that this Comprehensive Settlement Agreement is not approved, or is approved with conditions that are unacceptable to any Party who subsequently withdraws, the negotiations or discussions undertaken in conjunction with the agreement shall not be admissible into evidence in this or any other proceeding, except as may be necessary in any proceeding to enforce this Comprehensive Settlement Agreement.

Approval by the Commission of this Comprehensive Settlement Agreement shall constitute a determination that the agreement represents a just, equitable and

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[21] Pursuant to Section 17(A) of the CECP Settlement, Public Service and the Parties that are signatories to the CECP Settlement have agreed to jointly request ARRR and, if necessary, a second ARRR of any Commission order that would result in the termination of the CECP Settlement.

reasonable resolution of all issues that were or could have been contested among the Parties in this proceeding. The Parties state that reaching agreement in this docket by means of a negotiated settlement is in the public interest and that the results of the compromises and settlements reflected by this Comprehensive Settlement Agreement are just, reasonable and in the public interest.

All Parties to this Comprehensive Settlement Agreement have had the opportunity to participate in the drafting of this agreement. There shall be no legal presumption that any specific Party was the drafter of this agreement.

This agreement may be executed in counterparts, all of which when taken together shall constitute the entire agreement with respect to the issues addressed by this agreement.

Dated this 3rd day of December, 2004.

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Settlement Agreement

This Settlement Agreement is executed this ___ day of _________, 2004, by and between Public Service Company of Colorado and the Concerned Environmental and Community Parties, as defined below.

Recitals

A. Public Service Company of Colorado has proposed to construct a new 750 MW coal-fired unit at the Comanche Station located near Pueblo, Colorado.

B. Concerned Environmental and Community Parties object to the environmental impacts associated with Comanche 3 and Public Service Company of Colorado's proposed 2003 Least-Cost Resource Plan filed with the Colorado Public Utilities Commission ("CPUC").

C. This Settlement Agreement is intended to address Concerned Environmental and Community Parties' objections regarding the pre-construction air permit for the new unit at Comanche 3 and the 2003 Least-Cost Resource Plan.

Agreement

1. Parties.

A. Public Service Company of Colorado ("PSCo") is a Colorado public utility and a wholly owned subsidiary of Xcel Energy Inc., a public utility holding company. PSCo does business in Colorado as "Xcel Energy."

B. Concerned Environmental and Community Parties ("CECP") consists of the following organizations and their Affiliated Organizations:

a. Western Resource Advocates;
b. Sierra Club;
c. Environmental Defense;
d. Environment Colorado;
e. Better Pueblo;
f. Diocese of Pueblo;
g. Southwest Energy Efficiency Project;
h. Colorado Renewable Energy Society; and
i. Smart Growth Advocates.

C. The term "Affiliated Organizations" means any organization under common management and control with any of the CECP parties or any successor to any CECP party.

D. The term "PSCo" means Public Service Company of Colorado or any of its successors or assigns.

2. Definitions.

A. "Comanche 3" shall be defined to mean a new coal-fired steam electric generating unit with a net summer dependable capacity of 750 MW, and a maximum gross heat input rate of approximately 7421 million Btu per hour as set forth in the preconstruction air permit application, and to be located at the existing Comanche Station near Pueblo, Colorado. PSCo shall amend the Clean Air Act Title V operating permit for Comanche Station to reflect the rated heat input of Comanche 3 in the same manner as the rated heat input is reflected for Comanche 1 & 2.

B. "Comanche 1" and "Comanche 2" shall be defined to mean the existing coal-fired steam electric generating units located at the Comanche Station near Pueblo, Colorado. PSCo owns and operates Comanche 1 and Comanche 2.

C. "2003 LCP" shall be defined to mean PSCo's 2003 proposed Least-Cost Resource Plan and to include any contingency plans for the 2003 Least-Cost Resource Plan pursuant to Rule 3614(b)(II) of the Colorado Electric Least-Cost Resource Planning Rules or any amendments to the 2003 Least-Cost Resource Plan pursuant to Rule 3615 of the Colorado Electric Least-Cost Resource Planning Rules.

D. "All-Source Solicitation" shall be defined to mean the All-Source solicitations under the 2003 LCP.

3. Emission limits for sulfur dioxide emissions.

A. PSCo shall amend its pre-construction permit application for Comanche 3 to propose one or more emission limits for sulfur dioxide ("SO_2") that are equivalent to Best Available Control Technology ("BACT") as defined in the Clean Air Act at 42 U.S.C. § 7479(3). PSCo shall design, install and operate a lime spray dryer sulfur dioxide removal system at Comanche 3 consistent with all SO_2 emission limits determined by the Colorado Department of Public Health and Environment ("Department") to be equivalent to BACT in accordance with the federal Clean Air Act at 42 U.S.C. § 7479(3). In no event shall the mass emission SO_2 limit determined by the Department to be equivalent to BACT for Comanche 3 be less stringent than 0.1lb./mmbtu heat input on a 30-day rolling average basis including emissions from shutdown and malfunction events. PSCo shall not seek an exemption for emissions during startup, shutdown or malfunction except for emissions during cold startups but such exemption shall be for no more than two hours after coal is first fed to the boiler.

B. PSCo shall comply with the emission limits set forth and contemplated by Section 3.A within 60 days after achieving the maximum production rate at which Comanche 3 will be operated, but no later than 180 days after initial startup.

C. PSCo shall install lime spray dryer SO_2 removal systems at Comanche 1 and 2 and meet a mass emissions SO_2 limit of 0.12 lb/mmbtu heat input on each unit as determined on a 30-day rolling average basis including emissions from shutdown and malfunction events. PSCo shall not seek an exemption for emissions during startup, shutdown or malfunction except for emissions during cold startups but such exemption shall be for no more than two hours after coal is first fed to the boiler. In addition, PSCo agrees that the combined average SO_2 emissions from both Comanche 1 and 2 taken together shall not exceed a 0.1 lb/mmbtu heat input emission limit on an annual rolling average basis (rolling on a daily basis) including emissions during startup, shutdown and malfunction events.

D. Within 60 days of the effective date of this Settlement Agreement, PSCo shall incorporate the emission limits set forth in this Section for Comanche 1, 2, and 3 into the pre-construction permit application filed for Comanche 3.

4. Emission limits for oxides of nitrogen.

A. PSCo shall amend its pre-construction permit application for Comanche 3 to propose one or more emission limits for oxides of nitrogen ("NO_x") that are equivalent to BACT as defined in the Clean Air Act at 42 U.S.C. § 7479(3). PSCo shall design, install and operate a selective catalytic reduction system for NO_x removal at Comanche 3 consistent with all NO_x emission limits determined by the Department to be equivalent to BACT in accordance with the federal Clean Air Act at 42 U.S.C. § 7479(3). In no event shall the NO_x emission limit determined by the Department to be equivalent to BACT for Comanche 3 be less stringent than 0.08 lb/mmbtu heat input on a 30-day rolling average basis, including shutdown and malfunction events. PSCo shall not seek an exemption for emissions during startup, shutdown or malfunction except for emissions during cold startups but such exemption shall be for no more than two hours when natural gas-fired igniters are in use, and for no more than four hours after coal is first fed to the boiler.

B. PSCo shall comply with the emission limits set forth and contemplated by Section 4.A within 60 days after achieving maximum production rate at which Comanche 3 will be operated, but no later than 180 days after initial startup.

C. PSCo shall install advanced low-NO_x emission control or reduction technologies on the existing Comanche 1 and 2 units and meet a NO_x

emission limit of 0.2 lb/mmbtu heat input at each unit as determined on a 30-day rolling average basis, including shutdown and malfunction events. In addition, PSCo agrees that the combined average NO_x emissions from both Comanche 1 and 2 taken together shall not exceed a 0.15 lb/mmbtu heat input limit on an annual rolling average basis (rolling on a daily basis), including shutdown and malfunction events. With respect to these limits, PSCo shall not seek an exemption for emissions during start up, shutdown or malfunction except for emissions during cold startups but such exemption shall be for no more than two hours when natural gas-fired igniters are in use, and for no more than four hours after coal is first fed to the boiler.

D. Within 60 days of the effective date of this Settlement Agreement, PSCo shall incorporate the emission limits set forth in this section for Comanche 1, 2 and 3 into the pre-construction permit application filed for Comanche 3.

5. Limits for particulate matter.

A. PSCo has submitted a pre-construction permit application for Comanche 3 that proposes emission limits for particulate matter ("PM") that PSCo represents is BACT as defined in the Clean Air Act at 42 U.S.C. § 7479(3). PSCo shall design, install and operate a fabric filter dust collection system for PM removal at Comanche 3 consistent with all PM emission limits determined by the Department to be BACT in accordance with the federal Clean Air Act at 42 U.S.C. §§ 7475(a)(4) and 7479(3). In no event shall the PM limits determined by the Department to be BACT for Comanche 3 be less stringent than those set forth below, and within 60 days of this Settlement Agreement PSCo shall amend its pre-construction permit application to incorporate such limits to the extent they are not currently in such application:

a. Filterable PM_{10} emissions shall be no greater than 0.0130 lb/mmbtu heat input;

b. Total PM_{10} emissions (including condensibles) shall be subject to enforceable emission limitations as determined by the Department;

c. Opacity shall be no more than 10 percent on a 6-minute average, excluding excess emissions during periods of startup, shutdown and malfunction if properly documented and reported consistent with 40 C.F.R. 60.7(c) and any other applicable requirements.

The emission limits set forth in this Section shall become enforceable under this Settlement Agreement in accordance with the terms of the final Comanche 3 preconstruction permit.

6. Installation and compliance schedule.

PSCo shall design and install all SO_2 and NO_x control equipment required to comply with the emissions limitations for Comanche 1 and 2 described in, and contemplated by, Sections 3 and 4 so that such control equipment is operational by December 31, 2008. PSCo shall meet the unit-specific emission limits for Comanche 1 and 2 no later than 180 days after initial startup of the SO_2 and NO_x control equipment for each unit, or by July 1, 2009, whichever is earlier. PSCo shall begin calculating compliance with the SO_2 and NO_x combined annual rolling average emission limits (rolling on a daily basis) for Comanche 1 and 2 no later than 180 days after initial startup of the SO_2 and NO_x control equipment for the last unit. PSCo shall incorporate the installation and compliance schedule for Comanche 1 and 2 set forth in this Section into the pre-construction permit application filed for Comanche 3.

Compliance with the SO_2, NO_x, and opacity limits set forth in, or contemplated by, this Settlement Agreement shall be determined at the Comanche Station by continuous SO_2, NO_x, and opacity monitors, and any other monitors or systems required by the Department or the U.S. Environmental Protection Agency ("EPA"), and PSCo shall install and operate all such monitoring systems in conformance with all applicable Department and EPA requirements and performance specifications.

7. Monitoring, testing and emission limits for mercury.

A. PSCo shall comply with any applicable mercury emission limitations and requirements at Comanche 1, 2, and 3, including the requirement for case-by-case maximum achievable control technology emission limitations under the Clean Air Act at 42 U.S.C. § 7412(g)(2) for Comanche 3. PSCo shall also amend its permit application for Comanche 3 to request a mercury emission limit at Comanche 3 that is at least as stringent as the $20x10^{-6}$ lb/MWh mercury emission limit as proposed by EPA at 69 Fed. Reg. 4652 (January 30, 2004) for new coal-fired steam electric generating units burning sub-bituminous coal.

