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

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RE: IN THE MATTER OF ADVICE LETTER NO. 1597-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 7-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER CHANGES EFFECTIVE DECEMBER 23, 2011))))))))	DOCKET NO. 11AL-947E

SETTLEMENT AGREEMENT

April 2, 2012

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SETTLEMENT AGREEMENT

Public Service Company of Colorado ("Public Service" or the "Company"), the Staff of the Colorado Public Utilities Commission ("Staff"), the Colorado Office of Consumer Counsel ("OCC"), Colorado Energy Consumers ("CEC"), Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel (collectively "Climax/Evraz"), the Federal Executive Agencies ("FEA"), the Kroger Co. on behalf of its King Soopers and City Market Divisions ("Kroger"), AARP, Energy Outreach Colorado[1] ("EOC"), and Noble Energy, Inc. ("Noble") and EnCana Oil & Gas (USA) ("EnCana") (collectively, the "Settling Parties") hereby enter into this Settlement Agreement in resolution of the issues raised in this docket.

[1] Energy Outreach Colorado joins in the Settlement Agreement with the understanding that during the term of the MYP the Company will continue to make donations to EOC in the amount of residential late payment revenues it receives and that such revenues will not be included in the calculation of earnings under the Earnings Test provided in Section 5. See, Attachment D, ¶ 39.

INTRODUCTION

On November 22, 2011, Public Service filed Advice Letter No. 1597 – Electric (Docket No. 11AL-947E), together with supporting direct testimony and exhibits of seventeen witnesses, requesting an increase in its annual retail base rate revenues based on a forecast test year ("FTY") ending December 31, 2012, totaling $281 million, including the effects of shifting the recovery of certain costs from the Purchased Capacity Cost Adjustment ("PCCA"), the Transmission Cost Adjustment ("TCA") and the Demand Side Management Cost Adjustment ("DSMCA") to base rates. The net effect of the Company's rate request was an increase of $141.9 million in revenues, or about a 5 percent increase in the Company's total annual rate revenues, or approximately a 10.45 percent increase in the Company's annual base rate revenues. The Company also filed, for informational purposes a historic test year revenue requirement study ("HTY") for the twelve months ending June 30, 2011 showing a revenue deficiency of $160.8 million[2], net of the shift in costs from the PCCA, TCA and DSMCA.

On January 4, 2012, the Company filed Supplemental Direct Testimony addressing details related to the expiration of the Black Hills Colorado Electric Utility ("Black Hills") contract the Commission ordered in Decision No. C11-1330. On February 7, 2012, the Company filed additional Supplemental Direct Testimony and Revised Exhibits, including an update to its FTY and corrections to the HTY cost of service. The FTY filed on February 7 reflected an increase in the Company's claimed net revenue deficiency to $153.2 million on an annual basis.

[2] The revenue deficiency identified here is the as-filed deficiency prior to updates and corrections that were filed subsequently.

On March 2, 2012, various parties filed Answer Testimony and Exhibits objecting to aspects of the Company's requested rate changes, overall revenue requirement and return on equity, among other issues Staff and the OCC each used the Company's filed HTY as the starting point for their revenue requirement calculations. CEC used the Company's FTY as the basis for its revenue requirement calculations. Neither AARP nor Climax/Evraz sponsored a full revenue requirement calculation, but recommended specific adjustments to the Company's FTY or HTY in the case of AARP and to the Company's HTY in the case of Climax/Evraz.

Staff's proposed revenue requirement was summarized by Mr. Reis in Exhibit RTR-1, Table 7, and Staff's individual adjustments were summarized in Exhibit RTR-1, Table 6

Table RTR-7

Table line	Item in CPUC revenue requirement	Staff RTR-1	299E	Increase (FTY over 299E)	Increase %
1	Plant	$ 9,281.3	$ 7,802.1	$ 1,479.2	
2	Reserves	(2,927.6)	(2,499.7)	(427.9)	
3	Reg. Assets	34.0	-	34.0	
4	CWIP	290.8	141.4	149.4	
5	ADIT Other	(1,331.4)	(945.3)	(386.1)	
6	All Other items	241.6	40.2	201.4	
7	Total Rate Base	$ 5,588.7	$ 4,538.7	$ 1,050.0	23%
8				-	
9	O&M (net of below)	$ 459.7	$ 407.9	$ 51.8	13%
10	Acct 926	62.6	54.7	7.9	14%
11	MPB expense	9.9	-	9.9	
12	DSM	106.7	89.3	17.4	19%
13	Depreciation	271.6	208.9	62.7	30%
14	Taxes Other than income	95.4	69.3	26.1	38%
15	Return and Income taxes	566.0	560.2	5.8	1%
16	All other items	(72.1)	(34.3)	(37.8)	110%
17	Revenue Requirement	$ 1,499.7	$ 1,356.0	$ 143.7	11%
18	Less Existing Revenues	(1,351.3)	(1,356.0)	4.7	
19	Calpine/TCA/DSM	(141.1)	-	(141.1)	
20	Net Revenue requirement	$ 7.3	$ -	$ 7.3	

Table RTR-6

Table Line	Adjustment	Staff witness	Impact on revenue requirement
1	Modify the requested debt rate to 5.06%	Sigalla	($14.3) million
2	Modify the requested ROE to 9.09%	England	($83.1) million
3	Modify the requested capital structure to 48.38 % debt / 51.62 % equity	England	($28.3) million
4	Remove the PHFU amortization and remove the unamortized amount from rate base	McGee	($10.4) million
5	Remove the SLV amortization and remove the unamortized amount from rate base	McGee	($.9) million
6	Remove the ICT Cameo amount from rate base	McGee	($.4) million
7	Remove the ICT Solar Battery amount from rate base	McGee	($.03) million
8	Remove all MPB amounts from rate base	McGee	($.3) million
9	Add Oil and Gas revenues as a revenue credit in revenue requirement	McGee	($2.1) million
10	Modify the "flowback" of the gain on TSB to one year and remove regulatory liability	McGee	($1.9) million
11	Remove aviation expense	Moreno	($1.1) million
12	Adjust Property Taxes to a reasonable level	Kunzie	$5.6 million
13	Adjust rate case expenses downward	Kunzie	($.2) million
14	Adjust cost of removal downward	Brown	($1.9) million
15	Adjust $4.8 million out of O&M to recognize efficiency measures	Sigalla	($4.8) million
16	Adjust the Company's trading A&G adjustment to reflect 100% to trading threshold	Brown	($1.5) million
17	Adjust MPB expense to current 2011 levels	Kunzie	$.2 million

The OCC summarized its recommended adjustments to the Company's proposed HTY revenue requirements in Mr. Shafer's Exhibit FCS-1:

PUBLIC SERVICE COMPANY OF COLORADO
Colorado Jurisdiction - Electric Department
Dollar Value of Each OCC Proposed Adjustment
Test Year Ended June 30, 2011

Line No	Description	Monetary Value of Proposed Adj
1.	Public Service's Requested Historic Test Year Base Rate Revenue Requirement	$145,259,622
2.	Change ROE to 9.25%	($76,251,888)
3.	Change Capital Structure to 50.55% Equity and 49.45% Debt	($28,511,270)
4.	13-month Average Rate Base	$2,844,763
5.	Roll Transmission Plant Balances forward to 12/31/2011	$8,416,101
6.	Remove Plant Held for Future Use for SE Water Rights and Metro Ash Site	($10,023,196)
7.	Remove the remaining $16.6 million of SmartGridCity Investment	($3,190,358)
8.	Remove Regulatory Assets for MPB and ICT and Retain Regulatory Liability for TSB	($573,385)
9.	Change CWC Factors because lead-lag study does not reflect compliance with late payment tariff	($1,138,802)
10.	Include Interest on Long-Term Debt in CWC	($2,508,544)
11.	Include 2-year average of Oil and Gas Royalty Revenues	($1,839,209)
12.	Earnings Adjustment for Excess Capacity	($11,316,021)
13.	Remove SLV Transmission Line Amortization	($778,797)
14.	Reduce Property Tax Expense for Pueblo Incentive Tax Credit	($3,037,699)
15.	Reduce Mountain Pine Beetle Expenses	($2,246,354)

PUBLIC SERVICE COMPANY OF COLORADO
Colorado Jurisdiction - Electric Department
Dollar Value of Each OCC Proposed Adjustment
Test Year Ended June 30, 2011

Line No.	Description	Monetary Value of Proposed Adj.
16.	Reduce A&G Exp for Executive Mgmt Cost Saving Measures in 2012	($3,802,757)
17.	Remove O&M Costs Associated with Prop Book Trading	($1,364,567)
18.	Share Rate Case Expenses with Shareholders	($610,130)
19.	OCC Recommended Base Rate Revenue Increase	$9,357,569

CEC's proposed revenue requirement was summarized by Mr. Higgins in Exhibit KCH-1-Revised:

Colorado Energy Consumers
Calculation of Revenue Deficiency / Excess
For 12 Months Ended December 31, 2012

Line No.	Description	Amount
1	CPUC Jurisdictional Revenue Requirement	$ 1,525,555,600
2		
3	CPUC Jurisdictional Pro Forma Revenue (1)	$ 1,356,703,259
4		
5	Required Base Revenue Increase / (Decrease)	$ 168,852,341
6		
7	Present Retail Base Rate Revenue	$ 1,356,703,259
8		
9	Less: Street Light Maintenance Revenue (1)	$ 2,121,786
10	Less: (0.2%) GRSA Rider (1)	$ (2,714,560)
11		
12	Rider Applicable Revenue	$ 1,357,296,033
13		
14	Proposed GRSA Rider	12.44%
15		
16	PSCo Requested Revenue Increase/(Decrease) (1)	$ 281,029,142
17		
18	Less Revenue Requirements added to COS from Other Riders: (2)	
19	Calpine Revenue Requirement	$ (110,703,919)
20	Transmission Cost Adjustment (TCA)	$ (11,055,923)
21	DSM Revenue Requirement	$ (17,388,438)
22	PSCo Requested Revenue Increase/(Decrease) - Net	$ 141,880,862
23		
24	CEC Recommended Revenue Increase/Decrease	$ 168,852,341
25		
26	Less Revenue Requirements added to COS from Other Riders: (2)	
27	Calpine Revenue Requirement	$ (110,703,919)
28	Transmission Cost Adjustment (TCA)	$ (11,055,923)
29	DSM Revenue Requirement	$ (17,388,438)
30	CEC Recommended Revenue Increase/(Decrease) – Net	$ 29,704,061
31		
32	CEC Reduction from PSCo Requested Amount	$ (112,176,801)

Data Sources:
(1) - PSCo Exhibit DAB-1, Schedule 1
(2) - PSCo Exhibit DAB-1 Model

Climax/Evraz's proposed revenue requirement, based on an HTY, is summarized on page 5 of Mr. Kollen's Answer Testimony as follows:

Public Service Company of Colorado Revenue Requirement
Summary of CF&I - Climax Adjustments
Docket No. 11AL-947-E
Historic Test Year Ending June 30, 2011
($ millions)

	Amount
PSCo Requested Increase - Overall - Using Historical Test Year	286.408
Less: Shift of Calpine Acquisition Costs from PCCA	(112.704)
Less: Shift of Transmission Costs from the TCA	(11.056)
Less: Roll-In of Additional DSM Costs Expected During 2012	(17.388)
PSCo Requested Increase - Net of Cost Shifts from Other Riders	145.260
Rate Base Issues	
Remove Post-Test Year CACJA CWIP	(13.006)
Reflect the Reserve for Bad Debt Expense	(2.257)
Remove Account 190 ADIT Related to Litigation Reserves	(1.295)
Reflect the Balance of Accrued Interest Payable	(2.072)
Operating Income Issues	
Increase AFUDC Offset to Operating Income for Non-CACJA CWIP	(5.786)
Reduce O&M Expense for Company Proposed Adjustments to FTY	(7.508)
Reduce Amortization Expense Related to Regulatory Assets	(5.339)
Include Oil and Gas Royalty Revenues	(2.090)
Rate of Return Issues	
Reflect Return on Equity of 9.20%	(76.619)
Total CF&I - Climax Adjustments to PSCo Request	(115.971)
CF&I - Climax Recommended Change in Base Rates	29.288

As early as October 2011, the Company began discussions with Commission Staff, the OCC and some of the other potential Intervenors in its planned Phase I electric rate case about a potential multi-year rate plan ("MYP"). During these discussions Public Service informed these parties that without a MYP, the Company would need to file additional rate cases in 2012 and 2013. The parties were also aware of the Commission's interest in a MYP as expressed in orders issued in Docket No. 10M-245E. The MYP structure is intended to keep rates lower than they otherwise would be during 2012 through 2014 while affording the Company the opportunity to earn a reasonable return on its investment during this period. Additionally, the MYP avoids the need for rate cases and certain other regulatory proceedings (and the litigation costs for all parties) and serves the public interest by creating a series of predetermined annual rate increases that are likely lower than they would have been otherwise. In addition, it would provide appropriate safeguards for customers and the Company in the event that the Company is able to achieve higher than expected earnings or in the event of unforeseen and unavoidable circumstances. This Settlement Agreement, which was the subject of intense and lengthy negotiations, promotes the dual objectives of rate stability and earnings stability.

A critical component of the Settlement around a MYP is that the Company would be authorized to put into effect an increase in base rates for 2012 by May 1, subject to a burden letter, pending the Commission's full consideration of the Settlement Agreement. The Settlement Agreement then calls for additional rate increases to take effect in two phases, beginning January 1, 2013 and January 1, 2014. In addition, during the 32 month period in which the MYP is in effect, the Company would forego the opportunity the Clean Air Clean Jobs Act ("CACJA") affords it to seek special additional rate mechanisms to allow for the current recovery of CACJA plan costs and instead recover carrying costs through book income in the form of Allowance for Funds Used During Construction ("AFUDC") at a slightly modified rate. In addition, the Settlement Agreement would permit the Company to defer projected and significant increases in property taxes but with a reasonable mechanism to pay for these deferrals in a manner that is not likely to increase future rates.[3] In the spirit of compromise, the Settling Parties have agreed to modify their positions advanced in Docket No. 11AL-947E in order to enter into this Settlement Agreement.

The signatories to this Settlement Agreement have reached settlement on all contested issues in this case. Other parties may elect to support, oppose or remain silent on this Settlement Agreement.

PUBLIC INTEREST

The Parties to this Settlement Agreement state that reaching agreement by means of this negotiated settlement rather than through a formal adversarial process is in the public interest, consistent with Commission Rule 1408 encouraging settlements and that 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.

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[3] See Section 3.N.

SETTLEMENT

1. MYP for Base Rate Revenue Increases – Stay-Out Provision – Customer Impact.

The Settling Parties agree that the Company shall be permitted to implement over a period May 1, 2012 through December 31, 2014 a series of three base rate revenue increases, as follows:

A. May 1, 2012 GRSA Change.

On May 1, 2012, the Company shall be allowed to implement a $73[4] million rate increase, net of the shift of $109.313 million from the PCCA and $11.1 million from the TCA, to base rates. This increase shall be accomplished by applying a General Rate Schedule Adjustment ("GRSA") to base rates similar to historical practice by determining underlying revenues by use of the most recent sales forecast available applied by use of the most recent forecast available applied to all base rates.

B. January 1, 2013 GRSA Change.

On January 1, 2013, the Company shall be allowed to implement a $16 million base rate increase by filing an Advice Letter by December 15, 2012, using its then most recent sales forecast available at the time to calculate the component of the 2013 GRSA designed to collect this incremental GRSA increase.

C. January 1, 2014 GRSA Change.

On January 1, 2014, the Company shall be allowed to implement a $25 million rate increase by filing an Advice Letter by December 15, 2013, using its then most

[4] The $73 million is an annual revenue increase. Because rates will take effect on May 1, 2012, the Company will only receive eight months of revenues associated with this increase in 2012.

recent sales forecast available at the time to calculate the component of the 2014 GRSA designed to collect this incremental GRSA increase.

D. Associated TCA and PCCA Reductions.

The Company will file, through a request for action on less than statutory notice, and will be allowed to implement on May 1, 2012, reductions to its TCA and PCCA riders to reflect the movement of the plant-in service component of the TCA in the amount of $11.1 million and the revenue requirements associated with the Blue Spruce Energy Center ("BSEC") and the Rocky Mountain Energy Center ("RMEC") in the amount of $109.313 million, that are currently being collected in the PCCA, to base rates. The Company shall be allowed to add the revenue requirements associated with these shifts of costs from the TCA and PCCA to base rates to the GRSA calculated in Section 1.A.

E. Customer Impact.

The Parties have included as Attachment A the incremental impact of the MYP on the average monthly total bills for small commercial and residential customers. These impacts compare the estimated average monthly bills during 2012, 2013 and 2014 assuming no multi-year plan with the estimated average monthly bills in these same years under the MYP. The estimated average monthly bills in 2012 under the MYP reflect four months of current rates and eight months of rates under the MYP – based on an implementation date of new rates of May 1, 2012. The analysis then captures the incremental effects on estimated average monthly total bills of the rate increases set forth in Sections 1.B. and 1.C. for 2013 and 2014, assuming all riders remain constant during the term of the MYP at their May 2012 levels -- after the PCCA and TCA roll-ins described in Sections 1.A. and 1.D.

F. Stay-Out Provision.

With approval of the MYP as set forth in this Settlement Agreement, the Company agrees to forego for the period in which the MYP is in effect the opportunity to obtain current recovery on Construction Work in Progress ("CWIP") for expenditures on projects associated with its emissions reduction plan as authorized by C.R.S. §40-3.2-207(3) and to request approval of any other special electric ratemaking mechanism under C.R.S. §40-3.2-207(4). Further, subject to the exceptions specified in Sections 4 and 7, the Company agrees that it will not seek any further changes in its base rates for retail electric service during the term of the MYP and will not file a Phase 1 electric rate case seeking either interim or permanent rates to take effect prior to January 1, 2015.[5] It is understood that under this Stay-Out provision the Company would be permitted to file a Phase 1 electric rate case as early as May 1, 2014, but that, allowing for the 210 day suspension period, the earliest new rates could take effect would be January 1, 2015.

2. <u>New Rates To Take Effect May 1, 2012</u>.

The Settling Parties agree that it is in the public interest to have the rate increase for the first Phase of the MYP, as specified in Section 1.A., be effective May 1, 2012. If the Commission is unable to consider and approve this Settlement Agreement prior to May 1, 2012, the Settling Parties agree that the rate increase described in Section 1.A.

[5] Limits on the Company's ability to address rate design issues during the term of the MYP is addressed in Section 3.

should be allowed to take effect, subject to the conditions of a burden letter in the form appended as Attachment B to this Settlement Agreement.

The May 1, 2012 implementation date for the first phase of the MYP is a critical component of Public Service's willingness to settle this case and not to seek recovery of amounts deferred under Decision No. C12-0103 issued in Docket No. 12A-066E. The Settling Parties recommend this date to facilitate implementation of the MYP, which the Settling Parties view as providing benefits to customers in terms of rate certainty and relative rate stability over the three years of the MYP, and the avoidance of expense associated with potential future rate cases over the period of the MYP.

