BEFORE THE DEPARTMENT OF PUBLIC SERVICE REGULATION

MONTANA PUBLIC SERVICE COMMISSION

DOCKET NO. D2012.5.49

Electricity Supply Tracker

**Colstrip Unit 4 Generation Asset
Variable Cost/Adjustment**

**Dave Gates Generating Station
Variable Cost/Credit Adjustments**

July 1, 2012 to June 30, 2013

NorthWestern Energy

CELEBRATING OUR FIRST CENTURY
1912 - 2012
BUILDING FOR OUR SECOND

May 31, 2012

Ms. Kate Whitney
Administrator, Regulatory Division
Montana Public Service Commission
1701 Prospect Avenue
PO Box 202601
Helena, MT 59620-2601

RE: D2012.5.49 – NorthWestern Energy's Electricity Supply Tracker, Colstrip Unit 4 Variable Cost/Credit True-up, Dave Gates Generating Station Variable Cost/Credit True-up Filing

Dear Ms. Whitney:

Pursuant to Montana law, the Montana Public Service Commission ("MPSC" or "Commission") rules, the Deferred Accounting Electric Procedure approved by the Commission in Order No. 6382c in Docket No. D2001.10.144 on June 26, 2002, Order No. 6943a in Docket D2008.8.95, and Order No. 6925f in Docket D2008.6.69, NorthWestern Energy ("NWE" or "NorthWestern") hereby transmits an original and ten copies of its annual Application for approval of electric rates which:

- Reflects rate treatment for the net balance in the Electric Supply Deferred Cost Account, for the 12-month period ending June 30, 2012, including electricity supply costs, Colstrip Unit 4 ("CU4") variable costs/credits, and the Dave Gates Generating Station ("DGGS") variable costs/credits;

- Reflects the projected load, supply, and related electricity supply costs for the 12-month tracker period July 1, 2012 through June 30, 2013;

- Reflects the projected load and CU4 variable costs for the 12-month period July 1, 2012 through June 30, 2013; and

- Reflects the projected load and DGGS variable costs for the 12-month period July 1, 2012 through June 30, 2013.

This filing also includes:

- The CU4 fixed cost of service; and
- The DGGS fixed cost of service.

No rate treatment is requested for these fixed cost of service items.

NorthWestern has separated this annual electric supply filing into three components:

1. Electricity Supply Tracker;
2. CU4 Generation Asset Variable Cost True-up; and
3. DGGS Generation Asset Variable Cost True-up.

The associated separate rate components are bundled together into a single overall supply rate and net deferred cost rate for customer billing. Appendix A to the Application presents a summary of the current tariff rates and the proposed rates in this filing, as well as the resulting dollar and percentage changes.

The market-based Electricity Supply Cost section of the tracker model continues to be the rolling 12-month forecast updated for current market prices and loads. The CU4 fixed cost revenue requirement is identical to the information provided in the past annual tracker filing and will remain the same until an order is issued in a future revenue requirement filing. The CU4 variable cost section is the 12-month forecast updated for current fuel prices.

The DGGS fixed cost revenue requirement rate is unchanged from the May 1, 2012 monthly tracker filing reflecting Order No. 6943e in Docket No. D2008.8.95 and will remain the same until an order is issued in a future revenue requirement filing. The DGGS variable cost section is the 12-month forecast updated for current fuel prices. Since the DGGS estimated deferred account over-collection balance at the end of June 2012 is not material, NWE proposes to set the rate at zero and carry forward the DGGS Variable Cost/Credit deferred account balance into the 2012-2013 true-up period.

The Electric Supply Deferred Cost Account Balance of $8,502,457 for the period ending June 30, 2012 includes an under-collection of $11,496,428 of electricity supply costs offset by the over-collection of $(2,993,971) in the CU4 Variable Cost/Credit Account Balance. As stated above, the DGGS Variable Cost/Credit Account Balance is not material and will be carried forward into the next true-up period.

The projected overall Electric Supply Cost and net Supply Deferred Cost in this filing result in an increase for a typical residential customer using 750 kWh per month of $2.62 per month or $31.44 per year on the total bill. This will result in an overall 5.94% increase for supply-related costs.

The typical residential bill calculation shows the combined effect of the proposed July 1, 2012 rate changes for the decreased Competitive Transition Charge for Qualifying Facilities ("CTC-QF"), and the increased BPA Residential Exchange Credit ("BPA Credit"). The total effect of the increase in the Total Electric Supply rates, along with the CTC-QF and BPA Credit rate adjustments on the typical residential customer's bill, is a projected increase of $2.16 per month or $25.92 per year.

Including all July 1, 2012 rate adjustments, the total overall bill increase for the typical residential customer is estimated to be 2.70%. The actual increase will depend on each customer's type and usage. Typical bill computations by customer class are included in Appendix B to this Application.

Other documents submitted with this filing are:

1. Application for Interim and Final Rate Adjustment, including Appendices A and B;

2. Notice of Interim Rate Adjustment Request and Certificate of Service of said notice to the media; and

3. Prefiled Testimony and Exhibits of David E. Fine, Kevin J. Markovich, Frank V. Bennett (three components), Cheryl A. Hansen (three components), and William M. Thomas.

Three copies of this letter and documents submitted herewith are being delivered to the Montana Consumer Counsel ("MCC").

NWE's next monthly tracking filing will be for rates effective August 1, 2012, unless electricity prices move dramatically in either direction prior to June 15, 2012. If this occurs, NWE will file an updated electricity supply tracker filing for a July 1, 2012 monthly rate adjustment.

The NWE employee responsible for answering questions concerning this rate change request or for inquiries to the appropriate members of the Utility Staff is:

Joe Schwartzenberger
Regulatory Affairs Department
NorthWestern Energy
40 East Broadway
Butte, MT 59701
(406) 497-3362
joe.schwartzenberger@northwestern.com

NorthWestern's attorneys in this matter are:

Mr. Al Brogan
NorthWestern Energy
208 N. Montana, Suite 205
Helena, Montana 59601
Tel. (406) 443-8903
Fax (406) 443-8979
al.brogan@northwestern.com

Ms. Sarah Norcott
NorthWestern Energy
208 N. Montana, Suite 205
Helena, Montana 59601
Tel. (406) 443-8996
Fax (406) 443-8979
sarah.norcott@northwestern.com

Along with Joe Schwartzenberger, Al Brogan, and Sarah Norcott, please add Nedra Chase to the official service list in this docket to receive copies of all documents. NWE also requests that all electronic correspondence related to this filing be sent to nedra.chase@northwestern.com.

If there are any questions in this regard, I can be reached at (406) 497-3362.

Sincerely,

Joe Schwartz

Joe Schwartzenberger
Director of Regulatory Affairs

Enclosures
cc: Montana Consumer Counsel

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of NorthWestern Energy's Annual Electricity Supply Tracker, Colstrip Unit 4 Generation Asset Variable Cost/Adjustment and Dave Gates Generating Station Variable Cost/Credit Adjustments under Docket No. D2012.5.49 will be e-filed with the PSC. It will also be served upon the attached service list.

Dated this 31st day of May 2012

Nedra Chase

Nedra Chase
Administrative Assistant

A. Service List
D2012.5.49

Al Brogan
NorthWestern Energy
208 N. Montana Suite 205
Helena MT 59601

Nedra Chase
NorthWestern Energy
40 E. Broadway
Butte MT 59701

Robert Nelson
Montana Consumer Counsel
111 N. Last Chance Gulch
Suite 1B Box 201703
Helena MT 59620-1703

Sarah Norcott
NorthWestern Energy
208 N. Montana Suite 205
Helena MT 59601

Joe Schwartzenberger
NorthWestern Energy
40 E Broadway
Butte MT 59701

Kate Whitney
Montana PSC
1701 Prospect Box 202601
Helena MT 59620-2601

AL BROGAN
NorthWestern Energy
208 N. Montana, Suite 205
Helena, Montana 59601
Tel. (406) 443-8903
Fax (406) 443-8979
al.brogan@northwestern.com

SARAH NORCOTT
NorthWestern Energy
208 N. Montana, Suite 205
Helena, Montana 59601
Tel. (406) 443-8996
Fax (406) 443-8979
sarah.norcott@northwestern.com

Attorneys for NorthWestern Energy

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

In the Matter of NorthWestern Energy's Application For:	)	
(1) Approval of Deferred Cost Account Balances for	)	
Electricity Supply, CU4 Variable Costs/Credits, and	)	Docket No. D2012.5.49
DGGS Variable Costs/Credits; and (2) Projected	)	
Electricity Supply Cost Rates, CU4 Variable Rates,	)	
and DGGS Variable Rates	)	

APPLICATION FOR INTERIM AND FINAL ELECTRICITY RATE ADJUSTMENT

COMES NOW, NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern," "NWE," or "Applicant") by and through its undersigned counsel, and respectfully submits this Application for approval of (1) Deferred Cost Account Balances for Electricity Supply, Colstrip Unit #4 ("CU4") Variable Costs/Credits, and Dave Gates Generating Station ("DGGS") Variable Costs/Credits; and (2) projected Electricity Supply Cost Rates, CU4 Variable Rates, and DGGS Variable Rates to the Montana Public Service Commission ("Commission") in the above-captioned docket. In support thereof, NorthWestern states as follows:

I.

Applicant's full name and address are:

NorthWestern Energy
40 East Broadway
Butte, MT 59701

II.

Applicant is a Delaware corporation doing business as NorthWestern Energy in the states of Montana, South Dakota, and Nebraska as a public utility.

III.

The following described tariff sheet is the only electric sheet impacted by the proposals in this submittal that is presently in effect in the State of Montana and on file with the Commission. All other electric tariff sheets remain as previously approved by the Commission:

Schedule	Description	Sheet No.
ESS-1	Electric Supply Service	60.1

The applicable rates for this tariff sheet are summarized and contained in Appendix A (attached hereto).

IV.

Applicant will submit new a tariff sheet for electric service to customers upon approval of the proposed rates contained in Appendix A. The proposed new rates will replace the present tariff sheet as follows:

Schedule	Description	Sheet No.
ESS-1	Electric Supply Service	60.1

V.

In accordance with the Deferred Accounting method approved by the Commission in Order No. 6382c in Docket No. D2001.10.144 on June 26, 2002, Order No. 6925f in Docket No. D2008.6.69, and Order No. 6943a in Docket No. D2008.8.95, the balance in Account No. 191, Electric Supply Deferred Costs, for the 12-month period ending June 30, 2012 is an under-collection of $8,502,457. This balance consists of $11,496,428 for the under-collection of electricity supply costs from July 1, 2011 to June 30, 2012 offset by an over-collection of $(2,993,971) of CU4 Variable Costs/Credits. Because the over-collection of $(161,231) of DGGS Variable Costs/Credits is not material, NorthWestern proposes to set the rate at zero and carry forward the DGGS Variable Cost/Credit deferred account balance into the 2012-2013 true-up period. NWE proposes to amortize the electricity supply and CU4 net under-collection balance in rates over the 12-month period ending June 2013. The net deferred electric supply rate per kWh is shown on Appendix A. The tracking market supply and electricity costs for the 12-month period, July 1, 2012 to June 30, 2013, produce an overall electricity supply cost per kWh as shown on Appendix A to this filing. This overall rate includes the following components: Electricity Supply Costs, CU4 Fixed Cost of Service, CU4 Variable Costs/Credits, DGGS Fixed Cost of Service, and DGGS Variable Costs/Credits. No adjustments are requested for the fixed cost of service rates.

In addition, NWE proposes to continue to use the monthly tracking methodology in which a forecast of 12 months is used in this annual filing for the period July 1 through June 30 of the tracking year. Each subsequent monthly calculation is also based on a rolling 12-month forecast.

VI.

The proposed new rates contained in Appendix A reflect:

1. The treatment of the Electricity Supply Deferred Cost Account Balance, the CU4 Variable Cost/Credit Account Balance, and the DGGS Variable Cost/Credit Account Balance described in Paragraph No. V; and

2. The projected overall monthly market supply and costs—including electricity supply costs, CU4 costs, and DGGS costs—as described in Paragraph No. V.

VII.

Attached hereto and incorporated by reference are the following documents:

- Appendix A – Current and proposed rates;
- Appendix B – Typical bill computation;
- Notice of Interim Rate Adjustment Request and the Certificate of Service of said notice to the media; and
- Prefiled Direct Testimony and exhibits of David E. Fine, Kevin J. Markovich, Frank V. Bennett (three components), Cheryl A. Hansen (three components), and William M. Thomas.

WHEREFORE, Applicant respectfully requests that the Commission:

1. Grant interim and final approval of the proposed rates included as Appendix A to be effective on a monthly basis for service on and after July 1, 2012;
2. Grant such other and additional relief, as the Commission shall deem just and proper.

RESPECTFULLY SUBMITTED this 31st day of May 2012.

NORTHWESTERN ENERGY

By: Al Brogan

Al Brogan
NorthWestern Energy
and

Sarah Norcott
NorthWestern Energy

Attorneys for NorthWestern Corporation
d/b/a NorthWestern Energy

NorthWestern Energy
Electric Utility
Electricity Supply Costs, CU4 Fixed Cost of Service & Variable Costs\Credits, DGGS Fixed Cost of Service and Variable Costs/Credits & Deferred Electricity Supply and CU4 Variable Cost/Credit
Rate Change Detail
Effective July 1, 2012

Overall Electric Supply Rate ($/kWh)	Current 6/1/2012	Proposed	Rate Change	Percentage Change
Residential	$ 0.059487	$ 0.060912	$ 0.001425	2.40%
Employee	$ 0.035692	$ 0.036547	$ 0.000855	2.40%
GS-1 Secondary Non-Demand	$ 0.055922	$ 0.057184	$ 0.001262	2.26%
GS-1 Secondary Demand	$ 0.059486	$ 0.060911	$ 0.001425	2.40%
GS-1 Primary Non-Demand	$ 0.057855	$ 0.059241	$ 0.001386	2.40%
GS-1 Primary Demand	$ 0.054698	$ 0.055940	$ 0.001242	2.27%
GS-2 Substation	$ 0.057358	$ 0.058732	$ 0.001374	2.40%
GS-2 Transmission	$ 0.057012	$ 0.058378	$ 0.001366	2.40%
Irrigation	$ 0.055922	$ 0.057184	$ 0.001262	2.26%
Lighting	$ 0.055922	$ 0.057184	$ 0.001262	2.26%

Net Deferred Electric Supply Rate ($/kWh)	Current 6/1/2012	Proposed	Rate Change	Percentage Change
Residential	$ (0.000640)	$ 0.001435	$ 0.002075	324.22%
Employee	$ (0.000384)	$ 0.000861	$ 0.001245	324.22%
GS-1 Secondary Non-Demand	$ (0.000640)	$ 0.001435	$ 0.002075	324.22%
GS-1 Secondary Demand	$ (0.000640)	$ 0.001435	$ 0.002075	324.22%
GS-1 Primary Non-Demand	$ (0.000623)	$ 0.001396	$ 0.002019	324.08%
GS-1 Primary Demand	$ (0.000623)	$ 0.001396	$ 0.002019	324.08%
GS-2 Substation	$ (0.000617)	$ 0.001384	$ 0.002001	324.31%
GS-2 Transmission	$ (0.000614)	$ 0.001376	$ 0.001990	324.10%
Irrigation	$ (0.000640)	$ 0.001435	$ 0.002075	324.22%
Lighting	$ (0.000640)	$ 0.001435	$ 0.002075	324.22%

