Portland General Electric Company
Legal Department
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Douglas C. Tingey
Assistant General Counsel

November 6, 2006

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
PO Box 2148
Salem OR 97308-2148

Re: UE 180, UE 181 AND UE 184

Attention Filing Center:

Pursuant to the request of the PUC, enclosed for filing, please find an original and five copies of:

- **PGE's Exhibits 3100-3113. (Please note that page numbers have been added to the top right hand corner).**

This document is being filed by electronic mail with the Filing Center.

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

DOUGLAS C. TINGEY

DCT:jbf
Enclosures

cc: Service List – UE 180, 181 and 184 (w/enclosures)

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the following: **COVER LETTER OF DOUGLAS TINGEY DATED NOVEMBER 6, 2006 AND PGE'S EXHIBITS 3100-3113 (RESUBMITTED WITH PAGE NUMBERS PER THE REQUEST OF THE PUC)** to be served by electronic mail to those parties[1] whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service.

Dated at Portland, Oregon, this 6th day of November 2006.

DOUGLAS C. TINGEY

[1] *Denotes Party received hardcopies
** Denotes Party Received CD version only

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 180/ UE 181/ UE 184

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision (UE 180),	)
	)
In the Matter of	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)
	)
In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision relating to the Port Westward Plant (UE 184).	)

PGE EXHIBITS 3100-3113

November 6, 2006 Revised

14. With respect to the testimony at page 4, line 1 and footnote 6, please confirm that the sample selection of fourteen companies is the same sample selection as used by Mr. Morgan in Docket UE 179, PacifiCorp's Oregon rate proceeding.

a. If so, please explain how Mr. Morgan arrived at a 9.30% recommended ROE for PGE as compared to the 9.50% ROE recommended for PacifiCorp in Docket UE 179.

b. Is the difference due solely to use of later market data (from August 8, 2006) for PGE rather than the June 28 market data used for PacifiCorp? Please explain.

c. If not, please identify the other factors that contribute to the different recommendations, and quantify the impact of each factor.

Staff Response:

Yes. The same sample of companies was used in both Dockets (UE 179 and UE 180.)

a. The results of the analysis were based on the information available when testimony was written in each docket.

b. Yes. The market data, (i.e., expected growth rates, prices and dividends) were updated to reflect the most current information.

c. See b.

41. Referring to Staff/1000 Morgan/26, what are the "requirements of the Modern Portfolio Theory" that should be included in the regression? Please explain.

Staff Response:

Staff's statement reflects its concern that the model proffered by PGE does not properly capture the impact of non-diversifiable risks, which are the only risks that the MPT indicates investors are properly compensated.

September 26, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 19, 2006
Question No. 532

Request:

Referring to UE 180 – UE 181 – UE 184 / PGE /2000, Hager-Valach/9, lines 1-3, please provide a detailed description (including bond ratings and other characteristics) of "the market."

Response:

PGE does not have a detailed listing of PacifiCorp's, Northwest Natural's or some other market proxy's detailed bond ratings and other characteristics. Staff refers frequently to Northwest Natural or PacifiCorp's bonds issued at similar times as a reason for marking down the cost of PGE bonds. We rely on the most recent Moody's or S&P's utility bond ratings. Please refer to PGE Exhibit 2000 Work Papers, page 184.

PGE's view of the market is the broader capital market in which we compete for funding with every other utility in the country as well as other types of businesses seeking capital funding.

September 26, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 19, 2006
Question No. 535

Request:

Referring to UE 180 – UE 181 – UE 184 / PGE /2000, Hager-Valach/9, lines 14-15, please describe in detail how PGE defined "the market."

Response:

PGE did not define "the market" in this instance. For our qualitative analysis, we used Moody's and S&P indices. Additional market information is provided in PGE Exhibit 1105 and pages 88-91 of the work papers for PGE Exhibit 1100 as well as Exhibit 2014. The work papers for PGE Exhibit 2000, pages 175-239 provide updated market information to our original work papers.

October 2, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 25, 2006
Question No. 629

Request:

Regarding UE 180 – UE 181 – UE 184/PGE/2000, Hager-Valach/61, line 22 through Hager-Valach/62 line 2, please provide all evidence PGE relied upon to conclude that time-series statistical testing would be limited to testing whether there is correlation across the months. Were any other time periods considered? Please explain.

Response:

PGE did not say that statistical testing would be limited to testing for monthly correlations, or autocorrelation. Staff's testimony said they were "troubled that PGE did not perform any basic statistical tests" to check for common problems. Autocorrelation is a common problem in time series data; hence our testimony regarding correlation.

The cited testimony stated that it was unlikely that a correlation would exist because the data are not consecutive.

October 2, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated September 25, 2006
Question No. 631

Request:

Regarding UE 180 – UE 181 – UE 184/PGE/2000, Hager-Valach/58, lines 7-8, please list all additional variables PGE considered including in its regression analysis and the reason for each variable's exclusion from the regression analysis.

Response:

PGE did not consider adding additional variables to its Risk Positioning given the theoretical basis for the model, the more than satisfactory explanatory value of the regression, and the potential bias and possible other statistical problems created by adding another variable.

October 18, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated October 6, 2006
Question No. 646

Request:

Referring to Exhibit 2104, please include the credit rating and S&P's business ranking for each water company used by Dr. Zepp.

Response:

Dr. Zepp relied upon data in Staff Exhibit 1003, pages 119-123 for the requested information. Mr. Morgan's data shows PGE is more risky than the water utilities sample based on consideration of business profiles and bond ratings.

November 1, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated October 30, 2006
Question No. 681

Request:

Please provide all workpapers showing PGE's Revenue Requirement request consistent with the Company's position as presented in Sursurrebuttal Testimony filed on October 25, 2006. Please include a breakout of all adjustments to the model consistent with any stipulated issues in the case to date, with a reference for each adjustment and a narrative description of the adjustments.

Response:

Attachment 681-A is a copy of PGE's revenue requirement model for this case, reflecting adjustments for the O&M stipulation, Depreciation stipulation, and additional adjustments consistent with PGE's sursurrebuttal testimony and the update of 2007 net variable power costs (NVPC) and loads as filed on November 2, 2006. The final update of 2007 NVPC will be filed on November 9, 2006. PGE expects to file a supplemental response to this request on November 10, 2006 that reflects this final NVPC update.

Portland General Electric Company
UE-180, UE-181, UE-184 (2007 RVM, General Rate Case, Port Westward)
2007 Revenue Requirement
Dollars in $000s
PER PGE SUR SUR REBUTTAL INCLUDING STIPULATIONS AND THE NOV 2 NVPC UPDATE AND REVENUE UPDATE

BEFORE PORT WESTWARD

	2007 Results B4 Rate Change Per Company Filing	Adjustments to Filed Case	Adjusted 2007 Results	Add'l Rev for ROE	Results at Reasonable Return
	(1)	(2)	(3)	(4)	(5)
1 Sales to Consumers	1,546,707	(90,146)	1,456,561	85,237	1,541,798
2 Sales for Resale	-	-	-		-
3 Other Revenues	17,728	40	17,768		17,768
4 Total Operating Revenues	1,564,435	(90,106)	1,474,329	85,237	1,559,566
5 Net Variable Power Costs	856,968	(67,540)	789,428		789,428
6 Production O&M (excludes Trojan)	71,970	-	71,970		71,970
7 Trojan O&M	218	-	218		218
8 Transmission O&M	10,279	(34)	10,245		10,245
9 Distribution O&M	60,336	(1,623)	58,713		58,713
10 Customer & MBC O&M	60,015	(1,644)	58,371		58,371
11 Uncollectibles Expense	8,198	(478)	7,720	452	8,172
12 A&G, Ins/Bene., & Gen. Plant	109,785	(12,876)	96,909		96,909
13 Total Operating & Maintenance	1,177,769	(84,195)	1,093,575	452	1,094,026
14 Depreciation	154,384	(6,346)	148,038		148,038
15 Amortization	18,848	-	18,848		18,848
16 Property Tax	34,674	-	34,674		34,674
17 Payroll Tax	11,592	-	11,592		11,592
18 Other Taxes	1,231	(2,267)	(1,036)		(1,036)
19 Franchise Fees	36,193	(2,109)	34,084	1,995	36,078
20 Utility Income Tax	30,757	615	31,372	32,515	63,887
21 Total Operating Expenses & Taxes	1,465,448	(94,302)	1,371,146	34,961	1,406,107
22 **Utility Operating Income**	98,986	4,196	103,183	50,276	153,459
					153,459
23 **Average Rate Base**					
24 Avg. Gross Plant	4,316,780	(16,009)	4,300,771		4,300,771
25 Avg. Accum. Deprec. / Amort	(2,463,112)	2,925	(2,460,187)		(2,460,187)
26 Avg. Accum. Def Tax	(205,677)	-	(205,677)		(205,677)
27 Avg. Accum. Def ITC	(5,005)	-	(5,005)		(5,005)
28 **Avg. Net Utility Plant**	1,642,987	(13,084)	1,629,902	-	1,629,902
29 Misc. Deferred Debits	4,689	-	4,689		4,689
30 Operating Materials & Fuel	50,176	-	50,176		50,176
31 Misc. Deferred Credits	(28,082)	-	(28,082)		(28,082)
32 Working Cash	76,203	(4,904)	71,300	1,818	73,118
33 **Average Rate Base**	1,745,972	(17,988)	1,727,985	1,818	1,729,803
34 **Rate of Return**	5.67%		5.97%		8.871%
35 **Implied Return on Equity**	4.86%		5.31%		10.750%

BEFORE PORT WESTWARD

	2007 Results B4 Rate Change Per Company Filing	Adjustments to Filed Case	Adjusted 2007 Results	Add'l Rev for ROE	Results at Reasonable Return
	(1)	(2)	(3)	(4)	(5)
36 Effective Cost of Debt	6.689%		6.730%	6.730%	6.730%
37 Effective Cost of Preferred	8.432%		0.000%	0.000%	0.000%
38 Debt Share of Cap Structure	43.752%		46.730%	46.730%	46.730%
39 Preferred Share of Cap Structure	0.291%		0.000%	0.000%	0.000%
40 Weighted Cost of Debt	2.927%		3.145%	3.145%	3.145%
41 Weighted Cost of Preferred	0.025%		0.000%	0.000%	0.000%
42 Equity Share of Cap Structure	55.957%		53.270%	53.270%	53.270%
43 State Tax Rate	6.617%		6.617%	6.617%	6.617%
44 Federal Tax Rate	35.000%		35.000%	35.000%	35.000%
45 Composite Tax Rate	39.301%		39.301%	39.301%	39.301%
46 Bad Debt Rate	0.530%		0.530%	0.530%	0.530%
47 Franchise Fee Rate	2.340%		2.340%	2.340%	2.340%
48 Working Cash Factor	5.200%		5.200%	5.200%	5.200%
49 Gross-Up Factor	1.6475		1.647	1.647	1.647
50 ROE Target	10.750%		10.750%	10.750%	10.750%
51 Grossed-Up COC	12.8771%		12.579%	12.579%	12.579%
Utility Income Taxes					
52 Book Revenues	1,564,435	(90,106)	1,474,329	85,237	1,559,566
53 Book Expenses	1,434,691	(94,917)	1,339,774	2,446	1,342,220
54 Interest Deduction	51,097	3,247	54,344	57	54,401
55 Production Deduction	4,017	-	4,017		4,017
56 Permanent Ms	(7,623)	-	(7,623)		(7,623)
57 Deferred Ms	(30,787)	-	(30,787)		(30,787)
58 Taxable Income	113,039	1,564	114,603	82,734	197,337
59 State Taxes	7,479	104	7,583	5,474	13,057
60 State Tax Credits	(166)	-	(166)		(166)
61 Net State Taxes	7,313	104	7,417	5,474	12,891
62 Federal Taxable Income	105,726	1,461	107,187	77,259	184,446
63 Federal Taxes	37,004	511	37,515	27,041	64,556
64 ITC Amort	(1,461)	-	(1,461)		(1,461)
65 Deferred Taxes	(12,099)	-	(12,099)	-	(12,099)
66 Total Income Tax Expense	30,757	615	31,372	32,515	63,887
67 Effective Tax Rate	39.11%	39.30%	39.11%	39.30%	39.21%
68 Regulated Net Income	42,808		48,839	50,219	99,058
					99,058

Portland General Electric Company
UE-180, UE-181, UE-184 (2007 RVM, G
2007 Revenue Requirement
Dollars in $000s
PER PGE SUR SUR REBUTTAL INCLUDING STI

PORT WESTWARD IMPACT

	2007 Port Westward Impact per Filing	Results with Port Westward	Adjustments to Port Westward	Adjusted 2007 Results	Add'l Rev for ROE	Results at Reasonable Return
	(6)	(7)	(8)	(9)	(10)	(11)
1 Sales to Consumers		1,541,798	-	1,541,798	39,010	1,580,808
2 Sales for Resale		-	-	-		-
3 Other Revenues		17,768	-	17,768		17,768
4 Total Operating Revenues	-	1,559,566	-	1,559,566	39,010	1,598,576
5 Net Variable Power Costs	(11,746)	777,682	(2,999)	774,683		774,683
6 Production O&M (excludes Trojan)	8,440	80,410	-	80,410		80,410
7 Trojan O&M		218	-	218		218
8 Transmission O&M		10,245	-	10,245		10,245
9 Distribution O&M		58,713	-	58,713		58,713
10 Customer & MBC O&M		58,371	-	58,371		58,371
11 Uncollectibles Expense	-	8,172	-	8,172	207	8,378
12 A&G, Ins/Bene., & Gen. Plant	315	97,224	-	97,224		97,224
13 Total Operating & Maintenance	(2,991)	1,091,035	(2,999)	1,088,036	207	1,088,243
14 Depreciation	10,667	158,705	(1,988)	156,717		156,717
15 Amortization		18,848	-	18,848		18,848
16 Property Tax		34,674	-	34,674		34,674
17 Payroll Tax		11,592	-	11,592		11,592
18 Other Taxes		(1,036)	-	(1,036)		(1,036)
19 Franchise Fees	-	36,078	-	36,078	913	36,991
20 Utility Income Tax	(6,216)	57,670	1,711	59,381	14,881	74,263
21 Total Operating Expenses & Taxes	1,460	1,407,567	(3,276)	1,404,290	16,001	1,420,291
22 **Utility Operating Income**	(1,460)	151,999	3,276	155,275	23,010	178,285
						178,285
23 **Average Rate Base**				-		
24 Avg. Gross Plant	285,205	4,585,976	-	4,585,976		4,585,976
25 Avg. Accum. Deprec. / Amort	(5,333)	(2,465,520)	994	(2,464,526)		(2,464,526)
26 Avg. Accum. Def Tax	(1,758)	(207,435)	-	(207,435)		(207,435)
27 Avg. Accum. Def ITC		(5,005)	-	(5,005)		(5,005)
28 **Avg. Net Utility Plant**	278,114	1,908,016	994	1,909,010	-	1,909,010
29 Misc. Deferred Debits		4,689	-	4,689		4,689
30 Operating Materials & Fuel		50,176	-	50,176		50,176
31 Misc. Deferred Credits		(28,082)	-	(28,082)		(28,082)
32 Working Cash	76	73,193	(170)	73,023	832	73,855
33 **Average Rate Base**	278,190	2,007,992	824	2,008,816	832	2,009,648
34 **Rate of Return**		7.570%		7.73%		8.871%
35 **Implied Return on Equity**		8.306%		8.61%		10.750%

PORT WESTWARD IMPACT

	2007 Port Westward Impact per Filing	Results with Port Westward	Adjustments to Port Westward	Adjusted 2007 Results	Add'l Rev for ROE	Results at Reasonable Return
	(6)	(7)	(8)	(9)	(10)	(11)
36 Effective Cost of Debt	6.730%	6.730%	6.730%	6.730%	6.730%	6.730%
37 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
38 Debt Share of Cap Structure	46.730%	46.730%	46.730%	46.730%	46.730%	46.730%
39 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
40 Weighted Cost of Debt	3.145%	3.145%	3.145%	3.145%	3.145%	3.145%
41 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
42 Equity Share of Cap Structure	53.270%	53.270%	53.270%	53.270%	53.270%	53.270%
43 State Tax Rate	6.617%	6.617%	6.617%	6.617%	6.617%	6.617%
44 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
45 Composite Tax Rate	39.301%	39.301%	39.301%	39.301%	39.301%	39.301%
46 Bad Debt Rate	0.530%	0.530%	0.530%	0.530%	0.530%	0.530%
47 Franchise Fee Rate	2.340%	2.340%	2.340%	2.340%	2.340%	2.340%
48 Working Cash Factor	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%
49 Gross-Up Factor	1.647	1.647	1.647	1.647	1.647	1.647
50 ROE Target	10.750%	10.750%	10.750%	10.750%	10.750%	10.750%
51 Grossed-Up COC	12.579%	12.579%	12.579%	12.579%	12.579%	12.579%
Utility Income Taxes						
52 Book Revenues	-	1,559,566	-	1,559,566	39,010	1,598,576
53 Book Expenses	7,676	1,349,896	(4,987)	1,344,909	1,120	1,346,028
54 Interest Deduction	8,141	62,542	633	63,176	26	63,202
55 Production Deduction		4,017	-	4,017		4,017
56 Permanent Ms		(7,623)	-	(7,623)		(7,623)
57 Deferred Ms	8,947	(21,840)	-	(21,840)		(21,840)
58 Taxable Income	(24,764)	172,573	4,354	176,927	37,865	214,791
59 State Taxes	(1,639)	11,418	288	11,706	2,505	14,212
60 State Tax Credits		(166)	-	(166)		(166)
61 Net State Taxes	(1,639)	11,252	288	11,540	2,505	14,046
62 Federal Taxable Income	(23,126)	161,320	4,066	165,386	35,359	200,746
63 Federal Taxes	(8,094)	56,462	1,423	57,885	12,376	70,261
64 ITC Amort		(1,461)	-	(1,461)		(1,461)
65 Deferred Taxes	3,516	(8,583)	-	(8,583)	-	(8,583)
66 Total Income Tax Expense	(6,216)	57,670	1,711	59,381	14,881	74,263
67 Effective Tax Rate	39.30%	39.20%	39.30%	39.20%	39.30%	39.22%
68 Regulated Net Income	(9,601)	89,457	2,643	92,099	22,984	115,083
						115,083

Portland General Electric Company
UE-180, UE-181, UE-184 (2007 RVM, General Rate Case, Port Westward)
2007 Revenue Requirement (Change from Filed Case)
Dollars in $000s

Before Port Westward:			
Change in Revenue Requirement Filed by PGE:	$	97,917	
Adjustments:			
O&M Stipulation:			
S-1 Taxes Other Than Income		(2,349)	O&M/Rate Base Reductions per Stipulation
S-3 A&G / O&M		(6,789)	O&M/Rate Base Reductions per Stipulation
S-5 Incentives		(4,689)	O&M/Rate Base Reductions per Stipulation
S-6 Wages and Salaries		(3,796)	O&M/Rate Base Reductions per Stipulation
S-8 Other Revenue		(41)	O&M/Rate Base Reductions per Stipulation
S-9 Cap Ex		(908)	O&M/Rate Base Reductions per Stipulation
S-12 Memberships		(85)	O&M/Rate Base Reductions per Stipulation
S-14 Weatherization		(72)	O&M/Rate Base Reductions per Stipulation
S-15 Customer Service		(1,632)	O&M/Rate Base Reductions per Stipulation
Other:			
PGE-1 Beaver 8		(1,386)	Removes Beaver 8 from Filed Case, per PGE Rebuttal Testimony
PGE-2 Other NVPC Adjustments		-	Intentionally left blank.
PGE-3 Interest Ded from Weighted Cost of Debt Change		(2,558)	Additional Tax Deduction per Weighted Cost of Debt Change
PGE-4 Depreciation Stipulation		(5,682)	Reductions to Book Depreciation (excluding PW) for Depreciation Stipulation
PGE-5 Updated Revenue and NVPC		20,137	Updates NVPC to Nov 2 NVPC Update and Revenues before Price Increase for Updated Load Forecast
Impact of Weighted Cost of Equity Change		(9,306)	Reduction in Equity Return per Weighted Cost of Equity Change
Impact of Higher Interest Cost (Tax Deduction is PGE-3)		6,494	Additional Interest Cost per Weighted Cost of Debt Change (Tax effect is PGE-3)
Net Adjustments		(12,662)	
Rounding		(18)	
Change in Revenue Requirement before Port Westward		85,237	
Port Westward:			
Change in Revenue Requirement Filed by PGE:		44,911	
Adjustments:			
PGE-PW-1 Interest Ded from Weighted Cost of Debt Change		(408)	Additional Tax Deduction per Weighted Cost of Debt Change
PGE-PW-2 PW Life Change		(1,931)	Reduction to Book Depreciation for PW Depreciable Life Change
PGE-PW-3 Update NVPC		(3,108)	Updates NVPC to Nov 2 NVPC Update
Impact of Weighted Cost of Equity Change		(1,483)	Reduction in Equity Return per Weighted Cost of Equity Change
Impact of Higher Interest Cost		1,035	Additional Interest Cost per Weighted Cost of Debt Change (Tax effect is PGE-PW-1)
Net Adjustments		(5,895)	
Rounding		(5)	
Change in Revenue Requirement before Port Westward		39,010	

Adjustments to Filed Case
Dollars in $000s

	S-1 Taxes OTI	S-3 A&G/O&M	S-5 Incentives	S-6 W&S	S-8 Other Rev	S-9 Cap Ex	S-12 Memberships	S-14 Weatherization	S-15 Cust Svc	PGE-1 Beaver 8	PGE-2 Other NVPC	PGE-3 Int Ded
1 Sales to Consumers												
2 Sales for Resale											-	
3 Other Revenues					40							
4 Total Operating Revenues	-	-	-	-	40	-	-	-	-	-	-	-
5 Net Variable Power Costs											-	
6 Production O&M (excludes Trojan)												
7 Trojan O&M												
8 Transmission O&M		(34)										
9 Distribution O&M		(1,623)										
10 Customer & MBC O&M								(69)	(1,575)			
11 Uncollectibles Expense	-	-	-	-	-	-	-	-	-	-	-	-
12 A&G, Ins/Bene., & Gen. Plant		(4,894)	(4,366)	(3,534)			(82)					
13 Total Operating & Maintenance	-	(6,551)	(4,366)	(3,534)	-	-	(82)	(69)	(1,575)	-	-	-
14 Depreciation										(497)		
15 Amortization												
16 Property Tax												
17 Payroll Tax												
18 Other Taxes	(2,267)											
19 Franchise Fees	-	-	-	-	-	-	-	-	-	-	-	-
20 Utility Income Tax	892	2,577	1,733	1,403	16	86	32	27	620	278	-	(1,497)
21 Total Operating Expenses & Taxes	(1,375)	(3,974)	(2,633)	(2,131)	16	86	(50)	(42)	(955)	(219)	-	(1,497)
22 **Utility Operating Income**	1,375	3,974	2,633	2,131	24	(86)	50	42	955	219	-	1,497
23 **Average Rate Base**												
24 Avg. Gross Plant			(1,271)	(1,029)		(7,000)				(6,709)		
25 Avg. Accum. Deprec. / Amort												
26 Avg. Accum. Def Tax												
27 Avg. Accum. Def ITC												
28 **Avg. Net Utility Plant**	-	-	(1,271)	(1,029)	-	(7,000)	-	-	-	(6,709)	-	-
29 Misc. Deferred Debits												
30 Operating Materials & Fuel												
31 Misc. Deferred Credits												
32 Working Cash	(72)	(207)	(137)	(111)	1	4	(3)	(2)	(50)	(11)	-	(78)
33 **Average Rate Base**	(72)	(207)	(1,408)	(1,140)	1	(6,996)	(3)	(2)	(50)	(6,720)	-	(78)
34 **Rate of Return**												
35 **Implied Return on Equity**												
36 Effective Cost of Debt	6.730%	6.730%	6.730%	6.730%	6.730%	6.730%	6.730%	6.730%	6.730%	6.730%	6.730%	6.730%
37 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
38 Debt Share of Cap Structure	46.730%	46.730%	46.730%	46.730%	46.730%	46.730%	46.730%	46.730%	46.730%	46.730%	46.730%	46.730%
39 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
40 Weighted Cost of Debt	3.145%	3.145%	3.145%	3.145%	3.145%	3.145%	3.145%	3.145%	3.145%	3.145%	3.145%	3.145%
41 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
42 Equity Share of Cap Structure	53.270%	53.270%	53.270%	53.270%	53.270%	53.270%	53.270%	53.270%	53.270%	53.270%	53.270%	53.270%

Adjustments to Filed Case
Dollars in $000s

	S-1 Taxes OTI	S-3 A&G/O&M	S-5 Incentives	S-6 W&S	S-8 Other Rev	S-9 Cap Ex	S-12 Memberships	S-14 Weatherization	S-15 Cust Svc	PGE-1 Beaver 8	PGE-2 Other NVPC	PGE-3 Int Ded
43 State Tax Rate	6.617%	6.617%	6.617%	6.617%	6.617%	6.617%	6.617%	6.617%	6.617%	6.617%	6.617%	6.617%
44 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
45 Composite Tax Rate	39.301%	39.301%	39.301%	39.301%	39.301%	39.301%	39.301%	39.301%	39.301%	39.301%	39.301%	39.301%
46 Bad Debt Rate	0.530%	0.530%	0.530%	0.530%	0.530%	0.530%	0.530%	0.530%	0.530%	0.530%	0.530%	0.530%
47 Franchise Fee Rate	2.340%	2.340%	2.340%	2.340%	2.340%	2.340%	2.340%	2.340%	2.340%	2.340%	2.340%	2.340%
48 Working Cash Factor	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%
49 Gross-Up Factor	1.647	1.647	1.647	1.647	1.647	1.647	1.647	1.647	1.647	1.647	1.647	1.647
50 ROE Target	10.750%	10.750%	10.750%	10.750%	10.750%	10.750%	10.750%	10.750%	10.750%	10.750%	10.750%	10.750%
51 Grossed-Up COC	12.579%	12.579%	12.579%	12.579%	12.579%	12.579%	12.579%	12.579%	12.579%	12.579%	12.579%	12.579%
Utility Income Taxes												
52 Book Revenues	-	-	-	-	40	-	-	-	-	-	-	-
53 Book Expenses	(2,267)	(6,551)	(4,366)	(3,534)	-	-	(82)	(69)	(1,575)	(497)	-	-
54 Interest Deduction	(2)	(6)	(44)	(36)	0	(220)	(0)	(0)	(2)	(211)	-	3,810
55 Production Deduction												
56 Permanent Ms												
57 Deferred Ms												
58 Taxable Income	2,269	6,557	4,410	3,570	40	220	82	69	1,577	708	-	(3,810)
59 State Taxes	150	434	292	236	3	15	5	5	104	47	-	(252)
60 State Tax Credits												
61 Net State Taxes	150	434	292	236	3	15	5	5	104	47	-	(252)
62 Federal Taxable Income	2,119	6,124	4,118	3,334	37	205	77	64	1,472	661	-	(3,558)
63 Federal Taxes	742	2,143	1,441	1,167	13	72	27	23	515	232	-	(1,245)
64 ITC Amort												
65 Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-
66 Total Income Tax Expense	892	2,577	1,733	1,403	16	86	32	27	620	278	-	(1,497)
67 Effective Tax Rate	39.30%	39.30%	39.30%	39.30%	39.30%	39.30%	39.30%	39.30%	39.30%	39.30%	#DIV/0!	39.30%
68 Revenue Requirement Effect	(2,349)	(6,789)	(4,689)	(3,796)	(41)	(908)	(85)	(72)	(1,632)	(1,386)	-	(2,558)

