Decision No. C03-0670

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 02S-315EG

RE: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO ADVICE LETTER NO. 1373 – ELECTRIC, ADVICE LETTER NO. 593 – GAS, AND ADVICE LETTER NO. 80 - STEAM.

ORDER APPROVING SETTLEMENT WITH MODIFICATIONS

Mailed Date: June 26, 2003
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I. BY THE COMMISSION

A. Introduction

1. It has been nearly ten years since Public Service Company of Colorado (Public Service or the Company) filed a combined general rate case.[1] There have been many changes in the Company since the 1993 case. Most notably in 1997 Public Service merged with Southwestern Public Service Company to form New Century Energies, Inc. Then in 2000, New Century Energies and Northern States Power Company merged to form Xcel Energy, Inc.[2] Xcel Energy directly owns six utility subsidiaries that serve electric and natural gas customers in 12 states.[3] Xcel Energy also is involved in non-regulated businesses, the largest of which is NRG Energy, Inc., a publicly traded independent power producer, which is now in bankruptcy.

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[1] Public Service's last combined (Electric, Gas, and Thermal Departments) general rate case was in 1993 (*see,* Docket No. 93S-001EG). Since the 1993 rate case, Public Service has filed three general rate cases for its Gas Department. S*ee,* Docket Nos. 96S-290G, 99S-609G, and 00S-422G.

[2] Xcel Energy, a Minnesota corporation, is a registered holding company under the federal Public Utility Holding Company Act of 1935.

[3] The six utility subsidiaries are Northern States Power Company, a Minnesota corporation (NSP-M); Northern States Power Company, a Wisconsin Corporation (NSP-W); Public Service Company of Colorado; Southwestern Public Service Company (SPS); Black Mountain Gas Company; and Cheyenne Light, Fuel and Power Company.

2. Since 1993, the State's population has grown by over 1 million people. According to Company records, at the end of 2001 it provided regulated energy services to 1,264,942 electric customers,[4] 1,131,375 gas customers[5] and 134 thermal energy customers.[6]

3. Another significant change relating to the Company's electric operations since the last rate case is the increasing use of natural gas to generate electricity. In 1996, natural gas generation was 0.21% of the Company's fuel and purchase energy mix. For the year 2001, the test year in this case, the percentage is 25.85%.

4. With this increased use of gas in its electric operations, the cost to generate electricity has become much more volatile. This cost dynamic is demonstrated in this case. The proposed Settlement between the parties here (discussion *infra*) seeks to increase the Company's fuel adjustment clause by $215.5 million dollars; while the Electric Department's base rates would decrease by about $230,000. As for the Gas Department, the proposed Settlement results in a decrease in base rates of $33.3 million dollars; while the Thermal Department base rates would decrease slightly by $26,045.[7]

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[4] Public Service provides wholesale and retail electric service throughout various portions of the State of Colorado. Public Service's retail service territory includes areas in and along the Front Range from south of Fort Collins to the southern reaches of the Denver Metro area, on the Eastern Plains in the area of Sterling and Fort Morgan, in the central mountain areas along I-70 extending to and including Grand Junction, and in the San Luis Valley including the city of Alamosa.

[5] Public Service provides natural gas sales and transportation services in various portions of the State of Colorado, including areas in and along the Front Range from Fort Collins to Pueblo, in the mountains from Grand Lake south to the Bayfield and the San Luis Valley areas, and in Western Colorado from Grand Junction north to Steamboat Springs and east to Vail.

[6] Public Service provides thermal energy services in downtown Denver through a system of steam and chilled water piping.

[7] The average customer rate impact for each type of customer (electric residential or commercial gas, for example) is shown on Attachment L to the proposed Settlement.

II. PROCEDURAL HISTORY

5. On May 31, 2002, Public Service filed Advice Letter No. 1373 - Electric, Advice Letter No. 593 - Gas, and Advice Letter No. 80 - Steam. The proposed tariff sheets attached to those Advice Letters proposed certain revenue increases for the Company as compared to base rate revenues: Electric $74,404,991; Gas $2,581,416; and Steam $1,360,827. In Decision No. C02-640, we suspended the effective date of the proposed tariffs pursuant to the provisions of § 40-6-111(1), C.R.S., set this matter for prehearing conference, and allowed interested persons to intervene in this case within 30 days of the effective date of that order. The following parties intervened in this matter: CF&I Steel LP; the City and County of Denver; Climax Molybdenum Company; the Colorado Business Alliance for Cooperative Utility Practices; the Colorado Energy Assistance Foundation; the Colorado Energy Consumers Group; the Colorado Municipal League; the Colorado Office of Consumer Counsel (OCC); the Colorado Office of Energy Management and Conservation; Staff of the Colorado Public Utilities Commission (Staff); the Colorado Renewable Energy Society; Holy Cross Electric Association; Intermountain Rural Electric Association; the Kroger Company; the Land and Water Fund of the Rockies (LAW Fund); Tri-State Generation & Transmission Association, Inc.; and the United States Department of Defense--Federal Executive Agencies.

6. On August 7, 2002, the Company filed Supplemental Direct Testimony, Corrected Testimony and Revised Exhibits. This filing changed the Company's requested revenue increase to base rate revenue as follows: Electric $60,257,656; Gas $2,249,166, and Steam $1,360,827.

7. On November 22, 2002, many intervenors filed Answer Testimony and exhibits objecting to various aspects of the Company's requested rate changes. Additionally, on that date the Company, the OCC, and Staff filed their Stipulation and Agreement Regarding Depreciation

Issues (Depreciation Stipulation), and the Company and Staff filed their Stipulation Regarding Corrections to the Direct Case Filed by Public Service Company of Colorado (Stipulation on Corrections). The Depreciation Stipulation modified Public Service's requests for changes to base rate revenue by the following amounts: Electric ($29,266,852); Gas $609,935; and Steam ($4,658). The Stipulation on Corrections modified the Company's revenue requirement requests in this case in various ways (*e.g.,* cash working capital allowances, and *pro forma* adjustment to firm wheeling service), and contemplated certain further corrections to the revenue calculations. Those further corrections were set forth in the Supplemental Stipulation Regarding Corrections to the Direct Case Filed by Public Service Company of Colorado dated January 23, 2003. The Supplemental Stipulation Regarding Corrections further modified the Company's revenue requirement requests in certain specified ways.

8. On January 24, 2003, Public Service filed its Rebuttal Testimony and Exhibits. That testimony accepted some of the intervenors' positions raised in Answer Testimony. As a result, the Company, in conjunction with the three stipulations discussed above, modified its requested changes to base rate revenues as follows: Electric $16,193,383; Gas ($6,387,191); and Steam $1,089,092.

9. On February 12, 2003 the Company filed its Supplemental Rebuttal Testimony and Exhibits to correct certain errors in its Rebuttal Testimony and Exhibits, and to concede certain issues raised by intervenors. After that filing, the Company's proposed changes to base rate revenues were: Electric $14,503,382; Gas $ (5,984,401); and Steam $1,089,084.

10. In addition to proposing changes to base rates, the Company's filings in this case also suggested certain revenue increases for 2003 to be collected in its electric cost adjustment

clause.[8] The Company's initial filing (in its Direct Testimony) proposed to collect revenues of $113,003,685 via its electric cost adjustment mechanism during 2003. In its February 12, 2003 Supplemental Rebuttal, the Company projected its 2003 electric cost adjustment revenues to be $186,473,283.

11. On February 18, 2003, Public Service, the OCC, and Staff filed their motion to vacate the hearings (then scheduled to begin on February 24, 2003), and to set a new schedule including new hearing dates. The motion stated that the parties were likely to reach a comprehensive settlement of issues in this case, and requested more time to continue negotiations. We granted the motion in Decision No. C03-0190.

12. Later, in Decision No. C03-431, we granted Public Service's Unopposed Motion for Leave to File Comprehensive Settlement Agreement on or before April 4, 2003. That motion had requested until April 4 to finalize the agreement reached by the parties, and to file it with the Commission. Additionally, Decision No. C03-431 set hearings for April 28-30, and May 1, 2003 to consider the settlement between the parties.

13. Public Service, in its Advice Letters, initially proposed that the new rates become effective on July 1, 2002. However, for various reasons (*e.g.,* to allow the parties additional time to reach settlement) the Company filed amendments to the Advice Letters to extend the proposed effective date: the first amendments were filed on August 15, 2002; the second amendments were filed on February 19, 2003; and the third amendments were filed on April 4, 2003.

[8] As explained *infra*, the electric cost adjustment mechanisms, such as the Incentive Cost Adjustment and the Interim Adjustment Clause, collect the Company's energy costs (*i.e.* fuel costs to generate electricity, purchased energy, and purchased wheeling expense).

In view of those amended Advice Letters, the Commission has now suspended the tariffs proposed in this case until July 1, 2003.

14. On April 14, 2003, Public Service filed the Settlement Agreement (Settlement). The Settlement resolves all issues between the parties to this case. Generally, the Settlement, after proposing resolution of all specific revenue requirement issues raised in the prefiled testimony, suggests the following changes to base rate revenues for the Company: Electric ($21,082,702); Gas ($17,843,528), and Steam $880,653. The Settlement also proposes to recover $215,508,934 in 2003 energy costs through the Interim Adjustment Clause (IAC). In addition, the Settlement proposes an Electric Commodity Adjustment (ECA) for recovery of 2004-2006 energy costs. Finally, the Settlement establishes specific regulatory treatment of the Company's trading operations pending further proceedings before the Commission in 2004.

15. Consistent with the directives in Decision No. C03-431, we conducted hearings on the Settlement on April 28-30, and May 1, 2003. Witnesses for Public Service, the OCC, and Staff testified to explain the Settlement and to respond to questions regarding the Settlement from the Commission and the Commission's advisors. Now being duly advised in the premises, we approve the Settlement consistent with the discussion below.

III. PROPOSED SETTLEMENT

16. The Settlement represents the culmination of thousands of hours of work for the settling parties. The give and take nature of negotiations is demonstrated by comparing the parties' prefiled cases to the resolution contained in the Settlement. The Commission heard testimony during the hearing regarding how the Settlement represented an 'acceptable end result' for the settling parties with each party negotiating hard on the issues it felt most strongly about. Notwithstanding the parties' agreement to resolve this case as set forth in the Settlement, it is the

Commission's independent obligation to review the Settlement to ensure it is just and reasonable, especially in light of ratepayers' interests.

17. Besides the changes in base rates previously discussed, the Settlement has many other features, which will be discussed more fully below. For example, the Settlement: (1) continues the Company's electric trading operations with some modifications; (2) creates a new energy cost adjustment clause, the Electric Commodity Adjustment (ECA); and (3) establishes many ratemaking principles to be used in the Company's 2004 to 2006 Earnings Tests.

A. Interim Adjustment Clause

18. The Settlement proposes that the Company's 2003 electric energy costs (*i.e.* fuel costs, purchased energy, and purchased wheeling) be recovered through an adjustment clause that passes through to retail customers 100% of these costs. In fact, the Commission has already approved an Interim Adjustment Clause (IAC) for recovery of 100% of the Company's energy costs during 2003. *See* Decision No. C02-609. According to Decision No. C02-609, the IAC was to remain in effect only until the rates from the present proceeding became effective. The Settlement now proposes that 2003 energy costs continue to be recovered through the IAC. Specifically, the Settlement proposes that new IAC rates become effective by July 1, 2003 at the latest. However, the parties also agree that the Company could file a less-than-statutory-notice (LSN) application with the Commission by April 9, 2003 requesting that new IAC rates take effect May 1, 2003. In fact, the Company did file that application.

19. On April 29, 2003, the Commission approved the LSN request by Public Service to implement an increase in the IAC effective May 1, 2003. The IAC is intended to provide 100% recovery of the Company's 2003 Energy Costs via a 100% pass through mechanism.

20. In the LSN application, the Company estimated that $215.5 million dollars would need to be collected through the IAC for the portion of the 2003 Energy Costs not recovered through base rates.[9] The Company presented two different calculations allowing the Commission to choose to start collections on either May 1 or July 1, 2003. As more fully discussed in Decision No. C03-0444, we approved the collection of 2003 Energy Costs to commence on May 1, 2003. Part of the Commission's reason for allowing the collection to start on May 1 instead of the July 1, when all other rates associated with the Proposed Settlement would take effect, was that the additional two months of collection would reduce the size of the monthly increase. Given our decision on Public Service's LSN application relating to 2003 Energy Costs, the Settlement's proposal for continuing the IAC until December 31, 2003 is accepted.

B. Trading

21. Public Service initially proposed that its trading operations be left unchanged and continue to conform, with two exceptions, to the trading stipulation adopted in Decision No. R00-0830, in Docket No. 99A-557E. The two exceptions are that the definition of short-term wholesale sales be changed to include sales up to two years in length instead of one, and that negative, as well as positive, annual aggregated trading margins, calculated separately for Proprietary (Prop) Book and Generation (Gen) Book trading, be shared between customers and stockholders. The latter request was withdrawn by Public Service in its rebuttal testimony.

22. A number of other parties including Colorado Energy Consumers Group, City and County of Denver, the Office of Consumer Council (OCC), and Staff criticized Public Service's position. They uniformly objected to customers' sharing negative annual aggregated margins.

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[9] *See,* Docket No. 03L-140E.

They further argued that trading, especially Prop Book trading, is speculative and, therefore, should be eliminated as a regulated activity. For similar reasons, they contended that Administrative and General and non-production Operations and Maintenance expenses related to such trading should be disallowed.

23. The Proposed Settlement addresses both short-run (through the end of 2004) and long-run issues. Concerning the short run, the 2000 trading stipulation will remain in effect except where changes are explicitly indicated. In addition, business rules for trading are presented as an attachment to the Proposed Settlement.[10] Public Service will continue to record Gen and Prop Book trading activities separately. Negative annual aggregated margins will be absorbed entirely by stockholders. Positive annual aggregated margins, on the other hand, will be shared between stockholders and customers, with different sharing mechanisms for Gen Book and Prop Book margins. Specific amounts of trading expenses will be disallowed in this docket[11] and in the 2004 Earnings Test; the level of disallowance for the 2005 and 2006 Earnings Tests depends upon how much trading is done in those years. The definition of short-term electric energy transactions will be extended to include transactions up to two years in length.

24. The Proposed Settlement does not specify how Public Service's trading operations will be treated beginning in 2005. What it does do is establish a procedure by which this will be determined later. This procedure consists of two parts, an audit of Public Service's trading operations to be conducted in 2003[12] and an application to be filed with the Commission

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[10] See Attachment J entitled "Public Service Company of Colorado Policy for Resource Management and Cost Assignment for Short-Term Electric Energy Transactions."

[11] The reductions shall be $1.74 million related to Gen Book expense and $1.00 million related to Prop Book expense.

[12] It will cover the period January 1, 2003 through June 30, 2003 and shall be completed by October 1, 2003.

by Public Service in 2004 to review all aspects of its trading operations. This review will include consideration of the regulatory treatment of trading, Public Service's trading business rules, and its cost assignment and cost allocation procedures related to short-term wholesale transactions. The proceedings should be completed prior to October 15, 2004, and the results implemented on January 1, 2005. Because the Company believes that trading and the ECA (discussed *infra*) are closely related, one of the terms under the Proposed Settlement is that if Public Service believes that the outcome of the trading investigation docket does not afford it sufficient opportunity to cover its risks, it can unilaterally terminate the ECA and implement a 100% pass through mechanism instead. To assist the Staff and OCC in their preparation and possible litigation in the trading investigation docket, Public Service will initially pay for both the audit and for the consultant. The audit expenditure will then be treated as an allowable expense in the 2004 Earnings Test, and the consultant fee will be recoverable through Public Service's IAC and/or ECA, depending upon when the expenditure is made.

25. The Commission agrees with the parties that the topic of Public Service's trading operations is too large and complicated to be resolved entirely in this docket. Consequently, it supports the attempt to fashion an interim treatment of trading which can be in place until a more thorough reconsideration is completed.

26. The Commission finds both of these components of the Proposed Settlement reasonable. In the interim, the customers are protected from any substantial negative impact from Public Service's trading because negative annual aggregated margins are not shared by customers, because at least some of the expenses associated with trading are disallowed, and because the Company's business rules are in place. On the other hand, customers will continue to benefit from sharing positive annual aggregated margins, to the extent they occur.

27. The Commission finds the process for a more thorough reconsideration of Public Service's trading operations for 2005 and beyond to be reasonable as well. An audit of these operations is a logical first step. The results of the audit will provide parties with a base of information upon which to begin the substantive reconsideration of Public Service's trading operations. During the course of this reconsideration in 2004, Staff, OCC, and others will be able to acquire an even greater understanding of the trading operations and be in a position to propose either that the interim procedures be retained or amended.

28. The Commission agrees with the Proposed Settlement's provision that Public Service pay for the audit but that the Company should subsequently be able to treat such monies as an allowable expense in the 2004 Earnings Test. The Commission also believes that Public Service should pay for a consultant to Staff and OCC in the follow-up docket. These parties will likely need such outside assistance because of the magnitude of the project.

29. The Proposed Settlement establishes confidential, maximum dollar amounts for each of these expenditures. This approach benefits the ratepayers because ceilings are placed on the amounts for which they are ultimately liable. These maximum amounts, however, will not necessarily be spent. The competitive procurement process will evaluate competing bids based on a variety of factors, including price. The Commission finds that this competitive procurement process will achieve the desired goal of cost containment while providing valuable resources to parties, such as Staff and OCC, in their efforts to substantively evaluate Public Service's trading operations.

30. We disagree with the dissent's proposal to modify the trading provisions in the Settlement Agreement. First, we accept the Settlement's proposals on trading because we believe those provisions to be more in keeping with the public interest than the modifications suggested

in the dissent. That the parties themselves, including parties such as Commission trial Staff and the OCC which are charged with protecting ratepayers' interests, agreed to these trading provisions is significant to us. We recognize that it is the Commission's duty to independently examine all provisions in the Settlement and reject those not within the public interest. After considering the trading provisions in the Settlement and the dissent's proposals for modifying those provisions, we conclude that the Settlement on this issue is just and reasonable.

31. The dissent would modify the agreement on trading in two ways. First, the dissent would not approve the funds for the audit and a trading consultant for trial Staff and the OCC at this time, but would require the Commission to specifically approve the RFPs for the audit and for the consultant, the selection of the consultant, and the scope of any consultant contract with Staff and the OCC. Second, the dissent would dispense with the requirement that Public Service file an application for Commission review of its trading operation in January 2004. Instead, the dissent would require that the Company's trading operations be examined by the Commission at the same time as the ECA mechanism is reviewed, in April 2006. We disagree with both suggestions.

32. With respect to the first proposed modification of the Settlement, concerning the funds for an audit and a trading consultant for trial Staff and the OCC, the dissent notes that these funds will be recovered by the Company in its rates. The dissent then asserts that the Settlement gives a blank check to trial Staff and the OCC at ratepayer expense; that the purpose of the audit and the consultant is simply to educate the Staff and the OCC; and that the benefits of the audit and trading consultant to ratepayers are not commensurate with the costs. To address these problems, the dissent proposes that the Commission oversee the process for audit and for selecting and compensating the consultant.

33. We note that the Settlement does not give a blank check to Staff and the OCC. The Settlement specifies caps on the money to be spent on the audit and for the consultant. Staff and the OCC indicated that, given present information, the amounts specified in the Settlement are appropriate. While these amounts may appear large to some observers, nothing in this record indicates that these caps are inappropriate given the importance and the complexity of the issues being investigated here. Moreover, the amounts specified in the Settlement *are caps*. We are trusting Staff and the OCC, as representatives of ratepayer interests, to be prudent in using the fund established in the Settlement, and use no more than necessary to carry out their obligations in this important and complex matter.

34. We also disagree that the purpose of the audit and the consultant is to educate the Staff and the OCC. The Settlement makes these monies available to Staff and the OCC for their preparation and participation *in the formal application on trading to be filed in January, 2004*. That application will, according to the Settlement, involve formal Commission review of the Company's trading operations, including the regulatory treatment to be afforded those trading operations, the Company's business trading rules, and cost assignment and allocation procedures for short term wholesale transactions. All these issues are important ones, and, it appears at this time that the Commission will issue decisions on these matters. Therefore, the audit and the consultant are intended to assist Staff and the OCC, and ultimately the Commission itself when we hear the January 2004 application, in establishing actual regulatory policies relating to Public Service's trading operations. We conclude that given the size and complexity of Public Service's trading operations, funds for an audit and for Staff and the OCC to retain a trading consultant are monies well-spent.

35. As for the suggestion that the Commission oversee the audit and consultant process--the dissent proposes that the Commission approve the RFPs, select the consultant, and establish the scope of the consultant's work Trial Staff and the OCC are participating in the trading investigation (*i.e.* the audit, the consultant process, and the application for review of Public Service's trading operations) as parties to an impending proceeding, and, as discussed above, the audit and the consultant are intended to assist them in preparation for that proceeding. The Commission's detailed oversight of these processes would likely require us to intrude upon these parties' preparation for an upcoming case where the Commission is to be the decision-maker. We note the dissent's suggestion that the Commission, even before the formal application has been filed by the Company, establish the scope of the consultant's work for Staff and the OCC. We think it inadvisable that we involve ourselves in parties' preparation for potential litigation in this manner.

36. In conclusion, the Commission accepts the trading portions of the Proposed Settlement without amendment.

C. Electric Commodity Adjustment

37. In its Direct Testimony, the Company proposed a new adjustment clause called the Electric Commodity Adjustment (ECA) to recover fuel, purchased energy and purchased wheeling expense (Energy Costs). The Company argued that its proposed ECA employs the same concept of incentives as did the Company's existing Incentive Cost Adjustment (ICA.)

38. Both the ICA and the ECA set a base amount per megawatt hour of Energy Costs and compare that base amount with actual Energy Costs incurred by the Company each year. Fifty percent of the difference between the base amount and the actual Energy Costs (positive or negative) is shared between the Company and the customers. The primary difference between the

Company's proposed ECA and the ICA is that the ICA contained a fixed dollar per megawatt hour base amount. The Company's proposed ECA would have a base that is determined by a formula that would vary with gas commodity prices and the level of PUC jurisdictional sales.

39. The Company explained that natural gas-fired generation has become a larger portion of its resource mix, that gas prices are volatile and hard to predict, and that the Company is a "price-taker" on gas commodity prices. Consequently, the Company contended that it could no longer accept an incentive clause with a fixed Energy Costs per megawatt hour base. The Company further explained in its filed testimony that it derived its ECA formulaic base from 2001 test year Energy Costs, with certain *pro forma* adjustments due to the unusual Western United States market conditions in the 2001 test year.

40. The Company proposed that if the ECA were not acceptable, the Company would accept an adjustment clause that passed through 100% of Energy Costs, without an opportunity to earn an incentive from cost reductions.

41. Generally, all of the parties contested the Company's proposed ECA. Numerous parties objected to the Company's proposal to calculate and change the ECA rate monthly. Other parties raised numerous other issues with respect to the Company's proposed ECA, including assertions of the following positions: the use of the 2001 test year to develop the ECA base created "baked-in-value" for the Company; it is imprudent to use a complicated formula with numerous benchmarks that could provide the opportunity for the Company to "game" the adjustment clause; the Company's *pro forma* adjustments to 2001 test year coal plant availabilities should not be accepted; and separate treatment of gas and non-gas resources could bias future resource selection. Staff, OCC, and the City and County of Denver generally favored

a 100% pass-through mechanism for Energy Costs in lieu of the Company's proposed ECA incentive mechanism.

42. The Settlement proposes that Public Service's 2004 to 2006 Energy Costs be recovered through an incentive adjustment clause that is designed generally in the same manner as the Company's proposed ECA, but the test year in the ECA base will be the twelve-month period ending August 31, 2003. The Settlement places limits on sharing within the ECA such that the maximum gain or loss for the Company is $11.25 million. In addition, the Settlement provides for workshops in which the Company will explain to interested parties its calculations of the 2004 to 2006 ECA. The Company will make an application with the Commission by April 1, 2006, addressing the Company's proposed regulatory treatment of Energy Costs incurred after December 31, 2006.

43. The Settlement contains a fuel clause similar to that proposed by the Company, and that, as stated above, was strenuously opposed by virtually all parties in their filed testimony. At the hearing, parties who had opposed the Company's ECA proposal explained how, as a result of the negotiations, they came to support the modified ECA presented in the Settlement.

44. At the hearing, witnesses for the Company, Staff and the OCC testified that the Settlement's resolution of ECA issues resulted in an incentive mechanism that was in the public interest. OCC witness Mr. Reif testified that he was initially skeptical that an incentive mechanism, such as the ECA, would motivate the Company to take cost saving actions it would not otherwise pursue. However, he was eventually convinced by the argument that utilities do a better job of managing energy costs when there actions result in direct dollar profits or losses. Mr. Reif also claimed that the sensitivity runs the Company performed for the parties helped

assure him that the ECA mechanism would result in outcomes that fall within an acceptable range.

45. Staff witness Dr. Schmitz explained that Staff originally had concerns with the value of the ECA incentive versus the risks involved, and the complexity of the mechanism. He stated that Staff was concerned that such a complex mechanism could have unintended consequences. However he testified that the ECA in the Settlement alleviated his concerns. He noted that the Settlement's ECA limits the Company's maximum "profit" or "loss" with respect to Energy Costs in any one year to $11.25 million. This provision reassured Staff by capping the risk of unintended results at $11.25 million. Additionally, Dr. Schmitz testified that the expiration of the ECA after three years, and the fact that the starting point will be based on an updated test year also helped alleviate Staff concerns. Finally, Dr. Schmitz explained that the sensitivity runs the Company provided to the parties helped to determine the bounds the parties agreed to, and gave him confidence that the $15 million dollars annually eligible for sharing was "about right."

46. Company witnesses testified that the Settlement's ECA accomplishes what the Company originally intended. It keeps an incentive for the Company to manage its Energy Costs, but reduces the Company's risks from volatile natural gas prices. Company witnesses also explained why the risks inherent in the ECA require that the Company engage in trading operations to cover them. Specifically, Company witness Mr. Eves explained the linkage between the ECA and the Company's trading operations. He explained that it is difficult to manage the price risk inherent in the ECA without the ability to offset that risk with the Company's trading operations. As an example he described a situation in which the Company might reschedule an outage to take advantage of hydro generation when the price is low. He

testified that if the Company could not lock in that advantage via its trading operations it would make the decision to reschedule a much bigger risk. He also described the risk of scheduling dispatch and maintenance and how it could be mitigated by the Company's trading operations. Finally, he contended that by buying and selling energy all the time the Company is able to mask what it is doing within the ECA to manage its energy costs. This prevents the market from taking advantage of the Company's need to purchase or sell energy at any specific point in time.

47. The hearing clarified several areas where Public Service's proposed ECA formula should be modified. With respect to the proposed tariffs, Company witness Mr. Darnell agreed that the Retail Jurisdictional Allocation Percentage factor (RJA%) should be applied to the F, P, and W terms in the formula on tariff page 111B, attached to his rebuttal testimony. Mr. Darnell further agreed that definitions for the terms Forecast Price Volatility Mitigation (FPVM) and Actual Price Volatility Mitigation (APVM) should be added to the tariff page.

48. Public Service Witness Mr. Haeger also agreed to a change in the computation of daily gas index pricing under the proposed ECA formula. In his direct testimony, Mr. Haeger stated that Public Service intended to use a straight average of the actual Gas Daily Publications for each month to represent the daily index price in its ECA formula. This was largely to accommodate the short time available to calculate and file a new ECA rate each month. Since the Company now proposes to change ECA rates annually instead of monthly, Mr. Haeger agreed that a weighted average of actual daily purchases could be used. [13]

49. In response to questioning at the hearing, Mr. Haeger clarified the operation of the daily/monthly percentage of index prices used in the Company's ECA formula. Public Service

[13] The Settlement requires Public Service to make additional ECA rate filing(s) if the deferred account exceeds +/- $40 million.

proposed to derive the percentage of daily and monthly gas purchases from the 12-month test period ending August 31, 2003. The Company then proposed to apply this test-year percentage split to actual daily and monthly index prices in its proposed formula. Public Service has generally proposed to remove gas index price volatility from sharing through its formula approach. Rather than using actual index prices for representative volumes of daily and monthly purchases to remove the gas price volatility, the Company has chosen to use the test-year percentage multiplied by the published daily and monthly indices for a different period.