	A	B	C	D	E	F	G	H	I	J	K
1											
2	NorthWestern Energy										
3											
4											
5											
6	Typical Bill Calculation										
7											
8											
9	Electric Residential Service							*CTC-QF, BPA-Credit and Overall Electric Supply			
10					*Current Rates*			[1] *Proposed Rates*			
11		**kWh per month**	750		**Date**			**Date**			
12					**Effective**	Total Bill		**Effective**	Total Bill		
13					**6/1/2012**	Amount		**7/1/2012**	Amount		
14	Res. Dist.-Service Charge				$ 5.05	$ 5.05		$ 5.05	$ 5.05		
15											
16	Plus:										
17	Res. Supply-Energy				$ 0.059487	$ 44.62		$ 0.060912	$ 45.68		
18	Res. Deferred Supply Costs				$ (0.000640)	$ (0.48)		$ 0.001435	$ 1.08		
19	Res. CTC-QF				$ 0.003439	$ 2.58		$ 0.003384	$ 2.54		
20	Res. Transmission-Energy				$ 0.008866	$ 6.65		$ 0.008866	$ 6.65		
21	Res. Distribution-Energy				$ 0.027599	$ 20.70		$ 0.027599	$ 20.70		
22	Res. USBC				$ 0.001334	$ 1.00		$ 0.001334	$ 1.00		
23	Res. BPA-Credit				$ (0.000258)	$ (0.19)		$ (0.000818)	$ (0.61)		
24	Total Kwh Charge				$ 0.099827	$ 74.88		$ 0.102712	$ 77.04		
25											
26	**Total Bill**				**$ 0.106560**	**$ 79.93**		**$ 0.109445**	**$ 82.09**		
27											
28						Monthly Increase (Decrease)			$ 2.16		
29						Annual Increase (Decrease)			$ 25.92		
30						**Percent Change**			**2.70%**		
31											
32											
33											
34	[1]**Column represents the proposed rate changes for CTC-QF, BPA Credit, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2012.**										

NorthWestern Energy

	A	B	C	D	E	F	G	H	I	J	K
1											
2											
3											
4											
5											
6	Typical Bill Calculation										
7											
8	**General Service - Secondary**										
9	**Non-Demand**										
10								**CTC-QF and Overall Electric Supply**			
11					***Current Rates***			***[1] Proposed Rates***			
12		**kWh per month**	**3500**		**Date**			**Date**			
13					**Effective**	Total Bill		**Effective**	Total Bill		
14					**6/1/2012**	Amount		**7/1/2012**	Amount		
15	GS-1 Dist.-Service Charge				$ 7.15	$ 7.15		$ 7.15	$ 7.15		
16											
17	Plus:										
18	GS-1 Supply-Energy				$ 0.055922	$ 195.73		$ 0.057184	$ 200.14		
19	GS-1 Deferred Supply Costs				$ (0.000640)	$ (2.24)		$ 0.001435	$ 5.02		
20	GS-1 CTC-QF				$ 0.003439	$ 12.04		$ 0.003384	$ 11.84		
21	GS-1 Transmission-Energy				$ 0.007719	$ 27.02		$ 0.007719	$ 27.02		
22	GS-1 Distribution-Energy				$ 0.035745	$ 125.11		$ 0.035745	$ 125.11		
23	GS-1 USBC				$ 0.001143	$ 4.00		$ 0.001143	$ 4.00		
24	Total Kwh Charge				$ 0.103328	$ 361.66		$ 0.106610	$ 373.13		
25											
26	**Total Bill**				**$ 0.105370**	**$ 368.81**		**$ 0.108650**	**$ 380.28**		
27											
28						Monthly Increase (Decrease)			$ 11.47		
29						Annual Increase (Decrease)			$ 137.64		
30						**Percent Change**			**3.11%**		
31											
32											
33	**[1]Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2012.**										

NorthWestern Energy

Typical Bill Calculation

General Service - Secondary Demand

Row	A	B	C	E	F	H	I
10						**CTC-QF and Overall Electric Supply**	
11		**Kw**	11	***Current Rates***		***[1] Proposed Rates***	
12		**kWh per month**	3500	**Date**		**Date**	
13				**Effective**	Total Bill	**Effective**	Total Bill
14				**6/1/2012**	Amount	**7/1/2012**	Amount
15	GS-1 Dist.-Service Charge			$ 8.95	$ 8.95	$ 8.95	$ 8.95
16							
17	Plus:						
18	GS-1 Supply-Energy			$ 0.059486	$ 208.20	$ 0.060911	$ 213.19
19	GS-1 Deferred Supply Costs			$ (0.000640)	$ (2.24)	$ 0.001435	$ 5.02
20	GS-1 CTC-QF			$ 0.003439	$ 12.04	$ 0.003384	$ 11.84
21	GS-1 Transmission-Demand			$ 2.949439	$ 32.44	$ 2.949439	$ 32.44
22	GS-1 Distribution-Demand			$ 6.012368	$ 66.14	$ 6.012368	$ 66.14
23	GS-1 Distribution-Energy			$ 0.004769	$ 16.69	$ 0.004769	$ 16.69
24	GS-1 USBC			$ 0.001143	$ 4.00	$ 0.001143	$ 4.00
25	Subtotal				$ 337.27		$ 349.32
26							
27	**Total Bill**			**$ 0.098920**	**$ 346.22**	**$ 0.102360**	**$ 358.27**
28							
29					Monthly Increase (Decrease)		$ 12.05
30					Annual Increase (Decrease)		$ 144.60
31					**Percent Change**		**3.48%**
32							
33							

[1] **Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2012.**

NorthWestern Energy

Typical Bill Calculation

General Service - Primary Non-Demand

					CTC-QF and Overall Electric Supply	
		Current Rates			[1] *Proposed Rates*	
	kWh per month	2000	Date Effective 6/1/2012	Total Bill Amount	Date Effective 7/1/2012	Total Bill Amount
GS-1 Dist.-Service Charge			$ 7.60	$ 7.60	$ 7.60	$ 7.60
Plus:						
GS-1 Supply-Energy			$ 0.057855	$ 115.71	$ 0.059241	$ 118.48
GS-1 Deferred Supply Costs			$ (0.000623)	$ (1.25)	$ 0.001396	$ 2.79
GS-1 CTC-QF			$ 0.003345	$ 6.69	$ 0.003291	$ 6.58
GS-1 Transmission-Energy			$ 0.008075	$ 16.15	$ 0.008075	$ 16.15
GS-1 Distribution-Energy			$ 0.018514	$ 37.03	$ 0.018514	$ 37.03
GS-1 USBC			$ 0.001143	$ 2.29	$ 0.001143	$ 2.29
Total Kwh Charge			$ 0.088309	$ 176.62	$ 0.091660	$ 183.32
Total Bill			**$ 0.092110**	**$ 184.22**	**$ 0.095460**	**$ 190.92**
				Monthly Increase (Decrease)		$ 6.70
				Annual Increase (Decrease)		$ 80.40
				Percent Change		**3.64%**

[1]Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2012.

NorthWestern Energy

	A	B	C	D	E	F	G	H	I	J	K
1											
2	NorthWestern Energy										
3											
4											
5											
6	Typical Bill Calculation										
7											
8	General Service - Primary Demand										
9											
10								CTC-QF and Overall Electric Supply			
11		Kw	400		*Current Rates*			[1] *Proposed Rates*			
12		kWh per month	200000		Date			Date			
13					Effective	Total Bill		Effective	Total Bill		
14					6/1/2012	Amount		7/1/2012	Amount		
15	GS-1 Dist.-Service Charge				$ 24.10	$ 24.10		$ 24.10	$ 24.10		
16											
17	Plus:										
18	GS-1 Supply-Energy				$ 0.054698	$ 10,939.60		$ 0.055940	$ 11,188.00		
19	GS-1 Deferred Supply Costs				$ (0.000623)	$ (124.60)		$ 0.001396	$ 279.20		
20	GS-1 CTC-QF				$ 0.003345	$ 669.00		$ 0.003291	$ 658.20		
21	GS-1 Transmission-Demand				$ 3.584870	$ 1,433.95		$ 3.584870	$ 1,433.95		
22	GS-1 Distribution-Demand				$ 3.936395	$ 1,574.56		$ 3.936395	$ 1,574.56		
23	GS-1 Distribution-Energy				$ 0.006896	$ 1,379.20		$ 0.006896	$ 1,379.20		
24	GS-1 USBC				$ 0.001143	$ 228.60		$ 0.001143	$ 228.60		
25	Subtotal					$ 16,100.31			$ 16,741.71		
26											
27	**Total Bill**				**$ 0.080620**	**$ 16,124.41**		**$ 0.083830**	**$ 16,765.81**		
28											
29						Monthly Increase (Decrease)			$ 641.40		
30						Annual Increase (Decrease)			$ 7,696.80		
31						**Percent Change**			**3.98%**		
32											
33											
34	[1]Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2012.										

NorthWestern Energy

	A	B	C	D	E	F	G	H	I
1									
2	NorthWestern								
3									
4	Energy								
5									
6	Typical Bill Calculation								
7									
8	Irrigation & Sprinkling Service								
9	Non-Demand								
10								CTC-QF, BPA Credit and Overall Electric Supply	
11					*Current Rates*			[1] *Proposed Rates*	
12		**kWh per month**	**1342**		**Date**			**Date**	
13					**Effective**	Total Bill		**Effective**	Total Bill
14					**6/1/2012**	Amount		**7/1/2012**	Amount
15	Irr. Dist.-Service Charge			(a)	$ 8.72	$ 8.72		$ 8.72	$ 8.72
16									
17	Plus:								
18	Irr. Supply-Energy				$ 0.055922	$ 75.05		$ 0.057184	$ 76.74
19	Irr. Deferred Supply Costs				$ (0.000640)	$ (0.86)		$ 0.001435	$ 1.93
20	Irr. CTC-QF				$ 0.003439	$ 4.62		$ 0.003384	$ 4.54
21	Irr. Transmission-Energy				$ 0.011248	$ 15.09		$ 0.011248	$ 15.09
22	Irr. Distribution-Energy				$ 0.022920	$ 30.76		$ 0.022920	$ 30.76
23	Irr. USBC				$ 0.001144	$ 1.54		$ 0.001144	$ 1.54
24	Irr. BPA Credit				$ (0.000258)	$ (0.35)		$ (0.000818)	$ (1.10)
25	Total Kwh Charge				$ 0.093775	$ 125.85		$ 0.096497	$ 129.50
26									
27	**Total Bill**				**$ 0.100270**	**$ 134.57**		**$ 0.102990**	**$ 138.22**
28									
29						Monthly Increase (Decrease)			$ 3.65
30						Season Incr (Decr) (6 Months)			$ 21.90
31						**Percent Increase**			**2.71%**
32									
33									
34	(a) The seasonal charge is divided by 6 months to compute a monthly average.								
35									
36	[1] Column represents the proposed rate changes for CTC-QF, BPA Credit, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2012.								

NorthWestern Energy

Typical Bill Calculation

Irrigation & Sprinkling Service Demand

					Current Rates		*[1] Proposed Rates* (CTC-QF, BPA Credit and Overall Electric Supply)	
Row	A	B	C	D	Date Effective 6/1/2012	Total Bill Amount	Date Effective 7/1/2012	Total Bill Amount
11		**Kw**	41					
12		**kWh per month**	12260					
15	Irr. Dist.-Service Charge			(a)	$ 20.55	$ 20.55	$ 20.55	$ 20.55
16								
17	Plus:							
18	Irr. Supply-Energy				$ 0.055922	$ 685.60	$ 0.057184	$ 701.08
19	Irr. Deferred Supply Costs				$ (0.000640)	$ (7.85)	$ 0.001435	$ 17.59
20	Irr. CTC-QF				$ 0.003439	$ 42.16	$ 0.003384	$ 41.49
21	Irr. Transmission-Demand				$ 1.929804	$ 79.12	$ 1.929804	$ 79.12
22	Irr. Distribution-Demand				$ 7.032714	$ 288.34	$ 7.032714	$ 288.34
23	Irr. Distribution-Energy				$ 0.003809	$ 46.70	$ 0.003809	$ 46.70
24	Irr. USBC				$ 0.001144	$ 14.03	$ 0.001144	$ 14.03
25	Irr. BPA Credit				$ (0.000258)	$ (3.16)	$ (0.000818)	$ (10.03)
26	Subtotal					$ 1,144.94		$ 1,178.32
27								
28	**Total Bill**				**$ 0.095060**	**$ 1,165.49**	**$ 0.097790**	**$ 1,198.87**
29								
30						Monthly Increase		$ 33.38
31						Season Increase (6 Months)		$ 200.28
32						**Percent Increase**		**2.86%**

(1) The seasonal charge is divided by 6 months to compute a monthly average.

[1]Column represents the proposed rate changes for CTC-QF, BPA Credit, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2012.

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

In the Matter of NorthWestern Energy's Application For: (1) Approval of Deferred Cost Account Balances for Electricity Supply, CU4 Variable Costs/Credits, and DGGS Variable Costs/Credits; and (2) Projected Electricity Supply Cost Rates, CU4 Variable Rates, and DGGS Variable Rates	))))))	Docket No. D2012.5.49

NOTICE OF INTERIM RATE ADJUSTMENT REQUEST

NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern" or "NWE") serves notice pursuant to ARM 38.5.503 that it has filed with the Montana Public Service Commission ("MPSC"), via its Application, a request for an interim rate increase in electric supply rates in this Docket to reflect forecast overall Electric Supply Costs and the net Electric Supply Deferred Cost Account Balance. This Interim request includes the use of monthly electricity supply cost adjustments, Colstrip Unit 4 ("CU4") Variable Cost/Credit true-ups, and Dave Gates Generating Station ("DGGS") Variable Cost/Credit true-ups going forward. Applicant requests that the proposed rates, monthly electricity supply cost rate adjustment, CU4 true-up rate adjustments, and DGGS true-up rate adjustments become effective for service on and after July 1, 2012.

This Docket commenced on May 31, 2012 when NorthWestern filed testimony and exhibits with the MPSC in its annual Electricity Supply Tracker, CU4 Variable Cost/Credit True-up, and DGGS Variable Cost/Credit True-up Filing. NorthWestern requested an interim change in rates effective July 1, 2012 pending a final decision on its Application.

The rate changes are required to: 1) reflect an increase in the projected electricity supply costs, an increase in the projected CU4 variable costs/credits, and a decrease in the projected DGGS variable costs/credits; and 2) amortize the amounts in the Deferred Cost Account Balances for Electricity Supply and CU4 Variable Costs/Credits for the 12-month period ending June 30, 2012. Because the DGGS Variable Costs/Credits balance is not material, NorthWestern proposes to set this rate at zero and carry forward the DGGS deferred account balance into the 2012-2013 true-up period.