B. Within one year after the date that the Comanche 3 pre-construction air permit is issued by the Department, PSCo shall install, properly maintain and operate a continuous mercury emissions monitoring system on Comanche 1 and 2 using Q-SEMS technology as described at 69 Fed. Reg. at 4694 (January 30, 2004), or such other technology as the Parties may agree. PSCo shall monitor mercury emissions from Comanche 1 and 2 beginning 18 months after the issuance of the Comanche 3 air permit and shall report the quality assured and quality controlled data to CECP and the Department on a calendar quarterly basis thereafter.

C. PSCo shall operate and maintain the mercury monitoring technology in accordance with EPA requirements and the manufacturer's specifications. In the event of any mercury monitoring technology malfunction, PSCo shall either repair or replace such monitoring technology. If the mercury monitoring technology identified in Section 7.B is unable to meet applicable performance requirements, despite PSCo's efforts to repair and replace such technology, PSCo agrees to install alternate mercury monitoring technology unless technologically or economically infeasible or to conduct annual stack testing if monitoring technology is technologically or economically infeasible.

D. Within 60 days after achieving the maximum production rate at which Comanche 3 will be operated, but in no event later than 180 days after initial startup of Comanche 3, PSCo shall install equipment necessary to use sorbent injection technology to control mercury at Comanche 3. On or before the SO_2 and NO_x controls installation deadline for Comanche 1 and 2 as provided in Section 6, PSCo shall install equipment necessary to use sorbent injection technology to control mercury at Comanche 1 and 2.

E. Within 60 days after achieving the maximum production rate at which Comanche 3 will be operated, but no later than 180 days after initial startup, PSCo shall test for a period of one year different mercury emission control methods or technologies on Comanche 1 and 2. Such methods or technologies shall be selected by PSCo in its sole discretion after consultation with CECP and may include methods or technologies other than sorbent injection. PSCo shall provide CECP with a report detailing the results of the tests, the conclusions arising from the tests and the bases for such conclusions. The report required under this paragraph shall be provided to CECP within 18 months after the commencement of the testing required by this paragraph. If PSCo claims information in the report contains trade secrets, any organization listed in Section 1 shall nevertheless be allowed to review such information after signing a reasonable confidentiality agreement that ensures that such trade secrets are protected.

F. No later than two years after the initial startup of Comanche 3, PSCo shall comply with a plant-wide mercury emission limit for the Comanche Station that maximizes cost-effective (as defined below) mercury reductions on a plant-wide basis. To implement this paragraph, PSCo shall propose a plant-wide emission limit to the Department in accordance with this paragraph after consultation with CECP. Unless otherwise agreed by the Parties, PSCo shall comply with an emission limit under this paragraph that represents the maximum cost-effective reduction of mercury at Comanche Station, achievable through the expenditure of no less than $2 million per year and no more than $5 million per year in the first year's operations and maintenance costs directly associated with mercury controls, excluding mercury monitoring costs and the operations and maintenance control costs for SO_2, NO_x, PM or any other pollutant regardless of whether such controls reduce mercury emissions but including the mercury control costs necessary to comply with the applicable mercury emission limitations set forth in Paragraph 7.A. If PSCo proposes to set an emission limit that will cost less than $5 million per year in the first year operations and maintenance costs to maximize the reduction of mercury, PSCo shall bear the burden of demonstrating to the Department that a more stringent emission limitation than that proposed by PSCo is not cost-effective based on a dollar per pound of mercury removed.

PSCo shall seek from the Department a determination under this paragraph that is reviewable by the Colorado Air Quality Control Commission in a proceeding in which CECP may be a party. The Parties recognize that the Department shall have the responsibility to set the emission limit in accordance with its procedures. PSCo agrees that CECP shall have full rights and discretion under law to participate in the Department's proceeding and in any subsequent review by the Colorado Air Quality Control Commission commenced in accordance with this paragraph.

G. Within 60 days after the effective date of this Settlement Agreement, PSCo shall amend its preconstruction air permit application for Comanche 3 to incorporate the requirements of Section 7.A that are applicable to Comanche 3 and to incorporate the requirement to install and operate the Q-SEMS technology under this Section.

8. Other air permit issues.

A. This Settlement Agreement is not a permit. Furthermore, PSCo shall comply with all applicable present and future federal, state and local laws, regulations and permitting requirements regardless of whether they are set forth in this Settlement Agreement. To the extent any conflict arises between any requirement in this Settlement Agreement and any other applicable present or future requirement described above, the most stringent requirement shall apply.

B. Notwithstanding any other provision of this Settlement Agreement, PSCo retains ownership of and all rights associated with any and all credits or emission allowances allocated to it under any law, rule, regulation, policy, or contract, whether such law, rule, regulation, policy or contract is currently in effect or becomes effective in the future.

C. In addition to other purposes, PSCo is installing the emission controls on Comanche 1 and 2 pursuant to this Settlement Agreement for the purpose of netting out of Prevention of Significant Deterioration ("PSD") review for SO_2 and NO_x for Comanche 3; as such controls are necessary and appropriate to ensure timely permitting of Comanche 3. PSCo agrees that such emission reductions necessary for netting shall become federally enforcable in the pre-construction permit and, pursuant to Section 16.F, the Clean Air Act Title V operating permit. All other emission reductions required by this Settlement Agreement shall become federally enforceable as otherwise provided under the Agreement.

D. In addition to the other emission limits, acid gas emissions (including sulfuric acid mist, hydrogen fluoride and hydrogen chloride) shall be subject to enforceable emissions limitations as determined by the Department.

E. Provided that PSCo's pre-construction air permit application, and the final permit, are consistent with Sections 3-8 of this Settlement Agreement, CECP agrees that it shall not submit any adverse formal comments or testimony on the permit application or proposed or final permit to the Department or EPA during the pre-construction permit review proceeding for Comanche 3 unless any provision in such permits is materially inconsistent with, or materially diminishes the stringency of, any requirement in this Settlement Agreement. Notwithstanding the above, if PSCo appeals any Comanche 3 permit term, CECP shall be allowed to intervene and participate as a party in the appeal proceeding regarding such term.

F. The Parties agree that they shall provide the Department with a copy of this Settlement Agreement as part of the pre-construction air quality permit proceeding for Comanche 3.

G. PSCo shall include in its pre-construction air permit application for Comanche 3 and the air permit for Comanche 1 and 2 a request for a condition that, at all times, including periods of startup, shutdown, and malfunction, PSCo shall, to the extent practicable, maintain and operate any emission control equipment required under this Settlement Agreement in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Department which may include, but is not limited to, monitoring results, observations, review of operating and maintenance procedures, and inspection of the source.

9. Additional environmental mitigation.

To mitigate the potential impacts to the Pueblo area of emissions from Comanche 3:

A. Within 3 months after issuance of the preconstruction air permit for Comanche 3, PSCo shall contribute $50,000 to the Department for implementation of a program to reduce mercury contamination in shredded car bodies provided to the Rocky Mountain Steel plant in Pueblo. PSCo shall make an additional contribution of $50,000 to the Department for the same program within one year after its initial contribution.

B. Within 6 months after the issuance of the Comanche 3 air permit, PSCo shall contribute a total of $250,000 to Pueblo School Districts No. 60 and 70 to reduce air pollution from existing diesel school buses in the Pueblo area, provided that the school districts agree to accept the donation, maintain the funds in a separate account, and expend the funds to achieve the maximum reduction of air pollution from existing diesel school buses at the least cost. School bus emissions may be reduced through any one or more of the following: retrofitting existing buses with EPA verified pollution control devices such as particulate filters and diesel oxidation catalysts, replacing existing buses with new buses that are consistent with EPA's Clean School Bus USA program, and using ultra-low sulfur diesel fuel or other cleaner fuels.

10. Sustainable development in the Pueblo region.

A. PSCo and CECP shall jointly sponsor, in cooperation with other appropriate stakeholders, a series of public forums addressing sustainable development in the Pueblo area. The parties shall invite other stakeholders from the Pueblo community (including, but not limited to, the Pueblo Economic Development Corporation, Better Pueblo, industry, government and citizens of Pueblo and surrounding areas) to participate in the public forums.

B. The sustainable development forums shall consider and examine the following issues generally applicable to the Pueblo community:

a. Long-term economic development;

b. Energy and technology issues;

c. Environmental concerns;

d. Environmental justice;

e. Public safety;

f. Water and water rights; and

g. Other issues that the forums may identify.

C. In conjunction with these forums, PSCo shall participate in the Pueblo Sustainable Development Program.

D. PSCo and CECP shall make best efforts to begin these forums within three months and shall begin these forums no later than four months after execution of this Settlement Agreement. Both parties are jointly responsible for the logistics and arrangement of these meetings. PSCo recognizes that CECP shall not have any financial responsibility under this Section. The Parties shall make best efforts to include other stakeholders in the process by the date of commencement of the forums.

E. Among other things, the forums created hereunder shall:

a. consider the preparation of a study to identify appropriate analytical tools to help the community evaluate the impact of economic development proposals; and

b. identify opportunities to seek funding from third party charitable foundations or other sources for technical assistance on sustainable development issues. PSCo shall provide reasonable assistance, appropriate involvement and support in seeking such funding.

F. PSCo's obligations under this Section shall cease upon termination of the Settlement Agreement unless otherwise agreed to by the Parties.

11. Emissions data.

A. Beginning within one year after the date that the Comanche 3 pre-construction air permit is issued by the Department, PSCo shall make available on the Xcel Energy website electronic links to the emissions reports and emissions data related to the Comanche plant that are submitted to EPA and the Department. Such reports and data shall be made available only after they have been subject to quality assurance and quality control measures.

B. PSCo shall use its best efforts to make the emissions data described in this Section available on the Xcel Energy website within 30 days after submission to EPA

C. PSCo shall provide each organization listed under Section 1 an opportunity to review and comment on the format of the emissions data posted on its website under this Section.

12. Carbon Dioxide Proxy Cost.

A. PSCo shall include a carbon dioxide ("CO_2") proxy cost in its analysis and evaluation of the cost of resource bids submitted in response to the All-Source Solicitation. PSCo shall issue the Request for Proposals ("RFP") for the All-Source Solicitation consistent with this Section.

B. The CO_2 proxy cost shall:

a. be set at $9 per ton[1] of CO_2;

b. be first applied to resources beginning in the year 2010 in the bid evaluation process; and

c. escalate at a rate of 2.5% per year starting in 2011 and continuing over the planning life of the resource.

C. The CO_2 proxy cost shall be included in both the initial economic screening and in the dynamic portfolio optimization steps of the bid evaluation process. In evaluating bids during the initial economic screening, PSCo shall reflect the costs associated with the CO_2 proxy cost as a $/MWh variable operating cost. In evaluating the bids dynamically, PSCo shall model the costs associated with the CO_2 proxy cost as a $/MWh variable operating cost affecting resource dispatch. In the dynamic portfolio optimization modeling, the CO_2 proxy cost shall be applied to both existing and new resources. For any CO_2 emitting resource, the variable $/MWh CO_2 cost of a resource shall be calculated using the following formula:

$$CO_2\ cost_t = [E_t * HR_t * C_t]/(2*10^6)$$

where: E_t = CO_2 emission rate of the resource in lb/mmbtu heat input at time t;
HR_t = heat rate of the resource in btu/kWh at time t; and
C_t = CO_2 proxy cost in $/ton at time t.