50. As a result of the reliance on daily/monthly gas information in the ECA, the Commission will require Public Service to maintain records of daily and monthly index-related purchases, along with the associated quantities, so that the issue may be fully investigated when a subsequent method for energy cost recovery is explored in the future docket, as required in the Settlement (page 61). The purpose of this information is to produce adequate data for an analysis of how gas prices impact the design of a future energy cost recovery mechanism, including the impact of a location/seasonal premium and monthly/daily index percentages. At a minimum, Public Service shall maintain the following electric department gas purchasing records for the years 2004 through 2006: actual daily and monthly gas index prices; actual costs for monthly gas purchases for each month; and actual costs for daily gas purchases for each day.

51. Broadly speaking, the public policy issue before the Commission is whether the ECA creates incentives for the Company that will result in net benefits to Colorado' ratepayers in the form of lower electricity rates. In order for this to occur, the cost savings from Company actions must be greater than the costs and risks of the mechanism. Any incentive mechanism should reward or penalize the Company only for actions under its control. The unbounded nature of the originally proposed ECA created the possibility that the Company would reap

windfall gains or losses from changes in Energy Costs that resulted from market conditions not under the control of the Company.

52. After reviewing the Settlement and the testimony and exhibits provided at the hearing, we agree with the settling parties that the ECA proposed in the Settlement is in the public interest. As Staff witness Dr. Schmitz explained, the Settlement gives us a set of short-term solutions for recovering energy costs and allows the Companies' trading operations to continue, under the rules specified in the Settlement, while establishing a process in the longer term to allow the Commission to more fully understand the nature and consequences of the Company's energy cost recovery mechanism and its trading operations. As the settling parties pointed out, the limits placed on the sharing mechanism ease concerns with gaming opportunities and help ensure an incentive mechanism that does not result in windfall gains or losses to the Company caused by events outside of the control of the Company. In addition, at the hearing the Commission reviewed the same sensitivity runs provided by the Company to the settling parties during negotiations.[14] This helped ease our concerns with respect to the complexity of the mechanism and provided assurance that the Settlement's bounds in the ECA sharing mechanism are reasonable.

53. In addition, the Settlement establishes workshops for interested parties conducted by the Company to explain its calculation of the 2004 to 2006 ECA as soon as the new test year data become available and the ECA equation is developed. This provision also helps reduce our concern with the complexity of the ECA mechanism. The fact that under the Settlement the ECA

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[14] *See Exhibit* No. 111. In this confidential Exhibit the Company projected (by using its PROSYM model) its fuel and purchased energy costs to serve retail customer load under a prescribed set of gas prices and compared these costs to the revenue that the Company would collect under the Company's proposed ECA for the same retail load and gas prices. Sensitivity runs were performed that varied the availability of the coal plants, water use restrictions and higher gas prices.

base will be calculated with an updated test year alleviates concerns with the anomalies present in the originally proposed 2001 test year. Finally, the three-year limit on the life of the proposed ECA will allow the Commission the opportunity to review the effectiveness of this incentive mechanism after a reasonable period of time.

54. As previously noted, the Company maintains that the risks inherent in the ECA require that the Company engage in trading operations to cover them. If the Company is right, and given our approval of the Settlement's treatment of the Company's trading operations, the synergy between these two components of the Settlement should improve the likelihood that the ECA will result in Energy Cost savings for ratepayers.

55. As the Company explained in its filed testimony, natural gas-fired generation has become a larger portion of its resource mix, gas prices are volatile and unpredictable, and the Company is likely a "price-taker" on gas commodity prices. As part of the Integrated Resource Planning process (now called Least Cost Planning) for Public Service, the Commission previously found these changes in the Company generation portfolio to be in the public interest because they reduce the overall cost of producing electricity. However, these changes expose the Company and ratepayers to greater risks due to the volatility of natural gas prices. The Settlement's ECA will have a base that is determined by a formula that varies with gas commodity prices. This will help mitigate the Company's risk. Though the baseline shifts with gas index prices, the ECA is still designed to provided an incentive for the Company to manage all of its energy costs efficiently.

56. The Commission approves the ECA portion of the Settlement, with the modifications discussed above (*i.e.* the agreed upon tariff changes for the ECA). In addition, Public Service will be required to maintain those records discussed above.

D. Return on Equity

57. As in most Phase I rate cases, the appropriate return on equity for Public Service was one of the most contentious issues discussed in the prefiled testimony. All witnesses addressing this issue derived their estimates of the appropriate return on equity using discounted cash flow analyses. While the calculation of an investor's expected rate of return under a discounted cash flow method is rooted in finance theory, there is quite a bit of judgment involved in selecting the comparable companies and expected growth rates. As a result, we were presented with a wide range of recommended rates of return on equity in this case; from a high of 12.25% (by Public Service) to a low of 9.90% (by the OCC). In the Settlement, the parties agreed to use a return on equity of 10.75% for the Electric Department, which was Staff's recommendation, but 11.0% for both the Gas and Thermal Departments. Company witness Mr. Stoffel explained that the 25 basis point adder for the Gas Department was consistent with past Commission practice because of the vulnerability of the Gas Department to attrition. As for the Thermal Department, Mr. Stoffel noted that the capital costs are high for this department and "local politics" impact the department's operations.

58. The agreed upon values for rate of return on equity are within a range of reasonableness. We have some question regarding the 25 basis point premium allowed for the Gas and Thermal Departments. The parties' reasoning that the Commission had previously permitted a 25 basis point premium for the Gas Department does not persuade us that this treatment should continue without specific support for such a premium in specific cases. Likewise, we question the 25 basis point premium for the Thermal Department. Still, given the prefiled testimony and the testimony on these issues at the hearing, we accept the parties' proposals as within the zone of reasonableness.

59. Therefore, we accept the ROE figures of the Settlement without modification.

E. Capital Structure

60. The parties in the Settlement agreed to use the capital structure recommended by Public Service and the Staff: 48.60% Long-Term Debt and 51.40% Equity.

61. The disputed issues associated with the capital structure in this case centered on possible inclusion of short-term debt, whether one specific debt issuance had a higher interest rate because the Company was negatively impacted by NRG,[15] and elimination of the debt and equity associated with Public Service of Colorado Credit Corporation, which the Company rolled into its capital structure.

62. We conclude that the agreed upon values are reasonable. The Settlement provides that for purpose of the earnings sharing for 2004 to 2006, the Company shall use year-end capital structure adjusted to include notes payable to subsidiaries, and that an adjustment will be made to remove any Earnings Test accruals from the common equity balance, if necessary.

63. We accept the capital structure for the Company as proposed in the Settlement without modification.

F. Average vs. Year-End Rate Base

64. Plant investment (*i.e.,* rate base) generally increases over time (in nominal dollars). For any given weighted average of the allowed return on debt and equity, the larger the rate base, the larger the allowed revenue requirement. The Commission has generally used average-year rate base in setting revenue requirement for public utilities in Colorado, with

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[15] As noted above, NRG is a corporate affiliate of Public Service. NRG is now in bankruptcy.

the notable exception of Public Service; the Commission has used year-end rate base for the Company for approximately the last 30 years.

65. In direct testimony Public Service proposed to continue using year-end rate base. Both Staff and OCC proposed the alternative, namely, average-year rate base. They argued that Public Service is currently experiencing less attrition than it did in the past when the Commission approved the use of year-end rate base; hence, there is no justification to use year-end rate base in this case. Moreover, they contended that an average-year rate base does a better job of recognizing that plant changes continuously over the course of the test year, and of representing each month equally with all the others.

66. Public Service opposed these arguments, stating that there was no compelling reason for the Commission to change its long-standing treatment of the Company. It contended that attrition is still a substantial problem, even though inflation is lower, because it continues to experience growth. The Company also argued that, since rate base generally grows over time, year-end rate base would better reflect what the rate base will be when the new rates actually go into effect.

67. The Settlement utilizes an average-year rate base, relying upon the 13-month average of month-end balances for all rate base items, except cash working capital, and for *pro forma* adjustments to the extent possible. The appropriate rate base to use for the 2004-2006 Earnings Tests is left as an unsettled issue.

68. We approve the Settlement's adoption of average-year rate base. We believe that such a rate base better reflects the fact that plant is continuously being added and subtracted throughout the year. Moreover, the factors which historically motivated the Commission to

allow year-end rate base for Public Service, and which are enumerated in the settlement on page 23, do not at this time appear to be as prominent as they once were. For these reasons the Commission adopts this portion of the Settlement without modification. The Commission recognizes, however, that adopting average-year rate base in this docket has no bearing upon its choice of rate base in the 2004-2006 Earnings Tests.

G. Gas Stored Underground

69. The Company has proposed in Docket No. 02A-267G to use Weighted Average Cost (WAC) rather than its current Last-In First-Out (LIFO) method for gas storage inventory. Docket No. 02A-267G is still pending before an Administrative Law Judge; hearings have been suspended at the request of parties to continue settlement negotiations.

70. In this case, Public Service proposed a pro-forma adjustment in its direct case to reflect the switch to WAC gas storage inventory pricing. Some of the parties objected to the Company's proposed adjustment, raising the same objections as in Docket No. 02A-267G.

71. In the Settlement, the parties agree that the gas revenue requirement in this rate case should include an inventory allowance for gas stored underground, calculated using test period volumes multiplied by the average per-Dth inventory price for the 36-month period beginning with the January 1, 2000 LIFO balance.

72. The Settlement then prescribes the treatment for gas storage inventory that Public Service will use in future gas revenue requirement filings. In future filings, the Company will use the method approved by the Commission here, based on the 13-month average of month-end balances.

73. The resolution in the Settlement is a reasonable solution to this issue. By establishing a starting date of January 1, 2000 (for the gas inventory allowance) based on the LIFO balance, the parties have resolved the primary concern related to the average pricing issue.

74. The Commission accepts the inventory allowance for the gas stored underground as proposed in the Settlement without modification.

H. Purchased Power Capacity Costs

75. In its direct case, Public Service proposed a *pro forma* adjustment to test period expenses to reflect projected increases in electric purchased capacity costs for year 2002. The Settlement includes actual 2002 purchase power costs in the revenue requirement. One of the tenets underlying adjustments to ratemaking expenses is that there be a proper matching between revenues and expenses. This principle would require that if costs are changed (as in this Settlement adjustment) for an expense which can have a revenue effect associated with it, then there should be a corresponding adjustment to revenues.

76. When the parties were questioned at the hearing about whether a corresponding adjustment to revenue had been made (in response to the adjustment for 2002 purchased power expenses), they indicated that it had not. The net effect of using the 2002 purchase power capacity costs is an increase of $4.402 million in the Company's expense level.

77. When OCC witness Reif was asked about this adjustment, he indicated that since this Settlement was concerned about an acceptable end result, he did not think that making a corresponding adjustment for revenues would have resulted in a different settlement outcome.

78. Accepting the proposed adjustment for 2002 purchased power expenses without a corresponding adjustment to revenues will, technically speaking, result in a mismatch of

expenses and revenues. Nevertheless, we accept this adjustment in the Settlement. Generally, we do not approve of this kind of mismatch in ratemaking proceedings. However, in this case we conclude that the overall revenue requirement proposed in the Settlement based, in part, upon the proposed adjustment for 2002--is just and reasonable. Therefore, we accept this proposed adjustment without modification.

I. Insurance Expense

79. In the Settlement, the parties agree to use the actual 2002 insurance expense in calculating the revenue requirement. Another ratemaking concept is to make the test year amounts, as modified by Commission adjustments, reflective of future conditions in which the utility will operate.

80. Unlike the change in purchase power capacity cost, it would not be expected that increased insurance expense would generate any additional sales and revenues, simply because it costs more to insure the Company's assets. Thus, increasing the Company's insurance expenses without an associated revenue change, in this case, is appropriate.

81. The Commission accepts this proposed adjustment of the Settlement without amendment.

J. Pension Costs

82. In the Settlement, the parties agreed to add approximately $13 million dollars to the 2001 pension and benefit costs in order to account for some of the increase in pension costs the Company has recently experienced due to declining returns from the stock market. At the hearing, the parties stated that the justification for making this adjustment was that it produced an end result that all parties could accept. The Settlement also explains (page 36) that failing to

accept this adjustment could necessitate another Phase I filing by the Company "shortly after the conclusion of this proceeding."

83. From a regulatory principle standpoint, this proposed adjustment to expenses violates the known and measurable principle. That principle, as applied by the Commission in the past, allows for *pro forma* adjustments up to one year past the end of the test year. The Settlement's adjustment to pension expenses is based upon anticipated increased expenses in 2003, well beyond one year past the test year.

84. The parties at the hearing stated that allowing this adjustment would not set any regulatory precedent for future cases. We certainly agree with those statements, inasmuch as the parties' proposal is inconsistent with accepted ratemaking principles and practices. We accept this adjustment only because the overall revenue requirement proposed in the Settlement is just and reasonable, and that the overall requirement is based in part upon this pension cost proposal. Nevertheless, we are concerned that allowing Public Service to set rates based on a low point in the stock market would effectively "lock-in" higher than needed pension costs in rates.

85. The parties suggest that the Electric Department's Earnings Test would help to address any excess pension costs recovery which the Company may obtain from the Settlement, because the actual pension costs will be used for future Earnings Test purposes. Notably, this solution does not address how Gas and Thermal Department customers would receive any flow back of excess pension cost recovery, which the Settlement may create.

86. As the parties have structured the Settlement, if pension costs for 2004, for example, turn out to be less than the amount allowed through this case (the 2001 pension costs plus a portion of the 2003 pension costs), those excess pension cost collections would be pooled

together with all other cost changes (comparing 2004 Earnings Test amounts to the amounts provided for in rates from the Settlement) and possibly shared, depending on the overall results within the Earnings Tests for 2004.

87. We do not accept the pooling of possible excess pension cost collections with other cost changes in the Earnings Tests for possible sharing. In exchange for the unique regulatory treatment the parties have crafted for pension costs (violating the known and measurable principle), a unique safeguard should be created. The safeguard the Commission will require is: If actual pension costs for the years 2004 to 2006 for the Electric Department are less than what is allowed in rates through the Settlement, 100% of the excess pension cost recovery (*i.e.* the difference between actual costs for years 2004, 2005, and 2006 individually and the costs allowed in the Settlement) will be flowed back to ratepayers in the annual Earnings Test regardless of the overall Earnings Test sharing calculation. This treatment will not be symmetrical. For example, if the Company's 2004 pension costs were greater than the amount of pension costs allowed in rates from the Settlement, the Company will not recover any of that difference directly from ratepayers. Instead, the pension costs will be pooled with other expenses to perform the Earnings Test calculation.

88. We realize that our modification only addresses possible over-collections for the Electric Department, since there is no Earnings Test mechanism for the Gas and Thermal Departments currently. At the hearing the parties stated that only a portion of 2003 pension costs have been included as part of the adjustment, and that the Company expects pension costs to continue to be higher in 2004 and beyond. If this proves correct, Gas and Thermal ratepayers will not be adversely affected by this provision.

89. However, if pension costs do fall in the future because the stock market recovers, then ratepayers will get 100% of the benefit and the Company will not get a windfall. In order for the Commission to specifically establish the results of this modification to the Settlement, the Company will be required to provide to the Commission the total amount of pension costs allowed for the Electric Department as a result of the Settlement.

90. We modify the Settlement on pension costs as it relates to the Electric Department's Earnings Test, as discussed above.

K. Public Service of Colorado Credit Corporation (PSCCC)

91. As a result of the dissolution of PSCCC, in the settlement, the parties agree to adjustments to the lead/lag factors in the calculation of Cash Working Capital; to capital structure; to the rate base for the coal inventories; and to eliminate the financing charge by PSCCC to Public Service.

92. PSCCC was created to finance certain of Public Service's more liquid assets using mostly short-term debt and a much higher-leveraged capital structure. In 1986, the Commission approved the periodic transfer of certain accounts receivable and coal inventories from Public Service to PSCCC pursuant to an agreement that included a financing charge paid by Public Service to PSCCC. The financing charge was calculated to cover the financing and operating costs of PSCCC, plus a return on equity set at Public Service's authorized rate of return on equity. This agreement was terminated by the Company in the fourth quarter of 2001, and all remaining assets of PSCCC were transferred to Public Service.

93. The Commission accepts the changes (to the rate base for coal inventories, to the lead/lag factors, to the capital structure, and to the elimination of the financing charge) to reflect the dissolution of PSCCC as proposed in the Settlement without modification.

L. Cost Allocation Between Regulated and Non-Regulated Activities:

94. In the Settlement the parties agree to a number of items related to cost allocations for non-regulated activities. First, the parties accept the Company's allocation and assignment of costs as reflected in its rebuttal testimony. Public Service agrees to provide the Governor's Office of Energy Management and Conservation with access to 12 months of historical data for its metered accounts which it does not currently have in electronic format. The parties also agree to engage in good faith workshops on cost allocations and assignments. Within 30 days following the completion of the workshop the Company will file any appropriate modifications to its Cost Allocation Manual (CAM). Finally, in 2005, the Company will file its FDC (Fully Distributed Cost) study and CAM with its annual Earnings Test report for the year 2004.

95. Both Staff and the Business Alliance contended that Public Service's CAM and FDC did not comply with the Commission's cost allocation rules. Staff had further concerns regarding the allocation of three specific items: Customer Accounting Overheads, General and Administrative costs, and Common Plant.

96. Originally the Company allocated $392,089 of Customer Accounting costs to non-regulated operations. In its rebuttal case, it allocated $599,575. As for Administrative and General costs, originally the Company allocated $635,634 to non-regulated operations. In its rebuttal case, it allocated $1,974,564. As for Common Plant, the Company originally allocated no Common Plant to its non-regulated operations. In its rebuttal case, it allocated approximately $1.6 million dollars to non-regulated operations. There was much debate between Staff and the

Company concerning whether costs should be allocated based on revenues or certain operating and maintenance expenses, and whether a two or three factor allocation method should be used for Common Plant.

97. The Business Alliance concerns related to whether specific items were properly handled for cost allocation purposes, for example: 1) whether all appropriate costs (such as postage and envelope stuffing costs) for *Update* were allocated to non-regulated operations; 2) whether other costs such as Computer Information System (CIS) capital costs were being allocated to non-regulated operations; 3) whether the Company has met the standard of the higher of fair market value or costs for employees of its HomeSmart business; and 4) whether, in light of the lack of studies prepared by Public Service, the methodologies used to assign or allocate costs have a logical or observable correlation with cost causation.

98. As the parties' prefiled testimony demonstrates, there is still substantial disagreement and interpretational differences among the parties relating to our cost allocation rules and the actual cost allocations. The Commission finds that the workshops provided for in the Settlement are a good start to try to narrow the differences among the parties.

99. As it relates to the revenue requirement determination, the adoption of the approach in the Company's rebuttal testimony results in over $1.5 million dollars more of costs for Customer Accounting Costs and Administrative and General Costs being allocated to non-regulated operations, as well as $1.6 million dollars of Common Plant in rate base being allocated to those operations.

100. We accept the Settlement's proposals for cost allocation to non-regulated operations without modification.

M. Depreciation

101. The Company currently uses the straight-line method, average life group procedure, remaining life technique to determine depreciation rates for its electric and thermal assets. For this rate case Public Service performed depreciation studies for its electric and thermal assets. In its direct testimony Public Service proposed to continue the use of the straight-line method, but to change to individual unit procedure, remaining life technique to determine depreciation rates for electric and thermal production facilities (i.e., electric generating plants and steam heat facilities).

102. The Company further proposed to continue the use of the straight-line method, but to change to broad group procedure, average service life technique to determine depreciation rates for electric distribution and transmission assets. Public Service also proposed that the straight-line method, vintage group procedure, and whole life technique be used to determine depreciation rates for electric, gas, and thermal common general assets (*e.g.,* office furniture and computers) .

103. On November 22, 2002, Public Service, Staff and the OCC filed the Stipulation and Agreement Pertaining to Depreciation Issues (Depreciation Stipulation). The Depreciation Stipulation addressed disputed issues concerning Public Service's depreciation proposals. The parties agreed to: net salvage and depreciation rates for electric and thermal production assets; average service lives, net salvage and depreciation rates for electric distribution and transmission assets; and average service lives, survivor curves, net salvage and depreciation rates for electric, gas, and thermal common general assets.

104. The Depreciation Stipulation addresses all depreciation issues except for the amortization period for large, company-wide computer software systems; the frequency of

depreciation study reviews; and the ability of Staff to access for review and verification the underlying proprietary software used by the Company to perform the depreciation studies.

105. In the rebuttal testimony, the Company agreed with Staff's recommendation that three-year amortization periods are appropriate for workstation operating systems, and five-year amortization periods are appropriate for intermediate-sized software systems. For gas assets the Company proposed to maintain the depreciation rates that were approved by the Commission in the last gas rate case.

106. In the Settlement, the Company and Staff agree that Public Service shall amortize large base computer software systems over a 10-year life, and shall amortize all software upgrades to those systems such that the upgrades are retired at the end of this same 10-year life.

107. The Staff and the Company agree that every aspect of the Company's plant shall be the subject of at least one depreciation study submitted on or before December 31, 2007. Finally, Staff agrees that, in this proceeding, it will not pursue the issue of the Company's continued use of proprietary software programs for its depreciation studies that Staff asserts its cannot evaluate.

108. We accept the Settlement including the Stipulation and Agreement Pertaining to Depreciation Issues included as Attachment B to the Settlement without modification.

N. Reclassification of Substation Plant and Treatment of Radial Transmission Lines

109. In Public Service's last electric rate case, the Commission accepted the classification of certain high voltage facilities within its substations as distribution plant, and accepted the direct assignment of radial transmission lines for ratemaking purposes. In this case, Public Service proposed to reclassify the high voltage facilities within its substations as

transmission plant, and to eliminate the direct assignment of radial transmission lines by treating all of the radial transmission lines as central transmission plant. Staff disagreed with the Company's proposed reclassification and with the Company's proposal to roll-in its radial transmission lines with its central system transmission plant.

110. For purposes of determining the Phase I revenue requirement in this case, the Company's proposed classification and treatment will be used. The Settlement quantifies the impact of a change in classification should the Commission's Phase II ruling be different than what is allowed under the Settlement. Reclassifying the high voltage facilities in substations from transmission plant back to distribution plant would increase the Company's jurisdictional revenue requirement on a going-forward basis by $505,013; directly assigning radial transmission lines, rather than treating them as central system transmission plant, would increase the Company's jurisdictional revenue requirement on a going-forward basis by $159,070. The combined effect would be an increase of $639,448 in the revenue requirement on a going-forward basis should both reclassifications change from what is allowed under the Settlement.

111. We accept the reclassification of substation plant and treatment of radial transmission lines as proposed in the Settlement without modification.

O. Windsource

112. In the Settlement the parties agree that the Company's base rates will continue to recover the $12.78 per MWh of Energy Costs, and the Company will withdraw its proposed base energy credit. The Company reserves its right in Phase II to propose removal of Energy Costs from base rates, and to recover all of this expense through an adjustment clause. The LAW Fund and other parties reserve the right to respond to the Company's proposal. Further, the Company agrees to work informally with the LAW Fund and other interested parties to evaluate

the costs of service for the Windsource program. The Parties reserve the right to propose a stand-alone rate for Windsource energy in lieu of the rate rider mechanism in the current tariffs.

113. Currently, Windsource customers pay an additional $2.50 per 100 kWh block of Windsource energy. Neither the previous ICA riders, nor the current IAC rider are applied to Windsource energy. The Company implies that the $2.50 Windsource amount does not cover the cost. The LAW Fund contends that the actual costs for Windsource have not been provided by the Company. The agreement to defer decision on this issue to Phase II, and for Public Service to provide Windsource cost information to the LAW Fund and other interested parties, is reasonable.

114. We accept the provision to maintain the $12.78 per MWh in base rates, the withdrawal of the proposed base energy credit, and for the parties to work informally to evaluate Windsource costs. We will require Public Service to provide as a report to the Commission any Windsource cost information that is shared with the parties.

P. Special Amortizations

115. In the Settlement, the parties agree that the Company will file in June 2007 to implement a negative rider to eliminate the collection of the amortizations for the Pawnee 2 Pre-Engineering costs and the Metro Ash Disposal Site.

116. In its prefiled testimony, Staff advocated preface pages to the Company's tariff. A preface page would show the General Rate Schedule Riders or specific amortizations, either in dollar amounts or percentages, which are designed into rates. While traditionally the Commission has not adjusted tariffs for amortizations that expire between rate cases, the parties

have agreed to the elimination of costs for amortization for the Pawnee 2 Pre-Engineering costs and the Metro Ash Disposal Site.

117. We accept the provisions relating to special amortizations proposed in the Settlement without modification.

Q. Ratemaking Principles for Future Earnings Tests:

118. In the Settlement, the parties agreed to certain ratemaking principles for eleven specific areas which are to be used in the 2004 to 2006 Earnings Tests. In addition to these eleven principles, the Proposed Settlement provides that the jurisdictional allocations (used in the revenue requirement determination) and all other cost assignment/allocation methodology in the current CAM will also be used for the 2004 to 2006 Earnings Tests.

119. While it would have been more efficient that all regulatory issues addressed in the Settlement would be the agreed upon principles for future Earning Tests, we understand the parties' inability to agree to such a provision in this case. As the parties pointed out, the Earnings Tests have become “mini” rate cases because new issues arise that have not previously been addressed by the Commission. We believe that the agreement to use the listed regulatory principles in the Settlement in future Earning Tests will make the future Earnings Test more efficient for all involved.

120. We accept the proposal in the Settlement that the listed ratemaking principles (pages 80-82) will apply in future Earnings Tests, except as specifically modified in this Decision.

R. Qualifying Facilities Capacity Cost Adjustment (QFCCA):

121. The Company indicated in Advice Letter 1373 (the Advice Letter that initiated this rate case) that it was eliminating the QFCCA consistent with Decision No. C93-1500. On March 29, 2002, the QFCCA rate was set to 0.00% even though QF capacity costs exceeded those designed into base rates because the deferred account had an over-recovered balance. The Company estimated that the deferred balance would cover the costs through the end of 2002. In the decision granting the QFCCA rate of 0.00%, the Commission required Public Service to propose an appropriate mechanism to return any remaining over-collection to customers once the final deferred balance is known. [16]

122. According to the Settlement, the delay in the establishment of new rates in this case (from January 1, 2003 to July 1, 2003) has caused the QFCCA deferred account to go from an over-recovered to an under-recovered balance. The parties agree that the Company shall be entitled to recover the remaining QFCCA deferred balance if under-recovered, or shall be required to return the remaining QFCCA deferred balance if over-recovered.

123. During the hearing, Company witnesses testified that as part of the negotiation process on the Settlement, the Company agreed to stop accumulating costs in the QFCCA deferred account as of April 1, 2003. This early termination of cost collection was a trade-off for other agreements made in the Settlement. According to the witnesses, the Company would not recover from ratepayers QF capacity costs of approximately $2 million dollars per month for the months of May and June 2003.

[16] *See* Decision C02-0327, Docket No. 02L-156E.

124. The actual amount of under-recovered deferred costs is not known at this time due to the two-month billing cycle process the Company employs. During the hearing, Company witness Keyser indicated that the final under-recovered amount will be known in the Fall of 2003. Under the Settlement, once the deferred balance is known, the Company will file an application proposing the mechanism to be used to recover (or return) the deferred balance over a period of not more than 12 months.

125. We accept the QFCCA portion of the Settlement without modification. We acknowledge that Public Service has already filed Advice Letter 1390 to remove the QFCCA from its tariffs, and that this was allowed to go into effect by operation of law.

S. Phase II Filings:

126. Within the Settlement, the parties agree that the Phase II filings for the Electric and Thermal Departments will be made within 120 days of the final order in this case.

127. The parties also agree that, given that the cost allocations and rate design underlying the Company's current gas rates that were approved by the Commission in July 2000, no Phase II filing is necessary for the Gas Department. The Commission asked Mr. Stoffel during the hearing whether a Phase II proceeding for the Gas Department would help to address any attrition problem. Mr. Stoffel stated that there are other factors such as the construction allowance proceeding and a "normal" winter[17] which would help any attrition problem in the Gas Department. He did say that the Company proposal to move more fixed costs to non-throughput components of the bill in a previous Phase II rate case for the Gas Department was strongly opposed by certain parties.