The net adjustments proposed in this filing result in the following:

- Overall electric supply costs per kWh increase as shown in the table below:

Overall Electric Supply Rate ($/kWh)	Current	Proposed	Rate Change	% Change
Residential	$ 0.059487	$ 0.060912	$ 0.001425	2.40%
Employee	$ 0.035692	$ 0.036547	$ 0.000855	2.40%
GS-1 Secondary Non-Demand	$ 0.055922	$ 0.057184	$ 0.001262	2.26%
GS-1 Secondary Demand	$ 0.059486	$ 0.060911	$ 0.001425	2.40%
GS-1 Primary Non-Demand	$ 0.057855	$ 0.059241	$ 0.001386	2.40%
GS-1 Primary Demand	$ 0.054698	$ 0.055940	$ 0.001242	2.27%
GS-2 Substation	$ 0.057358	$ 0.058732	$ 0.001374	2.40%
GS-2 Transmission	$ 0.057012	$ 0.058378	$ 0.001366	2.40%
Irrigation	$ 0.055922	$ 0.057184	$ 0.001262	2.26%
Lighting	$ 0.055922	$ 0.057184	$ 0.001262	2.26%

- The electric supply deferred costs balance for the 12-month period ending June 30, 2012 is an under-collection of $8,502,457. This balance consists of $11,496,428 for the under-collection of electricity supply costs from July 1, 2011 to June 30, 2012 plus the CU4 variable costs/credits over-collection of $(2,993,971) for the same time period. As described above, the DGGS variable costs/credits balance will be carried forward into the 2012-2013 true-up period. NWE proposes to amortize the net under-collection in rates over the 12-month period ending June 2013. The resulting net electric deferred cost rates are shown below:

Net Electric Deferred Cost Rate ($/kWh)	Current	Proposed	Rate Change	% Change
Residential	$(0.000640)	$ 0.001435	$ 0.002075	324.22%
Employee	$(0.000384)	$ 0.000861	$ 0.001245	324.22%
GS-1 Secondary Non-Demand	$(0.000640)	$ 0.001435	$ 0.002075	324.22%
GS-1 Secondary Demand	$(0.000640)	$ 0.001435	$ 0.002075	324.22%
GS-1 Primary Non-Demand	$(0.000623)	$ 0.001396	$ 0.002019	324.08%
GS-1 Primary Demand	$(0.000623)	$ 0.001396	$ 0.002019	324.08%
GS-2 Substation	$(0.000617)	$ 0.001384	$ 0.002001	324.31%
GS-2 Transmission	$(0.000614)	$ 0.001376	$ 0.001990	324.10%
Irrigation	$(0.000640)	$ 0.001435	$ 0.002075	324.22%
Lighting	$(0.000640)	$ 0.001435	$ 0.002075	324.22%

The interim request and supporting documents can be examined at NorthWestern's General Office, 40 East Broadway, Butte, Montana; at the office of the Montana Consumer Counsel ("MCC"), 111 North Last Chance Gulch, Suite 1B, Helena, Montana; or at the office of the MPSC, 1701 Prospect Avenue, Helena, Montana. The MCC is available to assist in the representation of consumer interests in this matter, and its phone number is 406-444-2771.

Any response which any person wishes to have the MPSC take into consideration in its decision on this matter should be delivered to the MPSC at the above address as soon as possible or mailed to the MPSC at P.O. Box 202601, Helena, MT 59620-2601.

Any portion of the interim adjustment approved by the MPSC pending hearing and final decision would, pursuant to § 69-3-304, MCA (2011), be subject to rebate or surcharge if the final decision in this docket is to approve a final revenue level which is different than the interim level.

DATED: May 31, 2012

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

In the Matter of NorthWestern Energy's Application For: (1) Approval of Deferred Cost Account Balances for Electricity Supply, CU4 Variable Costs/Credits, and DGGS Variable Costs/Credits; and (2) Projected Electricity Supply Cost Rates, CU4 Variable Rates, and DGGS Variable Rates	))))))	Docket No. D2012.5.49

CERTIFICATE OF SERVICE
OF NOTICE OF INTERIM RATE ADJUSTMENT REQUEST
FOR ELECTRICITY SUPPLY RATES

The undersigned certifies that a Notice of Interim Rate Adjustment Request was this day served by mail upon the following:

Daily Newspapers

Montana Standard	Helena Independent Record
Missoulian	Billings Gazette
Great Falls Tribune	Livingston Enterprise
Bozeman Chronicle	Ravalli Republic
Daily Inter Lake	Havre Daily News

Associated Press Print and Broadcast Services

Television Stations

Billings	-	KTVQ and KULR
Butte	-	KXLF
Missoula	-	KECI and KPAX
Great Falls	-	KFBB and KRTV
Bozeman	-	KTVM
Helena	-	KTVH

DATED: May 31, 2012

NorthWestern Energy

By: Claudia Rapkoch

Claudia Rapkoch
40 East Broadway
Butte, Montana 59701

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2012.5.49
Annual Electric Supply Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY
OF DAVID E. FINE
ON BEHALF OF NORTHWESTERN ENERGY

TABLE OF CONTENTS

Witness Information

Q. Please state your name and business address.

A. My name is David E. Fine and my business address is 40 East Broadway, Butte, Montana 59701.

Q. By whom are you employed and in what capacity?

A. I am employed by NorthWestern Energy ("NWE" or "NorthWestern") as the Director of Energy Supply Planning. My areas of responsibility include a variety of energy supply and planning functions including the preparation of the electricity resource procurement plan and associated analysis, load and resource analysis, load forecasting, and other Supply portfolio planning and management functions performed by planning staff.

Q. Please summarize your educational and employment experiences.

A. I earned a Bachelor of Arts degree in Geology from the University of Montana and have worked in the energy industry since 1979.

I began employment with NWE in 1982 with an unregulated subsidiary of the Montana Power Company. I have worked in energy exploration and development, mining, energy resource evaluations, economic evaluations, business development, and technical evaluations associated with energy production and power generation. Since 2003 I have worked in the Energy Supply area where I currently oversee planning activities including tasks such as the preparation of the electricity procurement plan and other long-term procurement planning and analysis.

As an employee of NWE I have previously provided information and testimony on energy- and utility-related matters before the Montana Public Service Commission ("Commission").

Purpose of Testimony

Q. What is the purpose of your testimony in this filing?

A. My testimony is intended to provide the necessary information to satisfy the filing requirements set forth in ARM 38.5.8226(3). In my testimony, I discuss recent supply planning, supply management, and resource procurement activities and the action plan items that NorthWestern has executed and those it proposes to implement. In addition, I introduce the other NWE witnesses submitting testimony in this filing and briefly describe the topic(s) covered by each.

NWE's Electricity Resource Procurement Plans

Q. Please discuss the framework that guides NWE's electricity planning and acquisition activities.

A. Montana's statutes and regulations guide NorthWestern's planning and acquisition decisions. See, e.g., §§ 69-8-419 through 421, MCA (2011), and ARM 38.5.8201 through 38.5.8301.

ARM 38.5.8226(1) requires NWE to file a comprehensive long-term portfolio management and electricity supply resource procurement plan in

December of odd-numbered years. NorthWestern's most recent plan was filed in December 2011 ("2011 Plan") in Docket No. N2011.12.96. The 2011 Plan is a comprehensive analysis of NWE's retail electricity load-serving obligations for its retail customers in Montana. Chapter 10 of the 2011 Plan identifies and discusses key initiatives and baseline activities that will be addressed during the three-year action plan period. As initiatives and baseline activities progress, NWE will communicate the results of these activities to the Commission and stakeholders. The descriptions of the action items in the 2011 Plan illustrate the transparent processes that NWE employs to apprise the Commission and other parties of the scope and focus of its resource planning and acquisition activities.

As described and demonstrated in this annual electric tracker filing, the supply portfolio is composed of a diverse set of resources in terms of resource type, duration of delivery, and generation ownership. The electricity supply portfolio has evolved over time to include a mixture of market products, contracted and owned generation resources, and resources fueled by a range of fuel types including coal, natural gas, hydro, and wind.

Q. Please describe NorthWestern's electricity resource plans and their relationship to its procurement activities.

A. NWE has produced and filed five biennial electricity supply procurement plans (Plans). The Plans, and the accompanying Commission and stakeholder comments, provide guidance to the resource planning and acquisition processes that NWE follows in order to cost-effectively and reliably meet its retail load-serving obligations. Energy and resource procurement is a dynamic process because of changing needs, changes to market conditions, and other variables that NorthWestern must consider as it works to balance the costs and risks of electricity supply alternatives.

Consistent with information presented in the 2011 Plan, NWE is evaluating alternatives for resource additions to the portfolio. Alternatives include new-build gas-fired resources, market purchases, and potential opportunity resource acquisitions associated with existing generation. Beginning in July 2014, following the expiration of the seven-year PPL Montana purchase power agreement, a substantial volume of electricity must be secured to meet expected retail load. NWE will carefully consider the existing resource portfolio and projections of future retail loads as it examines and determines the timing and volume of resource additions.

Action Plan

Q. What has NWE done regarding the action items that were identified and discussed in the 2011 Plan?

A. In addition to cost-effective market purchases, the current market has created opportunities for NWE to evaluate strategic asset acquisitions to serve future Montana retail load. These opportunities are a result of changed market conditions and other factors that are causing resource owners to consider alternatives, such as disposing of assets, to meet changing business expectations and needs. NorthWestern is in a position to consider these "opportunity" acquisitions because of unfulfilled resource needs in the future coupled with the newfound ability provided by statute to own and operate generation assets. When it is appropriate, NWE will inform the Commission and stakeholders about possible asset acquisition activities. Electric generation resource acquisitions, should NWE elect to pursue them, would involve use of the Commission advanced approval process, including stakeholder participation and input, and the demonstration of utility ownership value to customers.

<u>NWE's Supply Portfolio</u>

Q. Briefly discuss NWE's recent activities that have been performed to manage the supply portfolio.

A. During the 2011/2012 tracker year NWE accomplished the following:

- Issued Notice to Proceed to Compass Wind to commence construction of the 40-megawatt Spion Kop Wind Project during 2012. NWE expects construction activity during 2012 will result in the project being completed, placed into commercial operation, and transferred to NWE ownership in the fourth quarter of 2012.

- Entered into four new long-term Qualifying Facility ("QF") contracts including two new wind projects totaling approximately 20 megawatts and two small hydro contracts totaling approximately 2.5 megawatts. All of these projects include bundled energy output and renewable energy credits ("RECs") that will be used to help meet retail customer energy needs and the renewable portfolio standard ("RPS"). Commercial operation of the projects is expected during 2012 with the exception of one wind project which may achieve commercial status in 2013. The energy cost and associated estimated energy production information for QF projects is summarized in Exhibit__(FVB-2)12-13 attached to the Prefiled Direct Testimony of Frank V. Bennett.
- Continued to execute market purchases to meet near-term load-serving needs. Favorable market conditions have resulted in attractive pricing for products purchased in the hourly, day-ahead, and short-term markets. NWE has continued to use market purchases and products to reliably meet customer energy demands while effectively managing price and limiting customer and utility risk exposure.
- Continued to implement the demand-side management ("DSM") plan included and described in the 2011 Plan with the goal of achieving 6 aMW of incremental energy savings capability annually. NWE continued its deliberate and aggressive plan to help customers install

energy conservation measures as outlined in the 2011 Plan through voluntary programs using both internal and external resources (contractors) to achieve annual targets. Please see the Prefiled Direct Testimony of William M. Thomas for detail about NWE's DSM implementation.

- Satisfied the RPS requirement for compliance year 2011 as prescribed in § 69-3-2004(2), MCA (2011). During 2011 and 2012, NWE purchased bundled electricity and RECs from three eligible projects located in Montana including Gordon Butte (wind), Judith Gap (wind), and Turnbull (hydro). Using RECs carried over from 2010 and a portion of the RECs from 2011 renewable production, NWE retired 577,561 RECs from its Western Renewable Energy Generation Information System account to satisfy its 2011 RPS obligation.

Q. Is the Dave Gates Generating Station at Mill Creek ("DGGS") providing service to supply customers?

A. Yes. DGGS is supplying regulation service to the NWE transmission control area and to retail customers in Montana. The circumstances surrounding the operation of DGGS and the return to service following the outage in the first and second quarters of 2012 are presented in the Prefiled Direct Testimony of Mr. Michael R. Cashell.

Introduction of Other Witnesses

Q. Please introduce the other witnesses in this filing.

A. In addition to my testimony, this electric tracker filing includes the testimony of the following:

- Mr. Kevin J. Markovich, Director, Energy Supply Market Operations. Mr. Markovich offers Prefiled Direct Testimony that:
    - Presents an overview of supply market operations including activities associated with term trading, pre-schedule, and real-time operations;
    - Confirms the continued implementation of the electric supply hedging strategy as presented in the 2011 Plan; and
    - Summarizes other activities including the results of competitive solicitations and products that were purchased and placed into the portfolio.
- Mr. Frank V. Bennett, Contract and Regulatory Specialist. In his Prefiled Direct Testimony, Mr. Bennett presents the following information:
    - Updated 12-month ended June 2012 tracking periods for electricity supply costs, Colstrip Unit 4 ("CU4") variable costs/credits, and DGGS variable costs/credits, and
    - The forecasted 12-month ended June 2013 tracking periods for each of the segments listed above.

- Ms. Cheryl A. Hansen, Senior Analyst in the Regulatory Affairs Department. Ms. Hansen offers Prefiled Direct Testimony that:
    - Presents the 2011-2012 tracker year billing statistics and explains how they are derived;
    - Presents the derivation of proposed deferred electricity supply rates resulting from the over/under collection reflected in the 2011-2012 tracking periods for electricity supply costs, CU4 variable costs/credits, and DGGS variable costs/credits;
    - Presents the derivation of proposed electricity supply cost rates, CU4 variable rates, and DGGS variable rates for the forecasted 2012-2013 tracker period; and
    - Presents the all-in electricity supply rates incorporating all individual rate components.
- Mr. William M. Thomas, Manager Regulatory Support Services. Mr. Thomas offers Prefiled Direct Testimony that:
    - Presents a review of the Electric Supply DSM energy efficiency programs administered by NorthWestern for Tracker Year 2011-2012 and the results from the Universal System Benefit ("USB") program for the same period;

- Provides updated numbers for DSM Program costs and associated lost revenues for Tracker Year 2011-2012; and
- Provides forecasted numbers for DSM Program costs and associated lost revenues for Tracker Year 2012-2013.

- Mr. Michael R. Cashell, Vice President, Transmission. Mr. Cashell provides Prefiled Direct Testimony that:
  - Explains the status and operation of DGGS as the facility supplying required regulation service for the NWE transmission balancing authority including service to retail customers.

