Decision No. C08-0929

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 07A-447E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2007 COLORADO RESOURCE PLAN.

PHASE I DECISION

Mailed Date: September 19, 2008
Adopted Date: August 19, 2008

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I. BY THE COMMISSION

A. Statement of the Case

1. On November 15, 2007, Public Service Company of Colorado (Public Service or Company) filed its 2007 Electric Resource Plan (ERP), pursuant to recently amended Commission Rules 4 *Code of Colorado Regulations* 723-3-3600 through 3615. This Decision addresses "Phase I" of Public Service's ERP Application. As part of the Phase I determination, this Decision makes specific findings regarding Public Service's proposed plan to acquire electric resources through the year 2015, in order that Public Service may proceed with the next steps of resource solicitation which will occur in Phase II of the ERP process. Consistent with the ERP Rules, in this Phase I Decision, we approve a framework for the solicitation of additional resources and we instruct Public Service and the Independent Evaluator (IE) how to assess the various attributes of bids and utility proposals so that the Commission can determine the preferred resource portfolio in the subsequent Phase II proceeding.

B. Overview

2. In its 2006 and 2007 sessions, the Colorado Legislature made substantive changes to several statutes under Title 40 that impacted utility resource planning. These changes, enacted pursuant to House Bill (HB) HB 06-1281, HB 07-1037, HB 07-1281, and Senate Bill (SB) SB 07-100 significantly impacted the Commission's Least Cost Planning Rules (LCP) that were in effect prior to those legislative changes. For example, HB 07-1037 requires that the Commission establish energy savings and demand reduction goals, and sets minimum goals for investor-owned utilities to achieve in their energy efficiency, conservation, load management, and demand response programs. This legislation also indicates that the goal of electric utility resource planning is to minimize the net present value of revenue requirements, consistent with allowing all classes of customers an opportunity to participate in Demand Side Management

(DSM) Programs and giving due consideration to the impact of DSM Programs on non-participants and on low income customers.

3. HB 07-1281 increases the amount of electricity a utility must generate or cause to be generated from renewable energy resources under Colorado's Renewable Energy Standard (RES). Prior to HB 07-1281, the RES required utilities to meet a 10 percent RES by 2015, of which 4 percent was to be obtained from solar energy sources. However, under HB 07-1281, those requirements were doubled, requiring qualifying retail utilities, such as Public Service, to meet a 20 percent RES by the year 2020. The requirement that 4 percent of the RES was to be obtained from solar resources remains in effect.

4. HB 06-1281 requires the Commission to consider proposals by Colorado electric utilities to fund, and construct an Integrated Gasification Combined Cycle Project with CO_2 capture and sequestration.

5. SB 07-100 requires the designation of energy resource zones and the development of additional transmission infrastructure to deliver energy from those zones to the load center of the utility.

6. In response to the 2007 legislative directives, we amended our LCP Rules through an emergency rulemaking and subsequently through a permanent rulemaking. The result, based on much input from numerous parties obtained in comments, workshops, and hearings, was the Electric Resource Plan Rules, adopted as permanent rules on December 27, 2007 in Decision No. C07-1101.[1]

[1] In anticipation of Public Service's resource plan application, we adopted emergency rules on September 28, 2007 pursuant to Decision No. C07-0829. Because Public Service's resource plan application was due to be filed on November 15, 2007, its application will be considered under the emergency rules. We note however, that the permanent rules adopted on December 27, 2007 are identical to the emergency rules.

7. We also revised the resource planning rules to accommodate the non-cost factors contained in the legislation that expanded the requirements for renewable energy resources and other clean energy resources. The new legislation expanded the Commission's role in resource planning beyond a strict least-cost approach. In response, our new ERP Rules establish a framework for the Commission to approve a plan for resource acquisition in Phase I, similar to the previous LCP Rules, but add a Phase II process wherein the Commission weighs the various risks and benefits of proposed resources to establish a preferred resource portfolio. This new Phase II approach is built on an expedited proceeding in which the utility and the IE will perform various system model runs, as directed in the Phase I Commission Decision, to compare potential resources in order to explore all aspects of the possible portfolios.

8. Following their analysis, the utility and the IE will file reports with the Commission. Parties will be able to comment on the reports, and the Commission will then select a preferred portfolio in Phase II. This process is designed to provide the Commissioners the best information, based on modeling of actual bids and a full understanding of the non-cost aspects. As part of the ERP process, the Commission must consider various goals such as balancing carbon reduction with consumer cost increases, and maximizing new renewable resources without compromising system reliability. As discussed in detail below, we intend for the Phase II process to provide sufficient information for the Commission to consider all aspects of supply-side and demand-side resources and all benefits and risks of the various proposals.

9. In this Phase I Decision we determine resource needs, procurement specifications, and set the modeling assumptions and scenarios to establish how Public Service and the IE will compare resources. Public Service has requested that we also make certain additional determinations in addition to the ERP Rule requirements, such as whether to retire certain coal

plant resources, to assess imputed debt impacts, to consider the merit of a utility ownership percentage for new resources, to consider a proposed 850 MW limit on intermittent resources, and to consider a proposal for an interim filing in 2009 or 2010. The Commission's decisions in Phase I and II must also consider new issues, including possible federal carbon regulations, the Governor's Climate Change Action Plan goal of CO_2 reduction goal of 20 percent by 2020, the 2 percent renewable rate cost cap, DSM potential, new renewable resources such as concentrating solar power (CSP) which may include energy storage, as well as many other electricity supply and demand variables.

10. Although the ERP Rules are set up for the Commission to make resource decisions in Phase II, parties have requested certain decisions be made in Phase I. Ideally, we would defer all resource decisions to Phase II so that the Commission has the best information available to make such decisions. However, we are well aware of the modeling limitations and time constraints that will apply in the expedited Phase II process. Consequently, arriving at certain decisions in Phase I will simplify the Phase II analysis so that the limited analytical resources can be used for higher priority issues.

11. It is no longer debatable that the threat of climate change is the main driving force behind many of the changes in utility resource planning. The new legislative changes identified above are inspired at least in part by concerns that utility generation emissions are a critical component of the causes of climate change. The governor's directive to reduce carbon emissions by 20 percent by the year 2020 stems directly from concerns about climate change. Parties in this docket have certainly provided substantial evidence that our climate is changing, and that we must take decisive action to reduce utility carbon emissions. The evidence of climate change in

this docket is essentially undisputed, and supports a finding that carbon emissions will undoubtedly be subjected to regulation or increased economic burden in the future.

12. In public comment hearings, held April 14, 2008, many witnesses testified that climate change is a real concern for Colorado citizens. Those public witnesses represented a broad cross-section of utility customers. The public witnesses included professionals in climate-related occupations who specifically raised concerns about evidence of climate change they have encountered in their fields. A number of witnesses expressed concern regarding future impacts, and the impact to their children and grandchildren, due to the impacts of climate change.

13. Parties in the case also addressed the economic opportunities associated with renewable resources in Colorado. While the threat of climate change will likely mean serious economic consequences for continued carbon emissions, the problem also presents an opportunity for states like Colorado with vast solar, wind, and geothermal resources to develop and export power to areas with fewer renewable resource options. We recognize that there are a number of issues, including transmission, energy storage, and integration of intermittent resources that must be overcome; on the other hand, it is imperative that we enact policies that allow Colorado to realize its future as a leader in renewable resources.

14. We agree with the parties that climate change is real and that we must address utility carbon emissions now. Public Service has shown remarkable leadership in addressing climate change in its ERP Application. Though some aspects of its plan require Commission input and modification, Public Service has proposed a laudable plan that advances the new energy economy in our state. The proposal to retire two of its least efficient coal plants marks a turning point in the supply of electricity in Colorado; the Company’s plan to approach a 30 percent renewable resource penetration set new standards for the industry; and Public

Service's willingness to expand DSM beyond initial proposed limits demonstrates a new level of cooperation and understanding. Though the Commission had initially expressed concern with Public Service's compliance with the emergency ERP Rules, the Company has worked diligently to modify its filing to comply with the intent of the new rules. Public Service's willingness to adapt to the new Section 123 resource development also demonstrates its responsiveness to the changing utility landscape.

15. In this Phase I decision, we weigh the statutory directives, climate change concerns, constraints on Phase II analysis, utility needs, competitive concerns, and public interest issues such as cost and rate impacts to construct a proper framework for the Phase II analysis. As discussed in detail below, we accept Public Service's proposal for an interim filing in 2010; we grant the request for a Phase I decision to retire the Cameo and Arapahoe coal plants; we acknowledge the benefits in both utility and Independent Power Producer (IPP) generation ownership and set parameters to specify the final ownership allocation in Phase II; we deny an imputed debt adder and absolute capital lease control, but allow contract negotiation to avoid capital lease impacts in Purchase Power Agreements (PPAs); we establish load forecasts, gas prices, and other modeling inputs for resource evaluation; we specify modeling scenarios and procedures for the IE and Public Service to follow in resource evaluation; and we make numerous other determinations regarding Requests for Proposal (RFPs), renewable resources, DSM, and Section 123 resources that are necessary to proceed with resource solicitation.

C. Procedural History

16. As indicated above, Public Service filed its ERP Application on November 15, 2007. Throughout the course of this docket, leading up to the scheduled hearings, this Commission issued approximately 28 orders dealing with various procedural issues such as

petitions to intervene; petitions for intervention out of time; motions to file testimony out of time; motions for extraordinary protection; and substantive issues related to the All-Source bidding process and the selection of the IE. While it is not necessary to reiterate each decision on those issues here, we note some milestones in this docket.

17. By Decision No. C08-0046, we granted the timely petitions to intervene of the following parties:

Aquila Networks – WPC
Black Hills Energy, Inc.
CF&I Steel, LP and Climax Molybdenum Company
Colorado Energy Consumers
Colorado Independent Energy Association
Colorado Mining Association
Colorado Solar Energy Industries Association
Ms. Leslie Glustrom
The Governor's Energy Office
High Plains Energy Association, LLC
Iberdrola Renewable Energies USA, LTD
Intermountain Rural Electric Association
Interwest Energy Alliance
Ms. Nancy LaPlaca
Ratepayers United of Colorado
Rocky Mountain Farmers Union and Colorado Working Landscapes
Trans-Elect Development Co., LLC and the Wyoming Infrastructure Authority
Tri-State Generation & Transmission Assoc., Inc.
Western Resource Advocates

Motions for interventions out of time were granted to: the Town of Palisade, the Colorado Department of Public Health and Environment (CDPHE), FPL Energy, Mr. Sol Shapiro, American Clean Skies Foundation (ACSF), and the City and County of Denver (Denver).

18. Staff of the Commission (Staff) and the Office of Consumer Counsel (OCC) timely filed notices of intervention.

19. On August 15, 2008, Joshua Perry and Steven King filed a Motion for Late Intervention. Since this request was filed after the conclusion of hearings, we find that it is appropriate to deny the request for intervention, but grant *amicus curiae* status pursuant to Rule 1200(c).

20. Given the scope of the docket, as well as the overlap of the issues of this docket with several other existing dockets, including the DSM docket (07A-420E); the Renewable Energy Standard docket (07A-462E); the Renewable Energy Standard Adjustment docket (RESA) (07A-522E); the Interruptible Service Option Credit (ISOC) docket (07S-521E); the Pawnee/Smoky Hill Certificate of Public Convenience and Necessity (CPCN) docket (07A-421E); and the Fort St. Vrain CPCN docket (07A-469E), we scheduled several pre-hearing conferences in this docket (coordinated with those other dockets) to address the scope of the issues, the overlap of these dockets with the ERP docket and certain other procedural issues.

21. We held a multi-docket pre-hearing conference on January 23, 2008. Issues addressed at that time included deferring decisions on certain interventions, the "early wind" RFPs in this docket, our intention to practice "active case management", the consideration of other related dockets, the scope of the various dockets indicated above, and other procedural matters.

22. We also discussed the overlap of the various dockets and the effect of our decisions in those dockets on the matter at hand. For example, we expected that the DSM docket would produce a range of potential DSM amounts rather than a single point result to be utilized in this docket, especially in Phase II. We contemplated comparing points in a range of DSM levels against points in a range of supply-side options so that the optimum level of resources could be determined.

23. Similarly we expected the RES docket to produce various costs and other associated parameters for wind, solar, and other renewable resources which would be utilized later in the ERP docket in Phase II resource optimization phase. The results of the ISOC docket were also expected to be utilized as inputs to the ERP docket so that an optimum resource mix could be determined.

24. We also set discovery schedules in this docket as well as the in Docket Nos. 07A-420E and 07A-462E. We set another pre-hearing conference for February 6, 2008 and provided a list of additional issues for parties to discuss.

25. Pursuant to Decision No. C08-0183, issued February 26, 2008, we set a Public Comment Hearing for April 14, 2008, to take comments from the general public regarding the important issues of this docket.

26. In Decision No. C08-0185, issued February 22, 2008, we further clarified the scope of this docket, based on comments received from the parties to this matter. Written comments were filed regarding all-source versus segmented bidding, the issue of imputed debt, transmission issues, and the Public Service application for the waiver of the competitive acquisition provisions in the ERP Rules for its proposal to repower its Arapahoe Station generation facility.

27. In Decision No. C08-0239, issued march 7, 2008, we clarified the role of the IE in the Phase II process of this docket.

28. In Decision No. C08-0418, we accepted the late-filed supplemental direct testimony of Public Service witness Mr. Paul J. Bonavia.

29. In Decision No. C08-0437, we granted the motion to intervene out of time of Mr. Sol Shapiro.

30. In Decision No. C08-0471, issued May 5, 2008, based on the comprehensive information submitted and because of the consulting team's extensive experience with the STRATEGIST model, we selected Concentric Energy Advisors as the IE for the Phase II portion of this docket.

31. In Decision No. C08-0478, issued May 8, 2008, we granted the motion to intervene out of time of the ACSF.

32. In Decision No. C08-0539, issued May 30, 2008, we identified the issues to address in rebuttal and limited supplemental answer testimony. Those issues included an analysis of the RFPs and model PPAs and how Public Service intended to fashion a plan for the simultaneous bid evaluation process in the All-Source bid evaluation. We also included the issues of transmission planning, the effects of HB 08-1164, a discussion of the "early wind" RFP proposal by Public Service, as well as the impact of the RES docket and the DSM docket on this docket.

33. In Decision No. C08-0589, issued June 11, 2008 we granted the motion to intervene out of time of Denver.

34. Hearings were held in this matter at the appointed place and time. Hearings began on June 23, 2008 and continued through July 11, 2008. Hearings were initially held at the Public Service Technical Services Building. The final week of hearings were conducted at the Commission in Hearing Room A.

35. Due to the timing of the filings, several motions were disposed of during the first day of hearing, rather than through the Commission's Weekly Meeting deliberations process. Those are discussed below.

Black Hills Motion to Strike

36. On June 18, 2008, Black Hills Energy, Inc. (Black Hills) filed a Motion to Strike Portions of the Cross-Answer Testimony of OCC Witness Dr. P.B. Schecter. In its Motion, Black Hills contends that Dr. Schechter's cross-answer testimony should have addressed certain points raised by Aquila Networks – WPC (Aquila) in their answer testimony, and in fact, the testimony made several allegations regarding Black Hills instead of addressing Aquila.

37. On June 20, 2008, the OCC responded to Black Hills' Motion and argued that Dr. Schechter's cross-answer testimony was relevant because Black Hills is in the process of merging or acquiring assets or being acquired by Aquila. We deny the Black Hills' Motion to Strike. Since Dr. Schecter is available and subject to cross-examination in this matter, any disputed matter can be ironed out at that time.

WRA Motion to Strike

38. On June 18, 2008, Western Resource Advocates (WRA) filed a Motion to Strike the Testimony of Thomas Hewson and Stuart Sanderson, on behalf of the Colorado Mining Association (CMA), and Martin Blake, on behalf of the Intermountain Rural Electric Association (IREA). We address our ruling regarding Martin Blake's testimony below in the context of Public Service's motion to strike the Blake testimony. WRA seeks to strike Mr. Hewson and Mr. Sanderson's testimony because they filed their testimony on June 9, 2008, and this is answer testimony which is 42 days late. WRA also argues that this will prejudice WRA and other parties since the parties will not be able to address the concepts and ideas addressed in the testimony.

39. In its response on June 20, 2008, the CMA stated that it was under the belief, according to Decision No. C08-0326, that parties can file the testimony regarding the economics

of the power plants and certain model inputs until June 9, 2008, and Mr. Hewson's and Mr. Sanderson's testimony addresses these topics.

40. We deny these motions. We have reviewed the testimony and find it addresses the modeling inputs and other topics we addressed in Decision No. C08-0326, which allowed testimony on those topics to be submitted until June 9, 2008.

Public Service Motion to Strike

41. On June 18, 2008, Public Service filed a Motion to Strike Exhibits and Testimony to strike certain exhibits and testimony, including Attachments B, C, D, and E to Ms. Nancy LaPlaca's testimony dated April 28, 2008; Attachment A to Ms. LaPlaca's limited supplemental testimony, dated June 8, 2008; Attachments 1 through 22, 24, 25, 29, 30, 52, and 54 to the answer testimony of Ms. Leslie Glustrom, dated April 28, 2008; Attachments 2, 15 through 19, 20 and 22 to the supplemental and cross-answer testimony of Ms. Glustrom dated June 9, 2008; and Ms. Glustrom's supplemental and cross-answer testimony in its entirety as improper repetition of answer testimony or in the alternative striking all portions of her supplemental and cross-answer testimony that repeat her answer testimony.

42. Public Service's argument for its Motion to Strike is that these are attachments or specific references to internet websites that constitute hearsay because they are statements or positions taken by third parties. Public Service argues it would be unfair and prejudicial to Public Service and the other intervenors to present this as evidence. Public Service also argues that, in the alternative, the Commission can assign these exhibits and references diminished weight.

43. On June 27, 2008, Ms. LaPlaca and Ms. Glustrom filed separate responses with similar arguments opposing Public Service's Motion to Strike. Both parties were concerned that

the Motion to Strike was untimely because it referred to testimony presented about two months ago. Ms. Glustrom and Ms. LaPlaca also argue that the Commission is not bound by the rules of evidence. Their responses also address why each exhibit relates to this docket and should be admitted.

44. If we were to take the attachments and references that Ms. LaPlaca and Ms. Glustrom include in their pleadings as factual evidence, the other parties in this matter will not have the opportunity to cross-examine the authors of the proposed evidence. We grant Public Service's Motion to Strike in part. We will allow the exhibits and references, but we will assign them diminished weight with the understanding that these align more with public comments and opinions rather than purported facts, subject to cross-examination.

Aquila's Motion to File Surrebuttal Testimony.

45. On June 13, 2008, Aquila filed a Motion for Leave to File Surrebuttal Testimony. Aquila states that it would like to respond to rebuttal testimony filed by Public Service witnesses Hyde and Prager, which would allow Aquila to focus and reduce their amount of cross-examination in this proceeding. Aquila contends that the Hyde testimony addresses new matters related to PPAs and Prager's testimony addresses new matters related to carbon dioxide accounting. Aquila argues that it is necessary for fairness and due process for Aquila to have the opportunity to address these issues.

46. On June 18, 2008, Public Service responded in opposition to Aquila's Motion for Leave to File the Surrebuttal. Public Service argues that Aquila's reasons for requesting surrebuttal testimony are insufficient and that the purpose of Aquila's surrebuttal testimony is to address new matters. Public Service also states that Aquila fails to specify how the testimony of

Hyde and Prager address new matters. Public Service also states that the rebuttal testimony directly responds to Aquila's testimony.

47. We find that the rebuttal testimony is not sufficiently beyond the scope of previous testimony to allow surrebuttal testimony in this docket. However, we will allow the parties to flesh out details regarding any issues surrounding this testimony during cross-examination.

Public Service Motion to Strike Testimony

48. Public Service filed a motion to strike the answer testimony of Dr. Martin Blake, who pre-filed testimony on behalf of IREA. This testimony was e-mailed to Public Service and other parties on May 28, 2008. Public Service points out that the testimony does not contain a certificate of service and that it is untimely as the deadline for answer testimony expired on April 28, 2008. Public Service concludes that it will be unduly prejudiced if this testimony is permitted.

49. IREA filed a reply on June 12, 2008. IREA argues that Dr. Blake only addresses Public Service’s proposal to retire Arapahoe and Cameo and that his testimony, although labeled “answer testimony” is actually supplemental answer testimony and as such it was filed one day late, not one month late. IREA argues that Public Service will not be prejudiced if Dr. Blake’s testimony is permitted because he does not introduce any new information and some of his points have been already addressed by other witnesses. As noted above, WRA moved to strike the Blake testimony on similar grounds.

50. We deny Public Service’s and WRA’s motions to strike. We are concerned that the testimony was filed late. Nevertheless, we note that is not very lengthy and, furthermore, it may assist us with reaching a just and reasonable decision in this matter.

II. COMMISSION DISCUSSION AND FINDINGS OF FACT

A. Rule 3613(c) Commission Review and Approval of Resource Plans

51. The Commission's Electric Resource Planning Rules require specific items to be addressed in the Commission decision approving or denying the utility's plan. Rule 3613(c) provides:

> If the record contains sufficient evidence, the Commission shall specifically approve or modify: (1) the utility's assessment of need for additional resources in the resource acquisition period; (2) the utility's plans for acquiring additional resources through the competitive acquisition process or through an alternative acquisition process; (3) components of the utility's proposed RFP, such as the model contracts and the proposed evaluation criteria; and (4) the three alternate scenarios for assessing the costs and benefits from the potential acquisition of Section 123 resources.

52. Assessment of Need – As discussed in detail in the Load Forecast and Modeling Scenario Sections below, we endorse Public Service's forecast methodology with some modifications and endorse the Company's proposal to update its forecasts in December 2008. We direct Public Service and the IE to perform modeling runs using the resulting base forecast. However, we also find it prudent to require additional modeling runs with assumptions of medium and high DSM levels, medium and high Section 123 resource levels, and one test case using the low load forecast. As discussed further in the Future Filings Section, we also accept Public Service's proposal to submit an interim ERP filing in 2010. As a result, a portion of the resource needs for 2015 may be deferred to that proceeding, depending on the resource timing as established in Phase II. We do not set a numerical resource need for the resource acquisition period, but instead establish a procedure to use the range of forecast needs and other parameters to allow the Commission to select the proper portfolio size in Phase II.

53. Competitive Acquisition or Alternate – The Utility Ownership and Modeling Scenario Sections set parameters for soliciting and comparing both IPP bids and utility rate-based proposals.

54. RFP Approval and Evaluation Criteria – We approve the RFPs and model contracts, with modification, as discussed in these sections. The evaluation criteria are established through numerous sections that address Modeling Inputs and Externalities. Bids and utility-owned proposals will be evaluated quantitatively based on the results of the Modeling Scenarios, with the Commission considering non-quantitative attributes derived from bid information, utility and IE reports, and intervenor responses to those reports.

55. Section 123 Scenarios - The Modeling Scenarios Section establishes four scenarios for evaluating various DSM and Section 123 resource levels. We specify two additional gas price sensitivities, so that there are three gas price cases for each scenario, and require the modelers to provide details of the top three to five portfolios from each of these 12 runs.

B. Rule 3604(a) - Resource Acquisition Period and Planning Period

56. As required by Rule 3604(a), the utility must establish two relevant time periods. The first is the "planning period." This is the period over which the economic analyses are performed, and Rule 3604(a) requires the utility to specify this period between 20 to 40 years, beginning on the date the utility files the plan with the Commission. Public Service proposes a planning period of 40 years, so that the full value of long-term resources can be reflected in the analyses.