13. Innovative technologies.

A. PSCo and CECP shall work jointly on innovative technologies, practices and measures to examine cost-effective programs and strategies to reduce greenhouse gas emissions, including but not limited to the innovative technology program described herein. The programs and strategies may also include terrestrial or geological carbon sequestration and small-scale and community-owned renewable energy projects.

B. PSCo shall work with CECP to seek passage of legislation in the 2005 legislative session of the Colorado General Assembly to create the framework for an innovative technology program in the state of Colorado. The innovative technology program shall promote the use of innovative technologies on a demonstration scale to generate or conserve electricity for Colorado electricity consumers. The program shall promote the use of technologies designed to allow more efficient production or consumption of electricity with fewer emissions of greenhouse gases on a plant or system-wide basis. The program shall ensure that utilities implementing a demonstration project under its terms shall have the right to full and timely recovery of all costs associated with any subject demonstration project.

C. If the Colorado General Assembly enacts innovative technology program legislation consistent with Section 13.B in the 2005 legislative session, PSCo shall, within 12 months after the date that the Comanche 3 pre-construction air permit is issued by the Department, propose an innovative technology demonstration project under the terms of that program. Such innovative technology demonstration project shall be selected by PSCo in its sole discretion after consultation with CECP. In proposing the project under this paragraph, PSCo may consider technologies that include, but are not limited to, compressed air storage/wind combination, renewably generated hydrogen for fuel cells, or integrated gasification combined cycle power plants fueled with western coal.

D. The Parties shall consider siting the innovative technology measures, practices or demonstration project in the Pueblo area.

E. The goal of the innovative technology demonstration project under this Section shall be to reduce in a cost-effective manner CO_2 emissions by a cumulative total of 1.67 million tons as measured over the years 2006-2013. Progress toward the cumulative 1.67 million ton reduction goal shall be measured through expansion or production cost model projections associated with the innovative technology demonstration project. PSCo shall make its best efforts to achieve this goal. The Parties recognize that the performance of innovative technology demonstration projects is uncertain, and cost or technology performance problems may prevent achievement of the goal.

F. Notwithstanding the foregoing, PSCo shall not be required to achieve the CO_2 mitigation goal set forth above or implement the innovative technology practices, measures or demonstration project above unless it receives adequate assurance of timely cost recovery and all required approvals for the practices, measures or projects.

G. The Parties agree to work in good faith to obtain additional funding for the innovative technology demonstration project from the United States Department of Energy and obtain authority to implement the project and recover its costs from the Colorado General Assembly and the Public Utilities Commission, as appropriate.

14. Energy Efficiency.

A. PSCo shall use its best efforts to acquire, on average, 40 MW of demand reduction and 100 GWh of energy savings per year over the period beginning January 1, 2006 and ending December 31, 2013, so that by January 1, 2014, the company will have achieved 320 MW of total demand reduction and 800 GWh of annual energy savings. Notwithstanding the foregoing sentence, PSCo's actual annual demand reductions and energy savings during this period may vary from these averages. PSCo shall expend $196 million (in 2005 dollars) to meet such demand reduction and energy savings unless these demand reduction and energy savings are achieved with a lower level of expenditure. The demand-side management ("DSM") levels set forth in this Section shall include the demand reduction and energy savings achieved by PSCo through the All-Source Solicitation. All DSM programs implemented outside of the All-Source solicitation shall be required to pass the Total Resource Cost test. PSCo shall strive to implement a set of DSM programs that give all classes of customers an opportunity to participate.

B. PSCo shall conduct a market study to determine, generally, levels of efficiency available for various customer classes and the costs associated with such measures, and whether such levels of DSM are cost-effective and prudent in Colorado. In addition, PSCo shall conduct program-specific market and load research, and ongoing DSM program measurement and evaluation. The cost of the market study and these other research and evaluation activities is included in the total amount of DSM expenditures in Section 14.A but shall not exceed $4 million. PSCo agrees to involve other stakeholders in the design of the market study and the review of the contractor summary results. PSCo shall complete the study as expeditiously as practicable, but no later than March 31, 2006.

C. PSCo shall be entitled to fully recover its expenses and investments associated with the acquisition of the DSM programs under Section 14.A and the cost of the market study and other activities described in Section 14.B through PSCo's Demand-Side Management Cost Adjustment Clause or other mechanisms.

D. Within three months of completing the market study described in Section 14.B but no later than July 1, 2006, PSCo shall request that the CPUC open a docket to consider issues related to DSM, including the appropriate test used to judge the cost effectiveness of DSM projects, the viability of additional DSM in Colorado's economy, best DSM practices and other issues related to increased investment in energy efficiency measures by PSCo. In this docket, the Parties shall advocate a DSM policy that (1) uses the Total Resource Cost test to determine the cost-effectiveness of DSM programs; (2) provides for recovery of all costs of approved DSM programs, including, but not limited to, administrative, internal and external labor, and promotion costs; and (3) creates an incentive mechanism that promotes PSCo's investments in additional energy efficiency beyond the levels set forth in Section 14.A. The incentive program described in this paragraph may include compensation to PSCo for its loss of energy sales as a result of the DSM program.

E. PSCo shall report to the CPUC and other parties on DSM expenditures, energy savings, and peak demand reductions achieved by the programs each year.

F. PSCo shall establish and maintain a DSM working group that shall meet at least twice a year. The DSM working group shall be open to all interested parties and shall provide input to PSCo in DSM program design, analysis and other issues relevant to helping PSCo meet or exceed the minimum energy savings and peak demand reduction levels.

15. Renewable energy.

A. PSCo shall accelerate and complete those components of the wind ancillary service cost study[2] that are necessary to obtain projections of ancillary service costs for nameplate wind capacity penetration levels of 15% of PSCo's system peak demand. These necessary components of the study shall be completed in time to evaluate wind resource bids submitted in the All-Source Solicitation. For purposes of the study, the 15% wind penetration level shall be based on PSCo's 2007 peak demand forecast or the Company's best available peak demand forecast for 2007 at the commencement of the study. The study shall include consideration of the operational flexibility of its Cabin Creek pumped-storage generation facility. PSCo has solicited participation of stakeholders on a technical review committee with the intent of incorporating their specific interest and knowledge base into the study. The invitation was sent to industry experts, intervenors, PUC staff and PSCo personnel. PSCo shall produce a report detailing the results of the study. If PSCo claims information in the report is confidential, any member of the technical review committee or any organization listed in Section 1 shall nevertheless be allowed to review such information after signing a reasonable confidentiality agreement that ensures that commercially sensitive or trade secret information is protected.

B. As previously ordered by the CPUC in the 2003 LCP Renewable Energy RFP docket, PSCo shall use an ancillary service cost of $2.50/MWh (escalating at the same rate as gas prices) for wind bids up to 500 MW that are acquired in the renewable energy RFP. PSCo shall use the results of the study in Section 15.A to evaluate all wind bids in the All-Source Solicitation.

C. PSCo shall accept wind bids up to a 15% penetration level, so long as the wind bids are part of PSCo's Least Cost Resource Portfolio. For this purpose, the 15% wind penetration level shall be based on PSCo's peak demand forecast used to determine resource need and acquisition at the time of the bid evaluations and shall be calculated based on the year in which the wind resource would be projected to come on-line. If PSCo selects wind generation resources in response to the Renewable Energy RFP and All-Source Solicitation that increase nameplate wind generation on its system above 720 MW, PSCo agrees to undertake an additional wind ancillary service cost study to obtain projections of ancillary service costs at a 20% penetration level. This additional 20% wind penetration study shall be used to inform subsequent resource solicitations. PSCo shall not be required to "hold" bids for further evaluation pending the outcome of the 20% wind penetration study, but nothing in this Settlement Agreement prevents PSCo from doing so.

D. PSCo shall use a capacity value of wind generation resources equal to 10% of nameplate capacity in evaluating bids submitted in response to the All-Source Solicitation. PSCo shall perform a study of effective load carrying capability on its system as a means of determining the capacity value of wind generation resources. The study shall include consideration of the uncertainty or variability of hourly wind generation patterns from year to year and the combined effects of diverse wind farm locations. PSCo agrees to (1) file, by November 1, 2006, the study results with the CPUC; (2) advocate that the reliability contribution or capacity value of wind generation resources should be based on a method that incorporates consideration of reliability contribution in all hours in the year; and (3) include recommendations for ascribing capacity value to existing and new wind generation resources. PSCo shall solicit participation of industry experts, intervenors, CPUC Staff and PSCo personnel on a technical review committee with the intent of incorporating their specific interest and knowledge base into the study. PSCo shall produce a report detailing the results of the study. If PSCo claims the information in such report is confidential, any member of the technical review committee or any organization listed in Section 1 shall nevertheless be allowed to review such information after signing a reasonable confidentiality agreement that ensures that commercially sensitive or trade secret information is protected.

E. PSCo shall include a renewable energy credit ("REC") value of $8.75/MWh in its analysis and evaluation of the cost of renewable resource bids submitted in response to the All-Source Solicitation. To qualify for the REC value in the bid evaluation, a renewable energy bid must meet the definition of "Eligible Renewable Energy Resource" under the 2004 Colorado Ballot Initiative Amendment 37 as may be updated by the Colorado Legislature by the time that bids are due in the All-Source Solicitation. The REC value shall be included in both the initial economic screening and in the dynamic portfolio optimization steps of the bid evaluation process. PSCo shall apply the REC value to renewable resource bids in the All-Source Solicitation, for all operating years of the renewable energy project beginning in 2006. CECP acknowledges that nothing in this provision shall prohibit PSCo from negotiating with individual bidders exceptions to the Model Nondispatchable Power Purchase Agreement allowing such bidders to retain some or all the RECs associated with a renewable energy bid, but such bids shall not include the $8.75 REC value in the bid evaluations in the All-Source Solicitation for any RECs so retained.

16. Commitments of the Parties.

A. As long as PSCo remains in material compliance with this Settlement Agreement, the CECP organizations agree not to make any adverse formal comments before the Department or EPA or to bring a lawsuit asserting that any projects or construction undertaken at Comanche Station prior to the effective date of this Settlement Agreement in any way violated the requirements of section 165(a) of the federal Clean Air Act, 42 U.S.C. § 7475(a), or the related requirements of the federally enforceable applicable implementation plan. The CECP organizations also agree not to initiate, fund or participate in any such comments or lawsuit by any other entity. If for any reason PSCo does not materially comply with this Settlement Agreement, or otherwise does not satisfy its obligations, or if the Department does not issue a proposed or final Clean Air Act pre-construction permit and/or Clean Air Act Title V operating permit that is consistent with the terms of this Settlement Agreement in all material respects, the CECP organizations are released from their agreement not to comment or sue described above in this paragraph. PSCo agrees that in any ensuing proceeding PSCo shall not use or count the period of time in which CECP's agreement not to challenge or sue was in effect as support for any otherwise available defense of statute of limitations, laches, delay or other defense based on failure to timely comment on or prosecute any such violations of the federal Clean Air Act or the federally enforceable applicable implementation plan.