[17] As measured by heating degree days.

128. We accept without modification the proposals in the Settlement relating to Phase II filings.

IV. OTHER PROVISIONS

129. To the extent other provisions in the Settlement are not specifically discussed in this order, we accept those provisions without modification.

V. ATTACHMENTS

130. Attachment A to this order is the Settlement with the modifications, shown in red-line, made during the hearing.

131. Attachment B to this order is selected financial exhibits to show the various revenue requirement spreadsheets for the Electric, Gas, and Thermal Departments.

VI. ORDER

A. The Commission Orders That:

1. The Commission approves the Settlement with certain modifications as summarized below:

- The ECA formula shall be modified such that the Retail Jurisdictional Allocation Percentage factor (RJA%) is applied to the F (actual cost of fuel), P (actual purchase power costs), and W (actual wheeling costs) terms in the ECA formula.
- Definitions for the terms Forecast Price Volatility Mitigation (FPVM) and Actual Price Volatility Mitigation (APVM) shall be added to the tariff.
- The computation of daily gas index pricing under the ECA formula shall be a weighted average of actual daily purchases instead of a straight average.
- Public Service Company of Colorado shall maintain, for the years 2004 through 2006, records of: actual daily and monthly gas index prices; actual costs for monthly gas purchases, for each month; and actual costs for daily gas purchases, for each day.
- The Settlement is modified, as discussed above, as related to the Electric Department's Earnings Test treatment of pension costs. In part, if the actual annual pension costs for the

2004 to 2006 Earnings Test are less than the costs the Commission has allowed in rates for pension costs in this case, 100% of any excess will be returned to ratepayers regardless of the overall results of the Earnings Test.

- Within ten days of the effective date of this order, Public Service Company of Colorado shall file with the Commission the dollar amount of pension costs for the Electric Department included in the Settlement.

- Public Service Company of Colorado shall provide as a report to the Commission any Windsource cost information that is shared with the parties pursuant to the Settlement.

2. The Joint Motion to Approve Stipulation and Agreement Pertaining to Depreciation Issues filed by Public Service Company of Colorado, Staff of the Public Utilities Commission, and the Office of Consumer Counsel filed on November 22, 2002, is granted.

3. The Stipulation Regarding Corrections to the Direct Case filed by Public Service Company and the Staff of the Public Utilities Commission filed on November 22, 2002, is approved.

4. The Supplemental Stipulation Regarding Corrections to the Direct Case filed by Public Service Company of Colorado on January 23, 2003 is approved.

5. The tariff sheets filed by Public Service Company pursuant to Advice Letter No. 1373--Electric, Advice Letter No. 593--Gas, and Advice Letter No. 80--Steam, all as amended, are permanently suspended.

6. Public Service Company of Colorado shall file, on not less than one day notice to the Commission, tariffs consistent with this Decision. Such tariffs shall be filed to become effective on July 1, 2003.

7. The twenty-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration begins on the first day following the Mailed Date of this decision.

8. This order is effective immediately on its mailed date.

B. ADOPTED IN COMMISSIONERS' DELIBERATION MEETING May 29, 2003

(S E A L)

ATTEST: A TRUE COPY

Bruce N. Smith
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

POLLY PAGE

JIM DYER

Commissioners

CHAIRMAN GREGORY E. SOPKIN
DISSENTING.

VII. CHAIRMAN GREGORY E. SOPKIN CONCURRING, IN PART, AND DISSENTING, IN PART:

1. I concur with the majority opinion on all issues save two: the idea that ratepayers should have to pay amounts in the six figures so that PUC Trial Staff and the Office of Consumer Counsel (OCC) may gain a better understanding of Public Service Company's trading operations; and, second, that an expensive and automatic open-ended procedure on trading operations occurs in 2004 instead of in tandem with an ECA review in 2006. Because a majority of Commissioners allow such a blank check to be written on the backs of ratepayers toward little purpose, and allow an unnecessary mandated proceeding, I dissent from this portion of the opinion.

2. To be sure, the parties in this case have executed a settlement agreement that, overall, benefits the public interest. Public Service Company has agreed to reduce base rates in its

electric, gas, and thermal departments, and the other parties have agreed to an ingenious ECA mechanism and the continuation of trading operations which has shared multiple millions of dollars of positive margins with ratepayers. The agreement reflects compromise over a vast array of technical issues, and I commend the parties for this sizable accomplishment.

3. I do not take lightly the idea of tinkering with a comprehensive settlement agreement with many moving parts. To modify one provision in isolation often upsets the give and take that occurred between the parties. However, it is the Commission's responsibility to analyze each part of the agreement, and I would not be fulfilling that responsibility if I consented to a provision that does not serve the public interest in the name of avoiding a "deal-breaker."[18] This Commission must not be reluctant to modify or delete objectionable terms even if that means parties may withdraw, and a lengthy hearing thereby must be held.

4. The first provision to which I dissent is the one that requires the Commission to hold a hearing in 2004 that would comprehensively examine Public Service Company's electric commodity trading operations. The second objectionable provision requires the Commission to pre-authorize a blank check, subject to a confidential maximum,[19] to pay for an audit of the trading operations and a consultant to advise Staff and OCC concerning the operations, and participate in litigation.

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[18] In particular, I do not agree with the significance attached by the majority to the simple fact that the parties agreed to the trading provisions. There are many instances in which the interests of persons not adequately represented by a party will not be safeguarded in a proposed settlement. That is exactly the case here, since the interests of Trial Staff and OCC were placed above those of ratepayers.

[19] That the pre-authorized amounts are capped gives little comfort, because the caps are high. The majority trusts Staff and OCC not to spend more than necessary, but since the Commission abdicates any responsibility over how those funds are spent, we have no recourse if there is imprudence. No one has adequately explained why the Commission almost never gives up prudence reviews of how ratepayer dollars are spent by utilities, but should do so for Staff and the OCC.

5. Now, had the agreement called for the auditor and consultant to be paid from existing Commission and/or OCC funds, I would not be writing a dissent. OCC has an outside consultant budget of $100,000 per year, and the Commission has $25,000. Not a dime of these funds will be tapped pursuant to the agreement. Instead, ratepayers ultimately will be responsible for paying the full amounts of the audit and the consultant.[20]

6. Perhaps this would be justified if the ratepayers were to benefit or be held from harm in an amount greater than the maximum confidential amount the Commission pre-authorizes be spent by its order today. But that is clearly not the case here. *Under the agreement, net negative gross margins from trading operations are not passed on to ratepayers.* This means, quite simply, that ratepayers cannot be charged for net losses incurred as a result of Public Service Company's trading operations.[21]

7. Add to that the fact that the trading operations have shared tens of millions of dollars of gain over the last few years—and has to date not incurred an aggregated annual loss—and the cause for concern seems less than overwhelming.

8. Staff and OCC profess nervousness because of the dollar value of annual trading, and the fact that bad decisions or rogue traders could theoretically bankrupt the company. There are three responses to this. First, the ultimate safeguard against these horribles is that the Company's

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[20] Under the settlement agreement, the cost of the audit shall be treated as an allowable expense through the 2004 Earnings Test, and the cost of the consultant shall be fully recoverable, dollar for dollar, as a separate expense through the Company's IAC and/or ECA. The cost of the consultant is the majority of expenditures ultimately to be paid for by ratepayers.

[21] The majority compares the funds to be spent on the audit and consultant with the dollars spent on trading, and indicates that the funds are small by comparison and "monies well-spent." With respect, this is not the proper comparison, because the millions of dollars spent on trading cannot be shared with ratepayers, even if the expenditure resulted in a net margin loss. Rather, the proper comparison is between the costs inflicted and benefits conferred on ratepayers. *See* Commission discussion of the ECA proposal, *supra*. Nowhere does the majority apply this fundamental regulatory principle to the six figure checks about to be written by ratepayers.

shareholders would suffer massive losses if the trading operations were managed badly. Second, the idea that government can prevent all things bad because it can design mechanisms to prevent losses better than those who run and understand the system—and who have much more of a stake in avoiding those losses—is pure folly. Third, if trading operations are such an important concern, why is it that the Commission has allowed electric commodity trading, including Prop and Gen Book trading, to occur for the last few years? (It is facile to say that trading was permitted via prior settlement or ALJ decision when the Commission at any time can bring a proceeding on its own motion, and Staff can propose a show cause proceeding.)

9. What we are left with is a desire for Staff and OCC to understand the trading operations better, but no clear benefit to ratepayers from that understanding. It is in essence a six-figure educational seminar.[22] Again, I would have no objection to this if OCC and Staff tapped their own existing budgets for this purpose. That those budgets have or may be tapped for another purpose is no excuse for shifting the onus onto ratepayers.

10. Recognizing that Staff and OCC may not have agreed to trading without the ability to analyze and seek change to the program, what I proposed at the deliberations meeting was actually quite modest. I did not propose elimination of the audit or consultant. Rather, I expressed that the Commission should have more control over the dollars spent on the audit and consultant by requiring the parties to seek approval of the scope and bidding procedure, then seek approval of which bid would be accepted. Also, I allowed for the possibility that part of the cost be funded through OCC's and Staff's consultant budgets.

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[22] The majority opinion argues that the purpose of the audit and consultant is more than education because the monies will help Trial Staff and OCC in their preparation and participation in the mandated formal 2004 proceeding. Since I dissent from the mandated formal 2004 proceeding as unnecessary and an additional waste of ratepayer dollars (unless it is an efficient and focused proceeding initiated by a party), this argument is mere bootstrapping.

11. The reason why this proposal was rejected—as expressed during deliberations—was that the Commission would somehow "prejudice" its independence by exercising such control over the auditor and consultant. I am frankly flabbergasted by this reasoning. The Commission under my proposal would preapprove the scope and dollars spent on the auditor and consultant, which necessarily entails deciding which bid to accept. Choosing Company "X" to conduct an audit or be a consultant to trial Staff does not mean that the Commission has abandoned its objectivity as to whatever recommendations are made by "X"—and I take as an insult any suggestion that the Commission is so easily biased.

12. The logical conclusion of this reasoning is that the Commission should abandon its responsibility to oversee how ratepayer funds are spent lest there be any suggestion it is exercising too much control. I fail to see why it is "inadvisable" for the Commission to exercise its traditional prudency review function with respect to ratepayer dollars. I reject this "no strings attached" blank check mindset.

13. The second provision about which I dissent is the automatic open-ended proceeding in 2004. Here again, my proposal to my fellow Commissioners was a modest procedural change. Instead of an automatic, open-ended proceeding in 2004 to examine trading operations, I suggested that Staff, OCC, or Public Service Company could make a filing at any time to suggest changes to the program. The filing party would have the burden of going forward, but Public Service Company would retain the burden of persuasion.[23] The trading rules and limitations

[23] It is true that the Company proposed that trading be changed to allow sharing of negative margins in their direct testimony, but the Company backed off of that proposal in its rebuttal testimony. In essence, Public Service proposed to continue the status quo, which ordinarily does not result in assuming the burden of persuasion. Nevertheless, my proposal would have Public Service Company bear the burden of persuasion in any proceeding brought by any party regarding trading operations. In my view, such a proposal does not change any party's existing legal rights.

in place as a result of the settlement agreement and the 2000 Trading Stipulation would remain in place until the end of 2006, and trading would be examined alongside the ECA mechanism in 2006 for use starting in 2007. I made these suggestions for several reasons.

14. First, given that aggregated negative trading margins are not shared with ratepayers, I believe that the Business Rules and limitations governing trading—reached in the 2000 Trading Stipulation and the instant settlement agreement—are more than sufficient in protecting ratepayers from whatever dangers are presented by the operations. It is inaccurate to say that there are no safeguards in place for trading (or it would be given "free reign") under my proposal. Pages 69 through 74 of the settlement agreement, as well as Attachment J, contain a plethora of strictures too numerous to list here.

15. Second, trading should be examined in 2006 alongside the ECA mechanism because the ECA expires at the end of 2006. Public Service Company testified adamantly that the two programs have a symbiotic relationship. Indeed, Public Service Company would not have proposed the ECA without the ability to continue trading. Demonstrating this interrelationship between ECA and trading is a settlement agreement provision that allows Public Service Company the right to revert to a 100% pass-through mechanism in lieu of the ECA if the Commission required any changes to the trading program resulting from the automatic 2004 docket.[24] Therefore, for policy reasons and efficiency, trading and the ECA should be examined in tandem in 2006, rather than trading in 2004 and ECA in 2006.

16. Third, I believe that my proposal that parties have the burden of going forward and defining what changes they seek to trading in advance of any hearing will both make for a better

[24] Since I am convinced the ECA benefits the public interest, I do not like the idea of an automatic 2004 open-ended hearing on trading, including whatever "wish-lists" OCC and Staff may have, that could jeopardize the continued existence of the ECA.

proceeding and lessen the attendant costs of that proceeding. Most notably, the cost of a consultant advising Staff and OCC during litigation would presumably be less if the proceeding is limited and well defined. Of course, if no party files to change trading, the cost of a consultant would be that much less.

17. In sum, my proposal involved more Commission oversight into the cost and scope of an audit and consultant, and a different procedural approach to how changes to trading might be litigated. That this proposal was rejected reflects, I fear, an overriding timidity on the part of the Commission to make changes, however modest, to a settlement agreement.[25] It is the Commission, not the parties, that is charged with the duty to protect the public interest. In placing the entire burden of Staff and OCC's desire to better understand trading operations on the backs of ratepayers, with no commensurate benefit to ratepayers, the public interest was not upheld by that portion of the settlement.

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

CHAIRMAN GREGORY E. SOPKIN

Commissioner

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[25] I am aware that the Commission imposed a few changes to the settlement agreement, however all of those changes save one involve record keeping requirements, or changes that the parties agreed to at the settlement hearing. None of the changes involve bold Commission action to protect the public interest.

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

RE: THE INVESTIGATION AND SUSPENSION	)	
OF TARIFF SHEETS FILED BY PUBLIC SERVICE	)	
COMPANY OF COLORADO ADVICE LETTER NO.	)	DOCKET NO. 02S – 315 EG
1373 – ELECTRIC, ADVICE LETTER NO. 593 –	)	
GAS AND ADVICE LETTER NO. 80 – STEAM)		

SETTLEMENT AGREEMENT

April 4, 2003

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

RE: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO ADVICE LETTER NO. 1373 – ELECTRIC, ADVICE LETTER NO. 593 – GAS AND ADVICE LETTER NO. 80 – STEAM	DOCKET NO. 02S – 315 EG

SETTLEMENT AGREEMENT

Public Service Company of Colorado, the Staff of the Colorado Public Utilities Commission, the Office of Consumer Counsel, the Colorado Governor's Office of Energy Management and Conservation, the City and County of Denver, the Colorado Energy Consumers, The Kroger Company, the Federal Executive Agencies, the Land and Water Fund of the Rockies, the Colorado Energy Assistance Foundation, and the Colorado Business Alliance for Cooperative Utility Practices (collectively, the "Parties") hereby enter into this Settlement Agreement.

INTRODUCTION[1]

On May 31, 2002, Public Service Company of Colorado ("Public Service" or the "Company") filed Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, and Advice Letter No. 80 – Steam with the Colorado Public Utilities Commission ("Commission" or "CPUC"), tendering revised tariff sheets in which the Company proposed comprehensive rate and tariff changes. The Company also filed Direct Testimony and Exhibits in support of the proposed rate and tariff changes. The

[1] Attachment A is a spreadsheet showing the adjustments to the Company's original case as a result of the corrections and stipulations identified in this Settlement Agreement.

Company requested the following changes in rate revenue (as summarized in Table No. FCS-1, filed with the Direct Testimony of Fredric C. Stoffel):

Table No. FCS-1
Summary Chart of 2002 Rate Case Impact

	A	B	C	D	E	F
Department	Base Rate Revenue (No Riders)	Revenue From Existing Riders	Proposed Revenue Increases Compared To Base Revenue	Net Change to Annual Revenue (C-B)	Net Change Annual Percent (D/A)	Percent Rider (C/A)
Gas	$ 285,411,606	$ 15,483,440	$ 2,581,416	$(12,902,024)	-4.52%	0.90%
Electric						
Base	$ 1,427,853,011	$(32,678,899)	$ 74,404,991	$107,083,890	7.50%	5.21%
ECA	$ -	$ -	$ 113,003,685	$113,003,685	7.91%	7.91%
	$ 1,427,853,011	$(32,678,899)	$ 187,408,676	$220,087,575	15.41%	
Steam	$ 7,524,464	$ 906,698	$ 1,360,827	$ 454,129	6.04%	18.09%
Total	$ 1,720,789,081	$(16,288,761)	$ 191,350,919	$207,639,680	12.07%	

As Column C of the table above shows, in its direct case Public Service proposed revenue increases as compared to base rate revenue as follows: Gas $2,581,416; Electric $74,404,991; and Steam $1,360,827. In its Direct Testimony, the Company proposed an Electric Commodity Adjustment ("ECA") that would recover $113,003,685 in 2003.[2]

On August 7, 2002, the Company filed Supplemental Direct Testimony, Corrected Testimony and Revised Exhibits, primarily as a result of the Commission-approved restructuring of two power purchase agreements between the Company and the Thermo companies. This filing reduced the Company's requested increases in base rate revenue for the electric and gas departments but increased projected ECA revenue. The Company's Supplemental Direct filing requested the following revenue increases to base rate revenue: Gas $2,249,166; Electric $60,257,656; and Steam

[2] As explained *infra* at Section XII.A., the Company's proposed ECA has been replaced by the Interim Adjustment Clause ("IAC") for 2003.

$1,360,827. The Company projected 2003 ECA revenue to be $127,256,402 (Exhibit No. RND-4 (Revised 8/07/02)).

Contemporaneous with the preparation of Answer Testimony and Exhibits, the Staff and the OCC engaged in negotiations with the Company concerning depreciation issues and corrections to the Company's filed position. These negotiations resulted in the execution of two stipulations that were filed on November 22, 2002.

The first Stipulation and Agreement Regarding Depreciation Issues ("Depreciation Stipulation," attached as Attachment B) was entered into between Public Service, Staff and the OCC and dealt with the details of calculating the Company's depreciation expense. The effect of the Depreciation Stipulation changed the Company's requests for base rate revenue increases by the following amounts: Gas $609,935; Electric ($29,266,852)[3]; and Steam ($4,658). The Depreciation Stipulation did not affect the projected 2003 ECA.

The second Stipulation Regarding Corrections to the Direct Case Filed by Public Service Company of Colorado ("Stipulation on Corrections," attached as Attachment C) was entered into between Public Service and Staff and reflected an agreement on numerous changes and acknowledged errors in the Company's Direct and Supplemental Direct Testimony and Exhibits. The seven issues addressed in the Stipulation on Corrections were primarily identified through Staff's audit of the Company's Direct Case. The corrections changed the Company's revenue requirement request with respect to: (1) the cash working capital allowance resulting from a revision of certain lead/lag factors in the Company's lead/lag study; (2) the proper accounting of

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[3] Numbers in brackets denote negative numbers or decreases in expense.

Other Comprehensive Income in the common equity portion of the capital structure; (3) the *pro forma* adjustment to firm wheeling service for a reclassification of the revenue credit for autotransformer capacity charges; (4) the rent expense to reflect the correct utility allocators; 5) the calculation of the thermal department cash working capital; (6) the proper elimination of the amortization of gas rate case expenses; and (7) the correct allocation of common deferred tax expenses.

The Stipulation on Corrections contemplated certain further corrections to calculations, which corrections were agreed to between Staff and the Company and set forth in a Supplemental Stipulation Regarding Corrections to the Direct Case Filed By Public Service Company of Colorado ("Supplemental Stipulation Regarding Corrections," attached as Attachment D) dated January 23, 2003. The three issues addressed in the Supplemental Stipulation Regarding Corrections reflect additional corrections to the Company's revenue requirement request with respect to: (1) the correct labor overheads and Administrative and General ("A&G") Engineering and Supervision overheads used to develop the loaded labor rates for the Company's proposed non-gratuitous charges; (2) the income tax expense to remove the amount of Allowance for Funds Used During Construction ("AFUDC") multiplied by the composite tax rate; and (3) reallocation of certain bad debt expenses to the Federal Energy Regulatory Commission ("FERC") jurisdiction.

The changes reflected in these three Stipulations are summarized in spreadsheet form in Attachment A to this Settlement Agreement. Incorporating the cumulative result of the three Stipulations, the Company's direct case reflected increases (or decreases) to base rate revenue in the following amounts: Gas ($6,891,919); Electric $18,945,647; and Steam $1,144,393.

On November 22, 2002, many parties filed Answer Testimony and Exhibits objecting to aspects of the Company's requested rate changes. Some parties objected primarily to the Company's proposed ECA and raised issues with respect to the Company's electric trading operation.[4] Other parties concentrated their objections on issues that were reflected in the changes that the Company proposed to Base Rate Revenue Requirements for the electric, gas and thermal departments.

Staff and the OCC each summarized their Answer testimonies using tables similar to the Company's Table FCS-1. Staff's case in Answer Testimony is summarized by the following table presented in the updated Answer Testimony of Dr. Gary E. Schmitz[5]:

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4 Among the parties filing Answer Testimony addressing the ECA were CF&I Steel, LLP ("CF&I") and Climax Molybdenum Company ("Climax"). CF&I and Climax take no position with respect to the Settlement Agreement.

5 Dr. Schmitz filed corrections to his Answer Testimony on February 18, 2003, to reflect the Company's direct case revenue change request as of January 23, 2003. Table GES-1 presented in this Settlement Agreement is the corrected Table GES-1.

Table No. GES-1

Summary Chart of Staff View of PSCo's 2002 Rate Case Impact[6]

	A	B	C	D	E	F
Department	Pro Forma 2001 Base Rate Revenues	Revenue from Existing Riders	Proposed Revenue Increases Compared to Base Revenue	Net Change to Annual Revenue	Net Change Annual Percent	Percent Rider
				(C-B)	(D/A)	(C/A)
Gas	$ 290,226,216	$ 15,483,440	$ (30,056,558)	$ (45,539,998)	-15.6912%	-10.3563%
Electric						
Base	$ 1,427,501,814	$ (32,678,899)	$ (51,024,042)	$ (18,345,143)	-1.2851%	-3.5744%
ECA			$ 111,738,600	$ 111,738,600	7.83%	7.8276%
SubTotal	$ 1,427,501,814	$ (32,678,899)	$ 60,714,558	$ 93,393,457	6.5424%	
Thermal	$ 7,524,464	$ 906,698	$ 771,263	$ (135,435)	-1.7999%	10.2501%
Total	$ 1,725,252,494	$ (16,288,761)	$ 31,429,263	$ 47,718,024	2.7659%	

The OCC's case is summarized in the Answer Testimony of Kenneth V. Reif[7]:

Department	Base Rate Revenue (No Riders)	Revenue From Existing Riders	Proposed Revenue Increases Compared Base Revenue	Net Change To Annual Revenue	Net Change Annual Percent	Proposed Percent Rider
Gas	$285,411,606	$15,483,440	($16,666,246)	($32,149,686)	-11.26%	-5.84%
Electric						
Base	$1,427,853,011	($32,678,899)	($47,974,605)	($15,295,706)	-1.07%	-3.40%
ECA	$0	$0	$113,003,685	$113,003,685	7.91%	7.91%
	$1,427,853,011	($32,678,899)	$65,029,080	$97,707,979	6.84%	
PSCo Total	$1,713,264,617	($17,195,459)	$48,362,834	$65,558,293	3.83%	

6 The table included in the updated Answer Testimony of Dr. Schmitz did not reflect the impact of expiration of a portion of the negative electric base rate rider on August 1, 2002. After August 1, 2002, revenues from the existing base rate electric rider changed from ($32,678,899) to ($20,852,893).

7 The table included in the Answer Testimony of Kenneth V. Reif did not reflect the corrections agreed to in the Stipulation on Corrections or the Supplemental Stipulation Regarding Corrections, nor did it reflect the expiration of a portion of the negative electric base rate rider on August 1, 2002.

On January 24, 2003, the Company filed its Rebuttal Testimony and Exhibits. In its Rebuttal Testimony, the Company accepted some of the issues or positions raised in the Answer Testimony and defended the Company's position against other issues. After the filing of the Company's Rebuttal Case and the three stipulations discussed above, the Company's requested changes to base rate revenue were as follows: Gas ($6,387,191); Electric $16,193,383; and Steam $1,089,092.

In its Rebuttal Case filed on January 24, 2003, the Company updated its projected 2003 ECA to reflect an updated sales forecast, an updated jurisdictional split and an updated gas commodity cost forecast. Based upon this updated information, the Company projected the 2003 ECA to be $152,448,122.[8] However, a portion of the 2003 ECA revenue is already being collected through the Interim Adjustment Clause ("IAC") that went into effect January 1, 2003 pursuant to Commission Decision No. C02-609 (May 24, 2002) in Docket No. 02A-158E. The Company projected that the revenues that would be collected under its proposed 2003 ECA would exceed the revenue currently collected under the IAC by $29,772,639 (Exhibit No. RND-4 (Revised 1/24/03), line 17).

On February 12, 2003, the Company filed Supplemental Rebuttal Testimony and Exhibits to correct errors found in its Rebuttal Testimony and Exhibits, to concede the issue of the production capacity adjustment related to Windsource which had been opposed by the Staff and the Land and Water Fund of the Rockies ("LAW Fund"), to allocate an appropriate share of plant associated with the Company's Customer

[8] Although not set forth on Exhibit No. RND-4, page 1 (Revised 1/24/03), this updated ECA projection may be derived by netting the ECA Factors on line 9 and the ECA Credits on line 10, and then multiplying the net amount by the jurisdictional sales by delivery level on line 14.

Information System ("CIS") to its non-regulated business activities, and to correct the interest expense on customer deposits for the gas department. After these filings, the Company's proposed case stood as follows: Gas ($5,984,401); Electric $14,503,382; and Steam $1,089,084.[9] The Company further updated its projections of 2003 ECA revenue, projecting the 2003 ECA revenue to be $186,473,283. The Company projected that the revenue it would collect under its proposed 2003 ECA would exceed the revenue currently collected under the IAC by $63,899,985. (Exhibit No. RND-4 (Revised 2/12/03)). These are the requests for base rate revenue changes that the Company would have sought had this matter proceeded to a fully contested hearing.

Subsequent to the filing of its Rebuttal testimony, the Company has been in settlement discussions with opposing parties regarding all issues. These settlement discussions have been successful. The Parties have reached compromise and settlement on all contested issues in this case. The resolutions of all contested issues are set forth in this Settlement Agreement. For the purpose of determining Phase I revenue requirements~~ and for purposes of Earnings Test filings until the next general rate case~~, to the extent an issue is not specifically addressed in this Settlement Agreement or detailed in the supporting cost of service in Attachment E, the Parties have accepted the Company's last filed position on that issue.

As a result of this Settlement Agreement, the Parties have agreed to the following changes to the base rate revenues of the Company: Gas ($17,843,528); Electric ($21,082,702); and Steam $880,653. When the revenues from expiring rate

[9] These amounts are set forth in the Supplemental Rebuttal Testimony (2/12/03) of Timothy L. Willemsen at page 4. They differ from those set forth in Table FCS-1 to the Supplemental Rebuttal Testimony (2/12/03) of Fredric C. Stoffel at page 2 because of the exclusion of Street Light Maintenance revenue.

riders are taken into account, the net result of this settlement on base rate revenue is as follows: Gas ($33,326,968); Electric ($229,809)[10]; and Steam ($26,045) (compare to Column D of the above summary charts). The following table sets forth the results of this Settlement Agreement:

	A	B	C	D	E	F
Department	Base Rate Revenue (No Riders)	Revenue From Riders as of May, 2003	Proposed Revenue Increases Compared To Base Revenue	Net Change to Annual Revenue (C-B)	Net Change Annual Percent (D/A)	Percent Rider (C/A)
Gas	$ 288,019,186	$ 15,483,440	$ (17,843,528)	$ (33,326,968)	-11.57%	(1)
Electric						
Base	$ 1,427,853,011	$ (20,852,893)	$ (21,082,702)	$ (229,809)	-0.02%	(1)
IAC	$ -	$ -	$ 215,508,934	$ 215,508,934	15.09%	
	$ 1,427,853,011	$ (20,852,893)	$ 194,426,232	$ 215,279,125	15.08%	
Steam	$ 7,524,464	$ 906,698	$ 880,653	$ (26,045)	-0.35%	(1)
Total	$ 1,723,396,661	$ (4,462,755)	$ 177,463,357	$ 181,926,112	10.56%	

'(1) See Attachment E, Schedule 2 for the rider calculations.