57. The second relevant time period is the "resource acquisition period." This is the period of time over which the utility plans to acquire specific resources to meet the forecast need.

Rule 3604(a) requires the utility to specify this period between six to ten years, beginning on the date the utility files the plan with the Commission. Public Service proposes a resource acquisition period of eight years. The Company maintains that this eight-year period, through 2015, will allow adequate time to consider 2016 resources in its next resource plan filing.

58. We agree that these proposed periods are reasonable. We approve the 8-year resource acquisition period of October 2007 through October 2015, and the 40-year planning period of October 2007 through October 2046.

C. Other Commission Determinations Required by ERP Rules

59. Rule 3613(b) requires the Commission to issue a written decision approving, disapproving, or ordering modifications, in whole or in part, to the utility's plan filed in accordance with Rule 3604. Rule 3604 outlines all of the components that the utility is required to file in its plan. We approve Public Service's proposed plan with certain modifications. To the extent that we do not address an issue in this Decision, we approve Public Service's plan as revised in its supplemental and rebuttal testimonies as to that issue.

D. Resource Solicitation Approach

60. In its direct testimony, Public Service proposed numerous separate acquisitions. This would have triggered multiple Phase II proceedings at different times. Early in this docket, we clarified that the intent of the Phase II process in the ERP Rules is to compare simultaneously all resources in a single proceeding, except where timing constraints would not allow such a comparison. In its rebuttal testimony, Public Service revised its plan. The Company now proposes to compare all resources in a single Phase II proceeding, except for its early wind and early central solar RFPs. Public Service represents that it has already issued its 300 MW early wind RFP and has received bids. However, Public Service indicates that it does not intend to

include these wind resources as a part of this ERP proceeding. Rather, it plans to make a separate filing for Commission approval. Similarly, it has issued its 25 MW central solar RFP and has received bids and plans to make a separate filing for approval outside of this ERP proceeding. Although the early wind and central solar RFPs are not at issue in this proceeding, and we agree that the ERP Rules allow for multiple solicitations over time, the rules contemplate Commission approval of the RFPs before they are issued. The rules do not require all resource solicitations to be a part of the ERP filing, but solicitations outside of the ERP process do not receive the presumption of prudence provided under Rule 3613(d). We clarify that we are not considering or approving the RFPs used in the early wind and central solar solicitations as a part of this docket and the resulting resources are not provided the presumption of prudence as indicated under Rule 3613(d).

61. Except as discussed above, Public Service now proposes a single solicitation and simultaneous comparisons for all remaining resource needs. The solicitation will include four RFPs. The four RFPs are: Wind RFP; Dispatchable RFP; Non-wind, Non-dispatchable RFP; and Firm Capacity, Semi-dispatchable RFP (*e.g.*, solar with storage). The Company proposes other operational limitations, for example: 850 MW limit for intermittent resources,[2] acquired at the rate of 100 to 200 MW per year; and a 600 MW limit for solar with storage.

62. While we are concerned about service reliability and we concur with this limitation, we also note that the 850 MW intermittent resource limit is not based on a thorough analysis or study. It appears that this limit is based on operators' opinions stemming from the recent experience of Public Service when it added a large amount of wind to its system. Although Public Service did not encounter any specific outages or catastrophic problems, it

[2] These intermittent resources include wind and solar without storage.

asserts that this experience indicates that it needs to implement wind in steps in order to gain experience with the higher levels of this intermittent resource. Public Service states that the increasing wind penetration level has already reached a point where peak wind levels are at or near minimum system requirements. Further, peak wind levels in Colorado generally occur in spring and fall, which coincide with low electric load. We agree that increased wind penetration levels may exacerbate the operational difficulties. As a result, we direct Public Service to take all reasonable steps that are necessary to protect system reliability. Therefore, we approve the 850 MW limit and the requirement that intermittent resources be limited to 100 to 200 MW per year. However, given the relative uncertainty of the specific levels of the proposed limits, we treat them as “soft targets” and direct Public Service and the IE to allow variations as necessary to accommodate actual bids. It is unlikely that resources will fit neatly into these limits, so these limitations must be flexible to accommodate reasonable differences when actual resources are considered. As discussed in the Future Filing Section below, we also require Public Service to perform a thorough analysis of the wind penetration limits beyond 850 MW and file a revised proposal with its 2010 ERP filing.

63. Similarly, we approve the limitation of 600 MW for solar power with storage, to be acquired at no more than 200 MW per year, as soft targets. Public Service also proposes a minimum 200 MW set-aside for solar with storage, to investigate the potential of this new technology as a Section 123 resource. We agree that the benefits of experience with this potential new resource, as well as the developmental progress that can be achieved by implementing such a utility-scale resource, warrants the 200 MW minimum acquisition of solar with storage.

64. Public Service plans to submit utility-owned rate-based proposals at the same time as competitive bids are due at the beginning of Phase II. We find that Public Service's proposed timing for these utility-based proposals is consistent with the intent of the ERP Rules – to simultaneously compare all resources in one All-Source comparison process. Specific requirements for the utility rate-based proposals are discussed in the Utility Ownership Section, below.

65. The four RFPs will generally be issued as an All-Source solicitation where all resources compete for an overall resource level rather than specifying individual amounts of each type of resource. Actual levels of the various resources will be determined in Phase II after all costs and benefits are compared. However, the operational limits discussed above will provide some natural limits to the amount of these resources that are acquired. Consequently, we direct Public Service to state these operational limits in the RFPs to inform bidders of the limitations.

E. Future Filing Requirements

66. In the course of this proceeding, Public Service has promised to make a number of filings. For convenience, we provide a summary of required filings at the end of this Decision. Public Service states that its resource planning efforts are ongoing and proposes to file an interim ERP filing in late 2009 or early 2010. The ERP Rules require an application to be filed every four years, but also allow interim filings. We agree that evolving circumstances regarding environmental regulations and numerous late-filed studies and other constraints in this docket warrant an interim filing prior to Public Service's next full ERP Application that is due on October 31, 2011.

67. Public Service acknowledges that it has failed to timely provide certain required studies and proposes to late-file these studies and other documents. At the conclusion of Public

Service's previous LCP docket the Commission ordered the Company to perform a reserve margin study and a wind integration study, to be used in its next resource planning proceeding – this ERP filing. Public Service did not complete either of these studies and avers that it will file both before Phase II. We are very concerned that Public Service failed to timely file these studies. This failure will prevent parties and the Commission from adequately reviewing and commenting on the studies prior to their use in Phase II. The Phase II proceeding is an expedited process and will not allow time for a traditional adjudication process (*e.g.*, direct, answer, and rebuttal testimony, and hearings). The ERP Rules are designed for such issues to be fully addressed in Phase I, where a full adjudicatory process provides adequate opportunity to address these issues. These studies are critical to determine the overall resource need and allowable wind penetration levels and costs. If we allow parties full comment on this new information, the Phase II process would be significantly delayed, resulting in stale bids and delays in resource implementation. Now, though Public Service did not provide these studies for consideration in Phase I, it proposes to use the new untested studies in Phase II. Further, Public Service proposes to limit intermittent resources (largely wind) to 850 MW through 2015. As we discussed above, this limit (which is speculative, in our view) warrants further consideration.

68. While we note that Public Service's proposed remedy of late-filing the studies provides a means to get through the Phase II proceeding, we are concerned that the overall resource need and wind limitations must be examined before the next full ERP filing in 2011. Therefore, a subsequent interim filing will be necessary to identify any shortcomings that result from a limited review of the late-filed studies.

69. Similarly, Public Service has proposed to file an updated load forecast in December 2008. Although Public Service filed an initial forecast in its direct case, this updated

forecast will respond to criticisms by other parties, and will present a new look at economic growth and other factors. Public Service also proposes to file its fourth RFP, the Semi-dispatchable RFP (*e.g.*, solar with storage), 60 days before the All-Source solicitation is released. The Company filed draft RFPs in its direct case and three of four revised RFPs in its rebuttal case, however, the fourth RFP will be filed after the conclusion of Phase I. Again, these post-Phase I filings will not allow parties' full scrutiny so a subsequent ERP filing is warranted.

70. During the hearings, several parties suggested that it would be beneficial to have more frequent resource planning proceedings, rather than a single proceeding every four years. Parties also commented that holding a full ERP proceeding every year or two is unrealistic because of the large burden it places on all parties involved in the case. Indeed, this docket set a new record for the number of intervenors and witnesses. Further, the resource contracts will not likely be complete within two years of the initial filing date. We agree that more frequent smaller filings could be beneficial, but a comprehensive proceeding is also necessary so that parties can fully address all issues; otherwise, it will be difficult to limit the issues that are raised in the smaller proceedings.

71. Public Service's proposal for a 2009/2010 filing could be used as a true-up proceeding to take a second look at critical forecast components and other limited updates for this docket. For example, if a quick turn-around ERP filing is planned for 2010, the Commission can approve a final resource portfolio in Phase II based on a relatively low needs assessment forecast because any shortfall can be picked up in the next filing. If necessary, Public Service can then be required to solicit more resources in 2010 based on a more accurate forecast, including impacts due to increased DSM, rising energy costs, economic issues, air conditioner penetration, and plug-in hybrid potential. This also provides the Commission the ability to adopt

Public Service's 850 MW intermittent resource limitation without question in this proceeding with the requirement that the Company investigate possible means of expanding it in the interim filing.

72. Further, Public Service states that, based on its experience, it can get more competition and better pricing by scheduling acquisitions in relation to the lead times required by developers of the technologies sought by the acquisition process. For example, several parties commented that it is difficult to bid wind resources several years out as turbine manufacturers are reluctant to quote a future fixed price.

73. We find this reasoning warrants an interim ERP filing. Therefore, we require Public Service to make such a filing, as it has offered to do. We require Public Service to file this application on or before March 31, 2010. We further require the Company to include an updated load forecast and a revised assessment of the intermittent resource limitations. Pursuant to the ERP Rules, Public Service can define the scope of the interim filing, but we encourage the Company to limit the scope to narrowly-defined issues stemming from this docket so that the interim filing does not result in a full ERP case. It is unclear whether the development of Section 123 resources in this instant proceeding will lead to better information in time for the interim filing; for that reason we raise this as a question for parties to address in Phase II. We suggest that Public Service limit the scope for the 2010 filing so that case can be completed before the next required filing in October 2011. We are concerned that, because the 2010 filing will be made immediately after this case, it may not reflect the full results of this docket, and we do not want it to delay the full filing in 2011. On the other hand, we do not want any 2010 scope limitations to interfere with Public Service's presentation of its plan for a 20 percent carbon

reduction level, which it has proposed to do as a part of the interim filing. In any case, Public Service must prudently plan for resources to best meet its needs.

74. We recognize that we may need to revise our ERP Rules after we have completed the Phase II proceeding. Since there will not be time between the Phase II and the interim filing for a rulemaking, we encourage Public Service to use this interim proceeding as a test-case for smaller more frequent filings.

F. Aquila/Black Hills Contract

75. In answer testimony Aquila, now known as Black Hills/Colorado Gas Utility Company, contests Public Service's proposal not to continue its contract with Aquila to provide wholesale electricity after it expires in December 2011. Aquila states that it was not aware that Public Service did not intend to extend or renew the contract until it was revealed in Public Service's ERP filing. Aquila requests that the Commission order Public Service to continue to serve Aquila so that it can phase-in an alternate supply. As discussed more fully below, Aquila asserts that Public Service is terminating the contract only to show a reduction in total carbon emissions.

76. In rebuttal testimony, Public Service responds that it has no obligation to continue to serve Aquila past the expiration of the contract, and the contract is under the jurisdiction of the Federal Energy Regulatory Commission (FERC), not this Commission. Public Service states that it is willing to serve Aquila if it has excess capacity. However, it is not clear that capacity is available, pending revised load forecasts. Further, Public Service asserts that if it is to continue to serve Aquila in 2012 and beyond, it would no longer do so under its system average rates, unless required to do so by the FERC. Instead, it would expect Aquila to pay the full cost of incremental supplies.

77. The OCC recommends that we deny Aquila's request to require Public Service to phase out its wholesale contract unless it can be shown not to have a negative effect on Public Service customers. While it would be inappropriate for Public Service to retain excess capacity, it would also be inappropriate for Public Service's customers to subsidize Aquila's customers.

78. Ms. Glustrom indicates that her review of Public Service's data shows that there will be excess capacity in 2012 and 2013 if gas plant contracts are renewed that could be used to provide Aquila more time to find generating resources.

Discussion and Findings

79. We find that the wholesale contract between Public Service and Aquila falls under FERC jurisdiction and we recognize Public Service's right to enter into such contracts. Therefore, we deny Aquila's request to require Public Service to extend the contract.

80. However, we encourage Public Service to work with Aquila to continue the contract, in a manner that is beneficial to both Public Service and Aquila customers. We note that contract continuation would likely be beneficial for Aquila because of the economies of scale that Public Service provides, even if Public Service charges an incremental rate rather than its system average. We also note that Public Service would likely see economy of scale benefits, particularly if it charges an incremental rate.

G. CO_2 Reduction

81. Public Service argues that the steps it has taken to reduce carbon should be approved, independent of the carbon accounting issues raised by Aquila and the OCC. The Company acknowledges that the discontinuation of the wholesale contract with Aquila may not reduce the State's overall carbon output, but it does reduce the carbon output in the portfolio of the resources that the Company is capable of managing. Public Service points out that there are

no federal, state or local statutes, rules, or regulations regarding the regulation of the emission of carbon dioxide.

82. In the joint statement of position (SOP) of Black Hills and Aquila, the parties assert that a portion of the carbon dioxide emission reductions in Public Service's plan was simply a result of the expiration of a wholesale contract with Aquila in 2012. Aquila contends that this neither reduces carbon nor is it in the best interest of the Colorado retail electric customers. The issue is whether the seller or the purchaser is to be charged with the emissions. Black Hills and Aquila contend that the purchaser should be allocated those emissions in order to avoid the appearance of an artificial decrease in greenhouse gas when a wholesale contract ends. The reality is that a purchaser must replace the power from new generation resources.

83. Black Hills requests that the Commission find that the carbon footprint associated with the 2005 wholesale purchase of electric power from Public Service by Aquila belongs to Aquila and subsequently Black Hills. The plan put forth by Public Service provides real carbon reductions irrespective of how we account for carbon. Public Service believes that its actions are reasonable and it is shedding load and associated carbon that need not be attributed to Public Service's retail customers. According to Public Service, it is not necessary at this time to resolve the carbon accounting issue because any resolution will be determined in future legislation.

84. WRA argues that it is not clear whether carbon reductions created by the expiration of wholesale contracts should be included in the calculation of total carbon reduction. As a result the Commission should open an investigatory docket, followed by a rulemaking to address how the utility carbon reductions should be calculated on a state-wide basis. WRA supports a collaborative process among all relevant stakeholders. Together, the Commission, the Governors' Energy Office (GEO), and CDPHE, should arrange a series of stakeholder workshops

to determine a consistent method for carbon emissions accounting for all the State's utilities and CO_2 emitting sources. A key principle should be that all emissions are accounted for and none are double counted. WRA notes that this issue is complex and it is not clear which entities are responsible for which CO_2 emissions.

85. CF&I Steel, LP and Climax Molybdenum Company (CF&I/Climax) note that Rule 3604(g) requires that a utility report the CO_2 emissions from new resources but there is no requirement for reporting on existing resources. Further, it was repeatedly acknowledged by Public Service that there are no federal, state or local statutes, rules or regulations regarding the regulation of the emission of carbon dioxide and there is no evidence that carbon dioxide will be regulated prior to 2009, when the Company intends to file its 2009 plan. At a minimum, costs for carbon dioxide should be further evaluated and considered in Phase II as opposed to being "guessed at."

86. Ms. Glustrom asks that we issue a clear ruling on the size of the CO_2 reduction actually achieved by Public Service and how it relates to the overall carbon reduction in the state.

Discussion and Findings

87. We agree with Public Service that it is premature at this point to stipulate how carbon responsibility will be allocated. Carbon reduction will likely be mandated by the federal government. However, we support and encourage parties to come together to address this matter through a stakeholder process as soon as possible, as Colorado State initiatives can influence the federal decisions. As utilities move toward realizing the goals set out in the Governor's Climate Action Plan, this issue will become more and more pressing. Since this issue pertains to an emissions concern and involves far more companies than the utilities under our jurisdiction, we suggest that the stakeholder process should be lead by CDPHE.

88. We also agree with Black Hills and Aquila that switching load from a wholesale contract to another source does not represent a reduction of carbon emissions on either a statewide or individual utility basis. To conclude otherwise would either result in a double counting of carbon emissions or the mischaracterization of the 2005 carbon footprint represented by the load served by Aquila.

89. The new language of § 40-2-123, C.R.S., provides a statutory justification for the Commission to consider carbon and we find Public Service's approach does not treat wholesale receipts and wholesale deliveries in a similar manner. Public Service counts carbon from power it purchases, but also counts carbon it sells to Aquila. To be consistent, Public Service should either not count the carbon from IPPs, or Aquila should count the carbon that Public Service delivers. Regardless of how carbon is ultimately counted, the treatment of receipts and deliveries should be consistent. However, federal regulations will ultimately dictate how carbon is counted and responsibility is assigned, sweeping aside state-level determinations. Therefore, we decline to rule affirmatively on the issue in this case, preferring to wait for recommendations of a stakeholder process.

90. Even if we remove the carbon reduction that Public Service claims from the expiring wholesale contracts, it is important to recognize that the Company will still achieve significant reductions. By recasting carbon reductions on a MWh basis, which removes other factors that affect the data such as the wholesale contracts and growth, we determine that Public Service's proposal will produce significant reductions.

91. To illustrate, Public Service produced 1,881 lbs/MWh of CO_2 in 2005.[3] Using that same standard, Public Service expects to produce 1,568 lbs/MWh of CO_2 in 2017 and 1,477 lbs/MWh in 2020.[4] These amounts represent a reduction of 17 percent by 2017 and 21 percent by 2020 on a per MWh basis. Further, if these values were compared with 2007[5] carbon per unit of power sold, the reduction would be 22 percent and 26 percent, respectively.

92. While carbon intensity comparisons are useful to demonstrate carbon reductions in this docket, it is not a final answer. Ultimately it must be decided whether an absolute carbon reduction should be measured by consistent production or consumption metrics. Regardless of the method finally adopted, carbon reductions should be measured in absolute tons in a manner that fairly accounts for the normal contracting practices of each load serving entity.

H. Early Retirement of the Arapahoe and Cameo Plants

93. Public Service states that the early retirement of Arapahoe Units 3 and 4 and the Cameo Units 1 and 2 is in the best interest of the public and should be approved in Phase I.

94. Public Service states in its direct case that the immediate retirement of the plants cannot be directly economically justified. Rather, Public Service requests that we afford it the discretion to retire these units. However, it acknowledges the testimony presented by WRA that

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[3] *See* Testimony of OCC witness Dr. Richard Rosen, Exhibit RAR-2 (Hearing Exhibit 119): Total CO_2 emissions in 2005 by Public Service was 31.9 million tons or 63.8 billion pounds. *See* Table 2.7-16 in Volume 2 of Public Service's Application (Hearing Exhibit 3): Actual energy sales for 2005 was 33,921 GWh or 33,921,000 MWh. Thus CO_2 production in 2005 was 1881 lb/MWh.

[4] *See* Table 2.9-6 in Volume 2 of Public Service's Application (Hearing Exhibit 3): Total CO_2 emissions in 2017 by Public Service for its High 123 plan is projected to be 28.624 million tons or 57.248 billion pounds and 28.869 million tons or 57.738 billion pounds in 2020. *See* Table 2.7-14A in Volume 2 of Public Service's Application (Hearing Exhibit 3): Base case forecasted energy sales for 2017 is 36,501 GWh or 36,501,000 MWh and for 2020 it is 39,082 GWh or 39,082,000 MWh. Thus, CO_2 production in 2017 is projected to be 1568 lb/MWh and 1477 lb/MWh in 2020.

[5] *See* Table 2.9-6 in Volume 2 of Public Service's Application (Hearing Exhibit 3): Total CO_2 emissions in 2007 by Public Service for its High 123 plan is projected to be 34.079 million tons or 68.158 billion pounds. *See* Table 2.7-14A in Volume 2 of Public Service's Application (Hearing Exhibit 3): Base case forecasted energy sales for 2007 is 34,265 GWh or 34,265,000. Thus, CO_2 production in 2007 was 1989 lb/MWh.

when public health externalities are taken into account, it is prudent to retire the plants now. Further, the Company asserts that its proposal in its rebuttal case to increase the escalation of carbon costs from 2.5 percent to 7.0 percent will result in an earlier cost-effective retirement date.

95. The base, medium, and high plans recommended by Staff all recognize that the Commission may approve the Arapahoe and Cameo retirements in Phase I of this docket. Staff maintains that the record is sufficient for the Commission to make such a determination for the purpose of carbon reduction.

96. CDPHE argues that the benefits of retiring the Arapahoe and Cameo plants are indisputable. Closure of these facilities would result in improved air quality which would translate to better health and environmental benefits for Colorado citizens. In addition, the retirements also represent a step toward achieving the Governor's Climate Action Plan to reduce carbon dioxide emissions.

97. While the OCC supports the proposal to achieve the goals of the Governor's Climate Action Plan, it recommends that additional modeling be conducted on the retirements of the Arapahoe and Cameo plants in order to obtain the maximum amount of carbon reduction per dollars spent.

98. WRA asserts that the retirement of the Arapahoe and Cameo plants is indeed economical when all components are considered. These components include: 1) consideration of capital and other costs associated in delaying the retirement; 2) the likely costs of plant replacement in the future; 3) the potential for future environmental regulations and carbon restrictions; 4) the human health related benefits; and 5) significant water savings.

99. WRA contends that the evidence presented overwhelmingly supports the early retirement of the Arapahoe and Cameo coal plants and that there is no reason to defer this decision to Phase II. A decision now on this matter is necessary in order to know and be able to model the appropriate resource need.

100. CMA contests the early retirement of the Arapahoe and Cameo plants. In response to the assertion that the retirement of the Arapahoe and Cameo facilities is necessary for carbon reduction, the CMA stresses that currently there is no state or federal program that mandates compliance; the reduction of carbon is voluntary.

101. CMA also raises economic and reliability concerns, citing to the Colorado Energy Forum that 3,700 MW to 4,500 MW will need to be added in Colorado by 2025. In addition to renewable energy, much of this need will be filled with gas fired resources, yet the cost of coal is expected to be considerably less than natural gas over the next 38 years. CMA contends that removing a reliable low cost source of energy will result in increased energy costs in a period of economic uncertainty and strain Public Service's ability to meet expected future demand.

102. CMA requests that the Commission not adopt Public Service's proposal. CMA argues that, until it is known what federal or state climate change legislation is adopted, the implementation of a cost effective plan is difficult to achieve. According to CMA, the Commission should consider alternative energy sources such as co-firing with biomass. This approach was also supported by Mr. Shapiro. CMA asserts that there are reasonable choices available which would reduce CO_2 while maintaining affordable energy resources.

103. Through the testimony of Martin Blake, IREA recommends that the life of the Cameo and Arapahoe units be extended and that the purchase of wind power be deferred for at

least five years. This approach would allow time for Public Service to develop more detailed cost estimates based on more complete information.

104. CF&I/Climax assert that closing the Cameo and Arapahoe plants is imprudent at this point, as there are currently no regulatory requirements for reducing carbon emissions. If such reductions are mandated in the future then Public Service can revisit this option. CF&I/Climax assert that, in the meantime, customers of Public Service should continue to enjoy the benefits of low cost resources.

