DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER of NorthWestern Energy's Electric Supply Tracker Filing for the Electric Supply Deferred Cost Account Balance as of June 30, 2010 and the Projected Electric Cost for the 12 Month Period July 1, 2010 through June 30, 2011.	)))))	UTILITY DIVISION DOCKET No. D2010.5.50

Direct Testimony
of
John W. Wilson
on Behalf
of
The Montana Consumer Counsel

September 16, 2010

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Economic Counsel
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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is John W. Wilson. I am President of J.W. Wilson & Associates, Inc. Our offices are at 1601 North Kent Street, Suite 1104, Arlington, Virginia, 22209.

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A. I hold a B.S. degree with senior honors and a Masters Degree in Economics from the University of Wisconsin. I have also received a Ph.D. in Economics from Cornell University. My major fields of study were industrial organization and public regulation of business, and my doctoral dissertation was a study of utility pricing and regulation.

Q. HOW HAVE YOU BEEN EMPLOYED SINCE THAT TIME?

A. After completing my graduate education I was an assistant professor of economics at the United States Military Academy, West Point, New York. In that capacity, I taught courses in both economics and government. While at West Point, I also served as an economic consultant to the Antitrust Division of the United States Department of Justice.

After leaving West Point, I was employed by the Federal Power Commission, first as a staff economist and then as Chief of FPC's Division of Economic Studies. In that capacity, I was involved in regulatory matters involving most phases of FPC regulation of electric utilities and the natural gas industry. Since 1973 I have been employed as an economic consultant by various clients, including federal, state, provincial and local governments, private enterprise and nonprofit organizations. This work has pertained to a wide range of issues concerning public utility regulation, insurance rate regulation, antitrust matters and economic and financial analysis. In 1975 I formed J. W. Wilson & Associates, Inc., a Washington, D.C. corporation.

Q. WOULD YOU PLEASE DESCRIBE SOME OF YOUR ADDITIONAL PROFESSIONAL ACTIVITIES?

A. I have authored a variety of articles and monographs, including a number of studies dealing with utility regulation and economic policy. I have consulted on regulatory, financial and competitive market matters with the Federal Communications Commission, the National Academy of Sciences, the Ford Foundation, the National Regulatory Research Institute, the Electric Power Research Institute, the U.S. Department of Justice Antitrust Division, the Federal Trade Commission Bureau of Competition, the

Commerce Department, the Department of the Interior, the Department of Energy, the Small Business Administration, the Department of Defense, the Tennessee Valley Authority, the Federal Energy Administration, and numerous state and provincial agencies and legislative bodies in the United States and Canada.

Previously, I was a member of the Economics Committee of the U.S. Water Resources Council, the FPC Coordinating Representative for the Task Force on Future Financial Requirements for the National Power Survey, the Advisory Committee to the National Association of Insurance Commissioners (NAIC) Task Force on Profitability and Investment Income, and the NAIC's Advisory Committee on Nuclear Risks.

In addition, I have testified as an expert witness in court proceedings dealing with competition in the electric power industry and on regulatory matters before more than 50 Federal and State regulatory bodies throughout the United States and Canada. I have also appeared on numerous occasions as an expert witness at the invitation of U.S. Senate and Congressional Committees dealing with antitrust and regulatory legislation. In addition, I have been retained as an expert on regulatory matters by more then 25 State and Federal regulatory agencies. I have also participated as a speaker, panelist, or moderator in many professional conferences and programs

dealing with business regulation, financial issues, economic policy and antitrust matters. I am a member of the American Economic Association and an associate member of the American Bar Association and the ABA's Antitrust, Insurance and Regulatory Law Sections.

II. OVERVIEW OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am presenting testimony in this proceeding on behalf of the Montana Consumer Counsel (MCC).

Q. PLEASE SUMMARIZE YOUR TESTIMONY?

A. My testimony pertains to NorthWestern Energy's ("NWE" or "the Company") proposed cost recovery under its Electric Supply Tracker filing for the period July 1, 2009 through June 30, 2010 and for the forecasted period July 1, 2010 through June 30, 2011.

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED COST RECOVERY UNDER ITS ELECTRIC TRACKER FILINGS FOR THE TWELVE-MONTH PERIOD ENDING JUNE 30, 2010 AND FOR THE FORECASTED PERIOD ENDING JUNE 30, 2011?