The Parties have also agreed to the mechanism that the Company shall use for recovery of fuel, purchased energy and purchased wheeling expense incurred by the electric department beginning January 1, 2003[11] and the sharing of margins from the Company's trading operations.

REVENUE REQUIREMENTS MODEL AND PHASE II

As a part of this Settlement Agreement, the Parties have agreed that the Company shall modify its revenue requirements model to reflect the jurisdictional cost of service, without functionalization, and including jurisdictional revenues, expenses and

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10 The net change to the electric base rate revenue does not reflect the full impact of the ($32,678,899) rider identified in Column B of the above tables because a portion of that negative rider expired on August 1, 2002. Instead, the net change to the electric base rate revenue of ($229,809) reflects a rider of only ($20,852,893).

11 Pursuant to the Settlement Agreement approved by Commission Decision No. C02-609 in Docket No. 02A-158E, the Company's fuel, purchased energy and purchased wheeling expenses incurred by the electric department beginning January 1, 2003, which are currently recovered through the Interim Adjustment Clause or IAC is to be recalculated and trued up to the recovery mechanism approved by the Commission in this general rate case.

rate base. The revised cost of service presentation is similar to the Company's cost of service presentation contained in its Earnings Test Reports. A summary of the Company's CPUC jurisdictional cost of service incorporating the results of this Settlement Agreement, including an income statement and rate base, the percent rider calculations, and the calculation of cash working capital, is attached to this Settlement Agreement as Attachment E. An electronic version of the cost of service model is filed contemporaneously with the filing of this Settlement Agreement.

As required by the Stipulation and Agreement, dated January 31, 2000, entered in Docket No. 99A-377EG and approved by the Commission in Decision No. C00-393 (the "Merger Stipulation"), Public Service will file an electric Phase II (cost allocation/rate design) case for its electric department within 120 days following the entry of the final order in this docket. In addition to the electric Phase II, Public Service plans to file a Phase II for its thermal department at that time. Given that the cost allocations and rate design underlying Public Service's current gas rates were approved by the Commission in July 2000 in Docket No. 99S-609G, the Parties agree that Public Service should not be required to file a Phase II case for its gas department until its next comprehensive gas base rate change.

The Company's revised cost of service model establishes the Company's CPUC jurisdictional cost of service and the resulting total jurisdictional revenue requirements for the Company's gas, electric and thermal departments. With the exception of certain adjustments to jurisdictional revenue requirements that are expressly permitted under Section VII of this Settlement Agreement (Reclassification of Substation Plant and Treatment of Radial Transmission Lines) concerning a change in the classification of high voltage facilities within distribution substations from transmission to distribution and/or the direct assignment of radial transmission facilities during Phase II, the Parties agree that the total jurisdictional revenue requirement amounts established by this Settlement Agreement shall be the revenue requirement amounts intended to be collected as a result of the allocation of costs among rate classes in Phase II. All Parties have reserved all rights to advocate any position regarding the design of rates and the means of allocating of costs among the customer classes for purposes of Phase II of the Company's rate proceeding.

EARNINGS TEST AND EARNINGS SHARING

It is the Parties' intent that, consistent with the Merger Stipulation, the outcome of this proceeding shall establish the ratemaking principles to be applied in the electric Earnings Tests for calendar years 2004, 2005 and 2006. Except as expressly modified by this Settlement Agreement, the Earnings Test and sharing mechanism described in the Merger Stipulation shall continue in effect and all Parties retain all rights with respect to the Earnings Test and sharing mechanism that are afforded under the Merger Stipulation. Section XVI *infra* identifies the revised sharing percentages and the ratemaking principles resulting from this Settlement Agreement that the Parties agree shall be applied in the 2004, 2005 and 2006 Earnings Tests unless altered by further order of the Commission entered in a subsequent rate case, or in an Earnings Test proceeding based on the Commission's finding of a "material change of circumstances" warranting such change as set forth at page 12 of the Merger Stipulation.

TERM OF THE SETTLEMENT AGREEMENT

This Settlement Agreement shall take effect upon its approval by the Commission. Nothing in this Settlement Agreement shall be construed to prevent the Company from filing a general rate case for its electric, gas or steam operations at any time. Nothing in this Settlement Agreement shall be construed to limit the Company from applying to the Commission for adjustment clauses or for any other change to the Company’s electric, gas and steam rates. Nothing in this Settlement Agreement shall be construed to prevent the Staff of the Commission (by seeking an Order to Show Cause) or any other party (by filing a Complaint) from seeking review by the Commission of the justness and reasonableness of the Company’s electric, gas or steam rates.

Where reference is made in the Settlement Agreement to provisions that apply for a period of time (for example the references to the 2004-2006 Energy Cost Adjustment), all such time period provisions of this Settlement Agreement may be modified by a subsequent filing with the Commission. Where references are made to settled principles for purposes of Earnings Tests, these settled principles shall only be deemed settled for Earnings Tests that apply to periods before the conclusion of a subsequent general rate case proceeding, whether initiated by the Company or by any other party.

PUBLIC INTEREST

The Parties to this Settlement Agreement state that reaching agreement as set forth herein by means of a negotiated settlement rather than through a formal adversarial process is in the public interest and, therefore, the compromises and settlements reflected in this Settlement Agreement are in the public interest. The Parties further state that approval and implementation of the compromises and settlements reflected in this Settlement Agreement constitute a just and reasonable resolution of this proceeding.

EXECUTIVE SUMMARY OF SETTLEMENT

Cost of Service

Public Service's original filing on May 31, 2002 requested the following revenue increases: $2.58 million for gas, $74.40 million for electric, and $1.36 million for thermal. These were increases above the levels included in the Company's base rates at the time of the filing and therefore did not reflect the revenue impact of the existing negative electric revenue riders associated with the mergers or the positive gas and thermal energy revenue riders from the Company's prior rate cases. On the electric side, the Company was also showing an increase in the ECA of $113 million due to higher purchased fuel and energy costs.

The Company's final rebuttal case, filed February 12, 2003, proposed a $5.98 million decrease for gas, a $14.50 million increase for electric operations, and a $1.09 million increase for thermal. The rebuttal case filing incorporated the correction of certain errors to the original filing, the restructured cost of a purchased power agreement (Thermo), reductions associated with the settlement of depreciation rates, and certain allocation issues.

This settlement proposes a cost of service decrease for gas operations of $17.84 million, a decrease of $21.08 million for electric operations, and a $0.88 million increase for thermal operations. These amounts are measured against the Company's original filing. After taking into account the elimination of existing riders and the current IAC, the electric base rates will decrease $229,809, and the IAC will recover an additional $93.1 million. The gas base rates will decrease $33.3 million and the thermal energy base rates will decrease $26,045.

Taken as a whole, typical residential natural gas customers will see a decrease of $1.74 on monthly bills, while typical small business natural gas customers will see a decrease of $5.55 a month. Typical residential electric customers will see an increase of $4.34 on their monthly bills, while typical small business electric customers will see an increase of $8.80 per month.[12]

Key aspects of the cost of service settlement are:

- Depreciation expense decreased from current levels for the electric and thermal departments, and increased from current levels for the gas department.
- Agreement to a 10.75% return on equity for electric and 11.0% for gas and thermal.
- Use of average rate base instead of year-end rate base.
- Amortization of the full Plant Held for Future Use balance of the Pawnee 2 Pre-engineering costs over four years.
- Agreement that the revenue requirement allowance for gas stored underground inventory will be based on test year period volumes using a three-year average price based on the Last In, First Out method (“LIFO”).

[12] These customer impacts are calculated as of July 1, 2003. Attachment L hereto sets forth the customer impacts of the rate changes that would result from this Settlement Agreement if approved by the Commission.

- Inclusion of actual 2002 property and casualty insurance expense levels.
- Adjustment of purchased capacity costs to reflect 2002 actual payments.
- Elimination of $2.74 million of A&G and non-production Operations and Maintenance ("O&M") expense associated with the Company's electric trading operations from the CPUC jurisdictional cost of service.
- Inclusion of oil and gas royalties and related administrative expenses in the determination of retail revenue requirements.
- Recognition of a portion of the anticipated increase in pension costs in 2003.
- Acceptance of the Company's *pro forma* adjustment relating to the discontinuation of operations at PS Colorado Credit Corporation ("PSCCC").
- Agreement to accept the Company's allocation and assignment of costs to its non-regulated business activities as reflected in its Rebuttal case; and that the Parties will engage in workshops to evaluate the form of the Company's Fully Distributed Cost ("FDC") study and endeavor to arrive at fair and reasonable assignments and allocations of costs to and between Public Service's regulated and non-regulated business activities.
- The Company agrees to phase out the use of FERC allocations in its JD Edwards general ledger accounting system as defined in the Company's 2002 Cost Allocation Manual.
- Agreement, pending the conclusion of the Phase II rate case, that the Company's base rates shall continue to recover energy costs in the

amount of $12.78 per MWh; the Company's fuel clause (first the IAC and then the ECA) shall recover Energy Costs in excess of $12.78 per MWh; and the Company shall withdraw its proposed Base Energy Credit.

- The Company agrees to file by June 1, 2007 to reduce base rates to eliminate the amortizations for the Pawnee 2 Pre-engineering costs and the Metro Ash Disposal Site option.

Electric Commodity Adjustment & Trading

Key aspects of the electric commodity adjustment (ECA) and trading issues are:

- 100% pass-through of CPUC fuel and purchased energy expense during 2003. Change existing rates using 2003 forecast beginning July 1, 2003. This would increase electric rates by $93.1 million above the amount being collected through the Interim Adjustment Clause that became effective January 1, 2003.
- Implementation of a new ECA based on the Company's formula on January 1, 2004. The formula will use as a test year the 12-month period ending August 31, 2003. The new ECA will remain in effect through calendar year 2006.
- The costs recovered through the ECA will be bounded as follows: The first $15 million above and $15 million below the ECA base is shared 50% to retail customers and 50% to shareholders. The next $15 million above and $15 million below is shared 75% to retail customers and 25% to shareholders. Beyond $30 million, 100% of the CPUC jurisdictional cost increases or decreases will be passed on to retail customers.

- The Company will file an application on April 1, 2006 addressing the regulatory treatment of fuel and purchased energy expenses beyond December 31, 2006.
- The 100% pass-through IAC that is in effect in 2003 and the incentive ECA rate that is in effect in each year generally will be modified annually, but shall be subject to more frequent modification within certain constraints.
- Within certain limits, the Company will be permitted to sell gas which was purchased for electric system operation, but which is not needed for certain months or certain days.
- Margin sharing shall be calculated separately for each of the Generation Book margins and Proprietary Book margins.[13] Within each book, the CPUC jurisdictional Gross Margins shall be aggregated annually. If these aggregated margins from either book are negative, the negative margin shall not be passed on to retail customers.

[13] *See* discussion of Trading, *infra* at Section XIII, in which further definition is supplied concerning the Company's Generation and Proprietary Book trading operations.

- For 2003 and 2004, positive Gross Margins shall be treated as follows:
  - Generation Book: customers get the first $1.74 million. The Company will retain the next $1.74 million. The remainder is shared on a 60%/40% (retail customer/shareholder) basis.
  - Proprietary Book: the Company receives the first $1 million and the remainder is shared on a 40%/60% (retail customer/shareholder) basis.
- The definition of short-term wholesale sales shall be modified to include sales of up to two years in term length.
- Agreement to use the Company's current Business Rules as the basis of the operation of trading and sharing during 2003 and 2004. If the Company operates by these rules for transactions made prior to January 1, 2005, its actions shall be deemed prudent.
- The Company shall arrange for a procedures audit of its Generation and Proprietary book trading operations. The audit shall be conducted and completed by October 1, 2003. The cost of the audit shall be deemed an allowable expense in the 2004 Earnings Test.
- In January 2004, the Company shall file an application for Commission review of its trading operation, including its Business Rules and cost allocation procedures related to costing short-term wholesale sales. The expectation would be that this new case would be completed by October 15, 2004. Any change in cost allocation procedures or in the Business Rules would apply prospectively only beginning January 1, 2005.

- Within ~~two~~ one months of the effective date of this Settlement Agreement, the Company shall provide funds to hire a consultant selected by the trial Staff and OCC to provide Staff and the OCC with technical advice and consulting regarding prospective changes that should be made, if any, to the Company's trading activities. The Company's expenditures for this consultant shall be recoverable through the 2003 or 2004 fuel and purchased energy adjustment clause.

SETTLEMENT OF DISPUTED ISSUES

I. Rate Of Return and Capital Structure

A. Rate of Return on Equity

Background. Five witnesses presented testimony regarding the proper rate of return on equity ("ROE"). Their recommendations are summarized in the table below:

Witness	Recommendation
Dr. Olson (PSCo)	12% (electric) 12.25% (gas and thermal)
Mr. Trogonoski (Staff)	10.75%
Mr. Copeland (OCC)	9.90%
Mr. Kahal (FEA)	10.70% (electric) 11% (gas)
Mr. Gorman (CEC)	10.50%

All of the witnesses who addressed the issue of ROE derived their estimates using a Discounted Cash Flow ("DCF") approach, supplemented, in some cases, by analyses using the Capital Asset Pricing Model, risk premium approach, or Dividend Discount Model. The pre-filed testimony of these witnesses reflects a variety of opinions regarding the selection of the appropriate group of comparable companies to use in the DCF analysis, and the determination of dividend yields and growth rates. In addition, Staff witness Mr. Trogonoski stated his opinion that the Commission should not allow the Company to earn a higher rate of return because of Xcel Energy's decision to expand into unregulated businesses, such as NRG Energy, Inc. ("NRG"). The Company disputes that Xcel Energy's participation in unregulated businesses, including NRG, during the test year should have any impact on the determination of its rate of return on equity. As Dr. Olson explained in his Direct Testimony, he purposefully excluded consideration of Xcel Energy and other large diversified holding companies from his DCF analysis in order to determine an appropriate return on equity unaffected by the risk associated with the merchant generation business.

Resolution. For purposes of settlement, the Parties agree that a fair and reasonable ROE for the electric utility is 10.75% and for the gas and thermal utilities is 11.00%.

B. Cost of Debt

Background. Staff witness, Mr. Trogonoski, recommended reducing the Company's embedded cost of debt from 7.31% to 7.20% to reflect an assumed refinancing of a $147,840,000 debt issue during 2002 at a lower coupon rate than that included in the Company's embedded cost of debt. As grounds for imputing to the Company a lower cost of debt than its embedded cost, Mr. Trogonoski suggested that, but for the fact that the Company's credit rating was under review by rating agencies, the Company would have refinanced this 8.75% debt at 7.63% during the summer of 2002. In her Rebuttal Testimony, the Company's witness, Ms. Schell, refuted Mr.

Trogonoski's assertion that the Company would have refinanced this high coupon rate debt during 2002 had its credit rating been higher. Ms. Schell contended that if all costs associated with such a refinancing were taken into consideration, refinancing the $147,840,000 debt issue at 7.63% would have resulted in an increase to the Company's embedded cost of debt rather than decreasing it as Mr. Trogonoski claimed. Ms. Schell challenged the adjustment on the basis that it was out-of-period and failed to reflect a known and measurable change.

Resolution. For purposes of settlement, the Parties agree that the Company's proposed cost of debt of 7.31% shall be used to determine the weighted average cost of capital. This 7.31% equals the Company's embedded cost of debt as of the end of the 2001 test year.

C. Capital Structure and Weighted Average Cost of Capital

Background. Public Service recommended that the Commission use its capital structure as of the end of the 2001 test year, excluding short-term debt, adjusted to include notes payable to subsidiaries as a part of long-term debt and to reflect the discontinuance of operations at PSCCC. CEC's witness, Mr. Gorman, found the Company's proposed capital structure to be reasonable for ratemaking purposes. Staff concurred with the Company's Direct Case as corrected on January 23, 2003. OCC's witness Mr. Copeland accepted the Company's proposal to use an historic year-end capital structure, excluding short-term debt, but opposed the Company's adjustments for PSCCC and for notes payable to subsidiaries. Kroger's witness, Mr. Higgins, proposed that the Commission include in the regulated capital structure $562.8 million of short-term debt on the Company's books as of the end of the test year.

The following table summarizes the Parties' final, as filed, recommendations with respect to capital structure ratios:

Party	Short-Term Debt	Long-Term Debt	Equity
Public Service		48.60%	51.40%
CEC		48.72 %	51.28 %
FEA		48.72%	51.28%
Staff		48.60%	51.40%
OCC		45.72%	54.28%
Kroger	13.575%	39.525%	46.90%

Resolution. For purposes of settlement, the Parties have agreed to the Company's and Staff's proposed capital structure of 48.60% long-term debt and 51.40% common equity. The Parties agree that Public Service's proposed capital structure is reasonable and should be used to establish the Company's revenue requirement in this proceeding. The Parties further agree that for purpose of the earnings sharing calculation in 2004, 2005 and 2006, the Company shall use year-end capital structure adjusted to include notes payable to subsidiaries as long-term debt. In addition, an adjustment will be made to remove any Earnings Test accruals from the common equity balance. The Parties also agree that the Commission should exclude short-term debt from the regulatory capital structure. The following tables reflect the weighted average cost of capital for the Company's electric, gas and thermal utility operations, respectively, that has been agreed to by the Parties:

Electric Utility

	Weight	Rate	Wtd Cost
Long-Term Debt	48.60%	7.31%	3.55%
Equity	51.40%	10.75%	5.53%

Total Cost:			9.08%

Gas and Thermal Utilities

	Weight	Rate	Wtd Cost
Long-Term Debt	48.60%	7.31%	3.55%
Equity	51.40%	11.00%	5.65%
Total Cost:			9.20%

II. Rate Base

A. Average Rate Base

Background. In its direct case, Public Service used year-end rate base in developing its proposed revenue requirements in accordance with the rate base calculation method approved by the Commission for Public Service in Colorado rate cases over the past 30 years.

In their Answer Testimony, Staff and the OCC recommended that the revenue requirement be developed based on an average rate base method. Staff and the OCC argued that the continued calculation of rate base using a year-end rate method rather than an average method is no longer warranted. Staff's and the OCC's position is that the factors justifying the use of year-end rate base including continued significant investment in non-revenue producing plant; upward-spiraling capital costs; sustained and continued customer growth that requires additional plant investment; and a high general inflation rate, are no longer present. Staff presented data to support its position that inflation rates since 1993 have been relatively stable at near record low levels and the rate of growth in the Company's gross plant has decreased since 1996. In addition, Staff and the OCC argued that any attrition has been mitigated by special tariff riders, such as the Gas Cost Adjustment, the electric cost adjustment as it existed prior to 1996, and the Y2K and air quality improvement riders.

In its Rebuttal Testimony, Public Service disputed Staff's and OCC's contention that the conditions relied upon by the Commission in adopting year-end rate base for Public Service have changed materially since that time, and asserted that, to the extent they have, other equally important factors have taken their place to justify the continued use of year-end rate base. In particular, Public Service argued that the sustained effect of earnings attrition, inflation and investment to meet rapid system growth is at least as significant today as the combination of factors relied upon 30 years ago, and the impact of regulatory lag is even more pronounced.

Resolution. In resolution of this issue, the Parties agree that an average rate base method should be employed for purposes of determining the revenue requirements in this case. Under this method, the 13-month average of month-end balances shall be used for all rate base items except cash working capital. Cash working capital is calculated using *pro forma* expenses multiplied by the appropriate working capital factors as reflected in Attachment E. The AFUDC addition to earnings shall be based upon actual test-period expenses, not annualized, and related adjustments for deferred taxes.[14]

To the extent possible, *pro forma* adjustments and unusual items occurring during the test year[15] will also be made using a 13-month average of month-end

~~14 The Parties acknowledge that the proposed treatment of AFUDC for purposes of this Settlement Agreement constitutes a modification of the principles approved by the Commission in Decision No. C95-52, mailed January 17, 1995, in Docket No. 94A-679EG.~~ [footnote intentionally deleted]

15 One example where it may not be possible to determine the thirteen-month average is if an adjustment to rate base is required to be made during the calendar year and the Company does not have thirteen

balances. In cases where the 13-month data is not available for *pro forma* adjustments, the sum of the prior year-end balance and the test year-end balance divided by two will be used. Specific assignment of plant to either the CPUC or FERC jurisdiction will use year-end balances. The use of average rate base for determining cost of service shall not be considered a settled principle for purposes of the 2004, 2005 and 2006 Earnings Tests.

B. Plant Held for Future Use

1. Southeast Water Rights

Background. In its direct case, Public Service proposed to continue the current rate treatment established in Docket No. 93S-001EG for the amount booked in Plant Held For Future Use associated with the water rights purchased for a prospective power plant in southeast Colorado; *i.e.*, the debt cost portion of the Company's carrying costs of these water rights is included in revenue requirements. Public Service argued that, since there is a potential use for these water rights in the future, including their potential sale, the Company should at a minimum be allowed to continue the current partial recovery rate treatment. OCC and CEC in their Answer Testimony objected to this proposed rate treatment, disputing the customer benefits of these water rights and whether they are used and useful.

Resolution. In settlement of this issue, the Parties agree that the Company should continue to include in the revenue requirement the debt cost portion of the Company's carrying costs for the Southeast Water Rights as long as and to the extent

months of data from which to calculate the thirteen-month average. The adjustment to rate base ordered as a result of Docket No. 94I-264E, the Pawnee Turbine Blade proceeding, is such an example.

that the Company continues to own such water rights. To reflect this rate treatment in the cost of service study, the balance associated with the water rights is eliminated from rate base and a negative amount is added to Miscellaneous Other Revenue, as originally proposed by the Company. This rate treatment shall continue through the 2004, 2005 and 2006 electric Earnings Tests, unless the water rights are sold during the applicable Earnings Test year, at which time the rate treatment of the Plant Held For Future Use balance and any proceeds resulting from the sale or transfer of the water rights shall be a new item identified in the Company's Earnings Test Report.[16] The Parties also reserve the right to argue the appropriate treatment of any gain or loss related to such a sale.

2. Pawnee 2 Pre-engineering Costs

Background. In its direct case, Public Service proposed to amortize the Pawnee 2 Pre-engineering Costs over a four-year period (2003 through 2006) and to include one year's amortized expense in the revenue requirement. The Company explained in its Direct Testimony that these engineering and study costs were incurred between 1982 and 1993 in connection with the development of a new power plant, the construction of which was delayed and ultimately obviated by Public Service's acquisition of the Colorado Ute generating resources as part of the resolution of the Colorado Ute bankruptcy. OCC and CEC in their Answer Testimony objected to this proposed rate treatment, disputing the customer benefits of these costs and recommending disallowance of the amortized expense. In its Answer Testimony, Staff did not oppose

[16] This Settlement Agreement does not address the question of whether and to what extent Commission approval may be required to transfer these assets under C.R.S. § 40-5-105 or Rule 55 of Commission Rules of Practice and Procedure.

the Company's proposed amortization, but proposed to offset some of the Pawnee 2 Pre-engineering costs by the amount of the gain on the sale of the Boulder Canyon Hydro Project and to amortize the difference over four years.

Resolution. In settlement of this issue, the Parties agree that the Company should be permitted to amortize the full Plant Held For Future Use balance of the Pawnee 2 Pre-engineering Costs through a straight-line amortization over four years, without any offset, and to include one year's amortization expense in the revenue requirement. The amortization will commence in the first full month after the effective date of rates from this case and continue for four years. This rate treatment shall continue through the 2004, 2005 and 2006 electric Earnings Tests.

3. Metro Ash Disposal Site

Background. In its direct case, Public Service proposed to amortize 100% of the book costs associated with the metro ash disposal site, which were incurred in 1993 to secure and improve a site for disposal of fly ash from the Arapahoe, Cherokee and potentially the Valmont coal-fired generating plants; these costs were incurred due to then anticipated changes in environmental regulations declaring fly ash to be a hazardous substance. The Company proposed to amortize over four years the original book cost of this 88-acre site, along with the cost of an option to purchase an additional 105 acres on an adjacent parcel of land, and to include one year's amortization expense in the revenue requirement. OCC and CEC in their Answer Testimony objected to this proposed rate treatment, disputing the customer benefits of these costs and recommending disallowance of the amortized expense. In its Answer Testimony, Staff concurred with the proposed amortization and rate treatment of the costs associated with the option for the 105-acre parcel, but believed amortizing the cost of the 88-acre Metro Ash Disposal Site was premature.

Resolution. In resolution of this issue, the Parties agree that the cost of the 88-acre Metro Ash Disposal Site should remain in Plant Held For Future Use, without amortization, and be included in the determination of rate base (full debt and equity return), and that Public Service should be permitted to amortize the costs associated with the option for the 105-acre parcel over four years and to include one year's amortization expense in the revenue requirement. The amortization will commence in the first full month after the effective date of rates resulting from this case and continue for four years.[17] This rate treatment shall continue through the 2004, 2005 and 2006 electric Earnings Tests, unless the 88-acre Metro Ash Disposal Site is sold during the applicable Earnings Test year, at which time the rate treatment of the Plant Held For Future Use balance, and any proceeds resulting from the sale or transfer of the site shall be a new item identified in the Company's Earnings Test Report.[18] The Parties reserve the right to argue the appropriate treatment of any gain or loss related to such a sale.

C. Underground Gas Storage Inventory Adjustment

Background. In its direct case, Public Service proposed a *pro forma* adjustment to gas stored underground (FERC Accounts 117 and 164) to reflect the gas storage inventory level on the basis of the weighted average cost method ("Average Cost")

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[17] If the option were to be sold, any net proceeds from the sale shall be netted against the balance to be amortized.

[18] This Settlement Agreement does not address the question of whether and to what extent Commission approval may be required to transfer this asset under C.R.S. § 40-5-105 or Rule 55 of Commission Rules of Practice and Procedure.

versus its current pricing method of LIFO. Public Service noted that in a separate application filed with the Commission in Docket No. 02A-267G, the Company was seeking Commission authorization to change its method of accounting for the cost of stored natural gas from the current LIFO pricing method to the Average Cost method. In its Answer Testimony, Staff objected to the Company's proposed adjustment citing its disagreement expressed in Docket No. 02A-267G over the Company's approach for calculating the Average Cost inventory amounts to accomplish this change in accounting. In addition, Staff disagreed with the Company's asserted basis for the proposed *pro forma* adjustment. In its Answer Testimony, OCC advocated that the Commission incorporate the same method of calculating gas stored underground as is approved in Docket 02A-267G. The Parties acknowledge that the proceeding in Docket No. 02A-267G is not concluded and that the Commission has not issued any final orders in that docket. The Company, the Staff, and the OCC additionally acknowledge their agreement to treat this rate case rate base issue separate and apart from the proceeding in Docket No. 02A-267G.

Resolution. In resolution of this issue, the Parties agree that the gas stored underground inventory allowance for inclusion in the gas revenue requirement should be calculated using test period volumes for all storage fields (excluding inventory amounts associated with the Leyden Gas Storage Facility and the Electric Department's portion of inventory in Young Gas Storage, Ltd.), multiplied by the average per Dth inventory price for the 36-month period beginning with the January 1, 2000 per book LIFO balance through the period ended December 31, 2002. In future gas revenue requirement filings, the Company will use the same inventory pricing method to value gas stored underground inventory that has been approved by the Commission for regulatory accounting purposes and will determine the value based on the 13-month average of month-end balances calculation method reflected in the Average Rate Base discussion in Section II.A. of this Settlement Agreement.

III. Income Statement

A. Insurance Expense

Background. In its direct case, Public Service proposed a *pro forma* adjustment to test period insurance expenses to reflect anticipated increases in property and casualty insurance premiums to be incurred by Public Service during and after 2002, citing the 9/11 terrorist attacks and other factors contributing to the general increase in property and casualty insurance costs. In Answer Testimony, Staff and OCC opposed the Company's adjustment on the ground that the Company's estimate was in excess of the actual 2002 insurance premiums. Staff and OCC recommended that the actual 2002 insurance cost levels be used in computing test year revenue requirements. In its Rebuttal Testimony, the Company reemphasized that, even though its estimate did not turn out to be accurate in hindsight, it was based on the best information available at the time the case was filed, and that these types of "true-up to actual" adjustments are inconsistent with the test period ratemaking principles historically followed by the Commission.