Q. Does this complete your testimony?

A. Yes, it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2012.5.49
Annual Electric Supply Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF KEVIN J. MARKOVICH

ON BEHALF OF NORTHWESTERN ENERGY

TABLE OF CONTENTS

Witness Information

Q. Please state your name and business address.

A. My name is Kevin J. Markovich, and my business address is 40 East Broadway, Butte, MT 59701.

Q. By whom are you employed and in what capacity?

A. I am employed by NorthWestern Energy ("NWE" or "NorthWestern") as Director of Energy Supply Market Operations.

Q. Please summarize your educational and employment experiences.

A. I attended Montana State University, graduating in 1983 with a Bachelor of Science degree in Business, Accounting option. Upon graduation, I went to work for Marathon Oil Company in Casper and Cody, Wyoming as a production accountant. In 1985, I enrolled at the University of Wyoming and earned a Master of Business Administration (MBA) degree in December 1986. In 1987, I went to work in the Treasury Department of Entech, Inc., a wholly owned subsidiary of The Montana Power Company ("MPC"). In 1996, I transferred to the Montana Power Trading & Marketing Company ("MPT&M"), another MPC subsidiary, where I worked in various capacities including real-time electric scheduler, gas marketer, and executive director of retail marketing. In 2000, prior to the sale of MPT&M to Pan Canadian, I transferred to MPC, now NorthWestern Energy, where I have worked on numerous energy supply activities. In January 2005, I became the Director of Risk Management, and in September 2006 I assumed my current position.

Q. What are your responsibilities as Director of Energy Supply Market Operations?

A. I am responsible for NorthWestern's energy supply market operations including daily, weekly, monthly, and term trading and scheduling activities. These responsibilities involve developing and maintaining relationships with suppliers, brokers, and other market participants; executing and managing term contracts; negotiating and approving supply arrangements that are consistent with regulatory guidelines and internal policies; and developing and implementing overall supply strategies to ensure there is adequate supply to meet demand at all times.

Q. Do you hold any professional certifications?

A. Yes. I am a Certified Public Accountant and a Certified Cash Manager.

<u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. My testimony will describe how electricity procurement and scheduling activities were conducted during the 2011/2012 tracker period and how NWE proposes to conduct them during the upcoming 2012/2013 tracker period. In addition, I will discuss format changes to purchase- and sale-related information included in an exhibit attached to the Prefiled Direct Testimony of Frank V. Bennett ("Bennett Direct Testimony") in this filing that are the result of requests from the Montana Public Service Commission ("MPSC" or "Commission") staff.

2011/2012 Tracker Period Activities

Q. What planning document guided electricity supply procurement and scheduling activities during the 2011/2012 tracker period?

A. The Hedging Strategy that is Appendix 1 of the 2009 Electric Default Supply Procurement Plan ("2009 Plan") submitted in Docket No. N2010.6.57 is the document that guided electricity supply procurement activities from July 1, 2011 to December 31, 2011. Appendix 1 of the 2011 Electricity Supply Resource Procurement Plan ("2011 Plan") submitted in Docket No. N2011.12.96 is the document that guided electricity supply procurement activities during the remainder of the tracker period.

Q. Please provide an overview of the 2011/2012 tracker period.

A. As detailed in the Bennett Direct Testimony, the 2011/2012 tracker period contained no material operational changes or issues that caused supply service to change from the previous tracker period. Market prices, however, decreased substantially during the 2011/2012 tracker period, primarily due to lower natural gas prices and favorable hydro conditions. NWE's portfolio philosophy and resulting hedging strategy, which incorporates structured levels of long-, medium-, and short-term resources and is intended to help insulate ratepayers from upward price movements of electricity purchases from the market, allowed NorthWestern to take advantage of the lower spot market prices and procure a substantial portion of supply needs at these lower prices. In addition, costs were also decreased by the prudent operation of Colstrip Unit 4 ("CU4").

Q. Explain in more detail how NWE schedulers dispatched CU4 in ways that allowed NWE to take advantage of lower market prices and in turn optimize value from this resource.

A. The variable cost to operate CU4 consists primarily of fuel and variable operations and maintenance expenses. On certain occasions during the 2011/2012 tracker period, market prices for power fell below the variable cost to operate the unit. When that occurred and there was available energy to purchase from the market – and it was believed market prices would remain at those levels for an appropriate period of time – NWE schedulers backed down NWE's share of the output from CU4 and replaced the energy with market purchases. It should be noted that all three conditions must exist before backing down plants of this type, as they are base-load units and not designed for frequent adjustments to output. The value realized from doing this was the difference between the purchase power cost and what the variable cost to operate the unit would have been.

Q. To what extent was CU4 dispatched in the manner you just described, and what was the value from doing so?

A. During the first ten months of this tracker period (July 2011 through April 2012) over 160,000 Megawatt hours ("MWh") of supply that normally would have come from this unit was replaced by market purchases at prices lower than the variable cost of CU4. This resulted in savings of over $1.2 million, all of which is credited directly to ratepayers in this tracker.

Q. Please provide an example that illustrates backing down NWE's share of the output from CU4 and replacing the energy with more economical market purchases.

A. Assume it is the spring of the year, snowpack is melting, rivers are flowing strong, and spot market prices are $3.00 per MWh due to an abundance of hydropower. CU4 is at maximum output which means NWE is entitled to 222 MW. The minimum NWE can take from CU4 per the operating agreement is 60 MW, and the variable cost to operate CU4 is $15 per MWh.

Under these conditions, for the next hour NWE would reduce its take from CU4 from 222 MW to 60 MW and make a market replacement purchase of 162 MW (222 less 60) at $3 per MWh. The savings for that hour would be $1,944 (162 MWh x ($15 - $3).

The $15 per MWh of variable costs that would have been incurred on the 162 MWh of replacement power is not included in the tracker, and, instead, a market purchase for 162 MWh at $3 is included in the tracker.

Q. Does this same concept apply to the Power Purchase Agreements ("PPA") that NWE has entered into?

A. No. Under a PPA, NWE is required to take the purchased power and pay the contract price, which, in my example, would have been substantially above the spot market price of $3 per MWh. The other party to the PPA would have the opportunity to back down their own generating units, purchase power from the spot market at the very low price, and receive the much higher contract price from NWE. The other party would gain the value from the lower market prices but, NWE, and therefore its customers, would not. Owning dispatchable generating units provides protection from very high prices and also provides incremental value when prices are low. PPAs and non-dispatchable generating resources do not provide that same value.

Q. How does the dispatch flexibility of CU4 complement other resources in the energy supply portfolio?

A. The attributes of CU4 demonstrate the value of owning resources that can be dispatched based on price. PPAs, wind generating facilities, and run-of-river hydro facilities do not allow for this type of flexibility and thus are not able to produce value in the same manner as CU4. Generation output from owned, dispatchable generating units can be moved up or down depending on market prices – unlike many other resources. In addition, dispatchable resources can be backed down to limit re-marketing expenses as well as increased and sold in the market to take advantage of high market prices. The flexibility provided by owned, dispatchable resources such as CU4 is fundamental to an efficient and well assembled energy supply portfolio.

Q. Did NWE make any longer-term energy market purchases during the 2011/2012 tracker period?

A. Yes. In October 2011, NWE issued an all-source Request for Proposals ("RFP") soliciting up to 100 MW of firm energy for the period January 1, 2013 through December 31, 2014. The RFP was sent directly to entities that were thought to be interested in providing this product, and a press release was issued in an attempt to inform other possible responders. From the responses to this RFP, NWE purchased 100 MW of on-peak and 100 MW of off-peak power at the Mid–C trading hub, and 50 MW of off-peak power delivered to the NWE transmission system. The energy purchased will come from six different suppliers, and the purchases are included beginning in the 2012/2013 tracker period.

Q. Did NWE meet an acceptable prudency standard in providing its energy supply service during the 2011/2012 tracker period?

A. Yes. NWE managed its energy supply portfolio in a systematic, structured manner with specific measures and timelines that provided a guided, disciplined approach to energy procurement. The hedging strategy goals are designed to maintain reasonable rates while dampening volatility and enhancing price stability. NWE did not speculate on energy price movements and, therefore, did not subject ratepayers to unnecessary risk. NWE adhered to its hedging strategies that provided a framework by which the prudence of NWE's procurement activities can be judged and should continue to be judged.

Furthermore, electricity service was never interrupted or restricted at any time during this period due to actions or inactions of NorthWestern's energy supply function. NWE did not receive any fines or penalties from oversight authorities regarding scheduling or operating performance. All contracts were properly scheduled, administered, checked out, and paid according to the terms and conditions. Also, as described above, NWE followed a logical and prudent strategy for procuring energy that resulted in just and reasonable rates and reduced exposure to market price volatility for its customers.

2012/2013 Tracker Period Forecast

Q. Please comment on the 2012/2013 tracker period forecast.

A. The Bennett Direct Testimony provides a detailed forecast of the upcoming tracker period. I would note that this is a forecast using information that is known at this time; actual results will vary and be based on actual transactions and prices.

The hedging strategy in the 2011 Plan will guide NWE's scheduling and procurement activities for the 2012/2013 tracker period. NWE will follow this strategy, while considering comments received from the Commission. NWE will adhere to the 2011 Plan unless a fundamental change occurs in the market or an opportunity presents itself that is not contemplated in the 2011 Plan. During this time NWE will continue to look for additional buying opportunities and search for other products and transactions that create value and efficiencies for the benefit of customers and will continue to inform stakeholders of noteworthy changes and developments.

<u>Electric Tracker Exhibit Format Changes</u>

Q. Please explain why you are proposing to make format changes to information included in an exhibit attached to the Bennett Direct Testimony in this filing.

A. The format changes NWE is proposing are in response to requests from MPSC staff for additional information regarding purchases and sales. In essence, Commission staff is interested in separate purchase and sale figures rather than combined and netted information, as previously presented. These changes impact Exhibit__(FVB-2)12-13 pages 3 through 5. Staff was willing to allow NWE to provide the information in supporting workpapers to the exhibit, but NWE decided to provide this information through revisions to the exhibit.

Q. Are all items previously included in this exhibit included in the re-formatted pages?

A. Yes. The exact same purchase, sale, and volume items are included as before; they are just separated and categorized differently. No additional items are incorporated, and the methodology for setting rates and calculating the deferred account balance is unchanged.

Q. What were NWE's goals in designing the new format for the exhibit?

A. There were two main goals in designing the new exhibit outlay. First, NorthWestern wanted to be responsive to the request of the MPSC staff.

NWE employees discussed internally the ways the information might be provided and ultimately settled on the proposed format shown in the Bennett Direct Testimony. Second, NWE wanted the new format to portray how the energy supply business operates so that the reader can logically discern from the exhibit the various components that comprise our resource portfolio. NWE believes it has accomplished both goals.

Q. Would you describe what is included in the additional detailed information shown on the new line items on pages 3, 4, and 5 of the re-formatted exhibit, Exhibit__(FVB-2)12-13?

A. Yes. Table 1 defines selected terms found in Table 2. Table 2 describes what is included in each tracker line item.

TABLE 1

PPA	Power Purchase Agreement. A contract between two entities documenting the terms and conditions of a purchase and associated sale.
RFP	Request for Proposal. A process soliciting responses from entities for either the purchase or sale of energy.
Index Price Transactions	PPAs with pricing based on a published index price that is unknown until the time of delivery. Index publishers include Dow Jones, Powerdex, and Intercontinental Exchange ("ICE"), among others. Dow Jones and Powerdex determine the index value based on a sample of transactions meeting the index requirements reported by market participants. ICE determines its indexes based on the actual transactions that meet the index requirements that are executed on its electronic trading platform.
Fixed Price Transactions	PPAs with pricing that is a known, fixed amount, typically in dollars per megawatt hour.
Base Transactions	Transactions with duration of greater than 18 months.
Real-Time Transactions	Hourly transactions that serve as the final iteration in estimating and balancing supply and demand quantities.

Pre-Schedule Transactions	Transactions normally done one day ahead (but can be as many as five days ahead, in accordance with the WECC scheduling calendar) that estimate the next day's hourly supply and loads.
Spot Transactions	Short duration transactions including Real-Time and Pre-Schedule transactions.
Term Transactions	Transactions with duration less than 18 months but greater than spot transactions.
MWh	Megawatt hour. One megawatt of electricity delivered for one hour.

TABLE 2

Description of Tracker Line Items	
Item	**Description**
Off System Transactions	**Transactions with delivery outside of the NWE transmission system. Almost all of these transactions are at the Mid-C trading hub and are used for hedging purposes.**
Fixed Price	
Base Fixed Price Purchases	**Fixed price purchases with durations in excess of 18 months.**
Competitive Solicitations	Base fixed price purchases that were entered into as part of a RFP or similar process.
Base Fixed Price Sales	**Fixed price sales with durations in excess of 18 months.**
Competitive Solicitations	Base fixed price sales that were entered into as part of a RFP or similar process.
Term Fixed Price Purchases	**Fixed price purchases with durations anywhere from a partial month to 18 months.**
Term Fixed Price Sales	**Fixed price sales with durations anywhere from a partial month to 18 months.**
Index Price	
Base Index Price Purchases	**Index price purchases with durations in excess of 18 months.**
Competitive Solicitations	Base index price purchases that were entered into as part of a RFP or similar process.
Base Index Price Sales	**Index price sales with durations in excess of 18 months.**
Competitive Solicitations	Base index price sales that were entered into as part of a RFP or similar process.
Term Index Price Purchases	**Index price purchases with durations anywhere from a partial month to 18 months.**
Term Index Price Sales	**Index price sales with durations anywhere from a partial month to 18 months.**

<u>Spot Purchases</u>	**Pre-schedule and Real Time purchases that are anticipated to be made at a later date.**
<u>Spot Sales</u>	**Pre-schedule and Real Time sales that are anticipated to be made at a later date.**
<u>On System Transactions</u>	**Transactions with delivery at a point on the NWE transmission system.**
<u>Fixed Price</u>	
Rate Based Assets	**Assets that have received regulatory scrutiny and are included in rate base. Only volumes from the assets are included; dollar costs are in other areas of the tracker.**
Colstrip Unit 4	NWEs 30% share of the output from Colstrip Unit 4, a 740 MW generating unit in Rosebud County, MT.
Dave Gates Generating Station	A natural gas fired electric generating unit located outside of Anaconda, MT.
Spion Kop	A 40 MW wind facility located in Judith Basin County, MT.
Base Fixed Price Purchases	**Fixed price purchases with durations in excess of 18 months.**
PPL 7-Year Contract	A seven-year contract with PPL that runs from July 1, 2007 through June 30, 2014. Volumes decline over the seven years, ending with 200 MW on-peak and 125 MW off-peak during the final two years.
Judith Gap	A 135 MW wind farm located in Wheatland County, MT.
Competitive Solicitations	Base fixed price purchases that were entered into as part of a RFP.
QF Tier II	Qualifying Facility (QF) contracts that were part of the Tier II settlement. The major contracts in this group are Colstrip Energy Limited Partnership (CELP), Yellowstone Energy Limited Partnership (YELP), and Broadwater Dam.
QF-1 Tariff	QF contracts other than Tier II that are administered under the QF-1 tariff.
Other Small PPA	Small PPAs not categorized individually.
Term Fixed Price Purchases	**Fixed price purchases with durations anywhere from a partial month to 18 months.**
Term Fixed Price Sales	**Fixed price sales with durations anywhere from a partial month to 18 months.**
<u>Index Price</u>	
Base Index Price Purchases	**Index price purchases with durations in excess of 18 months.**
Basin Creek	Volumes generated from the Basin Creek Generating Station.
Competitive Solicitations	Base index price purchases that were entered into as part of a RFP or similar process.
Term Index Price Purchases	**Index price purchases with durations anywhere from a partial month to 18 months.**

	Term Index Price Sales	**Index price sales with durations anywhere from a partial month to 18 months.**
	Spot Purchases	**Pre-schedule and Real Time purchases that are anticipated to be made at a later date.**
	Spot Sales	**Pre-schedule and Real Time sales that are anticipated to be made at a later date.**
	Imbalance, Current Month Estimate	Estimated purchases or sales from Imbalance transactions that have not yet been finalized.
	Imbalance, Prior Month True-up	True-ups of prior months' imbalance estimates.
	Imbalance, Accounting & BA Expense	Imbalance adjustments not directly attributable to a specific meter or customer.
Ancillary and Other		
	Basin Creek Fixed Costs	Fixed capacity and O&M charges paid monthly regardless of actual production at the plant. This line item does not include the portion of Basin Creek that is used to provide operating reserves.
	Basin Creek Variable Costs	Fuel and other costs that are a based on actual production levels.
	Operating Reserves	Contingency reserves required to be in place per the NWE transmission tariff. This line item includes the fixed costs of the portion of Basin Creek used to provide operating reserves.
	DSM Program & Labor Costs	Demand Side Management programs cost and external labor.
	DSM Lost T& D Revenues	Lost Transmission and Distribution revenues resulting from reductions in energy usage due to demand side management and Universal System Benefits programs.