A. Yes, I have. In addition to reviewing NWE's filing in this regard, I have also reviewed discovery responses provided by the Company to data and information requests that have been made by the MCC and the Commission Staff.

Q. IS THE ELECTRIC SUPPLY COST RECOVERY PROPOSED BY NWE FOR THE 12-MONTH TRACKING PERIOD ENDED JUNE 2010 REASONABLE?

A. In my opinion the Electric Supply cost recovery proposed by NWE for the 12-month tracking period ended June 2010 should be modified by the Commission.

III. ELECTRIC SUPPLY COST CHANGES

Q. HAVE THE COMPANY'S ELECTRIC SUPPLY COSTS CHANGED SIGNIFICANTLY OVER RECENT TRACKER YEARS?

A. On an overall basis the electric supply costs reported by the Company have remained relatively stable. In fact, due to large decreases in short term market purchase costs (i.e., a 36% reduction in spot market costs and a 28% reduction in other short term purchase costs), NWE's overall electric supply costs in 2009/2010 declined slightly more than had been projected, despite an increase in Colstrip Unit 4 ("CU4") costs. The Company's

average electric supply cost in the 2007/2008 tracker year was $47.15/Mwh. This was midway between average spot market costs of $58.08/Mwh and average CU4 costs of $36.20/Mwh. In the 2008/2009 tracker year the average cost increased slightly to $48.15/Mwh, and in the 2009/2010 tracker year it declined to $45.19. Again, this was midway between average spot market costs, which dropped to $31.46/Mwh, and average CU4 costs, which increased to $57.09/Mwh. The projected 2010/2011 tracker year cost estimate is $48.08/Mwh.

Q. HAVE THE COMPONENTS OF THE COMPANY'S ELECTRIC SUPPLY REMAINED RELATIVELY STABLE OVER THESE THREE TRACKER YEARS?

A. Yes; although some significant changes are projected for tracker year 2010/2011. As shown in Exhibit __ (JW-1), each of the major supply components accounts for approximately the same percentage of total electric supply in each of the last three tracker years.

Q. WHAT SIGNIFICANT SUPPLY CHANGES ARE PROJECTED FOR TRACKER YEAR 2010/2011?

A. The projection for tracker year 2010/2011 shows the base load PP&L contract supply decreasing from about 35% of total supply to about 30%, while supply derived from CU4 is projected to increase by about 7% (from

12.6% of total supply to 19.4%). Also, there is a substantial projected decrease in short term contract purchases (from 15.8% to 5.8%) to make room for increased CU4 deliveries and a new long term purchase from Citigroup (3.5% of total supply), and there is a projected increase in spot market purchases (from 12.5% of total supply to 17.2%).

Q. HAVE THE COSTS OF EACH OF THESE SUPPLY VOLUME COMPONENTS REMAINED THE SAME OVER TIME?

A. While the overall cost of electric supply has remained about the same over the four tracker years, the costs of some supply components have changed substantially. For example, the cost of spot market transactions has declined by almost 50 percent, from nearly $60/Mwh in the 2007/2008 tracker year to just over $30/Mwh in the 2009/2010 tracker year. In contrast to this decline in the cost of spot market purchases, the average cost of CU4 purchases increased by 58%, from $36/Mwh in 2007/2008 to $57/Mwh in 2009/2010. According to the Company, the average cost of CU4 purchases is projected to remain at $56.32 in 2010/2011, as its share of total supply rises from 12.6% to 19.4%.

Q. WHAT EXPLAINS THESE CHANGES IN CU4 SUPPLY VOLUMES AND COSTS?

A. The increase in CU4's share of total supply is attributable to less projected outage time for the plant, which was out of service from March 27 until October 28, 2009, and to the expiration of a contract which had previously resulted in the sale of about half of CU4 production to Puget Power. The increase in the CU4 supply cost level in the last two years is largely related to the cost of ratebasing the plant as opposed to previously existing long term contract purchases of about half the plant's output that were eliminated in conjunction with ratebasing. More details on the amount and cost of each electric supply component are shown in Exhibit __ (JW-1) for each of the last three tracker years and for the projected year.