Resolution. For purposes of settlement, the Parties agree that the actual 2002 insurance expense levels are more representative of insurance expense during the period the new rates will be in effect and should be included in the revenue requirement.

The 2004, 2005 and 2006 Earnings Tests will reflect actual insurance expense incurred during the applicable calendar year.

B. Purchased Capacity Costs

Background. In its direct case, Public Service proposed a *pro forma* adjustment to test period expenses to reflect projected increases in electric purchased capacity costs for calendar year 2002. In fact, the projected dollars upon which the *pro forma* adjustment was based fell short of the actual 2002 electric purchased capacity cost level.

Resolution. In conjunction with the Parties' comprehensive agreement of all of the other issues in this rate case, the Parties agree that the actual 2002 electric purchased capacity costs are more representative of purchased capacity costs during the period the new rates will be in effect and should be included in the revenue requirement.

C. Trading A&G and Non-Production O&M Expense

Background. In its Answer Testimony, Staff questioned the Company's accounting for its short-term wholesale energy sales activities. Staff expressed concern that Public Service's retail customers may be improperly subsidizing the Company's Proprietary Book trading operations and argued that the Company's Proprietary trading operations should be eliminated as a regulated activity.[19] Staff, through the use of an energy ratio, recommended excluding $8,661,947, its estimate of the A&G and non-production O&M expense associated with the Company's Proprietary Book trading operations, from the Colorado jurisdictional revenue requirement. Public Service

[19] See discussion of Trading, below, in which further definition is supplied concerning the Company's Generation Book and Proprietary Book trading operations.

offered Rebuttal Testimony refuting Staff's contention that retail customers have subsidized any portion of the Company's Proprietary Book trading operations. Public Service's Rebuttal Testimony acknowledged that the Company did not record A&G and Non-Production O&M Expense associated with the Generation Book and the Proprietary Book transactions separately in the 2001 test year. The Company had implemented a change in 2002 to record time spent by traders in performing Generation Book and Proprietary Book transactions. Relying on this data and other information, the Company argued that Staff's estimate of the non-production O&M expenses associated with the Proprietary Book trading operations was overstated.

Resolution. For purposes of settlement, the Company agrees that, where practicable, it will continue to separately record time spent by traders in performing Generation Book and Proprietary Book transactions. The Parties agree, given other provisions of this Settlement Agreement discussed later in the section entitled "Trading," that Public Service shall exclude $2.74 million from the calculation of its Colorado jurisdictional base rate revenue requirements: $1.74 million associated with Generation Book trading activities and $1 million associated with Proprietary Book trading activities. The Parties agree that $2.74 million reflects a reasonable estimate of the assigned and allocated A&G and non-production O&M expense incurred by the Company's trading operation beyond what would be incurred if the Company ceased Proprietary Book trading and if the Company's only Generation Book trading activities were intra-day energy transactions[20] and day-ahead energy transactions on the Company's system.

[20] Intra-day transactions are transactions entered into on the same day as the energy flows. In the trading business rules, attached to this Settlement Agreement as Attachment J, intra-day transactions are also referred to as "real time" and "hourly".

Public Service shall also make the same $2.74 million adjustment to test-year expenses for the purpose of calculating earnings sharing for the calendar year 2004.

As discussed later, the Parties have agreed that the Company shall file an application in January 2004 to initiate review of the Company's trading activities. If as a result of that docket the Commission determines that no material changes should be made to the scope of the Company's trading activity, then the Company shall make the same $2.74 million adjustment to test-year expenses for purposes of calculating earnings sharing in the Earnings Tests for calendar years 2005 and 2006. If the Commission determines that the Company should discontinue Proprietary Book trading and also discontinue Generation Book energy trading beyond intra-day energy transactions and day-ahead energy transactions on the Company's system, then no *pro forma* adjustment shall be made to test year expenses for the purposes of calculating earnings sharing from the Earnings Tests for calendar years 2005 and 2006. If the Commission determines that the Company's trading activities should be materially reduced in scope from the trading activities undertaken by the Company at the time of this Settlement Agreement, but not reduced to the level discussed in the prior sentence, then the Company shall propose in the applicable Earnings Test filing an adjustment to test year expenses that reflects the Company's reduced trading operations from those assumed in this general rate case.

Nothing in this Agreement shall require the Company to continue with its current scope of energy trading activity. The Company reserves the right to discontinue or reduce its energy trading activity at any time. Should the Company discontinue Proprietary Book trading and also discontinue Generation Book energy trading beyond intra-day energy transactions and day-ahead energy transactions on the Company's system, then no *pro forma* adjustment shall be made to test year expenses in any applicable Earning Test period. Should the Company otherwise reduce the scope of its energy trading activity, the Company shall propose in the applicable Earnings Test an adjustment to test year expenses that reflects the Company's reduced trading operations from those assumed in this general rate case.

In connection with the docket reviewing the Company's trading operations, this Settlement Agreement provides for the funding of an expert consultant to assist Staff and the OCC. That consultant may inquire of the Company, and advise the Staff and OCC, with respect to the A&G and Non-Production O&M expense associated with the Company's trading activity, among other things. However, in making such inquiry, the Staff/OCC consultant shall first utilize the information provided by the Company to Staff and OCC through discovery and audit in this general rate case. The issue of the appropriate adjustment to revenue requirements associated with trading A&G and Non-Production O&M expense shall not be an issue in the trading docket initiated by the Company's application in January 2004; that issue is deemed settled by this Settlement Agreement. However, should the Commission decide to restrict the scope of the Company's trading operations as a result of the 2004 inquiry, or should the Company decide to reduce the scope of its trading operation, the Staff and the OCC may use information provided by this consultant, as well as other information, in the appropriate Earnings Test proceedings to determine the appropriate reduction in the $2.74 million *pro forma* adjustment to trading A&G and non-production O&M expense associated with the change in scope of the Company's energy trading activity.

D. Oil and Gas Royalty Revenues

Background. In its Direct Case, Public Service excluded revenues received from oil and gas production royalties from the determination of the revenue requirement. In its Answer Testimony, Staff opposed this exclusion on the basis that the Company had not demonstrated that it had allocated associated assets to non-regulated activities. In its Rebuttal Testimony, the Company pointed out that for the past 30 years, the Commission's practice has been to treat the costs and revenues attributable to the oil and gas production segment of the Company's business as non-regulated. The Company further explained that much of the oil and gas royalties currently received are the result of efforts and business dealings of its former unregulated subsidiary, Fuel Resources Development Co. ("Fuelco"), which was incorporated in 1970 and dissolved in 1996. Moreover, the Company pointed out that the original land and land rights costs associated with the mineral rights associated with these revenues are negligible and likely cannot be traced on the Company's books. Finally, the Company asserted that the dissolution of Fuelco and the cessation of the Company's oil and gas production activities do not warrant a change in the regulatory treatment of these revenues.

Resolution. In settlement of this issue, the Parties agree that the full amount of oil and gas royalty revenues and any related administrative expenses shall be included in the determination of the revenue requirements. Such treatment shall similarly apply in the 2004, 2005 and 2006 electric Earnings Tests, unless such treatment is changed by order of the Commission. The Company shall be free to advocate in the Earnings Test and other future proceedings that certain oil and gas revenues and costs, including asset-based costs related thereto, should not be included as regulated utility revenues and costs.[21]

E. Pension Expense

Background. The Parties acknowledge information presented by Public Service indicating, based on actuarial calculations performed in the ordinary course of business, that the Statement of Financial Accounting Standard ("SFAS") No. 87 net periodic pension credit for the 2001 test year is not reflective of the SFAS 87 net periodic pension costs for the period in which the rates in this rate case will be in effect. The Company's actual 2003 pension expense will be substantially higher than the pension expense included in its cost of service for the 2001 test year. The Company, Staff, and the OCC are concerned that, if the Company is not permitted to recover this increase in pension expense in the rates that are approved as part of this proceeding, such an increase, in combination with other known increases in expense, could put the Company in the position of having to file a second Phase I rate case shortly after the conclusion of this proceeding.

Resolution. In order to accommodate this concern and as part of the overall settlement of the issues in this case, the Parties agree that a *pro forma* adjustment for pension costs should be made to reflect an increase in pension expense anticipated in 2003. This increases the revenue requirement for the ~~electric~~ gas department by $2,675,802, for the ~~gas~~ electric department by $4,950,196, and for the thermal

[21] The Company's demonstration that oil and gas royalties should not be considered regulated utility revenues may consist of a showing that any associated expenses or investments were not included as part of the cost of service used to determine base rates in this proceeding.

department by $102,211. The 2004, 2005 and 2006 Earnings Tests shall reflect actual pension expense incurred during the applicable calendar year.

F. Allocation of Labor – A&G and Other Corrections

Background In its Rebuttal Testimony, the Company changed the jurisdictional allocation factor for five administrative and general expense accounts from net plant in service to gross plant in service. Inadvertently, the Company did not change the labor allocation in these same accounts.

Resolution. The Parties agree that a correction should be made to labor in the following FERC accounts based on the gross plant in service allocation factor: Account 924 – Property Insurance; Account 929 – Duplicate Charges; Account 930 – Miscellaneous; Account 931 – Rents; and Account 935 – Maintenance of General Plant.

G. Dark Fiber

Background. In Docket No. 98A-262EG, the Commission approved the transfer of all of Public Service's dark fiber assets to NCE Communications, Inc. ("NCEC") and a lease back of the portion of those assets Public Service was using at the time of transfer. The Commission approved the transfer following consideration of the October 8, 1998, Stipulation and Agreement ("Dark Fiber S&A") between Staff and the Company that was filed to resolve all issues in Docket No. 98A-262EG. The Dark Fiber S&A contained a "Favored Nations Clause" that provided that Public Service and its customers would be entitled to the lowest rate at which NCEC leased a similar fiber optic route segment.

In August 1999, NCEC contributed the dark fiber to Northern Colorado Telecommunications, LLC d/b/a Touch America Colorado LLC, a partnership between

NCEC and Touch America, Inc. In its Answer Testimony, Staff expressed concern whether the level of the lease rate paid by Public Service continues to be reasonable and whether the Favored Nations Clause under the Dark Fiber S&A could operate in full force and effect following the contribution of assets to Touch America Colorado.

Resolution. For purposes of settlement, the Parties agree to the amount of lease expense and pole attachment fees included in the Company's original filed case; however, the Parties do not agree that the Company's filed position should reflect a settled ratemaking principle for purposes of the Earnings Test. Staff and Public Service reserve their rights to advocate in the Earnings Test or in any other appropriate proceeding any position regarding the level of expenses and revenues to be recognized for Colorado regulatory purposes relating to dark fiber, pole attachment fees and conduit rental and whether the Favored Nations Clause applies to the contribution.

H. Regulatory Treatment of § 40-3-104.3(2)(a) Discounts

Background. For contracts involving electric and steam service C.R.S. § 40-3-104.3(2)(a) requires that the Commission specify a fully distributed cost allocation method to be used to segregate rate base, expenses, and revenues associated with utility service provided by contract from other regulated utility operations. The Company in its Direct Case made an adjustment to miscellaneous revenues to add to booked revenues the discounts given to certain contract customers.

Resolution. The Parties agree that the Company's treatment in its Direct Case was acceptable for purposes of this Phase I proceeding and should be continued for purposes of the Earnings Tests for calendar years 2004, 2005, and 2006. The Parties further agree that for purposes of Phase II the Company shall perform and file a fully distributed cost study separating revenues, assets, liabilities, reserves and expenses and will specifically identify the class in which each customer receiving a discount resides. Further, at the time of the Phase II filing, for purposes of Phase II, the Company shall provide to Staff and OCC on a confidential basis consistent with the requirements of C.R.S. § 40-3-104.3, all available customer specific load information.

IV. PSCCC

<u>Background</u>. In December 2001, Public Service discontinued the operations of PSCCC. Subsequently, the Company dissolved PSCCC effective April 6, 2002. In its rate case filing, the Company made a number of *pro forma* adjustments to test-year rate base and capital structure to reflect the discontinuation of PSCCC. In their Answer Testimony, the Staff and the OCC objected to the Company's *pro-forma* adjustments related to PSCCC and recommended treating PSCCC as if its operations had not been discontinued. Staff also argued that, under Decision No. C86-1392, Application No. 37781, the Company should have applied to the Commission for approval prior to discontinuing operations at PSCCC. The Company disputed that such an application was necessary. In Supplemental Answer Testimony, filed on Februray 18, 2003 after Staff had had the opportunity to conduct a more thorough analysis of the impact of the dissolution of PSCCC on Public Service's cost of service, Staff observed that, due to the interrelationship of various inputs to the Company's cost of service, the impact of dissolving PSCCC can swing from negative to positive depending upon the lead/lag factors, return on equity and rate base used as inputs to the cost of service model.

<u>Resolution</u>. As part of the overall settlement of issues in this docket, which includes the resolution of issues relating to cash working capital and the rate of return

on equity, the Parties agree to accept the Company's *pro forma* adjustments related to the discontinuation of PSCCC as appropriate out-of-period adjustments reflecting known and measurable changes in the Company's rate base and capital structure.[22] Now that PSCCC has been dissolved, no additional adjustments associated with this entity will be required for purposes of future Earnings Tests.

V. Cost Allocation Between Regulated and Non-Regulated Business Activities

Background. In their Answer Testimony, the Staff and the Colorado Business Alliance for Cooperative Utility Practices ("CBA") challenged the sufficiency of the Company's fully distributed cost study used to allocate and assign costs to its non-regulated business activities. In particular, Staff disagreed with the revenue-based allocator used by Public Service to allocate A&G and Customer Accounting expenses to its non-regulated products and services. In the alternative, Staff recommended using an O&M-based allocator to calculate the A&G load and using a modified revenue-based allocator to calculate the Customer Accounting load. Staff also questioned the Company's failure to have allocated any investment in common plant or associated expenses, including return on such investment, to the non-regulated products and services. CBA's witness, Mr. Keating, was concerned that Public Service had not made a sufficient showing that its allocation of costs to the non-regulated business activities was consistent with the Commission's Cost Allocation Rules. OEMC raised a general issue of customer's access to historical data contained in the CIS regarding the customer's own account. OEMC recommended disallowance of a portion of the

[22] The Company's test-year cost of service did not reflect an adjustment to eliminate the fees Public Service paid to PSCCC during 2001 because the fees had been booked below-the-line as interest expense.

expense associated with the investment in CIS in the event that the Company did not make the historical data available to the customer.

In its Rebuttal Testimony, the Company agreed with Staff that the revenue-based allocator used to calculate the A&G load may not be the only reasonable approach for allocating costs. Accordingly, the Company proposed an alternative labor-based allocator, which resulted in a higher level of A&G cost allocation to the non-regulated products and services, compared to what the Company originally filed, and a lower level of cost allocation compared to what Staff proposed. In addition, the Company modified the method it used to develop the allocation factor for Customer Accounting costs. Public Service also conceded that certain expenses associated with investment in common plant, including CIS, should have been allocated to the non-regulated products and services.

Resolution. For purposes of this settlement, the Parties have agreed to accept the Company's allocation and assignment of costs to its non-regulated business activities as reflected in Public Service's Rebuttal case. Specifically, the Parties agree that the Company's proposed labor-based allocation factor shall be used to allocate A&G costs to the non-regulated products and services and further agree that the Company's proposed revenue-based allocation factor, excluding revenues associated with off-system energy sales, shall be used to allocate Customer Accounting costs. In addition, the Parties agree to the revised common plant allocations, including CIS, reflected in the Company's Rebuttal and Supplemental Rebuttal Testimony and Exhibits.

In resolution of the issues raised by OEMC, Public Service agrees to provide OEMC with access to twelve months of historical data for its metered accounts for which it does not currently have EDI.

The Parties agree to engage in good faith workshops to analyze cost allocation/assignments to and between Public Service's regulated and non-regulated business activities. The Company shall provide to all workshop participants who have executed an appropriate Non-Disclosure Agreement, its FDC study in the form of an income statement and balance sheet, supplemented by schedules in the form of Confidential Exhibit No. JSSP-3. The format for the Company's FDC study is shown in Attachment F to this Settlement Agreement, which attachment is an interim format subject to modification during the workshop process. All supporting workpapers and calculations, in electronic spreadsheet format to the extent available, will be provided concurrent with the Company's FDC study. The Company shall also make available to the participants its subject matter experts to explain the Company's position as well as supporting documentation.

The purpose of the workshops is for the workshop participants to evaluate the form of the FDC study attached as Attachment F and arrive at fair and reasonable assignments and allocations of costs to and between the Company's regulated and non-regulated business activities consistent with the requirements of C.R.S. § 40-3-114 and the Commission's Cost Allocation Rules, including the requirements of Rule 4 CCR 723-47-5 relating to transactions between the utility and non-regulated divisions, subsidiaries or affiliates. The participants shall have reasonable access to relevant information, subject to an appropriate non-disclosure agreement, concerning the

Company's costs that could be assigned between and among regulated and non-regulated services. In the event the participants do not receive such information in a timely fashion, the participants may formally seek assistance from the Commission including, as necessary, a request to employ formal discovery processes. The workshop participants will endeavor in good faith to complete the workshop process within four months following Commission approval of this Settlement Agreement. Within 30 days following completion of the workshop process or at such later time as the Parties may agree or the Commission may permit upon a showing that the Company requires greater than 30 days, Public Service will file any appropriate modifications to its Cost Allocation Manual ("CAM"). If the participants in the workshop process are not able to agree on an approach to accomplish a fair and reasonable allocation of costs to and between the Company's regulated and non-regulated business activities, the participants agree to submit the unresolved issue(s) to the Commission by no later than six (6) months following Commission approval of this Settlement Agreement.

The Company shall file its FDC study and CAM, updated to reflect the results of the workshop process, with its annual Earnings Test report commencing with the 2004 Earnings Test year filed in 2005.

VI. Depreciation Issues

Background. On November 22, 2002, Public Service, the Staff, and OCC entered into a Depreciation Stipulation resolving most of the issues raised by the Parties with respect to depreciation. As identified previously in this document, the Depreciation Stipulation is attached as Attachment B. With respect to the amortization period applicable to future computer software purchases (which was not included as part of the

November 22, 2002 Depreciation Stipulation), the Company and Staff, through the testimonies of Company witness Ms. Perkett and Staff witness Ms. Fischhaber, agree to 1) a three-year amortization period for a rollout of workstation operating systems where the rollout for the entire Company is completed in a 12-month period; and, 2) a five-year amortization period for all software purchases that qualify for capital treatment, but do not fit in the three-year or the large base systems software category that is discussed below.

Staff and the Company disagreed as to how large base computer software systems, such as accounting, human resources, billing and property accounting systems should be amortized. In its Direct Case, the Company proposed that the cost of these large base computer software systems be amortized over seven years to reflect an appropriate matching of system benefits and expenses. In its Answer Testimony, Staff proposed a 10-year amortization period for such large base computer software systems. In its Rebuttal Case, the Company modified its original proposal to state that the original installation as well as any subsequent modules of such large base computer software systems should be amortized over seven years. However, the Company stated that it would be willing to agree with Staff's proposal for a 10-year amortization period of the original large base computer system software provided that all subsequent large base computer system software upgrades would be amortized such that they would be retired at the end of this 10-year life.

Staff's and the Company's witnesses on depreciation also discussed the appropriate interval for filing updated depreciation studies, recognizing the need for periodic updates and the substantial work requirements on behalf of both Staff and the

Company. The Company expressed a desire to implement a Remaining Life Model applicable to its steam production facilities in this proceeding. Staff expressed concern that the Company's proposal may not be consistent with the Revision to Supplemental Settlement Agreement approved in Docket No. 94S-670EG that required the Company use the same depreciation methods as approved in that order through June 30, 2005. Staff recommended that the on-going review of the Remaining Life Model applicable to electric and thermal production facilities be performed at the same time as the Company's Least Cost Resource Planning ("LCRP") applications because similar information is needed and required for both activities.

Finally, Staff witness Ms. Fischhaber expressed concern regarding the Company's continued use of "black box" software programs for its depreciation studies. Public Service disputed Staff's characterization of its Power Plant software system as a "black box".

Resolution. For purposes of settlement, the Staff and the Company agree that Public Service shall amortize large base computer software systems over a 10-year life and shall amortize all software upgrades to such systems such that the upgrades are retired at the end of this same 10-year life. The Company agrees to exercise prudent judgment regarding upgrades of these systems towards the end of the useful life of the software. This treatment shall be reflected in the Company's Earnings Tests for 2004, 2005 and 2006.

Staff and the Company also agree that on a going-forward basis, after June 30, 2005, the Company shall revise its depreciation model applicable to its steam and other production facilities to a Remaining Life Model. These parties further agree that the

Company shall submit either to the Chief of Fixed Utilities for Staff review, or to the Commission as part of a proceeding where approval of depreciation rates is an issue, no later than October 2007, and thereafter at least every four years, its Remaining Life Model applicable to its electric and thermal production facilities. Unless the Remaining Life Model is submitted earlier, it is the intent of Staff and Public Service that the Company shall submit its Remaining Life Model at the same time as its LCRP applications starting in 2007.

Staff and the Company also agree that on a going-forward basis, the Company will submit either to the Chief of Fixed Utilities for the Staff, in accordance with an appropriate review schedule to be established jointly by the Company and the Staff within three (3) months following approval of this Settlement Agreement, or to the Commission as part of a proceeding where approval of depreciation rates is an issue, depreciation studies such that every aspect of the Company's plant shall be addressed in a depreciation study on an interval at least every five years. The Staff and the Company agree that every aspect of the Company's plant shall be the subject of at least one depreciation study submitted on or before December 31, 2007. The Parties recognize that any Commission approval of the depreciation studies (including the Remaining Life Model discussed in the previous paragraph) shall occur only in proceedings seeking approval of a change in depreciation rates.

Finally, Staff agrees that, in this proceeding, it will not pursue the issue of the Company's continued use of proprietary software programs for its depreciation studies that Staff asserts its cannot evaluate. Staff reserves the right to pursue this issue in any future Commission proceedings in which any of the Company's depreciation rates, net salvages, survivor curves, remaining lives, etc. are at issue.

VII. Reclassification of Substation Plant and Treatment of Radial Transmission Lines

Background. In its Direct Testimony, Public Service proposed to reclassify certain high voltage facilities within its distribution substations from distribution plant to transmission plant. The Company also proposed to eliminate the direct assignment of radial transmission lines and to treat all of these lines as part of the central transmission system. The impact of these proposals is reflected in the cost of service and in the associated revenue requirement developed for each of the affected functional categories in the Company's Cost of Service Model. Staff disagreed with the Company's proposed reclassification of high-voltage facilities in the distribution substations as transmission plant and with the Company's proposal to roll-in its radial transmission lines with its central system transmission.

Resolution. For purposes of settlement, the Parties agree that they may address the proper classification of the Company's high voltage facilities in distribution substations and its treatment of radial lines as part of Phase II of the Company's rate case. The Parties acknowledge that such changes will result in a change in the Company's retail revenue requirement from what is reflected in the Company's Cost of Service study approved as a part of this Settlement Agreement. Accordingly, the Parties agree that to the extent a change to the classification or allocation of these facilities is approved in Phase II, the Company shall be permitted to put into effect base rates that reflect the revised revenue requirement determined as a result of Phase II.

The maximum impact of a change in the classification of the Company's high voltage facilities in the distribution substations from transmission to distribution plant will be to increase the Company's jurisdictional revenue requirement by $505,013. The maximum impact of directly assigning radial transmission lines rather than treating them as central system is to increase the Company's jurisdictional revenue requirement by $159,070. The maximum cumulative impact of both these changes is to increase the Company's jurisdictional revenue by $639,448. The Parties agree that the 2004, 2005 and 2006 Earnings Tests shall reflect the outcome of these issues in the Commission's order in Phase II.

VIII. JD Edwards General Ledger Accounting System

Background. Effective October 1, 2001, Xcel Energy Inc. replaced Public Service's Walker general ledger accounting system ("Walker") and the general ledger accounting system used by other subsidiaries with a single general ledger accounting and financial reporting system. The new system uses JD Edwards ("JDE") software. The JDE general ledger accounting system was the basis for recording the financial transactions that underlie the Company's cost of service filed in this proceeding.

In recognition of Staff's and other Parties' need for additional time to review the major general ledger accounting system change, to establish confidence in the integrity of the Company's financial information underlying the Company's JDE general ledger accounting system, and to ensure that the new system continues to provide information consistent with the regulatory needs of the Commission, Public Service agreed to extend the effective date of its tariffs and the dates for hearing in this matter. In order to facilitate a greater understanding of the new general ledger system on the part of the

Parties, the Company conducted technical conferences on August 9 and 12, 2002 in which it provided detailed explanations of the accounting processes within JDE. As early as April 2002, the Company shared with the Staff and OCC an analysis comparing the electric department revenues and costs under Walker with those reflected under JDE for the first nine months of 2001. Beginning in August 2002, the Company made arrangements for Staff to have access to its general ledger system for the purpose of tracing transactions from Walker to JDE and from JDE back to source transactions. The Company engaged the services of the consultants who had assisted with the JDE implementation and made these people as well as Company personnel available to Staff for purposes of answering questions about the general ledger processing and track back of expenses and revenues. The Company also created a special model in JDE to allow the Staff and OCC to model "what if" scenarios so that they could see the impact of specified changes in allocation methods or other accounting processes upon the results of the cost of service.

As part of its review of the JDE general ledger accounting system, Staff performed studies tracking dollars step by step from Walker through to JDE. Through the audit and discovery process Staff identified the processes, calculations and formulas that were applied to the basic accounting information for purposes of performing multi-level allocations of costs. In its Answer Testimony, Staff identified concerns with the Company's FERC allocations, questioned whether some of the Company's accounting and recording methods, practices and procedures complied with state and federal regulatory requirements, and questioned whether the transition to the new system accurately mapped financial information from Walker to JDE accounts.

Staff argued that the Company's FERC allocations resulted in a misallocation and misclassification of expenses by FERC Account. Staff also raised questions about the Company's practices, policies and procedures for recording O&M and A&G expenses.

In Rebuttal, the Company disputed Staff's claim that ~~the~~ some of its accounting and recording methods, practices and procedures were inconsistent with state or federal regulatory requirements. Public Service also contested Staff's assertions that the FERC Allocations resulted in any misclassification of expenses by FERC account by explaining that the basis for the FERC allocations was detailed information regarding the nature of the Company's expenses contained in its work management systems. The Company also addressed Staff's concerns regarding the mapping of financial information from Walker to JDE and the level of A&G and O&M expenses.

Resolution. For purposes of settlement, Public Service agrees to phase out the use of FERC allocations in its JDE general ledger accounting system, as defined in the Company's 2002 CAM[23], by January 1, 2004, except in those instances in which the Company demonstrates that the elimination of a particular FERC allocation would be impracticable. The purpose of phasing out the FERC allocations is to achieve, to the fullest extent possible, the effect of a direct recording of costs to FERC accounts in the Company's general ledger accounting system.

Public Service also agrees that, during 2003, it shall take steps to improve its policies, procedures and oversight of O&M expense classification to achieve a greater level of accounting consistency. Specifically, a greater emphasis will be placed on the consistent recognition of O&M expenses by functional class (production, transmission,

[23] The Company revised its 2002 CAM with the filing of Janet Schmidt-Petree's Rebuttal Testimony and Exhibits on January 24, 2003. See Exhibit JSSP-2.

distribution, A&G, and customer operations). The Parties acknowledge that the phase out of the FERC allocations, the efforts to improve policies and procedures relating to the classification of O&M, and the cost workshops addressed in Section V may result in modification of the assignment/allocation methods from those that were used to develop the Company's cost of service in this proceeding. The Parties agree that any such modification in assignment/allocation methods resulting from the above described activities shall not constitute a violation of the Merger Stipulation.

Public Service agrees further that on or before June 30, 2003, September 30, 2003 and December 31, 2003, it shall provide Staff with a quarterly report describing its progress in phasing out the FERC allocations and any other significant changes in its general ledger accounting system being implemented to improve the regulatory accounting and reporting of the Company's retail cost of service. The Company agrees to meet with Staff following the submittal of each quarterly report to answer any questions Staff may have regarding the substance of the report.