PGE/3109/8

UE 180
PGE's Response toOPUC Data Request No. 681
Attachment A

Adjustments to Filed Case
Dollars in $000s

	PGE-4 Depr Stipulation	PGE-5 Update NVPC/Rev	Adjustments Before Port Westward	PGE-PW-1 Int Ded	PGE-PW-2 Depr	PGE-PW-3 Update NVPC	Port Westward Adjustments
1 Sales to Consumers		(90,146)	(90,146)				-
2 Sales for Resale			-				-
3 Other Revenues			40				-
4 Total Operating Revenues	-	(90,146)	(90,106)	-	-	-	-
5 Net Variable Power Costs		(67,540)	(67,540)			(2,999)	(2,999)
6 Production O&M (excludes Trojan)			-				-
7 Trojan O&M			-				-
8 Transmission O&M			(34)				-
9 Distribution O&M			(1,623)				-
10 Customer & MBC O&M			(1,644)				-
11 Uncollectibles Expense	-	(478)	(478)	-	-	-	-
12 A&G, Ins/Bene., & Gen. Plant			(12,876)				-
13 Total Operating & Maintenance	-	(68,018)	(84,195)	-	-	(2,999)	(2,999)
14 Depreciation	(5,849)		(6,346)		(1,988)		(1,988)
15 Amortization			-				-
16 Property Tax			-				-
17 Payroll Tax			-				-
18 Other Taxes			(2,267)				-
19 Franchise Fees	-	(2,109)	(2,109)	-	-	-	-
20 Utility Income Tax	2,265	(7,817)	615	(239)	770	1,180	1,711
21 Total Operating Expenses & Taxes	(3,584)	(77,945)	(94,302)	(239)	(1,218)	(1,819)	(3,276)
22 **Utility Operating Income**	3,584	(12,201)	4,196	239	1,218	1,819	3,276
23 **Average Rate Base**							
24 Avg. Gross Plant			(16,009)				-
25 Avg. Accum. Deprec. / Amort	2,925		2,925		994		994
26 Avg. Accum. Def Tax			-				-
27 Avg. Accum. Def ITC			-				-
28 **Avg. Net Utility Plant**	2,925	-	(13,084)	-	994	-	994
29 Misc. Deferred Debits			-				-
30 Operating Materials & Fuel			-				-
31 Misc. Deferred Credits			-				-
32 Working Cash	(186)	(4,053)	(4,904)	(12)	(63)	(95)	(170)
33 **Average Rate Base**	2,738	(4,053)	(17,988)	(12)	931	(95)	824
34 **Rate of Return**							
35 **Implied Return on Equity**							
36 Effective Cost of Debt	6.730%	6.730%	6.730%	6.730%	6.730%	6.730%	6.730%
37 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
38 Debt Share of Cap Structure	46.730%	46.730%	46.730%	46.730%	46.730%	46.730%	46.730%
39 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
40 Weighted Cost of Debt	3.145%	3.145%	3.145%	3.145%	3.145%	3.145%	3.145%
41 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
42 Equity Share of Cap Structure	53.270%	53.270%	53.270%	53.270%	53.270%	53.270%	53.270%

Adjustments to Filed Case
Dollars in $000s

	PGE-4 Depr Stipulation	PGE-5 Update NVPC/Rev	Adjustments Before Port Westward	PGE-PW-1 Int Ded	PGE-PW-2 Depr	PGE-PW-3 Update NVPC	Port Westward Adjustments
43 State Tax Rate	6.617%	6.617%	6.617%	6.617%	6.617%	6.617%	6.617%
44 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
45 Composite Tax Rate	39.301%	39.301%	39.301%	39.301%	39.301%	39.301%	39.301%
46 Bad Debt Rate	0.530%	0.530%	0.530%	0.530%	0.530%	0.530%	0.530%
47 Franchise Fee Rate	2.340%	2.340%	2.340%	2.340%	2.340%	2.340%	2.340%
48 Working Cash Factor	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%	5.200%
49 Gross-Up Factor	1.647	1.647	1.647	1.647	1.647	1.647	1.647
50 ROE Target	10.750%	10.750%	10.750%	10.750%	10.750%	10.750%	10.750%
51 Grossed-Up COC	12.579%	12.579%	12.579%	12.579%	12.579%	12.579%	12.579%
Utility Income Taxes							
52 Book Revenues	-	(90,146)	(90,106)	-	-	-	-
53 Book Expenses	(5,849)	(70,127)	(94,917)	-	(1,988)	(2,999)	(4,987)
54 Interest Deduction	86	(127)	3,247	607	29	(3)	633
55 Production Deduction			-				-
56 Permanent Ms			-				-
57 Deferred Ms			-				-
58 Taxable Income	5,763	(19,891)	1,564	(607)	1,959	3,002	4,354
59 State Taxes	381	(1,316)	104	(40)	130	199	288
60 State Tax Credits			-				-
61 Net State Taxes	381	(1,316)	104	(40)	130	199	288
62 Federal Taxable Income	5,382	(18,575)	1,461	(567)	1,829	2,804	4,066
63 Federal Taxes	1,884	(6,501)	511	(198)	640	981	1,423
64 ITC Amort			-				-
65 Deferred Taxes	-	-	-	-	-	-	-
66 Total Income Tax Expense	2,265	(7,817)	615	(239)	770	1,180	1,711
67 Effective Tax Rate	39.30%	39.30%	39.30%	39.30%	39.30%	39.30%	39.30%
68 Revenue Requirement Effect	(5,682)	20,137	(9,850)	(408)	(1,931)	(3,108)	(5,447)

Portland General Electric Company
UE-180, UE-181, UE-184 (2007 RVM, General Rate Case, Port Westward)
2007 Revenue Requirement

	Updated Cost of Capital				Original Filing			
	Share	Cost	Weighted	Pre-Tax	Share	Cost	Weighted	Pre-Tax
Common Equity	53.270%	10.750%	5.727%	9.434%	55.957%	10.750%	6.015%	9.910%
Preferred Equity	0.000%	0.000%	0.000%	0.000%	0.291%	8.432%	0.025%	0.040%
Long-Term Debt	46.730%	6.730%	3.145%	3.145%	43.752%	6.689%	2.927%	2.927%
Total	100.00%		8.871%	12.579%	100.000%		8.966%	12.877%

Revenue Sensitive Costs:	
Revenues	1.00000
Franchise Fees	0.02340
O&M Uncollectibles	0.00530
State Taxable Income	0.97130
State Tax @ 6.617%	0.06427
Federal Taxable Inc.	0.90703
Federal Tax @ 35%	0.31746
Total Income Taxes	0.38173
Total Rev. Sensitive Costs	0.41043
Utility Operating Income	0.58957
Net To Gross Factor	1.6961

NTG (Income Taxes only)	1.6475	
Revenue Sensitive Cost Factor	1.0295	Bad Debt/Franchise Fees only
Working Cash Factor	0.0026	
Revenue Sensitive Cost Factor	1.0323	Including WC
NTG (Including Working Cash)	1.7005	

Updated Revenue
Dollars in $000s

2007 Revenue at 2006 Prices as Filed	1,546,707	
Updated 2007 Revenue at 2006 Prices	1,456,561	Reflects the impact of the updated Load Forecast, including the September DA Window
Adjustment	(90,146)	

Updated NVPC
Dollars in $000s

Before Port Westward:

Monet Case - As Filed	856,968	
Monet Case - Nov 2 Update	789,428	GRC Case, No PW
Adjustment	(67,540)	

Port Westward Effect:

Monet Case - Nov 2 Update	789,428	GRC Case, No PW
Monet Case - Nov 2 Update	777,333	GRC Case, PW on March 1, 2007
Change in NVPC for PW	(12,095)	10-Month Effect
Annualization Factor	1.22	
Annualized Change in NVPC	(14,745)	Annual Effect
Annualized Change in NVPC	(11,746)	As Filed
Adjustment	(2,999)	
NVPC w PW	774,683	

Depreciation Stipulation Adjustment (for Non-PW Assets)
in Dollars

	Stipulation Adjustment 2007 Depreciation Expense
GENERATION	(220,079)
DISTRIBUTION	(5,376,748)
TRANSMISSION	(252,373)
OTHER BREAKOUT:	
BILLING	19
METERING	9
OTHER CONSUMER	23
RETAIL SERVICES	1
	(5,849,147)

Beaver 8 Adjustment
Remove Beaver 8 (Reg Asset Portion) from 2007 Test Year

6,957,301	Reg Asset Estimated Balance at 12/31/06 (See Integrated Model - Reg Asset tab)
14	Book Depreciation life for Beaver (Through 2020)
496,950	Book Depreciation Expense included in 2007 Test Year
6,708,826	Estimated Rate Base Balance in 2007 Test Year (Avg 2007 balance)

2007 Loads
For PW Annualization Calculation

Load Category	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
System	1,865,622	1,620,606	1,677,434	1,529,456	1,535,221	1,499,199	1,619,257	1,633,687	1,503,040	1,580,601	1,682,707	1,868,922	19,615,753
COS	1,750,515	1,514,604	1,556,969	1,408,180	1,407,773	1,370,829	1,490,563	1,509,641	1,381,815	1,459,946	1,568,148	1,747,260	18,166,243
System Percent	9.51%	8.26%	8.55%	7.80%	7.83%	7.64%	8.25%	8.33%	7.66%	8.06%	8.58%	9.53%	100.00%
COS Percent	9.64%	8.34%	8.57%	7.75%	7.75%	7.55%	8.21%	8.31%	7.61%	8.04%	8.63%	9.62%	100.00%
	82.03%												
	1.2191												

PORTLAND GENERAL ELECTRIC
Changes in Revenues Resulting from Price Changes before Port Westward ($000)

Category	2006 Current	Proposed	Change
Table 1 COS	$1,464,351	$1,551,060	$86,709
DA/76R	($10,480)	($12,140)	($1,660)
Cycle Totals	$1,453,872	$1,538,921	$85,049
COS Calendar Adjustment	1.0009		
Non-COS Calendar Adjustment	1.0016		
Calendar Basis Retail Revenues	$1,455,105	$1,540,225	$85,120
Add OATT Revenues	$1,456,561	$1,541,681	$85,120
OATT Revenues (priced at proposed retail)	$1,456	$1,456	

Reconciliation of Revenues and Revenue Requirement

Revenue Requirement	$1,541,801
Calendar Revenues	$1,540,225
OATT Revenues	$1,456
	$1,541,681
Base Rate Delta	($120)
Base Rate Employee Discount Delta	$75
Total Delta	($45)

October 31, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Pricing & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 18.205
Dated October 26, 2006
Question No. 205

Request:

Page 6, lines 7-9. Is PGE suggesting in this passage that it did not use the extrinsic value analysis to decide to enter into and justify the Super Peak contract? Can PGE demonstrate that it would have been prudent to enter into the Super Peak contract even without consideration of extrinsic value? Please provide all documents and analyses that refer or relate to this request.

Response:

PGE objects to this request because it is overly broad, unduly burdensome, and requires speculation. Without waiving its objection, PGE responds as follows:

PGE provided an extensive discussion of how we decided to enter into the Super Peak contract to meet part of the capacity contract needs acknowledged in Commission Order No. 04-375 on pages 35-37 of PGE Exhibit 1900. We used extrinsic value analysis as one element in our scoring process, which ranked the capacity bids we received in response to the 2003 Request for Proposals.

The question, "[can] PGE demonstrate that it would have been prudent to enter into the Super Peak contract even without consideration of extrinsic value?" requires speculation about how PGE would have evaluated RFP capacity bids without the extrinsic value analysis, but the analysis discussed in PGE Exhibit 1900 suggests "yes".

PGE's discussion on pages 35-37 of PGE Exhibit 1900 cites PGE's responses to ICNU Data Request Nos. 125-6 and 158-61.

October 31, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 18.210
Dated October 26, 2006
Question No. 210

Request:

Table 1, Page 10. Does PGE agree that the Monet dispatch benefit values shown are not computed on the basis of extrinsic value, but rather reflect the intrinsic value of the resources shown?

Response:

No. The figures shown for "Value of Coyote, Beaver, and PW Under ICNU Methodology" include both intrinsic and extrinsic value. The extrinsic values are calculated using the corrected ICNU methodology. ICNU's extrinsic value methodology is based on changes that might happen to the monthly on- and off-peak spark spreads that can be calculated from the MONET input data.

PGE has not defined extrinsic value. ICNU's methodology implies that intrinsic value is based on the monthly on- and off-peak monthly spark spreads implied by the MONET input data, and extrinsic value is based on possible changes in those spark spreads, the possible changes being based on historical data. According to this implication of ICNU's methodology, the figures shown for "Value of Coyote, Beaver, and PW in March MONET Run" include both intrinsic and extrinsic value, as the hourly spark spreads are based on both the monthly on- and off-peak spark spreads and hourly shaping of these spark spreads based on historical data.

October 31, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Randy Dahlgren
Director, Regulatory Pricing & Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 18.213
Dated October 26, 2006
Question No. 213

Request:

Page 10, line 15. Define "cherry picking." Would this be the same thing as requesting PCAM mechanisms when power costs are uncertain and increasing, but retuning to fixed rates when power costs are stable and declining?

Response:

PGE objects to this request on the basis that it is vague and ambiguous. It is unclear if the scenario described ("requesting PCAM mechanisms when power costs are uncertain and increasing, but retuning [sic] to fixed rates when power costs are stable and declining?") is meant to be a purely hypothetical scenario or if ICNU believes it refers to some actual historical facts. Without waiving objection, PGE responds as follows:

If ICNU is referring to the PCAM mechanism PGE had from 1979 through 1987, that PCAM mechanism was terminated by the Commission based on a recommendation from the OPUC Staff. PGE supported the continuation of the PCAM. If ICNU is referring to the PCAM mechanisms of 2001 and 2002, these were ended by the terms of a stipulation.

A tariff PCAM mechanism, such as the one proposed by PGE in this rate case, cannot end without Commission approval: either with an explicit sunset date (such as the UE 115 PCAM), or by Commission Order (such as the UE 47/ 48 decision that terminated the 1979-1987 PCAM). PGE assumes that, if the Commission terminated a PCAM on either of these bases, it had a good reason for doing so. PGE believes that a well-designed PCAM mechanism will lower cost of service risk for both customers and PGE. We disagree that the operation of PGE's proposed

Annual Variance Tariff (which has no explicit sunset date and thus must be terminated by Commission Order) in this case amounts to "cherry picking" since neither we, nor any of the other parties to this rate case, know what future power costs variances will be over the (unknown) operating period of the PCAM tariff.

In the context of the discussion on page 10 of PGE Exhibit 2600, "cherry picking" means "picking" or selecting to look only at possible decreases to the MONET power cost forecast, but ignoring possible increases to the forecast. This "picking" to propose decreases and "not picking" or ignoring possible increases worsens the problem that MONET likely underestimates power costs on an expected basis. PGE discussed this issue further on pages 4-5 of PGE Exhibit 2600.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

RE: THE INVESTIGATION AND SUSPENSION)
OF TARIFF SHEETS FILED BY PUBLIC SERVICE)
COMPANY OF COLORADO ADVICE LETTER NO.) DOCKET NO. 06S – 234 EG
1454 – ELECTRIC, ADVICE LETTER NO. 671 – GAS)

SETTLEMENT AGREEMENT

October 20, 2006

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

RE: THE INVESTIGATION AND SUSPENSION)
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SETTLEMENT AGREEMENT

Public Service Company of Colorado, the Staff of the Colorado Public Utilities Commission ("Staff"), the Colorado Office of Consumer Counsel ("OCC"), Colorado Energy Consumers, The Kroger Co., Climax Molybdenum Company, the Commercial Group, and Adams County (collectively, the "Settling Parties") hereby enter into this Settlement Agreement.

INTRODUCTION

On April 14, 2006, Public Service Company of Colorado ("Public Service" or the "Company") filed Advice Letter No. 1454 – Electric and Advice Letter No. 671 – Gas with the Colorado Public Utilities Commission ("Commission" or "CPUC"), tendering revised tariff sheets in which the Company proposed comprehensive rate and tariff changes. The Company also filed Direct Testimony and Exhibits in support of the proposed rate and tariff changes.

The Company requested the following base rate revenue and estimated adjustment clause revenue as summarized in the Direct Testimony of Fredric C. Stoffel:

Base Rate Revenue	$1,021,321,846	44.8%
PCCA Revenue	$ 336,297,476	14.8%
ECA Revenue	$ 851,707,000	37.4%
Other clauses	$ 68,814,056	3.0%
TOTAL	$2,278,140,378	100%

On August 11, 2006, the Company filed Supplemental Direct Testimony and Revised Exhibits. This filing increased the Company's requested increase in electric base rate revenue by $774,172. On August 18, 2006, various parties filed Answer Testimony and Exhibits objecting to aspects of the Company's requested rate changes, overall revenue requirement, Return on Equity, cost adjustment mechanisms and tariffs. Staff and the OCC each summarized their Answer Testimony using exhibits comparing the Company's proposed revenue requirement to the changes proposed by their respective organizations.

Staff's proposed revenue requirement was summarized by Dr. Shiao in his Corrected Exhibit LYS-4:

Public Service Company of Colorado **Calculation of Deficiency/Excess** **Docket No. 06S-234EG**
Electric Department **Corrected Exhibit LYS-4**
Test Year 2005 **Page 1 of 1**

	Description	PSCo Original Proposed	Staff Proposed	Difference
	Revenue Deficiency/Excess			
1	**Net CPUC Jurisdictional Rate Base**	3,376,712,664	3,241,377,676	(135,334,988)
2				
3	**Allowed Return on Rate Base**	9.15%	8.25%	-0.90%
4				
5	**Required Earnings**	308,969,209	267,413,658	(41,555,551)
6				
7	**Net CPUC Jurisdictional Operating Earnings**	199,374,216	216,348,146	16,973,930
8				
9	**Deficiency / (Excess)**	109,594,993	51,065,512	(58,529,480)
10				
11	**Gross-up**	1.62700225	1.62595431	(0.00104794)
12				
13	**Revenue Increase / (Decrease)**	178,311,300	83,030,190	(95,281,110)
14				
	Rider Calculation			
15	**Retail Rate Revenue**	843,010,546	846,880,268	3,869,722
16				
17	**Less: Street Light Maintenance Revenue**	2,251,108	2,251,108	
18				
19	**Rider Applicable Revenue**	840,759,438	844,629,160	3,869,722
20				
21	**Rider**	21.208%	9.830%	-11.378%

Note: Row 5 = Row 1 x Row 3
Row 7 from DAB-1 Schedule 1 & Staff's Exhibit LYS-2, Expenses
Row 9 = Row 5 - Row 7
Row 13 = Row 9 x Row 11
Row 15 from DAB-1 Schedule 4 & Staff's Exhibit LYS-2, Revenues
Row 21 = Row 13/ Row 19
Staff proposed GRSA Rider includes PSCo's corrections presented in its Supplemental Direct Testimony

The OCC summarized its recommended adjustments to the Company's proposed revenue requirements in Dr. Schechter's Revised Exhibit PBS-1:

PUBLIC SERVICE COMPANY OF COLORADO

Colorado Jurisdiction - Electric Department
Reconciliation of OCC Issues
Test Year Ended December 31, 2005
$(000)

	(A)	(B)
1.	PSCo revenue deficiency as filed	$178,311
	OCC adjustments:	
2.	Modify FERC production allocation factor	(662)
3.	Reduce ROE from 11.0% to 8.5%	(82,178)
4.	Revised revenue conversion factor	2
5.	Remove 2006 AFUDC on Comanche 3	(1,603)
6.	Remove 2006 Non-Comanche CWIP	(2,525)
7.	Correct M&S capitalized amount	(64)
8.	Cash working capital	(566)
9.	Reverse weather normalization adjustment	(3,876)
10.	Include RTD revenue	(1,412)
11.	Include oil & gas royalties	(2,026)
12.	Adjust rail car lease	(207)
13.	Adjust DSM employees	(216)
14.	Correct postage expense adjustment	(3)
15.	Remove targeted incentive compensation	(8,197)
16.	Reverse pensions & benefits adjustment	0
17.	Adjust depreciation expenses	(40,473)
18.	Revised AQIR revenue requirement	1,775
19.	Corrected Pawnee 2 and Metro Ash amortization	(1,038)
20.	Out of period adjustments	(33)
21.	Rendering service charges	150
22.	Subtotal OCC adjustments	($143,152)
23.	OCC calculated revenue deficiency	$35,159

In its Rebuttal Case filed on September 29, 2006, the Company updated its capital structure and projections of Comanche 3 CWIP, consistent with the terms of the Comprehensive Settlement Agreement dated December 3, 2004 in Dockets No. 04A-214E, 04A-215E, and 04A-216E, approved by Commission Decision No. C05-0049 (January 21, 2005) (the "2003 LCP Settlement"). The Company made other changes to reflect corrections or concessions to proposals advocated by the Parties. A summary of the changes to the Company's base rate revenue requirement as submitted in its Rebuttal Case is shown below:

Company's Filed Case	
1. Revenue Increase	$178,311,300
Supplemental Direct Corrections -	
2. Labor Capitalization for M&S	($78,726)
3. Lead-Lag Factors	$113,462
4. AQIR Revenue Credit	$1,799,200
5. Amortization of Pawnee 2 & Metro Ash	($1,064,163)
6. Tax Gross-Up Factor	$4,399
Rebuttal Testimony -	
7. Charges for Rendering Service	$149,608
8. Railcar Lease	($207,603)
9. Postage	($2,687)
10. Out-of-Period	($25,071)
11. P&B- new Watson & Wyatt estimate	($2,425,345)
12. Capital Structure - 60% vs. 59.93%	$205,224
13. Comanche 3 Update	($1,106,800)
14. Gain on Sale - Depreciation Reserve	($19,918)
15. Incremental DSM	($213,956)
16. Windsource - moved to ECA	($3,699,158)
17. Sub total	($7,345,706)
18. Final Revenue Increase	$171,739,766

In addition, as part of its proposal for treatment of the Windsource program, the Company proposed recovering the Wind Benefit through the ECA instead of through base rates. The Wind Benefit for 2007 was projected to be $4,618,374.

Subsequent to the filing of its Rebuttal Testimony, the Company invited all parties to this docket to participate in settlement discussions. Not all parties chose to participate in discussions. Settlement has been successfully reached among the signatories to this Settlement Agreement on all contested issues in this case. Other parties may elect to support, oppose or remain silent on this Settlement Agreement.

The Settling Parties have reached agreement as to a just and reasonable increase in the Company's base rate revenue. However, the Settling Parties do not necessarily agree among themselves as to the resolution of the rate case principles that make up the agreed-upon increase. Rather than continue to engage in litigation over rate case principles, the Settling Parties agree that this case should be resolved by agreement of a specific base rate revenue increase with a specific General Rate Schedule Adjustment ("GRSA"), without reaching agreement as to all the specific line items in the cost of service model that make up the settled increase. Because the settled base rate revenue increase is less than the level proposed by the Company and greater than the level proposed by other parties, a substantial record of evidence exists to support the settled number.

Because agreement has not been reached on all the rate case principles reflected in the competing cost of service models, the Settling Parties intend to minimize the number of new rate case principles that are reflected in the proposed settled base rate revenue increase. Other than the principles discussed in this

Settlement Agreement, the Settling Parties are not agreeing to the acceptance or rejection of any position raised by any party in filed testimony. However, due to the Company's accounting and reporting obligations, certain rate case principles will be specified in this Settlement Agreement. In addition, solely for accounting and reporting purposes, the Settling Parties agree that the rate case principles in effect prior to the filing of this Settlement Agreement shall continue to apply, except as modified by this Settlement Agreement.

The Settling Parties have also reached agreement on the base rates from which purchased capacity costs have been removed, the form of the Electric Commodity Adjustment ("ECA"), the form of the Purchased Capacity Cost Adjustment ("PCCA"), and the form of the Wind Energy Service Adjustment ("WESA") that should go into effect on January 1, 2007. The Settling Parties also agree to new tariffs for non-gratuitous charges and residential late payment fees. All Settling Parties specifically reserve the right to seek changes to any rate case principles in any subsequent regulatory proceeding dealing with Public Service's rates.

PUBLIC INTEREST

The Parties to this Settlement Agreement state that reaching agreement as set forth herein by means of a negotiated settlement rather than through a formal adversarial process is in the public interest, consistent with Commission Rule 1408 encouraging settlements and, therefore, the compromises and settlements reflected in this Settlement Agreement are in the public interest. The Parties further state that approval and implementation of the compromises and settlements reflected in this Settlement Agreement constitute a just and reasonable resolution of this proceeding.

SETTLEMENT

1. Base Rate Revenue Increase

The Settling Parties agree that Public Service should be authorized to put into effect, beginning January 1, 2007, a General Rate Schedule Adjustment of 12.70%. The GRSA shall apply to all base rate elements on retail customer bills. Because the Settling Parties agree to the continuation of the PCCA, discussed later, the base rates will not include any purchased capacity expense. A 12.70% GRSA represents a $107 million increase over test year base rate revenues. Attachment A sets forth the average bill impacts by service class from this proposed GRSA and the estimated effect of the rate adjustments discussed in this Settlement Agreement.

Attachment B sets forth the proposed electric tariffs. Attachment C sets forth the proposed gas tariffs. Certain tariff sheets contain numbers that are illustrative only and are marked "Illustrative." Where the tariff sheet is marked Illustrative, the Settling Parties have agreed to the form of tariff and to the method for determining rates. The Settling Parties have agreed that the Company shall file the rates under these tariffs using updated projected 2007 costs on or before December 1, 2006. .

2. New Rate Case Principles Incorporated into the Base Rate Revenue Increase

The following new rate case principles are incorporated into the compromise and settlement on the $107 million base rate revenue increase.

A. Authorized Return on Equity

The authorized Return on Equity shall be 10.5%.

B. Capital Structure and Return on Rate Base

Pursuant to the 2003 LCP Settlement, the approved capital structure for the Company shall be 60% equity and 40% debt. The test year cost of debt is 6.38%. The resulting return on rate base is 8.85%, calculated as follows:

	Ratio	Cost	Weighted Cost
Long Term Debt	40.00%	6.38%	2.55%
Common Equity	60.00%	10.50%	6.30%
Total	100.00%		8.85%

C. Depreciation Rates

The Company shall use the depreciation rates and remaining lives set forth by Mr. Camp in his Answer Testimony at page 12, line 9, through page 21, line 12, and in his Exhibit No. ELC-9, and by Ms. Perkett in her Exhibit No. LHP-1, Schedule 1 Hydraulic Production Plant and General Plant. These exhibits are attached as Attachment D. The Company shall include a footnote in its annual FERC Form 1 filing disclosing the non-legal asset retirement obligation portion of accumulated depreciation.

D. AFUDC on Transmission Investment (other than transmission needed for Comanche 3)

Transmission investment that is not related to Comanche 3 (and is not considered "Comanche CWIP" under the 2003 LCP Settlement) shall be included in Construction Work in Progress with an AFUDC offset.

E. Retail / Wholesale Jurisdictional Allocation of Capacity Costs

Retail/wholesale jurisdictional allocation for capacity costs (generation and transmission) will be determined using the 12 Coincident Peak (12 CP) method, except that the capacity sold under wholesale contracts that are for specific amounts of capacity (as opposed to wholesale contracts for full or partial requirements contracts) shall be directly assigned to the wholesale jurisdiction.[1] In addition, the wholesale load associated with the Cheyenne Light, Fuel & Power all-requirements contract shall be included in developing the production demand jurisdictional allocator.[2]

F. Comanche CWIP

In accord with the 2003 LCP Settlement, 2006 year-end Comanche Construction Work in Progress for generation and transmission shall be included in rate base without an AFUDC offset. AFUDC shall accrue on Comanche Construction Work in Progress for generation and transmission for all construction expenditures made through December 31, 2006, but will no longer accrue on these expenditures once rates take effect on January 1, 2007. In addition, for Comanche construction expenditures for generation and transmission made on or after January 1, 2007, AFUDC shall accrue until such time as these expenditures are included in effective rates without an AFUDC offset.