IV. CU4 RATES AND REVENUES

Q. DOES THE COMPANY PROPOSE TRACKER RATE ADDITIONS FOR CU4 REVENUES THAT IT ESTIMATES HAVE BEEN LOST DUE TO DEMAND SIDE MANAGEMENT ("DSM") CONSERVATION PROGRAMS?

A. Yes. The Company estimates that $649,709 of Commission-authorized CU4 revenues were "lost" in the 2009-2010 tracker year and that another $1,267,268 of Commission-authorized CU4 revenues will be "lost" in the 2010-2011 tracker year because of successful electricity conservation efforts under DSM programs.

Q. DOES THE COMPANY CLAIM THAT, WITHOUT THESE RATE ADDITIONS, CU4 REVENUES WOULD BE LESS THAN THE COMMISSION'S ALLOWED CU4 COST OF SERVICE BECAUSE OF SUCCESSFUL DSM?

A. No. The Company's fixed cost of service revenue requirement of $72,745,544 for CU4 was determined by the Commission in Order 6925f in Docket No. D2008.6.69 (as modified for property taxes in Order 7057b). NWE is not claiming that DSM has resulted in the collection of less than this Commission approved cost of service revenue requirement. In fact, NWE has consistently recovered more than its authorized fixed cost revenue requirement for CU4 in each year since the plant has been in rate base.

Q. DO YOU OBJECT TO NWE'S RECOVERY OF LOST REVENUES?

A. My recommendations in this case recognize that the Commission has implemented a mechanism to allow NWE to calculate and include in rates revenues it claims would have been received absent its DSM activities.

Q. DOES NWE BASE ITS COST RECOVERY CALCULATION ON ITS AUTHORIZED REVENUE REQUIREMENT FOR CU4?

A. No. NWE has consistently collected more than the Commission's allowed CU4 fixed cost requirement in large part because of the way that it has chosen to implement the Commission's revenue authorization. Very simply, NWE (1) uses a low historic projected sales volume (i.e., the prior 2007 test year sales volume) to convert the Commission's authorized $72.7 million revenue requirement into a price per kwh, (2) assumes that this converted price per kwh was authorized in Order 6925f, and (3) applies this converted price per kwh to its larger actual sales volumes. The inevitable end result is a larger CU4 revenue total than the $72.7 million that was actually authorized in Order 6925f. Because historic 2007 test year kwh sales were less than actual kwh sales in tracker years 2008/2009 and 2009/2010 and less than estimated kwh sales in tracker year 2010/2011, CU4 fixed cost revenues in each of these tracker years have exceeded the Commission's determined annual CU4 fixed cost of service revenue requirement.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED "LOST" REVENUE RECOVERY FOR CU4?

A. No. There are two obvious fallacies underlying this "lost" revenue claim. First, as stated above, the Company's actual CU4 revenue in each tracker year has exceeded the Commission-determined CU4 revenue amount

because the Company's actual sales have exceeded the 2007 test year sales amounts that NWE used to develop the CU4 rate component. Since ratepayers have already paid more than the Commission's determined CU4 fixed cost of service, providing for additional CU4 revenue in the tracker would be inappropriate.

Q. WHAT IS THE SECOND FALLACY UNDERLYING NWE'S CU4 LOST REVENUE CLAIM?

A. The second fallacy is in the calculation itself. The proceeding that resulted in CU4 going into rate base (Docket No. D2008.6.69) was held in 2008, and CU4 ratebasing became effective in January, 2009. However, in implementing rates to collect the authorized revenue requirement, the Company went back to its lower 2007 test year sales volumes rather than using actual or expected 2008 or 2009 sales. Using the lower 2007 test year sales volumes was not authorized in Commission Order 6925f, and the Company's intent to do so had not been addressed in Docket No. D2008.6.69. By the time that the CU4 rate case was completed and the plant went into rate base, it was known that 2007 test year sales were below actual 2008 sales and projected tracker year sales. NWE knew or should have known that using lower 2007 test year sales volumes as the basis for

establishing CU4 rates would immediately produce a revenue amount exceeding the fixed cost total that had been allowed by the Commission.

For these reasons, any CU4 "lost" revenue adjustment should be based on expected 2008/2009 sales and not on lower 2007 test year sales.[1] In addition, CU4 charges that were made to ratepayers in tracker year July 2009 through June 2010, based on 2007 test year sales volumes, were excessive, and a tracker adjustment should be made at this time to bring 2009/2010 tracker revenues back in line with the sales volume expectations that should have been used to calculate CU4 rates.