3. Rate Case Principles Incorporated into the Base Rate Revenue Increase.

The following rate case principles are incorporated into the compromise and settlement on the total $114 million base rate revenue increase that will be in effect by the final year of the MYP.

A. Authorized Return on Equity.

Background. The Company's witness Mr. Hevert recommended a Return on Equity ("ROE") of 10.75 percent. The Intervenors that addressed this issue recommended ROEs in the range of 9.09 to 9.60 percent.

Resolution. The Settling Parties agree that the authorized ROE during the term of the MYP shall be 10.00 percent.

B. Capital Structure and Return on Rate Base.

Background. The Company proposed a capital structure equal to its average regulated capital structure for the 13 month period ending December 31, 2012 and consisting of 56 percent common equity and 44 percent long-term debt. The Company proposed a weighted average cost of debt equal to 5.63 percent.

Both Staff and OCC advocated adjustments to the Company's recommended capital structure to reduce the percentage of equity from 56 percent to 51.62 percent in Staff's case and from 56 percent to 50.55 percent in the case of OCC. Staff and CEC also advocated a reduction in the Company's average cost of debt.

Resolution. The Settling Parties agree that the approved regulatory capital structure for the Company shall be 56 percent equity and 44 percent long-term debt. The average cost of debt is 5.63 percent based on the Company's forecast of the expected cost of the planned $750 million long-term debt issuance in the Fall of 2012. The resulting Return on Rate Base ("RORB") is 8.08 percent, calculated as follows:

	Ratio	Cost	Weighted Cost
Long Term Debt	44.00%	5.63%	2.48%
Common Equity	56.00%	10.00%	5.60%
Total	100.00%		8.08%

The Settling Parties agree that beginning on May 1, 2012 and during the term of the MYP, for purposes of calculating the TCA rider, the AFUDC rate applicable to CWIP associated with the Company's implementation of the Emissions Reduction Plan approved by the Commission in Docket No.10M-245E, and interest on the deferred balance under the Renewable Energy Standard Adjustment rider ("RESA"), the Company shall use 10.00 percent ROE, the then current capital structure and the then current average cost of long-term debt. Beginning May 1, 2012, the Company shall use the appropriate AFUDC calculation including short-term debt for all other AFUDC.

C. CACJA CWIP.

Background. The Company's FTY and HTY filed in its direct case included CWIP associated with projects it is pursuing under its Emissions Reduction Plan ("CACJA CWIP") in rate base without an AFUDC offset. No party objected to this treatment. However, for purposes of the MYP proposal, the Company proposed to remove the CACJA CWIP from rate base and to instead accumulate AFUDC at a rate equal to its authorized RORB during the term of the MYP.

Resolution. The CACJA CWIP will not be included in rate base during the term of the MYP, but will instead accumulate AFUDC at a rate equal to the RORB calculated as described in Section 3.B. until either: 1) the specific facility is reflected as plant in service in rate base, or 2) the CWIP associated with the facility is included in rate base with a current return as part of a future Phase 1 rate case, whichever is applicable. In addition, the Company will not seek current recovery of CACJA CWIP during the pendency of the MYP.

D. Regulatory Assets.

Background. The Company proposed to amortize the regulatory assets associated with the Cameo Innovative Clean Technology ("ICT") project; the Solar to Battery ICT project; the San Luis Valley Transmission costs; the lease for the Energy Supply Facility in Golden, CO; rate case expenses; and the Company's Mountain Pine Beetle ("MPB") expenditures for 2010 and 2011 over two years commencing with the date that new rates approved as a result of this proceeding take effect. The Company also proposed to include the unamortized balances associated with these regulatory assets in rate base and to earn a return on such balances equal to the RORB. The

Company also proposed to amortize the gain associated with its sale of the Technical Services Building ("TSB") over two years. All of the Intervenors that addressed the Company's proposed treatment of regulatory assets opposed including these assets in rate base. Certain intervenors also advocated extending the amortization period applicable to the regulatory assets and Staff advocated shortening the time over which the TSB gain was amortized.

Resolution. The Company agrees that the regulatory assets associated with the Cameo ICT project; the Solar to Battery ICT project; the lease for the Energy Supply Facility in Golden, CO; rate case expenses; and the Company's MPB expenditures for 2010 and 2011 shall not be afforded rate base treatment, and instead will be amortized beginning May 1, 2012 and ending December 31, 2014. The Company agrees that it shall commence amortization of the costs incurred to date to build the San Luis Valley Transmission Line on the first day of the month following the date upon which the Commission's Phase 1 order is no longer subject to review in Docket No. 11A-869E approving the Company's assumption that the line would not go forward if its proposed resource plan were approved.[6] The Company shall amortize the regulatory liability associated with the TSB gain over 32 months commencing May 1, 2012 and ending December 31, 2014.

E. Plant Held for Future Use.

Background. The Company proposed to amortize its investment in the Southeast Water Rights and the Metro Ash Disposal Site located in Bennett, CO,

[6] If the Commission decides in Docket No. 11A-869E that the San Luis Valley transmission line should be built, the incurred to date costs for the line will be included in the final cost of the project and depreciated over the life of the asset.

currently accounted for as Plant Held for Future Use ("PHFU") over four years and to earn a return equal to its authorized RORB on the unamortized asset balance during the course of the amortization period. The Intervenors that addressed this issue opposed the Company's proposed treatment and advocated that the assets should be removed from PHFU and that the Company should no longer earn any return on these assets.

Resolution. The Settling Parties agree that the Southeast Water Rights shall remain in PHFU, without amortization, and shall continue to be included in rate base at a debt-only return consistent with the treatment provided in the Settlement Agreement approved by the Commission in Docket No. 02S-315E. The Docket No. 02S-315E Settlement Agreement provided that this treatment of the Southeast Water Rights would continue for as long as the Company continues to own these assets. The Settling Parties further agree that Metro Ash Disposal Site located in Bennett, CO should also remain in PHFU, without amortization, and shall be included in rate base and earn a full RORB. This agreement is not intended to limit the rights of the Settling Parties in a proceeding to approve the sale of the Southeast Water Rights or the Metro Ash Disposal Site to take any position regarding the disposition of the proceeds of such sale or any other issue that is properly raised in such proceeding.

F. Depreciation Rates.

Background. The Company proposed certain changes to its depreciation rates applicable to both its facilities affected by the Emissions Reduction Plan approved in Docket No. 10A-245E and facilities that were not affected by this plan that had the effect of increasing depreciation expense by $15.6 million. CEC proposed certain adjustments to the rates proposed by the Company reducing the Company's proposed increase by approximately $6.7 million.

Resolution. The Settling Parties agree that there shall be no change in the depreciation rates applicable to its generating facilities other than the changes to the amortization of the regulatory assets associated with the early retirements of Cameo and Cherokee 1 and 2. The Company shall continue to apply the depreciation rates approved in Docket No. 06S-234EG and in Docket No. 09AL-299E (for Comanche 3 and FSV 5 and 6). For purposes of BSEC and RMEC, which are being included in base rates for the first time with this proceeding, the Company shall use the depreciation rates proposed by Ms. Perkett in this case. Attachment C to the Settlement Agreement is a list of the depreciation rates that will be applied to all of the Company's retail jurisdictional assets until the Commission establishes new rates as a result of a future Phase 1 rate proceeding.

G. Cost of Removal for Generating Facilities.

Background. The Company proposed an increase in its estimated cost of removal for its electric power generating units based on a methodology recommended by TLG Services, Inc. Staff witness Brown proposed a reduction to the Company's cost of removal estimate based on an alternate methodology described in his Answer Testimony.

Resolution. The Company and the Staff of the Commission agree to work together in good faith between now and May 1, 2014 to arrive at a mutually agreeable methodology for estimating the cost of removal for the Company's electric generating facilities to be included in the Company's cost of service filed in the Company's next

Phase 1 rate case. If these parties are unable to reach agreement, then the Company agrees to use the methodology for estimating the cost of removal proposed by Staff witness Brown in his Answer Testimony filed in this proceeding. The other Settling Parties are not bound to support, in the next Phase 1 rate case, either the methodology or the resulting estimate of the cost of removal that is agreed upon by Staff and the Company as set forth in this Section.

H. Roll-in of Calpine Assets from PCCA to Base Rates.

Background. The Company proposed to roll in to base rates the revenue requirement associated with the BSEC and the RMEC that is currently being collected through the PCCA. No party objected to this proposal.

Resolution. The Settling Parties agree that the GRSA that is effective May 1, 2012 shall include the annual revenue requirement associated with the Company's investment in the BSEC and RMEC and that the Company shall simultaneously implement a reduction in the PCCA to remove all costs associated with these assets. To the extent that the Federal Energy Regulatory Commission ("FERC") determines that a portion of the purchase price must be recorded as an acquisition adjustment, the Company will be permitted to include the net acquisition adjustment plus the remaining net book value associated with BSEC and RMEC in rate base for retail ratemaking purposes and shall depreciate such amounts based on the Depreciation rates set forth in Attachment C.

I. TCA.

Background. The Company proposed to roll-in costs associated with the plant in-service component of the TCA to base rates. The Company also proposed to revise the methodology used to measure the change in the transmission plant in service balance since the last rate case from using the most recent year's historic 13-month average transmission plant-in-service balance to using the forecasted 13-month average transmission plant in service balance as the measure of the change. No party objected to the roll-in of costs associated with the plant in-service component of the current TCA to base rates. However, all parties objected to the Company's proposal to change the methodology for calculating the plant in-service component of the TCA.

Resolution. The Settling Parties agree that the GRSA that is effective May 1, 2012 shall include a roll-in of the plant in-service component of the TCA which is estimated at $11.1 million and that the Company shall simultaneously implement a reduction in the TCA to remove all costs associated with the plant in-service component of the rider. The revised TCA that takes effect on May 1, 2012, shall continue to recover returns on the transmission-related CWIP balance as of December 31, 2011.

The Settling Parties agree that there shall be no change from the existing methodology used to calculate the plant in-service component of the TCA during the term of the MYP. For example, the TCA that goes into effect on January 1, 2013 will be designed to recover the authorized RORB on the change in the 13-month average plant in-service balance from December 31, 2011 to December 31, 2012, plus the return on the transmission associated CWIP balance as of December 31, 2012.

J. SmartGridCity Investment at issue in Docket No. 11A-1001E.

Background. The Company proposed to include in rate base the full capital costs associated with SmartGridCity in its revenue requirement consistent with the relief it has requested in Docket No. 11A-1001E. All Intervenors who addressed this issue opposed including the full capital costs associated with SmartGridCity pending entry of a final order in Docket No. 11A-1001E.

Resolution. The Settling Parties agree that there shall be no change in the negative GRSA, relating to SmartGridCity, currently in place during the term of the MYP. The negative GRSA shall be netted against the positive GRSA calculated in accordance with Sections 1.A., 1.B. and 1.C. If the Commission approves the Company's request to increase the amount of SmartGridCity investment that is included in rate base in Docket No. 11A-1001E, such additional investment shall thereafter be included in rate base for purposes of calculating earnings under the Earnings Test set forth in Section 5 and for purposes of determining base rates in the Company's next Phase 1 rate case.

K. On-Going O&M Associated with MPB Epidemic.

Background. The Company proposed to include in its revenue requirement approximately $6 million in annual ongoing transmission and distribution Operations and Maintenance ("O&M") costs associated with addressing the MPB epidemic. The OCC proposed to reduce the level of MPB O&M included in the cost of service by approximately $2.25 million based on the average of the Company's MPB expenses during 2010 and 2011.

Resolution. For purposes of this Settlement Agreement and for purposes of Docket No. 11A-966E, the Settling Parties agree that no ongoing MPB O&M expense shall be included in base rates in 2012 and that the Company shall be permitted to defer 100 percent of the actual MPB O&M it expends from January 1 through December 31, 2012. The Settling Parties further agree that the MPB O&M expense deferred in 2012 shall be amortized and recovered over a period of two-years beginning on January 1, 2013. The amortization is included in the rate increases agreed upon for 2013 and 2014 as set forth in Sections 1.B. and 1.C. and shall be recognized as an expense for purposes of the Earnings Test calculation pursuant to Section 5.

In addition to the deferred 2012 MPB O&M expense, the amount of on-going O&M expense to address the MPB epidemic during 2013 and 2014 that is assumed to be in base rates for 2013 and 2014 is $6 million. The Company shall defer any O&M expenditures related to MPB it incurs during 2013 or 2014 that is over or under the $6 million amount that has been included in base rates during those years and shall amortize and recover or repay any such over- or under-recovery over a two year period commencing on the date new rates take effect following the Company's next Phase 1 electric case.

L. Black Hills Deferral.

Background. On January 31, 2012, the Commission issued Decision No. C12-0103 in Docket No. 12A-066E authorizing the Company to begin deferral, on February 1, 2012, of cost increases associated with the change in the retail jurisdictional allocation of costs stemming from the expiration of the Black Hills wholesale power agreement. However, the Commission reserved the issue of whether the Company would be permitted to recover the deferred costs for determination in this proceeding. The Company sought approval to recover 100 percent of the costs deferred in accordance with Decision No. C12-0103 plus a return on any capital costs deferred. All of the Intervenors that addressed this issue opposed the Company's recovery of the costs deferred related to Black Hills and stated various grounds why such recovery should not be permitted in this case.

Resolution. The Settling Parties agree that the rates that take effect on May 1, 2012 include no incremental recovery of deferred costs associated with the Black Hills whole sale power agreement for the period February 1 through April 30, 2012.

M. Change in Retail Jurisdictional Allocator.

Background. The revised HTY and FTY sponsored by Company witness, Deborah Blair, reflected a change in the retail jurisdictional allocation of costs due to the December 31, 2011 expiration of the Black Hills wholesale power agreement. No party objected to the Company's proposed changes to the retail jurisdictional allocators used in its revenue requirement to reflect the expiration of this contract.

Resolution. The Settling Parties agree that the jurisdictional allocation used for purposes of determining the increase in base rates approved in this proceeding and to be used for all rider calculations and for purposes of calculating earnings under the Earnings Test under Section 5 shall include the effect of the expiration of the Black Hills wholesale power agreement as of December 31, 2011.

N. Property Taxes.

Background. When it filed its Direct Testimony and Exhibits on November 22, 2011, the Company included in its FTY its then current estimate of property taxes for 2012 of $89.7 million. In Supplemental Testimony filed on February 7, 2011, the Company updated the amount being accrued for 2012 property taxes to $97 million. The Company's HTY which was the starting point for OCC's and Staff's analysis reflected only $76.7 million of property tax expense. The Staff proposed a $5.6 million adjustment reflecting the known and measurable increase to property tax expense for the calendar year 2011. CEC used as the starting point for its analysis the Company's originally filed FTY that included $89.7 million in property tax expense.

Resolution. The Settling Parties agree that the base rates that will be in effect as a result of the MYP proposed in this Settlement Agreement include the recovery of $76.7 million in property tax expense which is the amount of property tax reflected in the Company's HTY filed in this proceeding. The Settling Parties further agree that the Company shall be permitted to defer and to establish a regulatory asset as follows:

a. For 2012, actual property tax expenses from February 1 2012, incurred in excess of $76.7 million prorated for eleven months shall be deferred and amortized over a three-year period beginning January 1, 2013, subject to the provisions of Section 3.O. The amortization expense from this deferral in 2013 and 2014 is recovered in the GRSA rates effective January 1, 2013.

b. For 2013, actual property tax expenses incurred in excess of $76.7 million shall be deferred and amortized over a three-year period beginning January 1, 2014, subject to the provisions of Section 3.O. The amortization expense from this deferral in 2014 is recovered in the GRSA rates effective January 1, 2014.

c. For 2014, actual property tax expenses incurred in excess of $76.7 million shall be deferred and, amortized over a three-year period subject to the provisions of Section 3.O.

O. Application of the Manufacturer's Sales Tax Refunds.

Background. As Ms. Hyde described in her Direct Testimony, for more than a decade the Company has been pursuing a case in Colorado courts to clarify the application of tax law. The Company is pursuing litigation to remedy a claimed inequity in the application of sales/use tax law as applied to the Company and to similarly situated taxpayers. The Company has received favorable rulings by the District Court and Colorado Court of Appeals and is now awaiting a ruling on the State of Colorado's Petition for Certiorari. If the Company is ultimately successful in this litigation, a sizeable refund, after payment of the Company's legal costs, would be available to offset other increases in the Company's cost of providing retail electric service.

Resolution. To the extent the Company is successful in the sales/use tax lawsuit currently in the Colorado Supreme Court in Case No. 11 SC 759, and obtains refunds from the State of Colorado of manufacturer's sales/use taxes paid during the period of time which is the subject of the lawsuit and at any time thereafter, the Company agrees to credit the retail jurisdictional portion of Public Service's share of any refunds and any associated interest received, first, against the retail jurisdictional share of the Company's legal fees incurred to prosecute the sales tax lawsuit and then against the retail jurisdictional share of property tax expenses deferred during 2014, 2013 and 2012, in that order.[7] If the Company is unsuccessful in its efforts to obtain any refunds of manufacturers' sales taxes paid, or the amount of the manufacturer's sales tax refund obtained net of legal fees is less than $10 million, then the Company agrees to write-down prior to January 1, 2015 that portion of the property taxes deferred in 2014 equal

[7] All remaining references to the manufacturers sales tax refund, legal fees, property taxes, and plant-in-service balances, shall be understood as limited to the retail jurisdictional share of such amounts.

to the difference between $10 million and the sales tax refund received, net of legal fees. The Company agrees that any expense write-down that may be based on this Section will not be included in the calculation of earnings for purposes of the Earnings Test under Section 5. The Company shall be permitted to amortize and recover the remainder of the unamortized deferred property tax balance after taking into account such write down for 2014, 2013 and 2012 as set forth in Section 3.N.

If the retail jurisdictional amount of the manufacturer's sales tax refund plus interest, net of legal fees is greater than $10 million but less than the unamortized balance of property taxes deferred in 2014, 2013, and 2012 as of December 31, 2014, then the Company shall amortize any deferred property tax balance that remains after application of the sales tax refund pursuant to this Section over a period of three years commencing on the date new rates take effect as a result of the Company's next Phase 1 rate case, but no earlier than January 1, 2015.

If the amount the Company receives from the manufacturer's sales tax refund is sufficient to offset the entire unamortized balance of property tax expenses deferred in 2014, 2013, and 2012 as of January 1, 2015, then any remaining refund amounts will be used to reduce CACJA capital investment as if it were customer contributed capital with no remaining refund obligation. The Settling Parties agree that there will be no adjustments to the plant in service balances that originally included payment of the manufacturer's sales taxes that were refunded. The Company agrees that the Staff may audit and other Settling Parties may review, subject to appropriate provisions to protect the attorney client privilege and the confidential nature of such information, the legal fees associated with the manufacturer's sales tax lawsuit and appeals for prudence.

P. Rate Case Expenses.

Background. The Company proposed to amortize $2,104,155 in rate case expense over a two year period. Staff and OCC both recommended adjustments that reduced the level of rate case expenses to be recognized on an annual basis.

Resolution. The Settling Parties agree that for purposes of calculating earnings under the Earnings Test provided in Section 5, the Company shall amortize total rate case expenses of $1,825,784 for the term of this agreement (32 months).