Lastly, the Company agrees that it shall submit to Staff and to OCC annually, with its February surveillance report, a list of any material changes in Company accounting policies, practices or procedures. The Company shall provide a copy of the list submitted with its most recent February surveillance report with its annual Earnings Test Report. In addition, Public Service agrees that, if there are significant unusual or non-recurring expenses within a calendar year, such as a several million-dollar severance expense associated with a downsizing, it shall separately identify such non-recurring expenses within its general ledger accounting system.

IX. Sterling Correctional Facility

On September 12, 2002, Administrative Law Judge Isley approved a Stipulation ("Sterling Stipulation") between Public Service and the State of Colorado for the benefit of the Department of Corrections regarding the primary electric distribution plant to be used at the Sterling Correctional Facility ("SCF"). Staff joined in the agreement. As part of the Stipulation, the Company agreed to hold retail customers harmless with respect to the investments that the Company made at SCF that were the subject of the Stipulation. In Answer Testimony, Staff identified the adjustments to electric distribution plant in service, reserve for distribution plant depreciation, and electric distribution maintenance expense necessary under the Sterling Stipulation. In its Rebuttal Testimony, the Company accepted all of Staff's adjustments as appropriate. This treatment shall continue in the 2004, 2005 and 2006 Earnings Tests.

X. Leyden Decommissioning Costs

As indicated in its Rebuttal Testimony and Exhibits, in response to objections raised by Staff and OCC, Public Service agreed to withdraw its proposal to hold its gas rates fixed and to credit any excess revenues from the gas department operations against the deferred Leyden decommissioning costs. The Company reserves its right to seek recovery of its decommissioning costs at a later date once those costs are known with reasonable certainty.

XI. Compliance With Commission Decision No. C97-168, Docket No. 94I-264E

Staff argued in Answer Testimony that the Company had failed to conduct certain analyses related to Company power plants as required by Commission Decision No. C97-168, Docket No. 94I-264E. In Rebuttal Testimony, the Company acknowledged that unfortunately it had lost track of these study and reporting requirements. The Company agrees to fully comply with Commission Decision No. C97-168 by January 1, 2004.

XII. Electric Commodity Adjustment

Background. The Company in its Direct Testimony proposed a new adjustment clause to recover fuel, purchased energy and purchased wheeling expense (hereinafter referred to as "Energy Costs"[24]) called the Electric Commodity Adjustment. The Company argued that its proposed ECA employs the same concept of incentives as did the Company's ICA. Both the ICA and the ECA set a base amount per megawatt hour of Energy Costs and compare that base amount with the actual Energy Costs incurred by the Company each year. Fifty percent of the difference between the base amount and the actual Energy Costs (positive or negative) is shared between the Company and the customers. For example, if the base amount were \$20 per MWH and the actual Energy Costs were \$22 per MWH, then the ECA (or ICA) would recover from retail customers \$21 per MWH; conversely, if the actual Energy Costs in any one year were \$18 per MWH, the ECA (or ICA) would recover \$19.

The primary difference between the Company's proposed ECA and the former ICA is that the ICA contained a fixed dollar per megawatt hour base amount. The Company's proposed ECA would have a base that is determined by a formula that would vary with gas commodity prices and the level of PUC jurisdictional sales. The Company explained in its filed testimony that natural gas-fired generation has become a larger portion of its resource mix, that gas prices are volatile and hard to predict, and

[24] The term "Energy Costs" in this Settlement Agreement shall have the same meaning as the term Energy Costs has in the Company's ICA tariff.

that the Company is a "price-taker" on gas commodity prices. Consequently, the Company can no longer accept an incentive clause with a fixed Energy Costs per megawatt hour base. The Company further explained in its filed testimony that it derived its ECA formulaic base from 2001 test year Energy Costs, with certain stated *pro forma* adjustments due to the unusual Western United States market conditions in the 2001 test year. The Company proposed that if the ECA were not acceptable, the Company would accept an adjustment clause that passed through 100% of Energy Costs, without an opportunity to earn an incentive from cost reduction.

Staff, the OCC, CEC, CF&I Steel, L.P. ("CF&I"), Climax Molybdenum Company ("Climax"), and the City and County of Denver ("CCOD") all contested the Company's proposed ECA. CF&I, Climax and CEC argued that the ECA should be differentiated by service delivery voltage. Public Service agreed and provided this differentiation in its Rebuttal Testimony. Numerous parties objected to the Company's proposal to calculate and change the ECA rate monthly. In its Rebuttal Testimony, the Company agreed to only change the ECA rate annually, unless the deferred balance (positive or negative) exceeded $50 million, in which case a change to the ECA rate would be made prior to the annual change in the ECA rate.

Staff, OCC, CEC, and CCOD raised numerous other issues with respect to the Company's proposed ECA, including assertions of the following positions:[25] the use of the 2001 test year to develop the ECA base created "baked-in-value" for the Company; it is not wise to use a complicated formula with numerous benchmarks that could

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[25] Several technical objections were raised to the tariff formula itself by CEC and by CCOD. The Company agreed with many of these technical criticisms and adopted the proposed changes in its Rebuttal Testimony.

provide the opportunity for the Company to "game" the adjustment clause; the Company's *pro forma* adjustments to 2001 test year coal plant availabilities should not be accepted; and separate treatment of gas and non-gas resources could bias future resource selection. The Staff, the OCC, and CCOD generally favored a 100% pass-through mechanism for Energy Costs in lieu of the Company's proposed ECA incentive mechanism. CEC generally favored an incentive mechanism and offered an alternative incentive mechanism based upon CEC's projection of gas prices.

Lengthy settlement discussions were held among the Parties on this issue and on the issue of the Company's trading operations (discussed below). In the course of discussions, at the request of the Parties objecting to the ECA, the Company projected (by using its PROSYM model) the Company's fuel and purchased energy costs to serve retail customer load under a prescribed set of gas prices and compared these costs to the revenue that the Company would collect under the Company's proposed ECA for the same retail load and gas prices. Sensitivity runs were performed that varied the availability of the coal plants, water use restrictions and higher gas prices. As a result of these analyses, the Parties opposing the ECA became more familiar with the operation of this incentive mechanism. However, many Parties still had concerns about adopting any adjustment clause that used 2001 test year Energy Costs, because of the undisputed anomalies in the operation of the Company's system in that year. In general, the Parties agreed that if the Company were to have an incentive fuel clause, the base needed to be determined from a test year other than 2001.

Further, the Company stated that it needed to have a viable trading organization with acceptable margin sharing to provide coverage against the risks to the Company inherent in any incentive Energy Costs mechanism. As explained in the Company's testimony, during the tenure of the ICA, the Company covered its increasing Energy Costs with the profits from its trading activity. In addition, various details of the Company's system operations were discussed that went beyond the issues raised in the filed testimony.

Resolution. As a result of these settlement discussions, the Parties have agreed to the following mechanisms for the recovery of the Company's Energy Costs for the calendar years 2003 through 2006.

A. 2003 Energy Costs

The 2003 Energy Costs shall be recovered through an adjustment clause that passes through to retail customers 100% of the CPUC jurisdictional share of 2003 Energy Costs. The Company shall project total 2003 CPUC jurisdictional Energy Costs and total 2003 retail sales (from January 1 through December 31) and shall design a rate that recovers these costs, taking into account the revenues already collected under the Company's Interim Adjustment Clause that has been in effect since January 1, 2003. [26] To avoid customer confusion, the 2003 clause shall continue to be called the

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[26] Commission Decision No. C02-609 in Docket No. 02A-158E approved a Settlement Agreement, which provided for an Interim Adjustment Clause or IAC to recover the Company's Energy Costs beginning January 1, 2003. The Settlement Agreement provided that the IAC would take effect on January 1, 2003 and would remain in effect until the new rates from the Company's general rate case (this Docket No. 02S-315EG) go into effect. The Settlement Agreement in Docket No. 02A-158E provides as follows:

> At the time that the new rates from the Company's May, 2002, general rate filing go into effect, the Company shall recalculate, for the period the 2003 interim adjustment clause was in effect, the level of Energy Costs (as defined in the current ICA tariff) and level of margins that would have been charged and credited to retail customers according to whatever method of allowing recovery for the Company's energy costs is adopted in the final order on the Company's May, 2002, rate filing. To the extent there is any discrepancy between the amounts charged and credited through the 2003 interim adjustment clause and the amounts thus recalculated, the difference (positive or negative) shall be returned or charged to customers through an appropriate rate mechanism.

Interim Adjustment Clause or "IAC"; the new rates under the IAC shall take effect July 1, 2003 and shall be calculated as described in Attachment G. The rates shall be as follows: $0.01125 per kWh for transmission service; $0.01151 per kWh for primary service; and $0.01178 per kWh for secondary service.[27] The Parties agree that, following the Commission's approval of this Settlement Agreement, Public Service shall file an advice letter to put the revised IAC rates into effect on July 1, 2003.[28]

Any difference between actual 2003 Energy Costs and billed IAC revenues shall be accumulated in a deferred account. Whenever the Company has accumulated in the deferred account a balance (taking into account unbilled revenue)[29] of $20 million of over-recovery, the Company shall file to prospectively change the IAC rate. Whenever the Company has accumulated in the deferred account a balance (taking into account

[27] These rates have been calculated to recover the Company's total projected 2003 Energy Costs by December 31, 2003, assuming that the new IAC rate goes into effect on July 1, 2003. Because these rates were calculated based upon the prehearing conference held on April 3, 2003, all Parties reserve the right to review and verify prior to April 21, 2003, the specific components and computations contained in the Attachment G and to suggest any changes required to meet the agreed goal of recovering projected 2003 Energy Costs by December 31, 2003. If the Parties agree that changes should be made to these proposed rates, the Parties will file on or before April 21, 2003, a Supplement to this Settlement Agreement.

[28] The Company shall also file with the Commission on or before April 9 an application to increase the IAC on May 1. The Company shall request that the IAC be revised on May 1 to provide for the following IAC rates: Transmission Level - $ 0.00968/kwh; Primary Level - $0.00990/kwh; Secondary Level - $0.01015/kwh. These rates have been calculated to recover the Company's total projected 2003 Energy Costs by December 31, 2003, assuming the new IAC rate goes into effect on May 1, 2003. These rates would remain in effect until the new rates go into effect as a result of the Commission's order in this Docket No. 02S-315EG. Attachment L reflects the customer impacts of implementing a revised IAC on May 1, 2003. The Parties agree not to oppose the Company's application to increase the IAC on May 1 to recover by December 31, 2003 the Company's projected 2003 Energy Costs. However, all Parties reserve the right to review and verify the specific components and computations contained in the Company's application and to suggest any changes required to meet the agreed goal of recovering projected 2003 Energy Costs by December 31, 2003. If the Company's application is approved, then no additional change to the IAC rates should be necessary on July 1, 2003, unless the other provisions of this Settlement Agreement require such a change.

[29] Unbilled revenue results from cycle billing and recognizes that revenues associated with usage in a given month are not billed (hence unbilled revenue) until subsequent months.

unbilled revenue) of $30 million of under-recovery, the Company shall have the option of filing to prospectively change the IAC rate. Any prospective change to the IAC rate shall be recalculated to forecast the 2003 Energy Costs for the remainder of calendar year 2003 and to recover (or reduce to zero) over the next 12 months the accumulated deferred balance. No interest shall be paid on the balance in the deferred account. The IAC rate will terminate after December 31, 2003 and any remaining deferred balance resulting from the IAC shall be transferred to the deferred account of the ECA, discussed next.

B. 2004 - 2006 Energy Costs

The 2004-2006 Energy Costs shall be recovered through an incentive adjustment clause that is designed generally in the same manner as the Company's proposed ECA, but the test year for the amounts in the ECA base shall be the twelve-month period ending August 31, 2003, instead of calendar year 2001. By using this different test year, the Parties hope to eliminate any problems associated with the anomalous 2001 test year. This clause shall be called the Electric Commodity Adjustment or "ECA" and shall take effect January 1, 2004. Except as specifically noted in this Settlement Agreement, the 2004 through 2006 ECA shall be calculated using the method described in the testimony filed by Public Service.[30]

In its testimony, the Company described several *pro forma* adjustments that were made to 2001 test year costs in developing the ECA base formula. With the agreed change in the ECA test year, instead of the *pro forma* adjustments in the Company's

[30] To the extent that the Company's Rebuttal or Supplemental Rebuttal testimonies revise the Company's Direct Testimony on the ECA, those revisions shall be used in calculating the ECA for 2004 through 2006.

filed testimony, the following two *pro forma* adjustments to new test year numbers shall be made:

- Adjustments shall be made based upon the known and measurable contract changes with respect to gas transport costs; and
- The monthly Fixed kWh used in calculating the Fixed Energy Cost ("FEC") shall be derived by taking the total annual Fixed kWh from the new test year and spreading the test year Fixed kWh to each of the twelve calendar months based upon the average percentage of the total annual coal-based energy generated in that specific month over the years 2000 through 2002.

In addition, the incentive sharing of the differences between CPUC jurisdictional actual Energy Costs and the ECA base formula shall be changed. These changes reflect a compromise among the Parties. Many Parties filed testimony urging the Commission to adopt a 100% pass-through mechanism; other Parties urged the adoption of some form of incentive mechanism, where not all cost increases and cost savings were passed on to customers. The agreed incentive sharing mechanism is as follows. The first $15 million difference (positive or negative) in any calendar year between the ECA base formula and actual CPUC jurisdictional Energy Costs shall be shared 50/50 between retail customers and the Company. The next $15 million difference (positive or negative) shall be shared 75% retail customers and 25% Company. If the difference (positive or negative) in any calendar year exceeds $30 million, the excess amount of such difference beyond $30 million shall be passed through to retail customers. This means that the maximum "profit" or "loss" with respect to Energy Costs that will be absorbed by the Company in any one year through this incentive mechanism will be $11.25 million. The remainder of any cost savings or cost increases shall be passed through to retail customers. This mechanism insures that the difference between ECA revenue paid by customers and prudently-incurred CPUC jurisdictional energy costs will never vary more that $11.25 million, either positive or negative.

The Company shall file on or before December 1, 2003, and on or before December 1 of 2004 and 2005, the Company's proposed ECA for the subsequent year, to take effect on January 1 of the subsequent year. As described in the Company's testimony, the ECA will be based upon a forecast of the costs that the Company is entitled to recover under the ECA formula rate over the next calendar year. In addition to the forecast ECA formula costs, the ECA rates will recover (or reduce to zero) over the next 12 months any accumulated deferred balance (including unbilled revenues) in the IAC or ECA as of the prior September 30.

The ECA rates will generally be modified only on an annual basis; however, a deferred account shall track the difference between the revenues billed under the ECA and the actual ECA-recoverable costs. Whenever the deferred account (including unbilled revenues) exceeds (positive or negative) $40 million, the Company shall file to change the ECA rates prospectively. The new ECA rates shall be recalculated to forecast the ECA-recoverable costs for the remainder of the then calendar year and to recover (or reduce to zero) over the next 12 months the accumulated deferred balance. No interest shall be paid on the balance in the deferred account.

The Company shall conduct a workshop with interested Parties to explain its calculation of the 2004 – 2006 ECA as soon as the new test year data becomes available and the ECA equation is developed. The Company shall file its new ECA on or before December 1, 2003 for an effective date of January 1, 2004. At the Company's option, the Company may elect to discontinue the ECA and put into effect a 100% pass-through clause to recover Energy Costs if, in the Company's opinion, the results of the trading investigation (described below) do not provide the Company with sufficient opportunity to cover risks inherent in the ECA incentive clause. If the Company makes such election, it shall file a pass-through clause like that specified for the year 2003 with 30 days notice, no later than 60 days after the final Commission order with respect to trading.

The Company shall make an application with the Commission by April 1, 2006 addressing the Company's proposed regulatory treatment of Energy Costs incurred after December 31, 2006.[31] Until the Commission rules on the Company's application, the Company shall be entitled to a 100% pass-through of its 2007 Energy Costs; however, once the Commission issues its decision on the appropriate regulatory treatment for 2007 Energy Costs, the Company shall recalculate, for the period beginning January 1, 2007, the Energy Costs that would have been charged and credited to retail customers under the recovery mechanism ultimately adopted by the Commission in its final order with respect to the Company's April 1, 2006 application. Any differences created by this recalculation shall be factored into the calculation of the recovery mechanism approved by the Commission.

[31] The Company's application shall also address the mechanism for returning the customers' share, if any, of the trading margins earned in calendar year 2006.

C. Conditions that Apply to both the IAC and the ECA

In addition, the Parties agree that there shall be certain other conditions that shall apply to both the 2003 IAC and the 2004 – 2006 ECA. First, both the IAC and ECA rates shall be differentiated by service voltage delivery level to reflect transformation losses between delivery levels.

Second, for purposes of both the IAC and the ECA, it is agreed that it shall be considered prudent[32] for the Company to sell gas which was purchased for electric system operation, but which is not needed for certain months or certain days. Revenues from the sale of this gas will be used to offset fuel expense otherwise recovered through the IAC or ECA. This agreement on prudence is subject to the following restrictions:

- Monthly gas sales may be made for a period no greater than 31 days and may be made no earlier than 31 days in advance of the first day of delivery.
- Daily gas sales may be made only within the current calendar month.
- No more than 20,000 Dth per day of monthly gas supplies may be sold for the month.
- Monthly sales will be based on market index prices.
- No more than 50,000 Dth of daily gas may be sold per day.

Any gas sales made in connection with electric system operation that do not comply with the restrictions in this paragraph may be challenged for prudence and the Company shall bear the burden of demonstrating that such sales were prudently made.

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[32] For purposes of this section, the Company's gas sales decisions shall not be considered imprudent based solely on the decision to sell gas. A specific Company gas sales decision could be challenged based upon other factors that would suggest that the specific gas sale transaction was not conducted in a prudent manner.

Third, CPUC jurisdictional gas hedging expense shall be separately identified and recorded in an appropriate FERC account and supported by original invoice and transaction documentation. In all regulatory filings made for the IAC and the ECA, CPUC jurisdictional net gas hedging costs shall be separately identified. Unless otherwise specifically approved by the Commission, the net gas hedging costs passed through to retail customers shall be capped at $15 million for each period of May 1 through April 30.[33] The calculation for determining the net gas hedging costs applicable to the gas hedging cost cap shall include all premium costs, all settlement costs in excess of the Commission-approved floor price,[34] and all gains from gas hedging transactions. The Parties agree that the purpose of hedging is to reduce the exposure of Public Service's electric sales customers to fluctuations in the price of gas used to generate electricity. Under this hedging activity, Public Service purchases and holds the financial derivative contracts only through the expiration date of the hedging transaction. Selling financial derivatives associated with the gas hedging program shall

[33] The gas price volatility mitigation plan for electric and the related cap of $15 million described herein is intended to apply solely to the CPUC jurisdictional retail electric customers of Public Service. The Company retains the right to: (1) implement the proposed gas price volatility mitigation plan to only the CPUC jurisdictional retail customers; (2) implement the same hedging plan to both the CPUC jurisdictional retail customers and the FERC jurisdictional wholesale electric customers; or (3) implement separate hedging plans for the CPUC jurisdictional retail customers and for the FERC jurisdictional wholesale customers. In option (2) above, to the extent that the Company elects to implement the same proposed gas price volatility mitigation plan for its CPUC jurisdictional retail customers and its FERC jurisdictional wholesale customers, the net gas hedging costs from such plan will be allocated using the Company's jurisdictional allocations. If Public Service elects to implement option (3), the net gas hedging costs from the CPUC jurisdictional retail customers' gas price volatility mitigation plan will be kept separate from, and not consolidated with, those of the FERC jurisdictional wholesale gas hedging program. In doing so, Public Service will separate the hedging transactions and net gas hedging costs as between the two price volatility mitigation plans. Under any of the proposed options, the $15 million cap described in this Settlement Agreement will apply only to the net gas hedging costs allocated to the CPUC jurisdictional retail customers.

[34] If at any time during an annual period the applicable index price of the gas associated with a hedge transaction is below the Commission-approved floor price, then settlement costs during such time that represent the difference between that index price and the floor price shall not be used in calculating the $15 million gas hedging cap for that annual period.

be prohibited; the effects of any such sales should they occur shall be eliminated from the IAC and the ECA. CPUC jurisdictional net gas hedging costs under both the IAC and the ECA shall be passed through to customers, dollar for dollar. For the year 2003 and through April 30, 2004, the Parties agree that the Commission should approve a floor price of $2.75 per Dth for purposes of the gas hedging cap.[35]

Public Service shall file an annual application with the Commission for approval of its gas hedging plan. The annual filing with the Commission shall include the following information: the volume of gas to be hedged, the timing of the hedges, a description of the types of hedging instruments that the Company may use in implementing the proposed hedging plan, the floor price for determining the costs related to the gas hedging cost cap and the Company's rationale in support of its floor price, a discussion of the hedging strategy for the upcoming year including an implementation plan and the proposed hedging instruments to be used to accomplish said plan, and a proposed format[36] for reporting on the Company's use of hedging instruments. The Commission will not be requested to approve the precise hedging instruments to be employed at various gas price levels as contained in the Company's implementation plan. The annual filing shall also include, for informational purposes, the Company's projections for the calendar year of the following: the Company's gas fuel requirements for electric production; megawatt hours of electric generation; total fuel

[35] Gas supply agreements that were assigned to the Company as part of the restructuring of the Company's power purchase contracts with the Thermo Companies, approved by the Commission in Docket No. 01A-181E, shall not be included in the calculation of any annual gas hedging cap.

[36] At a minimum, the proposed format should include information identifying contract date, counter party, transaction number, strike month, contract volume, contract price, settlement amount, NYMEX natural gas contract price for the month of delivery at the time of entering into the hedge, basis at the time of entering into the hedge and relevant remarks/exceptions.

cost by fuel type including gas price forecast; and purchased energy requirements and costs. The Company shall file its gas hedging plan by January 15 of each year, to be effective March 15. For calendar year 2003, the Company shall file its gas hedging plan as soon as practicable after a final Commission order in this docket, to be effective 30 days after the filing of the plan[37].

XIII. Trading

Background. The Company described in its testimony its electric commodity trading activities. The Xcel Energy Markets business unit ("XEM") of Xcel Energy Services Inc. has developed a sophisticated trading business that purchases on the wholesale market, on behalf of Public Service,[38] short term electric energy to reduce the overall cost of serving the Company's "native load" customers.[39] The costs of these short term purchases are reflected in the Energy Costs that have been recovered from retail customers through the ICA and IAC, and in the future will be recovered in accordance with this Settlement Agreement through the IAC and then the ECA.

In addition, XEM sells on the wholesale market, on behalf of Public Service, short term electric energy that is generated from generation units owned by Public Service, that is available to Public Service under long term contracts, or that is acquired in a short term market purchase. The margins earned on these short term sales have been shared for many years between the Company and its Colorado retail customers, with

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[37] Electric Department gas hedging cost documentation shall be included with the annual IAC and ECA prudence filing which shall be made no later than August 1 of each year. The prudence filing shall include Energy Cost information from the prior calendar year and the results of the gas hedging plan from the period May 1 through April 30.

[38] XEM also purchases and sells short term electric energy on behalf of the other operating companies that are owned by Xcel Energy Inc.

[39] "Native load" customers refers to the Company's retail customers and the Company's wholesale customers served under long term contracts.

the margin sharing reflected in the Company's Energy Cost recovery mechanism, most recently the ICA. In the filed testimony, these transactions are referred to as "generation book" sales or "gen book" sales. In practice, the Company is limited in the amount of Generation Book sales that it can make due to limited transmission capacity in the neighborhood of the Company's electric system and the limited spread between the Company's production costs and the production costs of other market participants.

In addition, XEM buys and sells electric energy on the wholesale market from and to entities that are not related to Public Service or to any other Xcel Energy operating company. These purchases and sales are referred to in the testimony as "proprietary" transactions or "prop" transactions. Certain transactions are undertaken on behalf of Public Service and are recorded in what is known as the Company's "prop book"; other transactions are undertaken on behalf of other Xcel Energy operating companies. Irrespective of the operating company engaged in the trading and executing the transactions, the margins earned from these "prop" transactions are shared among the Xcel Energy operating companies in accordance with the provisions of the Joint Operating Agreement[40] approved by the Federal Energy Regulatory Commission. Public Service's share of these "prop" margins have been shared with retail customers through the Company's ICA.

The accounting for these short term transactions has been governed by a Stipulation and Agreement, dated May 31, 2000, filed in Docket No, 99A-557E (the "2000 Trading Stipulation") and approved by the Commission by Decision No. R00-830

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[40] The Joint Operating Agreement was filed in this docket as Exhibit MEM-6 to the Rebuttal Testimony of Marvin E. McDaniel. The Joint Operating Agreement refers to Proprietary Book transactions as "off-system marketing."

(August 1, 2000), attached as Attachment H. The 2000 Trading Stipulation, by its terms, applies to transactions conducted through December 31, 2002. It was anticipated that transactions conducted after that date would be governed by the outcome of this general rate case. Under the 2000 Trading Stipulation, Public Service aggregated all Generation and Proprietary book gross margins[41] earned by the Company over each calendar year. Fifty percent of the annual aggregated gross margins, if positive, were provided to the retail customers through the ICA; if the annual aggregated margin were negative, no additional costs were passed through to retail customers.

The Company initially proposed in this Docket No. 02S-315EG to continue to account for its short term transactions and to share margins generally in the same manner as set forth in the 2000 Trading Stipulation but to make two changes. First the Company requested that the definition of short-term electric energy transactions under the 2000 Trading Stipulation be expanded from transactions of 12 months or less in term length, to transactions of two years or less in term length. Second, the Company requested that there be symmetrical sharing of aggregated margins, with fifty percent of the annual aggregated trading margin, positive or negative, flowing to retail customers. In Rebuttal Testimony, the Company retracted its request for the sharing of annual aggregated negative margins and agreed to continue to absorb any net negative loss from its electric commodity trading operations.

Many Parties objected to the Company's proposal. The Answer Testimony primarily focused on concerns about the Company's initial proposal to share aggregated

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[41] See definition of gross margins in footnote below.

negative margins with customers. Many Parties questioned whether it is appropriate for a regulated utility to engage in proprietary transactions at all, some alleging that the Company may be “gambling” with customer money in an enterprise they asserted provided no benefits to the customers. Others questioned whether the sharing levels of the Generation book and Proprietary book margins were appropriate. Some Parties questioned whether the Company’s trading operations were adversely affecting the accounting for Energy Costs in the Company’s ICA. Questions were raised by Staff concerning the effects of the Joint Operating Agreement and the dynamic recent changes in the electric industry, on the accounting of the Company’s short-term energy trading activities. The Company in its Rebuttal Testimony addressed the concerns raised in the Answer Testimony.

The Parties have been engaged in extensive settlement discussions on the issue of trading. The major issues discussed have been the Company’s accounting for short term transactions, the types of short term transactions made by the Company, the risks associated with the Company’s trading activity, and the Business Rules employed by the Company to assign costs and calculate margins. It became clear through these discussions that more time would be needed than could be provided in the procedural schedule governing this general rate case to communicate with the Parties about the Company’s trading operations and the Company’s accounting for short term transactions. Consequently, the Parties agree that the terms and conditions of the 2000 Trading Stipulation shall be extended through December 31, 2004, with some important changes set forth below, while the Parties are given more time to study the Company’s trading operations.

Resolution. Specifically, the Parties agree to the procedures set forth next. First, as discussed above, the Parties agree that *pro forma* adjustments will be made for CPUC jurisdictional ratemaking purposes to reduce A&G/non-production O&M expense associated with the Company's trading business in the setting of base rates in this case. The reductions shall be $1.74 million related to Generation Book A&G/non-production O&M expense and $1 million related to Proprietary book A&G/non-production O&M expense. The same respective *pro forma* adjustments shall be made to Earnings Tests revenue requirements in years 2004 through 2006, unless modified as discussed earlier in Section III.C. of this Settlement Agreement.

Second, the Parties agree to extend all of the terms and conditions of the 2000 Trading Stipulation[42] through December 31, 2004, except that the 2000 Trading Stipulation shall be modified as set forth in this Settlement Agreement. The modifications from the 2000 Trading Stipulation for the calendar years 2003 and 2004 shall be as follows:

- Margin sharing shall be calculated separately for each of the Generation Book margins and Proprietary Book margins. Proprietary Book margins shall be calculated from Public Service's share of margins under the Joint Operating Agreement. Within each of these books, the CPUC jurisdictional Gross Margin[43] shall be aggregated annually. If the aggregated Gross Margin from

[42] The 2000 Trading Stipulation addresses several issues in addition to the sharing of margins. Except as expressly modified by this Settlement Agreement, all terms and conditions in the 2000 Trading Stipulation are extended through December 31, 2004.