Q. HAS THE COMPANY EXPLAINED WHY IT CHOSE TO USE 2007 TEST YEAR SALES RATHER THAN SALES AT THE TIME OF THE CU4 CASE SO AS TO CALCULATE CU4 RATES THAT WOULD RECOVER MORE THAN THE COMMISSION'S ALLOWED CU4 FIXED COST REVENUES?

A. Data Request MCC-25 in Docket No. D2009.5.62 asked the Company to explain why it had used 2007 test year loads to determine CU4 rates in its filing. The Company responded that it did so because the CU4 fixed costs authorized by the Commission were based on a CU4 2007 test period revenue requirement.

[1] The Company's expected 2008/2009 tracker sales (5,902,371 Mwh) were nearly the same as actual sales (5,912,510 Mwh), and both were well above 2007 test year sales (5,741,321 Mwh).

Q. IS THIS A VALID JUSTIFICATION?

A. No. The basis for the Commission's approved CU4 fixed cost revenues was not even known in 2007, and did not come about until 2008. Indeed, the MCC had argued in the CU4 case (Docket No. D2008.6.69) that if CU4 was to be rate based, recoverable fixed cost revenues should be limited to CU4's actual 2007 fixed cost amounts. The Company opposed that position and argued that Commission approved fixed cost revenues for CU4 should not reflect the plant's actual costs at all, but a much higher "market value" for the plant that was, according to NWE, established in 2008 by a "bid" that had been received from another company that wanted to buy the plant. Ultimately, the Commission agreed with the Company and authorized fixed cost revenues that were not at all related to CU4's 2007 fixed costs.

For the Company to now claim that it should be allowed to charge excessive CU4 rates based on 2007 test year sales because the Commission authorized CU4 fixed revenues based on 2007 test year fixed costs is extreme overreaching. The Company strongly opposed the establishment of CU4 rates on the basis of the plant's actual 2007 costs. The Commission authorized rates do not reflect 2007 CU4 fixed costs at all, but a much

higher "market value" (which might be thought of as an "opportunity cost") that did not even exist in 2007.

Q. WHAT 2009/2010 TRACKER REVENUE ADJUSTMENTS SHOULD BE MADE TO PROPERLY REFLECT THE COMMISSION'S DETERMINED CU4 FIXED COST REVENUE REQUIREMENT OF $72,745,544?

A. There are two adjustments. First, excessive CU4 fixed cost recovery rates, calculated on the basis of 2007 test year sales, were charged throughout tracker year 2009/2010 on actual sales during the year of 5,743,422 Mwh. These rates were 2.8% higher than they would have been had they been more properly calculated on the basis of expected 2008/2009 sales as described above. Had the CU4 charge been more reasonably based on expected 2008/2009 sales volumes instead of lower 2007 test year sales that predated the ratebasing of CU4, the average CU4 fixed cost recovery rate would have been $0.012324 (as shown in Exhibit __ (JW-2)) rather than $0.012671 as used by the Company in the tracker. Correcting for this overcharge results in a 2009/2010 tracker year revenue reduction of $1,992,967.

Q. WHAT IS THE SECOND ADJUSTMENT THAT SHOULD BE MADE AS A RESULT OF USING 2008/2009 EXPECTED SALES

RATHER THAN 2007 TEST YEAR SALES TO CALCULATE CU4 FIXED COST RECOVERY RATES?

A. Any calculation of "lost" CU4 revenues should be based on expected 2008/2009 sales (which correspond with the time of the CU4 rate case and Order 6925f) rather than on lower historic 2007 test year sales. As shown in Exhibit __ (JW-3), this reduces total CU4-related DSM lost revenues for tracker year 2009/2010 to $631,903 from $649,709. Also, as shown in Exhibit __ (JW-3), total CU4-related DSM lost revenues for estimated tracker year 2010-2011 decline to $278,584 from $1,267,268. For the estimated 2010/2011 tracker year, $34,732 of the reduction is attributable to using expected 2008/2009 sales volumes instead of 2007 test year sales to develop CU4 rates, and $953,953 of the reduction is attributable to zeroing out the continuing DSM lost sales balance due to the interim rate increase that became effective in July 2010.