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[1] The wholesale contracts in the test year that are for specific amounts of capacity are contracts between Public Service and the Arkansas River Power Authority, the Municipal Energy Agency of Nebraska, and Aquila, Inc., respectively.

[2] Due to the adoption of the production demand allocator, there will be no PCCA revenue credit.

G. Amortization of Certain Expenses

Pawnee 2, Metro Ash, and actual rate case expenses incurred through December 31, 2006 shall be amortized over two years. The gain on the sale of rail cars shall be netted with the actual one-time 2006 costs and shall be amortized over ten years. The actual one-time 2006 costs shall include actual additional lease expense incurred in 2006, actual delivery charges for leased railcars in 2006, and actual incremental coal handling O&M at Cherokee and Pawnee incurred in 2006. These amortizations will be recorded on the Company's books beginning January 1, 2007.

3. Purchased Capacity Cost Adjustment

The Purchased Capacity Cost Adjustment shall continue but shall be revised beginning January 1, 2007 to recover all prudently-incurred costs paid by the Company under all power purchase agreements ("PPAs") that are not recovered through the Electric Commodity Adjustment. The ECA recovers fuel, purchased energy, and purchased wheeling expenses. The remaining costs paid under power purchase agreements are generally capacity-related costs, i.e., costs that do not vary with output from the generator. The PCCA will be designed as described by Company witness Mr. Darnell in his direct testimony at page 6, line 14, through page 8, line 13. The proposed form of PCCA tariff is included in Attachment B. The Company will project each November 1 the PCCA costs for the upcoming year, and such costs will be subject to true-up through a deferred account to compare actual PCCA costs with PCCA revenues. Interest shall not accrue on the PCCA deferred balance. The deferred balance as of September 30 of each year will factor into the calculation of the subsequent year's rate. The PCCA shall be temporary and shall expire at the earlier of rates taking effect after Comanche 3 goes into service or December 31, 2010.

Public Service shall file by April 1 of each year for an annual review of the costs recovered through the PCCA during the just completed calendar year. Public Service's reporting requirements shall be limited to the actual PCCA costs incurred by month and by PPA, the PCCA revenues received by month from the prior calendar year, calculation of the PCCA deferred balance, identification of New PPAs, and the status of regulatory approvals, if any, of each PPA. "New PPAs" shall encompass all PPAs, and all contractual amendments or modifications to PPAs, where the new, amended or modified contract has not been included in any Commission-approved rate or has not been otherwise approved by the Commission. New PPAs may be reviewed for prudence of contract execution and contract terms in the first annual review in which the New PPA costs appear. The prudence of contract administration giving rise to the costs under review in any annual review proceeding may also be raised in that annual review proceeding.

4. Electric Commodity Adjustment

Beginning January 1, 2007, the Electric Commodity Adjustment shall recover all prudently-incurred fuel, purchased energy and purchased wheeling expenses pursuant to the ECA tariff included in Attachment B. The ECA shall be forward-looking (subject to true-up through the use of a deferred account) and shall be filed every November 1 for the upcoming year. The annual filing shall project the ECA for the upcoming year and for the first calendar quarter. The ECA shall be updated quarterly, using the projected fuel, purchased energy and purchased wheeling expenses for the upcoming calendar quarter. The ECA shall continue to be differentiated by service delivery voltage, but the class allocations proposed by Public Service shall not be used.

There shall be no mandatory time-of-use ECA rate, but the Company shall offer an optional time-of-use ECA rate for all transmission and primary customers and for secondary customers with demands greater than 300 kw. The time-of-use rate design shall use the methodology shown on Attachment E. This time-of-use rate design is based on the ratio of the projected average marginal costs for the on-peak and off-peak periods, updated annually in the Company's November ECA filing. Public Service shall provide an assessment of the optional time-of-use program to the Settling Parties on or before July 1, 2008.

Interest shall accrue monthly on the average calendar month deferred balance (whether the balance is positive or negative). The monthly interest rate shall be the average of the rate for Dealer Commercial Paper (90 day rate) as published daily in the Wall Street Journal under Money Rates.

In addition to the recovery of prudently incurred fuel, purchased energy and purchased wheeling expenses, the Company shall have the opportunity to earn two incentive payments each year in its utility operations. These annual incentive payments shall be calculated at calendar year end and shall be paid on April 1 of the subsequent year by adjustments to the ECA deferred balance as set forth in the ECA tariff. The total incentive payment to the Company in any calendar year shall not exceed $11.25 million.

The first incentive shall be the Base Load Energy Benefit or "BLEB" to encourage efficient operation of base load coal plants. Under the BLEB, if the Company succeeds in obtaining coal production greater than a benchmark target, then the savings from the coal production over the benchmark will be shared 80% to customers and 20% to the Company. The BLEB formula shall be as set forth in the ECA tariff. The BLEB formula is the Company's proposal in this Docket with the following changes:

- The benchmark shall be the greater of the average annual coal production from Company-owned coal-fired power plants for the most recent three calendar years, or 18,300 GWH. The BLEB benchmark will be reset when the Company brings on line a new coal plant, including an Integrated Gasification Combined Cycle plant.
- The calculated heat rate in the BLEB formula shall be the actual heat rate from the prior calendar year of all natural gas-fired generation, either owned by the Company or under long-term PPAs.

The second incentive shall be the Energy Purchase Benefit or "EPB" to encourage cost reductions through purchases of economical short-term energy. The EPB shall be as proposed by Mr. Imbler in his direct testimony on page 16, lines 4 through 22 and his Exhibit TAI-6, with $6.7 million in energy purchase savings before an incentive is earned, except that the sharing shall be 80% to customers and 20% to the Company.

The Company shall continue to file by August 1 of each calendar year for an annual review of the ECA costs. Public Service's reporting requirements shall be limited to the actual fuel, purchased energy and the purchased wheeling expenses incurred by month; ECA revenues received by month; calculation of the ECA incentives; the trading margins from the prior year; and any other information previously required by Commission order.

5. Short Term Energy Trading

Short term energy trading shall continue under all the terms and conditions set forth in the Settlement Agreement approved in Docket No. 02S-315E (Public Service's last Phase 1 rate case), under the business rules approved by the Commission in the subsequent trading investigation Docket No. 04A-050E, and as modified by Commission orders in Docket No. 05A-161E and the Settlement Agreement filed in Docket No. 06A-015E. The only change to these terms and conditions shall be the sharing of the "Gross Margins," as that term is defined in footnote 43 of the Settlement Agreement in Docket No. 02S-315E. Public Service shall share with customers the retail jurisdictional share of aggregated annual positive Gross Margins over and above $1,023,070 from each of the Generation Book ("Gen Book") and the Proprietary Book ("Prop Book"). The sharing percentages of aggregated annual positive Gross Margins shall be: Gen Book 80% to customers and 20% to the Company; Prop Book 20% to customers and 80% to the Company. These aggregated annual Gross Margins shall be calculated at calendar year end and shall be paid to customers on April 1 of the subsequent year as set forth in the ECA tariff. If the aggregated annual Gross Margins in either book are negative, such losses may not be recovered from retail customers. Should the aggregated annual Gross Margins in either of the Gen Book or Prop Book fall below

$1,023,070, the Company shall not recover the shortfall from retail customers. This Settlement Agreement is allowing the Company to recover one-half of trading A&G/O&M expenses from the Gen and Prop Books prior to sharing Gross Margins with retail customers.[3] The changes to sharing of trading margins are set forth in the proposed ECA tariff in Attachment B.

6. Non-gratuitous charges

The settled tariffs concerning non-gratuitous charges are included in Attachments B and C.

7. Residential late payment fee

The Company shall be permitted to charge a late payment fee to residential customers. The residential late payment fee shall be 1% per month applied to all bill balances that are not paid by the billing date shown on the next bill. Upon customer request, the Company shall forgive a late payment fee, but not more frequently than once in any twelve month period. The proposed tariffs imposing the residential late payment fee are included in Attachments B and C.

8. Windsource

Except as discussed in this Settlement Agreement, the Wind Energy Rate that is incorporated into the Wind Energy Service Adjustment ("WESA") shall be calculated and designed as discussed by Mr. Darnell in his Rebuttal Testimony. The proposed form of WESA tariff is included in Attachment B. The projected avoided costs created by the Windsource generation shall be calculated using the ProSYM

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[3] $1,023,070 represents 25% of the retail jurisdictional share of the 2005 test year administrative and general and non-production operation and maintenance expenses of the Company's trading department.

analysis methodology described by Company witness Mr. Horneck in his Direct Testimony and updated in his Rebuttal Testimony. The Wind Energy Rate shall be calculated using the method set forth on Company witness Mr. Darnell's Rebuttal Exhibit RND-10, page 1. Exhibit RND-10, page 1 is attached to this Settlement Agreement as Attachment F. The projected avoided costs of the Windsource generation shall be added to the ECA as the "Wind Benefit." There shall be an annual projection of the Windsource stand-alone revenue requirement using a return on rate base of 8.85%.[4] The incremental cost of Windsource (the stand-alone Windsource revenue requirement less the Wind Benefit) shall be used to design the Wind Energy Rates used in the WESA. The Wind Energy Rates shall be designed assuming full subscription of Windsource generation projected for the upcoming year. No ECA shall be paid on the kilowatt hours of Wind Energy Service.

There shall be an annual true-up calculation of the Wind Benefit that was projected in the ECA using the method set forth in this Settlement Agreement. The true-up calculation shall be filed by April 1 of each year. The ProSYM model runs used to project the avoided energy cost prior to start of the year shall be preserved and shall be rerun using the actual gas prices from the prior period instead of the projected gas prices. The avoided energy cost per kilowatt hour shall be multiplied by the actual wind production from the prior period to determine the actual Wind Benefit from the prior period. The difference between the projected and the actual Wind Benefit (positive or negative) shall be reflected in the ECA deferred balance. Whenever an adjustment is made to the Wind Benefit in the ECA deferred balance,

[4] The interest expense used to determine the stand-alone Windsource revenue requirement shall be 2.55%.

a countervailing adjustment shall be made to the incremental wind cost, such that the countervailing adjustment is included in the calculation of the next year's Wind Energy Rates. Notwithstanding the foregoing, if the true-up to the Wind Benefit divided by the Windsource kilowatt hours is less than a penny per kilowatt hour, then no true-up shall be made to ECA deferred balance or to the Wind Energy Rates. If required, the ECA deferred balance and the Wind Energy Rate adjustment shall take effect on July 1 of each year.

Public Service agrees to conduct roundtable discussions to obtain input from interested persons for development of environmentally friendly products in addition to Windsource and for improving Windsource, particularly to address the subscription wait-list.

9. Miscellaneous

A. Imputed debt. This Settlement Agreement does not resolve the dispute raised in this docket with respect to imputed debt.

B. Future rate cases. If the Company plans to file a subsequent rate case using a future test year, at least 60 days in advance of its rate case filing the Company shall notify the Settling Parties and shall submit to Staff and the OCC its sales forecast, including all supporting data and assumptions.[5] Also, the Company shall file historic test year data with pro forma adjustments in the next electric rate case where the Company is relying on a future test year.

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[5] This information shall be made available to other interested persons upon request, except that Confidential individual customer load forecasts shall not be supplied.

IMPLEMENTATION

The Settling Parties agree that the rate and tariff changes resulting from this Settlement Agreement should be approved by the Commission to become effective January 1, 2007. Upon a final Commission order approving this Settlement Agreement in all material respects, Public Service shall file with the Commission amended advice letters to place into effect revised tariff sheets in the form reflected in the Attachments to this Settlement Agreement to become effective January 1, 2007. Public Service shall update its cost projections for the ECA, PCCA, and WESA and file them with the Commission on or before December 1, 2006 to take effect on January 1, 2007.

GENERAL TERMS AND CONDITIONS

The Settling Parties agree that all 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 is ready to proceed to hearing; the e-mail notice shall designate the precise issue or issues on which the party desires to proceed to hearing (the "Hearing Notice").

The withdrawal of a Settling Party shall not automatically terminate this Agreement as to the withdrawing party or any other party. However, within three business days of the date of the Hearing Notice from the first withdrawing party, all 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. 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 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 Agreement shall not be admissible into evidence in this or any other proceeding, except as may be necessary in any proceeding to enforce this Settlement Agreement.

Approval by the Commission of this Agreement shall constitute a determination that the Agreement represents a just, equitable and reasonable resolution of all issues that were or could have been contested among the 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. Nothing in this Settlement Agreement shall preclude the Company from seeking prospective changes in its electric rates by an appropriate filing with the Commission. Nothing in this Settlement Agreement shall preclude any other party from filing a Complaint or seeking an Order to Show Cause to obtain prospective changes in the Company's electric rates.

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

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

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

Dated this 20th day of October, 2006.

PUBLIC SERVICE COMPANY OF COLORADO

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By: [signature]
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CERTIFICATE OF SERVICE

I hereby certify that on the 20th day of October 2006, the original and seven (7) copies of the foregoing **SETTLEMENT AGREEMENT** were filed via hand delivery on:

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Public Service Company of Colorado
Electric Department
Total Customer Impact Study 2006 Rate Case Rates
Existing Rates - Direct Case Rates - Settled Case Rates

Customer Class		Existing Rate	Direct Case Proposed Rate	Settled Case Proposed Rate	Monthly Average Usage	Monthly Existing Bill	Monthly Direct Case Bill	Monthly Settled Case Bill	Monthly Difference Settled - Existing $	Monthly Difference Settled - Existing %	Monthly Difference Settled - Direct Case $	Monthly Difference Settled - Direct Case %
Residential - Schedule R												
Service and Facility Charge	$/Mo.	$ 6.25	$ 6.25	$ 6.25		$ 6.25	$ 6.25	$ 6.25	$ -		$ -	
Energy Charge - Winter	$/kWh	$ 0.04453	$ 0.03153	$ 0.03153	625 kWh	27.83	19.71	19.71	(8.12)		-	
Subtotal						$ 34.08	$ 25.96	$ 25.96	$ (8.12)		$ -	
GRSA		**0.00%**	**21.21%**	**12.70%**		-	**5.51**	**3.30**	**3.30**		**(2.21)**	
Base Rate Amount						$ 34.08	$ 31.47	$ 29.26	$ (4.82)	-14.14%	$ (2.21)	-7.02%
DSMCA *(a)*	$/kWh	$ 0.00062	$ 0.00062	$ 0.00062		$ 0.39	$ 0.39	$ 0.39	$ -		$ -	
PCCA *(b)*	**$/kWh**	**$ 0.00026**	**$ 0.01432**	**$ 0.01471**		**$ 0.16**	**$ 8.95**	**$ 9.19**	**$ 9.03**		**$ 0.24**	
ECA - Secondary *(b) (c)*	**$/kWh**	**$ 0.03274**	**$ 0.03274**	**$ 0.03291**		**$ 20.46**	**$ 20.46**	**$ 20.57**	**$ 0.11**		**$ 0.11**	
AQIR - Group 1	$/kWh	$ 0.00120	$ 0.00120	$ 0.00120		$ 0.75	$ 0.75	$ 0.75	$ -		$ -	
Subtotal Base Rate Adjustments						$ 21.76	$ 30.55	$ 30.90	$ 9.14	42.00%	$ 0.35	1.15%
Total Bill Subtotal						$ 55.84	$ 62.02	$ 60.16	$ 4.32	7.74%	$ (1.86)	-3.00%
RESA		0.60%	0.60%	0.60%		$ 0.34	$ 0.37	$ 0.36	$ 0.02		$ (0.01)	
Total Bill						$ 56.18	$ 62.39	$ 60.52	$ 4.34	**7.73%**	$ (1.87)	**-3.00%**

Customer Class		Existing Rate	Direct Case Proposed Rate	Settled Case Proposed Rate	Monthly Average Usage	Monthly Existing Bill	Monthly Direct Case Bill	Monthly Settled Case Bill	Monthly Difference Settled - Existing $	Monthly Difference Settled - Existing %	Monthly Difference Settled - Direct Case $	Monthly Difference Settled - Direct Case %
Commercial - Schedule C												
Service and Facility Charge	$/Mo.	$ 7.85	$ 7.85	$ 7.85		$ 7.85	$ 7.85	$ 7.85	$ -		$ -	
Energy Charge - Winter	$/kWh	$ 0.04475	$ 0.03120	$ 0.03120	1,025 kWh	45.87	31.98	31.98	(13.89)		-	
Subtotal						$ 53.72	$ 39.83	$ 39.83	$ (13.89)		$ -	
GRSA		**0.00%**	**21.21%**	**12.70%**		-	**8.45**	**5.06**	**5.06**		**(3.39)**	
Base Rate Amount						$ 53.72	$ 48.28	$ 44.89	$ (8.83)	-16.44%	$ (3.39)	-7.02%
DSMCA *(a)*	$/kWh	$ 0.00065	$ 0.00065	$ 0.00065		$ 0.67	$ 0.67	$ 0.67	$ -		$ -	
PCCA *(b)*	**$/kWh**	**$ 0.00028**	**$ 0.01499**	**$ 0.01541**		**$ 0.29**	**$ 15.36**	**$ 15.80**	**$ 15.51**		**$ 0.44**	
ECA - Secondary *(b) (c)*	**$/kWh**	**$ 0.03274**	**$ 0.03274**	**$ 0.03291**		**$ 33.56**	**$ 33.56**	**$ 33.73**	**$ 0.17**		**$ 0.17**	
AQIR - Group 1	$/kWh	$ 0.00120	$ 0.00120	$ 0.00120		$ 1.23	$ 1.23	$ 1.23	$ -		$ -	
Subtotal Base Rate Adjustments						$ 35.75	$ 50.82	$ 51.43	$ 15.68	43.86%	$ 0.61	1.20%
Total Bill Subtotal						$ 89.47	$ 99.10	$ 96.32	$ 6.85	7.66%	$ (2.78)	-2.81%
RESA		0.60%	0.60%	0.60%		$ 0.54	$ 0.59	$ 0.58	$ 0.04		$ (0.01)	
Total Bill						$ 90.01	$ 99.69	$ 96.90	$ 6.89	**7.65%**	$ (2.79)	**-2.80%**

Footnotes: *(see page 3)*

Public Service Company of Colorado
Electric Department
Total Customer Impact Study 2006 Rate Case Rates
Existing Rates - Direct Case Rates - Settled Case Rates

Customer Class		Existing Rate	Direct Case Proposed Rate	Settled Case Proposed Rate	Monthly Average Usage	Monthly Existing Bill	Monthly Direct Case Bill	Monthly Settled Case Bill	Monthly Difference Settled - Existing $	Monthly Difference Settled - Existing %	Monthly Difference Settled - Direct Case $	Monthly Difference Settled - Direct Case %
Secondary General - Schedule SG												
Service and Facility Charge	$/Mo.	$ 25.00	$ 25.00	$ 25.00	51.37% L.F.	$ 25.00	$ 25.00	$ 25.00	$ -		$ -	
Energy Charge	$/kWh	$ 0.00288	$ 0.00288	$ 0.00288	27,000 kWh	77.76	77.76	77.76	-		-	
Demand Charge - Winter	$/kW	$ 12.57	$ 8.40	$ 8.40	72.00 kW	905.04	604.80	604.80	(300.24)		-	
Subtotal						$ 1,007.80	$ 707.56	$ 707.56	$ (300.24)		$ -	0.00%
GRSA		**0.00%**	**21.21%**	**12.70%**		-	**150.07**	**89.86**	**89.86**		**(60.21)**	
Base Rate Amount						$ 1,007.80	$ 857.63	$ 797.42	$ (210.38)	-20.88%	$ (60.21)	-7.02%
DSMCA *(a)*	$/kW	$ 0.20	$ 0.20	$ 0.20		$ 14.40	$ 14.40	$ 14.40	$ -		$ -	
PCCA *(b)*	**$/kW**	**$ 0.08**	**$ 4.52**	**$ 4.65**		**$ 5.76**	**$ 325.44**	**$ 334.80**	**$ 329.04**		**$ 9.36**	
ECA - Secondary *(b) (c)*	**$/kWh**	**$ 0.03274**	**$ 0.03274**	**$ 0.03291**		**$ 883.98**	**$ 883.98**	**$ 888.57**	**$ 4.59**		**$ 4.59**	
AQIR - Group 1	$/kWh	$ 0.00120	$ 0.00120	$ 0.00120		$ 32.40	$ 32.40	$ 32.40	$ -		$ -	
Subtotal Base Rate Adjustments						$ 936.54	$ 1,256.22	$ 1,270.17	$ 333.63	35.62%	$ 13.95	1.11%
Total Bill Subtotal						$ 1,944.34	$ 2,113.85	$ 2,067.59	$ 123.25	6.34%	$ (46.26)	-2.19%
RESA		0.60%	0.60%	0.60%		$ 11.67	$ 12.68	$ 12.41	$ 0.74		$ (0.27)	
Total Bill						$ 1,956.01	$ 2,126.53	$ 2,080.00	$ 123.99	**6.34%**	$ (46.53)	**-2.19%**
Primary General - Schedule PG												
Service and Facility Charge	$/Mo.	$ 130.00	$ 130.00	$ 130.00	64.89% L.F.	$ 130.00	$ 130.00	$ 130.00	$ -		$ -	
Energy Charge	$/kWh	$ 0.00282	$ 0.00282	$ 0.00282	450,000 kWh	1,269.00	1,269.00	1,269.00	-		-	
Demand Charge - Winter	$/kW	$ 11.44	$ 7.21	$ 7.21	950.00 kW	10,868.00	6,849.50	6,849.50	(4,018.50)		-	
Subtotal						$ 12,267.00	$ 8,248.50	$ 8,248.50	$ (4,018.50)		$ -	0.00%
GRSA		**0.00%**	**21.21%**	**12.70%**		-	**1,749.51**	**1,047.56**	**1,047.56**		**(701.95)**	
Base Rate Amount						$ 12,267.00	$ 9,998.01	$ 9,296.06	$ (2,970.94)	-24.22%	$ (701.95)	-7.02%
DSMCA *(a)*	$/kW	$ 0.19	$ 0.19	$ 0.19		$ 180.50	$ 180.50	$ 180.50	$ -		$ -	
PCCA *(b)*	**$/kW**	**$ 0.08**	**$ 4.45**	**$ 4.58**		**$ 76.00**	**$ 4,227.50**	**$ 4,351.00**	**$ 4,275.00**		**$ 123.50**	
ECA - Primary *(b) (c)*	**$/kWh**	**$ 0.03191**	**$ 0.03191**	**$ 0.03208**		**$ 14,359.50**	**$ 14,359.50**	**$ 14,436.00**	**$ 76.50**		**$ 76.50**	
AQIR - Group 2	$/kW	$ 0.45	$ 0.45	$ 0.45		$ 427.50	$ 427.50	$ 427.50	$ -		$ -	
Subtotal Base Rate Adjustments						$ 15,043.50	$ 19,195.00	$ 19,395.00	$ 4,351.50	28.93%	$ 200.00	1.04%
Total Bill Subtotal						$ 27,310.50	$ 29,193.01	$ 28,691.06	$ 1,380.56	5.06%	$ (501.95)	-1.72%
RESA		0.60%	0.60%	0.60%		$ 163.86	$ 175.16	$ 172.15	$ 8.29		$ (3.01)	
Total Bill						$ 27,474.36	$ 29,368.17	$ 28,863.21	$ 1,388.85	**5.06%**	$ (504.96)	**-1.72%**

Footnotes: (see page 3)

Public Service Company of Colorado
Electric Department
Total Customer Impact Study 2006 Rate Case Rates
Existing Rates - Direct Case Rates - Settled Case Rates

Customer Class		Existing Rate	Direct Case Proposed Rate	Settled Case Proposed Rate	Monthly Average Usage	Monthly Existing Bill	Monthly Direct Case Bill	Monthly Settled Case Bill	Monthly Difference Settled - Existing $	Monthly Difference Settled - Existing %	Monthly Difference Settled - Direct Case $	Monthly Difference Settled - Direct Case %
Transmission General - Schedule TG												
Service and Facility Charge	$/Mo.	$ 9,362.00	$ 9,362.00	$ 9,362.00	67.23% L.F.	$ 9,362.00	$ 9,362.00	$ 9,362.00	$ -		$ -	
Energy Charge	$/kWh	$ 0.00276	$ 0.00276	$ 0.00276	9,000,000 kWh	24,840.00	24,840.00	24,840.00	-		-	
Demand Charge - Winter	$/kW	$ 8.61	$ 4.47	$ 4.47	18,338 kW	157,890.18	81,970.86	81,970.86	(75,919.32)		-	
Subtotal						$192,092.18	$116,172.86	$116,172.86	$(75,919.32)		$ -	0.00%
GRSA		**0.00%**	**21.21%**	**12.70%**		-	**24,640.26**	**14,753.95**	**14,753.95**		**(9,886.31)**	
Base Rate Amount						$192,092.18	$140,813.12	$130,926.81	$(61,165.37)	-31.84%	$ (9,886.31)	-7.02%
DSMCA *(a)*	$/kW	$ 0.19	$ 0.19	$ 0.19		$ 3,484.22	$ 3,484.22	$ 3,484.22	$ -		$ -	
PCCA *(b)*	**$/kW**	**$ 0.08**	**$ 4.35**	**$ 4.47**		**$ 1,467.04**	**$ 79,770.30**	**$ 81,970.86**	**$ 80,503.82**		**$ 2,200.56**	
ECA - Transmission *(b) (c)*	**$/kWh**	**$ 0.03118**	**$ 0.03118**	**$ 0.03135**		**$280,620.00**	**$280,620.00**	**$282,150.00**	**$ 1,530.00**		**$ 1,530.00**	
AQIR - Group 2	$/kW	$ 0.45	$ 0.45	$ 0.45		$ 8,252.10	$ 8,252.10	$ 8,252.10	$ -		$ -	
Subtotal Base Rate Adjustments						$293,823.36	$372,126.62	$375,857.18	$ 82,033.82	27.92%	$ 3,730.56	1.00%
Total Bill Subtotal						$485,915.54	$512,939.74	$506,783.99	$ 20,868.45	4.29%	$ (6,155.75)	-1.20%
RESA		0.60%	0.60%	0.60%		$ 2,915.49	$ 3,077.64	$ 3,040.70	$ 125.21		$ (36.94)	
Total Bill						$488,831.03	$516,017.38	$509,824.69	$ 20,993.66	**4.29%**	$ (6,192.69)	**-1.20%**

Footnotes:

(a) *The DSMCA rate is the rate that was in effect at the time that the Company filed its direct case.*

(b) *The ECA and PCCA rates are illustrative only. The Company will update its projections of 2007 costs and file new PCCA and ECA rates on or before December 1, 2006.*

(c) *The ECA rates for the existing rate, the direct case, and the settled case reflect the Company's most recent projections for 2007 fuel, purchased energy and purchased wheeling expense. The ECA rate for the settled case also includes the Company's most recent projection of the 2007 wind benefit. None of the ECA rates include an estimate of either short term sales margins or ECA incentives.*

ATTACHMENT B

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Note: Sheet Nos. not listed in this Table of Contents are Blank Sheets reserved for future filing.