105. Further, CF&I/Climax state that when cost effective and substantially depreciated resources are proposed to be decommissioned for the stated purpose of reducing Public Service's "carbon footprint," the Commission should proceed with caution.

106. The GEO asserts that the benefits of retiring the Arapahoe and Cameo plants are indisputable and will constitute a major step toward accomplishing the goals set forth in the Governor's Climate Action Plan. Though other parties have encouraged the Commission to wait and see, GEO argues that such a delay may result in Public Service incurring greater carbon reduction costs in the future. In addition, recent legislation makes it clear that the Commission may take into consideration "non-energy" benefits when considering such applications.

107. Holy Cross Electric Association, Inc. believes that while replacement generation will likely be more costly, reduced emissions justify these costs.

108. Ms. Glustrom advocates that the Commission approve the retirement of the Cameo and Arapahoe coal plants as part of Phase I.

109. The Interwest Energy Alliance (Interwest) supports WRA, GEO, CDPHE, Ms LaPlaca, and Ms Glustrom in their advocacy to retire the coal plants in favor of acquiring more energy from renewable resources.

110. As discussed in the "Externalities" Section, Denver provided testimony that it failed to comply with Environmental Protection Act (EPA) ozone standards in 2007 and is now required to develop an attainment plan. Denver maintains that if the Arapahoe plant is not retired as proposed by Public Service, attaining ozone compliance will be difficult. Denver also contends that if the Arapahoe plant is not retired, Public Service will have to undertake additional mercury emissions monitoring investments within the next 6 to 12 months.

Discussion and Findings

111. Any significant reduction in the emission of carbon from current levels will inevitably include the replacement of existing generation resources with resources that emit less carbon. Since the Arapahoe and Cameo plants are lower efficiency coal plants, they emit a large amount of carbon for the energy they produce. The retirement of the Arapahoe and Cameo plants presents an excellent opportunity to reduce carbon. Considering the age and relative inefficiency of the coal plants at issue, we find that the value of the reduction of CO_2 emissions outweighs the small cost savings achieved by the continued operation of the Cameo and Arapahoe plants. Public Service's plan proposes relatively aggressive increases in renewables and DSM, and when combined with the retirement of the two coal plants, we find that Public Service has made a significant effort to reduce carbon emissions.

112. In addition, the retirements also reduce pollutants and other environmental hazards, and therefore present significant health benefits. No party disputes that there are health benefits to retiring these facilities. Parties only differ in the quantification of these benefits.

113. CMA, CF&I/Climax, and IREA raise the point that Governor Ritter's goal to reduce carbon by 20 percent by 2020 does not have the force of law. However, that does not mean the Commission should not take reasonable steps to implement the plan. Further, recent

legislation codified at § 40-2-123(1)(b), C.R.S., permits the Commission to consider carbon emissions in resource evaluations such as this.

114. CMA further notes that some carbon reductions could be realized now if co-firing with biomass were to be used. We are concerned with the viability of such a plan, as no data was offered as to how much of a carbon reduction could be achieved; nor were the implications for other pollutants presented. Further, a biomass redevelopment of these facilities could be offered through the All-Source RFP to employ cleaner, more efficient technologies with significant reductions in carbon and other pollutants.

115. CMA also raises concerns about diversification of fuel resources, in particular, dependence on natural gas resources that can result in volatile electric prices. We share this concern but note that coal will remain a predominant component in the generation of power in Colorado, especially with the Comanche 3 unit soon to come on line.

116. Parties opposed to the immediate closure - IREA, OCC, and CMA recommend that the Commission take a wait and see approach, and that the decision should be based on a full economic analysis. We find that the economic analysis presented in Phase I fully justifies the retirements, especially when additional health and environmental concerns are considered. Further, the retirements were nearly cost effective under Public Service's initial carbon cost of \$20 plus an escalation rate of 2.5 percent. As discussed below, we approve Public Service's rebuttal carbon cost in its rebuttal testimony, which is \$20 plus an escalation rate of 7 percent. This would accelerate the retirement date, even in a purely economic analysis that does not consider the externalities of health benefits.

117. Last, we note that by initiating the early retirement, this capacity decrease could be subsequently delayed if construction of other capacity is delayed or if loads increase faster

than planned. For example, if the plant was planned for retirement at the end of 2010, but planned capacity for 2011 is delayed or other factors increase generation needs, Public Service could delay the retirement date. Early retirement provides the added advantage of a flexible retirement date.

118. We find that there is sufficient information to make the retirement determination in Phase I, and that this determination will simplify the analysis of Public Service and the IE in Phase II. In fact, the evidence here overwhelmingly indicates that the benefits of early retirement outweigh the costs. Therefore, we approve the early retirement of Arapahoe Units 3 and 4 and Cameo Units 1 and 2. However, we require Public Service and the IE to investigate the optimum timing for the retirements as part of the Phase II analysis.

119. As discussed in the Modeling Scenarios Section, we direct Public Service and the IE to propose specific early retirement date(s), based on the practical implementation of other proposed generation. Public Service shall also file, with its report at the beginning of the Phase II process, an estimate of the undepreciated value of these plants along with an updated estimate of the decommissioning costs. Based on the model analyses regarding the timing of the closure of the plants, we will specify additional detail in our Phase II order.

I. Imputed Debt Factor for Bid Evaluation

120. For the purposes of resource evaluation, Public Service proposes to use an imputed debt adder. The proposed adder would be calculated based on the imputed debt methodology used by Standard & Poors (S&P), to reflect the cost associated with the additional equity needed to offset the debt equivalent effects of PPAs. Public Service believes that it is impossible to fairly assess the cost-effectiveness of different resource alternatives without taking into account the real economic cost to the Company and its customers from the effects of

imputed debt. According to Public Service, not only is it important to include an imputed debt adder to ensure a fair comparison between utility-owned proposals and PPAs, the imputed debt adder will also ensure that all energy contract proposals for intermittent resources, such as wind and solar, can be fairly compared with proposals for natural gas or other generating resources which typically include large monthly capacity payments unrelated to the amount of energy produced.

121. The imputed debt effect of individual bids and thus, the associated cost to customers can differ significantly depending on the nature of the technology involved, the structure of the proposed contract, the contract term, and the proposed level of the capacity payments, if any. Accordingly, Public Service argues that it is imperative that the Commission direct it and the IE to include such an adder in their evaluations of alternative resource proposals in order to ensure a level playing field for all resource alternatives in a way to find the right mix of resources for customers.

122. Mr. Tyson discussed in his testimony how S&P imputes debt associated with PPAs and describes the actions Public Service has taken since 2005 to mitigate the balance sheet effects of such debt imputation and the cost impacts of those actions. Specifically, during the 2003 resource planning process, Public Service identified what it claimed was the negative impact that PPAs were exerting on its credit quality. To alleviate the imputed debt effects of PPAs, the Company sought, and was granted, approval to increase the regulated equity ratio to approximately 60 percent in order to achieve an economic equity ratio of approximately 50 percent when all of the imputed obligations were taken into account.

123. Mr. Tyson stated in his testimony that since June 2006, as a result of the Commission’s 2003 LCP decision, the Company has infused equity of over $500 million into

Public Service's capital structure to offset imputed debt from PPAs of approximately $719 million. The Company's current rates reflect this increased equity ratio due to imputed debt.

124. Equity infusions to retire debt represent a significant departure from the standard utility investment model, where investors generally expect the utility to raise equity and debt in order to make investments in a growing rate base. In Public Service's case, however, because of the burden of imputed debt from PPAs, the Company was required essentially to increase the level of equity investment underlying its existing rate base. It is the Company's position that there is no better evidence of the direct link between this additional equity and its PPAs.

125. In summary, Public Service represents that there are costs to the Company of acquiring PPAs that are already being borne by its customers, but that have not yet been reflected in resource evaluation and selection. Public Service advocates the need to start to recognize these costs as the Company makes choices among resources.

126. The Colorado Independent Energy Association's (CIEA) witness, Ms. Meal disputes that there is a direct link between the Company's additional equity layer and imputed debt from PPAs. On that basis, CIEA argues that the imputed debt adder should be rejected. CIEA claims that Public Service's assertions regarding imputed debt amount to little more than a claim that Public Service's finances and balance sheet might someday be adversely affected by entering into PPAs. In fact, CIEA represents that Public Service's financial health has improved at the very same time as the capacity provided by PPAs has reached its highest level, roughly 50 percent of Public Service's system MW.

127. Ms. Meal testified that credit ratings are determined based on a rating agency's assessment of numerous qualitative and quantitative factors. There is simply no way to correlate

a particular level of imputed debt with a particular credit rating, especially for any specific utility.

128. Ms. Meal represented that Public Service has overstated the adverse impact of PPAs and inappropriately uses these claims as the basis for excluding PPA options from essentially all of the ERP. As Ms. Meal explains in her testimony, the focus on imputed debt is to limit one element of PPA risk as assigned by one rating agency, while ignoring the offsetting benefits of PPAs as compared to utility-owned options. In summary, Ms. Meal advocates that the proposed imputed debt adders for evaluation of PPA bids should not be allowed. The Commission should continue to account for the impact of PPAs, if any, in Public Service's cost of capital proceedings.

129. The OCC supports Public Service's proposal to include a calculation for imputed debt in the bid evaluation process. The use of an imputed debt adder would take into account, for bid evaluation purposes, the effects of the higher equity level which the Commission has previously approved to offset the debt equivalent value created by PPAs.

130. Through the Answer Testimony of Mr. Shafer, the OCC supported the Company's request to include a calculation for imputed debt in the bid evaluation process. The OCC based its recommendation on the fact that the Commission had previously approved, in the Company's 2003 LCP docket, a higher equity ratio to offset the debt equivalent value of existing PPAs and to improve the Company's overall financial strength. Under the 2003 LCP settlement, Public Service was allowed to have a regulatory capital structure which would not exceed 60 percent for its 2006 Phase I rate case. In the Company's subsequent Phase I rate cases, the Commission approved the use of a 60 percent equity level for both its electric and gas departments. Exhibit FCS-1 to Mr. Shafer's Answer Testimony demonstrates that the cost to customers for the

higher equity ratio is approximately $54 million per year on a combined basis for the electric and gas departments.

131. The OCC believes that one of the benefits of isolating the effects of PPAs within the electric department through an imputed debt adder in the Purchased Capacity Cost Adjustment (PCCA) is that it would remove the current cross-subsidy, where gas department customers support a higher equity level not directly related to the service they purchase from the Company. The OCC contends that, as the level of PPAs is reduced over time, the size of the imputed debt adder will correspondingly decrease over time.

132. CF&I/Climax oppose an imputed debt adder. CF&I/Climax also represent that it became clear during the course of the proceeding that the imputed debt issue was inappropriate for consideration by the Commission in this docket. As Mr. Tyson acknowledged, Public Service's credit rating had been recently raised to BBB+/Stable by S&P with which Public Service seems most concerned. Moody's and Fitch have consistently rated Public Service higher than S&P until recently, when S&P rerated the Company at a higher level. As a consequence, the issue of imputed debt, which Mr. Tyson also acknowledged should be better addressed in the Company's next rate case proceeding as opposed to this docket, is misplaced and should not be included in the Commission's decision in this proceeding.

133. CF&I/Climax state that it is important for the Commission to continue to recognize that the alleged impact of the imputed debt attributable to PPAs is merely one factor of financial risk for consideration by the Commission in determining the Company's revenue requirement and rate of return. Nothing in this proceeding will impact the Company's credit rating in the near future. Mr. Tyson described the "stable" indicator as exhibiting confidence in the BBB+ rating for the next one to three years on the part of S&P. As a consequence, according

to CF&I/Climax, no "imputed debt adder" is necessary for purposes of the development of the Company's resource plan as proposed in this docket.

134. It is Staff’s recommendation that the Commission should find that Public Service has not established that PPAs adversely affect its access to the capital markets. Staff states that Public Service has not established any quantifiable “additional cost” that can be attributed to PPAs because of debt equivalency or other accounting adjustments. Staff believes the Commission should reject the premise that PPAs pose a quantifiable financial risk that should be negatively reflected in bid evaluation and, therefore, should reject the Company’s proposal to apply an imputed debt adder to bids received from IPPs for PPAs of any kind.

135. It is Staff’s position that this is the second resource plan in a row where Public Service has made debt equivalency a major theme of its case. In both cases, Staff has reviewed numerous documents and statements from S&P and other rating agencies. Staff’s position continues to be that there is no direct link between the amount of imputed debt associated with Public Service’s PPAs and its credit rating. Imputed debt is merely a factor in establishing financial metrics, which in turn are one of many factors considered in establishing a credit rating. Ultimately, it is how the capital markets behave in response to the credit rating agencies’ ratings and pronouncements that matter most.

136. Much attention has been paid to the Settlement Agreement in the Company’s 2003 LCP. It is clear from the Commission’s Decision that Staff saw no evidence that Public Service was having trouble securing capital even at the then current BBB- rating and that Staff was not persuaded by the Company’s debt equivalency arguments. In that docket, the settling parties, including Staff, agreed that Public Service had a need to increase its equity ratio in order to offset the debt equivalency value of existing purchased power agreements and to improve the

Company's overall financial strength. Public Service had been downgraded to BBB- specifically as a result of its affiliate NRG. The Company was also undertaking its most significant capital spending program in quite some time with the construction of Comanche 3. The agreement applied only to the 2006 rate case.

137. According to Staff, by most accounts, Public Service's ability to raise its equity level to 60 percent has been viewed favorably by S&P and the Company has been upgraded to BBB+. However, S&P has touted this equity level not so much for its ability to offset the impact of debt equivalency, but more for its mitigating effect on the large capital spending program and its overall effect on financial strength. Staff notes that in a recent report, S&P does not even allude to debt equivalency in its outlook, which is stable. Instead, S&P cites risks such as unfavorable rate outcomes and renewed emphasis on unregulated operations (presumably such as NRG) as its potential concerns. It also states that "an upgrade is currently not contemplated mostly due to the large capital spending program and consolidated debt leverage."

138. Staff asserts that ironically, the Company's ownership targets could result in another "large capital spending program", the very thing that has been cited as a barrier to a positive outlook. In addition, the Commission cannot do anything to improve the consolidated debt leverage at the holding company level, which appears to be more at the forefront of S&P's concerns rather than debt equivalency.

139. Staff represents that the record supports that Public Service and the holding company are on solid footing as compared with like utilities, and favorable regulatory mechanisms, particularly the PCCA, appear to have played a large role in providing needed cash flow stability.

140. Staff recommends that the Commission find that no debt equivalency adjustment should be implemented in the evaluation of PPAs. A negative impact on Public Service's financial health resulting from debt equivalency is not the imminent threat that Public Service has indicated. Additionally, Staff recommends that the Commission should weigh whether the risk presented to the financial health of the Company by debt equivalency is worse than a Commission decision allowing Public Service to negatively bias IPP bids. Staff believes that endangering the competitive market for resource acquisition is a more immediate and real threat than any concern involving debt imputation. Staff recommends that the Commission deny the use of a debt equivalency adjustment factor for resources in the 2007 ERP, and by doing so, demonstrate its support for maintaining a strong and robust competitive market for resource acquisition.

Discussion and Findings

141. The fundamental issue we must decide is whether an imputed debt factor should be included in PPA bid evaluations and what impact do the costs imputed by S&P have when Public Service goes to the financial markets for funding.

142. Public Service's witnesses contend that there are negative financial repercussions when the Company obtains generation through PPAs rather than building its own generation. For the purpose of evaluating bids, Public Service has proposed to add an imputed debt factor to all purchase power contract bids based on S&P's treatment of PPAs.

143. In Decision No. C08-0185, we determined that this issue should be included in this docket and be addressed in testimony. We found that many factual issues would need to be explored before we could rule on the issue and encouraged parties to investigate all options associated with this issue. We also found that the imputed debt issue, and related issues such as

Financial Accounting Standards Board (FASB) accounting and utility ownership requirements and other RFP restrictions, should be addressed in the normal course of testimony. However, in addition to Public Service, only Staff, the OCC, and CIEA provided substantial testimony regarding this issue. The OCC, in its testimony, supports an imputed debt factor to be included in PPA bid evaluations, while Staff and CIEA both oppose the inclusion of an imputed debt factor.

144. We heard testimony that the three major credit rating agencies, Moody's, Fitch, and S&P all take into account the impact of PPAs, as well as other financial metrics, in calculating their credit rating scores for Public Service. However, S&P is the only rating agency that explicitly addresses PPA impacts. S&P states, "PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in the assessment of a utility's credit worthiness." This agency also expresses its view that PPAs can reduce risks as follows, "…utilities that enter into contracts with suppliers will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build." The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

145. S&P assigns debt equivalence by explicitly adding: 1) a calculated amount of debt to the balance sheet; 2) the associated interest expense to the income statement; and 3) an implied amount of depreciation to the cash flow statement to calculate funds from operations. These changes are made to a utility's financial metrics in the evaluation of creditworthiness. No

changes are made to financial statements for FERC, Securities and Exchange Commission, or Generally Accepted Accounting Principles purposes.

146. We find the testimony presented by advocates against an imputed debt adder to be persuasive. We do not discount the testimony of Mr. Tyson that S&P does make adjustments to Public Service's financial statements in order to reflect the impact of imputed debt for PPAs when S&P does its credit evaluation. It has been the past practice of this Commission to address the financial matters at issue, including the impact of imputed debt on the Company's financial health, in a different forum such as a revenue requirement/ratemaking proceeding or an issue-specific docket. The rationale for examining a financial issue such as imputed debt in a revenue requirement/ratemaking proceeding is that all the moving parts of the issue will be examined at the same time, including the impact on the Company's financial health as well as the impact on ratepayers. In contrast, since this is a resource acquisition docket, all aspects of Public Service's capital costs as they relate to imputed debt are not examined as they would in a rate case. Therefore, we cannot accept the remedy proposed by the Company. By examining the imputed debt issue in a rate case context we can make the determination of whether S&P's method of imputing debt actually raises the cost of capital.

147. By this Decision, we endeavor to foster a robust competitive bidding environment. We question whether an imputed debt adder placed on PPA bid evaluations will detract from other benefits of having a competitive supply market. Therefore, we deny Public Service's proposal in this docket for the inclusion of an imputed debt adder.

J. Financial Impacts of Leasing and Consolidation

148. Public Service also seeks express authorization to refuse to enter into any PPAs that are, or potentially could be, classified for accounting purposes as a capital lease or which

would trigger consolidation under Financial Accounting Standards Board Interpretation No. 46R, Consolidation of Variable Interest Entities (FIN 46). The Company contends that there are potential financial reporting implications which would have negative impacts on its balance sheet and, therefore, increase its cost of capital.

149. Public Service discussed the FASB review of lease reporting requirements and stated its belief that possible changes would require greater on-balance sheet recognition of the Company's long-term PPAs. As a result the Company will have a more leveraged balance sheet and expects to incur additional financing costs. Public Service indicates that if the FASB makes lease reporting changes those changes could be effective as early as January 2013, which falls within this resource acquisition period.

150. An additional concern raised by Public Service is the effect on its balance sheet if a PPA prompts consolidation into Public Service's financial statements. If a PPA were found to trigger consolidation under FIN 46, then the Company would be required to consolidate the Variable Interest Entity (VIE) – in this case the assets, debt, and results of operations of the IPP – in its financial statements. Public Service anticipates that the VIE is likely to be a highly leveraged special purpose entity, so consolidation would have the effect of adding much more debt than equity to the balance sheet. Depending on the terms of a PPA and the legal structure of the entity owning and operating the power plant, Public Service maintains that FIN 46 could prompt consolidation which would increase its cost of capital.

151. The OCC did not present testimony on Public Service's position that it would not enter into PPAs that would trigger either capital lease treatment or consolidation under FIN 46. However, in its SOP, the OCC concurred with the Company's position and recommended the Commission adopt Public Service's position on this issue.

152. Staff finds the testimony of Company witness Madden on the status and mechanics of lease accounting to be factually accurate; however, Staff contends that the linkage between these facts and Public Service's chosen treatment of PPAs in Phase I is premature. Additionally, Staff asserts that the Company has not established any quantifiable "additional cost" that can be attributed to PPAs because of debt equivalency or other accounting adjustments. Public Service admitted that there are no current PPAs within the Public Service system or the Xcel Energy system that have been classified as capital leases and no PPAs have been consolidated onto the balance sheets of Public Service.[6] Regarding Public Service's concerns about capital leasing and consolidation, Staff argues that there is no direct linkage that a rating agency such as S&P will change the Company's credit rating solely due to these two accounting concerns. Staff recommends that the Commission preclude Public Service from disadvantaging an IPP bid in the Phase II bid evaluation because of its fear of potential accounting treatments.

153. Trans-Elect/WIA argue that Public Service has given "extraordinary, daunting and unwarranted prominence"[7] to the accounting issues of capital leasing and consolidation. Trans-Elect/WIA point out that during the evidentiary hearings, Commissioner Tarpey questioned Public Service's witness Madden as to whether the emphasis Public Service has given to these accounting issues would have a chilling effect on wind bids. Further, Trans-Elect/WIA states that bidder trepidation raised by threats and warnings about accounting issues may very well, either individually or in combination, discourage WCI-dependent Wyoming wind bidders from bidding into the Company's proposed 2008 wind RFP.[8] This would result in a lost opportunity for Public Service's ratepayers to receive cost-effective Wyoming wind.

[6] *See* Transcript June 27, 2008, pp. 48-49.
[7] *See* Trans-Elect/WIA Statement of Position, p.15.
[8] *Id.* p.16.

154. CF&I/Climax note that during the hearings Company witness Madden admitted that no single PPA on either Public Service's system or the Xcel Energy system has to date been treated as a capital lease. CF&I/Climax submit that the Company is seeking action on an issue that is inherently speculative at this point and does not warrant further Commission review and action in this docket. If, at some point in the future, a PPA is treated as a capital lease, it would be more appropriate for Public Service to come forward at such time and propose specific treatment to the Commission, enabling the Commission to deal with this issue from a position of fact. According to CF&I/Climax, no such requirement exists at this time. As a result, the Commission should reject the Company's capital lease argument in this proceeding.

155. CIEA and the Colorado Energy Consumers (CEC) assert a willingness to work with Public Service to avoid accounting situations that would result in a PPA being classified as a capital lease or that would force FIN 46 consolidation of an IPP's and Public Service's financial records. However, CIEA and CEC have concerns that the Company's request appears designed to impose a significant barrier to bidding by IPPs. For example, Public Service has proposed RFP language which requires a bidder to state its understanding of, and intent to avoid, capital lease accounting and FIN 46 consolidation issues.

156. CIEA and CEC point out that no current Public Service PPA has been classified as a capital lease, and likewise no PPA has triggered consolidation. Although Public Service witness Tyson stated that the "investment community may infer" a higher degree of risk to the utility due to lease accounting, he admitted that that had not yet actually happened.[9] Moreover, Public Service's witnesses acknowledged that "there currently is no bright line test as the FASB

[9] *See* Transcript June 26, 2008, pp.140-142.

standards look to the totality of circumstances in each contract."[10] As a result, CIEA and CEC argue that there is no way at the time of bid submission or evaluation to confirm capital lease status or FIN 46 consolidation applicability since the final terms of the PPA would not then be known. Further, the relevant accounting rules are in flux, which creates a moving target for those trying to avoid such accounting problems.

157. CIEA and CEC maintain that the concerns surrounding these evolving accounting issues seem uncertain enough to warrant a Commission ruling in Phase I that bids need not address the still-changing capital lease accounting and FIN 46 consolidation issues until after Phase I when the terms of PPAs are being negotiated (at which time such issues may for the first time become ripe to be addressed by the bidder in any useful way). Without such protections from the Commission in its Phase I Order, CIEA and CEC conclude that bidders are at risk of subjective disqualification by Public Service over an issue that cannot be meaningfully resolved at the bidding or evaluation stage of the process.