Q. SHOULD ESTIMATED LOST REVENUES, OTHER THAN CU4 REVENUES FOR THE FORECASTED TRACKER YEAR 2010/2011 ALSO BE MODIFIED TO ZERO OUT ONGOING REVENUE LOSSES AS OF JULY 2010 DUE TO THE COMMISSION'S APPROVAL OF INTERIM RATES IN DOCKET NO. D2009.9.129?

A. Yes. The Commission's approval of interim rates in that case should terminate ongoing lost revenues that originated from earlier DSM activities. As shown in Exhibit__ (JW-4), this reduces estimated 2010/2011 lost revenues from $3,612,263 to $742,567.

Q. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY AT THIS TIME?

A. Yes; it does.

NorthWestern Energy's Montana Electric Supply and Cost

2007 - 2011

	Tracker Year 2007/2008 (actual)		Tracker Year 2008/2009 (actual)		Tracker Year 2009/2010 (actual)		Tracker Year 2010/2011 (estimated)	
	%	$/Mwh	%	$/Mwh	%	$/Mwh	%	$/Mwh
PP&L Contract	35.41%	45.55	35.13%	47.15	35.32%	48.75	30.44%	50.35
S. T. Contract Transactions	14.13%	60.33	16.56%	64.66	15.82%	46.62	5.77%	48.59
Spot Market Transactions	12.70%	58.08	10.71%	49.38	12.53%	31.46	17.24%	40.56
CU4	13.18%	36.20	12.75%	49.01	12.64%	57.09	19.41%	56.32
QF Contracts	12.70%	33.89	13.70%	30.40	13.13%	34.83	13.02%	35.49
Judith Gap	7.95%	37.94	7.36%	39.86	6.72%	40.03	7.52%	36.97
Citigroup 08 RFP							3.46%	62.40
Other*	3.91%	77.29	3.79%	59.27	3.84%	56.77	3.13%	78.51
Total	100.0%	47.15	100.0%	48.15	100.0%	45.19	100.0%	48.08

* Other includes Tiber, J.P. Morgan, Powerex and Basin Creek. Starting in 2010-2011, Other includes Tiber, Basin Creek, PPL 09 RFP and Turnbull.

Northwestern Energy
Electric Supply Derivation of Rates
Colstrip Unit 4 Fixed Cost of Service Rates
July 1, 2010

Customer Rate Class	Loss Factor	Jul08 to Jun09 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	CU4 Fixed Cost of Service After Losses kWh Charges	CU4 Fixed Cost of Service Revenue/Cost Check
Residential	8.5100%	2,228,221,807	2,228,221,807	2,417,843,483	$ 0.012385	$ 27,596,527
Residential Employee	8.5100%	4,772,592	2,863,555	3,107,244	$ 0.007431	$ 35,465
GS 1 Secondary NonDemand	8.5100%	278,969,191	278,969,191	302,709,469	$ 0.012385	$ 3,455,033
GS 1 Secondary Demand	8.5100%	2,433,429,368	2,433,429,368	2,640,514,207	$ 0.012385	$ 30,138,023
GS 1 Primary NonDemand	5.5400%	512,450	512,450	540,840	$ 0.012046	$ 6,173
GS 1 Primary Demand	5.5400%	334,086,096	334,086,096	352,594,466	$ 0.012046	$ 4,024,401
General Service Substation	4.6300%	323,227,694	323,227,694	338,193,137	$ 0.011942	$ 3,859,985
General Service Transmission	4.0000%	151,000,897	151,000,897	157,040,933	$ 0.011871	$ 1,792,532
Irrigation	8.5100%	88,641,369	88,641,369	96,184,749	$ 0.012385	$ 1,097,823
Lighting	8.5100%	59,509,987	59,509,987	64,574,287	$ 0.012385	$ 737,031
MPSC System Average	7.4191%	5,902,371,450	5,900,462,413	6,373,302,813	$ 0.012328	$ 72,742,994
YNP Contract		19,093,231			Rounding Adjustment	$ 2,550
Total Supply Load		5,921,464,681				$ 72,745,544

Colstrip Unit 4 Fixed Cost of Service	$	72,745,544
Total CU4 Fixed COS Rate Before Losses	**$**	**0.011414**
Total CU4 Fixed COS Rate After Losses	**$**	**0.012324**