Q. Does this complete your testimony?

A. Yes, it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2012.5.49
Annual Electric Supply Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF WILLIAM M. THOMAS

ON BEHALF OF NORTHWESTERN ENERGY

TABLE OF CONTENTS

Witness Information

Q. Please state your name and business address.

A. My name is William M. Thomas, and my business address is 40 East Broadway, Butte, Montana 59701.

Q. By whom and in what capacity are you employed?

A. I am employed by NorthWestern Energy ("NorthWestern" or "NWE") as Manager of Regulatory Support Services in the Government and Regulatory Affairs Department.

Q. Please state your educational background, experience and responsibilities.

A. I graduated from Montana State University with a Bachelor of Science degree in Science and Education. I was employed by The Montana Power Company ("MPC") from 1980-1999 in a variety of staff and management positions. During that tenure, I served as Program Director for MPC Demand Side Management ("DSM") Programs for Residential and Commercial customers. I attended the Public Utility Executives Program at the University of Idaho in 1991. I joined NorthWestern in April 2004 in the capacity of DSM Program Coordinator and assumed my present position as Manager of Regulatory Support Services in April 2005. In addition to other departmental activities related to support of regulatory filings and proceedings, I am responsible for providing overall coordination and direction on development, implementation, and promotion/education of DSM programs and interaction with the Technical Advisory Committee on DSM matters. My duties also include preparing the information supporting NorthWestern's DSM-related activities and proposals in this filing.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I testify to the following:

1. Results from Universal System Benefit ("USB") and Electric Supply DSM energy efficiency programs conducted by NorthWestern for Tracker Year 2011-2012 and a description of the status of and plans for DSM programs and related activities in the forthcoming tracker period;
2. Updated numbers for the DSM Program costs and the Lost Revenue Recovery Mechanism for recovery of Electric Supply DSM Program costs and historical lost transmission, distribution, Colstrip Unit #4 ("CU-4"), and Dave Gates Generating Station ("DGGS") revenues ("Lost Revenues") associated with Electric Supply DSM and USB programs, as well as forecasted information; and
3. Updated status of the work in progress by SBW, Inc., an independent third-party evaluation firm, to perform a comprehensive review of NorthWestern's entire portfolio of DSM Programs.

2011-2012 Program Results

Q. Please describe the overall results of USB and Electric Supply DSM energy efficiency program activities in the 2011-2012 electric supply tracker period.

A. In the 2004-2005 time period, NorthWestern established a DSM Acquisition Plan with DSM goals set at the level of 2.6 aMW of installed energy savings capability in Program Year 1 (2004-2005 Tracker Year), ramping up to 3.7 aMW in Program Year 2 (2005-2006), and then to 5.0 aMW in Program Year 3 (2007-2008 Tracker Year) and leveling at 5.0 aMW each year through 2009-2010. In its 2009 Electric Default Supply Procurement Plan, NorthWestern increased its annual DSM goal to 6.0 aMW starting in the 2010-2011 time period. Table 1 below summarizes the annual targets, reported energy savings, budget, and spending for the 2004-2012 tracker periods.

Table 1: DSM Targets, Reported Savings, Budget and Spending

Program Year	Tracker Period	Installed Annual DSM Capability (Incremental)				Electric Supply DSM Tracker Budget ($)	Electric Supply DSM Program Expenditures ($)
		Target (aMW)	Reported Program Results (aMW)				
			USB	DSM	Total		
1	2004-05	2.60	2.04	0.22	2.26	$1,457,888	$ 320,389
2	2005-06	3.70	1.33	2.08	3.41	$2,097,734	$1,596,076
3	2006-07	5.00	0.36	3.04	3.40	$3,232,080	$2,497,359

4	2007-08	5.00	0.82	4.55	5.37	$3,631,683	$3,688,745
5	2008-09	5.00	1.11	5.58	6.69	$4,917,141	$5,504,111
6	2009-10	5.00	0.96	7.37	8.33	$6,625,192	$7,652,658
7	2010-11	6.00	0.57	8.63	9.20	$9,148,219	$7,086,931
8	2011-12	6.00	0.39	7.30	7.69	$8,063,519	$8,765,487
9	2012-13	6.00				$10,441,871	

Work to prepare the annual tracker begins in April of each year with a planned filing date of June 1. This schedule requires estimation of DSM energy savings and program costs for a portion of the end of the current tracking period.

The Electric Supply DSM Program Expenditures for DSM Program Year 8 (2011-2012) in Table 1 are based on 10 months of actual costs and 2 months (May-June 2012) of estimated expenses. The estimated amount of 7.69 aMW of incremental new installed DSM capability is based on 9 months of actual and 3 months (April, May and June 2012) of estimated program activity.

The annual aMW targets and reported savings are comprised of amounts of installed annual energy savings capability contributed from measures and actions implemented under both USB Programs and Electric Supply DSM Programs. The Reported Program Results represent the capability of installed conservation and efficiency measures to produce energy savings for a full year. Although energy savings produced by USB Programs are counted toward the overall annual aMW target and included in calculations of DSM Lost Revenues, USB Programs are funded through a separate charge and USB spending is not reported or included in Table 1.

Q. Please provide additional details on energy savings of individual USB and DSM Programs in operation during the 2011-2012 Tracker Year.

A. Exhibit__(WMT-1) provides individual program details on reported energy savings and develops numbers used in the updated DSM Lost Revenues computation. This exhibit presents the following two tables of tabulation and analysis:

1. Table A: Reported Electricity Savings from 2011-2012 USB and DSM Program Activity.

The data presented in this table represents summarized results for reported energy savings for programs and projects for the tracker period July 2011 through March 2012. Reported energy savings means estimates of electricity savings from either individual projects, where engineering calculations were submitted with project proposals and reviewed by NorthWestern staff for specific energy conservation projects (e.g., E+ Commercial Lighting projects, Business Partners site-specific projects, or Renewable Generation projects), or in those cases where engineering calculations are not required for program participation, average energy savings per DSM measure (also referred to as *deemed* *savings*) are used. Examples of this include residential and commercial audits and residential compact fluorescent lamps ("CFL"). Reported energy savings represent the <u>annual</u> energy savings that would occur if all energy savings measures were in place for a full 12 months.

For the final three months of the 2011-2012 tracker period (April - June 2012) estimates of energy savings were made based on previous program experience, pending applications for rebates and incentives, pending project proposals, and discussions with outside service providers assisting NorthWestern with USB and DSM program operation.

2. Table B: Residential and Commercial Electric Savings for Calculation of Lost Transmission & Distribution Revenues.

Consistent with previous years, NorthWestern's proposal for DSM cost recovery in tracker period 2011-2012 includes calculations for DSM Lost Revenues. Because the applicable transmission, distribution, CU-4 and DGGS rates used to compute those Lost Revenues are different for NorthWestern's residential and commercial customers, it is necessary to estimate the percentage split between residential and commercial DSM resources that were acquired in the 2011-2012 Program Year. Table B identifies portions of each USB and DSM program attributable to residential and commercial projects and/or customer participants and then develops a straightforward summing of the estimated residential and commercial program electricity savings from Table A to produce the overall percentage contribution by the residential (65.4%) and commercial (34.6%) customer classes to the total. These percentage splits are then used as inputs to the calculation of Lost Revenues (see page 3, lines 17-18 of Exhibit__(WMT-3)).

DSM Program Status Report

Q. What is the current status of electric supply DSM programs and what actions are planned for the 2012-2013 tracker year?

A. The process of preparing the 2011 Electricity Supply Resource Procurement Plan produced updated electric avoided costs used for analysis of DSM cost-effectiveness. The new DSM electric avoided costs are 23% lower than the previous avoided costs NorthWestern had been using. The new avoided costs were used to screen the list of possible DSM measures for cost-effectiveness and to review and revise the various rebates and incentives that are offered in NorthWestern's DSM programs. This, in turn, resulted in a reduction of the number of DSM measures that qualified as cost-effective measures to be included in DSM programs. The number of cost-effective commercial DSM measures fell by 10.4% (11 measures), and the number of cost-effective residential DSM measures (13 measures) was reduced by 19.7%.

Exhibit__(WMT-2) presents DSM spending by program for 2011-2012 (actual through April 2012, estimates for May-June 2012) and estimated spending for Tracker Year 2012-2013.

The following is an update of DSM program activities and future plans:

1. E+ Lighting Programs: KEMA Services, Inc. ("KEMA") provided lighting program implementation services for both commercial and residential customers in the 2011-2012 tracker period. Through KEMA, NorthWestern offered cash rebates for ENERGY STAR® qualified CFLs and indoor/outdoor fixtures. The program included several mechanisms to either distribute or encourage purchase and use of ENERGY STAR® CFLs and fixtures, including:

    a. Direct installation of CFLs in homes during home energy audits and commercial appraisals;
    b. Free CFL with mail-in home audits;
    c. Mail-in rebates for residential customers for CFLs and ENERGY STAR® fixtures;
    d. Rebates to commercial customers for energy efficient lighting equipment and controls;
    e. In-Store Instant Rebates with redeemed coupons;
    f. Simple Steps Program – buy-down of CFL prices at retailers through a regional campaign facilitated by the Bonneville Power Administration; and
    g. Non-Retailer Special Events (trade shows, fairs, Farmers Markets, Energy Expos, etc.).

New federal regulations relating to energy efficiency standards for lighting technologies were to begin phasing in over a three-year period beginning

January 1, 2012, but federal funding for enforcement of the new standards by the U.S. Department of Energy was blocked by Congress in late 2011.[1] NorthWestern expects this matter will be revisited by Congress in the near future, but it is unknown when enforcement of the standards will begin or whether additional modifications to the standards will be enacted.

These new regulations apply to manufacturing of lighting products, not to retail sale of them. Regardless of whether manufacturers have ceased production of targeted lighting products as a result of the unenforced regulations, remaining stock of lighting products (e.g., incandescent bulbs) will continue to be sold and installed by consumers for perhaps a year or more following the effective dates of the new regulations for each respective lighting product. Energy savings opportunities remain during this interim period while retailers' lighting stock clears of incandescent lighting products. During this stock clearing period, if consumers can be persuaded through NorthWestern's E+ Lighting Rebate programs to purchase CFLs or other lighting technologies instead of the less efficient bulbs (which will eventually be eliminated by the new regulations), then low-cost DSM resources will be acquired in the same manner as in the past – through operation of the E+ Lighting Rebate programs.

[1] Congress Passes FY 2012 Appropriations, Limits Funding for Energy Efficiency; Alliance to Save Energy; December 9, 2011; http://ase.org/efficiencynews/congress-passes-fy-2012-appropriations-limits-funding-energy-efficiency

NorthWestern will continue to monitor this transition and decide when to eliminate various wattage and lumen-rated CFLs and other lighting technologies from its list of qualified and eligible DSM measures and discontinue rebating those measures and reporting energy savings from them.

In view of this situation, NorthWestern renewed its contract with KEMA for services related to the E+ Lighting Programs and will offer these programs again in 2012-2013.

2. E+ Commercial DSM Programs and Contractors: Regardless of the final disposition of the federal standards for energy efficient lighting, it is likely that the contribution of energy efficient lighting to the overall DSM results will diminish in the future. To sustain a level of 6.0 aMW of annual DSM acquisition, additional energy savings must be captured from the commercial and small industrial sectors.

NorthWestern has taken additional steps to increase its capability to acquire commercial sector DSM. Two additional firms have been contracted to provide services in support of the E+ Business Partners Program, the E+ Commercial Lighting Rebate Program, the E+ Commercial Electric Rebate Program for New Construction, and the E+ Commercial Electric Rebate Program for Existing Facilities. This brings the total number of firms concentrating on the commercial and small industrial sectors to six:

1. National Center for Appropriate Technology ("NCAT")
2. ECOVA
3. McKinstry Essention
4. Portland Energy Conservation, Inc.
5. CTA Associates, Inc. (new in 2011)
6. Energy Resource Management, Inc. (new in 2011)

All of these contractors are compensated by NorthWestern on a performance basis, with payment based on a percentage of the energy conservation resource value of each individual DSM project that is completed with the contractor's involvement. All contractors are expected to deliver to NorthWestern a minimum of 0.25 aMW for incremental DSM each year.

These contractors are supported by a new four-member team of KEMA employees who have been given responsibility for direct contact, face-to-face marketing of DSM programs to commercial/small industrial customers in an effort to identify, qualify, and cultivate DSM projects for follow-up by the contractors listed above. Services provided by these contractors include marketing to architect/engineering firms and trade/industry associations in Montana, direct contact with candidate businesses with DSM potential, surveys and assessments of buildings and facilities, technical assistance for building owners, assistance with required engineering analysis and modeling, and assistance to customers with forms, contracts, and other paperwork used in and necessary for participation in these programs. Additional details regarding these contractors and their accomplishments to date are as follows:

CTA Architects & Engineers (new in 2011)

- First year of a two-year performance contract.
- 2012 projects completed or in progress to date, 0.0434 aMW potential:
  - Two commercial custom incentive electric conservation projects.
  - One commercial lighting rebate project.
  - Two commercial electric rebate projects.

Energy Resource Management Inc. (new in 2011)

- First year of a two-year performance contract.
- 2012 projects completed or in progress to date, 0.2163 aMW of conservation:
  - Four commercial custom incentive electric conservation projects.
  - One commercial lighting rebate project.

McKinstry Essention

- Second year of a two-year performance contract.
- 2012 projects completed or in progress to date, 0.07 aMW of conservation:
  - Nine commercial lighting rebate projects.
  - 15 commercial electric rebate projects.

ECOVA

- Second year of a two-year performance contract.
- 2012 projects completed or in progress to date, 0.1652 aMW of conservation:
  - Two commercial custom incentive electric conservation projects.