158. Consideration of the balance sheet impact that new or existing PPAs may or may not have in a cost of capital proceeding is consistent with prior Commission decisions. CIEA and CEC witness Meal states this is the best regulatory context in which to address such financial and accounting issues.

Discussion and Findings

159. We find Public Service's arguments persuasive that it should be permitted to include language in its RFPs addressing the capital lease and FIN 46 issues. Specifically, we approve use of the proposed paragraph offered in the Company's SOP. The following language

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[10] *See* Transcripts June 26, 2008 p.147 and June 27, 2008, p.42.

(Attachment A of the Company's SOP dated July 21, 2008) will be placed in Public Service's RFPs in this resource acquisition docket:

> The Company is unwilling to be subject to any accounting or tax treatment that results from a PPA's capital lease or FIN 46 treatment. As a result, all bidders are required to state in their proposal(s) (i) that the bidder has reviewed and considered applicable accounting standards in regard to capital leases and variable interest entities, i.e., FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities and Emerging Issues Task Force issue No. 01-08, Determining Whether an Arrangement Contains a Lease, (ii) summarize any changes that the bidder proposes to the Model PPA in order to attempt to address these issues, and (iii) to the bidder's knowledge and belief, the bidder's proposal should not result in such treatment as of the date of the proposal.

160. Additionally, Public Service is permitted, but not required, to include language in its model PPAs that direct Public Service and bidders to endeavor to resolve among themselves any disputes that arise with respect to this issue. If no resolution is reached, then Public Service or the bidder may bring the disagreement before the Commission.

161. However, we deny any terms in the model PPA that otherwise subject the IPP to continued liability for FIN 46 or Capital Lease issues after the contract is executed.

K. Utility Ownership – 229 MW and 40/60 Percent Issues

162. In its direct case Public Service proposed reverse-auction and build-transfer mechanisms that would potentially result in the utility owning 100 percent of new generation acquired as a result of this case. Several parties opposed this proposal as contrary to the Commission's rules and not in the public interest. CIEA and CEC, as well as other parties, provided significant testimony about the benefits of IPP ownership, and the detrimental impacts that Public Service's proposal would have on the competitive market in Colorado.

163. In its rebuttal case, Public Service substantially altered its position, advocating that the Commission establish a target ownership percentage of new incremental generation of between 40 and 60 percent plus utility ownership of 229 MW of replacement capacity for the

early retirement of the Arapahoe and Cameo coal facilities. Public Service acknowledges that in the mid-1990s Public Service made a conscious decision not to build generation assets, and developed a reliance on the Qualifying Facility and IPP market. Public Service agrees that it is wise to have a diversified portfolio of utility and IPP ownership, but it is concerned that it has a higher percentage of PPA ownership than other utilities.

164. Public Service explains that approach advocated in its rebuttal testimony will move it towards more utility ownership, while allowing IPP bids. Although full ownership of incremental generation would bring Public Service more in line with the IPP ownership percentages for other utilities, Public Service asserts that approving the proposed ownership percentages in Phase I will move the Company's ownership percentage part of the way to the ultimate goal. Public Service argues that there are many "optionality" advantages of rate-based plant over IPP ownership. The utility plant remains in service after the asset is depreciated and the utility has control of generation asset. Further the utility can more readily adapt the plant to changing circumstances, which would, in contrast, require a contract revision for IPP plants.

165. Public Service asserts that utilities that volunteer carbon reductions by retiring assets should not be disadvantaged. The net plant value of steam assets are $288 per kW, gas turbines are approximately $321 per kW, so that it would be fair to dedicate the replacement capacity to utility ownership.

166. Public Service acknowledges that Phase II will not provide time to resolve significant disputes between the utility and IPPs, so it recommends that the Commission approve its proposed ownership targets, but treat these utility ownership percentages as "soft targets." That is, if in Phase II the Commission determines that IPP or utility costs are not within a reasonable range, the Commission could deviate from the target percentage.

167. Public Service also argues that PPA contracts typically allow the IPP to recover its costs within the term of the contract, but recent history has shown that IPPs do not offer significantly lower contract prices in subsequent contract renewals – over-recovering their costs.

168. CIEA and CEC strongly oppose any utility ownership percentages or set-asides from the competitive bidding requirements established in the ERP Rules. The Commission's ERP Rules explicitly require competitive resource acquisition, with limited exceptions, and they argue that Public Service's proposal for utility ownership targets would require a rule waiver.

169. CIEA and CEC assert that any utility ownership set-asides would harm the competitive bidding environment to the detriment of ratepayers, IPPs, and the new energy economy. Any set-asides including capacity for coal retirements may set a dangerous precedent, as many coal plant retirements may be necessary in the future. They argue that Public Service's financial health has improved while 50 percent of capacity is being provided by PPAs, and assert that Public Service's percentage ownership of generation is certain to grow from 2008 to 2015. They go on to state that IPP ownership removes significant risk from ratepayers, as the IPP is at risk for cost overruns, performance failures, or future changes in energy or technology that render the plants unusable. With respect to "optionality" claims by Public Service, CIEA and CEC assert that other benefits of IPP ownership outweigh utility benefits. These include faster construction time, more experience with constructing and operating plants in many locations, and better working relationships with equipment vendors.

170. CF&I/Climax also take the position that the Commission should reject Public Service's proposed ownership targets.

171. Staff argues that the ERP Rules intend for the Commission to address in Phase I the methods to be used to evaluate resources in Phase II, so the Company's proposed utility ownership targets should be assessed after the proposals are compared in Phase II.

172. The OCC contends that IPPs typically recover their capital costs more than once, and recommend that the Commission grant Public Service's request as outlined in its direct case, resulting in 100 percent utility ownership. The OCC generally advocates for utility ownership of all resources.

173. Many parties state that Public Service should be commended for its forward thinking in proposing early retirement of coal generation facilities. These arguments generally favor allowing Public Service to own the replacement capacity for the early-retirement proposals.

Discussion and Findings

174. Although Public Service directs essentially all rebuttal and hearing testimony to its alternative rebuttal position, the Company requests that the Commission approve either its direct case or its rebuttal position. We deny the request in Public Service's direct case for potential ownership of 100 percent of incremental generation. As Public Service witness Bonavia recognized in rebuttal testimony, IPPs have a long-standing relationship in Colorado, and the public interest is best served through a portfolio of utility rate based and PPA generation. We deny Public Service's request to implement reverse-auction and build-transfer requirements as a part of its resource acquisition process as contrary to the public interest.

175. Public Service's primary argument for utility ownership is that PPAs negatively impact utility financial performance because of imputed debt impacts. Public Service asserts that it has a higher percentage of IPP generation ownership when compared to similar utilities. We

agree that being an "outlier" in this respect may impose a degree of investment risk. However, as discussed above, we do not agree that imputed debt impacts significantly alter utility finances, and do not warrant a guaranteed utility ownership percentage.

176. Regarding "optionality" advantages over IPP ownership, we agree that if the utility owns the resource it can better control its operation, and can more easily modify it to match changing circumstances. However, we agree with CIEA and CEC that IPP ownership significantly reduces risk to ratepayers.

177. We find that both utility and IPP ownership provide significant benefits to ratepayers. Utilities have access to inexpensive capital, and utility plants provide long-term benefits to customers. IPP contracts insulate ratepayers from many risks, and IPPs provide a wealth of experience in constructing and operating plants. Together, a portfolio of utility-owned and IPP generation can provide the best overall value to consumers. In fact, ratepayers are at risk if either the IPP or utility ownership mechanisms are impaired. It is important to maintain a vibrant environment for both utility and IPP generation so that both can continue to advance technological efficiencies, and so that they keep each other sharp through competition.

178. We are inclined to maintain a reasonable balance of utility and IPP ownership, and we agree that the ownership percentages proposed by Public Service are clearly intended to strike such a balance. We also agree that the percentage amounts proposed by Public Service will help the utility trend towards a balance that is similar to its peer utilities. Further, we are aware that Public Service proposed the Cameo and Arapahoe plant retirements for carbon reduction purposes, well before any federal or state mandates require such reductions. We agree that, under these circumstances, it would be appropriate for the utility to own the replacement capacity for the closed coal plants. Although CIEA and CEC make a good point that many coal

plant retirements may be necessary in the future, we find that this situation is unique as the plants are not retired for immediate compliance purposes. This is an unusual case, and does not set a precedent for future plant retirements.

179. The OCC's primary argument is that IPPs recover their cost of capital more than once, so ratepayers are better off with utility plant ownership. Public Service supports this argument, stating that IPPs recover their costs in the term of the contract, but plants that are re-bid do not appear to have significantly lower bids than new plants. The OCC's arguments seem to advocate full utility ownership regardless of how the utility costs compare to the IPP costs. We disagree that such arguments provide a basis for eliminating or reducing IPP ownership. Rather, we should consider the IPP value over the term of its contract, regardless of how it will be re-bid. We recognize that if capacity is scarce IPPs will likely re-bid at a higher price, but over-capacity could result in the opposite situation. If technology changes or other industry shifts occur, the IPP plant may become obsolete. Ratepayers may gain advantages from long-term utility ownership of assets, but shorter term IPP contracts avoid the risks of ratepayers having to continue to pay for facilities after they become obsolete or do not perform as well as the newest technology. Regardless of how IPPs may re-bid in the future, we must compare the value to ratepayers that is provided over the term of the contract.

180. We agree with Staff that the proper time to determine the appropriate utility ownership is in Phase II. We agree with CIEA and CEC that a set-aside in Phase I could have detrimental effects on the competitive spirit of the All-Source comparison, and would complicate the economic evaluation in Phase II. We find that any determination on this issue in Phase I could also reduce the utility's incentive to provide the best proposal at the least cost. We disagree with Public Service's assertion that its internal budgeting and project review alleviate

the need for further scrutiny of the economics of a utility proposal. An internal utility review cannot replace a cost comparison with competitive bids.

181. Although we affirm our commitment to supporting utility-owned generation as a part of the mix, we defer the ruling on the actual ownership amounts to Phase II. We note that the end result of our decision is quite similar to the "soft target" approach advocated by the Company, where a reasonableness test is used to vary the ownership amounts. Later in this decision, we will explain in detail how the modeling process in Phase II will be used to provide the Commission with a full picture of the relative costs and benefits of utility ownership of incremental generation in the range advocated by Public Service.

182. Last, we acknowledge that the utility may own 25 percent (or 50 percent under certain conditions) of new renewable resources pursuant to § 40-2-124, C.R.S., if it meets certain cost reasonableness standards. If Public Service intends to propose utility-owned resources in Phase II pursuant to this statute, then it must request a review from an IE, as required by statute. The IE employed by the Commission for ERP purposes will also fulfill the role of the IE in § 40-2-124, C.R.S. In order to meet the expedited timeline for Phase II, we require Public Service to submit proposed procedures for such Section 124 evaluation in conjunction with the IE participation in this ERP docket.

L. Requirements for Utility Proposals

183. In its rebuttal proposal, Public Service proposes to submit "CPCN quality" rate-based utility proposals at the same time as IPP bids are due. These will be sealed proposals, filed under extraordinary confidentiality provisions limited to the Commissioners, Staff, the OCC, and Commission Advisors. Public Service states that it will not bid at a fixed price. The Company asserts that it is not compensated for IPP risk and utility investors do not want this type of risk.

184. CIEA and CEC assert that the Commission should require Public Service to submit a binding fixed price bid for any utility proposals. If Public Service is not willing to submit a binding bid, then the Commission must take steps to place the utility proposal on equal footing with fixed price IPP bids. The Commission could require a bid "cap" or require a risk adjustment premium to be added to the utility rate-based proposals.

Discussion and Findings

185. Public Service states that it will not bid at a fixed price, as it is not compensated for IPP risk and utility investors do not want this type of risk. We agree that IPPs and utilities are entirely different types of entities. Each provides its own benefits and detriments to ratepayers in plant ownership. Therefore, we deny CIEA and CEC's request that we require Public Service to submit binding bids.

186. As described in Rules 3601 and 3610(b), new resources are required to be acquired through a competitive acquisition process, unless the utility proposes an alternate method (limited to 250 MW):

> 3601. Overview and Purpose.
>
> The purpose of these rules is to establish a process to determine the need for additional electric resources by Commission jurisdictional electric utilities. It is the Commission's policy that a competitive acquisition process will normally be used to acquire new utility resources. This process is intended to result in cost-effective resource portfolios, taking into consideration projected system needs, reliability of proposed resources, beneficial contributions of new clean energy and energy-efficient technologies, expected generation loading characteristics, and various risk factors. The competitive bid process should afford all resources an opportunity to bid, and all new utility resources will be compared in order to determine a cost-effective resource portfolio.
>
> 3610. Utility Plan for Meeting the Resource Need.
>
> (b) The utility shall meet the resource need identified in the plan through a competitive acquisition process, unless the Commission approves an alternative method of resource acquisition. If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the

> utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through a competitive acquisition process. In addition, the utility shall provide a cost-benefit analysis to demonstrate the reason(s) why the public interest would be served by acquiring the specific resource(s) through an alternative method of resource acquisition. The resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process. The utility shall also explain and shall justify how the alternative method of resource acquisition complies with the requirements of the Public Utility Regulatory Policies Act of 1978 and Commission rules implementing that act. The lesser of 250 megawatts or ten percent of the highest base case forecast peak requirement identified for the resource acquisition period shall be the maximum amount of power that the utility may obtain through such alternative method of resource acquisition (1) in any single resource acquisition period and (2) from any single specific resource, regardless of the number of resource acquisition periods over which the units, plants, or other components of the resource might be built or the output of the resource made available for purchase.

187. We find that a utility rate-based proposal without any form of a cost cap does not meet the competitive acquisition process intended by the ERP Rules. Cost overruns for this rate-based plant would be borne by ratepayers,[11] so a comparison with fixed IPP bids is rendered meaningless. In contrast, the rate-based proposal applies more directly to the 250 MW exemption from competitive procurement detailed in Rule 3610(b). With a rate-based proposal the utility has a reduced incentive to make sure the estimate will cover its costs, and it has a weaker incentive to make sure the project stays within budget.[12] The IPP has a large incentive in both cases. We agree with CIEA and CEC that we must take steps to place the utility proposal on equal footing with fixed price IPP bids.

188. At hearing, Public Service witness Mr. Bonavia testified that other utility proposals have been limited to a cost cap, and he stated that the Company would be open to

[11] These cost overruns would be subject to prudence review.

[12] As discussed above, we disagree with Public Service's argument that budgeting and internal review provides a meaningful limit on costs.

some form of symmetrical cap. We recognize a utility's reluctance to implement a cap, as it creates the same problems with submitting a fixed price bid. However, we find that any utility rate-based proposal must have a cap in order to be comparable with fixed price IPP bids. This cap must be established so that any expenditures above the cap would be borne by shareholders. The expedited Phase II timeline does not allow parties to have much input into the process to develop a fair bid cap, so the utility must establish a cap as a part of its proposal. Therefore, we find that utility rate-based proposals without a fixed price will only meet the competitive intent of the ERP Rules if such proposal is submitted with a cost cap.

189. Although Public Service typically provides facility cost proposals in the form of a cost plus or minus a certain percentage variance, we direct the Company to establish a point cost in its proposal. This may be a cost without any percentage variance. Alternatively, Public Service can include any such contingency as a part of its proposed cost, but the point cost used in bid comparison will include the full variance amount, and we will not consider a range. We expect this point cost cap level to be the maximum amount that is used in future cost recovery proceedings, absent a showing of extraordinary circumstances.

190. Consistent with Mr. Bonavia's statement that Public Service would be open to some form of a symmetrical cap, Public Service may want to explore sharing mechanism options of some type. The magnitude of a cost overrun under a firm cap could financially damage a utility, and is not consistent with Public Service's notion that its shareholders do not want to adopt the risk of an IPP. A sharing percentage would provide the utility with an incentive to accurately estimate its costs and follow with proper project management to keep the costs in line. It is unclear what "symmetrical cap" Public Service has in mind, but we agree that a sharing mechanism could be appropriate. For example, if the project is completed under budget.

However, we are concerned about potential unintended consequences of such a sharing mechanism. For example, significant brownfield advantages or other savings could allow the utility to substitute a high estimate that would guarantee incentive rewards, and still beat the IPP bids.

191. We require any utility rate-based proposals to include a proposed cost cap to be used for comparison with fixed price bids.

M. RFPs, Model Contracts

192. As a part if its direct case, Public Service provided draft RFPs and model contracts. However, because of the many changes to its case, the Company filed entirely new RFPs and model contracts in rebuttal. The four RFPs are: Wind RFP; Dispatchable RFP; Non-wind, Non-dispatchable RFP; and Firm Capacity, Semi-dispatchable RFP (*e.g.*, solar with storage). Further, Public Service did not complete the semi-dispatchable RFP in time to submit it with its rebuttal case, and commits to file it with the Commission 60 days before it issues the All-Source solicitation.

193. Trans-Elect/WIA recommend that the Commission require Public Service to make modifications with respect to security requirements, land control, and turbine commitments, and specification of milestones to ensure that projects that win are actually constructed. Trans-Elect/WIA state that while Public Service's current documents have a milestone structure that is workable in the context of acquiring wind projects with a three-year lead time, those milestones are not suitable for a longer lead time, which is necessary for wind using the proposed new WCI transmission line. In addition, price components of the bids should be allowed to be indexed as opposed to being quoted at a fixed price.

194. CIEA and CEC witness Muller recommends that the Commission require changes to the following terms in the model contract:

1. Security Requirements; (subordinated mortgage, flexibility)
2. Right of First Offer (RoFO)/Option to Purchase;
3. Change in Law Risk;
4. Force Majeure;
5. Events of Default;
6. Delay Damages/Replacement Energy Costs;
7. Partial Commercial Operation;
8. Company's Condition Precedent;
9. Conditions to Commercial Operation;
10. Maintenance Schedule;
11. Curtailment Risk; and
12. Renewable Energy Payment Rate

195. In rebuttal, Public Service witness Klein argues that Mr. Muller's changes only allocate risk away from the IPP, to the utility, and recommends denying all such requests.

196. With respect to the changes proposed by Trans-Elect/WIA, Public Service states that it will allow indexing on a limited basis, but the Company has not thoroughly thought through all the implications and is offering no changes to the model PPA. Instead, bidders that want to use indexing can submit the indexing details in their proposals. Similarly, Public Service does not propose any modifications to the model PPA to accommodate WCI or developers using that transmission line. Public Service states that it is concerned about the risk of WCI development failure after the awarding of bids. Wyoming developers can propose appropriate modifications to the PPAs to address these concerns.

197. Staff asserts that the major changes proposed by Public Service in its rebuttal testimony do not allow intervenors to adequately review the changes, and recommends that the Commission require Public Service to allow bidders to propose changes to the documents with the requirement that Public Service will not disqualify any bids for such changes.

Discussion and Findings

198. First, we agree with Staff that Public Service proposed wholesale changes to the RFPs and model contracts in its rebuttal case, and that one RFP has not yet been submitted. Public Service chose to file its direct case based on the controversial reverse-auction and bid-purchase requirements, but then reverted to a more traditional IPP bidding concept in rebuttal. The resulting delay significantly disadvantages other parties. We agree with Staff that, because of this problem, bidders should be allowed to make changes, and bids will not be disqualified for such changes. Public Service can then negotiate with bidders to resolve these changes as a part of contract negotiations.

199. We agree with CIEA and CEC that the end-of-term purchase option is unnecessary, and shall be deleted from the model contract. Regarding the other changes proposed by CIEA and CEC witness Muller, we agree with Public Service that these are simply changes that transfer risk from the IPP to the utility, and we decline to order these changes to the model contracts. Again, these types of issues can be addressed in contract negotiations.

200. Regarding the proposal offered by Trans-Elect/WIA, we agree with Public Service's recommendation that IPPs can propose indexing provisions as a part of bids. We also agree that other PPA issues can be addressed in contract negotiations after the IPP proposes specific exceptions as a part of its bid.

201. As discussed in the Capital Lease Section above, we will allow Public Service to put in the RFP the language proposed in its SOP addressing FIN 46 or Capital Lease issues. However, we deny the request to include any terms in the model PPA that subject the IPP to continued liability for FIN 46 or Capital Lease issues after the contract is executed.

202. Except as addressed above, we accept the RFPs and model contracts as proposed in Public Service's rebuttal case.

N. Energy and Peak Demand Forecasts

203. Public Service witness Marks sponsors the peak load and energy sales forecasts that serve as inputs into the STRATEGIST resource planning model. These forecasts would be part of the process in determining forecast needs in the future.[13] The Company forecasts load and sales growth using statistical and econometric forecasting methodologies. Various inputs are used to derive the forecasts: economic and demographic data, electricity prices, and various indices of cooling, heating, and base usage among others.

204. Public Service develops these forecasts by customer classes and sums them up to total peak load and energy sales forecasts. The forecasts are further adjusted to account for expected changes in wholesale accounts and levels of DSM that serve to alter those gross forecasts of future levels of peak load and sales. The Company used two alternative DSM forecasts, and initially requested that its "enhanced DSM" forecast be used in its Resource Plan.

205. Public Service is forecasting annual growth rates of 0.6 percent of peak load and 0.2 percent of energy sales. Public Service explains that the forecasted growth is significantly less than recent historical changes because of forecasted weak economic and customer growth,

[13] Exhibit No. 11 and Exhibit No. KTH-1, Sections 1.3 and 2.7, Technical Appendix to the Application.

reductions to wholesale sales, and rising levels of DSM. After 2012, when the reductions of wholesale sales end, annual growth of peak load growth returns to 2.4 percent although energy sales remain sluggish.

206. In addition to its base forecast, Public Service produces high and low alternative forecasts. These forecasts assume factors that would depress or accelerate growth. In the high forecast scenario, assumptions are made about plug-in electric cars, increased economic activity, and global warming. In the low forecast, factors such as higher than expected deployment of on-site solar, deployment of compact florescent lights, and slower economic growth decrease the base forecast.

207. Staff witness Harris[14] and OCC witness Rosen[15] provide answer testimony regarding the forecasts and methodology submitted by Public Service. Both Staff and OCC suggest that Public Service's forecasts are overstated and should be reduced for a variety of factors.

208. Generally, Staff is concerned with several factors, among them Public Service's assumption that the price of electricity will decline in real terms over the forecast horizon; that the current Electric Commodity Adjustment (ECA) reflects electricity prices that are triple the price that Public Service forecasts for 2035; and an overestimate of the number of residential customers. Mr. Harris asserts that the first two factors cause the Public Service forecast to be too high, since the forecast would be lower if consumers were faced with more realistically higher forecasted electricity prices. Mr. Harris also finds that the Company's forecast of residential customers is already in excess of actual customers, and the forecast does not reflect the effects of

[14] Exhibit No. 59
[15] Exhibit No. 49

the slowdown in residential construction and overall weakness in the residential housing market. Mr. Harris proposes to reduce the residential forecast by 31,000 customers over time. Because household growth has slowed, the forecast for street lighting should be reduced as well.

209. Staff also criticizes Public Service's forecast relative to the assumed future trend of the non-residential cooling factor that drives commercial energy sales and peak load. Staff takes the position that the cooling impact on non-residential usage should start to reach a plateau, reflecting the saturation of air conditioning in non-residential facilities. According to Staff, the cooling index increases continually during the forecast process even though an input to the index shows saturation of non-residential cooling. Staff witness Harris explains this conflict relative to a faulty forecasting methodology employed by Public Service.