DSM Lost Revenues - Colstrip Unit 4 - Using Corrected Rates

(fixed cost portion of CU-4 supply rate)

	A	B	C	D	E	F	G	H
4	DSM Targets and Results:		**January-June 2009**		**Tracker 2009-10**		**Tracker 2010-11**	
5			**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
6		Annual (Avg. MW)	2.50	3.34	5.00	6.93	6.00	6.00
7		Cumulative (Avg. MW)	2.50	3.34	8.34	10.27	6.00	6.00
10	Disaggregate Targets into Residential & Commercial/Industrial [1]							
11			**January-June 2009**		**Tracker 2009-10**		**Tracker 2010-11**	
12			**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
13		% Residential	67%	62%	67%	68%	67%	68%
14		% Commercial & Industrial	34%	38%	34%	32%	34%	32%
16		Incremental Res. (Avg. MW)	1.66	2.08	3.33	4.74	3.99	4.11
17		Cumulative Res. (Avg. MW)	1.66	2.08	4.99	6.82	8.98	10.93
18		Incremental C/I (Avg. MW)	0.84	1.26	1.68	2.19	2.01	1.89
19		Cumulative C/I (Avg. MW)	0.84	1.26	2.51	3.45	4.52	5.34
20		check fig:	2.50	3.34	5.00	6.93	6.00	6.00
22		1. Residential/commercial split based on DSM Program results						
24			**January-June 2009**		**Tracker 2009-10**		**Tracker 2010-11**	
25	Cumulative Annual Energy Savings[2]		**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
26		Residential (MWH)	7,282	9,113	32,789	38,999	17,476	17,990
27		C/I (MWH)	3,668	5,538	18,412	20,648	8,804	8,290
28		Total Savings (MWH)	10,950	14,651	51,201	59,648	26,280	26,280
29		Total Savings (Avg. MW)	1.25	1.67	5.84	6.81	3.00	3.00
31		2. "Half-year convention":						
32		Savings resulting from the "Increment" in any year is reduced by 50% in that year as associated projects						
33		are completed and start generating savings at different times throughout the first year. This assumption contemplates that						
34		associated projects start generating savings half way through the year on average. In the second year and						
35		beyond, projects completed in the first year generate savings for the entire year so the "Increment" is credited at 100%						
36		for the second year and each successive year.						
38	3)	Disaggregate C&I Savings by service level (tariff)						
40		C&I Savings is broken out as:*						
41		GS-1 Secondary, non demand	0.01	1.0%	1.0%	1.0%	1.0%	1.0%
42		GS-1 Secondary, demand	0.98	98.0%	98.0%	98.0%	98.0%	98.0%
43		GS-1 Primary, non demand	0	0.0%	0.0%	0.0%	0.0%	0.0%
44		GS-1 Primary, demand	0.01	1.0%	1.0%	1.0%	1.0%	1.0%
45		Total C&I	100%	100%	100%	100%	100%	100%

	A	B	C	D	E	F	G	H
48								
49		**Rates:**						
50		**CU4 Fixed Rates**						
51			**01/01/09**	**01/01/10****	**01/01/11**			
52		Residential	$0.013273	$0.012385	$0.012385	per kwh		
53								
54		GS-1 Sec Non-Demand	$0.013273	$0.012385	$0.012385	per kwh		
55		GS-1 Sec Demand	$0.013273	$0.012385	$0.012385	per kwh		
56		GS-1 Pri Non-Demand	$0.012910	$0.012046	$0.012046	per kwh		
57		GS-1 Pri Demand	$0.012910	$0.012046	$0.012046	per kwh		
58								
59		GS-2 Substation	$0.012798	$0.011942	$0.011942	per kwh		
60		GS-2 Transmission	$0.012721	$0.011871	$0.011871	per kwh		
61		** Rates adjusted to reflect calculation based on supply retail kwh sales in 2008						
62								
63								
64		**Calculate CU-4 related DSM Lost Revenues**						
65		**January - June 2009**						
66		**Based on Cumulative DSM Savings Since January 2009**						
67								
68		Residential		**Gross**			**Estimated**	
69				**Program**		**Net**	**Lost**	
70			**Rate[1]**	**Savings**	**Adjustment**	**Savings**	**Revenue**	
71		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**	
72		Residential	$0.013273	9,112,652	0.87	7,947,802	105,491	
73						**7,947,802**	105,491	
74								
75		Commercial & Industrial		**Gross**			**Estimated**	
76				**Program**		**Net**	**Lost**	
77			**Rate[1]**	**Savings**	**Adjustment**	**Savings**	**Revenue**	
78		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**	
79		GS-1 Sec Non-Demand	$0.013273	55,379	0.82	45,627	606	
80		GS-1 Sec Demand	$0.013273	5,427,155	0.82	4,471,404	59,349	
81		GS-1 Pri Non-Demand	$0.012910	0	0.82	0	-	
82		GS-1 Pri Demand	$0.012910	55,379	0.82	45,627	589	
83								
84		GS-2 Substation	$0.012798	0	0.00	0	-	
85		GS-2 Transmission	$0.012721	0	0.00	0	-	
86				**Sub Total General Service:**		**4,562,657**	60,544	
87								
88		**Total CU-4-related DSM Lost Revenues Before Stipulation**					**$ 166,035**	
89								
90			**Stipulated CU-4-related DSM Lost Revenues**				**$ 83,021**	
91								