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PUBLIC SERVICE COMPANY OF COLORADO

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

ELECTRIC RATES	RATE	
ELECTRIC SERVICE		
SCHEDULE OF CHARGES FOR RENDERING SERVICE		
To institute or reinstitute electric service requiring a premise visit	$ 33.00	
To institute or reinstitute both gas and electric service requiring a premise visit	67.00	
To provide a non-regularly scheduled final meter Reading at customers request	15.00	
To transfer service at a specific location from one customer to another customer where such service is continuous, either electric service or both electric and gas service at the same time not requiring a premise visit	8.00	
To perform non-gratuitous labor for service work, not specified below, (not including appliance repair and premium power) in addition to charges for materials, is as follows:		
Trip Charge	34.00	I
(Assessed when no actual service work is performed, other than a general diagnosis of the customer's problem)		
For service work during normal working hours per man-hour	66.00	I
Minimum Charge, one hour	66.00	I
An overtime rate will be applicable to non-gratuitous labor for service work performed before and after normal working hours of 8:00 AM to 5:00 PM Monday through Saturday. The overtime rate shall be, per man-hour	81.00	I
Minimum Charge, one hour	81.00	I

(Continued on Sheet No. 25A)

ADVICE LETTER NUMBER		ISSUE DATE	
DECISION NUMBER	VICE PRESIDENT, Policy Development	EFFECTIVE DATE	January 1, 2007

ELECTRIC RATES	RATE	
ELECTRIC SERVICE		
SCHEDULE OF CHARGES FOR RENDERING SERVICE		
When such service work is performed on Sundays and holidays, per man hour..........................	95.00	I
Minimum Charge, one hour..........................	95.00	I
When customer requests one or more of the specific non-gratuitous services listed below to be performed at a time specified by the customer that is different from when the Company would ordinarily schedule the service(s) to be performed, such service(s) will be charged at the applicable overtime rates.		N
Specific non-gratuitous services:		
Holding poles, minimum 4 hours..........................	$563.00	I
Each additional hour..........................	141.00	I
Line Covering - Primary, minimum 3 hours..............	702.00	I
Each additional hour..........................	234.00	I
Line Covering - Secondary, minimum 2 hours............	275.00	I
Each additional hour..........................	138.00	I
Relocate Overhead Loop, minimum 2 hours...............	151.00	I
Each additional hour..........................	75.00	I
Connect/Reconnect Loop Charge, minimum 2 hours.........	143.00	I
Each additional hour..........................	71.00	I
Transformer opening, minimum 1 hour..................	75.00	I
Each additional hour..........................	75.00	I
Meter Set Correction (unauthorized closed loop), minimum ½ hr..........................	34.00	I
Each additional hour..........................	67.00	I
Replace Customer Fuses, minimum ½ hr..................	34.00	I
Each additional hour..........................	67.00	I
To process a check from a customer that is returned to the Company by the bank as not payable..................	15.00	I

(Continued on Sheet No. 25B)

ELECTRIC RATES	RATE	
RESIDENTIAL GENERAL SERVICE		
SCHEDULE R		
APPLICABILITY Applicable to Residential service. Not applicable to standby or resale service.		
MONTHLY RATE Service and Facility Charge:	$ 6.25	
Energy Charge: All kilowatt hours used, per kWh		
Summer Season	0.03467	R
Winter Season	0.03153	R
The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.		
MONTHLY MINIMUM	$ 6.25	
ADJUSTMENTS This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.		
PAYMENT AND LATE PAYMENT CHARGE		T
Bills for electric service are due and payable within fifteen (15) days from date of bill. Residential customers have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of fourteen (14) business days from the scheduled due date. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive months. Any monthly total bill amounts of over $50 for an electric bill or over $50 for an electric and gas bill combined not paid by the bill date for the following month's bill shall be subject to a payment charge of one percent (1.0%) per month. The Company will remove the assessment of a late payment charge for one billing period, but not more frequently than once in any twelve-month period, at customer's request. The late payment charge will not apply in instances where a Company billing error is involved, or where complications arise with financial institutions in processing payments that are no fault of the customer, or where a customer is current on an active payment arrangement.		N N N N N N N N N N N
(Continued on Sheet No. 30A)		

ELECTRIC RATES	RATE
RESIDENTIAL GENERAL SERVICE	

SCHEDULE R

SERVICE PERIOD

All service under this schedule shall be for a minimum period of twelve consecutive months and monthly thereafter until terminated. If service is no longer required by customer, service may be terminated on three days' notice. S

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with The Public Utilities Commission of the State of Colorado. S

ELECTRIC RATES | RATE

RESIDENTIAL DEMAND SERVICE

SCHEDULE RD

APPLICABILITY

Applicable to Residential service. Not applicable to standby or resale service.

MONTHLY RATE

Service and Facility Charge:	$ 7.25	
Demand Charge:		
All kilowatts of billing demand, per kW		
Summer Season	7.52	R
Winter Season	7.24	R
Energy Charge:		
All kilowatt hours used, per kWh	0.00288	

The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.

MONTHLY MINIMUM .... $ 7.25

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE T

Bills for electric service are due and payable within fifteen (15) days from date of bill. Residential customers T have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of fourteen (14) business days from the scheduled due date. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive months. Any monthly total bill amounts of over $50 for an electric bill or over $50 for an electric and gas bill combined not paid by the bill date for the following month's bill shall be subject to a payment charge of one percent (1.0%) per month. The Company will remove the assessment of a late payment charge for one billing period, but not more frequently than once in any twelve-month period, at customer's request. The late payment charge will not apply in instances where a Company billing error is involved, or where complications arise with financial institutions in processing payments that are no fault of the customer, or where a customer is current on an active payment arrangement. N

(Continued on Sheet No. 33A)

ELECTRIC RATES | RATE

RESIDENTIAL DEMAND SERVICE

SCHEDULE RD

DETERMINATION OF BILLING DEMAND

Billing demand, determined by meter measurement, shall be the maximum fifteen (15) minute integrated kilowatt demand used during the month. S

SERVICE PERIOD

All service under this schedule shall be for a minimum period of twelve consecutive months and monthly thereafter until terminated. If service is no longer required by customer, service may be terminated on three days' notice. S

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with The Public Utilities Commission of the State of Colorado.

ELECTRIC RATES | RATE

RESIDENTIAL OUTDOOR AREA LIGHTING SERVICE

SCHEDULE RAL

APPLICABILITY

Applicable within all territory served for outdoor area lighting of customer's residential property where such service can be provided directly from existing secondary distribution lines of the Company. Not applicable for lighting of public streets or highways.

MONTHLY RATE

High Pressure Sodium Lamps, Burning Dusk to Dawn:	REF. NO.	RATE	
9,500 lumen lamps, 100 watts, per lamp, per month...	010	$ 11.03	R
27,500 lumen lamps, 250 watts, per lamp, per month...	020	13.31	R
50,000 lumen lamps, 400 watts, per lamp, per month...	030	15.70	R

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE T

Bills for electric service are due and payable within fifteen (15) days from date of bill. Residential customers T have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of fourteen (14) business days from the scheduled due date. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive months. Any monthly total bill amounts of over $50 N for an electric bill or over $50 for an electric and gas bill N combined not paid by the bill date for the following month's N bill shall be subject to a payment charge of one percent (1.0%) N per month. The Company will remove the assessment of a late N payment charge for one billing period, but not more frequently N than once in any twelve-month period, at customer's request. N The late payment charge will not apply in instances where a N Company billing error is involved, or where complications arise N with financial institutions in processing payments that are no N fault of the customer, or where a customer is current on an N active payment arrangement. N

SERVICE PERIOD

All service under this schedule shall be for a minimum period of twelve consecutive months and monthly thereafter until terminated. If service is no longer required by customer, service may be terminated on three days' notice.

(Continued on Sheet No. 36A)

ELECTRIC RATES

RATE

RESIDENTIAL OUTDOOR AREA LIGHTING SERVICE

SCHEDULE RAL

RULES AND REGULATIONS S

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with The Public Utilities Commission of the State of Colorado and the following special conditions:

1. Company will, at its expense, install, own, operate, and maintain its outdoor area lighting equipment, and furnish the necessary electric energy therefore.
2. Facilities shall consist of a luminaire mounted on a bracket not exceeding four feet in length and automatic control equipment, installed on an existing Company owned pole wherein secondary distribution exists, or Company will, upon request of customer, provide additional wood poles and spans of overhead secondary feed wire or underground cable for installation of additional lighting units.

   Company reserves the right to limit the number of lighting units requiring the installation of a pole and served from the overhead or underground distribution system to two lighting units from each existing Company owned pole or underground secondary service pedestal. The length of the span of secondary feed wire or underground cable shall be determined by the Company in accordance with good engineering practice. Company reserves the right to specify the location of all area lighting facilities and to refuse to provide outdoor area lighting service in those instances where the light from such service would be a visual nuisance to nearby residents as determined by Company.

(Continued on Sheet No. 36B)

ELECTRIC RATES | RATE

RESIDENTIAL OUTDOOR AREA LIGHTING SERVICE

SCHEDULE RAL

RULES AND REGULATIONS - Cont'd

3. Installed cost of all area lighting facilities for the requested type of service will be included with any required distribution extension costs for extension cost calculation purposes. Construction Allowance and customer Construction Payment requirements will be determined in accordance with the Service Connection and Distribution Line Extension Policy and the Construction Allowance amount shown in such Policy. Facilities used exclusively for area lighting, including overhead or underground conductors, will not be included in calculating any possible refunds of customer Construction Payments under the Service Connection and Distribution Line Extension Policy unless additional area lighting units are added during the refund period. In situations where area lights are installed concurrently with new residential, commercial or industrial service or are installed on existing extensions with refundable Construction Payments and involving service other than area lighting, the Construction Allowance for such new lights will apply against the cost of area lighting facilities only. S
4. The term "Burning Dusk to Dawn" means the operation of the lamp by automatic control equipment from approximately eighteen minutes after sunset to approximately eleven minutes before sunrise, with a total burning time of approximately 4,140 hours per year.
5. Customer shall notify Company of any service failure or damage to area lighting facilities. Burned out lamps shall be replaced as soon as practicable, subject to Company's operating schedules, after notification by customer of service failure. All maintenance, including replacement of lamps, will be done during regular working hours. No credit shall be allowed on customer's monthly bill for lamp outages.

(Continued on Sheet No. 36C)

ELECTRIC RATES

RATE

RESIDENTIAL TIME-OF-USE SERVICE

SCHEDULE RTOU

APPLICABILITY

Applicable to the first 1,072 residential customers whose total energy usage during the months of June, July, and August 2004 is at least 1,800 kWh and who sign and return to the Company a response card indicating their willingness to participate in the Experimental Residential Price Response Pilot program under this Schedule RTOU. Not applicable to standby, auxiliary or resale service.

AVAILABILITY

Available as a pilot program to residential customers who live within the Company's Denver Metro and Boulder regions, excluding Coal Creek Canyon. Service is available only to those customers whose total energy usage during the months of June, July, and August 2004 is at least 1,800 kWh. Service under this rate schedule is available to 1,072 eligible participants who subscribe to the Pilot.

MONTHLY RATE

Service and Facility Charge:	$ 6.25
Energy Charge:	
On-peak Energy Charge, all kilowatt-hours of on-peak energy, per kWh	$ 0.13203
Off-peak Energy Charge, all kilowatt-hours of Off-peak energy, per kWh	$ 0.03681
MONTHLY MINIMUM	$ 6.25

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Adjustments as on file and in effect in this tariff.

D

(Continued on Sheet No. 37A)

ELECTRIC RATES | RATE

RESIDENTIAL TIME-OF-USE SERVICE

SCHEDULE RTOU

PAYMENT AND LATE PAYMENT CHARGE S T

Bills for electric service are due and payable within fifteen (15) days from date of bill. Residential customers T have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of fourteen (14) business days from the scheduled due date. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive months. Any monthly total bill amounts of N over $50 for an electric bill or over $50 for an electric and N gas bill combined not paid by the bill date for the following N month's bill shall be subject to a payment charge of one N percent (1.0%) per month. The Company will remove the N assessment of a late payment charge for one billing period, N but not more frequently than once in any twelve-month period, N at customer's request. The late payment charge will not apply N in instances where a Company billing error is involved, or N where complications arise with financial institutions in N processing payments that are no fault of the customer, or a N where customer is current on an active payment arrangement. N

BILLING PERIOD

On-peak energy shall be the energy consumed during the on-peak periods of the month.

Off-peak energy shall be the energy consumed during the off-peak periods of the month.

The on-peak and off-peak periods applicable to service hereunder shall be as follows:

On-Peak period: The time between 2:00 PM and 8:00 PM weekdays, except holidays, during the months of June, July, August and September. Holidays excepted from the on-peak period are: Independence Day and Labor Day.

Off-peak period: All hours of the month that are not designated as on-peak.

(Continued on Sheet No. 37B)

ELECTRIC RATES

RATE

RESIDENTIAL TIME-OF-USE SERVICE

SCHEDULE RTOU

SERVICE PERIOD

Service supplied under this schedule is available as a pilot program offered from July 15, 2006 through July 14, 2007. If service is no longer required by customer, service may be terminated on three days' notice. S

RULES AND REGULATIONS

Service supplied under this schedule is subject to the Company's Rules and Regulations on file with the Public Utilities Commission of the State of Colorado. S

ELECTRIC RATES

RATE

RESIDENTIAL CRITICAL-PEAK PRICING SERVICE

SCHEDULE RCPP

APPLICABILITY

Applicable to the first 575 residential customers whose total energy usage during the months of June, July, and August 2004 is at least 1,800 kWh and who sign and return to the Company a response card indicating their willingness to participate in the Experimental Residential Price Response Pilot program under this Schedule RCPP. Not applicable to standby, auxiliary or resale service.

AVAILABILITY

Available as a pilot program to residential customers who live within the Company's Denver Metro and Boulder regions, excluding Coal Creek Canyon. Service is available only to those customers whose total energy usage during the months of June, July, and August 2004 is at least 1,800 kWh. Service under this Rate Schedule is available to 575 eligible participants who subscribe to the Pilot under Schedule RCPP.

MONTHLY RATE

Service and Facility Charge:	$ 6.25
Energy Charge:	
Critical-peak Energy Charge, all kilowatt hours of critical-peak energy, per kWh	$ 0.31487
Off-peak Energy Charge, all kilowatt hours of off-peak energy, per kWh	$ 0.04169
MONTHLY MINIMUM	$ 6.25

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Adjustments as on file and in effect in this tariff.

D

(Continued on Sheet No. 38A)

RESIDENTIAL CRITICAL-PEAK PRICING SERVICE

SCHEDULE RCPP

PAYMENT AND LATE PAYMENT CHARGE T

Bills for electric service are due and payable within fifteen (15) days from date of bill. Residential customers have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of fourteen (14) business days from the scheduled due date. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive months. Any monthly total bill amounts of over $50 for an electric bill or over $50 for an electric and gas bill combined not paid by the bill date for the following month's bill shall be subject to a payment charge of one percent (1.0%) per month. The Company will remove the assessment of a late payment charge for one billing period, but not more frequently than once in any twelve-month period, at customer's request. The late payment charge will not apply in instances where a Company billing error is involved, or where complications arise with financial institutions in processing payments that are no fault of the customer, or where a customer is current on an active payment arrangement.

T

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BILLING PERIOD

Critical-peak energy shall be the energy consumed during the critical-peak periods of the critical days of the month.

Off-peak energy shall be the energy consumed during the off-peak periods of the month.

The critical-peak and off-peak periods applicable to service hereunder shall be as follows:

Critical-peak period: The time between 2:00 PM and 8:00 PM Weekdays, except holidays, during the months of June, July, August and September (summer season). Holidays excepted from the critical-peak period are: Independence Day and Labor Day.

(Continued on Sheet No. 38B)

ELECTRIC RATES | RATE

RESIDENTIAL CRITICAL-PEAK PRICING SERVICE

SCHEDULE RCPP

Critical Days: Up to ten (10) days per summer season as designated by Company. Company will provide notice one-day ahead (by 4:00 p.m. the previous day) to customers prior to calling a Critical Day. S

Off-peak period: All hours of the month that are not designated as critical-peak. S

Once a Critical Day is called, the critical-peak Energy Charge shall apply to all energy consumed during the Critical-Peak period for that day, i.e. from 2:00 PM to 8:00 PM. S

SERVICE PERIOD

Service supplied under this schedule is available as a pilot program offered from July 15, 2006 through July 14, 2007. If service is no longer required by customer, service may be terminated on three days' notice.

RULES AND REGULATIONS

Service supplied under this schedule is subject to the Company's Rules and Regulations on file with the Public Utilities Commission of the State of Colorado.

1. Customers will be notified of the Critical Day by either e-mail or by leaving a voice message at the customer's primary phone number. If the primary phone number is unavailable, a voice message will be left at a secondary phone number provided by the customer. Successful notification will be determined by either receipt of a voice mail at the primary or secondary phone number or by delivery receipt of an e-mail message.

2. The Company may elect to remove the customer from the pilot program if the Company is unable to notify the customer as set forth herein more than once during the Service Period.

ELECTRIC RATES

RATE

RESIDENTIAL CRITICAL TIME-OF-USE SERVICE

SCHEDULE RCTOU

APPLICABILITY

Applicable to the first 780 residential customers whose total energy usage during the months of June, July, and August 2004 is at least 1,800 kWh and who sign and return a response card indicating their willingness to participate in the Experimental Residential Price Response Pilot program under this Schedule RCTOU. Not applicable to standby, auxiliary or resale service.

AVAILABILITY

Available as a pilot program to residential customers who live within the Company's Denver Metro and Boulder regions, excluding Coal Creek Canyon. Service is available only to those customers whose total usage during the months of June, July, and August 2004 is at least 1,800 kWh. Service under this rate schedule is available to 780 eligible participants who subscribe to the Pilot under this Rate Schedule.

MONTHLY RATE

Service and Facility Charge:	$ 6.25
Energy Charge:	
Critical-peak Energy Charge, all kilowatt hours of critical-peak Energy, per kWh	$ 0.31487
On-peak Energy Charge, all kilowatt hours of on-peak energy, per kWh	$ 0.09758
Off-peak Energy Charge, all kilowatt hours of off-peak energy, per kWh	$ 0.03681
MONTHLY MINIMUM	$ 6.25

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Adjustments as on file and in effect in this tariff.

D

(Continued on Sheet No. 39A)

PUBLIC SERVICE COMPANY OF COLORADO

COLO. PUC No. 7 Electric

PGE/3113/61

Sheet No. 39A

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

Cancels
Sheet No.

ELECTRIC RATES | RATE

RESIDENTIAL CRITICAL TIME-OF-USE SERVICE

SCHEDULE RCTOU

PAYMENT AND LATE PAYMENT CHARGE ST

Bills for electric service are due and payable within fifteen (15) days from date of bill. Residential customers have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of fourteen (14) business days from the scheduled due date. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive months. Any monthly total bill amounts of over $50 for an electric bill or over $50 for an electric and gas bill combined not paid by the bill date for the following month's bill shall be subject to a payment charge of one percent (1.0%) per month. The Company will remove the assessment of a late payment charge for one billing period, but not more frequently than once in any twelve-month period, at customer's request. The late payment charge will not apply in instances where a Company billing error is involved, or where complications arise with financial institutions in processing payments that are no fault of the customer, or where a customer is current on an active payment arrangement. T N N N N N N N N N N N N N

BILLING PERIOD

Critical-peak energy shall be the energy consumed during the critical-peak periods of the critical days of the month.

On-peak energy shall be the energy consumed during the on-peak periods of the month.

Off-peak energy shall be the energy consumed during the off-peak periods of the month.

The on-peak and off-peak periods applicable to service hereunder shall be as follows:

Critical-peak period: The time between 2:00 PM and 8:00 PM weekdays, except holidays, during the months of June, July, August and September (summer season). Holidays excepted from the critical-peak period are: Independence Day and Labor Day.

(Continued on Sheet No. 39B)

ADVICE LETTER NUMBER

ISSUE DATE

DECISION NUMBER

VICE PRESIDENT, Policy Development

EFFECTIVE DATE January 1, 2007

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

ELECTRIC RATES | RATE

RESIDENTIAL CRITICAL TIME-OF-USE SERVICE

SCHEDULE RCTOU

Critical Days:	Up to ten (10) days per summer season as designated by Company in its sole discretion. Company will provide notice one-day ahead (by 4:00 p.m. the previous day) to participating customers prior to calling a Critical Day.	S
On-peak period:	The time between 2:00 PM and 8:00 PM weekdays, except holidays, during the summer season that are not designated as Critical Days. Holidays excepted from the on-peak period are: Independence Day and Labor Day.	S
Off-peak period:	All hours of the month that are not designated as critical-peak or on-peak.	S

Once a Critical Day is called, the critical-peak Energy Charge shall apply to all energy consumed during the critical-peak period for that day, i.e. from 2:00 PM to 8:00 PM. S

SERVICE PERIOD

Service supplied under this schedule is available as a pilot program offered from July 15, 2006 through July 14, 2007. If service is no longer required by customer, service may be terminated on three days' notice.

RULES AND REGULATIONS

Service supplied under this schedule is subject to the Company's Rules and Regulations on file with the Public Utilities Commission of the State of Colorado.

1. Customers will be notified of the Critical Day by either e-mail or by leaving a voice message at the customer's primary phone number. If the primary number is unavailable, a voice message will be left at a secondary phone number provided by the customer. Successful notification will be determined by either receipt of a voice mail at the primary or secondary phone number or by delivery receipt of an e-mail message.

2. The Company may elect to remove the customer from the Pilot program if the Company cannot notify the customer as to set forth herein more than once during the Service Period.

ELECTRIC RATES | RATE

COMMERCIAL SERVICE

SCHEDULE C

APPLICABILITY

Applicable to customers whose demands are less than 25 kW for electric power service supplied at secondary distribution voltage. Not applicable to standby or resale service.

MONTHLY RATE

Service and Facility Charge:	$ 7.85	
Energy Charge:		
All kilowatt-hours used, per kWh		
Summer Season....................................	0.03497	R
Winter Season....................................	0.03120	R

The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.

MONTHLY MINIMUM	$ 7.85	

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

SERVICE PERIOD

All service under this schedule shall be for a minimum period of twelve consecutive months and monthly thereafter until terminated. If customer's maximum demand reaches 25 kW or greater during any billing month, the service period shall be terminated at the end of that billing month. Beginning with the succeeding billing month service will be provided under Schedule SG. However, beginning on the effective date of this rate schedule, the Company will allow a single one-time occurrence of a customer's monthly demand reaching 25 kW up through 30 kW without such termination. The single one-time allowance shall be applied to a customer once for as long as the customer receives electric service from the Company at the service address to which the one-time allowance is applied.

(Continued on Sheet No. 40A)

ELECTRIC RATES

RATE

COMMERCIAL SERVICE

SCHEDULE C

SERVICE PERIOD - Cont'd

Once the service under this Rate Schedule is terminated for exceeding the demand limit, the Company will place the customer on Schedule SG, but will allow the customer up to ninety (90) days to elect to receive service under Schedule SGL. If the customer remains on Schedule SG, the minimum service period will begin on the date the Company places the customer on Schedule SG. If during the ninety (90) day election period, the customer elects to receive service under Schedule SGL, the minimum twelve (12) month service period will begin on the date the Company receives notice of the election. If service is no longer required by customer, service may be terminated on three days' notice. SC

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with The Public Utilities Commission of the State of Colorado. S

ELECTRIC RATES | RATE

SECONDARY GENERAL LOW-LOAD FACTOR

SCHEDULE SGL

APPLICABILITY

Applicable to electric power service supplied at secondary voltage. Not applicable to standby or resale service.

MONTHLY RATE

Service and Facility Charge:	$ 25.00	
Demand Charge:		
All kilowatts of billing demand, per kW...............	$ 4.94	
Energy Charge:		
All kilowatt-hours of use, per kWh		
Summer Season.....................................	0.06084	R
Winter Season.....................................	0.04618	R

The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.

MONTHLY MINIMUM

The Service and Facility Charge plus the Demand Charge.

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

DETERMINATION OF BILLING DEMAND

Billing demand, determined by meter measurement, shall be the maximum fifteen (15) minute integrated kilowatt demand used during the month, except as set forth in the Commercial and Industrial Rules and Regulations.

SERVICE PERIOD

All service under this schedule shall be for a minimum period of twelve consecutive months and monthly thereafter until terminated. If service is no longer required by customer, service may be terminated on thirty days' notice. Greater minimum periods may be required by contract in situations involving large or unusual loads.

(Continued on Sheet No. 43A)

ELECTRIC RATES	RATE	
SECONDARY GENERAL SERVICE		
SCHEDULE SG		
APPLICABILITY Applicable to electric power service supplied at secondary voltage. Not applicable to standby or resale service.		
MONTHLY RATE Service and Facility Charge:	$25.00	
Demand Charge: All kilowatts of billing demand, per kW		
Summer Season.......................................	9.58	R
Winter Season.......................................	8.40	R
Energy Charge: All kilowatt hours used, per kWh	$ 0.00288	
The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.		
MONTHLY MINIMUM The Service and Facility Charge plus the Demand Charge.		
OPTIONAL SERVICE Customers receiving service under this rate may elect to receive interruptible service under the Interruptible Service Option Credit.		
ADJUSTMENTS This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.		
PAYMENT AND LATE PAYMENT CHARGE Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month.		T
DETERMINATION OF BILLING DEMAND Billing demand, determined by meter measurement, shall be the maximum fifteen (15) minute integrated kilowatt demand used during the month, except as set forth in the Commercial and Industrial Rules and Regulations.		

(Continued on Sheet No. 44A)

ELECTRIC RATES	RATE	
SECONDARY STANDBY SERVICE		
SCHEDULE SST		
DEFINITIONS - Cont'd		
Standby Service. Standby Service shall be the service provided by Company under this Secondary Standby Service rate schedule.		
MONTHLY RESERVATION FEE		
Service and Facility Charge:	$ 80.00	
Transmission and Distribution Standby Capacity Fee:		
Contract Standby Capacity, per kW	4.94	
Generation Standby Capacity Reservation Fee:		
Contract Standby Capacity, per kW		
Firm Standby - Summer Season..................	0.60	R
Firm Standby - Winter Season..................	0.45	R
Contractual or Physical Assurance	0.00	
MONTHLY USAGE CHARGE		
Demand Charge:		
All Demand used under this schedule after the Allowed Grace Energy has been exhausted will be charged at the following rate, per kW		
Summer Season..................................	4.04	R
Winter Season..................................	3.01	R
Reliability Purchase Demand Charge:		
All Demand used during a Reliability Purchase Period per kW	5.60	
Energy Charge:		
All energy actually used under this tariff shall be charged at the following rate, per kWh	$0.00288	
The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.		
MONTHLY MINIMUM		
The Service and Facility Charge plus the Transmission and Distribution Standby Capacity Fee plus the Generation Standby Capacity Reservation Fee.		

(Continued on Sheet No. 47B)

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

ELECTRIC RATES	RATE
SECONDARY STANDBY SERVICE	

SCHEDULE SST

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

DETERMINATION OF TRANSMISSION AND DISTRIBUTION STANDBY CAPACITY FEE PAYMENT

The Transmission and Distribution Standby Capacity Fee Payment shall be determined by multiplying the Contract Standby Capacity times the Transmission and Distribution Standby Capacity Fee.

DETERMINATION OF GENERATION STANDBY CAPACITY RESERVATION FEE PAYMENT

The Generation Standby Capacity Reservation Fee Payment shall be determined by multiplying the Contract Standby Capacity times the Generation Standby Capacity Reservation Fee.

DETERMINATION OF DEMAND

For billing purposes, the customer's billing demand for the Monthly Usage Demand Charge will be determined separately from and will have no effect on the billing demand determined under Schedule SG that this tariff compliments. The Monthly Usage billing demand will be the smaller of the following two amounts: (1) the amount of the Contract Standby Capacity minus the actual demand supplied by the customer's own generating facilities, but not less than zero, or (2) the amount of Monthly Usage Demand supplied by the Company.