B. The Parties agree that this Settlement Agreement is a fair and reasonable resolution of the issues related to the construction and operation of Comanche 3 as addressed in this Settlement Agreement. Subject to Section 8.A, the reservation of rights in Section 17.J, and the dispute resolution and repudiation provisions in Sections 17.F. and 17.G, the CECP organizations agree they shall not initiate, fund or participate in any formal administrative or legal action to oppose or knowingly impede any of the following administrative or regulatory approvals necessary for PSCo to construct or operate Comanche 3 in accordance with this Settlement Agreement:

a. The issuance of a certificate of public convenience and necessity ("CPCN") for Comanche 3 in the 2003 LCP proceeding;

b. The granting of PSCo's application to waive Rule 3610(b) of the CPUC Least Cost Planning Rules for Comanche 3 in the 2003 LCP proceeding; and

c. The issuance of the pre-construction air permit by the Department or the authorized permitting authority required for the construction of Comanche 3 and the Clean Air Act Title V operating permit for the Comanche Station necessary to implement this Settlement Agreement. Notwithstanding the above, the CECP organizations reserve their right to comment on and challenge any provision in such permits that is materially inconsistent with, or materially diminishes the stringency of any requirement in, this Settlement Agreement.

C. CECP agrees that if any of the CECP organizations initiate, fund or participate in any administrative or legal action to oppose or knowingly impede the permitting or approval of any activities necessary to complete the construction and initial startup of Comanche 3, including associated facilities such as the CPCN and right-of-way for the transmission, PSCo may take action to terminate this Settlement Agreement in accordance with the pre-enforcement and repudiation procedures in Section 17. Before taking any such action, any CECP organization may notify PSCo of any grievance it has with respect to any proposed permit or approval and PSCo shall meet with the CECP organization and use its best efforts to resolve timely such grievance. Upon termination under this paragraph, PSCo shall be relieved of any obligations under this Settlement Agreement, including any obligation to install emission controls under Sections 3-7, except as provided below. CECP's obligations under Sections 16.A and B shall survive termination under this paragraph. If PSCo's rights under this paragraph have been triggered after the pre-construction air permit for Comanche 3 is final and effective, PSCo's obligation to achieve and maintain compliance with the NO_x and SO_2 emission limits in this Settlement Agreement applicable to Comanche 1 and 2 shall survive termination.

D. In addition to the foregoing, the organizations listed under Section 1 that are Parties to the 2003 LCP/CPCN proceeding before the PUC agree not to oppose the regulatory plan submitted by PSCo in conjunction with the 2003 LCP/CPCN proceeding as such plan may be modified by PSCo so long as such regulatory plan is not inconsistent with and does not interfere with the requirements of this Settlement Agreement, and to support PSCo's recovery of the costs of all environmental components of this Settlement Agreement, including, but not limited to, the costs of any emission control equipment for the Comanche Station required hereunder. The organizations listed under Section 1 that are Parties to the 2003 LCP/CPCN shall not be bound to intervene in any future proceedings before the CPUC. The provisions of this paragraph do not apply to any CECP organization that is not a party to the PUC's 2003 LCP/CPCN proceeding.

E. Through a process established by mutual agreement of the parties, PSCo shall consult with CECP at least quarterly after execution of the Settlement Agreement to discuss the material issues associated with the implementation of the Settlement Agreement and other issues identified by mutual agreement. PSCo shall use best efforts to provide information as set forth in this paragraph, and its failure to provide information pursuant to this paragraph shall not be considered a breach of this Settlement Agreement. PSCo's obligation under this paragraph shall cease upon termination of the Settlement Agreement unless otherwise agreed by the Parties.

F. No later than 60 days after the last date for achieving the emission limits in this Settlement Agreement for Comanche Station, except for the mercury emission limit, PSCo shall file with the Department a proposed amendment to the Comanche Station Clean Air Act Title V operating permit to incorporate into the Title V permit such emission limits and all related applicable requirements set forth in this Settlement Agreement. If, however, the Comanche Station Title V permit will expire within 24 months of the last date described above, PSCo may advance or delay filing the application to amend the Title V permit until PSCo files its application to renew the Title V permit. PSCo agrees to include in any Title V permit for Comanche Station requirements no less stringent than those set forth in, or contemplated by, Sections 3-9 of this Settlement Agreement, which obligation shall survive termination of this Settlement Agreement under Section 20.

17. Enforceability and Reservation of Rights.

A. PSCo shall seek CPUC approval for the commitments in sections 3, 4, 5, 6, 7, 8, 12, 14, and 15 of this Settlement Agreement as part of the Commission order on the 2003 LCP. If CPUC action on such commitments is not approved and ordered in full, if a CPUC order significantly impedes implementation of any commitments under this Settlement Agreement, or if the CPUC order approving such commitments is reversed on judicial appeal in any significant respect, the Parties' obligations under this Settlement Agreement are terminated. If the Commission order on the 2003 LCP does not approve such commitments or if the Commission order on the 2003 LCP significantly impedes implementation of any commitments under this Settlement Agreement, PSCo and any party to the 2003 LCP proceeding listed under Section 1 that wish to seek rehearing, reargument or reconsideration agree to jointly request rehearing, reargument or reconsideration of the Commission order and, if necessary, request second rehearing, reargument or reconsideration. If PSCo reaches agreement with other parties to the 2003 LCP proceeding that significantly impedes implementation of any commitment under this Settlement Agreement, the Parties' obligations under this Settlement Agreement are terminated. PSCo agrees that if this Settlement Agreement is terminated under the provisions of this paragraph, PSCo shall not use or count the period of time in which CECP's agreement not to challenge or sue under Section 16.A was in effect as support for any otherwise available defense of statute of limitations, laches, delay or other defense based on failure to timely prosecute any such violations of the federal Clean Air Act or the federally enforceable applicable implementation plan.

B. Each organization listed under Section 1 shall have the full rights under the law afforded persons or corporations to enforce CPUC orders including the rights and powers under C.R.S. 40-7-101, et seq.

C. If PSCo fails to make amendments to its preconstruction air quality permit application for Comanche 3 or to propose emission limitations for Comanche 1 and 2 as required by this Settlement Agreement, or if either the Department's final federally enforceable Clean Air Act preconstruction permit or the Clean Air Act Title V operating permit for the Comanche Station is not materially consistent with the terms of this Settlement Agreement, or upon expiration of the pre-construction air permit for Comanche 3 before construction commenced, all of the Parties' obligations under this Settlement Agreement are terminated including but not limited to CECP's agreement not to comment, challenge or sue for alleged violations of the Clean Air Act under Section 16.A. In the event of termination under this paragraph, PSCo shall not oppose CECP's rights to challenge any pre-construction air quality or Clean Air Act Title V operating permit related to Comanche 3 or the Comanche Station solely as a result of CECP's failure to participate in the pre-construction air permitting administrative process.

D. CECP's Remedies for Breach. In consideration of PSCo's commitments under this Settlement Agreement, CECP and its Affiliated Organizations have agreed to forebear the exercise of specific procedural and substantive rights as set forth in Section 16 of the Settlement Agreement. In the event PSCo fails to perform any material obligation or commitment under Sections 3-11 of this Settlement Agreement, each organization listed under Section 1 or any Affiliated Organization shall, after exhausting the pre-enforcement procedures of Section 17.F, have the full discretion and rights to seek judicial or administrative relief to compel performance of such obligations pursuant to the terms hereof. PSCo hereby stipulates to subject matter jurisdiction under Colorado law, and to any such organization's standing to enforce specific performance of Sections 3-11 of this Settlement Agreement. In the event PSCo fails to perform any material commitments under Sections 3-11 of the Settlement Agreement, each of the organizations listed under Section 1 shall also have the option of exercising any rights that CECP has agreed to forego if this Settlement Agreement is fully performed.

E. PSCo's Remedies for Breach. In the event there is an alleged breach of Section 16 of the Settlement Agreement, PSCo, after exhausting the pre-enforcement and repudiation procedures of Section 17.E and 17.F, may bring suit against the particular organization listed under Section 1 that is alleged to be in violation. To the extent any alleged breach results in PSCo incurring additional costs or delay in the permitting or construction anticipated under this Settlement Agreement, PSCo may seek injunctive relief against the allegedly breaching organization. As provided in Section 17.H, each organization listed under Section 1 is a distinct and separate entity and the actions of one organization listed under Section 1 shall not be imputed to another. If injunctive relief for breach of this Settlement Agreement is granted against any of the organizations listed under Section 1 or a reviewing court declares any organization listed under Section 1 is in breach of this Settlement Agreement, PSCo shall not be obligated to undertake any action required under this Settlement Agreement including but not limited to the installation of emission control equipment on Comanche 1 and 2, provided that PSCo has complied with the material requirements under this Settlement Agreement prior to the alleged breach by the CECP organization.

F. Pre-enforcement Procedures. Before pursuing judicial relief to compel performance of obligations set forth in this Settlement Agreement, or before exercising any right to terminate this Settlement Agreement, CECP and PSCo shall first invoke the following notice and alternate dispute resolution procedures:

a. Notice. The affected Party shall provide written notice of alleged material breach to all parties to this Settlement Agreement. Such notice shall include a reasonable description of the facts and circumstances surrounding the alleged material breach, the term(s) of the Settlement Agreement at issue, and the measure(s) sought to correct any breach.

b. Informal Dispute Resolution. Within five business days of receipt of notice of alleged breach, the Parties shall meet and confer in person or by conference call at a mutually convenient time and place in an effort to resolve the alleged breach. Discussions to resolve the dispute among the parties shall continue for no less than 15 business days from the time notice of alleged breach is received and the affected party shall not institute or pursue an action in either state or federal court during this period. The bar against instituting or pursuing judicial enforcement of the obligations in this Settlement Agreement may be extended by mutual agreement of the Parties beyond the minimum period required for notice and informal dispute resolution.

c. Notice of Intent to Sue. Should the Parties be unable to resolve their disagreements within 15 business days from the time notice of alleged breach is received or the mutually agreed enlarged time for informal dispute resolution, the affected Party shall have the right, upon providing five business days notice of intention to seek judicial relief to all Parties, to seek judicial enforcement of the terms of this Settlement Agreement.

d. The requirements in this Section shall survive after termination of this Settlement Agreement to the extent any party seeks to enforce any obligation that survives after termination.

G. Repudiation by CECP. If any organization listed under Section 1 or any Affiliated Organization allegedly acts in breach of the commitments made in this Settlement Agreement, the organization listed under Section 1 or Affiliated Organization whose name has been invoked may repudiate such action either by letter (or other means mutually acceptable to the organization or Affiliated Organization and PSCo) within 15 business days of being informed of the alleged breach by PSCo pursuant to Section 17.E. Such letter or other mutually acceptable means shall constitute full and complete performance of the duties of any such organization or Affiliated Organization arising from the Settlement Agreement, and PSCo shall have no right to terminate or otherwise avoid its obligations under this Settlement Agreement. This provision shall survive termination of this Settlement Agreement.

H. The Parties agree that in no instance shall any Party or individual be responsible or liable for monetary damages, attorneys fees and/or costs incurred as a result of any alleged breach or breach of this Settlement Agreement. The parties acknowledge and agree that damages are not available as a remedy in the event the obligations of this Settlement Agreement are breached. The parties agree that damages would not be an adequate remedy for noncompliance with this Settlement Agreement, and that no adequate remedy at law exists for noncompliance with the terms of this Settlement Agreement. Accordingly, the parties expressly acknowledge that an award of equitable relief would be an appropriate remedy for a breach of the obligations under this Settlement Agreement, provided the reviewing court has followed standard procedures in issuing injunctive relief.