Q. Aviation Expenses.

Background. The Company proposed recovery of the majority of the aviation expense associated with travel on corporate aircraft allocated to the electric utility operations within Public Service. Several parties opposed inclusion of these costs.

Resolution. The Settling Parties agree that aviation expenses associated with travel on corporate aircraft shall not be included in the calculation of the earnings for purposes of the Earnings Test referenced in Section 5.

4. Future Rate Cases.

The Company agrees that it will not file a Phase 1 electric rate case to put rates into effect prior to January 1, 2015. The Settling Parties acknowledge that the Company may file a Phase I electric rate increase under this Section as early as May 1, 2014, so long as no rate increase takes effect on either an interim or permanent basis prior to January 1, 2015. The Settling Parties further agree that, as a result of this settlement, no Phase II rate case will be filed that would result in a change in interclass allocations or allocation methodology or would result in changes to rate design, provided however, the Company may propose changes to rate design as may be necessary to address the tiered rates applicable to residential customers, RESA Fair Share collection, rates for customers who are net metered, and the recovery of the low income program funds through service and facility charges.

This Section is not intended to limit the Company's ability to file for changes in its tariffs that do not affect its retail customers' base electric rates. Nor does this Section prohibit the Company from filing applications for additional incentive-based sharing mechanisms for products or services not currently subject to such a mechanism so long such sharing mechanism does not affect the Company's base electric rates. The Company may also file Advice Letters to introduce new services, including the establishment of base electric rates for such services.

If the Company files its next Phase I electric rate case based on a FTY the Company agrees that it will also file a HTY for informational purposes.

5. <u>Earnings Test</u>.

In consideration for agreeing to this MYP, the Settling Parties agree to implementation of an Earnings Test in order to protect customers in the event that the economy recovers and sales volumes grow or other factors positively affect the Company's earned ROE.

The purpose of the Earnings Test is to provide an annual sharing of the Company's earnings based on an updated annual period reflecting the Company's actual as-booked expenses and weather normalized revenues and application of the raternaking principles as described in Attachment D to this Settlement Agreement. In consideration for this Settlement Agreement, Public Service voluntarily agrees to share a portion of its earnings for calendar years 2012, 2013, and 2014, in excess of 10.00 percent ROE from the provision of electric service in Colorado with its Colorado retail electric customers. The earnings sharing amounts shall be determined annually on the basis of earnings test calculations. All Commission-ordered adjustments[8] and all accounting adjustments[9] as specifically described in Attachment D, except pro forma adjustments[10], shall be made to such earnings test calculations.

In the event that the Company incurs a new cost or identifies an issue for which there is no previously established regulatory treatment subsequent to the date on which new base rates take effect as a result of the Commission's order, it shall identify such cost or issue in its earnings test filing together with the proposed regulatory treatment.

For the 2012 through 2014 Earnings Tests, the electric earnings sharing shall be measured on the basis of an Earnings Test that uses the ratemaking principles set forth in this Settlement Agreement. The Settling Parties further agree that the sharing percentages for earnings over a 10 percent return on equity shall be as follows:

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8 Commission-ordered adjustments shall be defined as any adjustment adopted by the Commission to insure that revenues, expenses, and rate base reflect traditional ratemaking principles (e.g., "just and reasonable" and "used and useful" standards.)

9 Accounting adjustments shall be defined as any adjustment required to insure that transactions properly counted in the calculation of the review period's earnings are included in the annual filing and that transactions that are properly counted in the calculation of earnings for previous or future review periods are excluded.

10 Pro forma adjustments shall be defined as annualization of price changes that occurred within the test year (in-period adjustments) or outside the test year (out-of-period adjustments).

Measured Return on Equity	Sharing Percentages	
	Customers	Company
>10.00% ≤ 10.20%	60%	40%
>10.20% ≤ 10.50%	50%	50%
> 10.51%	100%	

6. **Earnings Test Procedures.**

Public Service shall file earnings test information on or before April 1 of each year beginning April 1, 2013 and continuing through April 1, 2015. To the extent that the Company's earnings during the prior year exceed 10.00 percent return on equity, the Company shall also file an Advice Letter seeking to put into effect, subject to a true-up, a revised GRSA sufficient to refund to customers the proposed earnings sharing. The Staff and any other person that disputes the Company's earnings test information shall file a notice with the Commission identifying any matters in the Company's earnings test filing with which such party takes issue and the basis for such dispute, no later than May 15 in any year. If all persons disputing the earnings sharing amount and the Company cannot resolve all of their differences by June 15, then all remaining disputes will be detailed in a written notice submitted to the Commission no later than July 1, together with a proposed procedural schedule for addressing such issues. Any over-collection of revenues resulting from the difference between the GRSA ultimately approved by the Commission and the GRSA implemented on July 1 will be refunded to customers.

The earnings sharing rider to base electric rates proposed by the Company shall go into effect on July 1 of each year and shall remain in effect until June 30 of the following year ("Rider period") or until modified in accordance with a Commission order issued as a result of an earnings test proceeding as described above.

7. <u>Regulatory Adjustments</u>.

A. GRSA Adjustment to Reflect Material Expense Changes.

The Settling Parties agree that certain material changes in the Company's forecasted expenses during the term of the MYP that are beyond the Company's control may require adjustment to the Company's GRSA then in effect or may be appropriate for deferral, provided that the change is reasonably expected to increase or decrease the Company's revenue requirement for its electric business by at least $10 million in that year.

Except to the extent a cost is addressed, more specifically in another Section of this Settlement Agreement, the types of cost changes that would qualify for a Regulatory Adjustment pursuant to this Section include:

- Changes in Generally Accepted Accounting Principles ("GAAP") that are appropriately reflected in rate regulation.
- Changes in tax laws.
- Changes in Public Service's obligations stemming from changes in federal, state, or municipal laws, or regulations issued or actions taken by federal, state or local governmental bodies, including but not limited to the Environmental Protection Agency, FERC, North American Electric Reliability Corporation ("NERC"), the Commission, the Colorado Department of Public Health and Environment, and local governments within the State of Colorado.

- Orders or acts of civil or military authority.
- Natural disasters or catastrophic events, net of any insurance proceeds.
- A Commission-approved asset acquisition or divestiture that exceeds $50 million.

The Company shall make a filing notifying all parties of any reductions or increases in its retail base rate revenue requirements that are or may be eligible for an adjustment under this Section within 60 days of the action or shall provide such notice in its Earnings Test filing on April 1st, whichever is sooner and shall either file an appropriate Advice Letter to change the GRSA or seek a deferral at the Company's discretion. The Settling Parties reserve their right to challenge prudency and the Company's calculation of the revenue requirement impact of such cost change

B. GRSA Adjustment to Reflect Significant Sales Reduction.

In addition, the Settling Parties agree that it is appropriate to provide the Company with some degree of protection against the risk of significant and unexpected reductions in it retail sales. The GRSA adjustment contemplated in this Section 7.B. will be made through Advice Letters filed on November 1, 2012, March 1, 2013, November 1, 2013 and March 1, 2014, and will work as follows.

If the Company's projected annual retail jurisdictional weather-normalized revenues ("ARWNR") from base rates plus the then current GRSA, based on nine months of actual revenues and three months of forecasted revenues, are two percent or more below the Targeted Revenues (shown below) for that calendar year, the Company may file an Advice Letter on or before November 1 to increase the base rate revenues to be collected through the GRSA on the following January 1 by an amount equal to 50 percent of the difference between the projected ARWNR and the Targeted Revenues, but in no event shall the increase to the GRSA implemented under this Section be greater than $27.9 million.[11]

Once the Company's actual ARWNR for the prior year is known, the Company shall compare its actual ARWNR with the Targeted Revenues for the prior year. If the GRSA that took effect on January 1 included an adjustment pursuant to this Section 7.B. and the actual ARWNR is less than two percent below the Targeted Revenues for the prior year, then the GRSA shall be recalculated by removing the increased revenue amount added on January 1 pursuant to this Section 7.B. The GRSA will be adjusted to reflect a refund of such revenues as will be collected between January 1 and April 1. If the GRSA that took effect on January 1 did not include an adjustment pursuant to this Section 7.B. and the actual ARWNR is two percent or more below the Targeted Revenues for the prior year, then the Company may file an Advice Letter to put into effect a GRSA adjustment pursuant to this Section 7.B. In either of these events, the Company shall file an Advice Letter on March 1 to put into effect a revised GRSA effective April 1. The GRSA calculations made pursuant to this Section 7.B. shall be calculated at all times using the Company's then most recent sales forecast.

The 2012 Targeted Revenues shall be $1,480,603,861 which is equal to the sum of: 1) the 2011 ARWNR; 2) 2/3rds of the $109.313 million associated with the roll-in of the PCCA and the $11.1 million roll-in of the TCA as set forth in Section 1.D.; and 3) 2/3rds of the $73 million increase authorized under Section 1.A.

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[11] The cap is intended to ensure that at no time during the time of the MYP Plan will the GRSA exceed $141.9 million, the rate increase originally noticed by the Company.

The 2013 Targeted Revenues shall be $1,561,060,297 which is equal to the sum of: 1) the 2011 ARWNR; 2) the PCCA roll-in; 3) the TCA roll-in; 4) the $73 million increase in revenues that took effect on May 1, 2012; and 5) the $16 million revenue increase authorized under Section 1.B.

This sales reduction provision is in addition to, and not in substitution for, other provisions in this Settlement Agreement that affect changes to the calculation of the GRSA. To inform the Parties of the potential of this settlement provision being applied in either 2012 or 2013, the Company shall provide actual year-to-date weather normalized base rate revenue amounts to the Parties on a quarterly basis and will notify the Parties in August if the Company forecasts that this provision will be triggered.

8. DSMCA Roll-In.

Resolution. The Settling Parties agree that the Company shall not roll in to base rates in this proceeding the recovery of any costs that are being recovered through the current DSMCA. Throughout the period of the MYP, base rates shall continue to recover the portion of the Company's DSM costs included as a result of the Commission's decision in Docket No. 09AL-299E. All DSM costs in excess of that amount shall be recovered through the DSMCA consistent with the Company's current DSMCA tariff.

9. Pueblo Incentive Tax.

Resolution. The Settling Parties agree that the benefits of the Pueblo Tax Incentive, if funded in any of the years covered by the MYP, shall be passed through to customers in the Electric Commodity Adjustment ("ECA").

10. Trading Margins.

Resolution. The Settling Parties agree that beginning for 2012, the trading margins shared through the ECA shall be changed such that 90 percent of the Generation ("Gen") Book trading margins are shared with customers and 10 percent of the Gen Book margins are retained by the Company. Likewise, 10 percent of the Company's Proprietary ("Prop") Book trading margins are shared with customers through the ECA and 90 percent of the Prop book margins are retained by the Company.

11. Consultant to Review Pension Benefits.

Resolution. Public Service agrees to engage an independent consultant, specializing in retirement benefit valuations, to evaluate the reasonableness of pension benefits provided by Xcel Energy to new hire non-bargaining unit employees of either Public Service Company or Xcel Energy Services, Inc. at the time of the study, as compared to such benefits provided by corporations comparable to Xcel Energy, Inc. and to corporations of similar size outside the utility industry with employees with similar job titles and responsibilities. The choice of consultant and the scope of work, which shall not exceed $100,000, will be agreed to by both the Staff and the Company. Costs of the independent consultant will be deferred and shall be included in the Company's next Phase I rate case and amortized over three years. The study will be provided to Staff and any Settling Party that may request it, 6 months before such rate case. None of the Settling Parties shall be bound by the results of the study. The OCC does not join in this provision of the Settlement Agreement.

12. <u>No Precedential Effect</u>.

With the exception of the agreements regarding deferred accounting and amortization and recovery of the regulatory assets addressed in Sections 3.K., 3.N., the rate base treatment afforded the BSEC and RMEC under Section 3.H., and the provisions of Section 11, nothing in this Settlement Agreement is intended to have precedential effect or bind the parties with respect to positions they may take in any future Phase I rate case regarding any of the issues addressed in this agreement.

13. <u>Compliance Filing</u>.

Within seven days following the effective date of the Commission's final order approving this Settlement Agreement, or at such other time as the Commission may prescribe, the Company shall file tariffs to implement the Sections 5, 7.B. and 10 of this Settlement Agreement.

GENERAL TERMS AND CONDITIONS

The Settling Parties agree that all their pre-filed testimony and exhibits shall be admitted into evidence in this docket without cross-examination by the Settling Parties. This Settlement Agreement reflects compromise and settlement of all issues raised or that could have been raised by the Settling Parties 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 that is unacceptable to any of the Settling Parties. In the event the Commission modifies this Settlement Agreement in a manner unacceptable to any Settling Party, that Settling Party shall have the right to withdraw from this Agreement and proceed to hearing on the issues that may be appropriately raised by that Settling Party in this docket. The withdrawing Settling Party shall notify the Commission and the Settling 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 desires to go 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 Settling Party shall not automatically terminate this Agreement as to any other party. However, within three business days of the date of the Hearing Notice from the first withdrawing party, all Settling 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 Settling 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 together with a proposed procedural schedule including a date for all parties who will proceed to hearing to file Rebuttal or Cross-Answer Testimony addressing any issues that remain in dispute. The Settling Parties who proceed to hearing shall have and be entitled to exercise all rights with respect to the issues that are heard that they would have had in the absence of this 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 Settlement

Agreement is not approved, or is approved with conditions that are unacceptable to any Settling Party who subsequently withdraws, the negotiations or discussions undertaken in conjunction with the Settlement 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.

Commission approval of this Settlement Agreement shall constitute a determination that the Settlement Agreement represents a just, equitable and reasonable resolution of all issues that were or could have been contested among the Settling 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.

The Settling Parties to this Settlement Agreement state that reaching agreement in this docket as set forth in this Settlement 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.

The Settling Parties understand that not all parties to this docket will execute this Settlement Agreement. The Settling Parties agree to reasonably defend this Settlement Agreement before the Commission against challenges that may be made by non-executing parties.

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

Dated this 2nd day of April, 2012.

Agreed on behalf of:

PUBLIC SERVICE COMPANY OF COLORADO

By: ______________________

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DATED this 2nd day of April, 2012

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ATTORNEYS FOR NOBLE AND ENCANA

Public Service Company of Colorado
Electric Department
MYP Settlement

		Base Increase	GRSA
2012*	$	127,076,189	**9.35%**
2013	$	206,614,284	**15.20%**
2014	$	231,614,284	**17.04%**

Base Revenue			
2012 Projected w/o -0.20% GRSA	$	1,359,417,819	
2013 & 2014 assumed at 2012 levels			

*Incorporates MYP increase effective May 1, 2012

Public Service Company of Colorado
Electric Department
Small Commercial - Schedule C

Customer Class	2012 Rates	2012 MYP Rates	Monthly Average Usage	Monthly 2012 Bill	Monthly 2012 MYP Bill	Monthly Difference $	Difference %
Commercial - Schedule C							
Service and Facility Charge	$ 10.75	$ 10.75		$ 10.75	$ 10.75	$ -	
Energy Charge	$ 0.04763 /kWh	$ 0.04763 /kWh	1,123 kWh	53.49	53.49	-	
Subtotal				$ 64.24	$ 64.24	$ -	0.00%
GRSA	-0.20%	9.35%		(0.13)	6.01	6.14	
Base Rate Amount				$ 64.11	$ 70.25	$ 6.14	9.58%
DSMCA	$ 0.00115 /kWh	$ 0.00115 /kWh		$ 1.29	$ 1.29	$ -	
PCCA	$ 0.01129 /kWh	$ 0.00829 /kWh		$ 12.68	$ 9.31	$ (3.37)	
TCA	$ 0.00049 /kWh	$ 0.00019 /kWh		$ 0.55	$ 0.21	$ (0.34)	
ECA - Secondary	$ 0.02835 /kWh	$ 0.02835 /kWh		$ 31.84	$ 31.84	$ -	
Subtotal Base Rate Adjustments				$ 46.36	$ 42.65	$ (3.71)	
Total Bill Subtotal				$ 110.47	$ 112.90	$ 2.43	2.20%
RESA	2.00%	2.00%		$ 2.21	$ 2.26	$ 0.05	
Total Bill				$ 112.68	$ 115.16	$ 2.48	**2.20%**
			Rate/kWh:	**$ 0.10034**	**#######**	**$ 0.00221**	**2.20%**

Notes:
ECA reflects most current 2012 projection
Incorporates MYP increase effective May 1, 2012

Public Service Company of Colorado
Electric Department
Small Commercial - Schedule C

Customer Class	2012 MYP Rates	2013 MYP Rates	Monthly Average Usage	Monthly 2012 MYP Bill	Monthly 2013 MYP Bill	Monthly Difference $	Difference %
Commercial - Schedule C							
Service and Facility Charge	$ 10.75	$ 10.75		$ 10.75	$ 10.75	$ -	
Energy Charge	$ 0.04763 /kWh	$ 0.04763 /kWh	1,123 kWh	53.49	53.49	-	
Subtotal				$ 64.24	$ 64.24	$ -	0.00%
GRSA	9.35%	15.20%		6.01	9.76	3.75	
Base Rate Amount				$ 70.25	$ 74.00	$ 3.75	5.34%
DSMCA	$ 0.00115 /kWh	$ 0.00115 /kWh		$ 1.29	$ 1.29	$ -	
PCCA	$ 0.00829 /kWh	$ 0.00679 /kWh		$ 9.31	$ 7.63	$ (1.68)	
TCA	$ 0.00019 /kWh	$ 0.00004 /kWh		$ 0.21	$ 0.04	$ (0.17)	
ECA - Secondary	$ 0.02835 /kWh	$ 0.02835 /kWh		$ 31.84	$ 31.84	$ -	
Subtotal Base Rate Adjustments				$ 42.65	$ 40.80	$ (1.85)	
Total Bill Subtotal				$ 112.90	$ 114.80	$ 1.90	1.68%
RESA	2.00%	2.00%		$ 2.26	$ 2.30	$ 0.04	
Total Bill				$ 115.16	$ 117.10	$ 1.94	**1.68%**
			Rate/kWh:	**$ 0.10255**	**$ 0.10427**	**$ 0.00173**	**1.68%**

Notes:
ECA reflects most current 2012 projection
Riders held constant at 2012 post roll-in levels
Incorporates MYP increases effective May 1, 2012 and January 1, 2013

Public Service Company of Colorado
Electric Department
Small Commercial - Schedule C