	A	B	C	D	E	F	G	H
92		**Tracker 2009-10 (rates adjusted)**						
93		**Based on Cumulative DSM Savings Since January 2009**						
94								
95		**Residential**		**Gross**			**Estimated**	
96				**Program**		**Net**	**Lost**	
97			**Rate****	**Savings**	**Adjustment**	**Savings**	**Revenue**	
98		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**	
99		Residential	$0.012385	38,999,284	0.87	34,014,094	421,265	
100						**34,014,094**	421,265	
101								
102		**Commercial & Industrial**		**Gross**			**Estimated**	
103				**Program**		**Net**	**Lost**	
104			**Rate****	**Savings**	**Adjustment**	**Savings**	**Revenue**	
105		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**	
106		GS-1 Sec Non-Demand	$0.012385	206,485	0.82	170,122	2,107	
107		GS-1 Sec Demand	$0.012385	20,235,516	0.82	16,671,931	206,482	
108		GS-1 Pri Non-Demand	$0.012046	0	0.82	0	-	
109		GS-1 Pri Demand	$0.012046	206,485	0.82	170,122	2,049	
110								
111		GS-2 Substation	$0.011942	0	0.00	0	-	
112		GS-2 Transmission	$0.011871	0	0.00	0	-	
113				**Sub Total General Service:**		**17,012,174**	210,638	
114								
115			**Total CU-4-related DSM Lost Revenues**				**$ 631,903**	
116								
117		**Tracker 2010-11**						
118		**Based on Cumulative DSM Savings Since July 2010**						
119				TARGET				
120		**Residential**		**Gross**			**Estimated**	
121				**Program**		**Net**	**Lost**	
122			**Rate****	**Savings**	**Adjustment**	**Savings**	**Revenue**	
123		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**	
124		Residential	$0.012385	17,476,200	0.87	15,242,257	188,775	
125						**15,242,257**	188,775	
126				TARGET				
127		**Commercial & Industrial**		**Gross**			**Estimated**	
128				**Program**		**Net**	**Lost**	
129			**Rate****	**Savings**	**Adjustment**	**Savings**	**Revenue**	
130		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**	
131		GS-1 Sec Non-Demand	$0.012385	88,038	0.82	72,534	898	
132		GS-1 Sec Demand	$0.012385	8,627,724	0.82	7,108,334	88,037	
133		GS-1 Pri Non-Demand	$0.012046	0	0.82	0	-	
134		GS-1 Pri Demand	$0.012046	88,038	0.82	72,534	874	
135								
136		GS-2 Substation	$0.011942	0	0.00	0	-	
137		GS-2 Transmission	$0.011871	0	0.00	0	-	
138				**Sub Total General Service:**		**7,253,403**	89,809	
139								
140			**Total CU-4-related DSM Lost Revenues**				**$ 278,584**	

Electric DSM Lost Revenues

Annual Energy Savings:

1) DSM Targets and Results:

	January-June 2008		Tracker 2008-09		Tracker 2009-10		Tracker 2010-11	
	Target	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
Annual (Avg. MW)	2.50	2.69	5.00	6.69	5.00	6.93	6.00	6.00
Cumulative (Avg. MW)	2.50	2.69	7.69	9.38	14.38	16.31	6.00	6.00