(Continued on Sheet No. 47C)

ELECTRIC RATES	RATE	
PRIMARY GENERAL SERVICE		
SCHEDULE PG		
APPLICABILITY Applicable to electric power service supplied at primary voltage. Not applicable to standby or resale service.		
MONTHLY RATE Service and Facility Charge:	$ 130.00	
Demand Charge: All kilowatts of billing demand, per kW		
Summer Season....................................	8.39	R
Winter Season....................................	7.21	R
Energy Charge: All kilowatt-hours used, per kWh......................	$ 0.00282	
The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.		
MONTHLY MINIMUM The Service and Facility Charge plus the Demand Charge.		
OPTIONAL SERVICE Customers receiving service under this rate may elect to receive interruptible service under the Interruptible Service Option Credit.		
ADJUSTMENTS This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.		
PAYMENT AND LATE PAYMENT CHARGE Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month.		T

(Continued on Sheet No. 52A)

ELECTRIC RATES	RATE	
PRIMARY STANDBY SERVICE		
SCHEDULE PST		
DEFINITIONS - Cont'd		
Standby Service. Standby Service shall be the service provided by Company under this Primary Standby Service rate schedule.		
MONTHLY RESERVATION FEE		
Service and Facility Charge:	$ 130.00	
Transmission and Distribution Standby Capacity Fee:		
Contract Standby Capacity, per kW	3.67	
Generation Standby Capacity Reservation Fee:		
Contract Standby Capacity, per kW		
Firm Standby - Summer Season..................	0.61	R
Firm Standby - Winter Season..................	0.46	R
Contractual or Physical Assurance	0.00	
MONTHLY USAGE CHARGE		
Demand Charge:		
All Demand used under this schedule after the Allowed Grace Energy has been exhausted will be charged at the following rate, per kW		
Summer Season................................	4.11	R
Winter Season................................	3.08	R
Reliability Purchase Demand Charge:		
All Demand used during a Reliability Purchase Period Per kW	5.47	
Energy Charge:		
All energy actually used under this tariff shall be charged at the following rate, per kWh	$0.00282	

The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.

MONTHLY MINIMUM

The Service and Facility Charge plus the Transmission and Distribution Standby Capacity Fee plus the Generation Standby Capacity Reservation Fee.

(Continued on Sheet No. 55B)

ELECTRIC RATES | RATE

PRIMARY STANDBY SERVICE N

SCHEDULE PST

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

DETERMINATION OF TRANSMISSION AND DISTRIBUTION STANDBY CAPACITY FEE PAYMENT

The Transmission and Distribution Standby Capacity Fee Payment shall be determined by multiplying the Contract Standby Capacity times the Transmission and Distribution Standby Capacity Fee.

DETERMINATION OF GENERATION STANDBY CAPACITY RESERVATION FEE PAYMENT

The Generation Standby Capacity Reservation Fee Payment shall be determined by multiplying the Contract Standby Capacity times the Generation Standby Capacity Reservation Fee.

DETERMINATION OF DEMAND

For billing purposes, the customer's billing demand for the Monthly Usage Demand Charge will be determined separately from and will have no effect on the billing demand determined under Schedule PG that this tariff compliments. The Monthly Usage billing demand will be the smaller of the following two amounts: (1) the amount of the Contract Standby Capacity minus the actual demand supplied by the customer's own generating facilities, but not less than zero, or (2) the amount of Monthly Usage Demand supplied by the Company.

(Continued on Sheet No. 55C)

ELECTRIC RATES | RATE

TRANSMISSION GENERAL SERVICE

SCHEDULE TG

APPLICABILITY

Applicable to electric power service supplied at transmission voltage. Not applicable to standby or resale service.

MONTHLY RATE

Service and Facility Charge:	REF. NO.	RATE	
General Services Admin (Fed Center)	020	$ 210.00	
Lockheed Martin Space Systems Company	030	10,100.00	
Rocky Mountain Arsenal	040	120.00	
Monfort, Inc.	200	390.00	
Rocky Mountain Steel (Mill)	250	6,850.00	
Rocky Mountain Steel (Furnace)	260	21,100.00	
Climax Molybdenum Company, Henderson Mine	270	41,100.00	
StorageTek	320	12,100.00	
Suncor Energy (U.S.A.) Inc.	330	13,100.00	
Climax Molybdenum Company, Climax Mine	370	13,300.00	
Air Liquide.	410	600.00	
American Soda L.L.P.	420	850.00	
IBM Corp	520	27,000.00	
EnCana Oil & Gas (U.S.A.) Inc. (Middle Fork)	530	850.00	
Demand Charge:			
All kilowatts of billing demand, per kW			
Summer Season		5.63	R
Winter Season		4.47	R
Energy Charge:			
All kilowatt hours used, per kWh		0.00276	

The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.

(Continued on Sheet No. 62A)

ELECTRIC RATES | RATE

TRANSMISSION GENERAL SERVICE

SCHEDULE TG

MONTHLY MINIMUM

The applicable Service and Facility Charge shown above plus the Demand Charge.

OPTIONAL SERVICE

Customers receiving service under this rate may elect to receive interruptible service under the Interruptible Service Option Credit.

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

(Continued on Sheet No. 62B)

ELECTRIC RATES | RATE

TRANSMISSION STANDBY SERVICE

SCHEDULE TST

MONTHLY RESERVATION FEE – Cont'd

Transmission Standby Capacity Fee:		
Contract Standby Capacity, per kW	1.01	
Generation Standby Capacity Reservation Fee:		
Contract Standby Capacity, per kW		
Firm Standby – Summer Season..................	0.60	R
Firm Standby – Winter Season..................	0.45	R
Contractual or Physical Assurance	0.00	

MONTHLY USAGE CHARGE

Demand Charge:		
All Demand used under this schedule after the Allowed Grace Energy has been exhausted will be charged at the following rate, per kW		
Summer Season................................	4.02	R
Winter Season................................	3.01	R
Reliability Purchase Demand Charge:		
All Demand used during a Reliability Purchase Period per kW	5.35	
Energy Charge:		
All energy actually used under this tariff shall be charged at the following rate, per kWh	$0.00276	

The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.

MONTHLY MINIMUM

The Service and Facility Charge plus the Interconnection Charge plus the Transmission Standby Capacity Fee plus the Generation Standby Capacity Reservation Fee.

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

(Continued on Sheet No. 63C)

ELECTRIC RATES | RATE

SPECIAL CONTRACT SERVICE

SCHEDULE SCS-7

APPLICABILITY

Applicable to the Regional Transportation District for all electric power and energy required by its Central and Southwest Corridor Light Rail Systems, and Central Platte Valley extension as set forth in the special contract for such service between Regional Transportation District and Company. Not applicable to standby, or resale service.

MONTHLY RATE

Service and Facility Charge:		
Per Delivery Point..................................	$130.00	
Production Demand Charge:		
All kilowatts of billing demand, per kW		
Summer Season..................................	4.72	R
Winter Season..................................	3.54	R
Transmission & Distribution Demand Charge:		
All kilowatts of billing demand, per kW	3.67	
Energy Charge:		
All kilowatt hours used, per kWh	0.00282	

The summer season shall be the period June 1 through September 30 of each year and the winter season shall be the period October 1 through May 31.

MONTHLY MINIMUM

The Service and Facility Charge plus the Transmission & Distribution Demand Charge.

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect with this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

(Continued on Sheet No. 77A)

ELECTRIC RATES | RATE

COMMERCIAL OUTDOOR AREA LIGHTING SERVICE

SCHEDULE CAL

APPLICABILITY

Applicable within all territory served for outdoor area lighting of customer's property where such service can be provided directly from existing secondary distribution lines of the Company. Not applicable for lighting of public streets or highways.

MONTHLY RATE

High Pressure Sodium Lamps, Burning Dusk to Dawn: REF. NO.	RATE	
9,500 lumen lamps, 100 watts, per lamp, per month...010	$ 11.03	R
27,500 lumen lamps, 250 watts, per lamp, per month...020	13.31	R
50,000 lumen lamps, 400 watts, per lamp, per month...030	15.70	R

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

SERVICE PERIOD

All service under this schedule shall be for a minimum period of twelve consecutive months and monthly thereafter until terminated. If service is no longer required by customer, service may be terminated on three days' notice.

(Continued on Sheet No. 80A)

ELECTRIC RATES

RATE

PARKING LOT LIGHTING SERVICE

SCHEDULE PLL

APPLICABILITY

Applicable to Parking Lot Lighting Service. Not applicable for lighting of public streets or highways.

MONTHLY RATE

High Pressure Sodium Lamps, Burning Dusk to Dawn:	REF. NO.	RATE	
9,500 lumen lamps, 100 watts, per lamp, per month......	010.	$ 10.61	R
16,000 lumen lamps, 150 watts, per lamp, per month......	020.	11.19	R
22,000 lumen lamps, 200 watts, per lamp, per month......	030.	11.80	R
27,500 lumen lamps, 250 watts, per lamp, per month......	040.	12.51	R
50,000 lumen lamps, 400 watts, per lamp, per month......	050.	14.49	R

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

SERVICE PERIOD

All service under this schedule shall be for a minimum period of twelve consecutive months and monthly thereafter until terminated. If service is no longer required by customer, service may be terminated on three days' notice.

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with The Public Utilities Commission of the State of Colorado and the following special conditions:

1. Company will provide, install, own, operate, maintain and replace all parking lot lighting facilities consisting of the poles, luminaires, brackets, light sensitive devices, lamps, glass or plastic lenses and lamp covers, foundations, conductors and the distribution facilities necessary to provide lighting service as well as furnish the energy required for such service.

(Continued on Sheet No. 81A)

COLO. PUC No. 7 Electric

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 85 PGE/3113/78

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

Cancels
Sheet No.

ELECTRIC RATES

STREET LIGHTING SERVICE

SCHEDULE SL

APPLICABILITY

Applicable within all territory served for Street Lighting Service.

MONTHLY RATE	REF. NO.	RATE	
Lights Burning Dusk to Dawn:			
High Pressure Sodium Lamps:			
4,100 lumen lamps, 50 watts, per lamp, per month..	010	$ 10.26	R
5,800 lumen lamps, 70 watts, per lamp, per month..	020	10.25	R
9,500 lumen lamps, 100 watts, per lamp, per month..	030	10.61	R
16,000 lumen lamps, 150 watts, per lamp, per month..	040	11.19	R
22,000 lumen lamps, 200 watts, per lamp, per month..	050	11.80	R
27,500 lumen lamps, 250 watts, per lamp, per month..	060	12.51	R
50,000 lumen lamps, 400 watts, per lamp, per month..	070	14.49	R
140,000 lumen lamps, 1,000 watts, per lamp, per month..	080	21.08	R
Metal Halide Lamps:			
8,500 lumen lamps, 100 watts, per lamp, per month..	110	$ 11.51	R
14,000 lumen lamps, 175 watts, per lamp, per month..	120	12.05	R
20,500 lumen lamps, 250 watts, per lamp, per month..	130	12.92	R
36,000 lumen lamps, 400 watts, per lamp, per month..	140	14.59	R
110,000 lumen lamps, 1,000 watts, per lamp, per month..	150	22.43	R
Induction Lamps:			
3,500 lumen lamps, 55 watts, per lamp, per month .	160	$ 10.39	R
6,000 lumen lamps, 85 watts, per lamp, per month .	170	10.70	R
12,000 lumen lamps, 165 watts, per lamp, per month .	180	11.76	R
Compact Fluorescent Lamps:			
1,100 lumen lamps, 18 watts, per lamp, per month..	210	$ 10.48	R
1,750 lumen lamps, 28 watts, per lamp, per month..	220	10.59	R

(Continued on Sheet No. 85A)

ADVICE LETTER NUMBER

ISSUE DATE

DECISION NUMBER

VICE PRESIDENT, Policy Development

EFFECTIVE DATE January 1, 2007

ELECTRIC RATES | RATE

STREET LIGHTING SERVICE

SCHEDULE SL

MONTHLY RATE - Cont'd

	REF. NO.	RATE	
Lights Burning Dawn to Dusk:			
High Pressure Sodium Lamps:			
5,800 lumen lamps, 70 watts, per lamp, per month...	310	$ 10.26	R
16,000 lumen lamps, 150 watts, per lamp, per month...	320	11.21	R
22,000 lumen lamps, 200 watts, per lamp, per month...	330	11.82	R
27,500 lumen lamps, 250 watts, per lamp, per month...	340	12.55	R
50,000 lumen lamps, 400 watts, per lamp, per month...	350	14.54	R
Lights Burning 24 Hours Per Day:			
High Pressure Sodium Lamps:			
5,800 lumen lamps, 70 watts, per lamp, per month...	410	$ 10.34	R
16,000 lumen lamps, 150 watts, per lamp, per month...	420	11.38	R
22,000 lumen lamps, 200 watts, per lamp, per month...	430	12.05	R
27,500 lumen lamps, 250 watts, per lamp, per month...	440	12.84	R
50,000 lumen lamps, 400 watts, per lamp, per month...	450	15.02	R

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

(Continued on Sheet No. 85B)

ELECTRIC RATES	RATE	
SPECIAL STREET LIGHTING SERVICE		

SCHEDULE SSL

APPLICABILITY

Applicable only within the area designated as the Georgetown/Silver Plume National Historic District for Special Street Lighting Service.

MONTHLY RATE	REF.NO.		
Mercury Vapor Lamps, Burning Dusk to Dawn:			
4,200 lumen lamps, 100 watts, per lamp, per month.....	010	$ 11.04	R

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations for Street Lighting Service and to all other applicable Rules and Regulations of the Company on file with The Public Utilities Commission of the State of Colorado and the following special conditions:

1. The Monthly Rate for Special Street Lighting Service includes the ordinary and routine maintenance and replacement for lamps and light sensitive devices. All other maintenance and replacement for street lighting facilities will be separately billed to customer in accordance with the provisions of Maintenance Charges for Street Lighting Service in Company's Rules and Regulations for Street Lighting Service.
2. Maintenance and replacement of Special Street Lighting facilities is subject to the availability of the special facilities involved.

ELECTRIC RATES | RATE

SPECIAL HIGHWAY LIGHTING SERVICE

SCHEDULE SHL

APPLICABILITY

Applicable to the Colorado Department of Transportation for Special Highway Lighting Service.

MONTHLY RATE

Description	REF. NO.	RATE	
Lights Burning Dusk to Dawn:			
High Pressure Sodium Lamps:			
9,500 lumen lamps, 100 watts, per lamp, per month	010	$ 1.81	R
16,000 lumen lamps, 150 watts, per lamp, per month	020	2.39	R
22,000 lumen lamps, 200 watts, per lamp, per month	030	3.00	R
27,500 lumen lamps, 250 watts, per lamp, per month	040	3.71	R
37,000 lumen lamps, 310 watts, per lamp, per month	050	4.59	R
50,000 lumen lamps, 400 watts, per lamp, per month	060	5.69	R
140,000 lumen lamps, 1,000 watts, per lamp, per month	070	12.28	R
Metal Halide Lamps:			
110,000 lumen lamps, 1,000 watts, per lamp, per month	110	$13.63	R
Lights Burning Dawn to Dusk:			
High Pressure Sodium Lamps:			
27,500 lumen lamps, 250 watts, per lamp, per month	210	$ 3.75	R
50,000 lumen lamps, 400 watts, per lamp, per month	220	5.74	R
Lights Burning 24 Hours Per Day:			
High Pressure Sodium Lamps:			
27,500 lumen lamps, 250 watts, per lamp, per month	310	$ 4.04	R
50,000 lumen lamps, 400 watts, per lamp, per month	320	6.22	R

(Continued on Sheet No. 87A)

ELECTRIC RATES	RATE

SPECIAL HIGHWAY LIGHTING SERVICE

SCHEDULE SHL

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations for Street Lighting Service and to all other applicable Rules and Regulations of the Company on file with The Public Utilities Commission of the State of Colorado and the following special conditions:

1. Company will provide ordinary and routine maintenance and replacement for lamps and light sensitive devices only and will deliver the required energy from Company's distribution system.
2. Customer will provide the original lamp and light sensitive device. Customer will provide and own all other street lighting facilities. All maintenance and replacement for street lighting facilities, other than the maintenance and replacement specified above to be provided by Company, will be the responsibility of the customer.
3. Special Highway Lighting Service is available only in locations where customer lighting facilities will not commingle with any of Company's lighting or distribution facilities.

ELECTRIC RATES	RATE	
STREET LIGHTING SERVICE - UNINCORPORATED AREAS		

SCHEDULE SLU

APPLICABILITY

Applicable within all territory served for street lighting service in such unincorporated areas in which there is no organization possessed of power to contract for such service. Not applicable to any other street lighting service.

MONTHLY RATE	REF. NO.	RATE
High Pressure Sodium Lamps, Burning Dusk to Dawn:		
9,500 lumen lamps, 100 watts per lamp, per customer, per month......................	010 .	$ 1.58

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

For Residential customers, bills for electric service are due and payable within fifteen (15) days from date of bill. Residential customers have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of fourteen (14) business days from the scheduled due date. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive months. Any monthly total bill amounts of over $50 for an electric bill or over $50 for an electric and gas bill combined not paid by the bill date for the following month's bill shall be subject to a payment charge of one percent (1.0%) per month. The Company will remove the assessment of a late payment charge for one billing period, but not more frequently than once in any twelve-month period, at customer's request. The late payment charge will not apply in instances where a Company billing error is involved, or where complications arise with financial institutions in processing payments that are no fault of the customer, or where a customer is current on an active payment arrangement.

N N N N N N N N N N N N N N N N T

For Commercial and Industrial customers, bills for electric service are due and payable within fifteen (15) days from date of bill. For commercial electric service, any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month.

(Continued on Sheet No. 88A)

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

ELECTRIC RATES	RATE

STREET LIGHTING SERVICE - UNINCORPORATED AREA

SCHEDULE SLU

RULES AND REGULATIONS S

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations for Street Lighting Service and to all other applicable Rules and Regulations of the Company on file with The Public Utilities Commission of the State of Colorado and the following special conditions:

1. Street Lighting Service will be provided hereunder only in such areas where the population density justifies service hereunder and in which there must be located sufficient electric customers of the Company to justify the installation of a minimum of five street lights in a manner so as to render adequate street lighting for the area on the basis of an average of not less than seven customers per street light.
2. Street Lighting Service provided hereunder shall be furnished as part of the residential electric service or commercial electric service to customers in the particular unincorporated area or subdivision receiving such service. The Company shall maintain records which delineate the boundaries within which said service is provided. Those customers located within the boundaries of the areas shall be billed for said Street Lighting Service.
3. Street Lighting Service will be installed and supplied by the Company in areas otherwise qualifying for street lighting hereunder on one of the following conditions:
   a) With respect to established and substantially fully developed areas, Street Lighting Service will be provided upon receipt by the Company of a petition or other written request from all of the electric customers located within such an area.
   (b) With respect to areas currently being subdivided and developed, Street Lighting Service will be provided upon receipt of a petition or other written request for service in the form satisfactory to the Company obtained by the builder or developer signed by each electric customer within such subdivision.
   (c) Upon an order or decision of The Public Utilities Commission of the State of Colorado directing Street Lighting Service hereunder in the area.

(Continued on Sheet No. 88B)

ELECTRIC RATES

RATE

STREET LIGHTING SERVICE - UNINCORPORATED AREA

SCHEDULE SLU

RULES AND REGULATIONS - Cont'd

(d) Where the area proposed to be served is subject to the terms and provisions of an unconditional restrictive covenant which provides in substance that present and subsequent owners of property in the area proposed to be served are subject to and bound by present and future Public Service Company of Colorado tariffs applicable to Street Lighting Service filed with The Public Utilities Commission of the State of Colorado.

4. Street lighting systems will be designed and installed by the Company in accordance with good engineering practices and under the terms and conditions of the Company's Service Connection and Distribution Line Extension Policy.
5. Street Lighting Service requested by a builder or developer for purposes of lighting streets adjacent to show houses, etc., will be supplied by written agreement at the rate applicable for Street Lighting Service. Such builder or developer shall be responsible for payment of bills therefore until such time as the development in the areas, as defined in paragraph 1 of these Rules and Regulations, is such that payment for the Street Lighting Service can be made on an individual customer basis at the rate specified under "Monthly Rate" herein.
6. The Monthly Rate for Street Lighting Service provided hereunder includes all maintenance and replacement for street lighting facilities owned and maintained by Company. Customer will not be billed separately for maintenance charges.
7. Customer shall notify Company of any Company owned street lighting unit damaged.

ELECTRIC RATES | RATE

TRAFFIC SIGNAL LIGHTING SERVICE

SCHEDULE TSL

APPLICABILITY

Applicable for service only to such cities and towns served by the Company for Traffic Signal Lighting Service.

MONTHLY RATE

Per watt of Connected Load .... $ 0.00609 R

ADJUSTMENTS

This rate schedule is subject to all applicable Electric Service Adjustments as on file and in effect in this tariff.

PAYMENT AND LATE PAYMENT CHARGE

Bills for electric service are due and payable within fifteen (15) days from date of bill. Any amounts not paid on or before the due date of the bill shall be subject to a late payment charge of 1.5% per month. T

CONNECTED LOAD

The Connected Load will be determined by the total watt load of all traffic signal lights connected to each load point or intersection.

DETERMINATION OF BILLING ENERGY

The Billing Energy to calculate all non-base rate Electric Rate Adjustments shall be determined according to the following formulas:

Ref. No. 010

Traffic Signal Lighting in Normal (continuous) Mode, where percent of flashing time is less than or equal to (50%):

Billing Energy in kWh = 0.2555 * Connected Load

Ref. No. 020

Traffic Signal Lighting in Flashing Mode, where percent of flashing time is more than fifty percent (50%):

Billing Energy in kWh = 0.1168 * Connected Load

(Continued on Sheet No. 89A)

ELECTRIC RATES

RATE

WIND ENERGY SERVICE

SCHEDULE WES

APPLICABILITY

Applicable as an option by contract to customers who take firm service. Not applicable to street lighting, area lighting, standby, or resale service.

DEFINITIONS

Contract Period. Wind Energy Service for residential customers and commercial customers on Rate Schedule C shall be for a minimum period of twelve consecutive months and then continuing month to month thereafter until terminated. Service for all other commercial and industrial customers shall be for a minimum period of three consecutive years and then continuing month to month thereafter until terminated. After the minimum period, service may be terminated on thirty days' notice.

Wind Energy Resource. Electric capacity and energy generated from wind resources designated for Wind Energy Service.

Wind Energy Service. Customer's monthly energy for which the customer has contracted under this tariff. Customer may contract, in 100 kWh increments, up to customer's total firm load as used under the standard filed tariff rate.

Service Restrictions. Service limited to the total capability of Wind Energy Resources acquired by the Company and designated for Wind Energy Service.

Wind Energy Rate. The Wind Energy Rates are designed starting from the net of the Annual Revenue Requirement for the Wind Energy Resource, less the Wind Benefit defined in the Electric Commodity Adjustment, Tariff Sheet 111B. The Wind Energy Rates are differentiated by delivery service voltage. N N N N N N

ADJUSTMENTS

The Wind Energy Service is subject to all base rate Electric Rate Adjustments. Wind Energy Service customers will be charged the non-base rate Adjustments, but the non-base rate Adjustments will be credited against the Wind Energy Rate as shown below to arrive at the Monthly Wind Energy Service Adjustment.

ELECTRIC RATES	RATE

WIND ENERGY SERVICE

SCHEDULE WES

INFORMATION TO BE FILED WITH THE PUBLIC UTILITIES COMMISSION S

The Company will file with the Commission on or before April 1 an annual report that specifies for the prior year the amount of kilowatt hours produced by or purchased from wind generation equipment, achieved annual capacity factors, the line losses associated with the transmission and distribution of energy to customers, and the amount of kilowatt hours sold to customers through the Wind Energy Service program. The Company shall also recalculate the Wind Benefit achieved in the prior year in the manner set forth in the Electric Commodity Adjustment Tariff. If an adjustment is required to be made to the Wind Benefit under the Electric Commodity Adjustment Tariff, the Company will make a corresponding adjustment to the Wind Energy Rates on July 1 so that the Wind Energy Rates are designed, assuming full subscription, to recover, together with the Wind Benefit, the Wind Energy Service Annual Revenue Requirement. C

WIND ENERGY SERVICE ADJUSTMENT

The Wind Energy Service Adjustment is calculated by subtracting the AQIR and ECA from the Wind Energy Rate. The Wind Energy Rate will change annually on January 1 of each year, except in those years where the Wind Benefit in the ECA is adjusted on July 1, in which case in that year the Wind Energy Rate will also be changed on July 1. The ECA rate will change every quarter. Consequently, the Wind Energy Service Adjustment will change every quarter. The following charges are used to determine the Wind Energy Service Adjustment amount. C

(Continued on Sheet No. 91B)

COLO. PUC No. 7 Electric

PUBLIC SERVICE COMPANY OF COLORADO

PGE/3113/89

Sheet No. 91B

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

Cancels
Sheet No.

ELECTRIC RATES	RATE	
WIND ENERGY SERVICE		
SCHEDULE WES		
MONTHLY WIND ENERGY SERVICE ADJUSTMENT		
Residential		
Wind Energy Rate, per 100 kWh block:	$3.5100	
Less ECA, per 100 kWh block:	$3.2910	R
Less AQIR, per 100 kWh block:	$0.1200	I
Monthly Wind Energy Service Adjustment, per 100 kWh block:	$0.0990	R
Small Commercial		R
Wind Energy Rate, per 100 kWh block:	$3.5100	I
Less ECA, per 100 kWh block:	$3.2910	
Less AQIR, per 100 kWh block:	$0.1200	R
Monthly Wind Energy Service Adjustment, per 100 kWh block:	$0.0990	R
C&I Secondary		I
Wind Energy Rate, per 100 kWh block:	$3.5100	
Less ECA, per 100 kWh block:	$3.2910	
Less AQIR, per 100 kWh block:	$0.1200	R
Monthly Wind Energy Service Adjustment, per 100 kWh block:	$0.0990	R
C&I Primary		I
Wind Energy Rate, per 100 kWh block: .	$3.4220	
Less ECA, per 100 kWh block: . . .	$3.2080	R
Less AQIR, per 100 kWh block: . .	$0.1000	
Monthly Wind Energy Service Adjustment, per 100 kWh block:	$0.1140	R I
C&I Transmission		
Wind Energy Rate, per 100 kWh block: .	$3.3430	R
Less ECA, per 100 kWh block: . . .	$3.1350	I
Less AQIR, per 100 kWh block: . .	$0.1000	
Monthly Wind Energy Service Adjustment, per 100 kWh block: . .	$0.1080	R

This Adjustment is in addition to the monthly energy charge on the customer's standard filed tariff rate.

ADVICE LETTER NUMBER ______

ISSUE DATE January 1, 2007

DECISION NUMBER ______

VICE PRESIDENT, Policy Development

EFFECTIVE DATE ______

ELECTRIC RATES

GENERAL RATE SCHEDULE ADJUSTMENT N

The charge for electric service calculated under Company's electric base rate schedules shall be increased by the Rider amount as shown below. Said increase shall not apply to charges determined by Non-Base Rate Adjustments.

RIDER

General Rate Schedule Adjustment (GRSA)	+12.70%	I
TOTAL:	+12.70%	I

ELECTRIC RATES
PURCHASED CAPACITY COST ADJUSTMENT

APPLICABILITY

All rate schedules for electric service are subject to a Purchased Capacity Cost Adjustment to reflect the cost of capacity purchased to supply electric service. The Purchased Capacity Cost Adjustment amount will be subject to T
annual changes to be effective on January 1 of each year. The Purchased T
Capacity Cost Adjustment for all applicable rate schedules is as set forth on T
Sheet No. 108D. The Purchased Capacity Cost Adjustment shall be different for each of the customer classes and for customers subscribing for Standby Service.