Customer Class	2013 MYP Rates	2014 MYP Rates	Monthly Average Usage	Monthly 2013 MYP Bill	Monthly 2014 MYP Bill	Monthly Difference $	Difference %
Commercial - Schedule C							
Service and Facility Charge	$ 10.75	$ 10.75		$ 10.75	$ 10.75	$ -	
Energy Charge	$ 0.04763 /kWh	$ 0.04763 /kWh	1,123 kWh	53.49	53.49	-	
Subtotal				$ 64.24	$ 64.24	$ -	0.00%
GRSA	15.20%	17.04%		9.76	10.95	1.19	
Base Rate Amount				$ 74.00	$ 75.19	$ 1.19	1.61%
DSMCA	$ 0.00115 /kWh	$ 0.00115 /kWh		$ 1.29	$ 1.29	$ -	
PCCA	$ 0.00679 /kWh	$ 0.00679 /kWh		$ 7.63	$ 7.63	$ -	
TCA	$ 0.00004 /kWh	$ 0.00004 /kWh		$ 0.04	$ 0.04	$ -	
ECA - Secondary	$ 0.02835 /kWh	$ 0.02835 /kWh		$ 31.84	$ 31.84	$ -	
Subtotal Base Rate Adjustments				$ 40.80	$ 40.80	$ -	
Total Bill Subtotal				$ 114.80	$ 115.99	$ 1.19	1.04%
RESA	2.00%	2.00%		$ 2.30	$ 2.32	$ 0.02	
Total Bill				$ 117.10	$ 118.31	$ 1.21	**1.03%**
			Rate/kWh:	**$ 0.10427**	**$0.10535**	**$ 0.00108**	**1.03%**

Notes:
ECA reflects most current 2012 projection
Riders held constant at 2012 post roll-in levels
Incorporates MYP increases effective May 1, 2012; January 1, 2013; and January 1, 2014

Public Service Company of Colorado
Electric Department
Residential General - Schedule R

Customer Class	2012 Rates	2012 MYP Rates	Monthly Average Usage	Monthly 2012 Bill	Monthly 2012 MYP Bill	Monthly Difference $	Difference %
Residential - Schedule R							
Service and Facility Charge	$ 6.75	$ 6.75		$ 6.75	$ 6.75	$ -	
Energy Charge	$ 0.05177 /kWh	$ 0.05177 /kWh	632 kWh	32.72	32.72	-	
Subtotal				$ 39.47	$ 39.47	$ -	0.00%
GRSA	-0.20%	9.35%		(0.08)	3.69	3.77	
Base Rate Amount				$ 39.39	$ 43.16	$ 3.77	9.57%
DSMCA	$ 0.00117 /kWh	$ 0.00117 /kWh		$ 0.74	$ 0.74	$ -	
PCCA	$ 0.01142 /kWh	$ 0.00839 /kWh		$ 7.22	$ 5.30	$ (1.92)	
TCA	$ 0.00050 /kWh	$ 0.00019 /kWh		$ 0.32	$ 0.12	$ (0.20)	
ECA - Secondary	$ 0.02835 /kWh	$ 0.02835 /kWh		$ 17.92	$ 17.92	$ -	
Subtotal Base Rate Adjustments				$ 26.20	$ 24.08	$ (2.12)	
Total Bill Subtotal				$ 65.59	$ 67.24	$ 1.65	2.52%
RESA	2.00%	2.00%		$ 1.31	$ 1.34	$ 0.03	
Total Bill				$ 66.90	$ 68.58	$ 1.68	**2.51%**
			Rate/kWh:	**$ 0.10585**	**$0.10851**	**$ 0.00266**	**2.51%**

Notes:
ECA reflects most current 2012 projection
Incorporates MYP increase effective May 1, 2012

Public Service Company of Colorado
Electric Department
Residential General - Schedule R

Customer Class	2012 MYP Rates	2013 MYP Rates	Monthly Average Usage	Monthly 2012 MYP Bill	Monthly 2013 MYP Bill	Monthly Difference $	Difference %
Residential - Schedule R							
Service and Facility Charge	$ 6.75	$ 6.75		$ 6.75	$ 6.75	$ -	
Energy Charge	$ 0.05177 /kWh	$ 0.05177 /kWh	632 kWh	32.72	32.72	-	
Subtotal				$ 39.47	$ 39.47	$ -	0.00%
GRSA	9.35%	15.20%		3.69	6.00	2.31	
Base Rate Amount				$ 43.16	$ 45.47	$ 2.31	5.35%
DSMCA	$ 0.00117 /kWh	$ 0.00117 /kWh		$ 0.74	$ 0.74	$ -	
PCCA	$ 0.00839 /kWh	$ 0.00687 /kWh		$ 5.30	$ 4.34	$ (0.96)	
TCA	$ 0.00019 /kWh	$ 0.00004 /kWh		$ 0.12	$ 0.03	$ (0.09)	
ECA - Secondary	$ 0.02835 /kWh	$ 0.02835 /kWh		$ 17.92	$ 17.92	$ -	
Subtotal Base Rate Adjustments			**Incorporate	$ 24.08	$ 23.03	$ (1.05)	
Total Bill Subtotal				$ 67.24	$ 68.50	$ 1.26	1.87%
RESA	2.00%	2.00%		$ 1.34	$ 1.37	$ 0.03	
Total Bill				$ 68.58	$ 69.87	$ 1.29	**1.88%**
			Rate/kWh:	**$ 0.10851**	**$ 0.11055**	**$ 0.00204**	**1.88%**

Notes:
ECA reflects most current 2012 projection
Riders held constant at 2012 post roll-in levels
Incorporates MYP increases effective May 1, 2012 and January 1, 2013

Public Service Company of Colorado
Electric Department
Residential General - Schedule R

Customer Class	2013 MYP Rates	2014 MYP Rates	Monthly Average Usage	Monthly 2013 MYP Bill	Monthly 2014 MYP Bill	Monthly Difference $	Difference %
Residential - Schedule R							
Service and Facility Charge	$ 6.75	$ 6.75		$ 6.75	$ 6.75	$ -	
Energy Charge	$ 0.05177 /kWh	$ 0.05177 /kWh	632 kWh	32.72	32.72	-	
Subtotal				$ 39.47	$ 39.47	$ -	0.00%
GRSA	15.20%	17.04%		6.00	6.72	0.72	
Base Rate Amount				$ 45.47	$ 46.19	$ 0.72	1.58%
DSMCA	$ 0.00117 /kWh	$ 0.00117 /kWh		$ 0.74	$ 0.74	$ -	
PCCA	$ 0.00687 /kWh	$ 0.00687 /kWh		$ 4.34	$ 4.34	$ -	
TCA	$ 0.00004 /kWh	$ 0.00004 /kWh		$ 0.03	$ 0.03	$ -	
ECA - Secondary	$ 0.02835 /kWh	$ 0.02835 /kWh		$ 17.92	$ 17.92	$ -	
Subtotal Base Rate Adjustments				$ 23.03	$ 23.03	$ -	
Total Bill Subtotal				$ 68.50	$ 69.22	$ 0.72	1.05%
RESA	2.00%	2.00%		$ 1.37	$ 1.38	$ 0.01	
Total Bill				$ 69.87	$ 70.60	$ 0.73	**1.04%**
			Rate/kWh:	**$ 0.11055**	**$0.11171**	**$ 0.00116**	**1.04%**

Notes:
ECA reflects most current 2012 projection
Riders held constant at 2012 post roll-in levels
Incorporates MYP increases effective May 1, 2012; January 1, 2013; and January 1, 2014

Attachment B
to Settlement Agreement
Page 1 of 6

Public Service Company of Colorado
Electric and Common Depreciation Rates
DOCKET NO. 11AL-947E

			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
	ELECTRIC INTANGIBLE PLANT				
301.00	Organization Costs				
302.00	Franchises & Consents	(6)	0.0000%		0.0000%
303.00	Miscellaneous Plant		0.0000%		0.0000%
303.40	Misc Computer Software 5 Yr		20.0000%		20.0000%
303.40	Misc Computer Software 10 Yr		10.0000%		10.0000%
	Total Electric Intangible Plant				
	STEAM PRODUCTION PLANT				
310.10	Land				
310.20	Land Rights		2.0000%		2.0000%
310.30	Water Rights		2.0000%		2.0000%
	Total Account 310				
311.00	Structures & Improvements				
	Arapahoe Unit 3		2.1006%	0.1744%	2.2750%
	Arapahoe Unit 4		2.4164%	0.2006%	2.6170%
	Arapahoe Common		3.3102%	0.2748%	3.5850%
	Cherokee Unit 2 SC		2.0878%	0.1942%	2.2820%
	Cherokee Unit 3		1.7502%	0.1628%	1.9130%
	Cherokee Unit 4		1.8240%	0.2330%	2.0570%
	Cherokee Common		2.3050%	0.2480%	2.5530%
	Comanche Unit 1		1.6360%	0.1970%	1.8330%
	Comanche Unit 2		1.3710%	0.1650%	1.5360%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.5000%	0.1780%	1.6780%
	Craig Unit 1		1.4600%	0.0880%	1.5480%
	Craig Unit 2		1.4380%	0.0870%	1.5250%
	Craig Common		1.4870%	0.0890%	1.5760%
	Hayden Unit 1		1.6759%	0.1961%	1.8720%
	Hayden Unit 2		1.3310%	0.1950%	1.5260%
	Hayden Common		2.2160%	0.2900%	2.5060%
	Pawnee Unit 1		1.4840%	0.0900%	1.5740%
	Pawnee Common		2.7150%	0.1440%	2.8590%
	Valmont Unit 5		2.3783%	0.1807%	2.5590%
	Valmont Common		2.6617%	0.2023%	2.8640%
	Zuni Unit 2	(2)	0.0000%	0.0000%	0.0000%
	Zuni Common		2.4184%	0.3216%	2.7400%
	Total Account 311				
312.00	Boiler Plant Equipment				
	Arapahoe Unit 3		2.7793%	0.2307%	3.0100%
	Arapahoe Unit 4		3.1440%	0.2610%	3.4050%
	Arapahoe Common		5.2419%	0.4351%	5.6770%
	Cherokee Unit 2 SC		2.7722%	0.2578%	3.0300%
	Cherokee Unit 3		2.4273%	0.2257%	2.6530%
	Cherokee Unit 4		1.6920%	0.2220%	1.9140%
	Cherokee Common		2.7650%	0.2910%	3.0560%
	Comanche Unit 1		1.9460%	0.2270%	2.1730%
	Comanche Unit 2		1.8040%	0.2080%	2.0120%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.6290%	0.1920%	1.8210%
	Craig Unit 1		1.5570%	0.1060%	1.6630%
	Craig Unit 2		1.5470%	0.1060%	1.6530%
	Craig Common		2.2670%	0.1440%	2.4110%
	Hayden Unit 1		2.9517%	0.3453%	3.2970%
	Hayden Unit 2		1.7300%	0.2370%	1.9670%
	Hayden Common		2.5300%	0.3190%	2.8490%
	Pawnee Unit 1		1.6670%	0.1130%	1.7800%
	Pawnee Common		2.8790%	0.1750%	3.0540%
	Valmont Unit 5		2.5920%	0.1970%	2.7890%
	Valmont Common		3.6357%	0.2763%	3.9120%
	Zuni Unit 2		2.3901%	0.3179%	2.7080%
	Zuni Common		3.0229%	0.4021%	3.4250%
	Total Account 312.0				

Public Service Company of Colorado
Electric and Common Depreciation Rates
DOCKET NO. 11AL-947E

			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
312.10	AQIR Equipment				
	Arapahoe Unit 3		6.6667%	0.0000%	6.6667%
	Cherokee Unit 3		6.6667%	0.0000%	6.6667%
	Cherokee Unit 4		6.6667%	0.0000%	6.6667%
	Cherokee Common		6.6667%	0.0000%	6.6667%
	Valmont Unit 5		6.6667%	0.0000%	6.6667%
	Total Account 312.1				
312.20	Coal Cars		3.1667%	0.0000%	3.1667%
	Total Account 312				
314.00	Turbogenerator Units				
	Arapahoe Unit 3		2.3850%	0.1980%	2.5830%
	Arapahoe Unit 4		2.7368%	0.2272%	2.9640%
	Arapahoe Common		4.0277%	0.3343%	4.3620%
	Cherokee Unit 2 SC		2.1116%	0.1964%	2.3080%
	Cherokee Unit 3		2.1985%	0.2045%	2.4030%
	Cherokee Unit 4		1.7190%	0.2240%	1.9430%
	Cherokee Common		4.6390%	0.4350%	5.0740%
	Comanche Unit 1		1.6980%	0.2040%	1.9020%
	Comanche Unit 2		1.6350%	0.1920%	1.8270%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		2.3140%	0.2520%	2.5660%
	Craig Unit 1		2.6570%	0.1590%	2.8160%
	Craig Unit 2		1.5140%	0.1010%	1.6150%
	Craig Common		1.5560%	0.1030%	1.6590%
	Hayden Unit 1		2.0627%	0.2413%	2.3040%
	Hayden Unit 2		1.4760%	0.2090%	1.6850%
	Hayden Common		2.7010%	0.3350%	3.0360%
	Pawnee Unit 1		1.5970%	0.1060%	1.7030%
	Pawnee Common		2.2750%	0.1420%	2.4170%
	Valmont Unit 5		3.4591%	0.2629%	3.7220%
	Valmont Common		4.1403%	0.3147%	4.4550%
	Zuni Unit 2		14.6920%	1.9540%	16.6460%
	Zuni Common		1.8464%	0.2456%	2.0920%
	Total Account 314				
315.00	Accessory Electric Equipment				
	Arapahoe Unit 3		4.3019%	0.3571%	4.6590%
	Arapahoe Unit 4		2.4811%	0.2059%	2.6870%
	Arapahoe Common		3.0849%	0.2561%	3.3410%
	Cherokee Unit 2 SC		3.0393%	0.2827%	3.3220%
	Cherokee Unit 3		2.2617%	0.2103%	2.4720%
	Cherokee Unit 4		1.5800%	0.2000%	1.7800%
	Cherokee Common		1.9540%	0.2050%	2.1590%
	Comanche Unit 1		1.5310%	0.1760%	1.7070%
	Comanche Unit 2		1.6290%	0.1790%	1.8080%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.6650%	0.1820%	1.8470%
	Craig Unit 1		1.5290%	0.0860%	1.6150%
	Craig Unit 2		1.4990%	0.0850%	1.5840%
	Craig Common		1.5410%	0.0870%	1.6280%
	Hayden Unit 1		1.9391%	0.2269%	2.1660%
	Hayden Unit 2		1.3750%	0.1870%	1.5620%
	Hayden Common		2.4740%	0.2960%	2.7700%
	Pawnee Unit 1		1.5620%	0.0880%	1.6500%
	Pawnee Common		2.1720%	0.1160%	2.2880%
	Valmont Unit 5		2.3950%	0.1820%	2.5770%
	Valmont Common		2.5678%	0.1952%	2.7630%
	Zuni Unit 2		2.6134%	0.3476%	2.9610%
	Zuni Common		2.2586%	0.3004%	2.5590%
	Total Account 315				

Public Service Company of Colorado
Electric and Common Depreciation Rates
DOCKET NO. 11AL-947E

Account Number	Description	Notes	Approved (1) Depr Rate	COR Depr Rate	Tot Depr Rate
315.20	Computers & Peripherals (Boiler Controls)				
	Arapahoe Unit 4		6.5088%	0.5402%	7.0490%
	Arapahoe Common		5.1099%	0.4241%	5.5340%
	Cherokee Unit 3		3.8545%	0.3585%	4.2130%
	Cherokee Unit 4		4.3147%	0.4013%	4.7160%
	Cherokee Common		3.1757%	0.2953%	3.4710%
	Comanche Unit 1		3.6712%	0.3488%	4.0200%
	Comanche Common		3.4484%	0.3276%	3.7760%
	Craig Common		2.8817%	0.1383%	3.0200%
	Hayden Unit 1		3.6598%	0.4282%	4.0880%
	Hayden Unit 2		3.4324%	0.4016%	3.8340%
	Pawnee Unit 1		2.9428%	0.1442%	3.0870%
	Pawnee Common		2.6463%	0.1297%	2.7760%
	Valmont Common		3.3690%	0.2560%	3.6250%
	Zuni Common		6.7582%	0.8988%	7.6570%
	Total Account 315.2				
316.00	Misc. Power Plant Equipment				
	Arapahoe Unit 4		4.7775%	0.3965%	5.1740%
	Arapahoe Common		3.7673%	0.3127%	4.0800%
	Cherokee Unit 2 SC		2.6807%	0.2493%	2.9300%
	Cherokee Unit 3		2.3449%	0.2181%	2.5630%
	Cherokee Unit 4		1.4290%	0.1700%	1.5990%
	Cherokee Common		2.1380%	0.2040%	2.3420%
	Comanche Unit 1		1.3680%	0.1450%	1.5130%
	Comanche Unit 2		1.3560%	0.1370%	1.4930%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.6030%	0.1580%	1.7610%
	Craig Unit 1		1.5120%	0.0690%	1.5810%
	Craig Unit 2		1.4780%	0.0690%	1.5470%
	Craig Common		1.6400%	0.0740%	1.7140%
	Hayden Unit 1		1.6902%	0.1978%	1.8880%
	Hayden Unit 2		1.3970%	0.1710%	1.5680%
	Hayden Common		2.3100%	0.2540%	2.5640%
	Pawnee Unit 1		1.5700%	0.0710%	1.6410%
	Pawnee Common		2.3210%	0.0980%	2.4190%
	Valmont Unit 5		2.4879%	0.1891%	2.6770%
	Valmont Common		2.7063%	0.2057%	2.9120%
	Zuni Unit 2	(2)	0.0000%	0.0000%	0.0000%
	Zuni Common		4.9409%	0.6571%	5.5980%
	Total Account 316				
	Total Steam Production				
	HYDRAULIC PRODUCTION PLANT				
330.10	Land				
331.00	Structures & Improvements				
	Ames		1.4679%	0.0191%	1.4870%
	Cabin Creek		0.9324%	0.1296%	1.0620%
	Georgetown		1.6952%	0.0068%	1.7020%
	Salida		1.8055%	0.0325%	1.8380%
	Shoshone		1.6234%	0.0536%	1.6770%
	Tacoma		1.3804%	0.0276%	1.4080%
	Total Account 331				
332.00	Reservoirs, Dams & Waterways				
	Ames		1.5420%	0.0200%	1.5620%
	Cabin Creek		0.9587%	0.1333%	1.0920%
	Georgetown		2.3038%	0.0092%	2.3130%
	Salida		1.5658%	0.0270%	1.5928%
	Shoshone		0.8325%	0.0275%	0.8600%
	Tacoma		1.3500%	0.0270%	1.3770%
	Total Account 332				
333.00	Waterwheels, Turbines & Generators				
	Ames		0.9299%	0.0121%	0.9420%
	Cabin Creek		1.0773%	0.1497%	1.2270%
	Georgetown		1.0269%	0.0041%	1.0310%
	Salida		0.6965%	0.0125%	0.7090%
	Shoshone		1.7212%	0.0568%	1.7780%
	Tacoma		1.8147%	0.0363%	1.8510%
	Total Account 333				