2) Disaggregate Targets into Residential & Commercial/Industrial [1]

	January-June 2008		Tracker 2008-09		Tracker 2009-10		Tracker 2010-11	
	Target	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
% Residential	69%	66.5%	67%	62%	67%	68%	67%	68%
% Commercial & Industrial	31%	33.5%	34%	37.8%	34%	32%	34%	32%
Incremental Res. (Avg. MW)	1.72	1.79	3.33	4.16	3.33	4.74	3.99	4.11
Cumulative Res. (Avg. MW)	1.72	1.79	5.04	5.95	8.37	10.69	3.99	4.11
Incremental C/I (Avg. MW)	0.78	0.90	1.68	2.53	1.68	2.19	2.01	1.89
Cumulative C/I (Avg. MW)	0.78	0.90	2.46	3.43	4.13	5.61	2.01	1.89
check fig:	2.50	2.69	5.00	6.69	5.00	6.93	6.00	6.00

1. Residential/commercial split based on DSM Program results

3) Cumulative Annual Energy Savings[2]

	January-June 2008		Tracker 2008-09		Tracker 2009-10		Tracker 2010-11	
	Target	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
Residential (MWH)	7,516	7,828	30,219	33,881	66,669	72,880	17,476	17,990
C/I (MWH)	3,434	3,943	15,223	18,962	37,375	39,611	8,804	8,290
Total Savings (MWH)	10,950	11,771	45,442	52,843	104,044	112,491	26,280	26,280
Total Savings (Avg. MW)	1.25	1.34	5.19	6.03	11.88	12.84	3.00	3.00

2. "Half-year convention":
Savings resulting from the "Increment" in any year is reduced by 50% in that year as associated projects are completed and start generating savings at different times throughout the first year. This assumption contemplates that associated projects start generating savings half way through the year on average. In the second year and beyond, projects completed in the first year generate savings for the entire year so the "Increment" is credited at 100% for the second year and each successive year.

	A	B	C	D	E	F	G	H	I
113									
114	**2010-11 Lost Revenues:**								
115	**Based on Cumulative DSM Savings Since July 2010**								
116									
117	**Residential**			**TARGET**					
118				**Gross**					**Estimated**
119				**Program**			**Net**		**Lost**
120		**Rate[1]**		**Savings**		**Adjustment**	**Savings**		**Revenue**
121	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
122	Transmission Energy	0.009098		17,476,200		0.872	15,242,257		138,674
123	Distribution Energy	0.028322		17,476,200		0.872	15,242,257		431,691
124					**Sub Total Residential:**		**15,242,257**		**$ 570,365**
125									
126									
127	**Commercial & Industrial**			**TARGET**	**TARGET**				
128				**Gross**	**Gross**				**Estimated**
129				**Program**	**Program**		**Net**	**Net**	**Lost**
130		**Rate[1]**	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
131	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
132	GS-1 Secondary, non demand, TX Energy	0.008276		88,038		0.824	72,534		600
133	GS-1 Secondary, non demand, Dist. Energy	0.038321		88,038		0.824	72,534		2,780
134									
135	GS-1 Secondary, demand, TX Demand		2.966604		17,907	0.824		14,754	43,768
136	GS-1 Secondary, demand, Dist. Energy	0.004797		8,627,724		0.824	7,108,334		34,099
137	GS-1 Secondary, demand, Dist. Demand		6.047358		17,907	0.824		14,754	89,221
138									
139	GS-1 Primary, non demand, TX Energy	0.008123		0		0.824	0		0
140	GS-1 Primary, non demand, Dist. Energy	0.018624		0		0.824	0		0
141									
142	GS-1 Primary, demand, TX Demand		3.806795		183	0.824		151	573
143	GS-1 Primary, demand, Dist. Energy	0.007322		88,038		0.824	72,534		531
144	GS-1 Primary, demand, Dist. Demand		4.18008		183	0.824		151	629
145				**Sub Total Commercial & Industrial:**			**7,253,403**		**$ 172,201**
146									
147		**2010-11 Lost Revenues:**		**Estimated Totals:**			**22,495,659**		**$ 742,567**
148	Note 1: using rates in effect at the time (see Rates tab)								