[43] Gross Margins shall be defined as follows:

either book is negative, the negative margin shall not be passed on to retail customers.

- If the annual CPUC jurisdictional aggregated Gross Margin in either book is positive, then such positive annual CPUC jurisdictional Gross Margin shall be shared annually with retail customers through the ECA as follows:
    - Positive Annual Generation Book Gross Margin: Retail customers will receive the first $1.74 million; the Company will retain the next $1.74 million; and the remaining Gross Margin will be shared 60% retail customers/ 40% Company.
    - Positive Annual Proprietary Book Gross Margin: The Company shall retain the first $1 million; the remaining Gross Margin will be shared 40% retail customers/ 60% Company.
    - Timing of Margin Sharing: The Company shall file on or before April 1 of 2004, 2005 and 2006 a change to the ECA rates, to go into effect on May 1 of each year, to reflect the customer share of margins from the prior calendar year. In calculating these prospective rate changes, the Company shall first apply the customer share of margins to reduce any balance (of under recovery) in the deferred account; then the ECA

Generation Book Gross Margins = (Revenues + Option Premium Received) - (Incremental fuel costs + variable O&M costs + Purchased Energy Costs + Transmission Costs + Option Premium Purchased + Financial Penalties)

Proprietary Book Gross Margins = (Revenues + Option Premiums received) - (Purchased Energy Costs + Transmission Costs + Broker Fees + Option Premiums Purchased + Financial Penalties)

In calculating both the Generation Book Gross Margins and the Proprietary Book Gross Margins, the Company shall adjust each book for Internal Trades. The CPUC jurisdictional Gross Margin refers to the Public Service Company Gross Margin times the retail jurisdictional allocator, which is the percentage of total energy sold by Public Service that is sold to retail customers.

rates shall be reduced to return to customers any remaining customer margins over a twelve month period.

- The Company agrees that it will not request approval from the Commission to share all or a portion of any net aggregated losses from either the Generation Book or the Proprietary Book with retail customers.

The definition of short-term electric energy transaction shall be modified to include transactions of up to two years in term length. The Company agrees that the Value at Risk limits for the Generation Book and the Proprietary Book will not be increased, in whole or in part, to specifically accommodate longer term trading. The regulatory treatment set forth in this Settlement Agreement for the Generation Book shall apply to all transactions with trade dates prior to January 1, 2005, irrespective of the future delivery date.[44] There shall be no Proprietary Book trades made on behalf of Public Service with delivery dates after December 31, 2004, absent CPUC approval. The regulatory treatment set forth in this Settlement Agreement for Proprietary Book trades applies only for deliveries through December 31, 2004.

Third, by July 1, 2003, the Company shall establish and use separate general ledger accounts to track the Generation Book and Proprietary Book costs and revenues that are used to calculate the Gross Margins in each of the Generation and Proprietary Books.

Fourth, in discussions with the Staff, the OCC and CEC, the Company has reduced to writing the trading Business Rules that the Company will follow from the

[44] This means that the regulatory treatment described in this Settlement Agreement would apply to realized gains or losses from the settlement of these transactions through December 31, 2006.

effective date of this Settlement Agreement through December 31, 2004. These trading Business Rules are entitled “Public Service Company of Colorado Policy for Resource Management and Cost Assignment for Short Term Electric Energy Transactions” and are attached as Attachment J. It is understood and agreed by the Parties that the trading Business Rules set forth in Attachment J are forward-looking and may not reflect in all respects the practices used by the Company prior to the effective date of this Settlement Agreement. The Parties further agree that any departure by the Company from the specific trading business rules set forth in Attachment J is insufficient, in and of itself, to establish imprudence by the Company in connection with its trading activity prior to the effective date of this Settlement Agreement.

In following these trading Business Rules, Public Service shall use at all times prudent utility practices to make capacity and energy available to serve its firm native load obligations. All Generation Book short term sales shall be subordinate to the Company’s firm native load obligations. Generation Book short term sales and Proprietary Book short-term sales (to the extent feasible) shall be interrupted if the energy is needed for the reliability of the Company’s system.[45]

To the extent that the Company follows the specific trading Business Rules in Attachment J for transactions made prior to January 1, 2005, the Company’s actions shall be deemed prudent. The burden of proof shall shift to any party opposing specific

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[45] In today’s wholesale energy market, many short term sales are made on a “financially firm” basis. The Company can interrupt the sale if the energy is needed for its native load. However, a financial penalty could be incurred to cover the buyer’s increased cost of replacing the energy not delivered by the Company. Any financial penalty incurred shall be reflected in the calculation of Gross Margins for the appropriate trading book. The Company shall track and report the circumstances under which the Proprietary Book makes an internal trade to the Generation Book for system reliability purposes and a financial penalty was incurred.

Company actions to show either that 1) the specific Company actions were not materially consistent with the trading Business Rules in Attachment J, or 2) due to changed circumstances timely known to the Company or that should have been known to a prudent utility, the specific Company actions were not prudent.[46]

Fifth, the Company shall arrange for an agreed-upon procedures audit of its Generation Book and Proprietary Book electric commodity trading operations. The intention of the procedures audit is to demonstrate that the Company has established a clear and verifiable process from transaction initiation to final accounting with respect to its energy trading activities. The audit will use standard statistical sampling procedures, and whatever other procedures are deemed necessary by the auditor, to verify whether the Company is in substantial compliance with its established policies, practices, and procedures for the period under review. The audit shall be performed in accordance with generally accepted auditing standards by a licensed CPA accounting firm selected by the Staff and the OCC but approved by the Company under a scope of work acceptable to the Company. The Staff and the OCC shall have input into the scope of the audit, but the Company shall direct the audit. The maximum amount paid for the audit shall be the amount set forth on Confidential Attachment I[47] and such monies shall be treated as an allowable expense through the 2004 Earnings Test.

The accounting firm shall be hired by the Company and all information obtained by the auditors and the audit report shall remain the property of the Company and shall

[46] The trading business rules in Attachment J provide for an exception that allows the Company to depart from the specific business rules to provide a benefit to Public Service's customers. If the Company relies on this exception for a transaction, the Company shall bear the burden of proof that its actions were prudent with respect to the Company's deviation from the trading business rules.

[47] The amounts to be provided for the audit shall be placed under seal to avoid improperly biasing competitive procurement procedures.

be afforded Confidential protection as commercially-sensitive information. If required by the auditor, the audit work papers produced by the auditor for this procedures audit shall remain the sole property of the auditor and shall not be requested for distribution by any Party. Unless otherwise agreed by the auditor, the sole output of this procedures audit that will be available to the Parties will be the audit report. The Company reserves the right to ask the Commission that portions of the audit report and/or auditor work papers (if applicable) that contain specific highly competitively sensitive information shall be afforded Extraordinary Confidential protection, with access to the information limited to the Staff and the OCC. Other Parties reserve the right to contest whether the information in the audit report and/or the auditor work papers (if applicable) to be protected should be afforded Extraordinary Confidential Protection. The audit shall cover the period of January 1, 2003 through June 30, 2003 and shall be conducted and completed by October 1, 2003.

The audit report shall contain the following information: a description of Xcel Energy Market's Front, Middle and Back Offices; a description of transaction flow through the various Offices; a description of the controls established to ensure deal and data integrity; a description of audit tests used to validate transaction cost accounting and record keeping; any substantive findings of non-compliance from the Company's policies, practices and procedures for the period under review; and any differences in the Company's policies, practices and procedures for the period under review from the Company's policies, practices and procedures set forth on Attachment J. The audit report shall be supplied to interested persons who have executed non-disclosure agreements in this Docket No. 02S-315EG, so long as each such person is qualified under the Commission's Confidentiality Rules to receive confidential information. The audit report may be used in connection with the Commission proceedings on the Company's application for review of its trading operation described next.

Sixth, in January 2004 the Company shall file an application for Commission review of its electric commodity trading operation, including the Company's proposal as to the Colorado regulatory treatment to be afforded the Company's trading operations, the Company's trading business rules and the Company's cost assignment and cost allocation procedures related to short term wholesale transactions. To facilitate review of the Company's fuel cost allocations to short term wholesale transactions, the Company agrees to retain records, beginning with the effective date of this Settlement Agreement, of the following daily information: 1) the day-ahead estimated gas prices by generation plant that the Company currently uses to dispatch its generation and to assign costs to wholesales sales; 2) the estimated gas price worksheet updated using actual gas commodity indices published for the gas day corresponding to the electric trading day; and 3) the gas commodity indices for the gas day.

The Parties expect that this trading investigation case would be completed prior to October 15, 2004.[48] The Commission Order resulting from the Company's application will govern the Colorado regulatory treatment of the Company's trading operation post December 2004. Any change in cost assignment, cost allocation or in the trading Business Rules ordered by the Commission would apply prospectively only, beginning January 1, 2005. As previously discussed, the Company reserves the right to terminate

[48] On November 1 of each year the Company must commit whether it wishes to continue to reserve firm transmission paths. In order to do so, the Company must know the Commission's decision with respect to the Colorado regulatory treatment to be afforded its trading operations.

the ECA and implement instead an adjustment mechanism for 100% pass-through of Energy Costs, should the Company believe that the Commission Order does not afford the Company with sufficient opportunity to cover the risks inherent in an incentive adjustment mechanism.

Seventh, within one month~~s~~ of the effective date of this Settlement Agreement, the Company shall provide funds (up to the amount set forth on Confidential Attachment I)[49] to hire a consultant selected by the trial Staff and OCC, who shall be, at all times, under the personal direction of the Chief of Fixed Utilities for the Staff, in consultation with the Director of the OCC. The consultant shall provide the trial Staff and OCC with technical advice and consulting services regarding prospective changes that should be made, if any, to the Colorado regulatory treatment of the Company's trading activities. Staff and the OCC shall determine the scope and nature of the investigative and consulting services provided by the consultant. Such consultant shall act as an advisor to the trial Staff and OCC during the Commission's review of the Company's trading application, described above. Such consultant may be advising or testifying as directed by the trial Staff and OCC in response to the Company's application. The Company's expenditures for this consultant shall be fully recoverable, dollar for dollar, as a separate expense through the Company's IAC and/or ECA, depending upon the year in which all or part of these expenditures are made.

XIV. Windsource and the Base Energy Credit

Background. Public Service proposed as part of its Phase I filing to recover all Energy Costs through its proposed ECA clause. However, until rates are redesigned in

[49] The amounts to be provided for the consultant shall be placed under seal to avoid improperly biasing competitive procurement procedures.

Phase II, the Company's current base rates contain recovery of $12.78 per MWh of Energy Costs. To avoid double recovery of this expense pending the completion of Phase II, the Company proposed a Base Energy Credit for all customers who were paying both a base rate and the ECA for their energy consumption. The Company excluded Windsource energy from receipt of the Base Energy Credit because Windsource customers would not pay the ECA for Windsource energy purchases.

The LAW Fund opposed the exclusion of Windsource energy from receipt of the Base Energy Credit because it argued it would violate the rate cap on the Windsource premium and the market-based pricing principles established by the Stipulation and Agreement in Docket No. 96A-401E (the "Windsource Stipulation"). Without agreeing with the LAW Fund's interpretation of the Windsource Stipulation, the Company does agree that the Base Energy Credit mechanism may give the wrong impression to Windsource customers as to the relative cost of wind energy vis-à-vis non-wind energy.

Resolution. The Company proposes, and all Parties agree, that pending the conclusion of the Phase II rate case, the Company's base rates shall continue to recover $12.78 per MWh, the Company's fuel clause (first the IAC and then the ECA) shall recover Energy Costs in excess of $12.78 per MWH, and the Company shall withdraw its proposed Base Energy Credit. The Company reserves the right in Phase II to remove Energy Costs from base rates and to recover all of this expense through an adjustment clause and the LAW Fund and other Parties reserve the right to respond to the Company's proposal. The Company agrees to work informally with the LAW Fund and other interested Parties to evaluate the costs of service for the Windsource program. The Company, the LAW Fund and the other Parties further reserve the right to propose a stand-alone rate for Windsource energy in lieu of the rate rider mechanism in the current tariffs.

Further the Parties agree that the Company's proposal in its Supplemental Rebuttal testimony to withdraw its proposed Windsource Production Capacity Adjustment should be accepted. As a result, the Company does not propose in this Docket a Windsource-related adjustment to revenue requirements.

XV. Special Amortizations

Background. Historically, the Commission has not generally adjusted tariffs for amortizations that occur between rate cases. However, in the last decade, amortizations have assumed a greater importance to Parties in their calculations to synchronize revenues and expenses. In its Answer Testimony, Staff recommended that certain amortized costs be recovered via a rider that is placed on a "preface page" of the Company's tariff, that the Company track the amounts collected by the rider, and that the Company file with the Commission for reduction (or elimination) of the rider at the time such amortized costs are recovered. In Rebuttal Testimony, Public Service objected to this specialized rate treatment for such a small increment of costs as excessively burdensome and unnecessary and inconsistent with test period ratemaking.

Resolution. In resolution of this issue, the Parties agree that the Company shall file by June 1, 2007, an advice letter on 30 days' notice to place into effect a negative general rate schedule adjustment rider that reduces base rates to eliminate the amortizations for the Pawnee 2 Pre-engineering costs and the Metro Ash Disposal Site option, as provided herein.[50] The negative rider shall be calculated using (1) twelve full months of amortization expense related to the amortization of Pawnee 2 Pre-engineering costs and the Metro Ash Disposal Site option and (2) a test year ending not earlier than seven months prior to June 30, 2007. If the rate changes resulting from this Settlement Agreement are delayed to the extent they become effective after July 1, 2003, then the date on which Public Service is required by this section to file an advice letter to implement a negative rider to eliminate the referenced amortizations shall be delayed by an equal number of days.

XVI. Transmission Reliability

Background. In Answer Testimony, Staff raised concerns about the Company's transmission planning criteria, the Company's ranking of projects, and the timeliness of Company investment in transmission additions. The Company responded with Rebuttal Testimony explaining its planning criteria and its commitment to make timely and sufficient investment in transmission facilities to maintain system reliability.

Resolution. Due to the complexity of these issues, the Company, Staff and the OCC agree that the issues need not be resolved as part of this proceeding. Public Service commits to meet with Staff and the OCC by April 15, 2003 and thereafter as necessary to address and resolve, if possible, Staff's and the OCC's concerns raised in this proceeding concerning transmission planning and reliability criteria. The Company, Staff and the OCC agree to engage in good faith discussions to resolve these issues in a reasonable manner and on a reasonable timeline that shall not exceed six months

[50] The Parties intent is to eliminate from base rates the amortization expense associated with the Pawnee 2 pre-engineering costs and the Metro Ash Disposal Site option following the 48-month amortization period. The Parties agree that in the event that an intervening rate proceeding prior to the expiration of the four-year amortization period, this aspect of the Settlement Agreement will need to be revisited so as to accomplish the Parties' intent.

from the effective date of this Settlement Agreement. As part of the process, the Company's subject matter experts will be available to explain the Company's position with respect to its interpretation and its use of transmission planning criteria.

To assist the discussions, the Company shall provide updates, as applicable, on all transmission projects identified in the N-1 filings pursuant to Decision No. C01-67, Docket No. 00A-067E. The Company also agrees to make available for Staff's and the OCC's review all existing supporting data it has available that demonstrate how the Company performs studies and plans its facilities to meet the N-1 performance standard. These data shall include but are not limited to: data with respect to the Company's as-constructed loading capabilities of transmission lines and associated priority assessment processes related thereto; the impact on generation redispatch; the potential for loss of load; and switching alternatives the Company uses in prioritizing transmission investment.

This Settlement Agreement does not intend to require the Company to generate any new documentation or studies. This Settlement Agreement shall not be construed to limit Staff's or the OCC's ability to request or receive the data necessary to perform their own studies or analyses if either Staff or the OCC ultimately determines that such analyses are necessary. In the event the issues are not resolved, the Company, the Staff and the OCC reserve their rights to pursue these issues in future Commission proceedings.

XVII. Ratemaking Principles for Future Earnings Test Filings

For the 2004 through 2006 Earnings Tests the electric earnings sharing shall be measured on the basis of an Earnings Test that uses the ratemaking principles and treatments specified in the following sections of this Settlement Agreement:

- Rate of Return and Capital Structure;
- Plant Held for Future Use;
- Insurance Expense;
- Pension Expense;
- Trading A&G and Non Production O&M Expense;
- Oil and Gas Royalty Revenues;
- Dark Fiber;
- Regulatory Treatment of C.R.S. § 40-3-104.3(2)(a) discounts;
- Cost Allocation Between Regulated and Non-Regulated Business Activities; and
- Reclassification of Substation Plant and Treatment of Radial Transmission Lines
- Sterling Correctional Facility

In addition, the Parties agree that the 2004 through 2006 Earnings Tests shall reflect the jurisdictional allocation methods used in developing the electric revenue requirement approved as a part of this Settlement Agreement and all other cost assignment/allocation methods identified in the Company's then current CAM on file with the Commission.

For the test periods 2004 through 2006, sharing percentages for earnings over 10.75 percent return on equity shall be as follows:

Measured Return on Equity	Sharing Percentages	
(10.75)	Customers	Company
>10.75% ≤ 11.75%	65%	35%
>11.75% ≤ 13.75%	50%	50%
>13.75% ≤ 14.75%	35%	65%
over 14.75%	100%	

XVIII. QFCCA

Background. In its Direct Case filed on May 31, 2002, the Company proposed to eliminate its current tariff with respect to the Qualifying Facility Capacity Cost Adjustment ("QFCCA"). The new base rates proposed by the Company would recover the Company's capacity cost associated with purchases from Qualifying Facilities (QFs) going forward. On March 29, 2002, the Company had set the QFCCA rate at 0.00% in order to work off a projected deferred balance of over-recovery of the QF capacity costs by January 1, 2003. However, the delay in the establishment of new rates from the rate case from January 1, 2003 until potentially July 1, 2003 has caused the QFCCA deferred account to go from an over-recovery balance to an under-recovery balance. The recovery of the remaining QFCCA deferred balance needs to be addressed.

Resolution. The Parties agree that the Company shall file an advice letter requesting authorization to terminate the QFCCA effective April 30, 2003. At that time, the Company shall stop accumulating costs in the QFCCA deferred account. The account shall remain open to reflect revenues associated with electric usage occurring prior to April 30, 2003, which will be booked into subsequent months due to cycle billing. The Company shall restate the federal/state jurisdictional split of the QF capacity costs for the 12 months ending June 30, 2003 in order to reflect the actual jurisdictional split for that period. The Parties agree that the Company shall be entitled to recover the remaining QFCCA deferred balance if under-recovered, or shall be required to return the remaining QFCCA deferred balance if over-recovered, over a period of not more than twelve months. Once the deferred balance is known, the Company shall file with the Commission an application setting forth the mechanism that shall be used to recover (or return) the deferred balance. The Parties reserve the right to suggest alternatives to the Company's proposed mechanism.

IMPLEMENTATION

The Parties hereto agree that the rate and tariff changes resulting from this Settlement Agreement should be approved by the Commission to become effective July 1, 2003. Attached as Attachment K are *pro forma* tariff sheets reflecting the rate and tariff changes resulting from this Settlement Agreement. The Parties hereto agree that upon a final Commission order approving this Settlement Agreement in all material respects, Public Service will file with the Commission amended advice letters on not less than one days' notice to the place into effect revised tariff sheets in the form reflected in Attachment K hereto to become effective July 1, 2003.

GENERAL TERMS AND CONDITIONS

The Parties hereby agree that all pre-filed testimony and exhibits shall be admitted into evidence in this docket without cross-examination. This Settlement Agreement reflects compromise and settlement of all issues raised or that could have been raised in this Docket. This Settlement Agreement shall be filed as soon as possible with the Commission for Commission approval.

This Settlement Agreement shall not become effective until the issuance of a final Commission Order approving the Settlement Agreement, which Order does not contain any modification of the terms and conditions of this Settlement Agreement which is unacceptable to any of the Parties. In the event the Commission modifies this Settlement Agreement in a manner unacceptable to any Party, that Party shall have the right to withdraw from this Agreement and proceed to hearing on the issues that may be appropriately raised by that Party in this docket. The withdrawing Party shall notify the Commission and the Parties to this Agreement by e-mail within three business days of the Commission modification that the Party is withdrawing from the Settlement Agreement and that the Party is ready to proceed to hearing; the e-mail notice shall designate the precise issue or issues on which the Party desires to proceed to hearing (the "Hearing Notice").

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

Hearing shall be scheduled on all of the issues designated in the formal notice filed with the Commission as soon as practicable. In the event that this Agreement is not approved, or is approved with conditions that are unacceptable to any Party who subsequently withdraws, the negotiations or discussions undertaken in conjunction with the Agreement shall not be admissible into evidence in this or any other proceeding, except as may be necessary in any proceeding to enforce this Settlement Agreement.

Approval by the Commission of this Agreement shall constitute a determination that the Agreement represents a just, equitable and reasonable resolution of all issues that were or could have been contested among the Parties in this proceeding.

All Parties specifically agree and understand that this Settlement represents a negotiated settlement in the public interest with respect to the various Public Service rate matters and terms and conditions of service for the sole purpose of the settlement of the matters agreed to in this Settlement. Neither Public Service, the Commission, its Staff or any other party or person shall be deemed to have approved, accepted, agreed to or consented to any concept, theory or principle underlying or supposed to underlie any of the matters provided for in this Settlement, other than as specifically provided for herein with respect to the 2004, 2005 and 2006 Earnings Tests. Notwithstanding the resolution of the issues set forth in this Stipulation, none of the methods or ratemaking principles herein contained shall be deemed by the Parties to constitute a settled practice or precedent in any future proceeding (other than the aforementioned electric Earnings Test proceedings). Nothing in this Settlement Agreement shall preclude the Company from seeking prospective changes in its electric, gas or steam rates by an appropriate filing with the Commission. Nothing in this Settlement Agreement shall preclude any other party from filing a Complaint or seeking an Order to Show Cause to obtain prospective changes in the Company's electric, gas or steam rates.

The Parties to this Agreement state that reaching agreement in this docket as set forth in this Agreement by means of a negotiated settlement is in the public interest and that the results of the compromises and settlements reflected by this Agreement are just, reasonable and in the public interest.

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

Dated this 4th day of April, 2003.

Respectfully submitted,

Public Service Company of Colorado
Rate Case Changes by Issue

Line No.	Description	Gas	Electric	Thermal Energy
1	Original Filing Revenue Change	2,581,416	74,404,991	1,360,827
2				
3				
4	Change due to Restructured Thermo Contract	0	(14,092,749)	0
5	Change due to errors in Revenue Credits	0	(54,586)	0
6	Change due to errors in gas dept. revenue requirements calculation	(332,250)	0	0
7				
8	Revenue Change 8/07/02 Corrected Filing	2,249,166	60,257,656	1,360,827
9				
10				
11	Depreciation Expense	609,935	(29,266,852)	(4,658)
12				
13				
14	Change due to revised lead/lag factors	(9,013,837)	(6,995,215)	(197,976)
15	Change due to error in capital structure	196,024	625,622	2,726
16	Change due to error in Revenue Credits	0	(293,110)	0
17	Change due to reallocation of rent expense adjustments	262,079	(241,646)	0
18	Change due to error in Thermal CWC calculation	0	0	(11,723)
19	Change due to error in amortization of gas rate case expenses	(46,327)	46,868	0
20	Change due to error in common deferred tax amounts	(712,048)	637,097	4,484
21	Change due to non-gratuitous charges	37,464	91,442	0
22	Change due to error in income tax calculation	(474,375)	(5,409,795)	(9,288)
23	Change due to Wholesale Bad Debt	0	(506,420)	0
24				
25	Revenue Change with Corrections through 1/23/03 Stipulation	(6,891,919)	18,945,647	1,144,393
26				
27				
28	Functional Allocator (DISTOPX to DISTMAX)	0	2,571	0
29	Postage Expense	31,044	12,232	(43,815)
30	Reallocation of CPUC Fees	(916,528)	948,119	(13,696)
31	Storm Expenses	(5,037)	(247,191)	0
32	Sterling Correctional Facility	0	(68,241)	0
33	TRANSLink	0	(7,613)	0
34	Windsource	0	(52,913)	0
35	Gas Storage - Average Cost	(139,269)	0	0
36	A&G and Customer O&M Load to Non-Utility Products & Services	(346,964)	(1,110,802)	0
37	Change Functional Allocator	0	(315,517)	0
38	Change Plant Allocator to Gross Plant incl Contrib.	0	5,891	0
39	Common Plant Allocator	1,881,482	(1,918,800)	2,210
40				
41	Revenue Change - Rebuttal Testimony 1/24/03	(6,387,191)	16,193,383	1,089,092
42				
43				
44	Common Plant Allocation - CIS	(44,220)	(44,665)	(8)
45	Gas Customer Deposit Interest	447,010	0	0
46	Windsource Adjustment	0	(1,645,336)	0
47				
48	Revenue Change - Supplemental Rebuttal Testimony 2/12/03	(5,984,401)	14,503,382	1,089,084
49				
50				
51	ROE - 10.75% Electric; 11% Gas & Thermal	(9,271,155)	(29,181,158)	(129,145)
52	Average Rate Base	(2,837,274)	(9,089,218)	(181,497)
53	Future Use Plant	0	(646,679)	0
54	Gas Storage Adjustment	(1,975,047)	0	0
55	Actual 2002 Insurance expense	(451,453)	(1,089,137)	0
56	Actual 2002 Purchase capacity costs	0	3,683,320	0
57	Trading A&G and non-production O&M adjustment	0	(2,736,058)	0
58	Oil & Gas Royalties Revenue	0	(1,478,277)	0
59	PSCo Pension Expense Adjustment	2,675,802	4,950,196	102,211
60	Allocation of Labor - A&G	0	(707)	0
61	Specific Assignment of Customer Service and Sales Expense	0	1,634	0
62				
63	Revenue Change - Settlement	(17,843,528)	(21,082,702)	880,853
64				
65	Revenue from Riders expiring with Phase 1 rates	15,483,440	(20,852,893)	906,698
66				
67	Net Change to Annual Revenue	(33,326,968)	(229,809)	(26,045)

Public Service Company of Colorado
Calculation of Riders
At December 31, 2001

Line No.	Description	Electric	Gas	Thermal
1	CPUC Jurisdictional Revenue Requirement	$ 1,407,008,137	$275,849,341	$ 8,405,117
2				
3	CPUC Jurisdictional Pro Forma Revenue	$ 1,428,090,839	$293,692,869	$ 7,524,464
4				
5	Required Revenue Increase / (Decrease)	$ (21,082,702)	$ (17,843,528)	$ 880,653
6				
7				
8	CPUC Jurisdictional Pro Forma Revenue	$ 1,428,090,839	$293,692,869	$ 7,524,464
9				
10	Less: Street Light Maintenance Revenue	$ 826,853		
11	Transformer Rental Revenue	$ 237,828		
12	Gas Transportation Discount Revenue		$ 5,673,683	
13				
14	Adjusted CPUC Jurisdictional Revenue	$ 1,427,026,158	$288,019,186	$ 7,524,464
15				
16	Required Revenue Increase	$ (21,082,702)	$ (17,843,528)	$ 880,653
17				
18	Less: Increase in Street Light Maintenance Revenue	$ 671,488		
19				
20	Increase Subject to Rider	$ (21,754,190)	$ (17,843,528)	$ 880,653
21				
22	Percent Rider	-1.52%	-6.20%	11.70%

Public Service Company of Colorado
Revenue Requirements Calculation - Electric Rate Base
At December 31, 2001