DEFINITIONS

Purchased Capacity Cost - For the purpose of this tariff, the Purchased Capacity Cost is defined as the fixed cost components of purchase power contracts recorded in Account 555-01 Purchased Power Demand and Account 555- T
05 Purchased Power Demand Qualifying Facilities. T

Purchased Capacity Cost Adjustment - The Purchased Capacity Cost Adjustment is the Retail Projected Purchased Capacity Cost Amount, plus the Deferred Purchased Capacity Cost Amount, on a dollar per kilowatt basis for tariff T
schedules with demand rates and on a dollar per kilowatt-hour basis for T
tariff schedules without demand rates. T

T

Retail Projected Purchased Capacity Cost - Retail Projected Purchased D
Capacity Cost is the retail portion of Purchased Capacity Cost forecasted for the calendar year less the Air Quality Improvement Rider Credit.

T

(Continued on Sheet No. 108A)

ELECTRIC RATES
PURCHASED CAPACITY COST ADJUSTMENT

DEFINITIONS - Cont'd

Deferred Purchased Capacity Cost - Deferred Purchased Capacity Cost is Actual Purchased Capacity Cost less Recovered Purchased Capacity Cost, and may be positive or negative.

Air Quality Improvement Rider Credit - The amount of incremental purchased capacity cost, net of avoided fixed cost associated with retired capacity generating units, recovered through the Air Quality Improvement Rider.

Actual Purchased Capacity Cost - Actual Purchased Capacity Cost is the Purchased Capacity Cost amount recorded in Account 555-01 and 555-05.

Recovered Purchased Capacity Cost - Recovered Purchased Capacity Cost is the Purchased Capacity cost recovered by the Company's currently effective Purchased Capacity Cost Adjustment Rates. T
D

RETAIL PROJECTED PURCHASED CAPACITY COST AMOUNT

1. The Retail Projected Purchased Capacity Cost Amount will be equal to the Retail Projected Purchased Capacity Cost projected for the calendar T
year of the Purchased Capacity Cost Adjustment. T

2. A revised Retail Projected Purchased Capacity Cost Amount will be calculated and filed on November 1 of each year to take effect on the T
next January 1. T

(Continued on Sheet No. 108B)

ELECTRIC RATES
PURCHASED CAPACITY COST ADJUSTMENT

DEFERRED PURCHASED CAPACITY COST

1. The Deferred Purchased Capacity Cost Amount will be equal to the Deferred Purchased Capacity Cost as of September 30 of the previous year. T T

2. The Deferred Purchased Capacity Cost will be calculated monthly by subtracting Recovered Purchased Capacity Cost from Actual Purchased Capacity Cost. The resulting amount, whether negative or positive, will be accumulated in Account 191.

3. Revised Deferred Purchased Capacity Cost rates will be calculated and filed on November 1 of each year to take effect on the next January 1. T T

ACTUAL PURCHASED CAPACITY COST

The Actual Purchased Capacity Cost will be the Purchased Capacity Cost amount recorded in Account 555-01 and 555-05 for the month.

RECOVERED PURCHASED CAPACITY COST

The Recovered Purchased Capacity Cost will be calculated monthly by applying the Purchased Capacity Cost Adjustment to the actual rate components for the month. T

(Continued on Sheet 108C)

ELECTRIC RATES
PURCHASED CAPACITY COST ADJUSTMENT

PURCHASED CAPACITY COST ADJUSTMENT

The following formula is used to determine the Purchased Capacity Cost Adjustment for class i: T

Purchased Capacity Cost Adjustment = $(A_i \pm C_i)/X_i$ C

A_i = Class's share of Retail Projected Purchased Capacity Cost C C
C_i = Class's share of Deferred Purchased Capacity Cost C C
X_i = Class i Billing Determinant C

INFORMATION TO BE FILED WITH THE PUBLIC UTILITIES COMMISSION

Each proposed revision in the Purchased Capacity Cost Adjustment will be accomplished by filing an advice letter on November 1 of each year to take T effect on the next January 1 and will be accompanied by such supporting data and information as the Commission may require from time to time. The advice T letter notice to customers of the revised rates will be accompanied by N placing a legal notice in the local classified section of a newspaper having N general circulation in the Company's service territory such notice will be N published within three (3) days after the annual filing. N

(Continued on Sheet 108D)

ELECTRIC RATES
PURCHASED CAPACITY COST ADJUSTMENT

RATE TABLE

Rate Schedule	Applicable Charge	Monthly Rider Rate	
Residential Service			
R	Energy Charge	$0.01471/kWh	I
RD	Demand Charge	3.86/kW-Mo	I
Small Commercial Service			
C	Energy Charge	0.01541/kWh	I
Commercial & Industrial General Service			
SGL	Energy Charge	0.05810/kWh	I
SG	Demand Charge	4.65/kW-Mo	I
PG	Demand Charge	4.58/kW-Mo	I
TG	Demand Charge	4.47/kW-Mo	I
Special Contract Service			
SCS-7	Production Demand Charge	4.58/kW-Mo	I
Standby Service			
SST	Gen Standby Capacity Reservation Fee	0.60/kW-Mo	I
	Usage Demand Charge	4.05/kW-Mo	I
PST	Gen Standby Capacity Reservation Fee	0.59/kW-Mo	I
	Usage Demand Charge	3.99/kW-Mo	I
TST	Gen Standby Capacity Reservation Fee	0.58/kW-Mo	I
	Usage Demand Charge	3.89/kW-Mo	I
Lighting Service			
RAL, CAL, PLL, SL, SSL SHL, SLU	Energy Charge	0.01481/kWh	I
TSL	Energy Charge	0.00761/kWh	I

ELECTRIC RATES

ELECTRIC COMMODITY ADJUSTMENT C

APPLICABILITY

All rate schedules for electric service are subject to an Electric Commodity Adjustment (ECA) to reflect the cost of energy utilized to supply electric service. The Electric Commodity Adjustment Factors for all applicable rate schedules are as set forth on Sheet No. 111F and will be applied to all kilowatt-hours sold by the Company with the exception of the kilowatt-hours subject to the Wind Energy Service and any buy-through kilowatt-hours (BT kWh) sold to participants in the Interruptible Service Option Credit (ISOC) program who buy through an Economic Interruption. The ECA Factors for lighting service bills and other non-metered service will be determined by applying the ECA Factor to the calculated monthly kilowatt-hour consumption.

OPTIONAL TIME-OF-USE ECA FACTORS APPLICABILITY

Applicable as an optional rate to customers who receive electric service under the Company's general service rate Schedules SG, PG, TG and Special Contract Service customers. To qualify for this option a Schedule SG customer must have demand in excess of 300 kW for twelve (12) consecutive months.

The On-peak hours shall be9:00 AM to 9:00 PM for all non-holiday weekdays. Holidays are defined as New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The Off-peak period shall be all other hours. The On-peak and Off-peak price differentials are based on the ratio of system marginal costs for a calendar year. The On-peak and Off-peak price ratio will be projected annually and will be filed with the Commission on the first business day of November, and shall remain in effect for the subsequent calendar year. The Optional TOU ECA rates will be updated with the Quarterly ECA rates and will be determined by applying the fixed annual On-peak and Off-peak ratio to the quarterly ECA cost of service.

OPTIONAL TIME-OF-USE NOTICE AND METERING REQUIREMENTS

Customers choosing the Optional Time-of-Use ECA must make written notification to the Company of this choice. Customers receiving service under the Optional Time-of-Use ECA must have their usage metered by an Interval Data Recorder ("IDR") meter. If a customer requesting the Optional Time-of-Use ECA is currently metered with an IDR meter then the Company shall place the customer on the Optional Time-of-Use ECA rate within thirty (30) days of receiving the customer's written request. If a requesting customer is not currently metered with an IDR meter then the Company will install an IDR meter as soon as reasonably practicable and the customer will be eligible for the Optional Time-of-Use rate beginning with the first billing cycle immediately subsequent to the installation of the IDR meter.

(Continued on Sheet No. 111A)

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT C

ELECTRIC COMMODITY ADJUSTMENT QUARTERLY FILING

The Company shall file each quarter, on not less than fifteen (15) days notice, an advice letter with the ECA Factors on Sheet No. 111F to be effective on the first day of the month of the next calendar quarter. Notice to customers of the new rates shall be accomplished by placing a legal notice in the legal classified section of a newspaper having general circulation in the Company's service territory and such notice shall be published within three business days of the filing of the revised ECA factors.

The notice shall inform customers of the ECA Factor changes as well as the impact of the change in average customer bills for residential, small commercial and industrial customers. The Company shall also place the ECA Factors and customer bill impacts on the Company's website. Finally, the Company shall issue a press release to media outlets regarding the filing, including the ECA Factors and the impacts on customers' bills.

ELECTRIC COMMODITY ADJUSTMENT

The ECA shall be calculated quarterly with the new ECA Factors to be effective on a prorated basis on the first day of the quarter. The ECA Factors shall be determined by dividing the Quarterly ECA Revenue Requirement by the projected kilowatt-hour sales to which the ECA is applicable for the next calendar quarter. The ECA Factors shall be differentiated by service delivery voltage to reflect line losses.

LOSS FACTOR

Loss Factors are as follows:

Transmission	1.0000
Primary	1.0235
Secondary	1.0500

Primary and Secondary voltage losses may be updated by the Company from time to time.

QUARTERLY ECA REVENUE REQUIREMENT

The Quarterly ECA Revenue Requirement ("ECARR") shall be calculated using the following equation:

$$ECARR= (PSC * PJA) + DAB + 1/4\ WB$$

Where:

1) PSC is the Projected System Fuel (F), Purchased Energy (P), and Purchased Wheeling (W) for the next quarter, with F, P, and W as defined below.
2) PJA is the projected retail jurisdictional allocation factor for the quarter.
3) DAB is the Deferred Account Balance.
4) WB is the Wind Benefit, as defined below.

(Continued on Sheet No. 111B)

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT C

ELECTRIC COMMODITY ADJUSTMENT - Cont'd

The Deferred Account Balance is the difference between the Actual Energy Costs incurred and the ECA revenues collected. Each quarterly filing shall include the Deferred Account Balance from the last day of the month prior to the ECA filing. For example, the February 28 Deferred Account Balance will be included in the ECA filing made in March for the second calendar quarter.

Actual Energy Costs shall be the total of:

(F+P+W) * Actual Retail Jurisdictional Allocation factor + PVM + 1/4 WB

Where:

1) F equals the Cost of Fossil Fuel for Generation as recorded in Accounts 501 and 547 (excluding all Handling and Unit Train expenses and excluding fuel allocated to BT kWh).

2) P equals the energy-related component of the costs of all Purchased and Interchange Power as recorded in Account 555 (excluding purchased energy expense allocated to BT kWh).

3) W equals the energy-related component of the costs of Wheeling associated with Purchased Power, as recorded in Account 565 (excluding wheeling energy expense allocated to BT kWh).

4) PVM is the actual Price Volatility Mitigation Costs of the following accounts for the applicable month: 1) Subsidiary Account for Financial Hedges and - FERC Account Numbers 501.17 (steam plants), 547.17 (combustion turbines) and 555.27 (tolling plants/purchased power); and 2) Subsidiary Account for Physical Hedges - FERC Account Numbers 501.15 (steam plants), 547.15 (combustion turbines) and 555.25 (tolling plants/purchased power). Actual PVM shall include only those premiums or settlement costs actually incurred by the Company in connection with its use of the following financial instruments: Fixed-for-float swaps, call options, costless collars, and New York Mercantile Exchange futures contracts in conjunction with market basis (between Colorado Interstate Gas Company, Northwest Pipeline Company, Henry Hub, or other monthly indices in the areas where the Company regularly procures its natural gas supplies).

(Continued on Sheet No. 111C)

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ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT C

ELECTRIC COMMODITY ADJUSTMENT - Cont'd

5) WB is the Wind Benefit. The Wind Benefit is the retail projected avoided capacity cost and projected avoided energy cost associated with the optional Wind Energy Resources on Tariff Sheet 91, less the projected foregone ECA revenue associated with Wind Energy Resource kilowatt hours. The Wind Benefit will be filed annually on the first working day of November for the upcoming year.

The ECA revenue collected for the quarter will be adjusted for billing cycle lag and will include energy-related revenues collected through the Air Quality Improvement Rider.

Interest shall accrue monthly on the average monthly deferred balance (whether the balance is positive or negative). The monthly interest rate shall be the average of the rate for Dealer Commercial Paper (90-day rate) as published daily in the Wall Street Journal under "Money Rates".

RECALCULATION OF WIND BENEFIT

By April 1 of each year, the actual Wind Benefit from the prior year shall be recalculated by substituting actual natural gas costs for the former projected natural gas costs in the analyses conducted to determine the avoided energy cost per kilowatt hour associated with the optional Wind Energy Resources on Tariff Sheet 91. The actual avoided energy cost per kilowatt hour shall be multiplied by the actual wind production from the prior calendar year. If the change from the projected Wind Benefit to the actual Wind Benefit, divided by the Wind Energy Resources kilowatt-hours, is greater than one cent, then the ECA Deferred Balance shall be adjusted, for effect July 1, by the change from the projected Wind Benefit to the actual Wind Benefit.

ADJUSTMENT FOR SHORT-TERM SALES MARGIN

Positive short-term sales margins from the calendar year shall be shared with retail customers through an adjustment to the ECA. Margin sharing shall be calculated separately for each of the Generation Book margins and Proprietary Book margins. Proprietary Book margins shall be calculated from the Company's share of margins under the Joint Operating Agreement. Within each of these books, the retail jurisdictional Gross Margin shall be aggregated annually. If the aggregated Gross Margin from either book is negative, the negative margin shall not be passed on to retail customers.

If the annual retail jurisdictional aggregated Gross Margin in either book is positive, then such positive annual retail jurisdictional Gross Margin in that book in excess of $1,023,070 shall be shared annually with retail customers through the ECA as follows:

(Continued on Sheet No. 111D)

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT C

ADJUSTMENT FOR SHORT-TERM SALES MARGIN - Cont'd

1) Generation Book: Gross Margin in excess of $1,023,070 shall be shared 80 percent retail customers/ 20 percent Company.

2) Proprietary Book: Gross Margin in excess of $1,023,070 shall be shared 20 percent retail customers/ 80 percent Company.

The Company shall include in its quarterly filing for effect April 1 of each year a report setting forth the retail customer share of positive short-term sales margins from the prior calendar year. The total positive short-term sales margins will be divided by three (3), and the quotient shall be subtracted from each quarterly ECARR for the remainder of the calendar year. The quarterly filing for effect April 1, 2007 shall also include the ECA deferred balance as of December 31, 2006, which shall be netted against the 2006 positive short-term sales margins.

INCENTIVE MECHANISM

The Incentive mechanism includes two components: the Base Load Energy Benefit ("BLEB") incentive and the Economic Purchase Benefit ("EPB") incentive. The two incentive mechanisms will be determined on a calendar year basis. Included in the Company's quarterly filing for effect April 1, beginning April 2008, will be the total amount of the Incentives earned in the prior calendar year. The total incentive amounts shall be divided by three (3) and the quotient shall be added to quarterly ECARR for the remainder of the calendar year. The maximum level of the two annual incentives, together, shall not exceed $11.25 million.

The BLEB reflects increased output from the Company's coal units and shall be calculated as follows:

BLEB Incentive = (Actual BLEB-BLEB Benchmark)*RJS * (GPI*GHR-CP)*0.20

Where:

1) Actual BLEB is the actual coal production from the Company's coal units for the calendar year.
2) BLEB benchmark equals the greater of 18,300,000 MWh, or the average annual coal production from Company-owned coal-fired power plants for the most recent three calendar years.
3) RJS is the actual retail jurisdictional share of the Company's actual production costs for the year.
4) GPI is the annual average of the actual Gas Price Index as identified in Inside FERC as the First of the Month Rocky Mountain Index.

(Continued on Sheet No. 111E)

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT C

INCENTIVE MECHANISM - Cont'd

5) GHR is the actual heat rate from the prior calendar year of all the Company's natural gas-fired generation, either Company-owned generation or generation acquired through long term power purchase agreements. The GHR shall be changed to equal the average annual heat rate of the Company's natural gas-fired generation, including both Company-owned generation and generation provided under long term power purchase agreements.

6) CP is the average coal price per MWh the Company actually incurred for the calendar year.

If the BLEB Incentive is negative, no incentive shall be earned by the Company or paid by the Company.

The EPB is the value created through short-term economic purchases. The EPB shall be calculated as follows:

EPB Incentive = ((ESC - ASC)-6.7 million)*RJS* 0.20

Where:

1) ESC is the Estimated System Costs to serve the Company's total native load (wholesale and retail) absent short-term purchases.

2) ASC is the Actual System Costs to serve the Company's total native load (wholesale and retail) with short-term energy purchase.

3) RJS is the actual Retail Jurisdictional Share of the Company's actual production costs for the year.

If the EPB Incentive is negative, no incentive shall be earned by the Company or paid by the Company.

(Continued on Sheet No. 111F)

PUBLIC SERVICE COMPANY OF COLORADO

COLO. PUC No. 7 Electric

PGE/3113/102

Sheet No. 111F

P.O. Box 840
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Cancels
Sheet No.

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT FACTORS | C

<u>ECA FACTORS FOR THE FIRST QUARTER OF 2007</u>

ILLUSTRATIVE

ECA Factors for Billing Purposes

Residential, applicable to all kilowatt-hours used under any Rate Schedule for Residential Service	$0.03291/kWh	I
Small Commercial, applicable to all kilowatt-hours used under any Rate Schedules for Small Commercial Service	$0.03291/kWh	I
Commercial and Industrial Secondary, applicable to all kilowatt-hours used under any Rate Schedule for Commercial and Industrial Secondary Service Rate Schedules for Commercial and Industrial Service	$0.03291/kWh	I
Optional Time-of-Use Off-Peak	$0.02770/kwh	I
On-Peak to Off-Peak Ratio	1.43	I
Optional Time-of-Use On-Peak	$0.03960/kwh	I
Primary General, applicable to all kilowatt-hours used under any Rate Schedule for Commercial and Industrial Primary or Special Contract Service	$0.03208/kWh	I
Optional Time-of-Use Off-Peak	$0.02740/kwh	I
On-Peak to Off-Peak Ratio	1.43	I
Optional Time-of-Use On-Peak	$0.03920/kwh	I
Transmission General, applicable to all kilowatt-hours used under any Rate Schedule for Commercial and Industrial Transmission Service	$0.03135/kWh	I
Optional Time-of-Use Off-Peak	$0.02710/kwh	I
On-Peak to Off-Peak Ratio	1.43	I
Optional Time-of-Use On-Peak	$0.03880/kwh	I
Lighting, applicable to all kilowatt-hours used under any Rate Schedule for Commercial Lighting or Public Street Lighting Service	$0.03291/kWh	I

ADVICE LETTER NUMBER

ISSUE DATE January 1, 2007

DECISION NUMBER

VICE PRESIDENT,
Policy Development

EFFECTIVE DATE

ATTACHMENT C

GAS RATES	RATE
GAS SERVICE	
SCHEDULE OF CHARGES FOR RENDERING SERVICE	
To institute or reinstitute gas service requiring a premise visit	$ 42.00
To institute or reinstitute both gas and electric service at the same time requiring a premise visit	67.00
To transfer service at a specific location from one customer to another customer where such service is continuous, either gas service or both gas and electric service at the same time not requiring a premise visit	8.00
To provide a non-regularly scheduled final meter Reading at customers request	15.00
To perform non-gratuitous labor for service work in addition to charges for material is as follows:	
Trip Charge	29.00
(Assessed when no actual service work, other than a general diagnosis of the customer's problem is performed.)	
For service work during normal working hours, per man-hour	53.00
Minimum Charge, one hour	53.00
An overtime rate will be applicable to non-gratuitous labor for service work performed before and after normal working hours of 8:00 AM to 5:00 PM Monday through Saturday.	
The overtime rate shall be, per man hour	67.00
Minimum Charge, one hour	67.00
When such service work is performed on Sundays and holidays, per man hour	81.00
Minimum Charge, one hour	81.00

D

PUBLIC SERVICE COMPANY OF COLORADO

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GAS RATES	RATE	
GAS SERVICE		
SCHEDULE OF CHARGES FOR RENDERING SERVICE		
To process a check from a customer that is returned to the Company by the bank as not payable	$ 15.00	S I
To achieve payment from a customer who opts to pay his/her monthly natural gas bill with a credit or debit card, a per transaction convenience fee of $4.85 shall be charged for any credit or debit card payment up to $500, and an additional $4.85 shall be assessed for each $500 increment above the initial $500 payment.		
For a customer with a combined gas and electric bill, the per transaction convenience fee shall be based on the total combined charges for gas and electric service and will be assessed only once if a customer pays his/her combined gas and electric monthly bill as a single credit/debit card transaction.		
	January 1, 2007	

NATURAL GAS RATES | RATE

RESIDENTIAL GAS SERVICE

SCHEDULE RG

APPLICABILITY

Applicable within the entire territory served by Public Service Company of Colorado as described on Sheet Nos. 4-9 to Residential service. Not applicable to resale service.

MONTHLY RATE

Service and Facility Charge, per customer	$10.00
Usage Charge, all gas used per Therm	$ 0.07923
MONTHLY MINIMUM..	$10.00

GAS RATE ADJUSTMENT

This rate schedule is subject to the Gas Rate Adjustments commencing on Sheet No. 40.

GAS COST ADJUSTMENT

This rate schedule is subject to the Gas Cost Adjustment commencing on Sheet No. 50.

PAYMENT AND LATE PAYMENT CHARGE

Bills for gas service are due and payable within fifteen (15) days from date of bill. Residential customers have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of fourteen (14) business days from the scheduled due date. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive months. Any monthly total bill amounts of over $50 for a gas bill or over $50 for an electric and gas bill combined not paid by the bill date for the following month's bill shall be subject to a payment charge of one percent (1.0%) per month. The Company will remove the assessment of a late payment charge for one billing period, but not more frequently than once in any twelve-month period, at customer's request. The late payment charge will not apply in instances where a Company billing error is involved, or where complications arise with financial institutions in processing payments that are no fault of the customer, or where a customer is current on an active payment arrangement.

T N N N N N N N N N N N

NATURAL GAS RATES

RATE

RESIDENTIAL GAS SERVICE

SCHEDULE RG

CONTRACT PERIOD S

All contracts under this schedule shall be for a minimum period of twelve (12) consecutive months and thereafter until terminated, where service is no longer required, on three days' notice.

RULES AND REGULATIONS S

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with The Public Utilities Commission of the State of Colorado.

NATURAL GAS RATES | RATE

RESIDENTIAL GAS OUTDOOR LIGHTING SERVICE

SCHEDULE RGL

APPLICABILITY

Applicable within the entire territory served by Public Service Company of Colorado as described on Sheet Nos. 4-9, only to Residential service, customer-owned gas luminaires of the mantle type where the natural gas for such luminaires does not pass through the meter measuring customer's other gas consumption and the luminaire was installed prior to April 1, 1976. Not applicable to resale service.

MONTHLY RATE

Charge for one or two mantle fixture, per fixture.......	$ 7.16
Charge for each additional mantle over two mantles, per mantle per fixture................................	3.58

MONTHLY MINIMUM

Minimum charge shall be the billing under this schedule.

GAS RATE ADJUSTMENT

This rate schedule is subject to the Gas Rate Adjustments commencing on Sheet No. 40.

GAS COST ADJUSTMENT

This rate schedule is subject to the Gas Cost Adjustment commencing on Sheet No. 50.

PAYMENT AND LATE PAYMENT CHARGE T

Bills for gas service are due and payable within fifteen (15) days from date of bill. Residential customers have the option of selecting a modified due date ("Custom Due Date") for paying their bill. The due date can be extended up to a maximum of fourteen (14) business days from the scheduled due date. Customers selecting a Custom Due Date will remain on the selected due date for a period not less than twelve (12) consecutive months. Any monthly total bill amounts of over $50 N
for a gas bill or over $50 for an electric and gas bill N
combined not paid by the bill date for the following month's N
bill shall be subject to a payment charge of one percent N
(1.0%) per month. The Company will remove the assessment of a N
late payment charge for one billing period, but not more N
frequently than once in any twelve-month period, at customer's N
request.

(Continued on Sheet No. 15A)

NATURAL GAS RATES

RATE

RESIDENTIAL GAS OUTDOOR LIGHTING SERVICE

SCHEDULE RGL

PAYMENT AND LATE PAYMENT CHARGE - Cont'd

The late payment charge will not apply in instances where a Company billing error is involved, or where complications arise with financial institutions in processing payments that are no fault of the customer's, or where a customer is current on an active payment arrangement. N N N N N

CONTRACT PERIOD

New contracts are not available hereunder. Where existing service is no longer required customer may terminate service on three days' notice. S

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with The Public Utilities Commission of the State of Colorado and the following special conditions:

1. The gas light fixture and customer's piping shall be owned and serviced by the customer. Should Company be requested to perform service on the gas light fixture or customer's piping such service shall be made in accordance with Company's standard gas service policy and charges shall be made in accordance therewith.
2. Service hereunder is available only to mantle type gas luminaires at locations receiving service under this rate schedule as of March 31, 1976.
3. Service hereunder is subject to further specific rules and regulations for gas lights as set forth in the Rules and Regulations section of this tariff.