210. In terms of the forecasted future price of electricity, Staff cites the following issues that will drive up the real price of electricity: the opening of the Rockies Express to the East, and Kern pipeline to the West; costs related to the Commission's RES; additional DSM charges; additional transmission expenses related to both renewable and traditional new utility resources; additional investments that will likely go into the Company's rate base for cost recovery in the very near future, including the remainder of the Comanche 3 capital costs and the costs of the new combustion turbines that are scheduled to go on-line in 2009 at the Company's Fort St. Vrain station; possible federal carbon taxes or expenses related to cap and trade schemes; and rising overseas demand for coal leading to inflated prices.

211. In summary, Staff recommends that Public Service use a significantly higher forecasted price of electricity, that it revise its cooling index factor for non-residential demand, and that it reduce the number of households in the forecast period.

212. OCC witness Rosen states that the base case forecast by Public Service is too high for several reasons. These include: the current economic recession in the United States which could last another year or two; Public Service's underestimate of future fossil-fuel prices; Public Service's omission of many of the elements of Governor Ritter's greenhouse gas reduction plan; and the cost of the Federal Energy Act of 2007. According to Mr. Rosen, Public Service's low load forecast is more likely to be the best one to use for planning purposes in this docket. Rosen argues that not only is the assumed price of electricity wrong for forecasting purposes, but the choice among different resource types will be skewed based on the underlying assumptions of future natural gas prices. Mr. Rosen points out that high energy prices not only reduce the consumption of electricity, but also filter through the economy and reduce economic growth, further decreasing demand. Mr. Rosen also contends that the statistical regression models used by Public Service do not produce accurate forecasts during times of dramatic changes.

213. Besides Staff and OCC, several other parties take issue with Public Service's assumptions concerning the forecast of electricity prices and the price of the underlying fuels. Glustrom, LaPlaca, GEO, WRA, ACSF, and others criticize Public Service's assumed price of fuels in the future. Other than ACSF, these parties claim that Public Service underestimates the increase in future natural gas and coal prices.

214. In Public Service witness Marks' rebuttal testimony and in the hearing in this docket, Public Service indicated that it will update its forecast to be used in the Phase II STRATEGIST analysis.[16] The decision to update its forecast was based partly on Staff concerns regarding the forecasting models and methodology, and is designed to allow Public Service to use the most recent data available both in terms of recent actual data and new economic forecasts

[16] Exhibit No. 12 and Transcript, Volume 10, July 7, p.50

among other items. Also, Public Service will be using DSM volumes from Decision No. C08-0560 to adjust the forecasts. Public Service indicates that this new forecast results in higher levels of peak demand and sales because of increasing levels of plug-in loads, new commercial and industrial customers, and increased loads from the Western Slope.

215. Public Service takes issue with some of the concerns raised by Staff witness Harris and OCC witness Rosen. Public Service agrees with Staff that customer counts have been over-estimated, and the resulting street lighting forecast is too high. Public Service stated that it is changing certain components of its forecast model, and will also be using a higher forecasted price of electricity, Public Service disagrees with Staff's criticisms of its method of forecasting non-residential peak load.

Discussion and Findings

216. Public Service witness Marks indicated that the Company was intending to update its load forecasts and file them with the Commission on December 1, 2008.[17] We approve of such a measure, as the original forecasts were prepared in advanced of its Resource Plan filing in this docket in November 2007. We find that these updated forecasts will true up the forecasts to the most recent actual data, and permit Public Service to update its forecasting data with newer economic and demographic forecasts.

217. As discussed above, various parties find fault with Public Service's load forecasts based on their belief that the assumed future prices of electricity and the fuels used to produce it will grow significantly faster than Public Service has assumed. Since these parties question the load forecasts based on this individual issue, and are as much concerned with the fuel price

[17] Exhibit 12 and Transcript, Volume 10, July 7, p.50

assumption impact of resource choices in Phase II of this docket, we discuss their testimony in our discussion on future energy prices in the Fuel Cost Section of this Decision.

218. We find Public Service's methodology to forecast peak load and energy sales to be generally sound and appropriate for use in this docket. Public Service has the knowledge of its business to produce forecasts that are reflective of the most likely outcome given all the uncertainties of forecasting future load and sales. We require the Company to use its base forecast as opposed to the high or low forecast.

219. At the same time, we recognize that Staff has performed a detailed analysis of the load and energy forecasts and filed testimony suggesting targeted modifications of the forecasts sponsored by Public Service. OCC has also discussed issues regarding the forecasts with respect to the underlying forecasts of economic growth and the future prices of electricity, natural gas, and coal. Both of these parties provide useful reasons as to why the variable price of electricity in the forecast period is seen as problematic.[18]

220. Public Service has decided to update its forecasts to reflect more recent actual data and economic and demographic inputs. Public Service also has indicated it will use a forecasted price of electricity that increases faster than it had originally predicted. Further, Public Service has indicated that it will use a different econometric relationship to forecast future

[18] The forecasted price of electricity is problematic, not only because of the effect of natural gas and coal price movements, but also because of the effects of the issues raised by Staff as discussed above, including the impacts from higher energy efficiency riders on customers bills, the lack of carbon costs from federal legislation, the increased need for cost recovery of transmission, etc. We agree that this price variable should be used to capture all elements of the price of electricity as much as possible. Moreover, we believe that the price of electricity should include any and all costs of electricity that are also inputs to various sections of the Strategist model. For example, Public Service witness Marks admitted that possible future carbon costs are not included in the price of electricity, even though those costs will be included in the resource planning model. Therefore, carbon costs will only impact the relative costs of different portfolios, not the base demand for electricity.[Transcript, volume 10, July 7, p.46]

residential customers. These two changes should address some of the criticisms of Staff and the OCC.

221. We have determined other issues in this Decision, discussed later, that bear on avoiding the risk associated with selecting specific load and sales forecasts. In the first instance, we will direct the IE to utilize two levels of DSM volumes to determine resource needs and plans in the resource planning period. This will allow us to view a range of estimated demand and the resulting impact on resource needs. Second, we will require a sensitivity analysis of various natural gas prices as they impact resource selection.

222. We direct Public Service to make a compliance filing in this docket to provide the updated load and sales forecasts that will be used in the Phase II STRATEGIST modeling scenarios. This filing should contain the same amount of detail about the forecasts, as well as the background underlying the forecast, as contained in Section 2.7 of the Technical Appendix to the resource plan Application in this docket. Public Service shall provide base load and sales forecasts, along with low and high forecasts as it provided in its original Application.

223. In addition, we require Public Service to provide the historical and forecasted values of the price of electricity term used in its econometric model, along with the underlying assumptions regarding the forecasted prices of natural gas and coal that comprise the electricity price index. Finally, we direct Public Service to describe how, if at all, its specific rate adders, such as the transmission cost adjustment, the RESA, carbon taxes, and any other non-fuel rate adjustments are contained within the forecasted price of electricity. If these are not in the price variable, Public Service shall explain why it is appropriate to exclude these rate adders from the price of electricity. This filing shall be made with the Commission no later than December 1, 2008.

O. Non-Energy Impacts (Externalities)

224. Commission Rule 3604(g) states that a Resource Plan shall include a "description of projected emissions in terms of pounds per MWh" and Rule 3610(d) states that "(t)he utility shall also propose, and other interested parties may provide input as part of the resource plan proceeding, criteria for evaluating the costs and benefits of resources such as the valuation of emissions and non-energy benefits."

225. Public Service, in its Application, presented emission rates, in accordance with Rule 3604(g). Public Service also proposed that emissions and water be valued as costs components within energy resource bids.

226. Our RES Rules, specifically Rule 3651, also address non-energy benefits, providing a general list of the various societal benefits of renewables such as: save consumers and businesses money, attract new businesses and jobs, promote development of rural economies, minimize water use for electric generation, diversify Colorado's energy resources, reduce the impact of volatile fuel prices, and improve the natural environment of the state.

227. CDPHE, Ratepayers United of Colorado (RUC), and WRA testified to the various health-related costs associated with fossil-fuel based electric generation. WRA used the same modeling methods as CDPHE concerning health effects, yielding higher values due to an update of the input values. These parties, as well as Ms. Glustrom, also presented the general correlation between fossil fuel combustion and adverse climate impacts.

228. CDPHE, RUC, and WRA testified to the specific health benefits that will result from the proposed retirements of combustion units at Arapahoe and Cameo. RUC also advocated that the replacement of the coal combustion units at Arapahoe with natural gas combustion would yield positive health benefits, but nonetheless significantly less than if the

replacement generation was not fossil-fuel based. RUC advocated for zero carbon dioxide emissions from the replacement generation at Arapahoe and Cameo.

229. As mentioned above, Denver testified that the City of Denver failed to comply with EPA ozone standards in 2007 and is now required to develop an attainment plan. Denver contends that if the Arapahoe plant is not retired as proposed by Public Service, attaining ozone compliance will be difficult. Denver also contends that if the Arapahoe plant is not retired, Public Service will have to undertake additional mercury emissions monitoring investments within the next 6 to 12 months.

230. In rebuttal testimony, Public Service challenged RUC's testimony regarding nitrous oxide emissions associated with the repowering of Arapahoe. Public Service contends that there are numerous flaws in the calculations presented by RUC witness Gerdes. Public Service also rebutted CDPHE's health risk assessments, citing uncertainty in the ability to specifically link health effects with specific individual emissions sources.

231. RUC, Ms. Glustrom, and Ms. LaPlaca testified to the adverse health and environmental concerns associated with natural gas production, advocating for the inclusion of these costs when incorporating non-energy benefits into the resource planning.

232. Ms. Glustrom also proposed that the list of externalities factored into the analysis include: climate change; mercury emissions; SO_2; NOx; particulates; volatile organic compounds; contributions to ozone formation; contributions to Colorado's energy security, economic prosperity, and environmental protection; insulation from fuel price increases/volatility; savings to consumers and businesses; attracting new businesses and jobs to Colorado; rural economic development; reduction in water use in electric generation; and diversification of Colorado's energy resources.

233. Interwest testified that Public Service's proposed plan underestimates the benefits of clean energy resources by omitting analysis of "non-utility" factors, such as: financial savings to consumers and businesses; consumer expectations for climate solutions, particularly with regard to Governor Ritter's climate action goals; energy portfolio diversification; reduced water consumption; economic development, particularly in rural areas; and job creation. Interwest offered specific data on the job creation resulting from a large-scale concentrating solar thermal power plant. Interwest also called upon the Commission to order Public Service to analyze non-utility costs and benefits, citing Rule 3610(g).

234. Interwest also testified that non-energy costs can and should be monetized so that their associated benefits can be factored into the resource planning modeling. In cross-answer/reply testimony, Interwest witness Cox proposed that a 10 percent "adder" be applied to renewable energy resources, citing the Commission's use of such an approach to externalities within the gas DSM Rules.

235. Ms. Glustrom proposed that the Commission develop a scoring system for taking the costs and benefits of externalities into account when evaluating bids. LaPlaca witness Bardwell testified that the modeling should include externalities, with each assigned a monetary value, either as estimates or as a range of values using a sensitivity analysis.

236. In its SOP, Public Service proposed that, to the extent that the Commission wishes to consider external costs or benefits that do not directly impact rates, those considerations should be made on a qualitative basis, rather than distorting the rate impact numbers.

Discussion and Findings

237. The emerging consensus from the scientific community concerning the adverse climate impact of fossil fuel combustion requires us to consider earnestly all viable options for reducing the carbon emissions associated with electric generation. We address this specific non-energy benefit under a separate heading in this Decision.

238. We find Public Service's proposal to address emissions (NOx, SOx, mercury, and particulates) and water through their costs being imbedded in generation resource bids is an appropriate first step in factoring externalities in resource planning.

239. We find that the use of a percentage adder for externalities, as used in the gas DSM Rules and Docket No. 07A-420E, is not appropriate at this time. Given the differences in the various externalities, it is difficult to create an adder that is fair and effective.

240. We find that the other identified externalities cannot readily be addressed quantitatively, because some factors are not quantifiable (such as "consumer expectations") or due to the inconclusive nature of the quantitative values presented by parties. For example, we agree with Public Service that it is not realistic to associate health concerns with one particular emissions source, when many sources contribute to the overall level of the pollutant. Electric generation emission sources may be a primary source of the pollutant, and pollutants from a single fixed-source generator may be easier to control than from multiple mobile sources such as automobiles, but we find that it would be more reasonable to address such externalities through qualitative means rather than through quantitative measures. However, we do find that some externalities (beyond emissions and water) merit incorporation into the final resource planning decision, at a level more significant than serving merely as a portfolio selection decision "tie-breaker."

241. Therefore, we find that the following externalities shall be factored qualitatively into the Phase II decision:

a) Economic development (rural impact; job development; tax base; etc.);

b) Resource diversification; and

c) Environmental benefits (particularly health benefits/costs) associated with emissions reductions and other environmental impacts beyond permit compliance.

242. We find that the following process shall be implemented for incorporating the non-quantifiable externalities into the Phase II resource planning process:

a) As discussed in the RFP Section, the RFP will direct bidders to include qualitative assessments of how the proposed project incorporates the three categories of qualitative non-energy factors listed above.

b) As discussed in the Resource Scenario Section, Public Service and the IE shall provide a narrative summary of the externality benefits associated with each likely portfolio of resources, based upon information provided by bidders.

c) The Commission will compare the cost differential (net present value of future revenue requirements (NPVRR) and rate impact) of the likely scenarios with other risks and benefits of the various portfolios, including those with a relatively better status regarding externalities. Parties will comment on the potential portfolios, and the Commission will then make a judgment as to the portfolio that has the best overall balance of costs, benefits, and risks; to properly consider those resources that provide increased externality benefits and minimum additional costs.

P. Fuel Costs

Gas Costs

243. In its direct case Public Service proposed to use a simple average of four gas price forecasts: EIA, NYMEX, CERA, PIRA.

244. GEO witness Mathews testified that it is a "fool's folly" to predict gas prices, but that gas prices will likely escalate in real terms in the applicable period. Domestic production peaked in 1973, and recent drilling increased reserves by 19 percent, but production decreased by 6 percent.

245. Interwest witness Hunt asserts that he has very little confidence in any gas price forecast. Most official U.S. forecasts show a downward trend to 2010, then an upward trend. He argues that costs to drill are a primary driver of gas costs, and that drilling costs have increased 195 percent from 1994 to 2004. He cautions that under-forecasting causes consumers to pay higher energy costs, but in contrast implementing a greater amount of wind minimizes forecasting error impacts.

246. Ms. Glustrom recommends that natural gas should be escalated at 10 percent annually and the Commission should require sensitivity analyses on the gas prices.

247. LaPlaca witness Andrews provides a very thorough list of factors that he asserts will likely cause gas prices to rise. These include: record drilling rates are not increasing production; annual gas production has not been over 21 trillion cubic feet since the 1920s; exploration and development costs rose 21 percent per year from 1999 through 2007; a 200 percent cumulative increase; gas-fueled generation increased 50 percent in the last decade – 10 percent in 2007; 109,428 MW new gas-fired generation was created between 2003 through 2007; the Rocky Mountain Express Pipeline will create higher ceiling and new floor prices in the

Rockies; liquefied natural gas will see world competition – South Korea and Japan are at $20/MMBTU (double the U.S. current gas price) and this is the level we would see if our current gas price matched the $/BTU oil price. Mr. Andrews recommends increasing Public Service's gas price forecast by increasing EIA by at least 25 percent. Mr. Hughes generally describes the case for higher real natural gas prices. He describes various supply constraints and demand increases that will cause gas prices to rise at a faster rate than Public Service assumes.

248. Many parties raised a particular concern with the EIA forecast, generally stating that EIA has consistently under-forecasted gas costs in recent years.

249. ACSF argues that new developments in shale drilling have opened up an entirely new supply source, and points to recent data showing that production is increasing substantially in recent years. ACSF argues that developments in gas technology have continued to provide an adequate supply of natural gas for decades and the recent shale developments ensure that a plentiful supply of natural gas will be available in the future.

250. In rebuttal testimony, Public Service witness Haeger recommends that we continue to use professional forecasting services. Mr. Haeger states that Public Service conducted its own forecasting for some time, but eventually realized that it should rely on professional agencies that have sufficient employees to investigate the various parameters that could potentially impact future gas prices. Public Service asserts that the parties that argue against its proposed forecast method are looking at only a few parameters. However, in recognition of the criticism that EIA received, Public Service recommends replacing the government agency EIA with Global Insight, another professional forecasting company.

Discussion and Findings

251. Numerous parties took issue with the gas prices that result from the forecasts, most recommending that a much higher forecast gas price be used. Many parties point to supply-and-demand factors that indicate a tightening of supply, and likely increased prices. Parties assert that, even with higher levels of drilling in recent years, the increased production has hardly kept up with declining production elsewhere. Increased gas fuel for electric generation continues to require more gas supply. Further, global demand for natural gas is increasing along with oil prices, and liquefied natural gas imports are not developing due to global demand outpacing supply.

252. In contrast, ACSF points to increased production in recent years from new shale drilling, arguing that this new gas supply technology will develop rapidly.

253. The primary difference between the parties' positions on gas price forecasts is future supply availability. On one hand, we have many indications of increased gas consumption from a limited supply resource. On the other hand, the natural gas technology continues to advance, particularly in light of recent price increases. The only consensus from the parties is that it is not likely that we will accurately predict gas prices.

254. Real prices could remain relatively constant for decades. Some forecasts indicate that natural gas prices will not escalate faster than inflation, based on the notion that recent increases in prices will continue to spur technology developments (*e.g.*, shale drilling) to advance gas supplies, as has occurred several times in history.

255. However, real prices could continue to escalate, consistent with energy price increases we have experienced in recent years. World demand for energy, dwindling supplies, and constraints on high carbon fuels could present a fundamental change in the future supply and

demand picture for natural gas. For example, shale gas may only be feasible in limited applications, and may only provide a short-term increase in supply. Fossil fuel supplies are finite, and new sources must be developed in more marginal areas. We cannot expect technological advances to be able to expand gas supplies forever.

256. Given this high degree of uncertainty in future gas prices, and the large impact gas prices have on resource selection, we find that, instead of developing and modeling only one price, we require Public Service and the IE to run sensitivities over a range of prices.

257. We agree with Public Service that it makes sense to employ the professional forecasting as advocated in its rebuttal case, but sensitivities at higher and lower prices should also be run. Given the range of proposed prices in the record, we find that it is appropriate to establish a low price beginning at the level established under Public Service's proposed method, but escalating only at the rate of inflation – reflecting a constant real price. For a high price, we establish the upper band at a 7 percent increase in real prices, with the real price doubling approximately every ten years; beginning at the level established under Public Service's proposed method.

258. For modeling purposes we direct Public Service and the IE to use Public Service's rebuttal position for gas prices, and then run sensitivity analyses at gas prices escalating at the rate of inflation and at a 7 percent increase above inflation. All prices shall include the gas price volatility adder proposed by Public Service.

Coal Costs

259. Ms. Glustrom asserts that the forecast price of coal by Public Service is too low given future trends in supply. Public Service has experienced increased coal costs that have exceeded all of these projected increases in just the two-year period between 2005 and 2007, and

Public Service does not have long term contracts in place for coal. She recommends that the cost of coal should be escalated at 7 to 10 percent, not 2.33 percent, and a coal cost sensitivity analysis should be conducted.

260. WRA witness Mendelsohn recommends that the Commission adjust the coal price forecast as part of its Phase I Decision to account for both the correct starting point to reflect actual 2007 prices paid and include a price volatility adder. He asserts that Public Service's proposed coal price forecast (from 2007 through 2027) incorporates a 1.26 percent price escalation, well below the expected inflation rate of 1.99 percent. Given the wide array of pressures on the international and domestic coal markets, the escalation rate embedded in the Company's coal price forecast is simply unrealistic. Mendelsohn recommends that the Commission require Public Service to adopt a 2 percent real escalation rate (*i.e*., 2 percent above the projected inflation rate) for its base-case coal price forecast. For the purposes of the low coal price forecast, Public Service should adopt an escalation rate equal to its proposed rate of inflation. For the high coal price forecast, the Commission should apply a 4 percent real escalation rate. He recommends that all three coal price forecasts start with a 2007 price of $1.20/MMBtu plus the price volatility adder as determined appropriate by the Commission and then escalate using the low, base, and high escalation rates, respectively.

Discussion and Findings

261. As with gas prices, the record contains a wide range of arguments regarding coal price. However, based on our decision in Phase I to retire the coal plants, the impact of coal prices on resource selection is quite narrow, assuming that no new coal plant bids are submitted. Coal plant bids are highly unlikely with the 50 percent sequestration requirement. All existing coal plants in the model will certainly be dispatched economically under the carbon costs that are

contemplated, so these should represent a constant value in the many scenarios we intend to run. Under high renewable or Section 123 modeling it is possible that coal plants must be shut down, or excess power sold off-system. However, as Public Service demonstrated in this docket in response to Staff's suggestion to ramp down the Cameo and Arapahoe plants, the operating efficiencies and costs of ramped down coal units present a whole new set of costs, negating any impact of potentially higher coal prices.

262. Therefore, we find that Public Service's proposed coal prices are within the range of accuracy needed to properly model the anticipated non-coal resources in Phase II. Similarly, we find that it is not necessary to implement coal sensitivities or coal volatility adders.

263. In the future, coal cost modeling may become more significant as we look at additional coal retirements. For modeling purposes, Public Service and the IE shall use Public Service's proposed coal price forecasts without a price volatility adder.

Q. CO_2 Costs

264. In its direct case Public Service proposes to use a CO_2 cost of $20/ton, escalated at the rate of inflation. Public Service also proposes to run sensitivity analyses at $10/ton and $40/ton.

265. Staff witness Dr. England states that Public Service's carbon adder is in the appropriate range, but that we should start at a lower price until we have federal direction. Economic impacts of carbon legislation are very substantial, and this will likely slow implementation of legislation. Dr. England cautions that intergenerational issues associated with carbon prices are significant. Current customers will pay for past, current, and future customers, but benefits will not begin to accrue until 2021. Staff states that, since carbon regulation is not guaranteed, any action taken today should reflect the lack of federal regulations, and if a carbon

adder is to be implemented by the Commission the level should be placed at a conservative level to reduce the welfare impact on current ratepayers. Staff recommends a $15.68 per ton of CO_2 in 2006 dollars.

266. WRA witness Nielsen states that a poll of 31 major corporations indicates that 90 percent believe federal legislation is imminent and 84 percent believe it will take effect before 2015. WRA also recommends that the Commission direct Public Service to develop a price volatility adder for CO_2 similar to the factor used for natural gas, and that CO_2 cost projections should use a higher escalation factor.

267. In rebuttal testimony, Public Service witness Prager disagrees with England's $15.68/ton. He agrees that economics and politics place a practical limit on carbon costs, but he asserts that the $20/ton proposal is within politically acceptable levels. Mr. Prager argues that Staff relies on articles from 1999 and 2005, which ignore changes since 2005. Public Service agrees with WRA that carbon costs will likely increase over time, and recommends increasing the escalation factor from inflation level (2.5 percent) to 7 percent per year. This equates to a levelized cost of $35.52/ton.

268. Public Service disagrees with WRA witness Mr. Mendelsohn that a CO_2 volatility adder is needed. CO_2 cost projections are too imprecise, and a volatility cost adder is not appropriate until a final policy and mature market is established.

Discussion and Findings

269. We agree with Staff witness England that the timing and ultimate levels of carbon regulation are uncertain, and we recognize that his approach provides a carbon value that is a compromise between no carbon regulation, delayed carbon regulation, and significant carbon regulation. However, new legislation enacted under § 40-2-23(1)(b), C.R.S., explicitly allows

the Commission to consider future carbon cost, and political acceptance of carbon legislation appears to be gaining momentum. Further, we agree with Public Service that CO_2 costs are likely to increase, and that $20/ton is a reasonable starting point.