Public Service Company of Colorado
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			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
334.00	Accessory Electric Equipment				
	Ames		2.4393%	0.0317%	2.4710%
	Cabin Creek		1.2581%	0.1749%	1.4330%
	Georgetown		1.6056%	0.0064%	1.6120%
	Salida		2.0010%	0.0360%	2.0370%
	Shoshone		2.2323%	0.0737%	2.3060%
	Tacoma		1.7667%	0.0353%	1.8020%
	Total Account 334				
334.20	Computers				
	Cabin Creek		1.1563%	0.1607%	1.3170%
	Total Account 334.2				
335.00	Misc. Power Plant Equipment				
	Ames		1.8095%	0.0235%	1.8330%
	Cabin Creek		1.4978%	0.2082%	1.7060%
	Georgetown		2.8665%	0.0115%	2.8780%
	Salida		3.6248%	0.0652%	3.6900%
	Shoshone		2.7396%	0.0904%	2.8300%
	Tacoma		1.8912%	0.0378%	1.9290%
	Total Account 335				
335.20	Recreational Facilities				
	Ames		2.3258%	0.0302%	2.3560%
	Cabin Creek		1.3565%	0.1885%	1.5450%
	Georgetown		2.2570%	0.0090%	2.2660%
	Salida		3.2711%	0.0589%	3.3300%
	Tacoma		1.6294%	0.0326%	1.6620%
	Total Account 335.2				
336.00	Roads, Railroads & Bridges				
	Ames		2.3722%	0.0308%	2.4030%
	Cabin Creek		0.9359%	0.1301%	1.0660%
	Salida		2.6189%	0.0471%	2.6660%
	Shoshone		1.0852%	0.0358%	1.1210%
	Tacoma		1.3029%	0.0261%	1.3290%
	Total Account 336				
	Total Hydraulic Production				
	OTHER PRODUCTION PLANT				
340.10	Land				
340.20	Land Rights		2.0000%	0.0000%	2.0000%
	Total Account 340				
341.00	Structures & Improvements				
	Alamosa		4.4734%	0.1566%	4.6300%
	Fruita CT		0.8302%	0.0548%	0.8850%
	FSV ST 1		1.3811%	0.0539%	1.4350%
	FSV GT 4		2.3994%	0.0936%	2.4930%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		1.6554%	0.0646%	1.7200%
	Ft. Lupton CT		2.4128%	0.1472%	2.5600%
	Valmont CT		0.7780%	0.0420%	0.8200%
	Total Account 341				
342.00	Fuel Holders, Producers & Access.				
	Alamosa		1.0058%	0.0352%	1.0410%
	Fruita CT		0.9756%	0.0644%	1.0400%
	FSV ST 1		2.3879%	0.0931%	2.4810%
	FSV GT 2		2.7469%	0.1071%	2.8540%
	FSV GT 3		2.7825%	0.1085%	2.8910%
	FSV GT 4		2.4321%	0.0949%	2.5270%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		1.6391%	0.0639%	1.7030%
	Ft. Lupton CT		3.6664%	0.2236%	3.8900%
	Valmont CT		1.2837%	0.0693%	1.3530%
	Total Account 342				

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Account Number	Description	Notes	Approved (1) Depr Rate	COR Depr Rate	Tot Depr Rate
343.00	Prime Movers				
	FSV ST 1		2.1280%	0.0830%	2.2110%
	FSV GT 2		2.2281%	0.0869%	2.3150%
	FSV GT 3	(2)	1.8582%	0.2118%	2.0700%
	FSV Common		2.6266%	0.1024%	2.7290%
	Total Account 343				
344.00	Generators				
	Alamosa		1.5633%	0.0547%	1.6180%
	Blue Spruce	(4)	2.5000%	0.1887%	2.6887%
	Fruita CT		0.9653%	0.0637%	1.0290%
	FSV ST 1		1.3705%	0.0535%	1.4240%
	FSV GT 2		2.3272%	0.0908%	2.4180%
	FSV GT 3		2.6237%	0.1023%	2.7260%
	FSV GT 4		2.5881%	0.1009%	2.6890%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		2.5881%	0.1009%	2.6890%
	Ft. Lupton CT		3.7945%	0.2315%	4.0260%
	Rocky Mountain	(4)	2.5000%	0.3491%	2.8491%
	Wind - Hydrogen	(4)	6.6700%	0.0000%	6.6700%
	Valmont CT		1.8046%	0.0974%	1.9020%
	Total Account 344				
345.00	Accessory Electric Equipment				
	Alamosa		3.6184%	0.1266%	3.7450%
	Fruita CT		3.9428%	0.2602%	4.2030%
	FSV ST 1		1.3831%	0.0539%	1.4370%
	FSV GT 2		1.9838%	0.2262%	2.2100%
	FSV GT 4		2.4456%	0.0954%	2.5410%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		2.5958%	0.1012%	2.6970%
	Ft. Lupton CT		1.2875%	0.0785%	1.3660%
	Valmont CT		4.3197%	0.2333%	4.5530%
	Total Account 345				
345.20	Computers				
	FSV ST 1		1.6487%	0.0643%	1.7130%
	FSV Common		2.1193%	0.0827%	2.2020%
	Total Account 345.2				
346.00	Misc. Power Plant Equipment				
	Alamosa		0.9430%	0.0330%	0.9760%
	Fruita CT		1.0610%	0.0700%	1.1310%
	FSV ST 1		1.4379%	0.0561%	1.4940%
	FSV GT 4		2.4283%	0.0947%	2.5230%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		2.5303%	0.0987%	2.6290%
	Ft. Lupton CT		1.3713%	0.0837%	1.4550%
	Valmont CT		4.5873%	0.2477%	4.8350%
	Total Account 346				
	Total Other Production				
	Total Electric Production				
	TRANSMISSION PLANT				
350.10	Land				
350.20	Land Rights		1.0300%	0.0000%	1.0300%
352.00	Structures & Improvements		1.3091%	0.1309%	1.4400%
352.10	Structures & Improvements-Production		1.3091%	0.1309%	1.4400%
353.00	Station Equipment		1.6481%	0.1319%	1.7800%
353.10	Station Equipment-Production		1.6481%	0.1319%	1.7800%
354.00	Towers & Fixtures		1.1238%	0.0562%	1.1800%
355.00	Poles & Fixtures		1.5619%	0.0781%	1.6400%
356.00	OH Conductors & Devices		1.7048%	0.0852%	1.7900%
357.00	UG Conduit		1.9400%	0.0000%	1.9400%
358.00	UG Conductors & Devices		1.8800%	0.0000%	1.8800%
359.00	Roads & Trails		0.9700%	0.0000%	0.9700%
	Total Transmission				

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			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
	DISTRIBUTION PLANT				
360.10	Land				
360.20	Land Rights		1.0900%	0.0000%	1.0900%
361.00	Structures & Improvements		1.7100%	0.0000%	1.7100%
361.10	Structures & Improvements-Production		1.7100%	0.0000%	1.7100%
362.00	Station Equipment		1.7826%	0.2674%	2.0500%
362.10	Station Equipment-Production		1.7826%	0.2674%	2.0500%
364.00	Poles, Towers & Fixtures		2.8077%	0.8423%	3.6500%
365.00	OH Conductors & Devices		2.3643%	0.9457%	3.3100%
366.00	UG Conduit		1.9135%	0.0765%	1.9900%
367.00	UG Conductors & Devices		1.8636%	0.1864%	2.0500%
368.00	Line Transformers		2.2100%	0.0000%	2.2100%
369.00	Services		1.9580%	0.3720%	2.3300%
369.10	Services-Overhead		1.9580%	0.3720%	2.3300%
369.20	Services-Underground		1.9580%	0.3720%	2.3300%
370.00	Meters		3.9700%	0.0000%	3.9700%
370.20	AMR Equipment		8.8100%	0.0000%	8.8100%
371.00	Installation on Customer Premises		0.8333%	0.1667%	1.0000%
373.00	Street Lighting & Signal Systems		2.4583%	0.4917%	2.9500%
	Total Distribution				
	ELECTRIC GENERAL PLANT				
389.00	Land				
390.00	Structures & Improvements		4.8800%	0.0000%	4.8800%
390.10	General Buildings		2.9800%	0.0000%	2.9800%
390.20	Partitions		7.6900%	0.0000%	7.6900%
391.00	Office Furniture & Equipment		4.7500%	0.0000%	4.7500%
391.20	Computer Hardware		20.0000%	0.0000%	20.0000%
392.00	Transportation Equipment		9.0000%	0.0000%	9.0000%
393.00	Stores Equipment		3.1700%	0.0000%	3.1700%
394.00	Tools, Shop & Garage Equipment		3.8000%	0.0000%	3.8000%
395.00	Laboratory Equipment		9.5000%	0.0000%	9.5000%
396.00	Power Operated Equipment		9.0000%	0.0000%	9.0000%
397.00	Communication Equipment		6.6700%	0.0000%	6.6700%
398.00	Miscellaneous Equipment		5.0000%	0.0000%	5.0000%
	Total Electric General				
	Total Electric Plant				
	COMMON INTANGIBLE PLANT				
301.00	Organization Costs				
302.00	Franchises & Consents	(6)			
303.04	Misc Computer Software-5 Year		20.0000%	0.0000%	20.0000%
303.04	Misc Computer Software-10 Year		10.0000%	0.0000%	10.0000%
303.14	CRS Computer Software		10.0000%	0.0000%	10.0000%
	Total Common Intangible				
	COMMON GENERAL PLANT				
389.01	General Land Owned in Fee		0.0000%	0.0000%	0.0000%
390.00	Genl Structures & Improve		2.7304%	0.4096%	3.1400%
390.07	Genl Str & Imp-Lease Bldg-CPR	(7)			
390.07	Genl Str & Imp-Lease Bldg-106		6.0606%	0.0000%	6.0606%
390.08	Genl Str & Imp-Partitions		3.8000%	0.0000%	3.8000%
390.85	GS&I-1800 Leasehold Imp	(5)	6.6666%	0.0000%	6.6666%
391.00	General Office Furn & Eqp		4.7500%	0.0000%	4.7500%
391.04	Computer Hardware		20.0000%	0.0000%	20.0000%
391.05	Genl Off Eq-Comp 3 Yr Life		33.3300%	0.0000%	33.3300%
391.07	Genl Office Equip-Leased		20.0000%	0.0000%	20.0000%
391.09	Genl Off Eq-Part Lease Fac		5.0000%	0.0000%	5.0000%
392.00	General Transportation Eqp		9.0000%	0.0000%	9.0000%
393.00	General Stores Equipment		3.1700%	0.0000%	3.1700%
394.00	General Tools & Shop Equip		3.8000%	0.0000%	3.8000%
395.00	Laboratory Equipment		9.5000%	0.0000%	9.5000%
396.00	General Power Operated Eqp		9.0000%	0.0000%	9.0000%
397.00	General Communication Eqp		6.6700%	0.0000%	6.6700%
398.00	General Miscellaneous Eqp		5.0000%	0.0000%	5.0000%
	Total Common General Plant				
	Total Common Plant				

Notes:
(1) Approved rates are from Docket 06S-234EG, unless specified in the Notes column.
(2) Approved rates are from Docket 02S-315EG
(3) Depreciation rates for Comanche 3, FSV GT 5 and FSV GT 6 were approved in Docket 08S-520E.
(4) Depreciation rates set in Docket 11-947E.
(5) Amortized over the 15 year lease term.
(6) Amortized over the terms of the franchise agreements
(7) Amortized over the lease term.

Xcel Energy℠
PUBLIC SERVICE COMPANY

P.O. Box 840
Denver, Colorado 80201-0840

April 02, 2012

Mr. Doug Dean
Director
Public Utilities Commission
of the State of Colorado
1560 Broadway, Suite 250
Denver, Colorado 80202

Re: Docket No. 11AL-947E Burden Letter with Regard to General Rate Schedule Adjustment (GRSA) Increase to Take Effect May 1, 2012

Dear Mr. Dean:

This letter is being filed in conjunction with the above-referenced docket. The Company filed with the Commission today in Docket No. 11AL-947E a Joint Motion asking the Commission to exercise its discretion to authorize the Company to put into effect a revision to the GRSA currently in effect sufficient to recover an additional $73 million on an annual basis in accordance with the Settlement Agreement also filed on this date, subject to refund under a utility burden letter. This letter constitutes the "burden letter" that can be relied upon by the Commission and the parties to this proceeding.

By this burden letter, the Company agrees that if the Commission enters a final order in this proceeding finding that some portion of the incremental rate relief allowed to take effect on May 1, 2012 is unjust and unreasonable, the Company will refund to customers the difference between the incremental $73 million annual revenue increase and the annual revenue increase that is ultimately determined by the Commission to be reasonable, for the period of time that the rates subject to this burden letter were in effect. The refund will be made through a negative GRSA, with interest calculated at the average interest rate for commercial bank twenty-four month loans for personal expenditures from the Federal Reserve Board's G. 19 Consumer credit for the second quarter of 2012, plus two percent.

If you have any questions concerning the contents of this letter, please contact Ms. Karen Hyde at (303) 294-2377 or Ms. Connelly at (303) 294-2222.

Sincerely,

David L. Eves
President and CEO
Public Service Company of Colorado

Paula M. Connelly
Managing Attorney
Xcel Energy Services Inc.
Attorney for Public Service Company of Colorado

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Public Service Company of Colorado
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Account Number	Description	Notes	Approved (1) Depr Rate	COR Depr Rate	Tot Depr Rate
	ELECTRIC INTANGIBLE PLANT				
301.00	Organization Costs				
302.00	Franchises & Consents	(6)	0.0000%		0.0000%
303.00	Miscellaneous Plant		0.0000%		0.0000%
303.40	Misc Computer Software 5 Yr		20.0000%		20.0000%
303.40	Misc Computer Software 10 Yr		10.0000%		10.0000%
	Total Electric Intangible Plant				
	STEAM PRODUCTION PLANT				
310.10	Land				
310.20	Land Rights		2.0000%		2.0000%
310.30	Water Rights		2.0000%		2.0000%
	Total Account 310				
311.00	Structures & Improvements				
	Arapahoe Unit 3		2.1006%	0.1744%	2.2750%
	Arapahoe Unit 4		2.4164%	0.2006%	2.6170%
	Arapahoe Common		3.3102%	0.2748%	3.5850%
	Cherokee Unit 2 SC		2.0878%	0.1942%	2.2820%
	Cherokee Unit 3		1.7502%	0.1628%	1.9130%
	Cherokee Unit 4		1.8240%	0.2330%	2.0570%
	Cherokee Common		2.3050%	0.2480%	2.5530%
	Comanche Unit 1		1.6360%	0.1970%	1.8330%
	Comanche Unit 2		1.3710%	0.1650%	1.5360%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.5000%	0.1780%	1.6780%
	Craig Unit 1		1.4600%	0.0880%	1.5480%
	Craig Unit 2		1.4380%	0.0870%	1.5250%
	Craig Common		1.4870%	0.0890%	1.5760%
	Hayden Unit 1		1.6759%	0.1961%	1.8720%
	Hayden Unit 2		1.3310%	0.1950%	1.5260%
	Hayden Common		2.2160%	0.2900%	2.5060%
	Pawnee Unit 1		1.4840%	0.0900%	1.5740%
	Pawnee Common		2.7150%	0.1440%	2.8590%
	Valmont Unit 5		2.3783%	0.1807%	2.5590%
	Valmont Common		2.6617%	0.2023%	2.8640%
	Zuni Unit 2	(2)	0.0000%	0.0000%	0.0000%
	Zuni Common		2.4184%	0.3216%	2.7400%
	Total Account 311				
312.00	Boiler Plant Equipment				
	Arapahoe Unit 3		2.7793%	0.2307%	3.0100%
	Arapahoe Unit 4		3.1440%	0.2610%	3.4050%
	Arapahoe Common		5.2419%	0.4351%	5.6770%
	Cherokee Unit 2 SC		2.7722%	0.2578%	3.0300%
	Cherokee Unit 3		2.4273%	0.2257%	2.6530%
	Cherokee Unit 4		1.6920%	0.2220%	1.9140%
	Cherokee Common		2.7650%	0.2910%	3.0560%
	Comanche Unit 1		1.9460%	0.2270%	2.1730%
	Comanche Unit 2		1.8040%	0.2080%	2.0120%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.6290%	0.1920%	1.8210%
	Craig Unit 1		1.5570%	0.1060%	1.6630%
	Craig Unit 2		1.5470%	0.1060%	1.6530%
	Craig Common		2.2670%	0.1440%	2.4110%
	Hayden Unit 1		2.9517%	0.3453%	3.2970%
	Hayden Unit 2		1.7300%	0.2370%	1.9670%
	Hayden Common		2.5300%	0.3190%	2.8490%
	Pawnee Unit 1		1.6670%	0.1130%	1.7800%
	Pawnee Common		2.8790%	0.1750%	3.0540%
	Valmont Unit 5		2.5920%	0.1970%	2.7890%
	Valmont Common		3.6357%	0.2763%	3.9120%
	Zuni Unit 2		2.3901%	0.3179%	2.7080%
	Zuni Common		3.0229%	0.4021%	3.4250%
	Total Account 312.0				

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			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
312.10	AQIR Equipment				
	Arapahoe Unit 3		6.6667%	0.0000%	6.6667%
	Cherokee Unit 3		6.6667%	0.0000%	6.6667%
	Cherokee Unit 4		6.6667%	0.0000%	6.6667%
	Cherokee Common		6.6667%	0.0000%	6.6667%
	Valmont Unit 5		6.6667%	0.0000%	6.6667%
	Total Account 312.1				
312.20	Coal Cars		3.1667%	0.0000%	3.1667%
	Total Account 312				
314.00	Turbogenerator Units				
	Arapahoe Unit 3		2.3850%	0.1980%	2.5830%
	Arapahoe Unit 4		2.7368%	0.2272%	2.9640%
	Arapahoe Common		4.0277%	0.3343%	4.3620%
	Cherokee Unit 2 SC		2.1116%	0.1964%	2.3080%
	Cherokee Unit 3		2.1985%	0.2045%	2.4030%
	Cherokee Unit 4		1.7190%	0.2240%	1.9430%
	Cherokee Common		4.6390%	0.4350%	5.0740%
	Comanche Unit 1		1.6980%	0.2040%	1.9020%
	Comanche Unit 2		1.6350%	0.1920%	1.8270%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		2.3140%	0.2520%	2.5660%
	Craig Unit 1		2.6570%	0.1590%	2.8160%
	Craig Unit 2		1.5140%	0.1010%	1.6150%
	Craig Common		1.5560%	0.1030%	1.6590%
	Hayden Unit 1		2.0627%	0.2413%	2.3040%
	Hayden Unit 2		1.4760%	0.2090%	1.6850%
	Hayden Common		2.7010%	0.3350%	3.0360%
	Pawnee Unit 1		1.5970%	0.1060%	1.7030%
	Pawnee Common		2.2750%	0.1420%	2.4170%
	Valmont Unit 5		3.4591%	0.2629%	3.7220%
	Valmont Common		4.1403%	0.3147%	4.4550%
	Zuni Unit 2		14.6920%	1.9540%	16.6460%
	Zuni Common		1.8464%	0.2456%	2.0920%
	Total Account 314				
315.00	Accessory Electric Equipment				
	Arapahoe Unit 3		4.3019%	0.3571%	4.6590%
	Arapahoe Unit 4		2.4811%	0.2059%	2.6870%
	Arapahoe Common		3.0849%	0.2561%	3.3410%
	Cherokee Unit 2 SC		3.0393%	0.2827%	3.3220%
	Cherokee Unit 3		2.2617%	0.2103%	2.4720%
	Cherokee Unit 4		1.5800%	0.2000%	1.7800%
	Cherokee Common		1.9540%	0.2050%	2.1590%
	Comanche Unit 1		1.5310%	0.1760%	1.7070%
	Comanche Unit 2		1.6290%	0.1790%	1.8080%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.6650%	0.1820%	1.8470%
	Craig Unit 1		1.5290%	0.0860%	1.6150%
	Craig Unit 2		1.4990%	0.0850%	1.5840%
	Craig Common		1.5410%	0.0870%	1.6280%
	Hayden Unit 1		1.9391%	0.2269%	2.1660%
	Hayden Unit 2		1.3750%	0.1870%	1.5620%
	Hayden Common		2.4740%	0.2960%	2.7700%
	Pawnee Unit 1		1.5620%	0.0880%	1.6500%
	Pawnee Common		2.1720%	0.1160%	2.2880%
	Valmont Unit 5		2.3950%	0.1820%	2.5770%
	Valmont Common		2.5678%	0.1952%	2.7630%
	Zuni Unit 2		2.6134%	0.3476%	2.9610%
	Zuni Common		2.2586%	0.3004%	2.5590%
	Total Account 315				