– Six commercial lighting rebate projects.
– 20 commercial electric rebate projects.

Portland Energy Conservation Inc.

- Second year of a two-year performance contract.
- 2012 projects completed or in progress to date, 0.06 aMW of conservation:
  – Two commercial custom incentive electric conservation projects.
  – Nine commercial lighting rebate projects.
  – Three commercial electric rebate projects.

National Center for Appropriate Technology

- Second year of a two-year performance contract.
- 2012 projects completed or in progress to date, 1.7 aMW of conservation:
  – 23 commercial custom incentive electric conservation projects.
  – 219 commercial lighting rebate projects.
  – 28 commercial electric rebate projects.

3. Northwest Energy Efficiency Alliance ("NEEA"): NEEA is a regional non-profit organization supported by electric utilities, public benefits administrators, state governments, public interest groups, and energy efficiency industry representatives. Through regional leveraging, NEEA encourages "market transformation" or the development and adoption of energy efficient products and services in Montana, Washington, Idaho, and Oregon. NEEA's regional market transformation activities target the residential, commercial, industrial and agricultural sectors.

NorthWestern is in Year Three of a five-year commitment that will continue its funding of and participation in NEEA activities and initiatives during the 2010-2014 time period. NorthWestern reported energy savings from NEEA activities totaling 0.72 aMW during the 2011-2012 tracker period. Information on NEEA's numerous projects and initiatives that were in progress during 2011-2012 and are continuing into the future can be found at http://www.nwalliance.org/.

4. E+ New Homes: NorthWestern renewed its contract with NCAT to provide services related to this program, including builder/owner education, technical assistance, marketing, and outreach. USB funds were used to market the program and educate architects, building contractors, and interested customers about ENERGY STAR® standards. NEEA funds some of the infrastructure development of ENERGY STAR® Northwest activities. In NorthWestern's Montana service area, three new electrically heated homes were certified in 2011-2012 and 70 new natural gas heated homes installed at least 50% ENERGY STAR® lighting as the result of NorthWestern's support of the ENERGY STAR® Homes Northwest building standards through this program.

5. E+ Electric Motor Rebate: This program was eliminated in 2010 as a standalone electric DSM program and incorporated as a qualifying measure in the new Commercial DSM Program. NorthWestern offers

cash rebates for purchase of premium efficiency electric motors. Prescriptive rebates are available for motors rated between 1 and 200 horsepower. Larger motors can qualify for rebates with individual, application-specific calculations performed by NorthWestern. Program marketing during 2011-2012 included sponsorship of motor management seminars (see Efficient Motor Management details in the training section below).

NorthWestern also offers incentives for motor rewinding. Currently, only four electric motor service centers in the NorthWestern's electric service area perform motor rewinding service. Rather than operating a separate and distinct electric motor efficiency program with attendant program-specific administrative costs, qualified motor rewinds (in addition to NEMA premium efficiency motors[2]) were also folded into the Commercial Electric Rebate Program for Existing Facilities and the Commercial Electric Rebate Program for New Construction.

Additional information about all of NorthWestern's DSM programs is available at NorthWestern's website at http://www.northwesternenergy.com/eplus.

[2] The National Electrical Manufacturers Association (NEMA) is a U.S. industry group representing those who design and manufacture electrical equipment. NEMA promulgates standards for high efficiency electric motors. More information is available at http://www.nema.org/media/pr/20060214a.cfm.

Q. Does NorthWestern conduct other supporting activities to build customer interest and participation in its DSM programs?

A. Yes. NorthWestern DSM staff and contractors sponsor many training seminars during the year to increase awareness of energy conservation and energy efficiency opportunities in buildings and facilities. The objectives are to educate and inform building operators, designers, builders, and trade allies about using electric equipment efficiently and to promote the E+ programs, services, information resources, and incentives. A blend of USB and DSM funds covers the cost of these activities. The following is a list of DSM and USB program-related training seminars that NorthWestern sponsored during 2011-2012:

1. <u>Preferred Contractor Training</u> – Each year NorthWestern provides training to various contractors that install energy savings measures in the residential homes of consumers who participate in its DSM programs. Training locations during the 2011-2012 period included:

a. Missoula
b. Helena
c. Billings
d. Bozeman
e. Butte
f. Great Falls
g. Kalispell

2. <u>Efficient Motor Management</u> – Sprint 2012 training was targeted at motor users, electricians, motor service shops; Continuing Education Units (“CEUs”) were offered; 103 total participants.

a. Helena - March 27 (17 attendees).
b. Billings - May 7 (20 attendees).
c. Great Falls - May 8 (15 attendees).

d. Bozeman - May 9, (24 attendees).

e. Butte - May 10 (17 attendees).

f. Missoula - May 11 (10 attendees).

3. Building Operator Certification – This is targeted at public schools, non-profit hospitals, state and local government; funding provided for tuition and travel.

a. Level II Training & Certification: November 14-18, 2011 in Helena with 15 attendees.

b. Level I Training & Certification: June 4-8, 2012 in Helena with 15 attendees expected.

4. Montana Energy Management Conference – March 27-29, 2012 in Helena

a. This event was co-organized with the Montana Department of Environmental Quality and NEEA's BetterBricks initiative targeting commercial facilities and trade allies. Approximately 170 persons attended.

b. This event included the 2012 Montana BetterBricks Award banquet recognizing "Montana Energy Champions." Training session content ranged from the business case for energy efficiency to lighting design basics and technical training on refrigeration. CEUs were offered. In its third year, this event continues to grow and is well-received by trade allies and customers. Details are online at www.montanaenergymanagement.com.

5. Northwest ENERGY STAR® Verifier Training – A Home Energy Rating System week-long course that includes Northwest Energy Star Homes ("NWESH") Program administration, Home Energy Rater System administration, performance testing, and use of home analysis software. Three two-day workshops for NWESH verifiers were conducted in Billings, Bozeman, and Missoula in May with 23 total attendees.

6. Northwest ENERGY STAR® Builder Training – Three types of training were conducted in 2011. Five four-hour NWESH version 3.0 workshops were conducted in Helena, Great Falls, Billings, Bozeman, and

Missoula. The Helena workshop was conducted on May 10 (3 attendees); Great Falls May 11 (7 attendees); Bozeman May 17 (17 attendees); Billings May 19 (7 attendees); and Missoula May 12 (23 attendees). Sessions targeted builders, trade allies, lenders, and realtors interested in the details of how to build ENERGY STAR® homes with an emphasis on the whole-house system.

7. Performance Testing – Five day-long workshops were conducted. Sessions targeted builders, trade allies, lenders, industry allies and local city building officials and provided instruction on blower door testing and heating duct blaster testing for Energy Star® Homes:

a. Bozeman - November 9, (5 attendees).

b. Billings - November 10 (5 attendees).

c. Helena - November 15 (7 attendees).

d. Great Falls - November 16 (13 attendees).

e. Missoula - November 18 (4 attendees).

8. Compressed Air Challenge – NWE co-sponsored training in Helena on September 27, 2011 for plant maintenance managers, plant and consulting engineers, vendors, compressed air operators and mechanics, technicians, and energy efficiency organizations. This training covered proven techniques for finding and fixing system leaks, actively managing compressed air systems, identifying and tracking energy savings, increased product quality, and higher productivity. CEUs were offered.

9. Understanding Pros and Con of Variable Frequency Drives ("VFDs") – NWE co-sponsored training in October 2011.

a. This class concentrated on design, installation, operation, and trouble-shooting of VFD and control systems.

b. Targeted operations staff and managers, technicians, plant/process engineers, industrial maintenance personnel, building operators and municipality staff.

c. CEUs were offered.

10. <u>Lighting Design Lab Training</u>

a. Comprehensive Lighting Training on September 14, 2011 in Billings and October 11-13, 2011 in Missoula.

b. Basic Lamp Technologies and Basic Lamp Design Principles in conjunction with the Montana Energy Management Conference in Helena in March 2012. CEUs were offered.

11. <u>Energy Data Analysis</u> – Introduction to Key Performance Indicators co-sponsored training was held November 10, 2011 in Helena. This session provided training on how to obtain and interpret energy use data and gain basic analytical tools for understanding energy performance. CEUs were offered.

12. <u>Pumping Systems</u> – Three pump classes were co-sponsored.

a. Butte - July 26, 2011

b. Billings - August 16, 2011

c. Missoula - April 17, 2012

These sessions focused on the importance of efficient pumping and system interaction, life-cycle cost analysis, and resources available to irrigation operators and pump system operators and managers. CEUs were offered.

13. <u>Industrial Customer Cohort</u> – NorthWestern joined with NEEA to pilot test a year-long training and networking process with five non-competing industrial customers to encourage customers to incorporate energy management into their business culture and operating practices. Participating customers commit to attending/hosting sessions, participating in “homework,” and reporting to the cohort of actions, including participation in other NWE training and E+ programs. A second cohort is scheduled for the second half of 2012.

Q. Did NorthWestern make additional efforts during the 2011-2012 tracker period to promote DSM?

A. Yes. To communicate information about DSM and other NorthWestern programs to its customers, NorthWestern sustains a presence in Montana communities through media, events, appearances, meetings, speaking engagements, booth sponsorships, trade fairs and shows, conferences, and other special events. NorthWestern maintains networks of retailers, distributors, and other trade allies and provides a steady stream of information about its DSM programs through print, radio, television, distribution literature, and personal contact. As with the training seminars described above, a mix of USB and DSM funding is used. The following list provides examples of the many activities NorthWestern performed during the past year to market its DSM programs:

1. Trade Shows – In fall 2011 and spring 2012, NWE staffed exhibits and educational display booths at eight home improvement trade shows around Montana providing educational materials and distributing four free CFLs per account to NWE's residential electric customers.

2. "Game Day" Exhibits – In September and October of 2011, NWE sponsored and staffed educational exhibits about its DSM programs at University of Montana, Montana State University, Montana Tech and Carroll College football games. The focus was on the promotion of the ENERGY STAR® "Most Efficient" televisions which use a fraction of electricity when compared to other flat screen models.

3. Montana Lodging and Hospitality Association Conference – November 2011, display booth.

4. Montana Joint Engineers Conference – November 2011, training and display booth in cooperation with NEEA's BetterBricks.

5. NorthWestern Energy Lighting Trade Ally Network – Focused on commercial lighting and the trade allies supporting this key energy efficiency opportunity; six meetings during the spring of 2012 in Billings, Bozeman, Butte, Missoula, Helena, and Great Falls.

6. Montana School Association – February 2012, display booth.

7. Montana Building Code Education Conference – April 2012, Bozeman, display booth.

8. Montana Hospital Association Conference – April 2012, display booth.

9. Montana American Institute of Architects Conference – April 2012, training and booth in partnership with BetterBricks.

10. Montana Society of Health Care Engineers/ASHRAE[3] Conference – May 2012, training and display booth in cooperation with BetterBricks.

11. CFL Instant Savings Coupon Campaigns – Fall 2011 and spring 2012 (in April to observe Earth Day).

12. "Simple Steps" Regional CFL Campaign – Upstream manufacturers buy-down for specialty CFLs.

13. Home Energy Weatherization Distribution Events – Fall 2011 - 39 events around Montana with a focus on:

a. Air infiltration sealing and CFLs.

b. Direct mail to targeted customers, with web and bill insert promotion.

c. "How-to-install" DVD was distributed with each weatherization kit.

[3] The American Society of Heating, Refrigerating and Air Conditioning Engineers is an international technical society for all individuals and organizations interested in heating, ventilation, air-conditioning, and refrigeration. See www.ashrae.org.

Table 2: 2011 Home Energy Events Schedule and Participants

Date	Location	Participants
01-Oct-11	Butte	345
01-Oct-11	Helena	173
30-Sep-11	Anaconda	144
30-Sep-11	East Helena	94
30-Sep-11	Deer Lodge	93
29-Sep-11	Twin Bridges	28
29-Sep-11	Three Forks	49
29-Sep-11	Sheridan	56
29-Sep-11	Belgrade	107
28-Sep-11	Livingston	115
28-Sep-11	Dillon	125
24-Sep-11	Kalispell	204
24-Sep-11	Missoula	476
23-Sep-11	Columbia Falls	88
23-Sep-11	Florence	53
23-Sep-11	Whitefish	84
23-Sep-11	Stevensville	126
22-Sep-11	Hamilton	166
22-Sep-11	Corvallis	69
22-Sep-11	Big Fork	43
21-Sep-11	Clancy	20
21-Sep-11	Montana City	55
21-Sep-11	Drummond	20
21-Sep-11	Clinton	35
17-Sep-11	Bozeman	290
17-Sep-11	Havre	84
16-Sep-11	Joplin	15
16-Sep-11	Hingham	11
16-Sep-11	Harlowton	31
16-Sep-11	Big Timber	37
15-Sep-11	Vaughn	57
15-Sep-11	Sun River	16
15-Sep-11	Columbus	55
15-Sep-11	Absarokee	35
14-Sep-11	Simms	16
14-Sep-11	Fort Shaw	23
14-Sep-11	Roberts	12
14-Sep-11	Red Lodge	51
13-Sep-11	Augusta	26
	TOTALS	**3527**

14. E+ Audit for the Home – Direct mail in fall 2011 and spring of 2012. Spot placement of television, radio and newspaper promotion.

15. E+ Tips, CFL, and Commercial Lighting television spots – Spot placement during selected events.

16. Home & Garden Improvement Shows

a. Fall 2011 – Billings.

b. Spring 2012 - Hamilton, Missoula (2 shows), Billings, Great Falls, Helena, and Butte.

17. Farmers Markets - CFL distribution.

18. Parade of Homes Sponsorships (Fall 2011) - Billings, Bozeman, Great Falls, Missoula, Helena, Hamilton.

19. Display-In-A-Box – An informational and educational tool used at various events for CFLs or natural gas rebates (Missoula, Kalispell, Bozeman, and Great Falls).

20. Other Special Events:

a. Montana Manufacturers Energy Conference – sponsorship, speaker and display booth.

b. NCAT grant-writing seminars – sponsorships and speakers for three sessions.

c. Laurel Aviation Youth Event – display booth.

More details about the techniques, mechanisms, locations, forms of media, and calendar schedule are presented in Exhibit__(WMT-4a) which describes the goals, objectives, audiences, strategies, tactics, methods, and tools of the DSM Communications Plan. Exhibit__(WMT-4b) provides a detailed schedule of specific programs and activities that will be implemented during a typical calendar year period. Together, these exhibits present a clear view of the scope and scale of NorthWestern's communications activities and sustained efforts to support its DSM programs, gain customer participation, and acquire cost-effective DSM resources. The DSM Communications Plan serves as a working plan that can and will be changed and adapted as conditions warrant or new knowledge is gained.

Q. Does NorthWestern plan to offer these DSM programs and conduct supporting activities again in the forthcoming tracker period?

A. Yes. NorthWestern will continue its contracts with previous and new outside services providers and will offer this group of electric DSM programs, modified and/or expanded as described herein, during the 2012-2013 tracker period.