270. Therefore, we adopt Public Service's rebuttal proposal for CO_2 costs of $20/ton plus 7 percent[19] escalation per year.

271. Regarding a CO_2 volatility adder, we also agree with Public Service that CO_2 cost projections are too imprecise at this point, and we cannot determine whether CO_2 prices are volatile enough to warrant such an adder until a carbon policy is established and the market stabilizes. We reject WRA's proposal for a CO_2 volatility adder.

R. Modeling Inputs

RESA and 850 MW Intermittent Resource Limit

272. Public Service takes the position that, in order to reduce carbon emissions, the full 2 percent RESA should be maximized subject only to limitations to ensure system reliability. Public Service requests that the Commission direct the Company and the IE to assume that the full 2 percent is available when evaluating and selecting resources thus resulting in portfolios that would likely contain more renewable resources than would otherwise be selected solely on an economic basis.

273. Public Service goes on to argue that this money should be collected now and refers to language in § 40-2-124(1)(g)(I), C.R.S., which states: "[i]f the retail rate impact does not exceed the maximum impact permitted by this paragraph (g), the qualifying utility may acquire more than the minimum amount of eligible energy resources and renewable energy

[19] This is a 5.5 percent real escalation rate, in addition to the 2.5 percent inflation factor.

credits required by this section." Public Service reads this statute to provide it with the discretion to spend the full 2 percent.

274. Regarding acquiring additional renewable energy resources, it is Public Service's position that intermittent resources should be limited to 850 MW. Public Service states that it does not want to compromise system reliability and complicating system operations by absorbing too many intermittent resources too quickly. According to Public Service, it continues to study the issues and expects to reconsider this limit in its 2010 filing.

275. OCC maintains that the Commission could approve a portfolio with more renewable energy resource than proposed by Public Service and above the 2 percent retail rate cap if it were found to be in the public interest. It asserts that any renewable energy credits (RECs) acquired above the retail rate impact should not be used for compliance and be deemed a "merchant REC."

276. WRA supports Public Service's proposal to maximize the amount of renewable energy acquired subject to the 2 percent rate cap. Because of the many benefits renewable energy provides such as reduced emissions, protecting human health, conserving water, and hedging against fuel price volatility, it is appropriate for Public Service to develop the maximum amount of renewable energy resources possible with the rate impact.

277. Interwest asserts that Public Service should be required to show exactly how and why its 850 MW and 250 MW limits make sense for consumers.

Discussion and Findings

278. Parties generally agree that Public Service may collect and use funds from the RESA to acquire renewable resources beyond what is needed for compliance as long as the 2 percent rate cap is not exceeded. We agree with, and support this position, and encourage

Public Service to present renewable projects to the Commission through RES compliance plan applications and RESA filings for approval and adjustments to the RESA.

279. While the full 2 percent retail rate is available to Public Service it seems that the 850 MW limit imposed on intermittent resources will be the actual limiting factor, as Public Service will likely hit the 850 MW limit before the 2 percent retail rate cap.[20]

Discount Rate

280. Public Service witness Hill advocates that that the Company's averaged weighted cost of capital, 7.88 percent, be used as the discount rate in the STRATEGIST model. The purpose of the discount rate is to calculate the NPVRR. The cost for each portfolio of resources resulting from STRATEGIST represents the Company's revenue requirement for that portfolio. In order to directly compare the revenue requirements across portfolios, the discount rate is used to calculate the NPVRR of each portfolio. This allows each portfolio's cost to be placed on common ground so that cross-portfolio costs can be examined. Effectively the discount rate allows portfolios with different generation investments and different dynamics of construction and operation to be evaluated on a common basis.

281. LaPlaca witness Bardwell takes issue with Public Service's choice of its weighted average cost of capital for the discount rate. Bardwell contends that Public Service's use of the discount rate in evaluating resource selections is improper and can lead to incorrect resource portfolio selections. According to Mr. Bardwell, the discount rate chosen by Public Service artificially minimizes the present value of costs to be paid by consumers in the long run life of a

[20] In Public Service's direct case it contends that all renewable resources, Section 123 and Section 124, could be acquired under the 2 percent rate cap. Subsequently, in Commission Decision No. C08-0559 in Docket No. 07A-462E, we determined that any incremental costs of Section 123 resources are not subject to the retail rate impact thus eliminating their impact on the retail rate impact calculation. Therefore, we will likely reach the 850 MW intermittent limit before exceeding the 2 percent rate cap.

project. Mr. Bardwell also asserts that the discount rate chosen by Public Service leads to a doubling of rates paid by future consumers in ten years.

282. Mr. Bardwell argues for the use of a discount rate equal to the rate of inflation. He argues that this will allow for projects to be compared on the same basis of only inflation-adjusted costs. When using a discount rate set at the inflation rate, rate stability will occur. Mr. Bardwell contends that renewables are at a disadvantage with a high discount rate, since a high discount rate artificially makes high future fuel costs minimal on an NPVRR basis. Finally, Mr. Bardwell argues that the evaluation of resources needs to include such items as rate volatility, rate escalation, health and environmental issues, and resource depletion.

283. In rebuttal testimony, Public Service witness Tyson also states that the discount rate should be set as recommended by witness Hill. Mr. Tyson argues that using the inflation rate, as recommended by Mr. Bardwell, ignores the time value of money for Public Service.

Discussion and Findings

284. The use of a discount rate allows us to evaluate the relative costs of different resource selections that are produced by STRATEGIST. We reiterate that the selection of resources in this docket is impacted by new factors that were not in the forefront in previous resource acquisition plans. For example, carbon cost and carbon reduction are important factors in this resource docket, and are explicitly modeled in STRATEGIST, as well as some environmental and health impacts. Renewable resources, such as wind and solar, will be evaluated not solely on the basis of capital and operating costs, but also on their ability to reduce carbon emissions and meet state goals for renewable deployment. In this docket we also evaluate different DSM targets, as well as different Section 123 resources.

285. We do not agree with Mr. Bardwell that using a higher discount rate leads to higher rates in the future. The discount rate is simply one tool to examine relative costs of investment choices. The future rates to consumers will be driven by the actual future costs of fuels, operation, and maintenance, and will be averaged over the entire embedded portfolio of utility generation and transmission and distribution facilities.

286. We find that using the average weighted cost of capital is an appropriate discount rate here for the relative evaluation of resource portfolios. This discount rate has been used previously in resource plans and reflects the cost to the utility and the ratepayer, of investing in certain generation facilities. We do not wish to use the discount rate to account for factors that are more appropriately handled on a direct basis. It is better that we account for higher fuel costs, the desire for carbon reduction, and other issues explicitly within our analysis.

287. Therefore, we direct Public Service and the IE to use the Company's average weighted cost of capital, 7.88 percent, as the discount rate in the STRATEGIST model.

Modeling Different Plant Lives

288. CIEA and CEC recommend using the annuity method to compare unequal plant lives in modeling. Under this method, the modeler uses the equivalent annual cost from a bid proposal to represent power costs for years past the termination of the contract in order to compare the bid to a resource with a longer life in the model.

289. Public Service disagrees with CIEA witness Monsen's recommendation to use the annuity approach. Public Service argues that a continuation of the annualized bid price does not account for inflation, and asserts that in Public Service's experience IPPs do not re-bid at the same price from a previous contract. Mr. Hill recommends using generic units for the years beyond the bid expiration.

Discussion and Findings

290. There has been significant discussion in this docket about the likely rates at which an IPP will re-bid its plant after contract expiration. An IPP is free to re-bid their plant at market price, regardless of whether its plant is fully paid out. Part of the benefit of IPP bids is that ratepayers' liability associated with an IPP bid ends with contract termination. If circumstances do not warrant the continued operation of that technology, ratepayers are not saddled with any continued obligation to pay for that plant, as would normally occur under a long-term rate-based plant. The risk to ratepayers of a short-term IPP contract is that the IPP will be able to re-bid its fully or partially paid-out facility at the same cost as a new facility. Of course, this depends on the market situation at the time the plant is re-bid. If there is excess availability of that technology at the time of re-bidding, then IPP bids would be expected to be lower than if excess capacity does not exist.

291. Therefore, we direct Public Service and the IE to use Public Service's generic unit approach to compare proposals with unequal lives.

Base Case Modeling Assumptions

292. We adopt the following recommendations from Public Service witness Hill as "base case assumptions" to be used in modeling:

a) Inflation Rate - 2.5 percent.

b) Surplus Capacity Credit – Starting in year 2012, resource portfolios with firm generation capacity in excess of the base reserve margin will be credited $4.00/kw-mo escalating at 2.0 percent annually, up to an excess of 500 MW.

c) Generic Resource Construction Cost Escalation – The construction cost estimates for generic resource options used in the Phase II analysis will be assumed to escalate at a rate of 3.5 percent annually from year 2008.

d) Capacity Credit for Wind Resources - Existing wind facilities and new wind proposals will be given a capacity credit in the evaluation process equal to 12.5 percent of their nameplate capacity, which was derived from the Company's Effective Load Carrying Capability study.

e) Integration Cost for Wind Resources - The results of the Company's 15 percent and 20 percent wind integration studies will be used to reflect the estimated integration costs of 100 to 400 MW of additional wind resources (*i.e.*, above the level currently installed). The Company will also incorporate the results of our ongoing internal analysis of wind integration and may vary assumptions or modeling techniques in the ways described in the testimony of Ms. Hyde.

f) Estimates of integration costs for additional wind resources above 400 MW will be derived in a manner similar to those illustrated in Figure JFH-1. That is, the Company will utilize a combination of the analytical work Public Service has done through its wind integration study efforts in combination with the Company's expectations and those of industry experts on how wind integration costs with increases in wind levels can be mitigated.

g) Since wind integration costs are correlated to the gas prices, changes in gas price assumptions compared to what was assumed in the wind integration studies will result in corresponding changes in wind integration costs. The Company's wind integration studies to date show that every $1.00 increase in gas prices results in approximately $0.75/MWh increased integration costs.

h) Capacity Credit for intermittent Solar Resources - The Company will perform an analysis that estimates the capacity credit to be afforded to intermittent solar resources. The results of this analysis will be provided to the Commission and prospective bidders no later than 60 days prior to the date responses to the Company's All-Source RFP are due.

i) Integration Cost for intermittent Solar Resources - The Company will perform an analysis that estimates the integration cost associated with intermittent solar resources. The results of this analysis will be provided to the Commission and prospective bidders no later than 60 days prior to the date responses to the Company's All-Source RFP are due. Solar integration costs will be correlated to the gas price forecasts used in the analysis.

j) Company Owned Plant Lives – With the exception of Zuni, Arapahoe, and Cameo, the Company owned units will be modeled to retire by their respective accounting book dates per the Settlement Agreement in Commission Docket No. 06S-234EG.

k) Modeling of Solar Resources - Within the STRATEGIST computer modeling of resource options, all solar resource options will be modeled with an hourly electric energy production profile that is based on an average day pattern for each month of the year by technology and proposed resource location. Solar facilities interconnected to the electric distribution system will have this solar energy production profile grossed up to reflect an estimate of the transmission and distribution related losses that are avoided as a result of the electric energy produced by the solar facility. Solar resources priced on an energy only basis (*i.e.*, $/MWh) will be modeled with an energy price reduction (from the price proposed) that is consistent with the percentage of transmission and distribution losses that are avoided. In this manner, the beneficial aspects of distribution interconnection are obtained while the overall costs of the energy are unchanged.

l) Credit for generation capacity value for facilities interconnected to the electric distribution system will be grossed up for transmission and distribution losses.

m) Modeling of Resources with indexed pricing - to the extent that resource proposals offer indexed pricing that meets the various criteria outlined in the Rebuttal Testimony of Company witnesses, the price of such resources will be modeled using the most current forecast of the related index available at the time of the Phase II evaluation.

n) Modeling Rate Impacts of DSM – The STRATEGIST model representation of the Public Service electric system that will be used in the evaluation of Phase II resources includes many of the power supply related costs of the system, but not all the costs that Public Service incurs to provide electric service to customers. Therefore, the magnitude of the average electric rates produced by the model for different resource portfolios will be somewhat understated. These electric rates will however, prove useful in providing a general indication of the magnitude of potential rate impacts that could result from increasing levels of DSM Programs provided that different portfolios would result in comparable costs for those items not reflected with the modeling (*e.g.*, transmission related costs).

o) Restrict Phase II to resources greater than 30 MW.

S. Modeling Scenarios

293. Public Service provided significant testimony at hearing regarding the modeling scenarios that the Company and the IE will perform. Public Service witness Hill provided Hearing Exhibit 141, which demonstrates the complexity associated with the many different variables. Mr. Hill explained that any changes in demand essentially require another optimization (including DSM level changes) and generally requests that the Commission limit the number of optimizations, as optimization runs are very labor intensive. Sensitivity runs are far easier. For example, re-pricing an optimized plan at a different fuel cost will result in new costs for the portfolios selected in the base optimization.

294. During the hearings, Staff proposed a solution that it contends better matches the ERP Rules. Staff's approach generally directs the IE to model utility and IPP proposals strictly based on economic modeling, and allows Public Service to propose its preferred resources with reasons why they should be selected. Staff also suggests that we receive the bids before we direct the IE in what scenarios to model, rather than specifying such in the Phase I decision.

295. At hearing, Chairman Binz inquired about the possibility of holding a technical conference with Public Service and the IE to discuss scenarios. In its SOP, Public Service asserts that if this technical conference is held, it must be done before bids are received, and also cautions that the model operators will be very busy in the time leading up to receipt of bids.

Discussion and Findings

296. This is the first time we will implement the new IE process in our ERP Rules. This will also be the first resource planning case where someone other than Public Service runs the STRATEGIST model. The fact that no other party has ever had STRATEGIST modeling

capabilities demonstrates the magnitude of effort involved in such modeling, and the importance of our involvement.

297. Given the many variables such as forecast demand levels, future gas costs, and other fundamental drivers of system modeling costs, it is not possible to establish a model that will give us "the answer." Instead, we must examine the risks and benefits of different portfolios under many different assumption scenarios. We will then have the information to consider how a portfolio performs under differing quantified inputs such as gas prices, carbon costs, and required level of Section 123 resources; as well as the non-quantifiable benefits such as health benefits and additional Colorado employment.

298. For purposes of this discussion, the fundamental resource comparison in STRATEGIST is called an "optimization run," which Public Service maintains take significant time to run and verify that the results are reasonable. Within this optimized model run, the STRATEGIST results provide an ordered "stack" of portfolios that will meet the system requirements, starting with the most cost-optimal solution. STRATEGIST will use NPVRR as a primary optimization parameter, consistent with the requirements of recent legislation, and can also use Net Present Value of Rate Impacts as a primary optimization parameter.

299. "Sub-optimal" portfolios can also be provided. These are portfolios further down in the stack, in descending order of NPVRR value. We can use these sub-optimal solutions to compare the costs, carbon levels, etc. of the different portfolios that satisfy the requirements in the optimization run.

300. STRATEGIST also allows "sensitivity runs" where the model operator takes an optimized run and changes certain inputs such as gas prices or carbon costs. A re-ordered stack is then provided, showing the new order of portfolios in the new order of NPVRR calculated

under the revised inputs. As discussed by witness Hill at hearing, any changes in demand generally require another full "optimization run." These include demand forecast changes as well as changes in DSM, which have the same impact as a reduction in load.

301. In hearing, significant testimony was dedicated to modeling limitations, and we agree that our Decision is very critical in this respect. We disagree with Staff's suggestion that the Commission issue direction to the IE in how to evaluate bids after the bids are received. Although this approach would provide the best analysis, there is simply not enough time for such an iterative approach under the expedited Phase II timelines.

302. The fundamental objective of the resource optimization process is to determine how we can achieve the best overall benefits for the resource dollars spent. The Phase II process is designed to provide the Commissioners the best available information – after bids are received and analyzed – in order to make a well-informed decision.

303. Since the modeling scenarios are essential in providing the Commission with a full analysis, and since modeling capabilities are limited, we will implement a variation of Staff's proposal. We adopt the workshop idea as mentioned by Chairman Binz at hearing. For this option, we solicit written input from Public Service and the IE (as well as other Parties) before finalizing the modeling scenarios, and will hold a technical workshop so that the Commission can discuss the issues with the modelers. We will then issue a final determination on the scenarios before bids are received so that we do not delay the expedited Phase II process. Although CIEA and CEC, and OCC advocate for involvement by parties in the modeling parameters and/or workshops, we find that the expedited nature of the Phase II proceeding will not allow for such input, and that our rules do not contemplate such a process. The technical

conference will be public, but only Public Service, the IE, and the Commissioners will participate. Instead, we will allow all parties to provide written comments before the workshop.

304. We provide our preferred modeling scenarios as shown on the diagram in Exhibit A to this Decision.[21] Public Service and the IE are required to provide a written response to these scenarios by October 6, 2008. All other parties may also provide a written response to these scenarios by October 6, 2008. We will then hold a technical conference on October 10, 2008, to discuss the issues with the Public Service modeler and the IE. Following the technical conference, we will issue a final determination on the modeling scenarios.

305. Our proposed modeling scenario analysis is based on four combinations: high Section 123 resources, Low Section 123 Resources, High DSM, and Standard DSM. High Section 123 targets 600 MW of Section 123 resources. This 600 MW level can be varied somewhat depending on actual capacity of bids or utility proposals. Low Section 123 targets 200 MW of Section 123 resources. This 200 MW level can also be varied depending on actual capacity of bids or utility proposals. High and Standard DSM are defined in the DSM Section of this Order.

306. We grant Public Service's request for a set-aside of 200 MW of solar with storage. We grant this 200 MW set-aside on the assumption that reasonable bids will be received, and that Public Service reserves the right to reject all such bids if the Commission determines that the Section 123 bids or proposed utility facilities do not represent the developmental technology contemplated in § 40-2-123, C.R.S., or is otherwise significantly out of line in the market for current technology. Although the ERP Rules contemplate a base-case scenario with no

[21] This is the same diagram that we handed out in deliberations on August 19, 2008.

Section 123 resources, we find that because we grant the 200 MW minimum, the base scenario contemplated in the rules is not necessary.

307. The Scenario Analysis diagram demonstrates the range of scenarios that the Commission believes are likely candidates for implementation, and therefore warrant a full analysis of the various combinations, along with gas price sensitivities. The diagram then lists information that we expect the IE and Public Service to provide as a part of their written reports in Phase II.

308. We direct Public Service and the IE to propose specific early retirement date(s) for the Cameo and Arapahoe coal plants, based on the practical implementation of other proposed generation. We recognize that a strict cost analysis in STRATEGIST will not include the non-quantifiable benefits of early retirement. Therefore, we direct Public Service and the IE to address the timing of the retirement assuming that it is cost neutral to retire the plants, and recommend retirement date(s) based on the best resulting mix of generation. Because the early retirement provides a net benefit, we suggest to Public Service and the IE that retiring the plants earlier is generally better than later, subject to practical considerations of resource timing. We require Public Service and the IE to recommend retirement dates between 2010 and 2015. We also require Public Service and the IE to assess any differences between different retirement dates they may propose.

309. The Scenario Analysis diagram also contains several bullets identifying information that Public Service and the IE must include in its report to the Commission. We will not address each item here, but we provide the following comments to clarify these requirements.

310. Consistent with our discussion in the Utility Ownership Section of this Order, we direct Public Service and the IE to model the utility rate-based proposals in comparison to all other bids. STRATEGIST will select utility proposals if they are economic. If not selected as economic, we direct Public Service and the IE to provide all sub-optimal portfolios that include utility-owned proposals, including those near the 40 percent and 60 percent utility ownership level. The Commission can then consider externality benefits, utility ownership benefits, and other non-quantifiable attributes of the utility proposals in making the final decision in Phase II.

311. Public Service can provide its recommended level of utility ownership as a part of its preferred case. The IE can also provide a preferred case, if it chooses to recommend a portfolio that is not included otherwise.

312. Public Service and the IE should not make policy decisions as to which resources are compliant with the Section 123 requirements. Therefore for modeling purposes, we direct Public Service and the IE to consider a resource as compliant with Section 123 requirements if the bidder states such. The Commission will determine whether individual proposals qualify as Section 123 resources in Phase II. Therefore, we require Public Service and the IE identify all sub-optimal portfolios containing Section 123 resources.

313. Similarly, we do not feel that Public Service and the IE should make policy decisions regarding the externality benefits of proposed resources. Instead, we allow bidders to list the externality benefits of their resources. We direct Public Service and the IE to provide a summary of the claimed externality benefits for each likely portfolio.

314. In addition to the scenarios listed on the diagram, we also request that the IE and Public Service perform additional test analyses so that the Commission can better understand some of the other parameters. These “tests” are designed to minimize modeling difficulties by

changing only one parameter from the "primary case" on the diagram, rather than re-running all possible combinations of variables. Similar to the modeling scenarios discussed above, we provide several test scenarios in this Order, and intend to issue a final decision on the required tests after discussing the various test possibilities with the IE and Public Service at the technical conference. We provide the following test scenarios as possible requirements for Public Service and the IE to perform:

a) Confirm that the 2 percent RESA rate cap is not exceeded in the primary case with the statutory minimum level of DSM. Consistent with the RES Rules, we find that it is not necessary to calculate the 2 percent cap for every possible modeling scenario. Under the RES Rules we verify that the cap is not exceeded in certain likely scenarios, and then require the utility to pursue that plan without recalculating the cap as conditions change. Similarly, we direct the IE and Public Service to evaluate the 2 percent cap only under certain likely scenarios. We find that the primary case with statutory minimum DSM represents a conservative approach to assessing the 2 percent cap.

b) Run the primary case using the low forecast instead of the base forecast, in order to see when additional resources to meet the base forecast must be on line. This may allow additional future DSM to meet the requirements, or may allow deferral of late-period resources to the 2010 filing.

c) Determine the NPVRR and Net Present Value Rate Impact, and utility cost test of "standard" DSM and statutory minimum DSM compared to the primary case.

d) Run the primary case assuming Public Service extends the Black Hills contract through 2015. Determine the incremental facilities necessary to serve Black Hills. Determine the CO_2 produced per MWh with and without the Black Hills contract extension. Determine the incremental cost to serve Black Hills.[22]

e) Run additional CO_2 sensitivity tests. Run sensitivity analyses at a levelized CO_2 price of $10 per ton and $40 per ton. Also determine the level of CO_2 cost that makes a significant difference in portfolios from the primary case.

f) Modify the High DSM, High Section 123 case to achieve a 10 percent reduction in CO_2 from 2005 to 2015, correcting for the wholesale load reduction.[23] This will likely require the modeler to modify the existing system by assuming further retirement of fossil fuel plants or other changes. We do not intend to use this information as a basis for retirement of such facilities, but want to investigate the steps that may need to be taken to achieve this target.

g) Determine the level of gas cost that makes a significant difference in portfolios from the primary case.

T. Phase II Evaluation Process

315. In order to guide our determination of what is to be accomplished in Phase I and what would be deferred to Phase II, Public Service witness Hill presented Hearing Exhibits 139, 140, and 141. These Exhibits describe the necessary tasks to be performed by Public Service and the IE in order to develop a resource portfolio from STRATEGIST and a Phase II report. Public Service advocates that we determine the portfolios before Phase II. There is not enough time in the 90-day Phase II process to conduct any further model runs.

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[22] We do not approve or endorse the incremental rate approach, but require the test for comparison purposes.