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Account Number	Description	Notes	Approved (1) Depr Rate	COR Depr Rate	Tot Depr Rate
315.20	Computers & Peripherals (Boiler Controls)				
	Arapahoe Unit 4		6.5088%	0.5402%	7.0490%
	Arapahoe Common		5.1099%	0.4241%	5.5340%
	Cherokee Unit 3		3.8545%	0.3585%	4.2130%
	Cherokee Unit 4		4.3147%	0.4013%	4.7160%
	Cherokee Common		3.1757%	0.2953%	3.4710%
	Comanche Unit 1		3.6712%	0.3488%	4.0200%
	Comanche Common		3.4484%	0.3276%	3.7760%
	Craig Common		2.8817%	0.1383%	3.0200%
	Hayden Unit 1		3.6598%	0.4282%	4.0880%
	Hayden Unit 2		3.4324%	0.4016%	3.8340%
	Pawnee Unit 1		2.9428%	0.1442%	3.0870%
	Pawnee Common		2.6463%	0.1297%	2.7760%
	Valmont Common		3.3690%	0.2560%	3.6250%
	Zuni Common		6.7582%	0.8988%	7.6570%
	Total Account 315.2				
316 00	Misc. Power Plant Equipment				
	Arapahoe Unit 4		4.7775%	0.3965%	5.1740%
	Arapahoe Common		3.7673%	0.3127%	4.0800%
	Cherokee Unit 2 SC		2.6807%	0.2493%	2.9300%
	Cherokee Unit 3		2.3449%	0.2181%	2.5630%
	Cherokee Unit 4		1.4290%	0.1700%	1.5990%
	Cherokee Common		2.1380%	0.2040%	2.3420%
	Comanche Unit 1		1.3680%	0.1450%	1.5130%
	Comanche Unit 2		1.3560%	0.1370%	1.4930%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.6030%	0.1580%	1.7610%
	Craig Unit 1		1.5120%	0.0690%	1.5810%
	Craig Unit 2		1.4780%	0.0690%	1.5470%
	Craig Common		1.6400%	0.0740%	1.7140%
	Hayden Unit 1		1.6902%	0.1978%	1.8880%
	Hayden Unit 2		1.3970%	0.1710%	1.5680%
	Hayden Common		2.3100%	0.2540%	2.5640%
	Pawnee Unit 1		1.5700%	0.0710%	1.6410%
	Pawnee Common		2.3210%	0.0980%	2.4190%
	Valmont Unit 5		2.4879%	0.1891%	2.6770%
	Valmont Common		2.7063%	0.2057%	2.9120%
	Zuni Unit 2	(2)	0.0000%	0.0000%	0.0000%
	Zuni Common		4.9409%	0.6571%	5.5980%
	Total Account 316				
	Total Steam Production				
	HYDRAULIC PRODUCTION PLANT				
330.10	Land				
331.00	Structures & Improvements				
	Ames		1.4679%	0.0191%	1.4870%
	Cabin Creek		0.9324%	0.1296%	1.0620%
	Georgetown		1.6952%	0.0068%	1.7020%
	Salida		1.8055%	0.0325%	1.8380%
	Shoshone		1.6234%	0.0536%	1.6770%
	Tacoma		1.3804%	0.0276%	1.4080%
	Total Account 331				
332.00	Reservoirs, Dams & Waterways				
	Ames		1.5420%	0.0200%	1.5620%
	Cabin Creek		0.9587%	0.1333%	1.0920%
	Georgetown		2.3038%	0.0092%	2.3130%
	Salida		1.5658%	0.0270%	1.5928%
	Shoshone		0.8325%	0.0275%	0.8600%
	Tacoma		1.3500%	0.0270%	1.3770%
	Total Account 332				
333.00	Waterwheels, Turbines & Generators				
	Ames		0.9299%	0.0121%	0.9420%
	Cabin Creek		1.0773%	0.1497%	1.2270%
	Georgetown		1.0269%	0.0041%	1.0310%
	Salida		0.6965%	0.0125%	0.7090%
	Shoshone		1.7212%	0.0568%	1.7780%
	Tacoma		1.8147%	0.0363%	1.8510%
	Total Account 333				

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Account Number	Description	Notes	Approved (1) Depr Rate	COR Depr Rate	Tot Depr Rate
334.00	Accessory Electric Equipment				
	Ames		2.4393%	0.0317%	2.4710%
	Cabin Creek		1.2581%	0.1749%	1.4330%
	Georgetown		1.6056%	0.0064%	1.6120%
	Salida		2.0010%	0.0360%	2.0370%
	Shoshone		2.2323%	0.0737%	2.3060%
	Tacoma		1.7667%	0.0353%	1.8020%
	Total Account 334				
334.20	Computers				
	Cabin Creek		1.1563%	0.1607%	1.3170%
	Total Account 334.2				
335.00	Misc. Power Plant Equipment				
	Ames		1.8095%	0.0235%	1.8330%
	Cabin Creek		1.4978%	0.2082%	1.7060%
	Georgetown		2.8665%	0.0115%	2.8780%
	Salida		3.6248%	0.0652%	3.6900%
	Shoshone		2.7396%	0.0904%	2.8300%
	Tacoma		1.8912%	0.0378%	1.9290%
	Total Account 335				
335.20	Recreational Facilities				
	Ames		2.3258%	0.0302%	2.3560%
	Cabin Creek		1.3565%	0.1885%	1.5450%
	Georgetown		2.2570%	0.0090%	2.2660%
	Salida		3.2711%	0.0589%	3.3300%
	Tacoma		1.6294%	0.0326%	1.6620%
	Total Account 335.2				
336.00	Roads, Railroads & Bridges				
	Ames		2.3722%	0.0308%	2.4030%
	Cabin Creek		0.9359%	0.1301%	1.0660%
	Salida		2.6189%	0.0471%	2.6660%
	Shoshone		1.0852%	0.0358%	1.1210%
	Tacoma		1.3029%	0.0261%	1.3290%
	Total Account 336				
	Total Hydraulic Production				
	OTHER PRODUCTION PLANT				
340.10	Land				
340.20	Land Rights		2.0000%	0.0000%	2.0000%
	Total Account 340				
341.00	Structures & Improvements				
	Alamosa		4.4734%	0.1566%	4.6300%
	Fruita CT		0.8302%	0.0548%	0.8850%
	FSV ST 1		1.3811%	0.0539%	1.4350%
	FSV GT 4		2.3994%	0.0936%	2.4930%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		1.6554%	0.0646%	1.7200%
	Ft. Lupton CT		2.4128%	0.1472%	2.5600%
	Valmont CT		0.7780%	0.0420%	0.8200%
	Total Account 341				
342.00	Fuel Holders, Producers & Access.				
	Alamosa		1.0058%	0.0352%	1.0410%
	Fruita CT		0.9756%	0.0644%	1.0400%
	FSV ST 1		2.3879%	0.0931%	2.4810%
	FSV GT 2		2.7469%	0.1071%	2.8540%
	FSV GT 3		2.7825%	0.1085%	2.8910%
	FSV GT 4		2.4321%	0.0949%	2.5270%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		1.6391%	0.0639%	1.7030%
	Ft. Lupton CT		3.6664%	0.2236%	3.8900%
	Valmont CT		1.2837%	0.0693%	1.3530%
	Total Account 342				

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			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
343.00	Prime Movers				
	FSV ST 1		2.1280%	0.0830%	2.2110%
	FSV GT 2		2.2281%	0.0869%	2.3150%
	FSV GT 3	(2)	1.8582%	0.2118%	2.0700%
	FSV Common		2.6266%	0.1024%	2.7290%
	Total Account 343				
344.00	Generators				
	Alamosa		1.5633%	0.0547%	1.6180%
	Blue Spruce	(4)	2.5000%	0.1887%	2.6887%
	Fruita CT		0.9653%	0.0637%	1.0290%
	FSV ST 1		1.3705%	0.0535%	1.4240%
	FSV GT 2		2.3272%	0.0908%	2.4180%
	FSV GT 3		2.6237%	0.1023%	2.7260%
	FSV GT 4		2.5881%	0.1009%	2.6890%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		2.5881%	0.1009%	2.6890%
	Ft. Lupton CT		3.7945%	0.2315%	4.0260%
	Rocky Mountain	(4)	2.5000%	0.3491%	2.8491%
	Wind - Hydrogen	(4)	6.6700%	0.0000%	6.6700%
	Valmont CT		1.8046%	0.0974%	1.9020%
	Total Account 344				
345.00	Accessory Electric Equipment				
	Alamosa		3.6184%	0.1266%	3.7450%
	Fruita CT		3.9428%	0.2602%	4.2030%
	FSV ST 1		1.3831%	0.0539%	1.4370%
	FSV GT 2		1.9838%	0.2262%	2.2100%
	FSV GT 4		2.4456%	0.0954%	2.5410%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		2.5958%	0.1012%	2.6970%
	Ft. Lupton CT		1.2875%	0.0785%	1.3660%
	Valmont CT		4.3197%	0.2333%	4.5530%
	Total Account 345				
345.20	Computers				
	FSV ST 1		1.6487%	0.0643%	1.7130%
	FSV Common		2.1193%	0.0827%	2.2020%
	Total Account 345.2				
346.00	Misc. Power Plant Equipment				
	Alamosa		0.9430%	0.0330%	0.9760%
	Fruita CT		1.0610%	0.0700%	1.1310%
	FSV ST 1		1.4379%	0.0561%	1.4940%
	FSV GT 4		2.4283%	0.0947%	2.5230%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		2.5303%	0.0987%	2.6290%
	Ft. Lupton CT		1.3713%	0.0837%	1.4550%
	Valmont CT		4.5873%	0.2477%	4.8350%
	Total Account 346				
	Total Other Production				
	Total Electric Production				
	TRANSMISSION PLANT				
350.10	Land				
350.20	Land Rights		1.0300%	0.0000%	1.0300%
352.00	Structures & Improvements		1.3091%	0.1309%	1.4400%
352.10	Structures & Improvements-Production		1.3091%	0.1309%	1.4400%
353.00	Station Equipment		1.6481%	0.1319%	1.7800%
353.10	Station Equipment-Production		1.6481%	0.1319%	1.7800%
354.00	Towers & Fixtures		1.1238%	0.0562%	1.1800%
355.00	Poles & Fixtures		1.5619%	0.0781%	1.6400%
356.00	OH Conductors & Devices		1.7048%	0.0852%	1.7900%
357.00	UG Conduit		1.9400%	0.0000%	1.9400%
358.00	UG Conductors & Devices		1.8800%	0.0000%	1.8800%
359.00	Roads & Trails		0.9700%	0.0000%	0.9700%
	Total Transmission				

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Account Number	Description	Notes	Approved (1) Depr Rate	COR Depr Rate	Tot Depr Rate
	DISTRIBUTION PLANT				
360.10	Land				
360.20	Land Rights		1.0900%	0.0000%	1.0900%
361.00	Structures & Improvements		1.7100%	0.0000%	1.7100%
361.10	Structures & Improvements-Production		1.7100%	0.0000%	1.7100%
362.00	Station Equipment		1.7826%	0.2674%	2.0500%
362.10	Station Equipment-Production		1.7826%	0.2674%	2.0500%
364.00	Poles, Towers & Fixtures		2.8077%	0.8423%	3.6500%
365.00	OH Conductors & Devices		2.3643%	0.9457%	3.3100%
366.00	UG Conduit		1.9135%	0.0765%	1.9900%
367.00	UG Conductors & Devices		1.8636%	0.1864%	2.0500%
368.00	Line Transformers		2.2100%	0.0000%	2.2100%
369.00	Services		1.9580%	0.3720%	2.3300%
369.10	Services-Overhead		1.9580%	0.3720%	2.3300%
369.20	Services-Underground		1.9580%	0.3720%	2.3300%
370.00	Meters		3.9700%	0.0000%	3.9700%
370.20	AMR Equipment		8.8100%	0.0000%	8.8100%
371.00	Installation on Customer Premises		0.8333%	0.1667%	1.0000%
373.00	Street Lighting & Signal Systems		2.4583%	0.4917%	2.9500%
	Total Distribution				
	ELECTRIC GENERAL PLANT				
389.00	Land				
390.00	Structures & Improvements		4.8800%	0.0000%	4.8800%
390.10	General Buildings		2.9800%	0.0000%	2.9800%
390.20	Partitions		7.6900%	0.0000%	7.6900%
391.00	Office Furniture & Equipment		4.7500%	0.0000%	4.7500%
391.20	Computer Hardware		20.0000%	0.0000%	20.0000%
392.00	Transportation Equipment		9.0000%	0.0000%	9.0000%
393.00	Stores Equipment		3.1700%	0.0000%	3.1700%
394.00	Tools, Shop & Garage Equipment		3.8000%	0.0000%	3.8000%
395.00	Laboratory Equipment		9.5000%	0.0000%	9.5000%
396.00	Power Operated Equipment		9.0000%	0.0000%	9.0000%
397.00	Communication Equipment		6.6700%	0.0000%	6.6700%
398.00	Miscellaneous Equipment		5.0000%	0.0000%	5.0000%
	Total Electric General				
	Total Electric Plant				
	COMMON INTANGIBLE PLANT				
301.00	Organization Costs				
302.00	Franchises & Consents	(6)			
303.04	Misc Computer Software-5 Year		20.0000%	0.0000%	20.0000%
303.04	Misc Computer Software-10 Year		10.0000%	0.0000%	10.0000%
303.14	CRS Computer Software		10.0000%	0.0000%	10.0000%
	Total Common Intangible				
	COMMON GENERAL PLANT				
389.01	General Land Owned in Fee		0.0000%	0.0000%	0.0000%
390.00	Genl Structures & Improve		2.7304%	0.4096%	3.1400%
390.07	Genl Str & Imp-Lease Bldg-CPR	(7)			
390.07	Genl Str & Imp-Lease Bldg-106		6.0606%	0.0000%	6.0606%
390.08	Genl Str & Imp-Partitions		3.8000%	0.0000%	3.8000%
390.85	GS&I-1800 Leasehold Imp	(5)	6.6666%	0.0000%	6.6666%
391.00	General Office Furn & Eqp		4.7500%	0.0000%	4.7500%
391.04	Computer Hardware		20.0000%	0.0000%	20.0000%
391.05	Genl Off Eq-Comp 3 Yr Life		33.3300%	0.0000%	33.3300%
391.07	Genl Office Equip-Leased		20.0000%	0.0000%	20.0000%
391.09	Genl Off Eq-Part Lease Fac		5.0000%	0.0000%	5.0000%
392.00	General Transportation Eqp		9.0000%	0.0000%	9.0000%
393.00	General Stores Equipment		3.1700%	0.0000%	3.1700%
394.00	General Tools & Shop Equip		3.8000%	0.0000%	3.8000%
395.00	Laboratory Equipment		9.5000%	0.0000%	9.5000%
396.00	General Power Operated Eqp		9.0000%	0.0000%	9.0000%
397.00	General Communication Eqp		6.6700%	0.0000%	6.6700%
398.00	General Miscellaneous Eqp		5.0000%	0.0000%	5.0000%
	Total Common General Plant				
	Total Common Plant				

Notes:

(1) Approved rates are from Docket 06S-234EG, unless specified in the Notes column.
(2) Approved rates are from Docket 02S-315EG
(3) Depreciation rates for Comanche 3, FSV GT 5 and FSV GT 6 were approved in Docket 08S-520E.
(4) Depreciation rates set in Docket 11-947E.
(5) Amortized over the 15 year lease term.
(6) Amortized over the terms of the franchise agreements
(7) Amortized over the lease term.

Public Service Company of Colorado
Docket No. 11AL-947E

Earnings Test Sharing Mechanism
Calculation Methodologies and Adjustments
for 2012 – 2014 Calendar Year Reports

Note: Shading represents new issues/adjustments presented in Docket No. 11AL-947E.

RATE BASE

1. **Rate Base will be calculated using a 13-month average of month-end balances except for Cash Working Capital, the coal, oil and natural gas used for electric generation inventory balances.**

2. **Coal, oil and natural gas used for electric generation inventory will be calculated using the average of the 12 monthly average balances during the calendar year.**

3. **The Accumulated Deferred Income Tax ("ADIT") balances are calculated using the average of the beginning of the year and end of year balances.**

4. **The ADIT reserve is a reduction to rate base, as opposed to a cost-free component in the capital structure. The ADIT balances will be functionalized. Adjustments to ADIT include eliminating amounts that are not included in the cost of service calculation and including adjustments related to plant adjustments.**

5. **The Company will calculate its earnings for purposes of the Earnings Test, using full tax normalization, allowing the Company to provide for deferred taxes on all book/tax timing differences, including any offset to ADIT for net operating losses ("NOL") or NOL carry forward applicable to the Company's electric department for income tax purposes.**

6. **Adjustments to rate base and specific assignment of plant to either CPUC or FERC jurisdictions will be made using the 13-month average of month-end balances.**

7. Construction Work In Progress ("CWIP") will be included in rate base with an Allowance for Funds Used During Construction ("AFUDC") addition to earnings. For construction unrelated to Clean Air Clean Jobs Act ("CACJA"), the AFUDC addition to earnings will be based the FERC AFUDC rate. For construction related to CACJA, the AFUDC addition to earnings shall be equal to the Company's Return on Rate Base ("RORB"). The Company will not annualize the AFUDC addition to earnings.

8. Excess AFUDC associated with the CACJA projects, resulting in the difference between the FERC AFUDC rate and the RORB, is included as an increase to rate base.

9. Pre-Funded AFUDC associated with the Comanche project and the transmission assets recovered through the Transmission Costs Adjustment ("TCA") that is included the plant in-service balances, is included as a reduction to rate base.

10. Eliminate contractor retentions from CWIP.

11. Adjustments to any rate base item for changes after the end of the calendar year being reviewed are not included.

12. Intangible plant in service will be functionalized in order to properly allocate to the retail jurisdiction.

13. Common plant is allocated to the electric, gas, thermal energy and non-regulated departments based on an annual study of all common plant assets and assigning an allocation method for each type of asset. A copy of the common plant study will be included with the earnings test sharing mechanism report when the report is filed with the Commission.