The Nexant/Cadmus study, *Assessment of Energy Efficiency Potentials (2010-2029*), identified numerous cost-effective electric conservation measures that pass the Total Resource Cost test using 2010 electric avoided costs. These multiple, newly qualified energy efficiency measures enabled NorthWestern to expand its existing program and design and offer three new Electric Rebate DSM Programs to its customers in Montana. These new/expanded programs feature prescriptive rebates for numerous DSM measures, and were introduced in the 2011-2012 tracker period:

a. E+ Residential Electric Rebate Program for Existing Homes
b. E+ Residential Electric Rebate Program for New Construction
c. E+ Commercial Electric Rebate Program for Existing Facilities
d. E+ Commercial Electric Rebate Program for New Construction

The last three programs listed above are new programs that were not previously offered to customers. The first program listed was significantly expanded; the number of measures offered to customers is now more than four times greater than the previous program offering.

Rebate levels are generally established at a level equal to either the lesser of 50% of incremental measure cost, or 50% of the incremental measure resource value. Various informational materials, program guidelines, and program rebate application forms are available at the following website: www.northwesternenergy.com/eplus.

Q. What is the status of NorthWestern's efforts to secure cost-effective DSM in NorthWestern's own buildings and facilities?

A. In 2010, NorthWestern DSM and Facilities Department staff acted on a suggestion from other employees to investigate costs and benefits of NWE buildings in Montana becoming as energy efficient as cost-effectively possible, as a means to reduce the corporation's overall future operating costs. The DSM/Facilities work team forwarded a proposal to NorthWestern management to examine the existing level of energy efficiency of NorthWestern's buildings and facilities in the Montana service territory and look for additional cost-effective DSM opportunities. NorthWestern management approved the project proposal and directed the work team to proceed with implementation of the measures and actions identified by NCAT. As of this writing, approximately 35% of the retrofit work has been completed.

Recovery of DSM Program Costs and Lost Revenues

Q. What are the DSM program costs for Tracker Year 2012-2013 and how does NorthWestern propose to recover them?

A. Exhibit__(WMT-2) presents budget figures for individual supply DSM programs that totals $10,441,871 (refer to cell N35) for the 2012-2013 Tracker Year. This amount represents estimated DSM program costs and is included as a line item with other supply expenses in the Prefiled Direct Testimony of Frank V. Bennett. The electric supply rates established to recover all supply power expenses include recovery of $10,441,871 for 2012-2013 Tracker Year DSM program costs.

Q. Does NorthWestern propose to continue recovery of Lost Revenues associated with DSM program activity?

A. Yes. DSM Lost Revenues are a function of reduced transmission and distribution ("T&D") throughput caused by NorthWestern's DSM program activity. Additional DSM has been acquired in this tracker period, adding to the accumulated energy savings from NorthWestern's DSM program activities since the last reset of transmission and distribution rates, which became effective on July 8, 2010.[4] This accumulating energy savings further reduces the transmission and distribution throughput volumes compared to the prior tracking period. This, in turn, negatively affects NorthWestern's ability to recover fixed costs associated with the transmission and distribution system through volumetric rates.

Q. Does NorthWestern propose to continue recovery of Lost Revenues associated with CU-4?

A. Yes, NorthWestern proposes to recover the Lost Revenues associated with the fixed cost portion of the revenue requirement of CU-4. Similar to T&D rates, the CU-4 fixed costs will be reset in a future CU-4 revenue requirements proceeding, but that did not occur during this tracking period. The Lost Revenues calculations associated with these fixed costs appear as a separate additional worksheet tab (pages 11-16 of Exhibit__(WMT-3)) in the Electric DSM Lost Revenues spreadsheet described on the next page.

Q. Does NorthWestern propose recovery of Lost Revenues associated with DGGS?

A. Yes, NorthWestern proposes to recover the Lost Revenues associated with the fixed cost portion of the revenue requirement of DGGS that was placed into commercial operation on January 1, 2011. Similar to T&D

[4] Refer to General Rate Case Docket No. D2009.9.129, Interim Order No. 7046g and Final Order No. 7046h.

rates, the DGGS fixed costs will be reset in a future revenue requirements proceeding. The Lost Revenue calculations associated with these fixed costs appear as a separate additional worksheet tab (pages 17-19 of Exhibit__(WMT-3)) in the Electric DSM Lost Revenues spreadsheet described immediately below.

Q. Please describe the individual components of the Electric DSM Lost Revenues spreadsheet and the various data inputs used in its calculations.

A. The Electric DSM Lost Revenues calculation is performed using a spreadsheet workbook model, included herein as Exhibit__(WMT-3), that is comprised of nine separate worksheet tabs (names of tabs in bold below) that compile program budgets, costs, energy savings estimates, rates, revenues, and adjustment factors into a series of calculations that result in DSM Lost Revenues. Additional notes and explanations are included on the individual spreadsheet tabs, identified as separate pages of Exhibit__(WMT-3).

1. **DSM LR Summary** (Exhibit__(WMT-3), page 1) presents the results of the DSM Lost Revenues computations for tracker periods starting with the 2009-2010 tracker period, including the calculations for Lost Revenues related to CU-4 and DGGS that are performed on the subsequent tabs.

2. **Rates** (Exhibit__(WMT-3), page 2) details rates in effect for residential and GS-1 customers by line item. The Electric DSM Lost Revenue calculations use transmission and distribution rates from this worksheet tab as inputs to Tab 7 Calc Lost Revenues. These rates are updated each time the Electric DSM Lost Revenues exhibit is prepared for the Annual Electric Supply Tracker filing.

3. **Res and CI Energy Savings** (Exhibit__(WMT-3), page 3) uses the annual DSM targets and disaggregates them into annual residential and commercial/industrial ("C&I") energy savings targets. These factors are updated each year as NorthWestern gains experience operating DSM programs, collects program participation data, and observes the proportion of energy savings contributed by each customer segment toward annual DSM targets. These savings have been de-rated for one week (seven days) to account for the fact that the new transmission and distribution rates became effective on July 8, 2010, rather than July 1, 2010. Thus, for the purpose of Reported DSM Program energy savings, the Tracker's 'annual' period is shortened by one week.

4. **C&I Demand Sav** (Exhibit__(WMT-3), page 4) uses C&I energy savings developed in Tab 3 to determine total C&I annual demand reduction in kilowatt-months ("kw-mths"). The inputs on this tab include the average monthly load factor and a coincidence factor. The monthly load factor is derived from NorthWestern load research data and the coincidence factor is estimated at this time.

5. **Savings by Cust Class** (Exhibit__(WMT-3), page 5) develops program reported billing savings based on annual energy savings in kWh for the residential class and annual energy savings and demand savings in kw-mths for the C&I class. Demand savings is further disaggregated between GS-1 secondary non-demand and GS-1 primary non-demand. Inputs on this tab are the percentage savings by service level for commercial and industrial Supply customers. The percentages are based on actual program experience. The calculations on this tab are driven by results from the calculations on Tabs 3 and 4.

6. **Adjustment Factors** (Exhibit__(WMT-3), page 6) develops factors to be applied to residential and C&I program reported billing savings for purposes of calculating Lost Revenues. These factors recognize that actual savings obtained typically differ and are generally less than program savings based solely on engineering calculations. These factors are taken from the findings and conclusions of the 2007 DSM Evaluation.

7. **Calc Lost Revenues** (Exhibit__(WMT-3), pages 7-10) calculates Lost Revenues based on input from tabs 2, 5 and 6. Results from this tab are used as inputs to Tab 1.

8. **CU-4 Related LRs** (Exhibit__(WMT-3), pages 11-16) calculates Lost Revenues that are specific to the portion of the energy supply rate associated with recovery of the fixed cost revenue requirement for NorthWestern's share of CU-4 that serves Montana jurisdictional loads. The same lost revenue calculation methodology used in tabs 2 through 7 is applied, and the time frame for DSM energy savings relevant to the calculation reflects the fact that the CU-4 rate became effective on January 1, 2009.

9. **DGGS Related LRs** (Exhibit__(WMT-3), pages 17-19) calculates Lost Revenues that are specific to the portion of the energy supply rate associated with recovery of the fixed cost revenue requirement for DGGS service to Montana jurisdictional loads. The same lost revenue calculation methodology used in tabs 2 through 7 is applied, and the time frame for DSM energy savings relevant to the calculation reflects the fact that DGGS was placed in commercial service on January 1, 2011.

Q. How are the Lost Revenues trued-up and what amounts are you proposing to include as an adjustment to supply rates to recover Lost Revenues?

A. Exhibit__(WMT-3) provides updated calculations of electric Lost Revenues. A true-up to the Lost Revenue calculations is required each time a new DSM tracker is prepared because NorthWestern prepares and files a new annual tracker before the current tracking period ends. This schedule requires computation of DSM Lost Revenues based on 9 months of actual reported energy savings (July through March) and 3 months of estimated energy savings (April through June) for the concluding (or current) tracking period. Normally, the savings can be updated to reflect 12 months of actual information in response to discovery or in rebuttal testimony in the current docket.

Also, when the final results of the DSM Evaluation that is now under way are available (see below), NorthWestern will have updated Adjustment Factors. At that time, NorthWestern will recalculate the Lost Revenues for each of the relevant past trackers using the new Adjustment Factors and true-up those previous Lost Revenues (for the time period covered by the evaluation) and determine an overall adjustment amount. Depending on the timing of the completion of the current DSM Evaluation work and availability of the study results, revised DSM savings estimates and adjustment factors will also be applied to relevant past and forward-looking Lost Revenue calculations and a true-up of the calculations will either be filed as supplemental testimony in this docket or filed in NorthWestern's 2013 Annual Electric Supply Tracker filing.

Q. What amounts are you proposing to include as an adjustment to supply rates to recover Lost Revenues?

A. NorthWestern proposes that electric supply rates include recovery of the amount of $5,700,564 for total Electric DSM Lost Revenues for the 2011-2012 Tracker Year (refer to cell E11 on page 1 of Exhibit__(WMT-3)).

The forward looking total Electric DSM Lost Revenues for the 2012-2013 Tracker Year are $8,243,046 (refer to cell E13 on page 1 of Exhibit__(WMT-3)).

DSM Program Cost-Effectiveness and Program Evaluation

Q. What is the status of the independent evaluation of NorthWestern's portfolio of DSM programs?

A. Following a competitive bidding process administered by an independent administrator, NorthWestern selected SBW, Inc. to conduct a comprehensive DSM Program Evaluation. A services agreement was negotiated and executed for an extensive scope of work, with final results due at the end of October 2012. This work will result in a thorough quantitative and qualitative evaluation of the processes used in and the impacts of NorthWestern's DSM programs and provide recommendations for changes that might improve future results.

Results of the evaluation will be used to refine energy savings estimates for DSM programs and measures and adjust the factors used in the DSM tracking mechanism to determine net energy savings and associated Lost Revenues. An important part of the work is the economic evaluation of individual DSM programs and the overall portfolio of programs using industry-standard cost-effectiveness tests.

Since the last DSM evaluation was performed, NorthWestern compiled a multi-volume set of detailed documentation on DSM program activity over the previous time period (2007-2011), and met with representatives of SBW early in 2012 to familiarize SBW with the information and answer questions. This documentation included program records, calculations performed by NWE, assumptions and databases used, marketing materials and informational literature used in promoting the programs, spending records, energy savings calculations, previous testimony in regulatory proceedings, individual project files, and any and all other DSM program data and information maintained by NorthWestern in the course of its work. A copy of the voluminous set of materials provided to SBW is available for inspection in NorthWestern's offices in Butte, Montana.

Since the initial kick-off meeting, SBW and NorthWestern have engaged in regular phone calls and interaction to provide additional information, explanation, and clarification on data and information provided, supply additional information and data as requested by SBW, and make decisions regarding work activities about which SBW sought guidance. Telephone interviewing of samples of program participants is under way, and on-site inspections of a sample of projects are being completed. This field data collection work will continue through the summer months.

At this time, SBW has indicated that there are no issues that merit discussion. Project file reviews, participant surveys, and other activities are under way as needed to complete the project in a timely fashion. The final report detailing the results, findings and recommendations will be provided to the Commission.

Q. Does this complete your testimony?

A. Yes, it does.

Table A: Reported Electricity Savings from 2011-12 USB and DSM Program Activity

Programs	Annualized Energy Savings[1] USB kWh	USB aMW	DSM kWh	DSM aMW
General Default Supply DSM Expenses	-	-	-	-
E+ Energy Audit for the Home or Business (Elec)	1,247,217	0.14	-	-
E+ Energy Audit for the Home or Business (Natural Gas)	-	-	-	-
E+ Business Partners Program	-	-	4,372,150	0.50
E+ Irrigation	130,902	0.01	-	-
E+ Commercial Lighting Rebate Program	-	-	12,491,936	1.43
E+ Residential Lighting Programs	-	-	35,884,865	4.10
Builder Operator Certification	1,068,513	0.12	-	-
Northwest Energy Efficiency Alliance (NEEA)	-	-	6,634,084	0.76
Energy Star 80 Plus Program	-	-	994,942	0.11
E+ Free Weatherization Program & Fuel Switch	280,199	0.03	-	-
Low Income Appliance Replacement	6,555	0.00	-	-
E+ Renewable Energy Program	594,018	0.07	-	-
Energy Star New Homes Program	49,791	0.01	-	-
E+ Residential NC Electric Rebate Program	-	-	29,685	0.00
E+ Residential EX Electric Rebate Program	-	-	70,010	0.01
E+ Commercal NC Electric Rebate Program	-	-	279,011	0.03
E+ Commercial EX Electric Rebate Program	-	-	3,223,302	0.37
E+ Residential NC Gas Rebate Program	-	-	-	-
E+ Residential EX Gas Rebate Program	-	-	-	-
E+ Commercial NC Gas Rebate Program	-	-	-	-
E+ Commercial EX Gas Rebate Program	-	-	-	-
Total	**3,377,195**	**0.39**	**63,979,986**	**7.30**

Note 1: Annualized energy savings are based on 9 months of actual savings (July - March) and 3 months estimated.

USB + DSM savings acquired in 2011-12 Tracker Period (aMW):	7.69

Table B: Residential and Commercial Savings for Calculation of Lost T& D Revenues

Programs	USB + DSM Programs % Residential	kWh	% Commercial	kWh	Total kWh	Residential % of Total[2]	Commercial % of Total[2]
General Default Supply DSM Expenses	0%	-	0%	-	-		
E+ Energy Audit for the Home or Business (Elec)	82%	1,017,160	18%	230,058	1,247,217		
E+ Energy Audit for the Home or Business (Natural Gas)	95%	-	5%	-	-		
E+ Business Partners Program	0%	-	100%	4,372,150	4,372,150		
E+ Irrigation	0%	-	100%	130,902	130,902		
E+ Commercial Lighting Rebate Program	0%	-	100%	12,491,936	12,491,936		
E+ Residential Lighting Programs	100%	35,884,865	0%	-	35,884,865		
Builder Operator Certification	0%	-	100%	1,068,513	1,068,513		
Northwest Energy Efficiency Alliance (NEEA)	95%	6,273,825	5%	360,259	6,634,084		
Energy Star 80 Plus Program	0%	-	100%	994,942	994,942		
E+ Free Weatherization Program & Fuel Switch	100%	280,199	0%	-	280,199		
Low Income Appliance Replacement	100%	6,555	0%	-	6,555		
E+ Renewable Energy Program	72%	429,236	28%	164,782	594,018		
Energy Star New Homes Program	100%	49,791	0%	-	49,791		
E+ Residential NC Electric Rebate Program	100%	29,685	0%	-	29,685		
E+ Residential EX Electric Rebate Program	100%	70,010	0%	-	70,010		
E+ Commercal NC Electric Rebate Program	0%	-	100%	279,011	279,011		
E+ Commercial EX Electric Rebate Program	0%	-	100%	3,223,302	3,223,302		
E+ Residential NC Gas Rebate Program	100%	-	0%	-	-		
E+ Residential EX Gas Rebate Program	100%	-	0%	-	-		
E+ Commercial NC Gas Rebate Program	0%	-	100%	-	-		
E+ Commercial EX Gas Rebate Program	0%	-	100%	-	-		
		44,041,326		**23,315,855**	**67,357,181**	**65.38%**	**34.62%**

Note 2: Overall Residential and Commercial percentages are used in calculation of Lost Revenues in Exhibit__(WMT-3).