Acct No.	Description	PSCo Exhibit LHP-2.1 (Col 1) Plant Balance	Existing Rate	PSCo Exhibit LHP-2.1 (Col 4) Present Recovery	Staff Rate	Staff Annual Amount	Increase or (Decrease)	PSCo Exhibit LHP-2.1 (Col 9) Proposed Amount	Increase or (Decrease) to PSCo Proposed
STEAM PRODUCTION									
311.0	Structures & Improvements								
	Arapahoe Unit 3	960,704	5.880	56,489	2.275	21,856	(34,633)	21,856	-
	Arapahoe Unit 4	1,759,985	1.360	23,936	2.617	46,059	22,123	46,059	-
	Arapahoe Common	9,599,386	6.260	600,922	3.585	344,138	(256,784)	344,138	-
	Cameo Unit 1	926,413	1.550	14,359	1.928	17,861	3,502	17,861	-
	Cameo Unit 2	629,663	2.440	15,364	1.964	12,367	(2,997)	12,367	-
	Cameo Common	2,266,989	1.880	42,619	3.558	80,659	38,040	80,659	-
	Cherokee Unit 1	2,894,555	2.570	74,390	2.563	74,187	(203)	74,187	-
	Cherokee Unit 2	1,544,525	3.250	50,197	2.282	35,246	(14,951)	35,246	-
	Cherokee Unit 3	1,120,260	2.690	30,135	1.913	21,431	(8,704)	21,431	-
	Cherokee Unit 4	10,300,331	3.230	332,701	2.057	211,878	(120,823)	370,915	(159,037)
	Cherokee Common	28,596,345	2.840	812,136	2.553	730,065	(82,072)	981,427	(251,362)
	Comanche Unit 1	16,365,595	1.670	273,305	1.833	299,981	26,676	461,837	(161,856)
	Comanche Unit 2	8,123,775	1.410	114,545	1.536	124,781	10,236	185,303	(60,522)
	Comanche Common	22,798,272	1.540	351,093	1.678	382,555	31,462	567,905	(185,350)
	Craig Unit 1	6,218,127	1.400	87,054	1.548	96,257	9,203	133,130	(36,873)
	Craig Unit 2	6,113,587	1.370	83,756	1.525	93,232	9,476	130,525	(37,293)
	Craig Common	5,816,376	1.460	84,919	1.576	91,666	6,747	126,855	(35,189)
	Hayden Unit 1	6,639,152	0.320	21,245	1.872	124,285	103,040	124,285	-
	Hayden Unit 2	10,266,585	1.280	131,412	1.526	156,668	25,256	229,048	(72,380)
	Hayden Common	2,258,207	2.300	51,939	1.506	34,009	(17,930)	82,741	(48,732)
	Pawnee Unit 1	140,323,866	1.390	1,950,502	1.574	2,208,698	258,196	3,021,173	(812,475)
	Pawnee Common	3,866,119	2.460	95,107	2.859	110,532	15,426	151,359	(40,827)
	Valmont Unit 5	5,648,243	2.080	117,483	2.559	144,539	27,055	144,539	-
	Valmont Common	12,159,458	2.380	289,395	2.864	348,247	58,852	348,247	-
	Zuni Unit 1	19,908	3.170	631	2.842	566	(65)	566	-
	Zuni Common	5,720,179	2.810	160,737	2.740	156,733	(4,004)	156,733	-
	Total Account 311.0	**312,936,605**	**1.875**	**5,866,373**	**1.907**	**5,968,495**	**102,122**	**7,870,390**	**(1,901,895)**
312.0	Boiler Plant Equipment								
	Arapahoe Unit 3	8,501,043	(0.050)	(4,251)	3.010	255,881	260,132	255,881	-
	Arapahoe Unit 3 - AQIR	2,016,832	6.654	134,192	6.667	134,456	264	134,456	-
	Arapahoe Unit 4	26,948,442	2.170	584,781	3.405	917,594	332,813	917,594	-
	Arapahoe Common	20,216,706	0.470	95,019	5.677	1,147,702	1,052,684	1,147,702	-
	Cameo Unit 1	7,186,570	3.580	257,279	3.613	259,651	2,372	259,651	-
	Cameo Unit 2	13,593,054	2.550	346,623	3.289	447,076	100,453	447,076	-
	Cameo Common	2,828,949	2.810	79,493	2.868	81,134	1,641	81,134	-
	Cherokee Unit 1	35,675,965	3.940	1,405,633	3.599	1,283,978	(121,655)	1,283,978	-
	Cherokee Unit 2 - AQIR	27,856,961	2.530	704,781	3.030	844,066	139,285	844,066	-
	Cherokee Unit 2	967,558	4.812	46,555	6.667	64,504	17,949	64,504	-
	Cherokee Unit 3	31,988,738	1.860	594,991	2.653	848,661	253,671	848,661	-
	Cherokee Unit 3 - AQIR	20,338,549	3.710	754,473	6.667	1,355,904	601,431	1,355,904	-
	Cherokee Unit 4	56,261,298	2.750	1,547,186	1.914	1,076,841	(470,344)	1,836,931	(760,090)
	Cherokee Unit 4 - AQIR	20,948,318	3.334	698,446	6.667	1,396,555	698,109	1,396,555	-
	Cherokee Common	29,352,239	2.260	663,361	3.056	897,004	233,644	1,187,592	(290,588)
	Cherokee Common - AQIR	37,327,681	2.788	1,040,534	6.667	2,488,513	1,447,979	2,488,513	-
	Comanche Unit 1	103,114,326	2.670	2,753,153	2.173	2,240,674	(512,478)	3,363,589	(1,122,915)
	Comanche Unit 2	86,520,916	2.020	1,747,723	2.012	1,740,801	(6,922)	2,521,219	(780,418)

Acct No.	Description	PSCo Exhibit LHP-2.1 (Col 1) Plant Balance	Existing Rate	PSCo Exhibit LHP-2.1 (Col 4) Present Recovery	Staff Rate	Staff Annual Amount	Increase or (Decrease)	PSCo Exhibit LHP-2.1 (Col 9) Proposed Amount	Increase or (Decrease) to PSCo Proposed
	Comanche Common	16,663,077	1.490	248,280	1.821	303,435	55,155	439,572	(136,137)
	Craig Unit 1	17,036,523	1.410	240,215	1.663	283,317	43,102	380,937	(97,620)
	Craig Unit 2	12,956,932	1.420	183,988	1.653	214,178	30,190	291,401	(77,223)
	Craig Common	21,852,249	1.570	343,080	2.411	526,858	183,777	709,980	(183,122)
	Hayden Unit 1	59,408,329	3.400	2,019,883	3.297	1,958,693	(61,191)	1,958,693	-
	Hayden Unit 2	52,007,070	1.940	1,008,937	1.967	1,022,979	14,042	1,461,919	(438,940)
	Hayden Common	24,870,012	2.930	728,691	2.849	708,547	(20,145)	1,011,961	(303,414)
	Pawnee Unit 1	238,955,079	1.920	4,587,938	1.780	4,253,400	(334,537)	5,663,235	(1,409,835)
	Pawnee Common	9,420,042	2.490	234,559	3.054	287,688	53,129	383,678	(95,990)
	Valmont Unit 5	41,484,481	1.990	825,541	2.789	1,157,002	331,461	1,157,002	-
	Valmont Unit 5 - AQIR	34,986,076	3.393	1,186,956	6.667	2,332,406	1,145,450	2,332,406	-
	Valmont Common	3,457,970	2.680	92,674	3.912	135,276	42,602	135,276	-
	Zuni Unit 1	3,734,655	8.030	299,893	2.975	111,106	(188,787)	111,106	-
	Zuni Unit 2	6,172,173	(0.080)	(4,938)	2.708	167,142	172,080	167,142	-
	Zuni Common	5,093,901	2.540	129,385	3.425	174,466	45,081	174,466	-
	Coal Cars - Old	15,898,384	0.700	111,289		-	(111,289)	-	-
	Coal Cars - New	11,041,220		-	3.167	349,639	349,639	349,639	-
	Total Account 312.0	**1,106,682,318**	**2.321**	**25,686,342**	**2.843**	**31,467,129**	**5,780,787**	**37,163,420**	**(5,696,291)**
314.0	Turbogenerator Units								
	Arapahoe Unit 3	3,488,574	2.660	92,796	2.583	90,110	(2,686)	90,110	-
	Arapahoe Unit 4	10,095,834	3.760	379,603	2.964	299,241	(80,363)	299,241	-
	Arapahoe Common	426,062	3.430	14,614	4.362	18,585	3,971	18,585	-
	Cameo Unit 1	2,069,875	0.940	19,457	2.172	44,958	25,501	44,958	-
	Cameo Unit 2	3,286,645	0.820	26,950	2.181	71,682	44,731	71,682	-
	Cameo Common	2,656,807	(0.160)	(4,251)	4.485	119,158	123,409	119,158	-
	Cherokee Unit 1	7,845,509	0.520	40,797	2.401	188,371	147,574	188,371	-
	Cherokee Unit 2	8,337,466	1.960	163,414	2.308	192,429	29,014	192,429	-
	Cherokee Unit 3	10,777,134	2.080	224,164	2.403	258,975	34,810	258,975	-
	Cherokee Unit 4	23,579,760	2.620	617,790	1.943	458,155	(159,635)	785,442	(327,287)
	Cherokee Common	424,565	7.430	31,545	5.074	21,542	(10,003)	28,616	(7,074)
	Comanche Unit 1	24,764,474	1.400	346,703	1.902	471,020	124,318	710,493	(239,473)
	Comanche Unit 2	28,629,108	1.800	515,324	1.827	523,054	7,730	761,248	(238,194)
	Comanche Common	2,173,080	3.270	71,060	2.566	55,761	(15,298)	81,143	(25,382)
	Craig Unit 1	57,988	2.130	1,235	2.816	1,633	398	2,213	(580)
	Craig Unit 2	3,802,620	1.400	53,237	1.000	38,026	(15,210)	84,000	(45,974)
	Craig Common	1,803,695	1.470	26,514	1.615	29,130	2,615	40,475	(11,345)
	Hayden Unit 1	12,834,931	0.710	91,128	2.304	295,717	204,589	295,717	-
	Hayden Unit 2	11,061,794	1.320	146,016	1.685	186,391	40,376	267,695	(81,304)
	Hayden Common	427,000	2.840	12,127	3.036	12,964	837	18,600	(5,636)
	Pawnee Unit 1	45,809,825	1.410	645,919	1.703	780,141	134,223	1,044,006	(263,865)
	Pawnee Common	11,883,307	2.460	292,329	2.417	287,220	(5,110)	384,900	(97,680)
	Valmont Unit 5	16,226,380	3.630	589,018	3.722	603,946	14,928	603,946	-
	Valmont Common	673,412	5.330	35,893	4.455	30,001	(5,892)	30,001	-
	Zuni Unit 1	6,941,014	4.730	328,310	2.988	207,397	(120,912)	207,397	-
	Zuni Unit 2	803,320	(0.180)	(1,446)	16.646	133,721	135,167	133,721	-
	Zuni Common	733,568	(0.180)	(1,320)	2.092	15,346	16,667	15,346	-
	Total Account 314.0	**241,613,747**	**1.970**	**4,758,925**	**2.249**	**5,434,671**	**675,746**	**6,778,464**	**(1,343,793)**

Acct No.	Description	PSCo Exhibit LHP-2.1 (Col 1) Plant Balance	Existing Rate	PSCo Exhibit LHP-2.1 (Col 4) Present Recovery	Staff Rate	Staff Annual Amount	Increase or (Decrease)	PSCo Exhibit LHP-2.1 (Col 9) Proposed Amount	Increase or (Decrease) to PSCo Proposed
315.0	Accessory Electric Equipment								
	Arapahoe Unit 3	2,202,212	(0.430)	(9,470)	4.659	102,601	112,071	102,601	-
	Arapahoe Unit 4	2,474,112	1.720	42,555	2.687	66,479	23,925	66,479	-
	Arapahoe Common	3,851,043	3.400	130,935	3.341	128,663	(2,272)	128,663	-
	Cameo Unit 1	918,598	0.160	1,470	2.045	18,785	17,316	18,785	-
	Cameo Unit 2	1,177,044	1.530	18,009	2.365	27,837	9,828	27,837	-
	Cameo Common	704,080	3.220	22,671	3.237	22,791	120	22,791	-
	Cherokee Unit 1	4,172,837	3.110	129,775	2.964	123,683	(6,092)	123,683	-
	Cherokee Unit 2	3,688,714	1.120	41,314	3.322	122,539	81,225	122,539	-
	Cherokee Unit 3	4,060,724	2.420	98,270	2.472	100,381	2,112	100,381	-
	Cherokee Unit 4	7,875,324	2.190	172,470	1.780	140,181	(32,289)	242,954	(102,773)
	Cherokee Common	5,160,668	1.970	101,665	2.159	111,419	9,754	148,834	(37,415)
	Comanche Unit 1	15,962,464	1.890	301,691	1.707	272,479	(29,211)	415,184	(142,705)
	Comanche Unit 2	17,107,590	1.890	323,333	1.808	309,305	(14,028)	454,378	(145,073)
	Comanche Common	1,815,159	2.090	37,937	1.847	33,526	(4,411)	49,245	(15,719)
	Craig Unit 1	3,253,984	1.420	46,207	2.615	85,092	38,885	71,750	13,342
	Craig Unit 2	3,168,502	1.390	44,042	2.584	81,874	37,832	69,327	12,547
	Craig Common	1,592,305	1.430	22,770	1.628	25,923	3,153	35,397	(9,474)
	Hayden Unit 1	4,506,849	1.870	84,278	2.166	97,618	13,340	97,618	-
	Hayden Unit 2	5,732,042	1.320	75,663	1.562	89,534	13,872	129,831	(40,297)
	Hayden Common	148,287	2.850	4,226	2.770	4,108	(119)	5,937	(1,829)
	Pawnee Unit 1	60,135,913	1.440	865,957	1.650	992,243	126,285	1,340,429	(348,186)
	Pawnee Common	698,073	2.570	17,940	2.288	15,972	(1,969)	21,570	(5,598)
	Valmont Unit 5	4,410,836	1.890	83,365	2.577	113,667	30,302	113,667	-
	Valmont Common	1,311,975	2.490	32,668	2.763	36,250	3,582	36,250	-
	Zuni Unit 1	1,378,046	9.300	128,158	2.760	38,034	(90,124)	38,034	-
	Zuni Unit 2	35,903	(0.180)	(65)	2.961	1,063	1,128	1,063	-
	Zuni Common	763,230	(0.180)	(1,374)	2.559	19,531	20,905	19,531	-
	Total Account 315.0	**158,306,514**	**1.779**	**2,816,461**	**2.010**	**3,181,579**	**365,118**	**4,004,760**	**(823,181)**
315.2	Computers & Peripherals (Boiler Controls)								
	Arapahoe Unit 4	646,473	3.080	19,911	7.049	45,570	25,659	45,570	-
	Arapahoe Common	26,518	3.080	817	5.534	1,468	651	1,468	-
	Cherokee Unit 1	756,840	3.080	23,311	3.903	29,539	6,229	29,539	-
	Cherokee Unit 2	452,893	3.080	13,949	3.667	16,608	2,658	16,608	-
	Cherokee Unit 3	1,234,347	3.080	38,018	4.213	52,003	13,985	52,003	-
	Cherokee Unit 4	1,441,413	3.080	44,396	4.716	67,977	23,582	67,977	-
	Cherokee Common	640,679	3.080	19,733	3.471	22,238	2,505	22,238	-
	Comanche Unit 1	1,407,970	3.080	43,365	4.020	56,600	13,235	56,600	-
	Comanche Common	198,745	3.080	6,121	3.776	7,505	1,383	7,505	-
	Craig Common	282,900	3.080	8,713	3.020	8,544	(170)	8,544	-
	Hayden Unit 1	80,217	3.080	2,471	4.088	3,279	809	3,279	-
	Hayden Unit 2	87,658	3.080	2,700	3.834	3,361	661	3,361	-
	Pawnee Unit 1	3,125,307	3.080	96,259	3.087	96,478	219	96,478	-
	Pawnee Common	540,973	3.080	16,662	2.776	15,017	(1,645)	15,017	-
	Valmont Common	14,092	3.080	434	3.625	511	77	511	-
	Zuni Common	1,275,201	3.080	39,276	7.657	97,642	58,366	97,642	-
	Total Account 315.2	**12,212,226**	**3.080**	**376,137**	**4.294**	**524,340**	**148,203**	**524,340**	-

Acct No.	Description	PSCo Exhibit LHP-2.1 (Col 1) Plant Balance	Existing Rate	PSCo Exhibit LHP-2.1 (Col 4) Present Recovery	Staff Rate	Staff Annual Amount	Increase or (Decrease)	PSCo Exhibit LHP-2.1 (Col 9) Proposed Amount	Increase or (Decrease) to PSCo Proposed
316.0	Misc. Power Plant Equipment								
	Arapahoe Unit 4	56,117	5.520	3,098	5.174	2,903	(194)	2,903	-
	Arapahoe Common	1,549,648	1.900	29,443	4.080	63,226	33,782	63,226	-
	Cameo Unit 1	5,894	(0.760)	(45)	1.810	107	151	107	-
	Cameo Unit 2	2,013	0.110	2	1.981	40	38	40	-
	Cameo Common	322,052	5.410	17,423	2.836	9,133	(8,290)	9,133	-
	Cherokee Unit 1	16,442	5.040	829	3.360	552	(276)	552	-
	Cherokee Unit 2	32,325	0.660	213	2.930	947	734	947	-
	Cherokee Unit 3	60,432	0.980	592	2.563	1,549	957	1,549	-
	Cherokee Unit 4	141,196	1.760	2,485	1.599	2,258	(227)	3,927	(1,669)
	Cherokee Common	1,947,644	2.780	54,145	2.342	45,614	(8,531)	60,903	(15,289)
	Comanche Unit 1	527,769	1.100	5,805	1.513	7,985	2,180	12,197	(4,212)
	Comanche Unit 2	671,523	0.880	5,909	1.493	10,026	4,116	14,753	(4,727)
	Comanche Common	1,639,159	1.530	25,079	1.761	28,866	3,786	42,405	(13,539)
	Craig Unit 1	122,465	1.350	1,653	1.581	1,936	283	2,639	(703)
	Craig Unit 2	117,201	1.350	1,582	1.547	1,813	231	2,502	(689)
	Craig Common	766,047	1.630	12,487	1.714	13,130	643	17,887	(4,757)
	Training Facility	2,566,007	6.550	168,073	6.378	163,660	(4,414)	163,660	-
	Hayden Unit 1	209,564	3.020	6,329	1.888	3,957	(2,372)	3,957	-
	Hayden Unit 2	513,904	1.380	7,092	2.568	13,197	6,105	11,691	1,506
	Hayden Common	167,793	3.000	5,034	2.564	4,302	(732)	6,207	(1,905)
	Pawnee Unit 1	5,974,312	1.250	74,679	1.641	98,038	23,360	132,152	(34,114)
	Pawnee Common	894,199	2.390	21,371	2.419	21,631	259	29,115	(7,484)
	Valmont Unit 5	340,161	2.580	8,776	2.677	9,106	330	9,106	-
	Valmont Common	1,095,161	3.270	35,812	2.912	31,891	(3,921)	31,891	-
	Zuni Unit 1	1,192	13.170	157	5.200	62	(95)	62	-
	Zuni Common	762,116	4.640	35,362	5.598	42,663	7,301	42,663	-
	Total Account 316.0	**20,502,336**	**2.553**	**523,387**	**2.822**	**578,592**	**55,206**	**666,175**	**(87,583)**
	Total Steam Production	**1,852,253,746**	**2.161**	**40,027,624**	**2.546**	**47,154,806**	**7,127,182**	**57,007,549**	**(9,852,743)**

Acct No.	Description	PSCo Exhibit LHP-2.1 (Col 1) Plant Balance	Existing Rate	PSCo Exhibit LHP-2.1 (Col 4) Present Recovery	Staff Rate	Staff Annual Amount	Increase or (Decrease)	PSCo Exhibit LHP-2.1 (Col 9) Proposed Amount	Increase or (Decrease) to PSCo Proposed
OTHER PRODUCTION									
341.0	Structures & Improvements								
	Alamosa	365,486	4.290	15,679	4.630	16,922	1,243	16,922	-
	Fruita CT	82,604	2.520	2,082	0.885	731	(1,351)	731	-
	FSV ST 1	22,739,565	2.340	532,106	1.435	326,313	(205,793)	378,614	(52,301)
	FSV GT 2	-		-		-	-	-	-
	FSV GT 3	-		-		-	-	-	-
	FSV GT 4	153,255	2.340	3,586	2.493	3,821	234	3,821	-
	FSV Common	10,768,973	2.340	251,994	1.720	185,226	(66,768)	185,226	-
	Ft Lupton CT	159,689	0.850	1,357	2.560	4,088	2,731	4,088	-
	Valmont CT 6	58,103	1.710	994	0.820	476	(517)	476	-
	Total Account 341.0	**34,327,675**	**2.353**	**807,798**	**1.566**	**537,577**	**(270,221)**	**589,879**	**(52,301)**
342.0	Fuel Holders, Producers & Accessories								
	Alamosa	352,693	1.340	4,726	1.041	3,672	(1,055)	3,672	-
	Fruita CT	263,692	10.250	27,028	1.040	2,742	(24,286)	2,742	-
	FSV ST 1	3,188,537	2.620	83,540	2.481	79,108	(4,432)	91,639	(12,531)
	FSV GT 2	134,776	2.620	3,531	2.854	3,847	315	4,189	(342)
	FSV GT 3	52,381	2.620	1,372	2.891	1,514	142	1,514	-
	FSV GT 4	27,702,801	2.620	725,813	2.527	700,050	(25,764)	700,050	-
	FSV Common	1,219,887	2.620	31,961	1.703	20,775	(11,186)	20,775	-
	Ft Lupton CT	333,614	0.910	3,036	3.890	12,978	9,942	12,978	-
	Valmont CT 6	97,388	5.050	4,918	1.353	1,318	(3,600)	1,318	-
	Total Account 342.0	**33,345,769**	**2.657**	**885,926**	**2.477**	**826,002**	**(59,924)**	**838,875**	**(12,873)**
343.0	Prime Movers								
	Alamosa	-		-		-	-	-	-
	Fruita CT	-		-		-	-	-	-
	FSV ST 1	60,343,237	2.070	1,249,105	2.211	1,334,189	85,084	1,549,011	(214,822)
	FSV GT 2	32,198,705	2.070	666,513	2.315	745,400	78,887	813,017	(67,617)
	FSV GT 3	-		-		-	-	-	-
	FSV GT 4	-		-		-	-	-	-
	FSV Common	223,282	2.070	4,622	2.729	6,093	1,471	6,093	-
	Ft Lupton CT	-		-		-	-	-	-
	Valmont CT 6	-		-		-	-	-	-
	Total Account 343.0	**92,765,224**	**2.070**	**1,920,240**	**2.248**	**2,085,682**	**165,442**	**2,368,122**	**(282,440)**
344.0	Generators								
	Alamosa	7,578,649	2.350	178,098	1.618	122,623	(55,476)	122,623	-
	Fruita CT	2,147,186	2.530	54,324	1.029	22,095	(32,229)	22,095	-
	FSV ST 1	13,927,831	2.190	305,019	1.424	198,332	(106,687)	229,531	(31,199)
	FSV GT 2	45,888,709	2.190	1,004,963	2.418	1,109,589	104,626	1,208,250	(98,661)
	FSV GT 3	4,563,559	2.190	99,942	2.726	124,403	24,461	124,403	-
	FSV GT 4	69,190,834	2.190	1,515,279	2.689	1,860,542	345,262	1,860,542	-
	FSV Common	50,225,187	2.190	1,099,932	2.689	1,350,555	250,624	1,350,555	-
	Ft Lupton CT	10,873,349	5.180	563,239	4.026	437,761	(125,478)	437,761	-
	Valmont CT 6	6,803,531	(1.300)	(88,446)	1.902	129,403	217,849	129,403	-
	Total Account 344.0	**211,198,835**	**2.241**	**4,732,351**	**2.536**	**5,355,302**	**622,951**	**5,485,161**	**(129,859)**

Acct No.	Description	PSCo Exhibit LHP-2.1 (Col 1) Plant Balance	Existing Rate	PSCo Exhibit LHP-2.1 (Col 4) Present Recovery	Staff Rate	Staff Annual Amount	Increase or (Decrease)	PSCo Exhibit LHP-2.1 (Col 9) Proposed Amount	Increase or (Decrease) to PSCo Proposed
345.0	Accessory Electric Equipment								
	Alamosa	132,162	3.660	4,837	3.745	4,949	112	4,949	-
	Fruita CT	53,775	6.110	3,286	4.203	2,260	(1,025)	2,260	-
	FSV ST 1	12,967,373	2.210	286,579	1.437	186,341	(100,238)	215,647	(29,306)
	FSV GT 2	-		-		-	-	-	-
	FSV GT 3	-		-		-	-	-	-
	FSV GT 4	7,251,673	2.210	160,262	2.541	184,265	24,003	184,265	-
	FSV Common	10,687,714	2.210	236,198	2.697	288,248	52,049	288,248	-
	Ft Lupton CT	138,901	0.620	861	1.366	1,897	1,036	1,897	-
	Valmont CT 6	540,560	4.690	25,352	4.553	24,612	(741)	24,612	-
	Total Account 345.0	**31,772,158**	**2.258**	**717,376**	**2.180**	**692,573**	**(24,803)**	**721,878**	**(29,306)**
345.2	Computers								
	FSV ST 1	95,966	2.210	2,121	1.713	1,644	(477)	1,903	(259)
	FSV Common	45,405	2.210	1,003	2.202	1,000	(4)	1,000	-
	Total Account 345.2	**141,371**	**2.210**	**3,124**	**1.870**	**2,644**	**(481)**	**2,903**	**(259)**
346.0	Misc. Power Plant Equipment								
	Alamosa	5,237	1.420	74	0.976	51	(23)	51	-
	Fruita CT	5,067	2.480	126	1.131	57	(68)	57	-
	FSV ST 1	3,986,249	1.880	74,941	1.494	59,555	(15,387)	69,002	(9,447)
	FSV GT 2	-		-		-	-	-	-
	FSV GT 3	-		-		-	-	-	-
	FSV GT 4	17,415	1.880	327	2.523	439	112	439	-
	FSV Common	206,014	1.880	3,873	2.629	5,416	1,543	5,416	-
	Ft Lupton CT	4,773	1.440	69	1.455	69	1	69	-
	Valmont CT 6	16,711	2.570	429	4.835	808	379	808	-
	Total Account 346.0	**4,241,466**	**1.882**	**79,840**	**1.565**	**66,396**	**(13,444)**	**75,843**	**(9,447)**
	Total Other Production	**407,792,498**	**2.243**	**9,146,655**	**2.346**	**9,566,176**	**419,521**	**10,082,661**	**(516,485)**

Acct No.	Description	PSCo Exhibit LHP-2.1 (Col 1) Plant Balance	Existing Rate	PSCo Exhibit LHP-2.1 (Col 4) Present Recovery	Staff Rate	Staff Annual Amount	Increase or (Decrease)	PSCo Exhibit LHP-2.1 (Col 9) Proposed Amount	Increase or (Decrease) to PSCo Proposed
TRANSMISSION PLANT									
350.2	Land Rights	35,571,064	1.000	355,711	1.030	366,382	10,671	366,382	-
352.0	Structures & Improvements	18,208,719	1.500	273,131	1.440	262,206	(10,925)	262,206	-
353.0	Station Equipment	330,826,148	1.580	5,227,053	1.780	5,888,705	661,652	5,888,705	-
354.0	Towers & Fixtures	171,851,035	1.280	2,199,693	1.180	2,027,842	(171,851)	2,371,544	(343,702)
355.0	Poles & Fixtures	77,076,126	1.810	1,395,078	1.640	1,264,048	(131,029)	1,479,862	(215,814)
356.0	OH Conductors & Devices	203,280,978	1.550	3,150,855	1.790	3,638,730	487,874	3,638,730	-
357.0	UG Conduit	14,875,049	2.000	297,501	1.940	288,576	(8,925)	288,576	-
358.0	UG Conductors & Devices	26,358,042	1.900	500,803	1.880	495,531	(5,272)	495,531	-
359.0	Roads & Trails	3,756,395	1.120	42,072	0.970	36,437	(5,635)	36,437	-
	Total Transmission Plant	**881,803,556**	**1.524**	**13,441,896**	**1.618**	**14,268,457**	**826,561**	**14,827,973**	**(559,516)**
DISTRIBUTION PLANT									
360.2	Land Rights	10,317,688	1.110	114,526	1.090	112,463	(2,064)	112,463	-
361.0	Structures & Improvements	43,918,580	2.100	922,290	1.710	751,008	(171,282)	799,318	(48,310)
362.0	Station Equipment	331,317,546	2.110	6,990,800	2.050	6,792,010	(198,791)	6,792,010	-
364.0	Poles, Towers & Fixtures	153,359,482	1.970	3,021,182	3.650	5,597,621	2,576,439	4,646,792	950,829
365.0	OH Conductors & Devices	189,296,618	1.850	3,501,987	3.310	6,265,718	2,763,731	7,647,583	(1,381,865)
366.0	UG Conduit	187,859,180	2.000	3,757,184	1.990	3,738,398	(18,786)	4,301,975	(563,577)
367.0	UG Conductors & Devices	870,403,180	1.900	16,537,660	2.050	17,843,265	1,305,605	24,893,531	(7,050,266)
368.0	Line Transformers	298,370,265	2.710	8,085,834	2.210	6,593,983	(1,491,851)	6,593,983	-
369.0	Services	233,070,626	1.560	3,635,902	2.330	5,430,546	1,794,644	5,500,467	(69,921)
370.0	Meters	124,943,052	4.640	5,797,358	3.970	4,960,239	(837,118)	4,960,239	-
370.2	AMR Equipment	58,668,704	7.870	4,617,227	8.810	5,168,713	551,486	5,767,134	(598,421)
371.0	I.O.C.P.	6,033,880	2.360	142,400	1.000	60,339	(82,061)	60,339	-
373.0	Street Lighting & Signal Equipment	155,845,870	2.820	4,394,854	2.950	4,597,453	202,600	4,597,453	-
	Total Distribution Plant	**2,663,404,671**	**2.310**	**61,519,204**	**2.550**	**67,911,755**	**6,392,551**	**76,673,287**	**(8,761,532)**
TOTAL DEPRECIATION ADJUSTMENT		**5,805,254,471**		**124,135,378**		**138,901,194**	**14,765,815**	**158,591,469**	**(19,690,276)**