14. The unamortized negative acquisition adjustment resulting from the Colorado Ute transaction is included in rate base and is being amortized over the remaining life of the assets acquired. The amortization will expire April 14, 2013.

15. An adjustment is made to eliminate from plant in service fifty percent of the investment in specific distribution substations serving Holy Cross Rural Electric Association ("HCE").

16. An adjustment is made to eliminate from plant in service the amount of cost associated with the Pawnee turbine blade project that exceeded the Commission-ordered expenditure cap.

17. An adjustment is made to eliminate from plant in service the costs associated with the Ponnequinn wind assets.

    a. The recovery of these assets are through the Renewable Energy Standard Adjustment ("RESA").

18. Capital lease assets are not included in rate base.

19. Recovery of the SmartGridCity™ ("SGC") assets will be determined in Docket No. 11A-1001E. If the Commission approves the Company's request to increase the amount of SGC investment that is included in rate base, such investments will be included in rate base for purposes of the Earnings Test. If the Commission denies the Company's request to increase the amount of SGC investment that is included in rate base, such investment will be excluded from rate base for purposes of the Earnings Test.

20. In the event the Company is required to change its accounting for the acquisition of the Calpine assets, as required by FERC in Docket No. AC11-99-000, and record an acquisition premium, the following FERC Accounts will be included in the Earnings Test calculation: Account 114 – Acquisition Adjustment, Account 115 – Accumulated Amortization of Acquisition Adjustment, and Account 407-Amortization of Acquisition Adjustment.

21. Southeast Water Rights recorded in Plant Held for Future Use ("PHFU") without amortization, and will continue to be included in rate base at a debt-only return.

22. The amounts recorded in PHFU associated with ash disposal site in Bennett, Colorado (known as "Metro Ash Disposal site") will continue to be included in rate base with a full return.

23. Regulatory assets will be included in rate base that are associated with the early plant retirements and cost of removal of Cameo units 1 and 2; Arapahoe units 3 and 4; and Cherokee 1 and 2. The amortization of these regulatory assets will be based on the depreciation rates proposed by the Company in Docket No. 11AL-947E.

24. The unamortized balance of the regulatory assets associated with the Innovative Clean Technology ("ICT") costs (Cameo Solar project and the Solar to Battery project) will not be included in rate base.

25. The unamortized balance of the regulatory asset associated with the vegetation management costs that have been deferred through 2011 associated with the Mountain Pine Beetle trees will not be included in rate base.

26. An adjustment is made to eliminate a portion of the materials and supplies inventory balance allocated to construction-related projects.

27. Cash working capital components consist of fuel costs, purchased power costs, operation and maintenance expenses ("O&M expense"), both directly incurred by the Company and charges from Xcel Energy Services, Inc., paid time off, taxes other than income (payroll taxes, property taxes, sales and use taxes), federal and state income taxes and franchise fees and sales taxes paid. The cash working capital factors used are based on a lead-lag study filed in Docket No. 11AL-947E, adjusting the revenue lag days to account for the billing of late payment changes to non-residential customers. See Exhibit A for the lead-lag factors that will be used for Earnings Test purposes.

28. The prepaid pension asset is recognized in rate base on a pre-tax basis.

29. Deductions from rate base include customer deposits, Qualifying Facilities ("QF") deposits (net of accrued interest), and customer advances for construction.

30. The unamortized balance of the regulatory liability associated with the gain on the sale of the Technical Services Building will not be included in rate base.

31. The unamortized balance of the regulatory liability associated with the gain on the sale of rail cars will not be included in rate base.

32. The retiree medical liability FAS 106 balance, will be included as a credit to rate base.

REVENUES

33. Retail Base Rate Revenue does not include revenues billed through various rider and fuel recovery mechanisms, e.g., ECA, PCCA, DSMCA, ISOC, TCA, and RESA. In addition, revenues billed through the following General Rate Schedule Adjustment ("GRSA") riders will also be excluded from the Earnings Test calculation, e.g., SCG and Earnings Test Sharing. Any costs or incentives associated with these recovery mechanisms are eliminated from the Earnings Test calculation. Unbilled revenues are not included in the Earnings Test calculation.

34. The revenues collected for the low-income program that are included in the Service & Facility monthly charge, will not be included in base rate revenue in the Earnings Test calculation. These revenues are tracked on the balance sheet along with the program expenditures.

35. No adjustments are included to account for customer additions or losses to the calendar year sales or base rate revenues.

36. Electric sales will be normalized for weather. The weather normalization method will be based on the methodology filed in Docket No. 11AL-947E. A description of the weather normalization methodology is provided in Exhibit B.

37. Any GRSA rider revenues associated with the Regulatory Adjustments detailed in the Settlement Agreement in Docket No. 11AL-947E will be included in the Earnings Test calculation.

38. Adjustments will be made to Miscellaneous Revenue to eliminate the rate refunds, Quality of Service Plan bill credits, DSM incentives, Joint Operating Agreement revenue, Wholesale related transmission and ancillary service revenues, unbilled transmission revenues, ISOC, deferred fuel revenues, Hybrid Renewable Energy Credits, and discounts given to certain contract customers under §40-3-104.3(2)(a).

39. The earnings test calculation will include a revenue credit equal to 50% of the oil and gas royalty revenues recorded as non-utility revenue.

40. Residential late payment revenues will be excluded from the cost of service calculation. The Company will continue to donate the residential late payment revenues to Energy Outreach Colorado, and will exclude the donation from the Earnings Test calculation.

EXPENSES

41. Fuel expenses, purchased power energy expenses and purchased wheeling expenses recovered through the fuel and purchased power recovery mechanisms are eliminated from the determination of revenue requirements.

42. The earnings test calculation will eliminate amounts that are booked in calendar years 2012, 2013 or 2014 that are applicable to periods prior to 2012. These adjustments are known as out-of-period accounting entries.

43. The earnings test calculation will eliminate the O&M associated with incremental wholesale sales are eliminated.

44. The earnings test calculation will eliminate the margins associated with the Company's trading activities that are return to customers through the ECA mechanism are eliminated.

45. Eliminate 50% of the expenses associated with the Company's trading activities as set forth in Docket 11A-947E, equal to $1,298,313.

46. Interest on QF deposits is included in Production O&M.

47. The Calpine acquisition costs will be amortized over ten (10) years beginning in December 2010, and will be included in the Earnings Test calculation.

48. The ICT costs associated with the Cameo Solar project and the Solar to Battery project will be amortized over thirty-two months beginning May 1, 2012.

49. The costs associated with the San Luis Valley-Calumet-Comanche transmission project through October 31, 2011 will be amortized over the remaining months of the period covered by the Settlement in Docket No. 11AL-947E (through December 31, 2014) from the date of final Commission decision in Docket No. 11A-869E (2011 Electric Resource Plan), if the Commission finds that the transmission line is no longer needed.

50. Interest on customer deposits is included in Customer Operations expense.

51. Lease expense associated with the Dark Fiber assets is included in the Earnings Test calculation.

52. Demand Side Management ("DSM") costs are included in base rates at the level of $89,263,631 as set in Docket No. 09AL-299E.

53. Advertising expense related to specific energy conservation, safety, and customer programs and services are included in the Earnings Test calculation.

54. Advertising expense related to marketing, promotion, community relations, image and political ads are eliminated.

55. All lobbying expenses and donations are excluded from the Earnings Test calculation.

56. Executive long-term incentive pay, excluding the portion attributable to environmental goals is not included in the Earnings Test calculation.

57. Discretionary pay is not included in the Earnings Test calculation.

58. Employee expenses that do not meet corporate guidelines will not be included in the Earnings Test calculation.

59. Regulatory commission expenses associated with the Commission fees as booked in the calendar year will be included in the Earnings Test calculation without adjustment.

60. Rate case expenses associated with Docket No. 11AL-947E equal to $1,825,784, will be amortized over thirty-two months beginning May 1, 2012.

61. Aviation expenses associated with the corporate aircraft will be excluded from the Earnings Test calculation.

62. Cost allocation between regulated and non-regulated business activities is based on the Cost Allocation Manual and the Fully Distributed Cost Allocation Study filed in Docket No. 11AL-947E. The Company will identify and provide the basis for any changes to cost allocation methodologies with the annual Earnings Test filing.

63. Depreciation expense is based on the depreciation rates provided in Exhibit C.

64. Adjustments to depreciation and amortization expense are made to correspond with adjustments made to plant and accumulated depreciation, or to exclude amounts not included in the Earnings Test calculation.

65. The un-recovered leasehold improvements associated with the Energy Supply Golden facility will be amortized over thirty-two months beginning May 1, 2012.

66. The vegetation management costs related to the Mountain Pine Beetle ("MPB") infestation through December 31, 2011, will be amortized over thirty-two months beginning May 1, 2012. All MPB costs incurred in 2012 will be amortized over twenty-four (24) months beginning January 1, 2013. The MPB on-going O&M expense in 2013 and 2014 are capped at $6 million/year for the Earnings Test calculation.

67. The retail property tax expense will be equal to $76.6 million annually for the Earnings Test calculations for calendar years 2012, 2013 and 2014. Beginning January 1, 2013, the difference between the actual property tax expense from February 1, 2012 through December 31, 2012, and the $76.6 million, prorated for 11 months will be deferred and amortized over three years. Beginning January 1, 2014, the difference between the actual property tax expense in 2013, and the $76.6 million, will be deferred and amortized over three years. These amortizations will be included in the Earnings Test calculation.

68. Adjustments to payroll taxes are made to correspond to labor adjustments made to O&M expense, e.g., trading O&M costs, aviation expenses, executive long-term incentive costs.

69. Current federal and state income taxes are calculated as follows: taxable income is derived by starting with revenue less expenses and then synchronized interest expense is deducted and taxable additions/deductions are added, then stated and federal income taxes are applied.

70. Adjustments to current and deferred income tax expense are made to correspond with adjustments made to plant or to exclude amounts not included in the Earnings Test calculation.

71. Income tax expenses are reduced for the Manufacturing Production Tax deduction.

72. Gain on the disposition of emission credits (SO_2 allowances) due to the Department of Energy auction is included as a credit to the Earnings Test calculation.

73. Gain on the sale of steel railcars, net of actual one-time 2006 costs, are amortized over ten (10) years beginning January 1, 2007.

74. Gain on the sale of the Technical Services Building will be allocated to the Electric Department based on the common plant allocation factor at the time of sale, as established in Docket No. 10AL-963G, and then amortized over thirty-two months beginning May 1, 2012.

CAPITAL STRUCTURE

75. The capital structure ratio will be based on year-end actual balances. Adjustments are made to the capital structure to eliminate the following items: 1) notes payable/receivable with subsidiaries; 2) investment in subsidiaries; 3) subsidiary retained earnings; 4) net non-utility plant; 5) other investments at cost; 6) other funds; and 7) other comprehensive income.

76. Cost of Debt is the actual cost as of the end of the year, and includes bond premiums or discounts, underwriting expenses, other expenses of issue, and amortization of the long-term credit facility.

77. The return on equity for measuring any sharing under the Earnings Test calculation is 10.0%. If the Company earns in excess of a 10.0%, earnings will be shared with customers using the following structure:

>10.0%≤10.20%	60% customers, 40% Public Service
>10.20%≤10.50%	50% customers, 50% Public Service
>10.50% and above	100% customers

JURISDICTIONAL ALLOCATION FACTORS AND DIRECT ASSIGNMENTS

78. The allocation between the retail and wholesale jurisdictions is performed on a line-by-line basis for both rate base and earnings based on either a fundamental allocator or a derived allocator. The fundamental allocators are either demand or energy related. The demand fundamental allocation factors are calculated based on the calendar year 12 Coincident-Peak method.

79. Direct assignment of any costs of service item to either retail or the wholesale jurisdiction is identified, consistent with the Company's 2nd Revised Exhibit No. DAB-3 in Docket No. 11AL-947E.

80. **Rent expense in FERC Account 923 will be analyzed to determine direct assignments to retail or allocated to retail based on labor.**

81. **The earnings test calculations will directly assign EEI dues and EPRI to retail jurisdiction.**

Exhibit A
to Attachment D
to Settlement Agreement

Public Service Company of Colorado
Lead Lag Factors
Docket No. 11AL-947E
12 Months Ended May 31, 2011

Electric Department

Line No.	Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	CWC Factor
	Public Service Company of Colorado				
1	Gas for Generation	39.53	39.88	-0.35	-0.000961
2	Coal Fossil Fuel & Freight	39.53	20.81	18.72	0.051284
3	Fuel Oil	39.53	12.75	26.78	0.073367
4	Purchased Power	39.53	39.14	0.39	0.001068
5					
6	Labor O & M - Regular	39.53	12.16	27.37	0.074984
7	Labor O & M - Incentive	39.53	252.13	-212.60	-0.582468
8	Other O & M	39.53	31.97	7.56	0.02071
9	Xcel Energy Services	39.53	37.88	1.65	0.004518
10	Paid Time Off Expense	39.53	362.41	-322.88	-0.884605
11					
12	Property Taxes	39.53	302.17	-262.64	-0.719564
13	Payroll Related Taxes	39.53	22.00	17.53	0.048025
14	Sales and Use Taxes	39.53	35.04	4.49	0.012299
15					
16	Federal Income Taxes	39.53	37.35	2.18	0.00597
17	Colorado Income Taxes	39.53	37.35	2.18	0.00597
18					
19	Sales Taxes Paid	39.53	35.04	4.49	0.012299
20	Franchise Fees Paid	39.53	45.53	-6.00	-0.016441
21					
22					
23	Xcel Energy Services				
24	Labor	37.88	12.16	25.72	0.070466
25	Other Operations & Management	37.88	31.97	5.91	0.016192

Exhibit B
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Public Service Company of Colorado
Docket No. 11AL-947E

Public Service Company of Colorado weather normalizes sales for the Residential service, Commercial service, Secondary General service, and Primary General service classes.

Degree –day data is used to estimate the amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature. Heating degree days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65 degrees Fahrenheit, and cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above the 65 degrees Fahrenheit. Each degree of temperature above 65 degrees Fahrenheit is counted as one CDD, and each degree of temperature below 65 degrees Fahrenheit is counted as one HDD.

Normal weather conditions are defined as the 30-year average of actual historical weather as measured at the NOAA's Denver International Airport (DIA) weather station. The 30-year average is recalculated each year, rolling in the most recent historical year's data and dropping of the earliest year's data.

The percentage increases (decreases) in normal and actual HDD and CDD are as follows for DIA reported weather:

	2011 vs. Normal	2010 vs. Normal	2011 vs. 2010
HDD	1.0%	-3.9%	5.1%
CDD	29.7%	17.1%	10.8%

Exhibit C
to Attachment D
to Settlement Agreement

Public Service Company of Colorado
Electric and Common Depreciation Rates
DOCKET NO. 11AL-947E

Account Number	Description	Notes	Approved (1) Depr Rate	COR Depr Rate	Tot Depr Rate
	ELECTRIC INTANGIBLE PLANT				
301.00	Organization Costs				
302.00	Franchises & Consents	(6)	0.0000%		0.0000%
303.00	Miscellaneous Plant		0.0000%		0.0000%
303.40	Misc Computer Software 5 Yr		20.0000%		20.0000%
303.40	Misc Computer Software 10 Yr		10.0000%		10.0000%
	Total Electric Intangible Plant				
	STEAM PRODUCTION PLANT				
310.10	Land				
310.20	Land Rights		2.0000%		2.0000%
310.30	Water Rights		2.0000%		2.0000%
	Total Account 310				
311.00	Structures & Improvements				
	Arapahoe Unit 3		2.1006%	0.1744%	2.2750%
	Arapahoe Unit 4		2.4164%	0.2006%	2.6170%
	Arapahoe Common		3.3102%	0.2748%	3.5850%
	Cherokee Unit 2 SC		2.0878%	0.1942%	2.2820%
	Cherokee Unit 3		1.7502%	0.1628%	1.9130%
	Cherokee Unit 4		1.8240%	0.2330%	2.0570%
	Cherokee Common		2.3050%	0.2480%	2.5530%
	Comanche Unit 1		1.6360%	0.1970%	1.8330%
	Comanche Unit 2		1.3710%	0.1650%	1.5360%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.5000%	0.1780%	1.6780%
	Craig Unit 1		1.4600%	0.0880%	1.5480%
	Craig Unit 2		1.4380%	0.0870%	1.5250%
	Craig Common		1.4870%	0.0890%	1.5760%
	Hayden Unit 1		1.6759%	0.1961%	1.8720%
	Hayden Unit 2		1.3310%	0.1950%	1.5260%
	Hayden Common		2.2160%	0.2900%	2.5060%
	Pawnee Unit 1		1.4840%	0.0900%	1.5740%
	Pawnee Common		2.7150%	0.1440%	2.8590%
	Valmont Unit 5		2.3783%	0.1807%	2.5590%
	Valmont Common		2.6617%	0.2023%	2.8640%
	Zuni Unit 2	(2)	0.0000%	0.0000%	0.0000%
	Zuni Common		2.4184%	0.3216%	2.7400%
	Total Account 311				
312.00	Boiler Plant Equipment				
	Arapahoe Unit 3		2.7793%	0.2307%	3.0100%
	Arapahoe Unit 4		3.1440%	0.2610%	3.4050%
	Arapahoe Common		5.2419%	0.4351%	5.6770%
	Cherokee Unit 2 SC		2.7722%	0.2578%	3.0300%
	Cherokee Unit 3		2.4273%	0.2257%	2.6530%
	Cherokee Unit 4		1.6920%	0.2220%	1.9140%
	Cherokee Common		2.7650%	0.2910%	3.0560%
	Comanche Unit 1		1.9460%	0.2270%	2.1730%
	Comanche Unit 2		1.8040%	0.2080%	2.0120%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.6290%	0.1920%	1.8210%
	Craig Unit 1		1.5570%	0.1060%	1.6630%
	Craig Unit 2		1.5470%	0.1060%	1.6530%
	Craig Common		2.2670%	0.1440%	2.4110%
	Hayden Unit 1		2.9517%	0.3453%	3.2970%
	Hayden Unit 2		1.7300%	0.2370%	1.9670%
	Hayden Common		2.5300%	0.3190%	2.8490%
	Pawnee Unit 1		1.6670%	0.1130%	1.7800%
	Pawnee Common		2.8790%	0.1750%	3.0540%
	Valmont Unit 5		2.5920%	0.1970%	2.7890%
	Valmont Common		3.6357%	0.2763%	3.9120%
	Zuni Unit 2		2.3901%	0.3179%	2.7080%
	Zuni Common		3.0229%	0.4021%	3.4250%
	Total Account 312.0				

Exhibit C
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Public Service Company of Colorado
Electric and Common Depreciation Rates
DOCKET NO. 11AL-947E