I. This Settlement Agreement does not create any legal relationship between or among the organizations listed in Section 1. Western Resource Advocates, Sierra Club, Environmental Defense, Environment Colorado, Better Pueblo, Diocese of Pueblo, Southwest Energy Efficiency Project, Colorado Renewable Energy Society, and Smart Growth Advocates are each separate and distinct organizations, and the actions of one organization shall not be imputed to another. The use of the term "Concerned Environmental and Community Parties" or "CECP" in this Settlement Agreement is intended merely for convenience and does not in any manner imply that one organization shall be held accountable or liable for the actions of another. Thus, each party is responsible only for its own actions and this Settlement Agreement is not intended to and does not in any manner create rights, duties, liabilities or legal consequences for the individual and separate entities Western Resource Advocates, Sierra Club, Environmental Defense, Environment Colorado, Better Pueblo, Diocese of Pueblo, Southwest Energy Efficiency Project, Colorado Renewable Energy Society, and Smart Growth Advocates arising out of the actions of any CECP or non-CECP organization, whether or not that organization is a party to this Settlement Agreement. No joint venture, agency, partnership or other fiduciary relationship shall be deemed to exist or arise between or among the parties or CECP groups as a result of this Settlement Agreement.

J. Further Reservation of Rights

a. Without in any way limiting CECP's commitments under Sections 16.A and 16.B, CECP reserves all rights not expressly waived in this Settlement Agreement, including but not limited to all rights:

- to seek administrative or judicial relief to address any violation of law by any private or governmental entity or any person;
- to challenge or enforce any federal, state or local statutory or regulatory or permit requirements, including any pre-construction permit application not required or necessary to complete the construction of Comanche 3 and associated facilities;
- to enforce any federal, state or local statutory or regulatory or permit requirements related to the operation of the Comanche Station after the effective date of and not otherwise addressed by this Settlement Agreement;
- to advocate any position in any future CPUC proceeding or forum and to promote clean energy and clean air throughout Colorado in any administrative, legislative or public forum;
- to challenge in every respect and in any proceeding or forum any proposal related to any new or expanded coal-fired power plant (except for Comanche 3 as set forth in this Settlement Agreement) including any proposals for any new power generation and associated facilities under the All-Source Solicitation and to obtain through all available means any information about such proposals for new power generation and associated facilities; and

- to comment publicly (positively or negatively) on any and all matters related to PSCo or any of its agents, subsidiaries, assigns or affiliated companies.

b. This Settlement Agreement constitutes a compromise and settlement of several contested issues. The commitments of PSCo hereunder are contingent upon the issuance of a CPCN for Comanche 3, the pre-construction air quality permit, the Clean Air Act Title V operating permit for Comanche 3, any other permits and approvals required for associated transmission and other facilities, any permits and approvals required to install pollution control equipment for Comanche 1 and 2 and assurance of adequate cost recovery. If PSCo withdraws the pre-construction air quality permit application for Comanche 3 for any reason (including third-party objections to the permit), or if PSCo does not diligently pursue a pre-construction air permit for Comanche 3 and such lack of diligence results in a delay in the issuance of the permit of more than 36 months from the effective date of this Settlement Agreement, or if the requisite approvals for the construction of Comanche 3 are not obtained, CECP's obligations under this Settlement Agreement including CECP's agreement under Section 16.A not to challenge or sue alleged Clean Air Act violations shall be terminated and PSCo shall have no obligation to undertake any of the improvements or actions set forth in this Settlement Agreement except that PSCo shall not be relieved of any obligation to comply with any order of the CPUC or any applicable legal requirements. PSCo's withdrawal of its pre-construction review permit application for Comanche 3 and/or a decision not to construct Comanche 3 shall not be considered a breach of this Settlement Agreement. PSCo agrees and acknowledges that in the event of termination under this paragraph PSCo shall not use or count the period of time in which CECP's agreement not to challenge or sue was in effect as support for any otherwise available defense of statute of limitations, laches, delay or other defense based on failure to timely prosecute any violations of the federal Clean Air Act or the federally enforceable applicable implementation plan at the Comanche Station.

  Further, except as necessary to enforce any terms of this Settlement Agreement, PSCo's or CECP's willingness to compromise its positions on many of the issues addressed in this Settlement Agreement, including but not limited to the CO_2 proxy cost, shall not be used by any Party against PSCo or any of the organizations listed under Section 1 at proceedings at the CPUC or in any other forum and the Settlement Agreement shall not be construed as an admission against interest and shall be precluded as evidence pursuant to Rule 408 of the Federal Rules of Evidence.

18. Force Majeure

Neither Party shall be deemed to have breached this agreement or trigger a right to terminate this Settlement Agreement for any delay or default in performing hereunder if such delay or default is caused by conditions beyond its control including, but not limited to Acts of God, Government restrictions, wars, insurrections and/or any other cause beyond the reasonable control of the Party whose performance is affected.

19. Notice

Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Settlement Agreement, they shall be made in writing and addressed as follows:

As to PSCo:

Mary Fisher
Xcel Energy
1099 18th Street Suite 3000
Denver, CO 80202
Ph: (303) 308-2822
mary.j.fisher@xcelenergy.com

Olon Plunk
V.P., Environmental
Xcel Energy
4653 TABLE MOUNTAIN DR
COORS TECHNOLOGY CENTER
Golden, CO 80403
Ph: (720) 497-2015
Fax: (720) 497-2117
olon.plunk@excelenergy.com

As to Sierra Club:

Sierra Club Coordinating Attorney
Sierra Club Environmental Law Program
85 Second Street, 2d Floor
San Francisco, CA 94105
Phone: (415) 977-5680
Fax: (415) 977-5793
aaron.isherwood@sierraclub.org

Susan LeFever, Chapter Director
Sierra Club Rocky Mountain Chapter
1536 Wynkoop Street, #4C
Denver, CO 80202
Ph: 303-861-8819
Fax: 303-861-2436
susan.lefever@rmc.sierraclub.org

As to Better Pueblo:

Ross Vincent, Chair
1829 S. Pueblo Blvd., #300
Pueblo, CO 81005-2105
Ph: 719-561-3117
Fax: 415-946-3442
chair@betterpueblo.org

As to Diocese of Pueblo:

Larry Howe-Kerr
Director, Office for Social Justice
1001 N. Grand Ave.
Pueblo, CO 81003
Ph: 800-354-2729, ext 112 (in CO)
Ph: 719-544-9861, ext 112
Fax: 719-544-5202
larryhk@aculink.net

As to Smart Growth Advocates:

Vickie P Massam, President
3511 Lucia Court
Pueblo, CO 81005-3914
719-565-0597
vmassam@comcast.net

As to Southwest Energy Efficiency Project (SWEEP):

Howard Geller
Executive Director
2260 Baseline Rd. Suite 212
Boulder, CO 80304
Ph: 303-447-0078 x1
hgeller@swenergy.org

As to Environment Colorado:

Matt Baker
Executive Director
1536 Wynkoop Street, Suite 100
Denver, CO 80202
Ph: (303) 573-3871
mbaker@environmentcolorado.org

As to Colorado Renewable Energy Society:

Ronal W. Larson
21547 Mountsfield Drive
Golden, CO 80401
Ph: 303-526-9629
Fax: 303-526-0704
ronallarson@qwest.net

As to Environmental Defense:

Air Attorney
2334 North Broadway
Boulder, CO 80304
Ph: 303-440-401
vpatton@environmentaldefense.org

As to Western Resource Advocates:

Energy Program Director
2260 Baseline Road, Suite 200
Boulder, CO 80302
Ph: 303-444-1188 x232
Fax: 303-786-8054
jnielsen@westernresources.org

All notifications, communications or submissions made pursuant to this Settlement Agreement shall be sent in electronic (pdf) format unless the size or other characteristics of the materials requires the submission of a hard copy. If hard copies are submitted, they shall be submitted by: (a) overnight mail or delivery service; or (b) certified or registered mail, return receipt requested. All notifications, communications and transmissions (a) sent by overnight, certified or registered mail shall be deemed submitted on the date they are postmarked, or (b) sent by overnight delivery service shall be deemed submitted on the date they are delivered to the delivery service. All notifications, communications, and submissions made by electronic means shall be deemed submitted on the date that the transmitting Party receives written acknowledgment of receipt of such transmission. Any Party may change either the notice recipient or the address for providing notices to it by serving the other Parties with a notice setting forth such new notice recipient or address. Nothing herein is intended to limit informal communication between the Parties as contemplated by this Settlement Agreement.

20. Termination.

Unless terminated by mutual written agreement of the parties, PSCo shall notify CECP in writing at such time that it has complied with all of the requirements in this Settlement Agreement, and has obtained all Clean Air Act Title V operating permits and all federally enforceable emission limits that reflect all applicable requirements for the Comanche Station (including the plant wide emission limitation for mercury under section 7). This Settlement Agreement shall terminate and no longer be binding upon any party unless within 30 days of PSCo's notification, CECP subjects this issue to the dispute resolution procedures set forth in Section 17.F. PSCo shall provide any materially relevant information requested by CECP to assist CECP in evaluating PSCo's compliance determination described above.

Termination of this Settlement Agreement under this Section shall not relieve PSCo of any obligation to comply with any order of the CPUC or any applicable statutory, regulatory or permit requirements, including the emission limitations provided for by this Settlement Agreement for the Comanche Station; provided, however, that CECP's covenant not to sue in Section 16.A, and PSCo's obligation to ensure that all future permits for Comanche Station contain provisions that are at least as stringent as those in this Settlement Agreement, shall survive termination.

21. Amendment.

This Settlement Agreement only may be amended in writing by mutual agreement of the Parties.

22. Choice of Law.

This Settlement Agreement shall be construed and governed by the laws of the state of Colorado, without regard to the principles of conflicts of law.

23. Effective Date

This Settlement Agreement becomes effective on the date of the signature of the last party.

24. Additional Provisions.

25. Each of the signatories to this Settlement Agreement affirm that he or she is authorized to enter into the terms and conditions of this Settlement Agreement. Each party hereto may validly execute this document by facsimile signature or in

counterparts each of which shall constitute an original and all of which shall constitute one and the same Agreement.

Endnotes

1. The term "ton" means 2000 English pounds.

2. The wind ancillary service cost study was previously ordered by the CPUC in the 2003 LCP Renewable Energy RFP docket (Docket No. 04A-325E) and is required to be completed by April 1, 2006. The parties recognize that some of the study components not required under Section 13.A, but required by the CPUC's Renewable Energy RFP order, cannot be completed in time to inform the All-Source Solicitation. Those components shall be included in the April 1, 2006 study results.