Public Service Company of Colorado
Comparison of Depreciation Rates and Annual Amounts

SCHEDULE 1

[1] Account Number	[2] Description	[3] December 31, 2005 Balance $	[4] Existing Rate %	[5] Annual Amount $	[6] Study Rate %	[7] Annual Amount $	[8] Increase or (Decrease) $
~~316.0~~	~~Misc. Power Plant Equipment~~						
	~~Arapahoe Unit 4~~	~~56,117~~	~~5.520~~	~~3,098~~	~~5.174~~	~~2,903~~	~~(194)~~
	~~Arapahoe Common~~	~~1,549,648~~	~~1.900~~	~~29,443~~	~~4.080~~	~~63,226~~	~~33,782~~
	~~Cameo Unit 1~~	~~5,894~~	~~(0.760)~~	~~(45)~~	~~1.810~~	~~107~~	~~151~~
	~~Cameo Unit 2~~	~~2,013~~	~~0.110~~	~~2~~	~~1.981~~	~~40~~	~~38~~
	~~Cameo Common~~	~~322,052~~	~~5.410~~	~~17,423~~	~~2.836~~	~~9,133~~	~~(8,290)~~
	~~Cherokee Unit 1~~	~~16,442~~	~~5.040~~	~~829~~	~~3.360~~	~~552~~	~~(276)~~
	~~Cherokee Unit 2~~	~~32,325~~	~~0.660~~	~~213~~	~~2.930~~	~~947~~	~~734~~
	~~Cherokee Unit 3~~	~~60,432~~	~~0.980~~	~~592~~	~~2.563~~	~~1,549~~	~~957~~
	~~Cherokee Unit 4~~	~~141,196~~	~~1.760~~	~~2,485~~	~~2.781~~	~~3,927~~	~~1,442~~
	~~Cherokee Unit Common~~	~~1,947,644~~	~~2.780~~	~~54,145~~	~~3.127~~	~~60,903~~	~~6,758~~
	~~Comanche Unit 1~~	~~527,769~~	~~1.100~~	~~5,805~~	~~2.311~~	~~12,197~~	~~6,391~~
	~~Comanche Unit 2~~	~~671,523~~	~~0.880~~	~~5,909~~	~~2.197~~	~~14,753~~	~~8,844~~
	~~Comanche Common~~	~~1,639,159~~	~~1.530~~	~~25,079~~	~~2.587~~	~~42,405~~	~~17,326~~
	~~Craig Unit 1~~	~~122,465~~	~~1.350~~	~~1,653~~	~~2.155~~	~~2,639~~	~~986~~
	~~Craig Unit 2~~	~~117,201~~	~~1.350~~	~~1,582~~	~~2.135~~	~~2,502~~	~~920~~
	~~Craig Common~~	~~766,047~~	~~1.630~~	~~12,487~~	~~2.335~~	~~17,887~~	~~5,401~~
	~~Training Facility~~	~~2,566,007~~	~~6.550~~	~~168,073~~	~~6.378~~	~~163,660~~	~~(4,414)~~
	~~Hayden Unit 1~~	~~209,564~~	~~3.020~~	~~6,329~~	~~1.888~~	~~3,957~~	~~(2,372)~~
	~~Hayden Unit 2~~	~~513,904~~	~~1.380~~	~~7,092~~	~~2.275~~	~~11,691~~	~~4,599~~
	~~Hayden Common~~	~~167,793~~	~~3.000~~	~~5,034~~	~~3.699~~	~~6,207~~	~~1,173~~
	~~Pawnee Unit 1~~	~~5,974,312~~	~~1.250~~	~~74,679~~	~~2.212~~	~~132,152~~	~~57,473~~
	~~Pawnee Common~~	~~894,199~~	~~2.390~~	~~21,371~~	~~3.256~~	~~29,115~~	~~7,744~~
	~~Valmont Unit 5~~	~~340,161~~	~~2.580~~	~~8,776~~	~~2.677~~	~~9,106~~	~~330~~
	~~Valmont Common~~	~~1,096,161~~	~~3.270~~	~~35,812~~	~~2.912~~	~~31,891~~	~~(3,921)~~
	~~Zuni Unit 1~~	~~1,192~~	~~13.170~~	~~157~~	~~5.200~~	~~62~~	~~(95)~~
	~~Zuni Common~~	~~762,116~~	~~4.640~~	~~35,362~~	~~5.598~~	~~42,663~~	~~7,301~~
	~~Total Account 316~~	~~20,502,336~~	~~2.553~~	~~523,387~~	~~3.249~~	~~666,175~~	~~142,788~~
	~~Total Steam Production~~	~~1,724,627,512~~	~~2.097~~	~~36,166,468~~	~~2.854~~	~~49,218,803~~	~~13,052,335~~
	HYDRAULIC PRODUCTION PLANT						
331.0	Structures & Improvements						
	Ames	135,794	1.520	2,064	1.487	2,019	(45)
	Cabin Creek	7,152,881	0.720	51,501	1.062	75,964	24,463
	Georgetown	89,612	(0.160)	(143)	1.702	1,525	1,669
	Palisade	8,275	0.930	77	1.282	106	29
	Salida	71,463	0.750	536	1.838	1,313	778
	Shoshone	669,525	1.070	7,164	1.677	11,228	4,064
	Tacoma	357,396	0.630	2,252	1.408	5,032	2,781
	Total Account 331	8,484,946	0.748	63,450	1.145	97,188	33,738
332.0	Reservoirs, Dams & Waterways						
	Ames	3,291,782	1.700	55,960	1.562	51,418	(4,543)
	Cabin Creek	20,299,241	1.020	207,052	1.092	221,668	14,615
	Georgetown	4,775,221	2.410	115,083	2.313	110,451	(4,632)
	Salida	819,728	1.280	10,493	1.594	13,066	2,574
	Shoshone	4,639,301	1.020	47,321	0.860	39,898	(7,423)
	Tacoma	1,947,640	0.910	17,724	1.377	26,819	9,095
	Total Account 332	35,772,913	1.268	453,632	1.295	463,320	9,687
333.0	Waterwheels, Turbines & Generators						
	Ames	137,148	0.160	219	0.942	1,292	1,072
	Cabin Creek	14,592,753	1.180	172,194	1.227	179,053	6,859
	Georgetown	55,253	0.740	409	1.031	570	161
	Palisade	249	0.770	2	1.120	3	1
	Salida	56,359	0.350	197	0.709	400	202
	Shoshone	1,792,417	1.330	23,839	1.778	31,869	8,030
	Tacoma	1,165,811	0.990	11,542	1.851	21,579	10,038
	Total Account 333	17,799,990	1.171	208,403	1.319	234,765	26,363
334.0	Accessory Electric Equipment						
	Ames	1,519,521	2.690	40,875	2.471	37,547	(3,328)
	Cabin Creek	3,700,723	1.000	37,007	1.433	53,031	16,024
	Georgetown	276,763	1.280	3,543	1.612	4,461	919
	Palisade	119,204	1.550	1,848	1.698	2,024	176
	Salida	358,999	1.210	4,344	2.037	7,313	2,969
	Shoshone	1,098,315	1.160	12,740	2.306	25,327	12,587
	Tacoma	1,465,401	1.160	16,999	1.802	26,407	9,408
	Total Account 334	8,538,926	1.374	117,356	1.828	156,111	38,755
334.2	Computers - Cabin Creek	56,206	1.000	562	1.317	740	178

Public Service Company of Colorado
Comparison of Depreciation Rates and Annual Amounts

SCHEDULE 1

[1] Account Number	[2] Description	[3] December 31, 2005 Balance $	[4] Existing Rate %	[5] Annual Amount $	[6] Study Rate %	[7] Annual Amount $	[8] Increase or (Decrease) $
335.0	Misc. Power Plant Equipment						
	Ames	69,502	2.130	1,480	1.833	1,274	(206)
	Cabin Creek	399,125	0.930	3,712	1.706	6,809	3,097
	Georgetown	112,103	0.210	235	2.878	3,226	2,991
	Salida	89,183	0.870	776	3.690	3,291	2,515
	Shoshone	878,735	1.430	12,566	2.830	24,868	12,302
	Tacoma	140,924	1.050	1,480	1.929	2,718	1,239
	Total Account 335	1,689,572	1.198	20,249	2.497	42,187	21,938
335.2	Recreational Facilities						
	Ames	168,012	2.410	4,049	2.356	3,958	(91)
	Cabin Creek	3,927	1.110	44	1.545	61	17
	Georgetown	240,335	2.120	5,095	2.266	5,446	351
	Salida	151,492	1.740	2,636	3.330	5,045	2,409
	Tacoma	478,920	1.120	5,364	1.662	7,960	2,596
	Total Account 335.2	1,042,686	1.648	17,188	2.155	22,469	5,282
336.0	Roads, Railroads & Bridges						
	Ames	21,231	2.830	601	2.403	510	(91)
	Cabin Creek	453,762	1.120	5,082	1.066	4,837	(245)
	Salida	20,450	0.350	72	2.666	545	474
	Shoshone	9,247	0.550	51	1.121	104	53
	Tacoma	270,175	0.770	2,080	1.329	3,591	1,510
	Total Account 336	774,865	1.018	7,886	1.237	9,587	1,701
	Total Hydraulic Production	74,160,104	1.198	888,725	1.384	1,026,367	137,642
	~~OTHER PRODUCTION PLANT~~						
~~341.0~~	~~Structures & Improvements~~						
	~~Alamosa~~	~~365,486~~	~~4.290~~	~~15,679~~	~~4.630~~	~~16,922~~	~~1,243~~
	~~Fruita CT~~	~~82,604~~	~~2.520~~	~~2,082~~	~~0.885~~	~~731~~	~~(1,351)~~
	~~FSV GT 1~~	~~22,739,565~~	~~2.340~~	~~532,106~~	~~1.665~~	~~378,614~~	~~(153,492)~~
	~~FSV GT 4~~	~~153,255~~	~~2.340~~	~~3,586~~	~~2.493~~	~~3,821~~	~~234~~
	~~FSV GT Common~~	~~10,768,973~~	~~2.340~~	~~251,994~~	~~1.720~~	~~185,226~~	~~(66,768)~~
	~~Ft. Lupton CT~~	~~159,689~~	~~0.850~~	~~1,357~~	~~2.560~~	~~4,088~~	~~2,731~~
	~~Valmont CT~~	~~58,103~~	~~1.710~~	~~994~~	~~0.820~~	~~476~~	~~(517)~~
	~~Total Account 341~~	~~34,327,675~~	~~2.353~~	~~807,798~~	~~1.718~~	~~589,878~~	~~(217,920)~~
~~342.0~~	~~Fuel Holders, Producers & Access.~~						
	~~Alamosa~~	~~352,693~~	~~1.340~~	~~4,726~~	~~1.041~~	~~3,672~~	~~(1,055)~~
	~~Fruita CT~~	~~263,692~~	~~10.250~~	~~27,028~~	~~1.040~~	~~2,742~~	~~(24,286)~~
	~~FSV GT 1~~	~~3,188,537~~	~~2.620~~	~~83,540~~	~~2.874~~	~~91,639~~	~~8,099~~
	~~FSV GT 2~~	~~134,776~~	~~2.620~~	~~3,531~~	~~3.108~~	~~4,189~~	~~658~~
	~~FSV GT 3~~	~~52,381~~	~~2.620~~	~~1,372~~	~~2.891~~	~~1,514~~	~~142~~
	~~FSV GT 4~~	~~27,702,801~~	~~2.620~~	~~725,813~~	~~2.527~~	~~700,050~~	~~(25,764)~~
	~~FSV GT Common~~	~~1,219,887~~	~~2.620~~	~~31,961~~	~~1.703~~	~~20,775~~	~~(11,186)~~
	~~Ft. Lupton CT~~	~~333,614~~	~~0.910~~	~~3,036~~	~~3.890~~	~~12,978~~	~~9,942~~
	~~Valmont CT~~	~~97,388~~	~~5.050~~	~~4,918~~	~~1.353~~	~~1,318~~	~~(3,600)~~
	~~Total Account 342~~	~~33,345,769~~	~~2.657~~	~~885,926~~	~~2.516~~	~~838,875~~	~~(47,051)~~
~~343.0~~	~~Prime Movers~~						
	~~FSV GT 1~~	~~60,343,237~~	~~2.070~~	~~1,249,105~~	~~2.567~~	~~1,549,011~~	~~299,906~~
	~~FSV GT 2~~	~~32,198,705~~	~~2.070~~	~~666,513~~	~~2.525~~	~~813,017~~	~~146,504~~
	~~FSV~~	~~223,282~~	~~2.070~~	~~4,622~~	~~2.729~~	~~6,093~~	~~1,471~~
	~~Total Account 343~~	~~92,765,224~~	2.070	~~1,920,240~~	2.553	~~2,368,122~~	~~447,881~~
~~344.0~~	~~Generators~~						
	~~Alamosa~~	~~7,578,649~~	~~2.350~~	~~178,098~~	~~1.618~~	~~122,623~~	~~(55,476)~~
	~~Fruita CT~~	~~2,147,186~~	~~2.530~~	~~54,324~~	~~1.029~~	~~22,095~~	~~(32,229)~~
	~~FSV GT 1~~	~~13,927,831~~	~~2.190~~	~~305,019~~	~~1.648~~	~~229,531~~	~~(75,489)~~
	~~FSV GT 2~~	~~45,888,709~~	~~2.190~~	~~1,004,963~~	~~2.633~~	~~1,208,250~~	~~203,287~~
	~~FSV GT 3~~	~~4,563,559~~	~~2.190~~	~~99,942~~	~~2.726~~	~~124,403~~	~~24,461~~
	~~FSV GT 4~~	~~69,190,834~~	~~2.190~~	~~1,515,279~~	~~2.689~~	~~1,860,542~~	~~345,262~~
	~~FSV GT Common~~	~~50,225,187~~	~~2.190~~	~~1,099,932~~	~~2.689~~	~~1,350,555~~	~~250,624~~
	~~Ft. Lupton CT~~	~~10,873,349~~	~~5.180~~	~~563,239~~	~~4.026~~	~~437,761~~	~~(125,478)~~
	~~Valmont CT~~	~~6,803,531~~	~~(1.300)~~	~~(88,446)~~	~~1.902~~	~~129,403~~	~~217,849~~
	~~Total Account 344~~	~~211,198,835~~	2.241	~~4,732,351~~	~~2.597~~	~~5,485,161~~	~~752,810~~
~~345.0~~	~~Accessory Electric Equipment~~						
	~~Alamosa~~	~~132,162~~	~~3.660~~	~~4,837~~	~~3.745~~	~~4,949~~	~~112~~
	~~Fruita CT~~	~~53,775~~	~~6.110~~	~~3,286~~	~~4.203~~	~~2,260~~	~~(1,026)~~
	~~FSV GT 1~~	~~12,967,373~~	~~2.210~~	~~286,579~~	~~1.663~~	~~215,647~~	~~(70,932)~~

Public Service Company of Colorado
Comparison of Depreciation Rates and Annual Amounts

SCHEDULE 1

[1] Account Number	[2] Description	[3] December 31, 2005 Balance $	[4] Existing Rate %	[5] Annual Amount $	[6] Study Rate %	[7] Annual Amount $	[8] Increase or (Decrease) $
	~~FSV GT 4~~	~~7,251,673~~	~~2.210~~	~~160,262~~	~~2.541~~	~~184,265~~	~~24,003~~
	~~FSV GT Common~~	~~10,687,714~~	~~2.210~~	~~236,198~~	~~2.697~~	~~288,248~~	~~52,049~~
	~~Ft. Lupton CT~~	~~138,901~~	~~0.620~~	~~861~~	~~1.366~~	~~1,897~~	~~1,036~~
	~~Valmont CT~~	~~540,560~~	~~4.690~~	~~25,352~~	~~4.553~~	~~24,612~~	~~(741)~~
	~~Total Account 345~~	~~31,772,168~~	~~2.258~~	~~717,376~~	~~2.272~~	~~721,879~~	~~4,503~~
~~345.2~~	~~Computers~~						
	~~FSV GT 1~~	~~95,966~~	~~2.210~~	~~2,121~~	~~1.983~~	~~1,903~~	~~(218)~~
	~~FSV GT Common~~	~~45,405~~	~~2.210~~	~~1,003~~	~~2.202~~	~~1,000~~	~~(4)~~
	~~Total Account 345.2~~	~~141,371~~	~~2.210~~	~~3,124~~	~~2.053~~	~~2,903~~	~~(221)~~
~~346.0~~	~~Misc. Power Plant Equipment~~						
	~~Alamosa~~	~~5,237~~	~~1.420~~	~~74~~	~~0.976~~	~~51~~	~~(23)~~
	~~Fruita CT~~	~~5,067~~	~~2.480~~	~~126~~	~~1.131~~	~~57~~	~~(68)~~
	~~FSV GT 1~~	~~3,986,249~~	~~1.880~~	~~74,941~~	~~1.731~~	~~69,002~~	~~(5,940)~~
	~~FSV GT 4~~	~~17,415~~	~~1.880~~	~~327~~	~~2.523~~	~~439~~	~~112~~
	~~FSV GT Common~~	~~206,014~~	~~1.880~~	~~3,873~~	~~2.629~~	~~5,416~~	~~1,543~~
	~~Ft. Lupton CT~~	~~4,773~~	~~1.440~~	~~69~~	~~1.455~~	~~69~~	~~1~~
	~~Valmont CT~~	~~16,711~~	~~2.570~~	~~429~~	~~4.835~~	~~808~~	~~379~~
	~~Total Account 346~~	~~4,241,466~~	~~1.882~~	~~79,840~~	~~1.788~~	~~75,843~~	~~(3,997)~~
	~~Total Other Production~~	~~407,792,498~~	~~2.243~~	~~9,146,655~~	~~2.472~~	~~10,082,661~~	~~936,006~~
	~~TOTAL PRODUCTION~~	~~2,206,580,114~~	~~2.094~~	~~46,201,848~~	~~2.734~~	~~60,327,830~~	~~14,125,983~~
	~~TRANSMISSION PLANT~~						
~~350.2~~	~~Land Rights~~	~~35,571,064~~	~~1.000~~	~~355,711~~	~~1.030~~	~~366,382~~	~~10,671~~
~~352.0~~	~~Structures & Improvements~~	~~18,208,719~~	~~1.500~~	~~273,131~~	~~1.440~~	~~262,206~~	~~(10,925)~~
~~353.0~~	~~Station Equipment~~	~~330,826,148~~	~~1.580~~	~~5,227,053~~	~~1.780~~	~~5,888,705~~	~~661,652~~
~~354.0~~	~~Towers & Fixtures~~	~~171,851,035~~	~~1.280~~	~~2,199,693~~	~~1.380~~	~~2,371,544~~	~~171,851~~
~~355.0~~	~~Poles & Fixtures~~	~~77,076,126~~	~~1.810~~	~~1,395,078~~	~~1.920~~	~~1,479,862~~	~~84,784~~
~~356.0~~	~~OH Conductors & Devices~~	~~203,280,978~~	~~1.550~~	~~3,150,855~~	~~1.790~~	~~3,638,730~~	~~487,874~~
~~357.0~~	~~UG Conduit~~	~~14,875,049~~	~~2.000~~	~~297,501~~	~~1.940~~	~~288,576~~	~~(8,925)~~
~~358.0~~	~~UG Conductors & Devices~~	~~26,358,042~~	~~1.900~~	~~500,803~~	~~1.880~~	~~495,531~~	~~(5,272)~~
~~359.0~~	~~Roads & Trails~~	~~3,756,395~~	~~1.120~~	~~42,072~~	~~0.970~~	~~36,437~~	~~(5,635)~~
	~~Total Transmission~~	~~881,803,556~~	~~1.524~~	~~13,441,896~~	~~1.682~~	~~14,827,973~~	~~1,386,076~~
	~~DISTRIBUTION PLANT~~						
~~360.2~~	~~Land Rights~~	~~10,317,688~~	~~1.110~~	~~114,526~~	~~1.090~~	~~112,463~~	~~(2,064)~~
~~361.0~~	~~Structures & Improvements~~	~~43,918,580~~	~~2.100~~	~~922,290~~	~~1.820~~	~~799,318~~	~~(122,972)~~
~~362.0~~	~~Station Equipment~~	~~331,317,546~~	~~2.110~~	~~6,990,800~~	~~2.050~~	~~6,792,010~~	~~(198,791)~~
~~364.0~~	~~Poles, Towers & Fixtures~~	~~153,359,482~~	~~1.970~~	~~3,021,182~~	~~3.030~~	~~4,646,792~~	~~1,625,611~~
~~365.0~~	~~OH Conductors & Devices~~	~~189,296,618~~	~~1.850~~	~~3,501,987~~	~~4.040~~	~~7,647,583~~	~~4,145,596~~
~~366.0~~	~~UG Conduit~~	~~187,859,180~~	~~2.000~~	~~3,757,184~~	~~2.290~~	~~4,301,975~~	~~544,792~~
~~367.0~~	~~UG Conductors & Devices~~	~~870,403,180~~	~~1.900~~	~~16,537,660~~	~~2.860~~	~~24,893,531~~	~~8,355,871~~
~~368.0~~	~~Line Transformers~~	~~298,370,265~~	~~2.710~~	~~8,085,834~~	~~2.210~~	~~6,593,983~~	~~(1,491,851)~~
~~369.0~~	~~Services~~	~~233,070,626~~	~~1.560~~	~~3,635,902~~	~~2.360~~	~~5,500,467~~	~~1,864,565~~
~~370.0~~	~~Meters~~	~~124,943,052~~	~~4.640~~	~~5,797,358~~	~~3.970~~	~~4,960,239~~	~~(837,118)~~
~~370.2~~	~~AMR Equipment~~	~~58,668,704~~	~~7.870~~	~~4,617,227~~	~~9.830~~	~~5,767,134~~	~~1,149,907~~
~~371.0~~	~~I.O.C.P.~~	~~6,033,880~~	~~2.360~~	~~142,400~~	~~1.000~~	~~60,339~~	~~(82,061)~~
~~373.0~~	~~Street Lighting & Signal Systems~~	~~155,845,870~~	~~2.820~~	~~4,394,854~~	~~2.950~~	~~4,597,453~~	~~202,600~~
	~~Total Distribution~~	~~2,663,404,671~~	~~2.310~~	~~61,519,204~~	~~2.879~~	~~76,673,287~~	~~15,154,083~~
	GENERAL PLANT						
390.0	Structures & Improvements	5,962,234	3.700	220,603	4.880	290,957	70,354
390.1	General Buildings	2,202,989	2.200	48,466	2.980	65,649	17,183
390.2	Partitions	125,814	6.250	7,863	7.690	9,675	1,812
391.0	Office Furniture & Equipment	2,248,715	4.750	106,814	4.750	106,814	0
391.1	Leased Partitions	8,551	5.000	428	5.000	428	0
391.2	Computers	5,459,664	20.000	1,091,933	20.000	1,091,933	0
392.0	Transportation Equipment	16,117,586	9.000	1,450,583	9.000	1,450,583	0
393.0	Stores Equipment	326,601	3.170	10,353	3.170	10,353	0
394.0	Tools, Shop & Garage Equipment	9,736,170	3.800	369,974	3.800	369,974	0
395.0	Laboratory Equipment	5,456,709	9.500	518,387	9.500	518,387	0
396.0	Power Operated Equipment	2,867,306	9.000	258,058	9.000	258,058	0
397.0	Communication Equipment	22,582,349	6.670	1,506,243	6.670	1,506,243	0
398.0	Miscellaneous Equipment	614,197	5.000	30,710	5.000	30,710	0
	Total General	73,708,885	7.625	5,620,414	7.746	5,709,763	89,349
	Total Electric Plant	5,825,497,226	2.176	126,783,361	2.704	157,538,853	30,755,492

Standard ECA Rate	
Secondary=	0.03291
Primary=	0.03208
Transmission=	0.03135

Optional TOU ECA Factor Derivation
12 hour peak begining at 9 AM

	On-Peak Share (A)	Ist Qtr Projected Sales @ Meter (B)	1st Qtr On Peak Sales @ Meter (C=A*B)	1st Qtr Off Peak Sales @ Meter (D=B-C)	On-/Off-Peak Price Ratio (E)	Weighted Sales (F=C*E+D)	Revenue Req (G=B*Stan Rate)	Off-Peak (H=G/F)	On-Peak (I=E*H)	Proof (J=(C*I)+(D*H))
SG	0.43472	2,697,022	1,172,461.60	1,524,560.40	1.43	3,201,180.49	$ 88,758,994	0.0277	0.0396	88,758,994
PG	0.39399	746,052	293,938.99	452,113.01	1.43	872,445.77	$ 23,933,348	0.0274	0.0392	23,933,348
TG	0.36218	434,714	157,444.46	277,269.54	1.43	502,415.12	$ 13,628,284	0.0271	0.0388	13,628,284
										126,320,626

A) This on-peak share will be in effect for the 2007 and 2008 Optional TOU ECA rates.
After the rate is in effect for one year, the Company will update load research, and every three years thereafter.
B) The Company will provide the monthly sales forecast every November.
E) The Price Ratio is the projected ratio of the average on-peak marginal cost to the average off-peak marginal cost for the year and will be updated annually in the November filing.
G) Is a calculation based on the standard ECA rate and will be updated quarterly.

Xcel Energy - Public Service of Colorado **Exhibit No. RND-10**
Development of Wind Benefit **Page 1 of 3**
Illustrative Windsource Rate Development Using Projected 2007 Avoided Costs, Projected 2007 ECA Revenue, and 2005 Windsource Revenue Requirement (1)

Line No.		Loss Factors	Loss Adjusted Rates	Sales	Revenue
1	**Development of Wind Benefit**				
2	Avoided Energy Costs	**$ 9,504,000**			
3	Avoided Capacity Costs	$ 419,520			
4	Less: Wholesale Portion of Avoided Costs	$ 1,071,122			
5	Less: Lost ECA Revenue	**$ 4,234,024**			
6	Total Wind Benefit (ECA)	$ 4,618,374			
7					
8	**Development of Windsource Rates**				
9			Loss Adjusted		
10		Loss Factors	Rates	Sales	Revenue
11	**Windsource Rate @ Transmission Excluding Wholesale**	1.0000	**$ 0.03343**	6,106,264	$ 204,132
12	Windsource Rate @ Primary	1.0235	**$ 0.03422**	5,203,090	$ 178,027
13	Windsource Rate @ Secondary Including Residential	1.0500	**$ 0.03510**	110,875,538	$ 3,891,898
14	Total			122,184,891	$ 4,274,057
15					
16	**Revenue Proof**				
17	Windsource Revenue Requirement	$ 8,891,812			
18	Windsource Full Credit	$ 4,274,057			
19	Wind Benefit	$ 4,618,374			
20	Total	$ (619)			
21					

22 (1) Public Service will use projected 2007 Windsource Revenue Requirement when it files the Windsource Rates on
23 or before November 1, 2006. All other projections are subject to updating on or before November 1, 2006.