Account Number	Description	Notes	Approved (1) Depr Rate	COR Depr Rate	Tot Depr Rate
312.10	AQIR Equipment				
	Arapahoe Unit 3		6.6667%	0.0000%	6.6667%
	Cherokee Unit 3		6.6667%	0.0000%	6.6667%
	Cherokee Unit 4		6.6667%	0.0000%	6.6667%
	Cherokee Common		6.6667%	0.0000%	6.6667%
	Valmont Unit 5		6.6667%	0.0000%	6.6667%
	Total Account 312.1				
312.20	Coal Cars		3.1667%	0.0000%	3.1667%
	Total Account 312				
314.00	Turbogenerator Units				
	Arapahoe Unit 3		2.3850%	0.1980%	2.5830%
	Arapahoe Unit 4		2.7368%	0.2272%	2.9640%
	Arapahoe Common		4.0277%	0.3343%	4.3620%
	Cherokee Unit 2 SC		2.1116%	0.1964%	2.3080%
	Cherokee Unit 3		2.1985%	0.2045%	2.4030%
	Cherokee Unit 4		1.7190%	0.2240%	1.9430%
	Cherokee Common		4.6390%	0.4350%	5.0740%
	Comanche Unit 1		1.6980%	0.2040%	1.9020%
	Comanche Unit 2		1.6350%	0.1920%	1.8270%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		2.3140%	0.2520%	2.5660%
	Craig Unit 1		2.6570%	0.1590%	2.8160%
	Craig Unit 2		1.5140%	0.1010%	1.6150%
	Craig Common		1.5560%	0.1030%	1.6590%
	Hayden Unit 1		2.0627%	0.2413%	2.3040%
	Hayden Unit 2		1.4760%	0.2090%	1.6850%
	Hayden Common		2.7010%	0.3350%	3.0360%
	Pawnee Unit 1		1.5970%	0.1060%	1.7030%
	Pawnee Common		2.2750%	0.1420%	2.4170%
	Valmont Unit 5		3.4591%	0.2629%	3.7220%
	Valmont Common		4.1403%	0.3147%	4.4550%
	Zuni Unit 2		14.6920%	1.9540%	16.6460%
	Zuni Common		1.8464%	0.2456%	2.0920%
	Total Account 314				
315.00	Accessory Electric Equipment				
	Arapahoe Unit 3		4.3019%	0.3571%	4.6590%
	Arapahoe Unit 4		2.4811%	0.2059%	2.6870%
	Arapahoe Common		3.0849%	0.2561%	3.3410%
	Cherokee Unit 2 SC		3.0393%	0.2827%	3.3220%
	Cherokee Unit 3		2.2617%	0.2103%	2.4720%
	Cherokee Unit 4		1.5800%	0.2000%	1.7800%
	Cherokee Common		1.9540%	0.2050%	2.1590%
	Comanche Unit 1		1.5310%	0.1760%	1.7070%
	Comanche Unit 2		1.6290%	0.1790%	1.8080%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.6650%	0.1820%	1.8470%
	Craig Unit 1		1.5290%	0.0860%	1.6150%
	Craig Unit 2		1.4990%	0.0850%	1.5840%
	Craig Common		1.5410%	0.0870%	1.6280%
	Hayden Unit 1		1.9391%	0.2269%	2.1660%
	Hayden Unit 2		1.3750%	0.1870%	1.5620%
	Hayden Common		2.4740%	0.2960%	2.7700%
	Pawnee Unit 1		1.5620%	0.0880%	1.6500%
	Pawnee Common		2.1720%	0.1160%	2.2880%
	Valmont Unit 5		2.3950%	0.1820%	2.5770%
	Valmont Common		2.5678%	0.1952%	2.7630%
	Zuni Unit 2		2.6134%	0.3476%	2.9610%
	Zuni Common		2.2586%	0.3004%	2.5590%
	Total Account 315				

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Public Service Company of Colorado
Electric and Common Depreciation Rates
DOCKET NO. 11AL-947E

			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
315.20	Computers & Peripherals (Boiler Controls)				
	Arapahoe Unit 4		6.5088%	0.5402%	7.0490%
	Arapahoe Common		5.1099%	0.4241%	5.5340%
	Cherokee Unit 3		3.8545%	0.3585%	4.2130%
	Cherokee Unit 4		4.3147%	0.4013%	4.7160%
	Cherokee Common		3.1757%	0.2953%	3.4710%
	Comanche Unit 1		3.6712%	0.3488%	4.0200%
	Comanche Common		3.4484%	0.3276%	3.7760%
	Craig Common		2.8817%	0.1383%	3.0200%
	Hayden Unit 1		3.6598%	0.4282%	4.0880%
	Hayden Unit 2		3.4324%	0.4016%	3.8340%
	Pawnee Unit 1		2.9428%	0.1442%	3.0870%
	Pawnee Common		2.6463%	0.1297%	2.7760%
	Valmont Common		3.3690%	0.2560%	3.6250%
	Zuni Common		6.7582%	0.8988%	7.6570%
	Total Account 315 2				
316.00	Misc. Power Plant Equipment				
	Arapahoe Unit 4		4.7775%	0.3965%	5.1740%
	Arapahoe Common		3.7673%	0.3127%	4.0800%
	Cherokee Unit 2 SC		2.6807%	0.2493%	2.9300%
	Cherokee Unit 3		2.3449%	0.2181%	2.5630%
	Cherokee Unit 4		1.4290%	0.1700%	1.5990%
	Cherokee Common		2.1380%	0.2040%	2.3420%
	Comanche Unit 1		1.3680%	0.1450%	1.5130%
	Comanche Unit 2		1.3560%	0.1370%	1.4930%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.6030%	0.1580%	1.7610%
	Craig Unit 1		1.5120%	0.0690%	1.5810%
	Craig Unit 2		1.4780%	0.0690%	1.5470%
	Craig Common		1.6400%	0.0740%	1.7140%
	Hayden Unit 1		1.6902%	0.1978%	1.8880%
	Hayden Unit 2		1.3970%	0.1710%	1.5680%
	Hayden Common		2.3100%	0.2540%	2.5640%
	Pawnee Unit 1		1.5700%	0.0710%	1.6410%
	Pawnee Common		2.3210%	0.0980%	2.4190%
	Valmont Unit 5		2.4879%	0.1891%	2.6770%
	Valmont Common		2.7063%	0.2057%	2.9120%
	Zuni Unit 2	(2)	0.0000%	0.0000%	0.0000%
	Zuni Common		4.9409%	0.6571%	5.5980%
	Total Account 316				
	Total Steam Production				
	HYDRAULIC PRODUCTION PLANT				
330.10	Land				
331.00	Structures & Improvements				
	Ames		1.4679%	0.0191%	1.4870%
	Cabin Creek		0.9324%	0.1296%	1.0620%
	Georgetown		1.6952%	0.0068%	1.7020%
	Salida		1.8055%	0.0325%	1.8380%
	Shoshone		1.6234%	0.0536%	1.6770%
	Tacoma		1.3804%	0.0276%	1.4080%
	Total Account 331				
332.00	Reservoirs, Dams & Waterways				
	Ames		1.5420%	0.0200%	1.5620%
	Cabin Creek		0.9587%	0.1333%	1.0920%
	Georgetown		2.3038%	0.0092%	2.3130%
	Salida		1.5658%	0.0270%	1.5928%
	Shoshone		0.8325%	0.0275%	0.8600%
	Tacoma		1.3500%	0.0270%	1.3770%
	Total Account 332				
333.00	Waterwheels, Turbines & Generators				
	Ames		0.9299%	0.0121%	0.9420%
	Cabin Creek		1.0773%	0.1497%	1.2270%
	Georgetown		1.0269%	0.0041%	1.0310%
	Salida		0.6965%	0.0125%	0.7090%
	Shoshone		1.7212%	0.0568%	1.7780%
	Tacoma		1.8147%	0.0363%	1.8510%
	Total Account 333				

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Public Service Company of Colorado
Electric and Common Depreciation Rates
DOCKET NO. 11AL-947E

			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
334.00	Accessory Electric Equipment				
	Ames		2.4393%	0.0317%	2.4710%
	Cabin Creek		1.2581%	0.1749%	1.4330%
	Georgetown		1.6056%	0.0064%	1.6120%
	Salida		2.0010%	0.0360%	2.0370%
	Shoshone		2.2323%	0.0737%	2.3060%
	Tacoma		1.7667%	0.0353%	1.8020%
	Total Account 334				
334.20	Computers				
	Cabin Creek		1.1563%	0.1607%	1.3170%
	Total Account 334.2				
335.00	Misc. Power Plant Equipment				
	Ames		1.8095%	0.0235%	1.8330%
	Cabin Creek		1.4978%	0.2082%	1.7060%
	Georgetown		2.8665%	0.0115%	2.8780%
	Salida		3.6248%	0.0652%	3.6900%
	Shoshone		2.7396%	0.0904%	2.8300%
	Tacoma		1.8912%	0.0378%	1.9290%
	Total Account 335				
335.20	Recreational Facilities				
	Ames		2.3258%	0.0302%	2.3560%
	Cabin Creek		1.3565%	0.1885%	1.5450%
	Georgetown		2.2570%	0.0090%	2.2660%
	Salida		3.2711%	0.0589%	3.3300%
	Tacoma		1.6294%	0.0326%	1.6620%
	Total Account 335.2				
336.00	Roads, Railroads & Bridges				
	Ames		2.3722%	0.0308%	2.4030%
	Cabin Creek		0.9359%	0.1301%	1.0660%
	Salida		2.6189%	0.0471%	2.6660%
	Shoshone		1.0852%	0.0358%	1.1210%
	Tacoma		1.3029%	0.0261%	1.3290%
	Total Account 336				
	Total Hydraulic Production				
	OTHER PRODUCTION PLANT				
340.10	Land				
340.20	Land Rights		2.0000%	0.0000%	2.0000%
	Total Account 340				
341.00	Structures & Improvements				
	Alamosa		4.4734%	0.1566%	4.6300%
	Fruita CT		0.8302%	0.0548%	0.8850%
	FSV ST 1		1.3811%	0.0539%	1.4350%
	FSV GT 4		2.3994%	0.0936%	2.4930%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		1.6554%	0.0646%	1.7200%
	Ft. Lupton CT		2.4128%	0.1472%	2.5600%
	Valmont CT		0.7780%	0.0420%	0.8200%
	Total Account 341				
342.00	Fuel Holders, Producers & Access.				
	Alamosa		1.0058%	0.0352%	1.0410%
	Fruita CT		0.9756%	0.0644%	1.0400%
	FSV ST 1		2.3879%	0.0931%	2.4810%
	FSV GT 2		2.7469%	0.1071%	2.8540%
	FSV GT 3		2.7825%	0.1085%	2.8910%
	FSV GT 4		2.4321%	0.0949%	2.5270%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		1.6391%	0.0639%	1.7030%
	Ft. Lupton CT		3.6664%	0.2236%	3.8900%
	Valmont CT		1.2837%	0.0693%	1.3530%
	Total Account 342				

Exhibit C
to Attachment D
to Settlement Agreement

Public Service Company of Colorado
Electric and Common Depreciation Rates
DOCKET NO. 11AL-947E

			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
343.00	Prime Movers				
	FSV ST 1		2.1280%	0.0830%	2.2110%
	FSV GT 2		2.2281%	0.0869%	2.3150%
	FSV GT 3	(2)	1.8582%	0.2118%	2.0700%
	FSV Common		2.6266%	0.1024%	2.7290%
	Total Account 343				
344.00	Generators				
	Alamosa		1.5633%	0.0547%	1.6180%
	Blue Spruce	(4)	2.5000%	0.1887%	2.6887%
	Fruita CT		0.9653%	0.0637%	1.0290%
	FSV ST 1		1.3705%	0.0535%	1.4240%
	FSV GT 2		2.3272%	0.0908%	2.4180%
	FSV GT 3		2.6237%	0.1023%	2.7260%
	FSV GT 4		2.5881%	0.1009%	2.6890%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		2.5881%	0.1009%	2.6890%
	Ft. Lupton CT		3.7945%	0.2315%	4.0260%
	Rocky Mountain	(4)	2.5000%	0.3491%	2.8491%
	Wind - Hydrogen	(4)	6.6700%	0.0000%	6.6700%
	Valmont CT		1.8046%	0.0974%	1.9020%
	Total Account 344				
345.00	Accessory Electric Equipment				
	Alamosa		3.6184%	0.1266%	3.7450%
	Fruita CT		3.9428%	0.2602%	4.2030%
	FSV ST 1		1.3831%	0.0539%	1.4370%
	FSV GT 2		1.9838%	0.2262%	2.2100%
	FSV GT 4		2.4456%	0.0954%	2.5410%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		2.5958%	0.1012%	2.6970%
	Ft. Lupton CT		1.2875%	0.0785%	1.3660%
	Valmont CT		4.3197%	0.2333%	4.5530%
	Total Account 345				
345.20	Computers				
	FSV ST 1		1.6487%	0.0643%	1.7130%
	FSV Common		2.1193%	0.0827%	2.2020%
	Total Account 345.2				
346.00	Misc. Power Plant Equipment				
	Alamosa		0.9430%	0.0330%	0.9760%
	Fruita CT		1.0610%	0.0700%	1.1310%
	FSV ST 1		1.4379%	0.0561%	1.4940%
	FSV GT 4		2.4283%	0.0947%	2.5230%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		2.5303%	0.0987%	2.6290%
	Ft. Lupton CT		1.3713%	0.0837%	1.4550%
	Valmont CT		4.5873%	0.2477%	4.8350%
	Total Account 346				
	Total Other Production				
	Total Electric Production				
	TRANSMISSION PLANT				
350.10	Land				
350.20	Land Rights		1.0300%	0.0000%	1.0300%
352.00	Structures & Improvements		1.3091%	0.1309%	1.4400%
352.10	Structures & Improvements-Production		1.3091%	0.1309%	1.4400%
353.00	Station Equipment		1.6481%	0.1319%	1.7800%
353.10	Station Equipment-Production		1.6481%	0.1319%	1.7800%
354.00	Towers & Fixtures		1.1238%	0.0562%	1.1800%
355.00	Poles & Fixtures		1.5619%	0.0781%	1.6400%
356.00	OH Conductors & Devices		1.7048%	0.0852%	1.7900%
357.00	UG Conduit		1.9400%	0.0000%	1.9400%
358.00	UG Conductors & Devices		1.8800%	0.0000%	1.8800%
359.00	Roads & Trails		0.9700%	0.0000%	0.9700%
	Total Transmission				

Exhibit C
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Public Service Company of Colorado
Electric and Common Depreciation Rates
DOCKET NO. 11AL-947E

			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
	DISTRIBUTION PLANT				
360.10	Land				
360.20	Land Rights		1.0900%	0.0000%	1.0900%
361.00	Structures & Improvements		1.7100%	0.0000%	1.7100%
361.10	Structures & Improvements-Production		1.7100%	0.0000%	1.7100%
362.00	Station Equipment		1.7826%	0.2674%	2.0500%
362.10	Station Equipment-Production		1.7826%	0.2674%	2.0500%
364.00	Poles, Towers & Fixtures		2.8077%	0.8423%	3.6500%
365.00	OH Conductors & Devices		2.3643%	0.9457%	3.3100%
366.00	UG Conduit		1.9135%	0.0765%	1.9900%
367.00	UG Conductors & Devices		1.8636%	0.1864%	2.0500%
368.00	Line Transformers		2.2100%	0.0000%	2.2100%
369.00	Services		1.9580%	0.3720%	2.3300%
369.10	Services-Overhead		1.9580%	0.3720%	2.3300%
369.20	Services-Underground		1.9580%	0.3720%	2.3300%
370.00	Meters		3.9700%	0.0000%	3.9700%
370.20	AMR Equipment		8.8100%	0.0000%	8.8100%
371.00	Installation on Customer Premises		0.8333%	0.1667%	1.0000%
373.00	Street Lighting & Signal Systems		2.4583%	0.4917%	2.9500%
	Total Distribution				
	ELECTRIC GENERAL PLANT				
389.00	Land				
390.00	Structures & Improvements		4.8800%	0.0000%	4.8800%
390.10	General Buildings		2.9800%	0.0000%	2.9800%
390.20	Partitions		7.6900%	0.0000%	7.6900%
391.00	Office Furniture & Equipment		4.7500%	0.0000%	4.7500%
391.20	Computer Hardware		20.0000%	0.0000%	20.0000%
392.00	Transportation Equipment		9.0000%	0.0000%	9.0000%
393.00	Stores Equipment		3.1700%	0.0000%	3.1700%
394.00	Tools, Shop & Garage Equipment		3.8000%	0.0000%	3.8000%
395.00	Laboratory Equipment		9.5000%	0.0000%	9.5000%
396.00	Power Operated Equipment		9.0000%	0.0000%	9.0000%
397.00	Communication Equipment		6.6700%	0.0000%	6.6700%
398.00	Miscellaneous Equipment		5.0000%	0.0000%	5.0000%
	Total Electric General				
	Total Electric Plant				
	COMMON INTANGIBLE PLANT				
301.00	Organization Costs				
302.00	Franchises & Consents	(6)			
303.04	Misc Computer Software-5 Year		20.0000%	0.0000%	20.0000%
303.04	Misc Computer Software-10 Year		10.0000%	0.0000%	10.0000%
303.14	CRS Computer Software		10.0000%	0.0000%	10.0000%
	Total Common Intangible				
	COMMON GENERAL PLANT				
389.01	General Land Owned in Fee		0.0000%	0.0000%	0.0000%
390.00	Genl Structures & Improve		2.7304%	0.4096%	3.1400%
390.07	Genl Str & Imp-Lease Bldg-CPR	(7)			
390.07	Genl Str & Imp-Lease Bldg-106		6.0606%	0.0000%	6.0606%
390.08	Genl Str & Imp-Partitions		3.8000%	0.0000%	3.8000%
390.85	GS&I-1800 Leasehold Imp	(5)	6.6666%	0.0000%	6.6666%
391.00	General Office Furn & Eqp		4.7500%	0.0000%	4.7500%
391.04	Computer Hardware		20.0000%	0.0000%	20.0000%
391.05	Genl Off Eq-Comp 3 Yr Life		33.3300%	0.0000%	33.3300%
391.07	Genl Office Equip-Leased		20.0000%	0.0000%	20.0000%
391.09	Genl Off Eq-Part Lease Fac		5.0000%	0.0000%	5.0000%
392.00	General Transportation Eqp		9.0000%	0.0000%	9.0000%
393.00	General Stores Equipment		3.1700%	0.0000%	3.1700%
394.00	General Tools & Shop Equip		3.8000%	0.0000%	3.8000%
395.00	Laboratory Equipment		9.5000%	0.0000%	9.5000%
396.00	General Power Operated Eqp		9.0000%	0.0000%	9.0000%
397.00	General Communication Eqp		6.6700%	0.0000%	6.6700%
398.00	General Miscellaneous Eqp		5.0000%	0.0000%	5.0000%
	Total Common General Plant				
	Total Common Plant				

Notes:
(1) Approved rates are from Docket 06S-234EG, unless specified in the Notes column.
(2) Approved rates are from Docket 02S-315EG
(3) Depreciation rates for Comanche 3, FSV GT 5 and FSV GT 6 were approved in Docket 08S-520E.
(4) Depreciation rates set in Docket 11-947E.
(5) Amortized over the 15 year lease term.
(6) Amortized over the terms of the franchise agreements
(7) Amortized over the lease term.