Line No.	Description	Plant in Service	Construction Completed Not Classified	Total Electric	Adjustments	Adjusted Total Electric	Adjusted Total FERC	Adjusted Total CPUC
1	Total Intangible	29,609,998	(165,322)	29,444,676	(29,444,676)	(0)	0	(0)
2	Total Steam Production	1,465,263,570	208,906,917	1,674,170,487	(32,780,934)	1,641,389,553	269,843,201	1,371,546,352
3	Total Hydraulic Production	63,513,241	5,166,512	68,679,753	2,286,349	70,966,102	11,666,775	59,299,327
4	Total Internal Combustion Equipment	147,895,850	247,263,710	395,159,560	(45,400,610)	349,758,950	57,500,108	292,258,842
5	**Total Production Plant**	1,676,672,661	461,337,139	2,138,009,800	(75,895,195)	2,062,114,605	339,010,084	1,723,104,521
6								
7	Total Transmission Plant	590,518,928	98,419,858	688,938,786	(12,751,557)	676,187,229	137,286,192	538,901,037
8	Total Distribution Plant	2,001,119,194	275,135,490	2,276,254,684	(129,602,870)	2,146,651,814	5,468,731	2,141,183,083
9	Total General Plant	35,659,747	16,609,222	52,268,969	1,252,756	53,521,725	5,278,432	48,243,293
10	Common Plant Allocated			249,635,247	65,124,081	314,759,328	31,042,266	283,717,062
11	**Total Electric Plant in Service**	4,333,580,528	851,336,387	5,434,552,162	(181,317,461)	5,253,234,701	518,085,705	4,735,148,996
12								
13	Total Reserve for Depreciation & Amortization			2,099,888,336	(71,443,707)	2,028,444,629	217,312,687	1,811,131,942
14								
15	**Total Net Plant in Service**			3,334,663,826	(109,873,754)	3,224,790,072	300,773,018	2,924,017,054
16								
17	Total Plant Held for Future Use			56,255,815	(45,797,037)	10,458,778	1,429,968	9,028,810
18	Total Construction Work in Progress			204,017,466	19,502,586	223,520,052	18,217,445	205,302,607
19	**Total Plant**			3,594,937,107	(136,168,205)	3,458,768,902	320,420,431	3,138,348,471
20								
21	Utility Materials & Supplies			35,300,591	(11,239,708)	24,060,883	2,372,938	21,687,945
22	Total Fuel Inventory			20,495,857	0	20,495,857	3,369,503	17,126,354
23	Total Cash Working Capital - Direct			4,771,191	(22,227,308)	(17,456,117)	(1,274,789)	(16,181,330)
24	Total Cash Working Capital - Service Company Charges			3,982,631		3,982,631	417,618	3,565,013
25	Regulatory Asset			0	52,278,000	52,278,000	4,875,918	47,402,082
26	Prepaid Assets			45,219,493	(6,724,101)	38,495,392	3,910,307	34,585,085
27	Total Accumulated Deferred Income Taxes			(389,026,587)	(58,951,303)	(447,977,890)	(41,782,461)	(406,195,429)
28	QF Deposits			(3,571,042)	1,268,542	(2,302,500)	(378,529)	(1,923,971)
29	Customer Deposits			(12,808,709)	339,484	(12,469,225)	0	(12,469,225)
30	Customer Advances for Construction			(59,520,947)	4,006,262	(55,514,685)	(55,856)	(55,458,829)
31								
32	**Net Original Cost Rate Base**			3,239,779,585	(177,418,337)	3,062,361,248	291,875,080	**2,770,486,166**

Public Service Company of Colorado								
Revenue Requirements Calculation - Electric Expenses								
12 Months Ended December 31, 2001								
						Adjusted	Adjusted	Adjusted
Line				Total		Total	Total	Total
No.	Description	Labor	Non-Labor	Electric	Adjustments	Electric	FERC	CPUC
1	**Cost of Sales**							
2	Total Steam Production Fuel	0	200,778,560	200,778,560	(17,492,942)	183,285,618	32,433,920	150,851,698
3	Total Combustion Production Fuel	0	150,862,200	150,862,200	0	150,862,200	26,696,326	124,165,874
4	Deferred Electric Generation Costs	0	(5,077,553)	(5,077,553)	5,077,553	0	0	0
5	Total Purchased Power	0	2,234,555,483	2,234,555,483	(1,635,877,947)	598,677,536	101,643,513	497,034,023
6	Deferred Purchased Power - QF	0	852,183	852,183	(852,183)	0	0	0
7	**Total Cost of Sales**	0	2,581,970,873	2,581,970,873	(1,649,145,519)	932,825,354	160,773,759	772,051,595
8								
9	Total Steam Production Operation	33,030,046	30,440,054	63,470,100	(1,250)	63,468,850	10,805,596	52,663,254
10	Total Steam Production Maintenance	25,794,911	7,448,470	33,243,381	(2,463,418)	30,779,963	5,400,123	25,379,840
11	Total Hydro Production Operation	1,430,995	752,065	2,183,060	991	2,184,051	360,303	1,823,748
12	Total Hydro Production Maintenance	605,693	247,134	852,827	(8,762)	844,065	143,310	700,755
13	Total Combustion Turbine Production Operation	1,728,991	856,766	2,585,757	(343,707)	2,242,050	368,618	1,873,432
14	Total Combustion Turbine Production Maintenance	4,273,868	3,253,223	7,527,091	(550,000)	6,977,091	1,147,028	5,830,063
15	Total Other Production	38,094	247,128	285,222	99,468	384,690	63,242	321,448
16	**Total Production O&M**	66,902,598	43,244,840	110,147,438	(3,266,678)	106,880,760	18,288,220	88,592,540
17								
18	Total Transmission Operations	4,123,092	2,712,489	6,835,581	0	6,835,581	1,395,609	5,439,972
19	Total Transmission Maintenance	1,594,224	994,337	2,588,561	(4,311)	2,584,250	524,679	2,059,571
20	Total Wheeling	0	8,468,085	8,468,085	(2,134,600)	6,333,485	1,286,834	5,046,651
21	**Total Transmission O&M**	5,717,316	12,174,911	17,892,227	(2,138,911)	15,753,316	3,207,122	12,546,194
22								
23	Total Distribution Operations	17,936,137	5,989,440	23,925,577	(288,348)	23,637,229	107,588	23,529,641
24	Total Distribution Maintenance	19,324,224	3,013,122	22,337,346	(236,182)	22,101,164	33,151	22,068,013
25	**Total Distribution O&M**	37,260,361	9,002,562	46,262,923	(524,530)	45,738,393	140,739	45,597,654
26								
27	Total Customer Accounting Expense	14,215,798	25,364,765	39,580,563	(1,237,233)	38,343,330	517,806	37,825,524
28	Total Customer Service Expense	1,242,436	1,034,998	2,277,434	(443,372)	1,834,062	57,482	1,776,580
29	Total Sales Expense	4,893,132	1,957,234	6,850,366	(4,384,757)	2,465,609	359,434	2,106,175
30	**Total Customer O&M**	20,351,366	28,356,997	48,708,363	(6,065,361)	42,643,002	934,722	41,708,280
31								
32	Total Administrative & General Expense	59,831,367	81,707,870	141,539,237	(19,631,800)	121,907,437	12,339,400	109,568,037
33	**Total O&M Expense Excluding Fuel & Purchased Power**	190,063,008	174,487,180	364,550,188	(31,627,280)	332,922,908	34,910,203	298,012,705
34								
35	Total Depreciation & Amortization Expense			181,480,701	(39,742,336)	141,738,365	13,505,561	128,232,804
36	Total Taxes Other Than Income	134,296	52,724,637	52,858,933	6,654,650	59,513,583	5,895,137	53,618,446
37	Total Income Tax Expense			109,481,566	(3,687,772)	105,793,794	10,557,471	95,236,323
38	Gain on Disp. of Allowances			0		0	0	0
39	Gain on Utility Plant			0		0	0	0
40								
41	**Total Operating Deductions**			3,290,342,261	(1,717,548,257)	1,572,794,004	225,642,131	1,347,151,873
42	Total AFUDC Addition			11,144,917	921,411	12,066,328	983,436	11,082,892
43	Total Deductions			3,279,197,344	(1,718,469,668)	1,560,727,676	224,658,695	1,336,068,981
44								
45	Revenue Requirements			3,573,369,330	(1,718,469,668)	1,838,790,077	251,160,952	1,587,629,125
46								
47	Total Revenue Credits - General Overhead			(40,653,418)	51,547,759	10,894,341	1,170,593	9,723,748
48	Total Revenue Credits - System Services			32,580,431	(25,880,980)	6,699,451	301,907	6,397,544
49	Total Revenue Credits			(8,072,987)	25,666,779	17,593,792	1,472,500	16,121,292
50	Net Revenue Requirements			3,581,442,317	(1,744,136,447)	1,821,196,285	249,688,452	1,571,507,833
51								
52	Adjust to ICA Base Cost Level							(164,499,696)
53								
54	**Total Adjusted CPUC Revenue Requirement**					1,821,196,285	249,688,452	**1,407,008,137**

Public Service Company of Colorado
Revenue Requirements Calculations - Gas Rate Base
At December 31, 2001

Line No.	Description	Plant in Service	Construction Completed Not Classified	Total Gas	Adjustments	Adjusted Total Gas
1	Total Intangible Plant	7,580,498	2,859	7,583,357	(199,169)	7,384,188
2	Total Production & Gathering Plant	6,183,136	(162,002)	6,021,134	220,556	6,241,690
3	Total Products Extraction Plant	4,326,995	793,565	5,120,560	(547,452)	4,573,108
4	Total Underground Storage	38,481,622	2,012,159	40,493,781	(297,492)	40,196,289
5	Total Transmission Plant	209,698,891	25,121,209	234,820,100	(11,215,470)	223,604,630
6	Total Distribution Plant:	921,358,261	127,962,126	1,049,320,387	(27,747,877)	1,021,572,510
7	Total General Plant	10,764,131	3,215,763	13,979,894	(1,756,456)	12,223,438
8	Gas Stored Underground			5,969,346	0	5,969,346
9	**Total**	1,198,393,534	158,945,679	1,363,308,559	(41,543,359)	1,321,765,200
10						
11	Common Plant Allocated			218,020,281	(91,495,022)	126,525,259
12	Total Gas Plant in Service	1,198,393,534	158,945,679	1,581,328,840	(133,038,381)	1,448,290,459
13						
14	Total Reserve for Depreciation and Amortization			610,064,340	(66,866,235)	543,198,105
15						
16	Total Net Plant in Service			971,264,500	(66,172,146)	905,092,354
17						
18	Total Plant Held for Future Use			1,203,520	0	1,203,520
19	Total Construction Work in Progress			40,060,147	(4,257,222)	35,802,925
20						
21	**Total Plant**			1,012,528,167	(70,429,368)	942,098,799
22						
23	Utility Materials and Supplies			5,115,632	(1,628,817)	3,486,815
24	Gas Stored Underground Average Balance			42,173,642	8,653,877	50,827,519
25	Total Cash Working Capital - Direct			(638,930)	(1,520,872)	(2,159,802)
26	Total Cash Working Capital - Service Company Charges			1,902,131		1,902,131
27	Regulatory Asset			0	4,021,500	4,021,500
28	Prepaid Assets			15,157,533	(2,253,913)	12,903,620
29	Total Accumulated Deferred Income Taxes			(77,546,426)	(46,498,553)	(124,044,979)
30	Lease Accruals			0		0
31	Customer Deposits			(10,475,618)	277,648	(10,197,970)
32	Customer Advances for Construction			(26,061,541)	1,935,923	(24,125,618)
33						
34	**Net Original Cost Rate Base**			962,154,590	(107,442,575)	854,712,015
35						
36	Allocated to FERC					4,114,584
37						
38	**Net CPUC Jurisdictional Rate Base**			962,154,590	(107,442,575)	**850,597,431**

Public Service Company of Colorado						
Revenue Requirements Calculation - Gas Expenses						
12 Months Ended December 31, 2001						
Line No.	**Description**	**Labor**	**Non-Labor**	**Total Gas**	**Adjustments**	**Adjusted Total Gas**
1	**Cost of Sales**					
2	Total Gas Purchased for Resale	192,428	932,936,758	933,129,186	(933,129,186)	0
3	Total Other Gas Supply	262,810	(1,796,268)	(1,533,458)	0	(1,533,458)
4	Total Underground Storage	662,491	991,396	1,653,887	0	1,653,887
5	Total Production Expense	30,383	39,891	70,274	0	70,274
6	Total Products Extraction Expense	92,494	1,129,511	1,222,005	0	1,222,005
7	**Total Production O&M**	1,240,606	933,301,288	934,541,894	(933,129,186)	1,412,708
8						
9	Total Transmission Operations	2,259,571	7,739,488	9,999,059	(3,207,708)	6,791,351
10	Total Transmission Maintenance	629,159	519,048	1,148,207	0	1,148,207
11	**Total Transmission O&M**	2,888,730	8,258,536	11,147,266	(3,207,708)	7,939,558
12	Total Distribution Operations	14,564,923	4,770,659	19,335,582	(12,506)	19,323,076
13	Total Distribution Maintenance	6,360,087	1,223,169	7,583,256	0	7,583,256
14	**Total Distribution O&M**	20,925,010	5,993,828	26,918,838	(12,506)	26,906,332
15	Total Customer Accounting	12,606,462	22,260,631	34,867,093	(1,133,562)	33,733,531
16	Total Customer Service	1,049,151	775,830	1,824,981	(71,934)	1,753,047
17	Total Sales Expense	499,328	418,949	918,277	0	918,277
18	Total Customer Operations	14,154,941	23,455,410	37,610,351	(1,205,496)	36,404,855
19	Total Administrative & General	24,499,662	34,008,801	58,508,463	(9,722,166)	48,786,297
20	**Total O&M**	63,708,949	1,005,017,863	1,068,726,812	(947,277,062)	121,449,750
21						
22	Total Depreciation & Amortization Expense			55,491,180	(13,754,913)	41,736,267
23						
24	Total Taxes Other Than Income			16,948,243	1,802,000	18,750,243
25	Total Income Tax Expense			31,749,614	(3,550,451)	28,199,163
26	Gain on Disp. of Allowances			0		0
27	Gain on Utility Plant			0		0
28	**Total Operating Deductions**			1,172,915,849	(962,780,426)	210,135,423
29						
30	AFUDC Addition			1,314,989	370,384	1,685,373
31	**Total Deductions**			1,171,600,860		208,450,050
32						
33	Allocated to FERC					3,308,102
34						
35	CPUC Jurisdictional Expenses			1,171,600,860		205,141,948
36						
37	**Revenue Requirements**			1,260,119,082		283,396,912
38						
39	Total Revenue Credits			6,978,662	690,621	7,669,283
40						
41	Allocated to FERC					121,712
42						
43	CPUC Jurisdictional Revenue Credits					7,547,571
44						
45	**Net Revenue Requirements**			1,253,140,420		**275,849,341**

Public Service Company of Colorado
Revenue Requirements Calculation - Thermal
12 Months Ended December 31, 2001

Line No.	Description	Plant in Service	Construction Completed Not Classified	Total Thermal	Adjustments	Adjusted Total Thermal
1	Total Intangible Plant	1,044,049	0	1,044,049	0	1,044,049
2	Total Production Plant	4,092,854	256,069	4,348,923	(13,971)	4,334,952
3	Total Distribution Plant	13,552,028	1,395,900	14,947,928	(331,296)	14,616,632
4	Total General Plant	10,241	0	10,241	0	10,241
5						
6	**Total**	18,699,172	1,651,969	20,351,141	(345,267)	20,005,874
7						
8	Common Plant Allocated			45,843	486,895	532,738
9						
10	**Total Thermal Plant in Service**			20,396,984	141,628	20,538,612
11						
12	Total Reserve for Depreciation and Amortization			8,693,854	549,387	9,243,241
13						
14	**Total Net Plant in Service**			11,703,130	(407,759)	11,295,371
15						
16	Total Plant Held for Future Use			0	0	0
17	Total Construction Work in Progress			1,268,408	(719,900)	548,508
18						
19	**Total Plant**			12,971,538	(1,127,659)	11,843,879
20						
21	Utility Materials and Supplies					
22	Fuel Inventory			137,576		137,576
23	Total Cash Working Capital			(68,360)	13,600	(54,760)
24	Total Cash Working Capital - Service Company Charges			180		180
25	Regulatory Asset			0	277,500	277,500
26	Prepaid Pension Asset			420,220	(62,486)	357,734
27	Total Accumulated Deferred Income Taxes			(918,369)	(737,914)	(1,656,283)
28	Customer Deposits			0		0
29	Customer Advances for Construction			0		0
30						
31	**Net Original Cost Rate Base**			12,542,785	(1,636,959)	**10,905,826**

Public Service Company of Colorado
Revenue Requirements Calculation - Thermal
12 Months Ended December 31, 2001

Line No.	Description	Labor	Non-Labor	Total Thermal	Adjustments	Adjusted Total Thermal
1	**Total Cost of Sales**	0	9,553,809	9,553,809	(5,854,556)	3,699,253
2						
3	Total Steam Production Operations	894,654	402,743	1,297,397	(90,488)	1,206,909
4	Total Steam Production Maintenance	363,142	222,334	585,476	(352,659)	232,817
5	**Total Production O&M**	1,257,796	625,077	1,882,873	(443,147)	1,439,726
6						
7	Total Distribution Operations	0	0	0	90,488	90,488
8	Total Distribution Maintenance	0	0	0	352,659	352,659
9	**Total Distribution O&M**	0	0	0	443,147	443,147
10						
11	Total Customer Accounting	10,094	0	10,094	44	10,138
12	Total Customer Service	0	0	0	0	0
13	Total Sales	0	0	0	0	0
14	Total Customer Operations	10,094	0	10,094	44	10,138
15	Total Administrative & General	498,344	0	498,344	103,744	602,088
16						
17	**Total O&M**	1,766,234	10,178,886	11,945,120	(5,750,768)	6,194,352
18						
19	Total Depreciation & Amortization Expense			538,432	31,797	570,228
20						
21	Total Taxes Other Than Income			245,522	17,000	262,522
22	Total Income Tax Expense			480,273	(52,349)	427,924
23	Gain on Disp. of Allowances					
24	Gain on Utility Plant					
25						
26	**Total Operating Deductions**			13,209,347	(5,754,320)	7,455,026
27						
28	AFUDC Addition			20,914	1,560	22,474
29						
30	Total Deductions			13,188,433	(5,755,880)	7,432,552
31						
32	Revenue Requirements			14,342,369	(5,755,880)	8,435,888
33						
34	Less Revenue Credits:			29,431	1,340	30,771
35						
36	**Net Revenue Requirements**			14,312,938	(5,757,220)	**8,405,117**

Public Service Company of Colorado
Electric Department Cost of Capital
At December 31, 2001

Line No.	Description	Per Books	(1) Pro Forma Adjustments	Adjusted Capital	Ratio
1	Long Term Debt	1,620,590,000	226,563,177	1,847,153,177	48.60%
2					
3	Common Equity	1,990,098,538	(36,896,465)	1,953,202,073	51.40%
4					
5	Total	3,610,688,538	189,666,712	3,800,355,250	100.00%
6					
7					
8					
9					
10		**Ratio**			
11					
12	Long Term Debt	48.60%	7.31%	3.55%	
13					
14	Common Equity	51.40%	10.75%	5.53%	
15					
16	Total	100.00%		9.08%	

(1) - Adjustments:	
Long Term Debt:	
Convert PSCCC short-Term Debt to Long-Term	208,444,473
Notes Payable to Subsidiaries	18,118,704
Total Long Term Debt	226,563,177
Common Equity:	
PSCCC Dividend	28,963,097
Eliminate Net Non-Utility Plant	(78,232,193)
Eliminate Investment in Subsidiary Companies:	(53,052,020)
Eliminate Other Comprehensive Income	4,332,716
Eliminate Unappropriated Retained Earnings of NCI	71,820,573
Eliminate Other Investments at Cost	(6,001,687)
Eliminate Other Funds	(4,726,951)
Total Common Equity	(36,896,465)

Public Service Company of Colorado
Gas Department Cost of Capital
At December 31, 2001

Line No.	Description	Per Books	(1) Pro Forma Adjustments	Adjusted Capital	Ratio
1	Long Term Debt	1,620,590,000	226,563,177	1,847,153,177	48.60%
2					
3	Common Equity	1,990,098,538	(36,896,465)	1,953,202,073	51.40%
4					
5	Total	3,610,688,538	189,666,712	3,800,355,250	100.00%
6					
7					
8					
9					
10		**Ratio**			
11					
12	Long Term Debt	48.60%	7.31%	3.55%	
13					
14	Common Equity	51.40%	11.00%	5.65%	
15					
16	Total	100.00%		9.20%	

(1) - Adjustments:	
Long Term Debt:	
Convert PSCCC short-Term Debt to Long-Term	208,444,473
Notes Payable to Subsidiaries	18,118,704
Total Long Term Debt	226,563,177
Common Equity:	
PSCCC Dividend	28,963,097
Eliminate Net Non-Utility Plant	(78,232,193)
Eliminate Investment in Subsidiary Companies:	(53,052,020)
Eliminate Other Comprehensive Income	4,332,716
Eliminate Unappropriated Retained Earnings of NCI	71,820,573
Eliminate Other Investments at Cost	(6,001,687)
Eliminate Other Funds	(4,726,951)
Total Common Equity	(36,896,465)

Public Service Company of Colorado
Thermal Department Cost of Capital
At December 31, 2001

Line No.	Description	Per Books	(1) Pro Forma Adjustments	Adjusted Capital	Ratio
1	Long Term Debt	1,620,590,000	226,563,177	1,847,153,177	48.60%
2					
3	Common Equity	1,990,098,538	(36,896,465)	1,953,202,073	51.40%
4					
5	Total	3,610,688,538	189,666,712	3,800,355,250	100.00%
6					
7					
8					
9					
10		**Ratio**			
11					
12	Long Term Debt	48.60%	7.31%	3.55%	
13					
14	Common Equity	51.40%	11.00%	5.65%	
15					
16	Total	100.00%		9.20%	

(1) - Adjustments:	
Long Term Debt:	
Convert PSCCC short-Term Debt to Long-Term	208,444,473
Notes Payable to Subsidiaries	18,118,704
Total Long Term Debt	226,563,177
Common Equity:	
PSCCC Dividend	28,963,097
Eliminate Net Non-Utility Plant	(78,232,193)
Eliminate Investment in Subsidiary Companies:	(53,052,020)
Eliminate Other Comprehensive Income	4,332,716
Eliminate Unappropriated Retained Earnings of NCI	71,820,573
Eliminate Other Investments at Cost	(6,001,687)
Eliminate Other Funds	(4,726,951)
Total Common Equity	(36,896,465)

Public Service Company of Colorado
Development of Weighted Cash Working Capital Factors - Electric
12 Months Ended December 31, 2001

Line No.	Description	Amount	Ratio	Factor	CWC Weighted Factor
1	Electric Energy Costs:				
2	Gas For Generation	178,173,791	17.69%	(0.003836)	(0.000679)
3	Other Fossil Fuel	173,149,379	17.19%	0.025945	0.004460
4	Fuel Oil	317,590	0.03%	0.026055	0.000008
5	Purchased Power	655,610,161	65.09%	0.008986	0.005849
6	Total	1,007,250,921	100.00%		0.009638
7					
8	Per Book Electric O&M Expense:				
9	Labor O&M	138,325,545	37.94%	0.075863	0.028782
10	Other O&M	95,815,799	26.28%	0.025589	0.006725
11	Service Co. Charges	123,549,892	33.89%	0.015205	0.005153
12	Vacation Expense	6,858,952	1.88%	(1.134164)	(0.021322)
13	Total	364,550,188	99.99%		0.019338
14					
15	Adjusted Electric O&M Expense:				
16	Labor O&M	122,749,717	36.87%	0.075863	0.027971
17	Other O&M	79,764,347	23.96%	0.025589	0.006131
18	Service Co. Charges	123,549,892	37.11%	0.015205	0.005643
19	Vacation Expense	6,858,952	2.06%	(1.134164)	(0.023364)
20	Total	332,922,908	100.00%		0.016381
21					
22	Per Book Taxes Other than Income:				
23	Property Tax	43,190,162	81.71%	(0.700658)	(0.572508)
24	Payroll Tax	8,718,621	16.49%	0.064986	0.010716
25	Other	950,150	1.80%	0.025041	0.000451
26	Total	52,858,933	100.00%		(0.561341)
27					
28	Pro Forma Taxes Other than Income:				
29	Property Taxes	49,844,812	83.75%	(0.700658)	(0.586801)
30	Payroll Tax	8,718,621	14.65%	0.064986	0.009520
31	Other	950,150	1.60%	0.025041	0.000401
32	Total	59,513,583	100.00%		(0.576880)
33					
34	Service Company O&M:				
35	Labor	51,737,463	41.88%	0.060658	0.025404
36	Other	71,812,429	58.12%	0.011753	0.006831
37	Total	123,549,892	100.00%		0.032235

Public Service Company of Colorado
Development of Weighted Cash Working Capital Factors - Gas
12 Months Ended December 31, 2001

Line No.	Description	Amount	Ratio	Factor	CWC Weighted Factor
1	Per Book Gas O&M Expense:				
2	Labor O&M	39,068,283	28.81%	0.070055	0.020183
3	Other O&M	34,118,190	25.16%	0.019781	0.004977
4	Service Co. Charges	60,112,233	44.33%	0.009397	0.004166
5	Vacation Expense	2,298,920	1.70%	(1.139973)	(0.019380)
6	Total	135,597,626	100.00%		0.009946
7					
8	Adjusted Gas O&M Expense:				
9	Labor O&M	39,068,283	32.17%	0.070055	0.022537
10	Other O&M	19,970,314	16.44%	0.019781	0.003252
11	Service Co. Charges	60,112,233	49.50%	0.009397	0.004652
12	Vacation Expense	2,298,920	1.89%	(1.139973)	(0.021545)
13	Total	121,449,750	100.00%		0.008896
14					
15	Per Book Taxes Other than Income:				
16	Property Taxes	12,735,414	75.14%	(0.706466)	(0.530839)
17	Payroll	3,897,041	22.99%	0.059178	0.013605
18	Other	315,788	1.86%	0.019233	0.000358
19	Total	16,948,243	99.99%		(0.516876)
20					
21	Pro Forma Taxes Other than Income:				
22	Property Taxes	14,537,414	77.53%	(0.706466)	(0.547723)
23	FICA	3,897,041	20.78%	0.059178	0.012297
24	Other	315,788	1.68%	0.019233	0.000323
25	Total	18,750,243	99.99%		(0.535103)
26					
27	Service Company O&M:				
28	Labor	24,448,238	40.67%	0.060658	0.024670
29	Other	35,663,995	59.33%	0.011753	0.006973
30	Total	60,112,233	100.00%		0.031643

Public Service Company of Colorado
Development of Weighted Cash Working Capital Factors - Thermal
12 Months Ended December 31, 2001

Line No.	Description	Amount	Ratio	Factor	CWC Weighted Factor
1	Per Book Thermal O&M Expense:				
2	Labor O&M	1,765,220	73.82%	0.073616	0.054343
3	Other O&M	551,405	23.06%	0.023342	0.005383
4	Service Co. Charges	11,058	0.46%	0.012959	0.000060
5	Vacation Expense	63,628	2.66%	(1.136411)	(0.030229)
6	Total	2,391,311	100.00%		0.029557
7					
8	Adjusted Thermal O&M Expense:				
9	Labor O&M	1,765,220	70.75%	0.073616	0.052083
10	Other O&M	655,193	26.26%	0.023342	0.006130
11	Service Co. Charges	11,058	0.44%	0.012959	0.000057
12	Vacation Expense	63,628	2.55%	(1.136411)	(0.028978)
13	Total	2,495,099	100.00%		0.029292
14					
15	Per Book Taxes Other than Income:				
16	Property Taxes	171,225	69.74%	(0.702904)	(0.490205)
17	Payroll Taxes	68,053	27.72%	0.062740	0.017392
18	Other	6,244	2.54%	0.022795	0.000579
19	Total	245,522	100.00%		(0.472234)
20					
21	Pro Forma Taxes Other than Income:				
22	Property Taxes	188,225	71.70%	(0.702904)	(0.503982)
23	Payroll Taxes	68,053	25.92%	0.062740	0.016262
24	Other	6,244	2.38%	0.022795	0.000543
25	Total	262,522	100.00%		(0.487177)
26					
27	Service Company O&M:				
28	Labor	1,014	9.17%	0.060658	0.005562
29	Other	10,044	90.83%	0.011753	0.010675
30	Total	11,058	100.00%		0.016237