AGREED & APPROVED BY:

Better Pueblo

____
Ross Vincent, Chair

Bishop of Pueblo
Diocese of Pueblo

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+Most Rev. Arthur N. Tafoya

Smart Growth Advocates

____
Vickie P Massam, President

Southwest Energy Efficiency Project

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Howard Geller, Executive Director

Environment Colorado

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Matt Baker, Executive Director

Sierra Club Rocky Mountain Chapter

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Susan LeFever, Chapter Director

Colorado Renewable Energy Society

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David Bowden, President

Environmental Defense

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Vickie Patton, Senior Attorney

Western Resource Advocates

____
Jim Martin, Executive Director

PSCo

____
Richard C. Kelly, President & COO

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Howard Geller, Executive Director

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Sierra Club Rocky Mountain Chapter

Susan LeFever, Chapter Director

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Colorado Renewable Energy Society

David Bowden

David Bowden, President

Environmental Defense

Vickie Patton

Vickie Patton, Senior Attorney

Western Resource Advocates

James B Martin

Jim Martin, Executive Director

PSCo

Richard C. Kelly, President & COO

Computer Modeling Analysis of Proposed LCP Settlement

CPUC Docket No. 04A-214E, 04A-215E, 04A-216E

Jim Hill - Manager Resource Planning
December 3, 2004

Summary

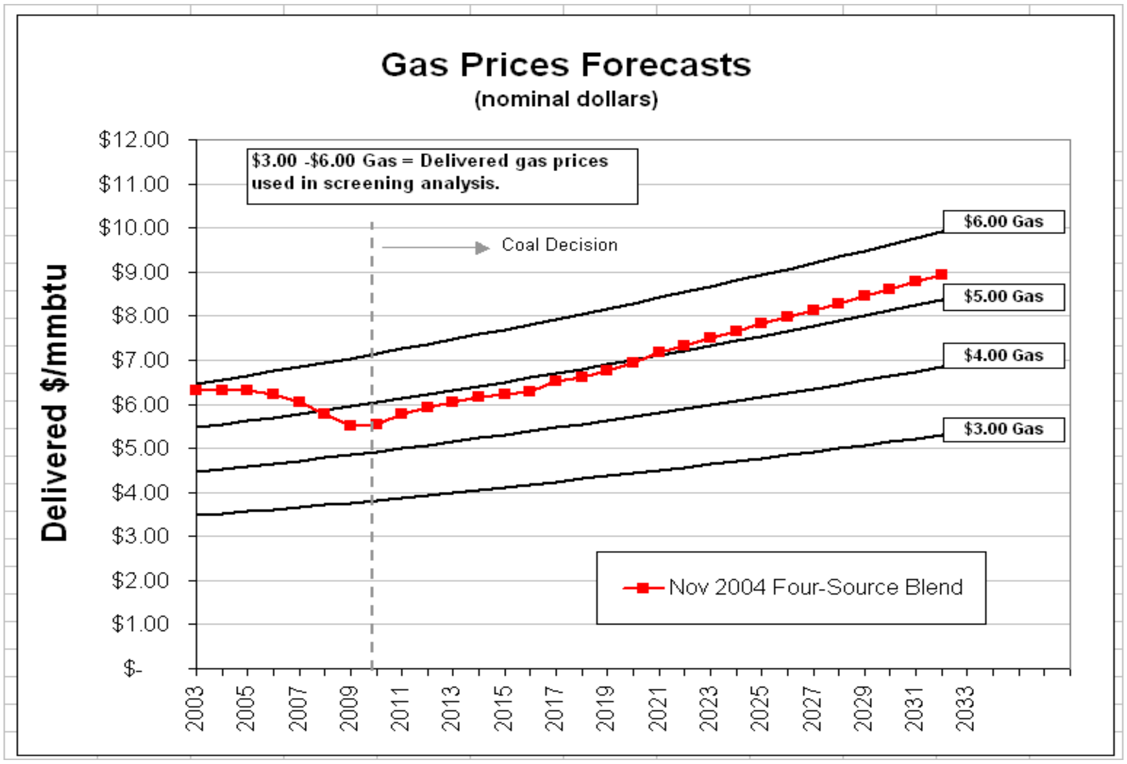
The Strategist computer model was used to examine the cost and average rate impacts of the proposed LCP Settlement under a set of updated modeling assumptions. These included the price forecast for natural gas, PSCo's cost of capital, reserve margins, and the Company's sales forecast. The cost of the Settlement least-cost expansion plan was compared with the cost of other least-cost expansion plans that were developed assuming 1) the Company's position as outlined in its October 18, 2004 rebuttal testimony and 2) Comanche 3 is not constructed.

The results of these model runs indicate that the proposed LCP Settlement is approximately $90 million (2003 PV) lower cost than a least-cost plan based on the Company's rebuttal testimony, and approximately $500 million to $1.3 billion lower cost than a least-cost plan based on revised generic screening runs.

Major Modeling Assumptions

- *Natural Gas Prices*

  Natural gas commodity prices used in this analysis are the same as those used in the Renewable Energy RFP bid evaluation in which a combination of four different long-term gas price forecasts were used to establish a single long-term gas commodity price forecast (CERA, PIRA, EIA, and NYMEX). Additional costs were added to the gas commodity price to account for transportation and Price Volatility Mitigation (PVM). Below is an illustration of the burner tip gas price used in these analyses compared to the range of gas prices used in the LCP screening analysis of Volume 1.



- *Cost of Capital*

  Capital revenue requirements for the Comanche 3 facility, Comanche 1 & 2 emission controls, and for all generic resources were modeled as if they were utility rate-based generation facilities. All revenue requirement calculations were performed using the following information from the 2002 PSCo rate case settlement.

Before Tax Weighted Cost of Capital				After Tax Weighted Cost of Capital		
	Weight	Rate	Wtd Cost	Weight	Rate*	Wtd Cost
Debt	48.60%	7.31%	3.55%	48.60%	4.53%	2.20%
Equity	51.40%	10.75%	5.53%	51.40%	10.75%	5.53%
	Return on Rate Base		9.08%		Discount Rate	7.73%
				* Settlement debt rate times .6199		

- *Reserve Margin*

  All analyses used a minimum reserve margin of 16% of firm load obligation. For all years of the analysis, the maximum allowable reserve margin was set at 25% with the exception of years 2010-2013. For these years, the maximum allowable reserve margin was set at 35% to allow consideration of the large generic coal units.

- *<u>Comanche 3 Modeling (including Emission Controls on Comanche 1&2)</u>*

The base Comanche 3 facility (i.e., the new 750 MW unit) was modeled consistent with the information contained in LCP Volume 1, Table 1.11-2, column labeled "Comanche 3 Hybrid Cooling". Whenever the base Comanche 3 facility was considered in these modeling analyses, it was accompanied by a set of additional emission controls on existing Comanche units 1&2 (i.e., capital costs, FOM, VOM, emission rate).

Two sets of Comanche 1&2 emission controls were considered.

<u>Rebuttal Scenario</u>. This scenario represents the Company's October 18, 2004 rebuttal testimony. Emission controls consist of a new Lime Spray Dryer (LSD) on Comanche 2 for SO2 control and NOx controls on both Comanche units 1&2. A breakdown of how these controls were modeled is as follows:

➢ LSD > Capital Cost $47.6 million (2003 $)
> Annual FOM $1.4 million
> VOM $0.44/MWh
> SO2 reduction of 85% (i.e. from 0.59 lbs/mmbtu to 0.09 lbs/mmbtu)

➢ NOx > Capital Cost $30 million (2003 $)
> Annual FOM $0 million
> VOM $0/MWh
> NOx reduction of 33% (i.e. from 0.3 lbs/mmbtu to 0.1 lbs/mmbtu)

<u>Settlement Scenario</u>. This scenario includes <u>all</u> the emission controls and costs of the Rebuttal Scenario plus a new Lime Spray Dryer (LSD) on Comanche 1 and mercury (Hg) controls on both Comanche 1 and 2. A breakdown of how these controls were modeled is as follows:

➢ LSD > Capital Cost $47.6 million (2003 $)
> Annual FOM $1.4 million
> VOM $0.45/MWh
> SO2 reduction 85% (i.e. from 0.59 lbs/mmbtu to 0.09 lbs/mmbtu)

➢ Hg > Capital Cost $3 million (2003 $)
> Annual FOM $2 million
> VOM $0/MWh
> Hg reduction 60% (i.e. from 0.000005 lbs/mmbtu to 0.000002 lbs/mmbtu)

- *<u>Generic Resources</u>*

Generic supply-side generation resources were modeled identical to that described in LCP Volume 1, Table 1.10-xx with the following exceptions:

Wind => To reflect the Company's Renewable Energy RFP, 480 MW of wind (i.e., six of the 80 MW generic wind facilities priced at $30/MWh flat) were added to the existing PSCo system upon which all additional least-cost resource plans were built. An additional 320 MW of wind resources above and beyond the 480 MW were made available to the Strategist model for all runs. Adding this level of wind (480 + 320) to the existing 222 MW of wind currently on the PSCo system represents a penetration of approximately 15%. No additional wind beyond the 15% penetration was allowed in any run. All wind was ascribed a 10% capacity credit.

It was assumed that the additional 320 MW of available wind would not be eligible for the Production Tax Credit (PTC) and would result in higher ancillary service costs than the $2.50/MWh assumed for wind penetration levels to 10%. The additional 320 MW of wind was priced as follows;

Revised Generic Screening and Rebuttal Scenario:

- Assumed PTC price = $27.50/MWh flat
- Assumed PTC = $18.00 MWh
- Non-PTC price = $27.50 + ($18/1-tax rate) = $27.50+ $18/.65 = $55.20/MWh
- Assumed Ancillary Cost = $7.00 MWh (for penetration from 10% to 15%)
- Assumed REC value = $2.13/MWh
- Total Price for additional wind = $55.20/MWh + $7.00/MWh - $2.13/MWh
  = $60.06/MWh

Settlement Scenario:

- Assumed PTC price = $27.50/MWh flat
- Assumed PTC = $18.00 MWh
- Non-PTC price = $27.50 + ($18/1-tax rate) = $27.50+ $18/.65 = $55.20/MWh
- Assumed Ancillary Cost = $7.00 MWh (for penetration from 10% to 15%)
- Assumed REC value = $8.75/MWh
- Total Price for additional wind = $55.20/MWh + $7.00/MWh - $8.75/MWh
  = $53.44/MWh

Conventional Gas CT => Allowed as an option for the Strategist model starting in year 2008. Last year available 2015 (when advanced CT assumed to replace it).

Conventional Gas CC => Allowed as an option for the Strategist model starting in year 2008. Last year available 2015.

Advanced Gas CT => Allowed as an option for the Strategist model starting in year 2016. Last year available 2034.

Advanced Gas CC => Allowed as an option for the Strategist model starting in year 2008. Last year available 2034.

Integrated Gasification Combined Cycle (IGCC) => Allowed as an option for the Strategist model starting in year 2009. Last year available 2034.

Coal => Two sizes of generic coal facility were examined in these analyses, a 750 MW unit and a 500 MW unit. A single 750 MW unit was allowed and up to two 500 MW units were allowed. The first year available for the 750 MW unit was 2011 for the "early generic coal" and 2012 for the "base generic coal" scenarios. The first year available for the 500 MW unit was 2012. The last year available for both the 750 MW and 500 MW units was 2013. One superfluous 500 MW unit was also allowed in these analyses (i.e., allowed to be considered in years when there was not a need for additional capacity to meet minimum reserves).

- *Emission Costs*

  Emissions of SO2, NOx, and Hg were modeled with the same Clear Skies Initiative (CSI) assumptions as those discussed in LCP Volume 1, section 1.10. These are as follows:

  - SO2 = $1,000/ton
  - NOx = $1,000/ton
  - Hg = $25 million/ton

  Emissions of CO2 were modeled at two different levels: $6.00 per ton for both the Revised Screening scenarios and the Rebuttal Scenarios, and $9.00 per ton for the Settlement scenario. Both the $6.00 and $9.00 levels escalated annually at a rate of 2.5%. In all scenarios, the first year the CO2 cost was applied was 2010.

- *Demand and Energy Forecast*

  The July 2004 demand and energy forecast was used to represent the "Base" level of peak demand and annual energy for all scenarios examined. This forecast was provided in the Company's 2004 LCP Annual Progress Report filed with the Commission on October 31, 2004. The July 2004 peak demand forecast is approximately 1% higher (i.e., 67 MW) by year 2013 than the peak demand forecast contained in the Company's April 2004 LCP. The July 2004 energy sales forecast is approximately 0.4% lower (i.e., 160 GWh) by year 2013 than the sales forecast contained in the Company's April 2004 LCP.