[23] For any wholesale load that was served in 2005 but is not served in 2015, remove the carbon from the 2005 case based on system average energy and carbon content.

316. In response to Public Service's Exhibits 140 and 141, Staff witness Davis offered Hearing Exhibits 168 and 169. Generally, Staff asserted that the Commission should have maximum flexibility and control in determining and selecting a resource portfolio and that it would be necessary to communicate with the IE and Public Service during the 120-day analysis period, prior to the filing of their final reports.

317. We appreciate these recommendations from both Staff and Public Service. We recognize the need to detail the scenario analysis upfront as supported by Public Service, while maintaining flexibility as advocated by Staff. To that end, we incorporate these positions into a process that both defines the modeling scenarios ahead of time, giving Public Service and the IE time to comment and before Phase II begins. At the same time, by requesting that Public Service and the IE perform sensitivity analyses as well as present multiple sub-optimal portfolios, we will have flexibility to apply discretion.

318. The actual modeling requirements are described in the Modeling Scenarios Section of this Decision. But in order to guide Public Service and the IE, this section describes the interaction between the two parties and lists some of the tasks these two modelers will perform.

319. Initially, all components of Public Service and the IE are free to work together with the Commission liaison. Typical tasks would be, but are not limited to, the following:

- Public Service shall issue RFPs, and submit updated forecasts, the reserve margin study, and the wind integration study.
- The IE STRATEGIST expert and the Public Service Resource Planning Group[24] shall evaluate the base STRATEGIST model for Public Service's system. The IE shall file a report about any changes made or that should be made to the base model as well as

[24] We make a distinction between the STRATEGIST experts of both Public Service and the IE and the rest of their teams. For Public Service this refers to the Resource Planning and Acquisition Department represented by James Hill and for the IE this refers to the STRATEGIST Expert from Ventyx Advisors, Eric Hughes.

any concerns regarding forecasts, integration costs, and implementation of the model or anything else seen as appropriate by the IE.

- Public Service shall advise the Concentric Project Team about how bids will be initially evaluated, transmission costs assigned, etc.
- The IE and Public Service shall advise the Commission on the "workability" of this process plan.
- Both the IE and Public Service shall advise the Commission about concerns with the updated forecast filed on December 1, 2008, and the need for further direction.

320. Once the bids are received, the IE STRATEGIST expert may no longer interface directly with the Public Service Resource Planning Group. Any information must be relayed through the Concentric Project Team and the Commission liaison shall be copied. The other members of the IE team may freely coordinate with Public Service. Typical tasks would include, but are not limited to, the following:

- Public Service shall lead the effort in evaluating bids and requesting additional information.
- Public Service shall keep the IE team informed of all activities related to the bid evaluation process.
- The IE project team shall evaluate the rejection of any bid. A brief description of the bid and the reasoning for its rejection shall be filed confidentially with the Commission. In the event the IE project team does not agree with Public Service, the IE is free to include the bid in its model scenarios.
- The IE project team shall update the Commission, Staff of the Commission, the OCC, and the Commission liaison with monthly reports.
- Public Service shall determine transmission costs for project bids which shall be relayed to the IE STRATEGIST Expert through the IE team lead.

321. Once the IE can effectively develop models and conduct evaluations without significant information from Public Service, analysis of the portfolios will begin. The IE STRATEGIST expert shall not interact directly with Public Service and the interaction between the Concentric Project Team and Public Service should also be limited. All necessary

communications should include the Commission liaison. The IE project team, together with the IE STRATEGIST expert and, separately, Public Service shall develop optimization runs, select portfolios, perform sensitivities, and provide analysis as described above, in the Modeling Scenarios Section.

322. Before the expiration of the 120-day period, Public Service and the IE will have the opportunity to review each others' reports. Once complete, the reports will be filed with the Commission, effectively starting the 90-day Phase II evaluation. The Commission may request that Public Service and the IE hold a workshop two weeks after filing the reports to present findings and answer questions from the Commission.

U. Transmission Issues

1. Transmission Cost Allocation

323. Public Service proposes to assign costs of any transmission project that is approved using the CPCN process to the ratebase as network additions. Transmission required to bring generation resources to network transmission facilities are assigned to the generator. This approach is in compliance with FERC Rules. Staff and Interwest agree with Public Service's transmission cost allocation proposal.

324. WRA argues that the costs of developing new, or expanding existing, transmission infrastructure to each of the identified Renewable Energy Zones through the SB 07-100 process should not be allocated to any specific generation resource and should be considered a network addition. Further, WRA states that only SB 07-100 transmission projects should be network additions and not any transmission project requiring a CPCN.

325. CIEA and CEC state that it is critical that IPP projects not be treated any differently in the Public Service transmission system than Public Service treats its own utility-owned projects with regards to interconnection cost assessments.

326. RUC states that the Commission should ensure that transmission costing does not unfairly harm renewable generation resources and that construction of these facilities should be accelerated.

Discussion and Findings

327. We agree with Public Service's proposal to treat transmission project costs after a CPCN is granted as a part of existing network costs. These costs will not be added to generator bid prices. Costs for any radial transmission project necessary to connect the generator to Public Service's existing network will be assigned to the generator. This approach is consistent with FERC policies, and represents an equitable approach to resource acquisition and bid comparison. We find that Public Service's proposal regarding transmission cost allocation is appropriate, and shall be adopted.

2. Transmission Planning

328. During hearings, Public Service stated it tends to do "just-in-time" transmission planning.

329. Public Service has historically added transmission in response to load growth or specific generation resource additions. Under the SB 07-100 process, transmission is proposed to be built in a proactive manner to a potential generation resource area rather than a specific, proposed generation resource.

330. To support this new SB 07-100 process, Public Service asserts that the Commission's review processes should be streamlined, and the Commission should take a more

interactive role at the transmission planning stage to give guidance to Public Service and others. Specifically, Public Service recommends that the Commission give deference to any consensus reached by participants in the SB 07-100 process when ruling on any CPCN filed to implement such results. In addition, Public Service argues that the Commission should provide input to Public Service early in the transmission planning phase, receive quarterly updates on transmission, and engage in informal work sessions.

331. Public Service maintains that the 30-year planning horizon proposed by Staff witness Dominguez is not practical and would lead to the duplication of work over time. It is too difficult to accurately plan transmission beyond ten years, and, therefore, Public Service asserts that its present transmission planning horizon is adequate and is consistent with industry practice and reliability standards.

332. Staff has offered many suggestions regarding this issue. Staff indicates that it will pursue a discussion of the appropriate planning horizon, as well as other ways to improve regional transmission planning in the recently opened transmission investigatory docket, Docket No. 08I-227E and future rulemaking proceedings.

Discussion and Findings

333. Rather than address this issue in this docket, we find it appropriate to address the transmission planning horizon issue and Commission participation in the transmission planning process in the transmission investigatory docket (Docket No. 08I-227E).

V. Planning Reserve Margin Issues - General

334. Public Service indicates that it is preparing a planning reserve margin study and will file this study with the Commission in December 2008. The Company maintains that it tried to provide this study to the Commission during the hearings in this proceeding, but was unable to

do so due to lack of information from other Colorado utilities. As a substitute, Public Service proposes using the 16 percent planning reserve margin presently in place as a result of the 2003 Least Cost Plan Settlement Agreement, until a new planning reserve margin study is submitted to, and approved by, the Commission. Public Service proposes to complete a simplified version of this study based on the existing Rocky Mountain Reserve Group reserve responsibility ratio and submit it to the Commission sometime in December 2008.

335. Staff is concerned that Public Service has not completed an updated planning reserve margin study, a study that is critical to a Commission determination of adequate resource need, generation, and demand resource. According to Staff, this study was due before this ERP docket was to be filed. The Company asserts that lack of cooperation from certain utilities prevented them from completing this study. Staff is concerned with the tardiness of this study, and suggests that the Commission develop a process that would allow it to review and comment on this updated study, and involve Staff in the timely resolution of issues identified as a result of the study.

Discussion and Findings

336. We find that an adequate planning reserve margin is a threshold issue in developing an effective ERP. It is unfortunate that a new reserve margin study was not provided during the hearings as promised. Public Service stated in hearings that an alternate reserve margin study could be provided to the Commission based on the Rocky Mountain Reserve Group data. Given the importance of this information, and that this is a critical aspect of Public Service's ERP, we order Public Service to provide this alternate reserve margin study to the Commission before Phase II of the ERP commences. Public Service shall submit this alternate plan to the Commission in its present state for Commission and Staff review and comment.

Public Service should involve Commission Staff and the OCC going forward to finalize this most important study in time for Phase II.

337. We also find the existing 16 percent planning reserve margin to be appropriate until such time as the new study is complete.

W. Adjusting the Planning Reserve Margin to Address DSM Reliability

338. In Docket No. 07A-420E, the Commission established a range of cost and MW savings information to be used to model DSM options in this ERP docket. We determined that DSM savings in excess of the Company's Enhanced Plan should include an increase in reserve margins to account for the risk of not achieving these higher levels of DSM savings. We also established that these increased reserve margins should decrease over time, as Public Service will have more experience in achieving these higher levels of DSM over time, so the risk of not achieving the goals should be reduced.

339. In Docket No. 07A-420E, we addressed the issue of how to incorporate DSM values into the ERP. One aspect of that issue was the reliability of DSM values for load forecasting purposes. We addressed that issue in Decision No. C08-0560, stating:,

> We find that, for the purposes of ERP modeling through 2015, DSM values that exceed the Enhanced Plan values shall have their associated costs adjusted in the modeling to reflect the risk that this portion of the DSM may not be achieved. This adjustment will take the form of monetizing the additional reserve requirement necessary to assure system reliability. We further find that as the gap between the Enhanced Plan and what is set forth as the range in paragraph 51 increases, this uncertainty is mitigated by increasing DSM performance capabilities occurring over time, and shall be factored into the DSM-related reserve modeling.[25]

340. Concerning the reserve margin adjustment for DSM, Public Service advocated that "every 1.0 MW of higher DSM would equate to 1.16 MW of supply-side generation which

[25] *See* Decision No. C08-0560, ¶ 66.

in turn equates to 1.16 MW of reserves".[26] The Company also proposed 100 percent reserve margin coverage for DSM values above the Enhanced Plan it proposed, and that the additional reserve margin capacity required each year to backup DSM be cumulative from 2010 to 2015. Hearing Exhibit 172 was provided by Public Service to further explain its proposed reserve margin adjustment corresponding to increasing DSM values. Further, during cross-examination, Public Service witness Hill stated that increases in DSM performance capabilities are not factored into proposed reserve margin adjustments. During the hearing witness Hill further explained the Public Service position, stating:

> So to the extent you have additional peak reductions of DSM above the enhanced levels an adjustment to the reserve margin level would essentially offset those and require the same amount of capacity to be added to the system as if you just did the enhanced level of DSM and kept a 16 percent reserve margin.[27]
>
> I interpret the Commission's decision to be, as we get further along with developing these programs we will get more certainty as to what we can achieve and can't achieve. At some point we should quit monetizing this continued spread at this increasing amount. My proposal would be we would, just, starting in 2016, whatever that associated added reserve margin amount would … stop at that point… (See Transcript July 1, 2008, pp. 85-86)
>
> The additional reserve margin adds – it can add cost, but it may not add cost. And it may not add cost to the extent that the system or portfolios are already long of reserve margin.[28]

341. Ms. LaPlaca, in her SOP, called for the Commission to "mitigate constraints on DSM" concerning reliability and the reserve margin. She called for the Commission to allow DSM to compete by meeting the additional reserve capacity in the most cost effective way. She further argued that economical resource planning requires maximizing DSM, and that the Commission should meet the required additional reserve capacity as economically as possible.

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[26] *See* Hill Direct Testimony, pp. 30-32.

[27] *See* Transcript July 1, 2008, p. 85.

[28] *See* Transcript July 1, 2008, p. 126.

342. Public Service expressed during the hearing that it would prefer for the Commission to give it a directive as to what percent risk of failure the Company should assume for DSM values exceeding the Company's proposed Enhanced Plan, if it is something less than the 100 percent the Company advocates. Public Service further affirmed that it would then translate the Commission directive using the same logic witness Hill set forth to yield a reserve margin adder. *See* Transcript July 1, 2008, p. 146-147. In its SOP, Public Service requested such direction from the Commission, and asked for clarification of the intent of paragraph 66 of Decision No. C08-0560.

Discussion and Findings

343. We find that the approach Public Service proposes to monetize the reserve margin impact, and have the STRATEGIST model handle that change, is an appropriate method and is consistent with our directive set forth in Decision No. C08-0560. This approach shall be incorporated into the Phase II modeling.

344. We find however, that the Public Service proposal, assuming 100 percent DSM failure each year, is excessively cautious and does not factor in DSM performance capabilities improvements as discussed in Decision No. C08-0560. We find it reasonable to adjust the reserve margin in 2009 by a value equal to 60 percent of the difference between the Enhanced Plan and the Commission-established DSM goals. Further, we find that this reserve margin adjustment percentage for DSM reliability should decrease each year, reflecting increasing DSM performance capabilities. This annual adjustment shall be 5 percent, culminating in a value of 30 percent in the year 2015.

X. DSM - Range of Values from Docket No. 07A-420E and Other DSM Issues

345. In its Application, Public Service proposed to use the Enhanced Plan DSM goals as proposed in Docket No. 07A-420E as a component of its proposed High Section and Medium 123 scenarios.[29] For the Low Section 123 scenario Public Service proposed DSM goals sufficient to comply with § 40-3.2-104(2), C.R.S.

346. In Decision No. C08-0560, we set forth DSM goals for inclusion in the ERP as follows:

a) Energy goals for 2009 through 2015 (1,744 GWh cumulative);

b) An expectation that DSM will not be less than the “midpoint” (100 percent value) of the DSM range (*See* Decision No. C08-0560, ¶ 52);

c) Demand goals for 2009-2015 equaling a cumulative total in the range of 421-449 MW;

d) 2009 goal = 36 MW; 2010 goal = 53 MW (*See* Decision No. C08-0560, ¶¶ 61-62);

e) Three data points for input into modeling (as the basis for a presumptive “DSM supply curve”); and

f) An expectation that one modeling run will include statutory minimum values for DSM (the 2009-2015 portion of minimum goals that must be achieved by 2018), equaling about 113 GWh/yr. and about 28 MW/yr. (See Decision No. C08-0560, ¶ 54)

347. The OCC recommended that Public Service acquire more cost-effective demand side resources and acquire those resources sooner than Public Service proposed. The OCC stated in testimony, “[u]pon further examination…the OCC now recommends that Public Service make every effort to ramp up its DSM Program even more aggressively, with a goal of ultimately reducing sales by more than one percent….”[30] The OCC did not limit the focus to strictly DSM, but also to government initiatives such as appliance standards and building codes. The OCC also

[29] *See* Application Volume 1, p. 7.
[30] Schechter Answer Testimony, p. 5-6

argued for an accelerated implementation of DSM, to protect consumers from higher energy prices, and to gain the climate impact benefits. The OCC advocated for a review of the DSM goals in each future planning docket in order to re-evaluate what is cost-effective. Further, the OCC argued that as fuel prices increase, DSM technologies that currently are not cost-effective may become cost-effective.[31]

348. GEO called for collaboration between GEO and Public Service in the design and implementation of commercial and residential DSM Programs. GEO advocated for increased education, improving building codes to the latest International Energy Confirmation Codes, providing financial incentives for energy efficient practices and innovative financing models for energy efficiency. GEO also proposed a new home labeling (such as ENERGY STAR), expanding the infrastructure for the Home Energy Rater System and utility-sponsored financial incentives for home builders.[32] GEO also affirmed the DSM goals set forth in Decision No. C08-0560.[33]

349. Public Service indicated that it is open to suggestions regarding DSM Programs, and encouraged parties to use existing channels to convey any suggestions, specifically referring parties to the Company's product development staff. Public Service also indicated that the next DSM docket (the filing of its biennial plan) will address program-specific issues.[34]

350. RUC advocated for a delay in the ERP Docket until all related dockets (Docket Nos. 07A-420E, 07S-521E, and 07A-462E) are completed. RUC also argued that the ISOC goals are inadequate and that Public Service should allow third-party aggregators to compete as

[31] Rosen Answer Testimony, pp. 8-10, 33-34

[32] Stern and Lyng Answer Testimony

[33] Plant Cross-Answer Testimony, P. 1-2

[34] *See* Public Service Reply Statement of Position, pp. 13-14.

interruptible service providers. RUC also suggested that the Saver's Switch Program should be made available to commercial customers and it called upon the Commission to make competitive procurement mandatory for DSM.

351. Mr. Shapiro argued that DSM is a "transference of money to a few by the many" and recommended that each individual pay for his or her own efficiency improvements. Shapiro testified that payback periods for residential energy efficiency are longer than consumers desire, thus inhibiting investments. Mr. Shapiro also suggested that energy efficiency upgrades be funded by the utility, with repayment through the utility's bills, and formatted so that energy savings equal monthly payments. He also suggested that this approach should include a return to the utility for being the financier, and that the repayment of the investments should be linked with the dwelling (such as a lien on the property), versus the customer.[35]

352. Ms. LaPlaca referenced the Governor's Climate Action Plan, specifically the call for 50 percent of the 2020 CO_2 reductions to occur using energy efficiency. She testified that this goal is very aggressive and far exceeds the DSM goals resulting from Docket No. 07A-420E, and advocated for additional DSM. Ms. LaPlaca also asserts that the Commission should keep the door open regarding the use of third party administrators for DSM.[36]

353. In rebuttal testimony, Public Service witness Ms. Sundin proposed modeling the following DSM scenarios: 1) a statutory minimum; 2) an Enhanced DSM Plan; 3) 1 percent annual retail sales reduction; and 4) 100 percent of Commission-approved goals (from Docket No. 07A-420E). Ms. Sundin also provided cost estimates for each of these scenarios.[37]

[35] *See* Shapiro Answer Testimony, pp. 4, 6.
[36] *See* LaPlaca Supplemental Answer Testimony, p. 3, line 14.
[37] *See* Exhibit DLS-1, Sundin Rebuttal Testimony.

Ms. Sundin testified that the 80 percent of goal scenario is roughly halfway between the Enhanced Plan and 1 percent sales reduction scenario and, thus, will not add appreciably to modeling. She also testified that there is currently insufficient information regarding the attributes of the 130 percent of Goal scenario necessary to model it effectively; specifically that Public Service has not defined which cost-effective DSM measures would be used to achieve this level of DSM, nor the corresponding load shapes, or how to estimate the cost.

354. Public Service argued that it does not believe that the 130 percent of goal level is attainable, since it would represent 94 percent of the currently measured economic potential. According to Public Service, using a 20 percent factor for naturally occurring DSM, there is not enough potential in the market upon which to achieve this goal. Public Service witnesses Hill and Hyde both advocated for limiting the number of DSM scenarios entered into the modeling as a means of reducing the complexity.[38]

355. Public Service provided estimated DSM costs corresponding with the proposed scenarios, as well as actual cost data for DSM performed in 2006 and 2007.[39]

356. Public Service responded to GEO's proposed energy efficiency targets, specifically by noting that: 1) updating building energy codes; 2) adopting lighting efficiency standards; and 3) implementing an industrial challenge, will all reduce the economic potential for DSM, and thus undercut goal attainment. Public Service argued that the DSM goals factored into the ERP modeling should reflect this possible undercutting of the DSM goals. Public Service further argued that GEO is proposing DSM goals that represent 120 percent of economic

[38] Hyde cross-examination by Chairman Binz (Transcript June 27, 2008, pp. 52-53) and Hill redirect by Paula Connelly (Transcript July 1, 2008, pp. 158-161).

[39] *See* Hearing Exhibit 150.

potential and that 80 percent of economic potential is the outer limit of feasibility, because 20 percent naturally occurs in the marketplace.

357. Public Service also argued that increasing gas prices will not have a significant impact upon DSM potential. Public Service testified that total avoided costs would need to increase by approximately 125 percent to yield an increase of 10 percent in economic potential.

358. Concerning the inclusion of DSM into ERP modeling, Public Service witness Hill testified that DSM values require an associated load shape so that they can be factored into STRATEGIST modeling. Hill further stated that DSM should not be treated as a supply-side resource, but as a subtraction from the demand projection, arguing that as a supply resource, all of the benefits of DSM (avoided emissions, etc.) would not be captured.[40]

359. WRA, in its SOP, proposed the modeling of two levels of DSM: 1) Commission-approved goals; and 2) 130 percent of the Commission-approved goals.[41]

360. Ms. Glustrom proposed that the Commission "assume 150 percent of Compliance for Demand Side Management Programs" for purposes of entering a DSM value into modeling.[42]

361. Ms. LaPlaca proposed modeling three DSM goals: 1) Commission's goals; 2) 130 percent of Commission goals; and 3) 200 percent of goal. LaPlaca argued for these DSM levels because Public Service's own data show DSM costs for 2007 at less than one cent/kWh, referring to Hearing Exhibit 150. LaPlaca further advocated that the Base Plan does not have to have the minimum level of renewable resources and DSM in order to comply with the Commission's ERP Rules.[43]

[40] Hill cross-examination by David Beckett, (Transcript July 1, 2008, pp. 16-19).
[41] *See* WRA Statement of Position, p. 2.
[42] *See* Glustrom Statement of Position, p. 5.
[43] *See* LaPlaca Statement of Position, p. 14.

362. RUC advocated for a review of the Public Service DSM cost projections, relative to actual costs documented in Hearing Exhibit 150, for possible larger DSM Programs than called for in Docket No. 07A-420E. RUC also argued that Public Service is missing DSM opportunities by relying on the DSM Programs that were the focus of the KEMA market study (presented in Docket No. 07A-420E).[44] RUC maintains that Public Service is "not interested in aggressively pursuing DSM."[45]

363. GEO called for a decision concerning the DSM goals in this docket that parallels or exceeds the Commission's DSM commitments in Docket No. 07A-420E. GEO further advocated that all cost-effective DSM should be acquired to the maximum extent practical.[46]

Discussion and Findings

364. We find that some of the DSM values proposed for modeling do not merit consideration. Specifically, the "Enhanced DSM Plan" scenario was proposed by Public Service in its Application in Docket No. 07A-420E; however, we did not approve that option in that docket.

365. We concur with Public Service that the 80 percent of Commission goals scenario and 1 percent of sales scenario are similar enough that both should not be used. We further conclude that 100 percent of the Commission goals scenario is the minimum DSM value that should be modeled, reiterating our expectation as stated in Decision No. C08-0560.

366. We find that the number of DSM scenarios used for modeling purposes shall be limited to two, so as to yield a manageable number of STRATEGIST outputs. We find that

[44] RUC Statement of Position, p. 10
[45] RUC Reply Statement of Position, p. 1
[46] GEO Statement of Position, pp. 2-3

attainment of 130 percent of the Commission goals is within the range of feasibility, given uncertainty regarding changes in technologies and other factors affecting market potential. We refer to this 130 percent level as the "High DSM" in modeling scenarios. We refer to the 100 percent of Commission goals as the "Standard DSM" in modeling scenarios. We find that the DSM values of 100 percent and 130 percent of Commission goals, as set forth in Decision No. C08-0560, are the values that shall be used for STRATEGIST optimization runs, as discussed in the Modeling Scenarios Section.