  When modeling different levels of DSM in these analyses, the peak demand reductions and energy reductions were applied to the July 2004 demand and energy forecast.

- *DSM Peak and Energy Reductions*

  Three levels of additional DSM were examined.

  1.) No additional DSM => The level of DSM embedded in the July 2004 forecast was all that was considered.

  2.) Rebuttal Scenario DSM => In this scenario, by year 2010 the base peak demand forecast was reduced by 153 MW and annual energy sales were reduced by 365 GWh. These DSM peak and energy savings were assumed to have a fifteen-year life.

  3.) Settlement Scenario DSM => In this scenario, by year 2013 the base peak demand forecast was reduced by 320 MW and annual energy sales were reduced by 800 GWh. These DSM peak and energy savings were assumed to have a fifteen-year life.

Year	Rebuttal DSM Scenario Peak Reductions MW	Rebuttal DSM Scenario Annual Energy Reductions GWh	Settlement DSM Scenario Peak Reductions MW	Settlement DSM Scenario Annual Energy Reductions GWh
2006	25.8	50.2	40	100
2007	54.1	111.1	80	200
2008	85.3	186.2	120	300
2009	119.5	275.6	160	400
2010	153.7	365.0	200	500
2011	153.7	365.0	240	600
2012	153.7	365.0	280	700
2013	153.7	365.0	320	800
2014	153.7	365.0	320	800
2015	153.7	365.0	320	800
2016	153.7	365.0	320	800
2017	153.7	365.0	320	800
2018	153.7	365.0	320	800
2019	153.7	365.0	320	800
2020	153.7	365.0	320	800
2021	127.9	314.8	280	700
2022	99.6	253.9	240	600
2023	68.4	178.8	200	500
2024	34.2	89.4	160	400
2025	0	0	120	300
2026	0	0	80	200
2027	0	0	40	100
2028	0	0	0	0
2029	0	0	0	0
2030	0	0	0	0
2031	0	0	0	0
2032	0	0	0	0
2033	0	0	0	0
2034	0	0	0	0

- *DSM Costs*

  The expenditures and associated revenue requirements for the Rebuttal and Settlement levels of DSM discussed above are as follows:

Year	Rebuttal DSM Scenario Expenditures 2004 Dollars $Millions	Rebuttal DSM Scenario Expenditures Nominal Dollars $Millions	Settlement DSM Scenario Expenditures 2005 Dollars $Millions	Settlement DSM Scenario Expenditures Nominal Dollars $Millions
2006	$16.00	$16.76	$17.31	$17.72
2007	$17.40	$18.66	$19.37	$20.29
2008	$19.00	$20.86	$22.97	$24.63
2009	$20.40	$22.92	$24.98	$27.42
2010	$22.20	$25.53	$25.97	$29.18
2011			$27.71	$31.88
2012			$28.84	$33.95
2013			$28.85	$34.77
Total	**$95.00**	**$104.74**	**$196.00**	**$219.85**

Revenue requirements calculations assumed 85% of the above expenditures were capital related and 15% administrative. Capital expenditures for the Rebuttal DSM Scenario were amortized over five years, while capital expenditures for the Settlement DSM Scenario were amortized over eight years. Revenue requirements for both scenarios were calculated assuming a 1-year lag between expenditure year and project in-service year, straight-line depreciation, zero AFUDC and an allowed rate of return of 9.08%. The resulting revenue requirements for both DSM scenarios are as follows:

Year	Rebuttal DSM Scenario Capital Revenue Requirements ($000) Nominal	Rebuttal DSM Scenario Administrative Costs ($000) Nominal	**Total Rebuttal DSM Scenario Revenue Requirements ($000) Nominal**	Year	Settlement DSM Scenario Capital Revenue Requirements ($000) Nominal	Settlement DSM Scenario Administrative Costs ($000) Nominal	**Total Settlement DSM Scenario Revenue Requirements ($000) Nominal**
=======	=======	=======	=======	=======	=======	=======	=======
2003	$0	$0	**$0**	2003	$0	$0	**$0**
2004	$0	$0	**$0**	2004	$0	$0	**$0**
2005	$0	$0	**$0**	2005	$0	$0	**$0**
2006	$0	$0	**$0**	2006	$0	$0	**$0**
2007	$4,014	$2,515	**$6,529**	2007	$3,165	$2,658	**$5,823**
2008	$8,224	$2,799	**$11,023**	2008	$6,618	$3,044	**$9,662**
2009	$12,673	$3,129	**$15,802**	2009	$10,652	$3,695	**$14,347**
2010	$17,293	$3,439	**$20,732**	2010	$14,945	$4,113	**$19,058**
2011	$22,184	$3,830	**$26,014**	2011	$19,287	$4,377	**$23,664**
2012	$17,848	$0	**$17,848**	2012	$23,831	$4,782	**$28,613**
2013	$13,461	$0	**$13,461**	2013	$28,437	$5,093	**$33,530**
2014	$9,006	$0	**$9,006**	2014	$32,862	$5,216	**$38,078**
2015	$4,538	$0	**$4,538**	2015	$28,944	$0	**$28,944**
2016	$0	$0	**$0**	2016	$24,934	$0	**$24,934**
2017	$0	$0	**$0**	2017	$20,683	$0	**$20,683**
2018	$0	$0	**$0**	2018	$16,384	$0	**$16,384**
2019	$0	$0	**$0**	2019	$12,173	$0	**$12,173**
2020	$0	$0	**$0**	2020	$7,969	$0	**$7,969**
2021	$0	$0	**$0**	2021	$3,862	$0	**$3,862**
2022	$0	$0	**$0**	2022	$0	$0	**$0**
Total Rev Req ($000)	$109,241	$15,711	$124,952	Total Rev Req ($000)	$254,746	$32,978	$287,724
Total Rev Req 2003 PV ($000)	$60,603	$9,950	**$70,554**	**Total Rev Req 2003 PV ($000)**	$114,344	$18,455	**$132,799**

- *IPP Contracts Not Extended*

  Least-Cost expansion plans were created with the assumption that no IPP contracts were extended but rather the contracts were assumed to terminate per their current contract term. Generic resources were selected by the Strategist model to replace the capacity lost due to these contract terminations.

- *IPP Contracts Extended*

  Least-Cost expansion plans were also created with the assumption that fifteen existing IPP contracts totaling 2,226 MW were extended. 1,500 MW of these contract extensions occur within the 10-year resource acquisition period of 2003 to 2013. The remaining 726 MW of contract extension occur beyond 2013.

	Summer	Termination
Contract	MW	Year
================	======	======
Thermo Restructuring	150	2009
Brush 2 QF	68	2009
Monfort Greeley QF	32	2011
Brush 1	50	2006
Brush 3	25	2006
Fountain Valley	232	2013
Black Hills Valmont 7&8	80	2013
Black Hills Arap 56	116	2013
Brush 4D	115	2012
ManChief	262	2012
Plains End	111	2012
Blue Spruce	259	2013
subtotal	*1500*	
UNC Greeley QF	69	2014
Rocky Mnt Energy (Calpine)	495	2014
Lamar Wind (1)	162	2019
subtotal	*726*	

Scenarios Modeled

The Strategist planning model was used to develop least-cost expansion plans for the PSCo system over the 2003-2034 time period for three main scenarios:

1.) Revised Screening Scenario - All generic resource technologies are considered for addition to the existing PSCo system (i.e., no Comanche 3). 480 MW of wind @ $30/MWh included as part of existing PSCo system starting in 2006. Additional 320 MW of wind available for consideration starting in 2007 at a non-PTC price of $60.06/MWh.

2.) Rebuttal Scenario - Comanche 3 considered along with all generic resources except the generic 750 MW coal unit. DSM peak and energy savings per Rebuttal Scenario (i.e., 153.7 MW and 365 GWh) with associated PVRR of $70.5 million. 480 MW of wind @ $30/MWh included as part of existing PSCo system starting in 2006. Additional 320 MW of wind available for consideration starting in 2007 at a non-PTC price of $60.06/MWh.

3.) Settlement Scenario - Comanche 3 considered along with all generic resources except the generic 750 MW coal unit. Additional DSM peak and energy savings per Settlement Scenario (i.e., 320 MW and 800 GWh) with associated PVRR of $132.8 million. 480 MW of wind @ $30/MWh included as part of existing PSCo system starting in 2006. Additional 320 MW of wind available for consideration starting in 2007 at a non-PTC price of $53.44/MWh.

Least-cost expansion plans for each of these three main scenarios were developed as follows:

The Revised Screening Scenario was examined with both an IPP contract extension scenario and a no-extension scenario under the following six sets of assumptions.

1.)No Additional Pulv Coal - No Additional DSM
2.)Early Generic Pulv Coal (2011) - No Additional DSM
3.)Base Generic Pulv Coal (2012)- No Additional DSM
4.)No Additional Pulv Coal - Rebuttal Scenario DSM
5.)Early Generic Coal (2011) - Rebuttal Scenario DSM
6.)Base Generic Coal (2012) - Rebuttal Scenario DSM

The Rebuttal Scenario was examined with both an IPP contract extension scenario and a no-extension scenario under the following two sets of assumptions.

1.)Comanche 3 in 2010 – Rebuttal Scenario DSM
2.)Comanche 3 in 2012 – Rebuttal Scenario DSM

The Settlement Scenario was examined for both an IPP contract extension scenario and a no-contract extension scenario under the following assumptions.

1.)Comanche 3 in 2010 – Settlement Scenario DSM

Scenario Modeling Results

- *IPP Contracts Not Extended Assumption*

Plan Present Value (PV) Costs and Average Rate Impacts

The Settlement Scenario Least-Cost Expansion plan was approximately $92 million (2003 PV) lower cost than the Rebuttal Scenario and $228 million (2003 PV) lower cost than the Rebuttal Scenario with a two-year delay in the Comanche 3 facility in-service date. The Settlement Scenario was lower cost than the six revised screening runs by $386 million to $1.343 billion (2003 PV). The Settlement Scenario resulted in an increase in average rates of $0.04 /MWh compared to Rebuttal Scenario 1 (i.e., Com 3 in 2010). Compared to all other scenarios, the Settlement Scenario resulted in a decrease in average rates ranging from $0.22/MWh to $2.14/Mwh.