367. We find that, based upon Public Service's actual (2006 through 2007) DSM performance (*See* Hearing Exhibit 150) compared with corresponding DSM budgets for those years, Public Service and the IE shall use a DSM $/kW value equal to 70 percent of budgeted amounts, for modeling purposes.[47]

a) Statutory Minimum DSM: $702.55 * .70 = $491.79/kW

b) "Standard DSM" level - 100 percent of Commission DSM Targets: $1,853.14 * .70 = $1,297.20/kW

c) "High DSM" level – 130 percent of Commission Targets: use full estimated cost presented by Public Service (DLS-1) for Commission-Approved Goals: $1,853.14/kW plus reserve margin adjustments

Y. Definition of Section 123 Resources

368. Public Service has requested that we provide specific guidance as to which technologies are to be considered Section 123 resources pursuant to § 40-2-123, C.R.S. Specifically, Public Service supports a Section 123 designation for solar power with thermal storage, geothermal located in Colorado, compressed air storage, and new applications for biomass. In general, the Company supports the definition offered by WRA witness Mendelsohn.

[47] 2006 actual: $525/kW; $0.13/kWh (1st yr. savings); 2007 actual: $431/kW;$0.088/kWh (1st yr. savings). These values are approximately 61 percent of the budgeted amounts for these years.

369. Public Service takes the position that the designation of a technology such as the Section 123 resource is not sufficient for it to be acquired. Rather, we also must find that such a resource be cost-effectively implemented. Further, Public Service emphasizes that system reliability not suffer due to the deployment of these resources.

370. WRA requests that we adopt the following definition of Section 123 resources:

> An eligible energy resource will be considered a new clean energy, or energy efficient technology, or a demonstration project if it is clean and incorporates one or more technologies, representing a substantial portion of its overall installed cost, that have not been regularly commercially demonstrated, up to the point in time that the resource is formally bid, or if not bid, acquired.[48]

371. WRA further proposes that a determination be made on a case-by-case basis, but specifically advocates concentrating solar power with and without storage, compressed air energy storage, and some forms of biomass and geothermal, be defined as Section 123 type resources.

372. WRA witness Mendelsohn mentions that any RECs produced by Section 123 resources should be allowed to apply as Section 124 resources (*See* § 40-2-124, C.R.S.). Such RECs could then be sold and any funds applied toward the 2 percent retail rate cap.

373. Staff simply states that it accepts WRA's definition and later states that is does not consider DSM as a Section 123 resource.

374. The OCC explains that the distinction between a Section 123 and Section 124 resource should be made based on the underlying purpose. "If the underlying purpose for acquiring the resource is to demonstrate a new technology associated with renewable energy generation or to increase the level of renewable energy because of the associated energy security,

[48] *See* Supplemental Answer Testimony of Michael Mendelsohn of WRA, p. 2.

economic prosperity, environmental protection, and insulation from fuel price increases as set forth in § 40-2-123 (1) C.R.S."[49] Any REC generated could not be used for RES compliance purposes.

375. Ms. Glustrom advocates that because Public Service has no existing CSP projects on its system, such resources present new operational and integration challenges, thus all CSP projects should be considered Section 123 resources.

Discussion and Findings

376. There was general agreement among numerous parties to accept WRA's definition of Section 123 resources. We also note that the definition offered by the OCC holds merit. We find it appropriate to adopt WRA's and OCC's definitions as an appropriate definition for a Section 123 type resource.

377. Parties also advocated numerous technologies as Section 123 type resources, but it is apparent that, due to the new, innovative nature such projects will employ, it is not possible to define all technologies in all the forms they may take as a Section 123 resource. In addition, it may not be necessary to determine whether every specific type of project is or is not considered a Section 123 resource, as it is not likely that a large number of different technologies will be proposed as such. Rather, we provide a list of Section 123 resources, and invite Parties to seek a declaratory order from the Commission as to whether other proposed resources shall be included. Any party may file a petition to this effect.[50]

[49] *See* Statement of Position of the OCC, p 14.

[50] We note that Public Service has a process for clarifying RFP requirements, and we encourage parties to pursue this process with respect to this issue as well.

378. We clarify that concentrating solar power with storage does qualify as a Section 123 resource. Further, wind with compressed air storage also qualifies. DSM in general does not qualify, as it is intended to be an implementation of cost effective programs. However, we may consider developmental DSM Programs that have not yet been proven as cost effective, on a case-by-case basis.

Z. Growth of Photo Voltaic Industry

379. The Colorado Solar Energy Industries Association (CoSEIA) supports Public Service's increased target for on-site solar as detailed in the rebuttal testimony of Public Service witness Newell. However, in order to continue the development of on-site solar, it is necessary to establish a growth rate in excess of the average annual growth rate for the solar industry nationwide. CoSEIA estimates this growth rate to be in excess of 40 percent.

380. Ms. Glustrom recommends that we set aggressive targets for on-site solar resources. Public Service should be encouraged to work with the emerging Colorado solar industry to ensure continued growth to help ratepayers avoid the rapidly increasing costs of fossil fuel generated electricity. Further, Ms. Glustrom asserts that we should direct Public Service to consider ways to increase solar installations for middle and lower income ratepayers.

381. Interwest notes that on-site solar provides benefits to the utility system with some locations benefiting more than others. However, Public Service is the only party with access to information about such benefits. An on-site solar development zone map would be helpful, according to Interwest.

382. Interwest urges the Commission to require Public Service to work with industry to develop a viable market and focus on driving down local costs which include marketing, sales, installation, support, permitting, and financing. According to Interwest, the Commission should

require Public Service to file an on-site solar acquisition plan as part of the 2009 resource plan which shows sufficient on-site solar acquisitions to sustain an orderly development of solar markets.

383. GEO encourages the Commission to work toward ensuring that utility-scale solar power is deployed and the Commission should move in full accordance with the legislative guidance as enacted as part of HB 08-1164. In addition the Commission should continue its forward-looking policies regarding photo voltaic (PV) as further cost-reductions are on the horizon.

384. WRA recommends that the REC portion of the on-site Solar*Rewards Program should be reduced to free up more dollars for additional installations and spread out the benefits. WRA recognizes that it might be best to consider this in the RES docket.

Discussion and Findings

385. We support development of the solar industry and see it as a vital component of future energy resources. However, any specific allocation of RESA funds to such projects was addressed in Commission Decision No. C08-0559, ¶ 107, where we stated that, "this allocation is effectively addressed through the RES requirement of four percent solar energy of which 50 percent must be from on-site solar system. This language is sufficient to define any special treatment of solar programs." Therefore, we decline to adopt any further solar development initiatives at this time.

AA. Other Renewable Issues - HomeSmart

386. CoSEIA asserts that there is a conflict of interest between Public Service being part of Xcel Energy and the unregulated HomeSmart subsidiary of Xcel Energy. The primary concern seems to be the use of the Xcel name and logo in association with HomeSmart. Further,

the fact that HomeSmart has begun to offer on-site solar electric systems may be a conflict of interest because Public Service would benefit from Solar*Rewards while being a part of the same company responsible for administering the funds. If this matter is not addressed in this docket, CoSEIA indicates that it will continue to raise it in future proceedings as appropriate.

387. Public Service states that HomeSmart is an unregulated business of Public Service and has limited its efforts to small solar electric systems. Further, there is no statute that prohibits a utility from participating in the installation of PV systems and is not in any position to garner any preferential treatment.

Discussion and Finding

388. We agree with Public Service that State law does not prohibit such unregulated activities. While Public Service must comply with the Commission's Unregulated Goods and Services Rules 3500 through 3505, nonetheless we find that it is not appropriate for the Commission to take any further action with respect to this issue.

BB. Retirement of Cherokee Facility

389. Witnesses for Ms. LaPlaca and Ms. Glustrom recommend that the Commission require Public Service to retire the Cherokee coal plant.

390. Consistent with the testimony of several parties regarding the health impacts of coal generation, Ms. LaPlaca also raises concerns with other Cherokee pollutants.

Discussion and Findings

391. Public Service has proposed the retirement of two coal plants in this docket, which is a significant undertaking. Though we understand the expressed desire to remove the Cherokee plant and further reduce CO_2 emissions, we find that implementation of more coal plant retirements should be part of an overall plan for carbon reduction. We note that the

Company has demonstrated in this docket that it is committed to reducing carbon by putting forth an aggressive carbon reduction plan, and we find that ordering any specific studies such as one for a Cherokee retirement would not be productive at this time. Therefore, we decline to adopt any requirements related to the Cherokee plant, and instead encourage Public Service to investigate its entire system to determine the best overall plan to reduce carbon.

CC. Base Load Energy Benefit and Energy Purchase Benefit

392. In his Answer Testimony, Staff witness England raises concerns that the incentive structure in Public Service's ECA mechanism could lead to increased carbon emissions. The Base Load Energy Benefit (BLEB) term provides an incentive for Public Service to increase base load generation output. While designed to increase cost efficiency, it provides an incentive for Public Service to increase coal emissions. The Energy Purchase Benefit (EPB) term shares savings of energy purchases, which could also lead to purchase of cheaper high-carbon power.

393. Staff witness England recommends that the Commission require Public Service to eliminate the BLEB and revise EPB to consider carbon.

394. Public Service acknowledges that its ECA mechanism contains provisions that provide incentives to the utility to maximize the economic benefits, which could lead to higher carbon emissions. However, Public Service recommends that the Commission take no action in this docket, and address the issue in a rate case.

395. We agree with Dr. England that the current incentives contained in the BLEB and EPB are counter-productive. However, we find that it would be best to address this issue in a rate case. Therefore we require Public Service to include such issues as a part of its next rate case filing.

DD. CO_2 Information on Customer Bills

396. Comments received during the April 14, 2008 Public Comment Hearing advocated that Public Service include CO_2 emissions information on customer bills. The OCC testified in support of this idea.[51] The GEO testified in support of the OCC proposal, arguing that "it would help the customers understand the consequences of their electric and natural gas consumption."[52]

397. Public Service testified that it is not considering adding carbon information to customers' bills at this time. The Company stated that it does not agree that the bill is the proper mechanism for sharing this information, that such information would not be in a meaningful context and customers would not have an opportunity to act on this information in that format. Public Service goes on to argue that putting carbon information on the customer bill, along with the contextual information customers would need, would entail a substantial cost. Public Service testified that it is "currently evaluating opportunities to share carbon information, but with added context (*i.e*., what is a carbon footprint, how is it related to my energy use, and how to reduce it)" and that "carbon emissions are not yet a top of mind issue for most customers."[53]

398. Concerning communications with its customers, Public Service testified that "if it's something you absolutely want to have somebody see, it's going to be an educational process over time. And having a credible resource that they can go and study on their own time is preferred." Public Service recommended using bill stuffer messages to direct customers to a website and at the website provide information regarding the average CO_2 output for the utility, against which a customer's usage would be multiplied. Public Service also recommended that

[51] *See* Shafer Answer Testimony, p. 12-13
[52] *See* Plant Answer Testimony, pp. 10-11.
[53] *See* T. Davis Rebuttal Testimony, pp. 5-6.

the website offer some helpful hints to customers concerning how they could reduce their CO_2 emissions related to electric usage.[54]

399. During cross-examination by WRA, Public Service testified that it has conducted surveys and focus groups concerning utility communications with customers through customer bills. Public Service witnesses testified that the conclusion is that customers basically are only looking for a due date and amount due on their bill. Further, Public Service testified that adding only data regarding the average pounds/kWh of CO_2 would not involve a substantial cost.[55]

400. During cross-examination, the Public Service witness testified that the Company has not found any other utilities that put CO_2 information on the customer bill. However, further testimony indicated that Public Service has found some utilities that put CO_2 information on their websites, with additional context provided. According to the Company, one utility has been identified that provides information on its website that allows customers to calculate their "carbon footprint."

401. Public Service indicated that it would be interested in partnering with other entities to provide information and education concerning energy usage and its relationship to CO_2 emissions to the extent that it would help our customers' understanding in a contextual manner. Public Service stated that it has no direct knowledge of what type of party is best suited to provide this information, and advocated that it should be someone who has credibility within the marketplace and that "the utility is seen as a credible procurer of this information.[56]

[54] *See* T. Davis cross-examination by Commissioner Baker.
[55] *See* T. Davis cross-examination by Steven Michel.
[56] Davis cross-examination by Becky Bye.

402. In its SOP, the OCC advocates inclusion in customer bills, of information regarding the amount of CO_2 emitted for that customer's electricity consumption during that customer's billing cycle, or in the alternative, implementation of a carbon information customer education program. The OCC contends that if Public Service does not believe that carbon information should be on the utility bill, then it should have provided an alternative proposal regarding carbon education in this proceeding. The OCC further argues that Public Service's contention that customers are not aware or interested in carbon emissions information should not excuse it from undertaking some form of education. The OCC also argues that the regulatory process would be remiss if it were to delay the education of utility customers regarding carbon emissions.[57]

Discussion and Findings

403. We find that customers need to be better informed about the relationship between electricity usage and the adverse climate impacts of carbon emissions. However, we concur with Public Service that the customer bill may not be the best channel for communicating with customers concerning carbon emissions.

404. We do find that using the customer bill stuffers to direct customers to carbon emissions information is an appropriate strategy for Public Service to pursue. We also find that this strategy is not the sole responsibility of Public Service, but should be pursued as a partnership. We therefore, direct Public Service to pursue a CO_2 information/education partnership, involving entities such as the Commission, OCC, GEO, CDPHE, and any other non-profit entities that are also established and credible in this arena.

[57] *See* OCC Statement of Position, p. 5.

405. We direct Public Service to address, through its testimony filed with its next ERP in 2010, a strategy for improving public knowledge concerning the relationship between electricity consumption and greenhouse gas emissions (carbon dioxide specifically), including key messages and communication channels. Public Service shall include in its proposed strategy those parties it has identified and contacted to serve as partners in the education strategy.

EE. Summary of Filing Requirements

406. The following is a summary of required studies and other documents that Public Service must file with the Commission:

a) Written comments on the Commission's proposed modeling scenarios – Due October 6, 2008.

b) Wind Integration Study – Due in December 2008.

c) Reserve Margin Study – Due in December 2008.

d) Updated Load Forecast – Due December 1, 2008.

e) Semi-dispatchable RFP – Due 60 days before All-Source solicitation is released.

f) Capacity Credit analysis for intermittent Solar Resources - Due 60 days prior to the date responses to the Company's All-Source RFP are due.

g) Integration cost analysis for intermittent Solar Resources - Due 60 days prior to the date responses to the Company's All-Source RFP are due.

h) Updated retirement costs for Arapahoe & Cameo – Due on bid due date.

i) Filing to eliminate BLEB and revise EPB – as part of Public Service's next rate case.

j) Customer carbon information proposal – include as part of 2010 interim filing.

k) Interim filing – due May 31, 2010.

III. ORDER

A. The Commission Orders That:

1. The Application for Approval of the 2007 Electric Resource Plan (ERP) of Public Service Company of Colorado (Public Service or Company), filed on November 15, 2008 is approved with modifications, consistent with the discussion above.

2. The request for late intervention filed on August 14, 2008 by Joshua Perry and Steve King are denied. Instead, these individuals are granted *amicus curiae* status pursuant to Rule 1200(c).

3. Public Service shall file an interim ERP application on or before March 31, 2010, consistent with the above discussion. As a part of this filing, Public Service shall include an updated forecast and a revised assessment of the intermittent limitations.

4. Aquila Networks – WPC's request to require Public Service to extend its contract is denied consistent with the above discussion.

5. Should Public Service propose utility-owned resources in Phase II pursuant to § 40-2-124, C.R.S., then it must request a review from an Independent Evaluator (IE), consistent with the discussion above. If applicable, Public Service shall submit proposed project acquisitions for Section 124 evaluation in conjunction with the Independent Evaluator's participation in this docket.

6. Public Service's request to determine utility ownership percentages in Phase I and defer the ruling on the ownership amounts to Phase II is denied consistent with the discussion above.

7. Public Service's request to implement reverse-auction and build-transfer requirements is denied consistent with the discussion above.

8. Public Service's proposal for the inclusion of an imputed debt adder into the Power Purchase Agreement bid evaluation process is denied consistent with the discussion above.

9. Public Service's request to add language in its Requests for Proposals (RFPs) that it be permitted to incorporate language in its model Purchase Power Agreements concerning capital leases and consolidation under the Financial Accounting Standards Board Interpretation No. 46R, Consolidation of Variable Interest Entities, as proposed in the Company's Statement of Position, is granted consistent with the discussion above.

10. Public Service is permitted, but not required, to include language in its model Power Purchase Agreements that direct parties to endeavor to resolve among themselves any disputes that arise with respect to this issue. If no resolution is reached, then parties may come before the Commission with their disagreement.

11. The early retirement of Arapahoe units 3 and 4 and Cameo units 1 and 2, is approved consistent with the discussion above.

12. At the time bids are due in Phase II, Public Service shall also file an estimate of the undepreciated value of Arapahoe units 3 and 4 and Cameo units 1 and 2, along with an updated estimate of the decommissioning costs.

13. We decline to make an affirmative ruling on Black Hills Energy Inc.'s request that the Commission find that the carbon footprint associated with the 2005 wholesale purchase of electric power from Public Service by Aquila belongs to Aquila, and subsequently Black Hills Energy, Inc., consistent with the above discussion.

14. Any utility rate-based proposals shall include a proposed cost cap to be used for comparison with fixed price bids, consistent with the above discussion.

15. The RFPs and Model Contracts as modified in the RFPs, Model Contracts Section are approved. As a part of each RFP, Public Service shall include a statement that bidders may include a discussion of the non-quantifiable (externality) benefits that the bidder attributes to its proposal.

16. As a part of its next rate case Public Service shall address the Base Load Energy Benefit and Energy Purchase Benefit consistent with the above discussion.

17. Public Service shall make a compliance filing in this docket to provide the updated load and sales forecasts no later than December 1, 2008, consistent with the above discussion.

18. In their reports, the IE and Public Service shall provide a narrative summary of the externality benefits associated with each likely portfolio of resources, based upon information provided by bidders.

19. For modeling purposes, Public Service and the IE shall use Public Service's rebuttal position for gas prices, and run sensitivity analyses with gas prices escalating at the rate of inflation and at a 7 percent increase above inflation, consistent with the above discussion.

20. For modeling purposes Public Service and the IE shall use Public Service's proposed coal price forecasts, without a price volatility adder.

21. We adopt Public Service's rebuttal CO_2 cost proposal of $20/ton plus 7 percent escalation per year, equating to a real 5.5 percent escalation rate in addition to the 2.5 percent inflation factor.

22. For modeling purposes, Public Service and the IE shall use the Company's averaged weighted cost of capital, 7.88 percent, as the discount rate.

23. For modeling purposes, Public Service and the IE shall use Public Service's generic unit approach to compare proposals with unequal lives.

24. We provide our preferred modeling scenarios as shown on the diagram in Exhibit A to this Decision. Public Service and the IE shall provide a written response to the proposed scenarios by October 6, 2008. All other parties may also provide a written response by October 6, 2008.

25. We will hold a technical conference on October 10, 2008 at 9:00 a.m., to discuss the modeling scenario issues with the Public Service modeler and the IE.

26. We find that Public Service's proposal regarding transmission cost allocation is appropriate, and shall be adopted.

27. Public Service shall provide an alternate reserve margin study to the Commission before Phase II of the ERP commences, consistent with the above discussion.

28. Public Service shall pursue a CO_2 information/education partnership, and Public Service shall include in its next ERP in 2010, a strategy for improving public knowledge concerning the relationship between electricity consumption and greenhouse gas emissions, consistent with the above discussion.

29. The 20-day time period provided by § 40-6-114(1), C.R.S., to file an application for rehearing, reargument, or reconsideration shall begin on the first day after the effective date of this Order.

30. This Order is effective on its Mailed Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING August 19, 2008.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

RONALD J. BINZ

JAMES K. TARPEY

MATT BAKER

Commissioners

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Variables

Level of Section 123 Resources	(optimize)
DSM	(optimize)
Gas Prices	(sensitivity)
CO_2 Cost	(sensitivity)
Retire Arapahoe & Cameo	(fix)
Forecast	(fix)
RESA (not 123, not economic)	(fix)
Ownership	(sub-optimum)
Externalities	(sub-optimum)

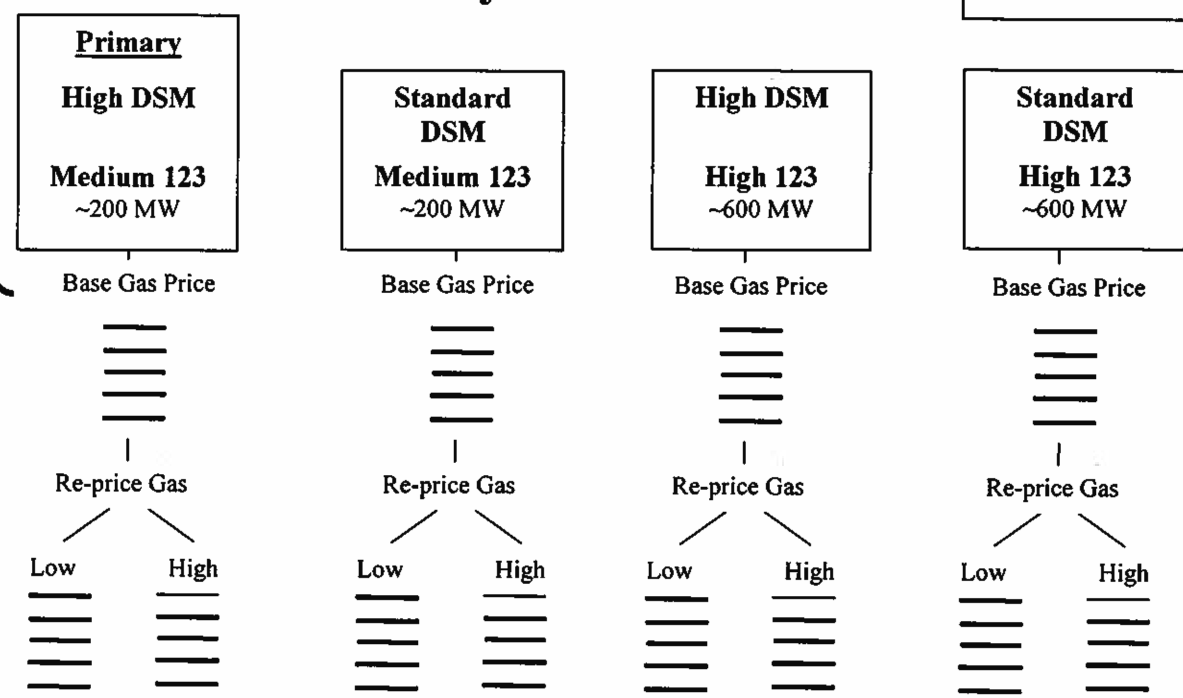
Scenario Analysis

Exhibit A

Likely Scenarios
Assumptions:
- -Base Forecast
- -RESA at 850 MW
- -CO_2 \$20/ton + 7%
- -Base gas cost (PSCo rebuttal position)
- -Arapahoe/Cam. retired

Gas Price Sensitivity Runs
Re-price at:
- High (7% real increase)
- Low (0% real increase)

Resulting "Stacks" of portfolios, in order of NPVRR



Information PSCo and IE Provide to the Commission:

- Summary of portfolios for the top 3 – 5 positions in the stack (and results for these portfolios as they appear further down in the stack in other sensitivity runs for that scenario). Note – we want qualitative differences for these 3-5 positions, not just minor differences such as resource timing.
- Any cases containing Section 123 resources (claimed by bidders), if not included in summary to see portfolios of alternate 123 resources if more than 200/600 MW are bid.
- Any cases containing exceptional externality benefits, if not included in summary.
- [~40% and ~60%??] ownership cases, regardless of where they appear in the stack (provided in sub-optimum portfolios if not economic).
- PSCo and IE to provide their preferred cases.
- Include discussion of externality benefits for each of these cases, based on bidder's claims.
- Assess level of gas price increase above base, where portfolios change significantly.