Run Description	Strategist PV $000	DSM Rev Req PV $000	$9 to $6 CO2 Cost Adjustment PV $000	REC Adjustment PV $000	Total Plan Cost PV $000	Cost Delta From Settlement PV $000	Average PV Rate $/MWh
==========	======	======	======	======	======	======	======
Revised Screen 1 = No More Coal - No DSM - Contracts Not Extended	$26,117,310	$0	$0	$0	**$26,117,310**	**$1,343,737**	**$49.84**
Revised Screen 2 = Early Generic Coal - No DSM - Contracts Not Extended	$25,300,200	$0	$0	$0	**$25,300,200**	**$526,627**	**$48.28**
Revised Screen 3 = Base Generic Coal - No DSM - Contracts Not Extended	$25,342,848	$0	$0	$0	**$25,342,848**	**$569,275**	**$48.36**
Revised Screen 4 = No More Coal - Rebuttal DSM - Contracts Not Extended	$25,895,524	$70,554	$0	$0	**$25,966,078**	**$1,192,505**	**$49.77**
Revised Screen 5 = Early Generic Coal - Rebuttal DSM - Contracts Not Extended	$25,089,454	$70,554	$0	$0	**$25,160,008**	**$386,435**	**$48.23**
Revised Screen 6 = Base Generic Coal - Rebuttal DSM - Contracts Not Extended	$25,123,488	$70,554	$0	$0	**$25,194,042**	**$420,469**	**$48.29**
Rebuttal Scenario 1 = Com 3 2010 - Rebuttal DSM - Contracts Not Extended	$24,794,992	$70,554	$0	$0	**$24,865,546**	**$91,973**	**$47.66**
Rebuttal Scenario 2 = Com 3 2012 - Rebuttal DSM - Contracts Not Extended	$24,931,480	$70,554	$0	$0	**$25,002,034**	**$228,461**	**$47.92**
Settlement Scenario = Com 3 2010 - Settlement DSM - Contracts Not Extended	$25,004,572	$132,799	($377,471)	$13,672	**$24,773,573**	**$0**	**$47.70**

CO2 adjustment

The "$9 to $6 CO2 Cost Adjustment" noted in the above table removes the added cost associated with CO2 between the Settlement Scenario and all others. CO2 was priced at $9/ton in the Settlement run and $6/ton in all other runs. The effect of the $9/ton CO2 assumption is embedded within both the least-cost resource mix developed by the Strategist planning model and the "Strategist PV $000" values for the Settlement Scenario (i.e., the $25,004,572). In order to compare the Settlement plan costs which include CO2 @ $9/ton with the other plans that include CO2 @ $6/ton, it is necessary to put all the plan costs on comparable terms. This was accomplished by taking the Settlement plan and recalculating its CO2 costs to reflect a $6/ton CO2 cost rather than a $9/ton cost.

REC adjustment

The "REC Adjustment" noted in the above table accounts for the lower wind cost between the Settlement Scenario and all others. As on page 4 of this report, wind was priced at $53.44/MWh in the Settlement run and $60.06/MWh in all other runs. In order to compare the Settlement plan costs with the other plans that, it is necessary to put all the plan costs on comparable terms. This was accomplished by taking the Settlement plan and recalculating its Non-PTC wind costs to reflect a $60.06/MWh cost.

Least-Cost Resource Mix for 10-Year Acquisition period

The actual mix of resources associated with the various modeling runs discussed above is illustrated below along with each plans total present value of costs over the 2003-2034 time period. For simplicity, only those resources contained within the ten-year resource acquisition period (2003-2013) are shown. The remaining mix of resource additions from 2014 –2034 are not shown; however their costs are included in the 2003-2034 PVRR values. It should also be noted that the PVRR costs shown do not include the adjustments for DSM, CO2 costs, and REC costs.

Year	Revised Screen Run 1 Least-Cost Resource Mix	Revised Screen Run 2 Least-Cost Resource Mix	Revised Screen Run 3 Least-Cost Resource Mix	Revised Screen Run 4 Least-Cost Resource Mix	Revised Screen Run 5 Least-Cost Resource Mix	Revised Screen Run 6 Least-Cost Resource Mix	Rebuttal Scenario Run 1 Least-Cost Resource Mix	Rebuttal Scenario Run 2 Least-Cost Resource Mix	Settlement Scenario Least-Cost Resource Mix
=====	========	========	========	========	========	========	========	========	========
2006	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)
2007	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (3)
2008	A_CC (1)	C_CT (2)	A_CC (1)	C_CC (1)	C_CC (1)	A_CC (1)	C_CT (2)	A_CC (1)	C_CT (2)
2009	IGCC (1)	C_CT (2) A_CC (1)	A_CC (1) C_CT (1)	IGCC (1)	C_CT (1) A_CC (1)	A_CC (1)	C_CT (1) A_CC (1)	A_CC (1)	C_CT (1) A_CC (1) NPTC_W (1)
2010	A_CC (1)	C_CT (3)	C_CC (1) C_CT (2)	A_CC (1)	C_CT (1) C_CC (1)	C_CT (3)	Com_3 (1)	C_CT (3)	Com_3 (1)
2011	A_CC (1)	C_750 (1)	C_CT (2)	C_CT (2)	C_750 (1)	C_CT (3)		C_CT (3)	
2012	C_CC (1) C_CT (4)	C_500 (1)	C_750 (1) C_500 (1)	C_CT (3) A_CC (1)	C_500 (1)	C_CT (1) C_500 (1)	C_500 (1)	Com_3 (1) C_500 (1)	C_500 (1)
2013	C_CT (3) IGCC (1)	C_CT (1) C_500 (1)	C_500 (1)	C_CT (3) IGCC (1)	C_CT (1) C_500 (1)	C_750 (1) C_500 (1)	C_CT (4) C_500 (1)	C_500 (1)	C_CT (3) C_500 (1)
2003-2034 PVRR	**$26,117,310**	**$25,300,200**	**$25,342,848**	**$25,895,524**	**$25,089,454**	**$25,123,488**	**$24,794,992**	**$24,931,480**	**$25,004,572**

PTC_W	= 80 MW PTC Subsidized Wind		**A_CC**	= 368 MW Advanced CC
NPTC_W	= 80 MW Non-PTC Subsidized Wind		**IGCC**	= 506 MW Integrated Gasification CC
C_CT	= 139 MW Conventional CT		**C_500**	= 500 MW Generic Pulverized Coal
C_CC	= 230 MW Conventional CC		**C_750**	= 750 MW Generic Pulverized Coal
A_CT	= 200 MW Advanced CT		**Com_3**	= 750 MW Comanche 3

- *IPP Contracts Extended Assumption*

Plan Present Value (PV) Costs and Average Rate Impacts

The Settlement Scenario Least-Cost Expansion plan was approximately $86 million (2003 PV) lower cost than the Rebuttal Scenario and $362 million (2003 PV) lower cost than the Rebuttal Scenario with a two-year delay in the Comanche 3 facility in-service date. The Settlement Scenario was lower cost than the six revised screening runs by $362 million to $1.257 billion (2003 PV). The Settlement Scenario resulted in an increase in average rates of $0.05 /MWh compared to Rebuttal Scenario 1 (i.e., Com 3 in 2010). Compared to all other scenarios, the Settlement Scenario resulted in a decrease in average rates ranging from $0.48/MWh to $1.98/Mwh.

Run Description	Strategist PV $000	DSM Rev Req PV $000	$9 to $6 CO2 Cost Adjustment PV $000	REC Adjustment PV $000	Total Plan Cost PV $000	Cost Delta From Settlement PV $000	Average PV Rate $/MWh
==========	======	======	======	======	======	======	======
Revised Screen 1 = No More Coal - No DSM - Contracts Extended	$25,341,850	$0	$0	$0	**$25,341,850**	**$1,257,054**	**$48.36**
Revised Screen 2 = Early Generic Coal - No DSM - Contracts Extended	$24,619,014	$0	$0	$0	**$24,619,014**	**$534,218**	**$46.98**
Revised Screen 3 = Base Generic Coal - No DSM - Contracts Extended	$24,809,344	$0	$0	$0	**$24,809,344**	**$724,548**	**$47.35**
Revised Screen 4 = No More Coal - Rebuttal DSM - Contracts Extended	$25,082,704	$70,554	$0	$0	**$25,153,258**	**$1,068,462**	**$48.21**
Revised Screen 5 = Early Generic Coal - Rebuttal DSM - Contracts Extended	$24,375,800	$70,554	$0	$0	**$24,446,354**	**$361,558**	**$46.86**
Revised Screen 6 = Base Generic Coal - Rebuttal DSM - Contracts Extended	$24,573,784	$70,554	$0	$0	**$24,644,338**	**$559,542**	**$47.24**
Rebuttal Scenario 1 = Com 3 2010 - Rebuttal DSM - Contracts Extended	$24,100,194	$70,554	$0	$0	**$24,170,748**	**$85,952**	**$46.33**
Rebuttal Scenario 2 = Com 3 2012 - Rebuttal DSM - Contracts Extended	$24,376,478	$70,554	$0	$0	**$24,447,032**	**$362,236**	**$46.86**
Settlement Scenario = Com 3 2010 - Settlement DSM - Contracts Extended	$24,330,658	$132,799	($378,661)	$0	**$24,084,796**	**$0**	**$46.38**

Least-Cost Resource Mix for 10-Year Acquisition period

The actual mix of resources associated with the various modeling runs discussed above is illustrated below along with each plan's total present value of costs over the 2003-2034 time period. For simplicity, only those resources contained within the ten-year resource acquisition period (2003-2013) are shown. The remaining mix of resource additions from 2014 –2034 are not shown, however, their costs are included in the 2003-2034 PVRR values. It should also be noted that the PVRR costs shown do not include the adjustments for DSM, CO2 costs, and REC costs.

Year	Revised Screen Run 1 Least-Cost Resource Mix	Revised Screen Run 2 Least-Cost Resource Mix	Revised Screen Run 3 Least-Cost Resource Mix	Revised Screen Run 4 Least-Cost Resource Mix	Revised Screen Run 5 Least-Cost Resource Mix	Revised Screen Run 6 Least-Cost Resource Mix	Rebuttal Scenario Run 1 Least-Cost Resource Mix	Rebuttal Scenario Run 2 Least-Cost Resource Mix	Settlement Scenario Least-Cost Resource Mix
=====	========	========	========	========	========	========	========	========	========
2006	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)	PTC_W (6)
2007	C_CT (4)	C_CT (4)	C_CT (4)	C_CT (3)	C_CT (3)	C_CT (3)	C_CT (3)	C_CT (3)	C_CT (3)
2008	C_CC (1)	C_CC (1)	A_CC (1)	C_CC (1)	C_CT (2)	A_CC (1)	C_CT (2)	A_CC (1)	C_CT (2)
2009	IGCC (1)	C_CT (1)	A_CC (1)	IGCC (1)	C_CT (1)	A_CC (1)	C_CT (3)	A_CC (1)	A_CC (1)
		A_CC (1)			A_CC (1)				
2010	C_CC (1)	C_CC (1)	C_CT (2)	C_CT (1)	C_CT (1)	C_CT (2)	Com_3 (1)	C_CC (1)	Com_3 (1)
2011	A_CC (1)	C_750 (1)	C_CT (2)	A_CC (1)	C_750 (1)	C_CT (2)		C_CT (2)	
2012		C_500 (1)	C_750 (1)		C_500 (1)	C_750 (1)	C_500 (1)	Com_3 (1)	C_500 (1)
2013	IGCC (1)	C_500 (1)	C_500 (1)	A_CC (1)	C_500 (1)	C_500 (1)	C_500 (1)	C_500 (1)	C_500 (1)
2003-2034 PVRR	**$25,341,850**	**$24,619,014**	**$24,809,344**	**$25,082,704**	**$24,375,800**	**$24,573,784**	**$ 24,100,194**	**$ 24,376,478**	**$24,330,658**

PTC_W	= 80 MW PTC Subsidized Wind	**A_CC**	= 368 MW Advanced CC
NPTC_W	= 80 MW Non-PTC Subsidized Wind	**IGCC**	= 506 MW Integrated Gasification CC
C_CT	= 139 MW Conventional CT	**C_500**	= 500 MW Generic Pulverized Coal
C_CC	= 230 MW Conventional CC	**C_750**	= 750 MW Generic Pulverized Coal
A_CT	= 200 MW Advanced CT	**Com_3**	= 750 MW Comanche 3