Dkt. No. D2012.5.49
EXHIBIT__(WMT-1)
PAGE 1 OF 1

Electric Supply DSM Program Spending & Budget

Electric DSM Program Spending	Order	2011-12 Tracker Year (10+2) — Actual Recorded Spending (July through April) - from SAP Records										Estimated	
		Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
General Expenses Related to All DSM Programs	17054	$ 2,822	$ 1,906	$ 17,097	$ 2,780	$ 4,574	$ 673	$ 67,744	$ 3,059	$ 122,237	$ 1,330	$ 418	$ 120,215
E+ Residential Lighting Program	17055	$ 26,115	$ 185,600	$ 125,216	$ 3,642	$ 337,405	$ 291,731	$ (1,488)	$ 93,354	$ 75,591	$ 27,931	$ 180,576	$ 260,471
E+ Residential Electric Savings Program	17056	$ 13,221	$ 19,078	$ 11,578	$ 12,680	$ 9,981	$ 7,882	$ 13,753	$ 12,390	$ 16,304	$ -	$ 22,000	$ 22,000
E+ Residential New Construction Program	17059	$ 5,161	$ 12,452	$ 1,030	$ 2,633	$ 3,221	$ 1,973	$ 1,075	$ 2,214	$ 1,560	$ -	$ -	$ -
E+ Commercial Lighting Program	17060	$ 121,848	$ 321,024	$ 153,757	$ 65,895	$ 173,122	$ 317,356	$ 339	$ 278,674	$ 165,082	$ 181,639	$ 690,389	$ 176,155
E+ Commercial New Construction Program	17062	$ 838	$ 2,989	$ 11,772	$ 1,803	$ 3,326	$ 1,993	$ 4,264	$ 4,117	$ 23,101	$ -	$ -	$ -
E+ Business Partners Program	17063	$ 347,766	$ 200,811	$ 130,552	$ 140,896	$ 86,779	$ 61,711	$ 3,421	$ 51,398	$ 13,320	$ 447,274	$ 66,228	$ 311,377
E+ Commercial Electric Rebate Program	17064	$ 20,740	$ 3,384	$ 76,358	$ 29,545	$ 103,883	$ 100,185	$ 8,041	$ 88,124	$ 72,844	$ 25,241	$ 37,000	$ 37,000
Market Transformation (NEEA)	17067	$ 365,888	$ 315	$ 1,273	$ 366,445	$ 537	$ 13	$ 365,540	$ -	$ 25	$ 358,907	$ -	$ -
Monthly Total Spending		$ 904,399	$ 747,559	$ 528,632	$ 626,320	$ 722,827	$ 783,516	$ 462,689	$ 533,330	$ 490,065	$ 1,042,322	$ 996,611	$ 927,217
Cumulative Total Spending (for 2011-12 Tracker Year 10+2)		$ 904,399	$ 1,651,957	$ 2,180,589	$ 2,806,909	$ 3,529,736	$ 4,313,252	$ 4,775,941	$ 5,309,271	$ 5,799,336	$ 6,841,658	$ 7,838,269	$ 8,765,487

Note: Actual Program Expenses through April 30, 2012 as of May 11, 2012

Electric DSM Program Spending	Order	2012-13 Tracker Year — Estimated											
		Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
General Expenses Related to All DSM Programs	17054	$ 96,047	$ 95,040	$ 111,749	$ 96,001	$ 97,974	$ 93,683	$ 167,461	$ 96,308	$ 227,404	$ 99,019	$ 93,403	$ 225,179
E+ Residential Lighting Program	17055	$ 26,115	$ 185,600	$ 125,216	$ 3,642	$ 337,405	$ 291,731	$ -	$ 93,354	$ 75,591	$ 251,462	$ 180,576	$ 260,471
E+ Residential Electric Savings Program	17056	$ 14,543	$ 20,986	$ 12,736	$ 13,948	$ 10,979	$ 8,670	$ 15,128	$ 13,628	$ 17,934	$ 24,200	$ 24,200	$ 24,200
E+ Residential New Construction Program	17059	$ 5,264	$ 12,701	$ 1,051	$ 2,686	$ 3,286	$ 2,012	$ 1,097	$ 2,258	$ 1,591	$ 8,659	$ -	$ -
E+ Commercial Lighting Program	17060	$ 121,848	$ 321,024	$ 153,757	$ 65,895	$ 173,122	$ 317,356	$ 339	$ 278,674	$ 165,082	$ 380,685	$ 690,389	$ 176,155
E+ Commercial New Construction Program	17062	$ 838	$ 2,989	$ 11,772	$ 1,803	$ 3,326	$ 1,993	$ 4,264	$ 4,117	$ 23,101	$ 7,774	$ -	$ -
E+ Business Partners Program	17063	$ 382,542	$ 220,892	$ 143,607	$ 154,985	$ 95,457	$ 67,882	$ 3,763	$ 56,538	$ 14,652	$ 313,520	$ 72,850	$ 342,515
E+ Commercial Electric Rebate Program	17064	$ 22,814	$ 3,722	$ 83,994	$ 32,500	$ 114,271	$ 110,204	$ 8,846	$ 96,937	$ 80,129	$ 24,200	$ 40,700	$ 40,700
Market Transformation (NEEA)	17067	$ 358,790	$ -	$ -	$ 358,790	$ -	$ -	$ 358,790	$ -	$ -	$ 358,790	$ -	$ -
Monthly Total Spending		$ 1,028,802	$ 862,954	$ 643,881	$ 730,250	$ 835,820	$ 893,531	$ 559,688	$ 641,814	$ 605,485	$ 1,468,309	$ 1,102,118	$ 1,069,220
Cumulative Total Spending (for 2012-13 Tracker Year)		$ 1,028,802	$ 1,891,756	$ 2,535,637	$ 3,265,887	$ 4,101,707	$ 4,995,238	$ 5,554,926	$ 6,196,740	$ 6,802,225	$ 8,270,533	$ 9,372,652	$ 10,441,871

Dkt. No. D2012.5.49
EXHIBIT__(WMT-2)
PAGE 1 OF 1

Electric DSM Lost Revenues

Time Period[1]	Montana T&D	Colstrip Unit #4[2]	Dave Gates Mill Creek Station[3]	Total DSM Lost Revenue[4]
Tracker 2009-10	$ 3,062,576	$ 716,410		$ 3,778,987
Tracker 2010-11:				
July-December 2010	$ 543,454	$ 762,879	$ -	$ 1,306,332
January-June 2011	$ 1,112,639	$ 762,879	$ 74,329	$ 1,949,846
	$ 1,656,092	$ 1,525,758	$ 74,329	$ 3,256,179
Tracker 2011-12	$ 3,127,095	$ 2,304,122	$ 269,347	$ 5,700,564
Tracker 2012-13	$ 4,746,366	$ 2,957,541	$ 539,139	$ 8,243,046

Notes:

1. Electric DSM Lost Revenues were reset Jan. 1, 2008 due to newly established T&D rates
Refer to Electric Default Supply Service D2007.7.80, Tariff 144-E and
General Rate Case D2007.7.82 Interim Order No. 6852b, Tariff 145-E
Tracker Period 2011-2012 based on 9+3 energy savings

Electric DSM Lost Revenues were reset again on Jan. 1, 2011 due to newly established T&D rates
Refer to Docket D2009.9.129, Final Order No. 7046h

2. MPSC Final Order 6921c authorizes CU-4 related Lost Revenues in the amount of $83,021 for the 2008-09 period.
There is no "reset" of DSM savings for CU-4 related Lost Revenues, because there were no new rates established.

3. DGGS began commercial service on January 1, 2011

4. MPSC Final Order 7093c authorizes DSM Lost Revenues in the amount of $3,778,987 for the 2009-10 period.
MPSC Final Order 7154b authorizes DSM Lost Revenues in the amount of $3,256,179 for the 2010-11 period.

Electric DSM Lost Revenues

2010-11 Tracking Period

Period July – December 2010

Reference: Compliance Filing on December 21, 2010 Docket D2009.9.129, Final Order 7046h; Work-Papers Section "Electric Utility Approved Revenue Requirement ACOS and Derivation of Rates" Page 3 of 4 Column D.

Period January – June 2011

Reference: 2011 Annual Tax Tracker Filing Application December 23, 2010, Docket D2010.12.116, Final Order 7131a; Appendix A Pages 1 – 4, Column (B) + (E), <u>excluding</u> rebate in Column (C).

2011-12 Tracking Period

Period July 2011-December 2011

Period January-June 2012

2012-13 Tracking Period

Period July 2012-June 2013

Reference: 2012 Annual Tax Tracker Filing Application December 8, 2011, Docket D2012.12.97., Final Order 7191a; Appendix A Pages 1-4

	Period July – December 2010	Period January – June 2011	Period July 2011-December 2011	Period January-June 2012	Period July 2012-June 2013
Residential:					
Transmission Energy	$0.008918 per kwh	$0.009051 per kwh	0.009078 per kwh	0.008866 per kwh	0.008866 per kwh
Distribution Energy	$0.027761 per kwh	$0.028176 per kwh	0.028259 per kwh	0.027599 per kwh	0.027599 per kwh
GS 1 Secondary, non-demand					
Transmission Energy	$0.007765 per kwh	$0.007881 per kwh	0.007904 per kwh	0.007719 per kwh	0.007719 per kwh
Distribution Energy	$0.035955 per kwh	$0.036493 per kwh	0.036600 per kwh	0.035745 per kwh	0.035745 per kwh
GS 1 Secondary, demand					
Transmission Demand	$2.966798 per kw	$3.011163 per kw	3.019986 per kw	2.949439 per kw	2.949439 per kw
Distribution Energy	$0.004797 per kwh	$0.004869 per kwh	0.004883 per kwh	0.004769 per kwh	0.004769 per kwh
Distribution Demand	$6.047753 per kw	$6.138191 per kw	6.156176 per kw	6.012368 per kw	6.012368 per kw
General Service - 1 Primary, Non Demand:					
Transmission Energy	$0.008122 per kwh	$0.008244 per kwh	0.008268 per kwh	0.008075 per kwh	0.008075 per kwh
Distribution Energy	$0.018623 per kwh	$0.018902 per kwh	0.018957 per kwh	0.018514 per kwh	0.018514 per kwh
General Service - 1 Primary, Demand:					
Transmission Demand	$3.605969 per kw	$3.659893 per kw	3.670616 per kw	3.584870 per kw	3.584870 per kw
Distribution Energy	$0.006936 per kwh	$0.007040 per kwh	0.007061 per kwh	0.006896 per kwh	0.006896 per kwh
Distribution Demand	$3.959563 per kw	$4.018774 per kw	4.030549 per kw	3.936395 per kw	3.936395 per kw

Dkt. No. D2012.5.49
EXHIBIT__(WMT-3)
PAGE 2 OF 19

Electric DSM Lost Revenues

Annual Energy Savings:

1) DSM Targets and Results:

	Tracker 2010-11[1]				Tracker 2011-2012		Tracker 2012-2013	
	Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Annual (Avg. MW)	3.00	**4.20**	3.00	**4.28**	6.00	**7.69**	6.00	**6.00**
Cumulative (Avg. MW)	3.00	4.20	7.20	8.48	14.48	16.17	22.17	22.17

1. Different T&D rates were in effect for each 6-month period, so Total Reported DSM Savings (8.56 aMW) was divided between the two periods. New rates went into effect on July 8, 2010, which is one week later than the beginning of the 2010-11 Tracker Period, so Reported Energy Savings has been "de-rated" by 7 days for the July-December 2010 period.

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

	Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
% Residential	67.4%	78.4%	67.4%	78.4%	67.4%	65.4%	67.4%	67.4%
% Commercial & Industrial	32.6%	21.6%	32.6%	21.6%	32.6%	34.6%	32.6%	32.6%
Incremental Res. (Avg. MW)	2.02	3.29	2.02	3.35	4.04	5.03	4.04	4.04
Cumulative Res. (Avg. MW)	2.02	3.29	4.04	6.65	10.69	11.67	15.72	15.72
Incremental C/I (Avg. MW)	0.98	0.91	0.98	0.93	1.96	2.66	1.96	1.96
Cumulative C/I (Avg. MW)	0.98	0.91	1.96	1.84	3.79	4.50	6.45	6.45
check fig:	3.00	4.20	3.00	4.28	6.00	7.69	6.00	6.00

2. Residential/commercial split based on DSM Program results

3) Cumulative Annual Energy Savings[3]

	Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Residential (MWH)	8,853	14,413	17,707	29,107	75,920	80,235	119,962	119,962
C/I (MWH)	4,287	3,980	8,573	8,038	24,649	27,734	47,965	47,965
Total Savings (MWH)	13,140	18,393	26,280	37,145	100,570	107,968	167,927	167,927
Total Savings (Avg. MW)	1.50	2.10	3.00	4.24	11.48	12.33	19.17	19.17

3. "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.

Electric DSM Lost Revenues

Commercial/Industrial Reduction in Peak Demand:

1) Commercial/Industrial Average Monthly Load Factor: 66%

2) Calculate Coincident Monthly Demand Reduction:

	Tracker 2010-11				Tracker 2011-2012		Tracker 2012-2013	
	Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
C/I Energy Savings (MWH)	4,287	3,980	8,573	8,038	24,649	27,734	47,965	47,965
C/I Energy Savings (Avg. MW)	0.5	0.5	1.0	0.9	2.8	3.2	5.5	5.5
C/I Avg. Monthly Demand Reduction (KW/Mth)*	741	688	1,483	1,390	4,263	4,797	8,296	8,296
C/I Annual Demand Reduction (KW-Mths)	8,897	8,261	17,794	16,683	51,161	57,563	99,554	99,554

3) Coincidence Factor: 100% *

* Coincidence Factor is estimated. 100% load factor assumes that, from a billing perspective, the impacts of class coincidence are offset by the potential of the impacts of specific technologies/projects to be non-coincident with the peak loads of individual customers.

	Tracker 2010-11							
	Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
4) C/I Annual Demand Reduction (KW-Mths)*	8,897	8,261	17,794	16,683	51,161	57,563	99,554	99,554

* Represents total C/I Demand reduction. Tariffs for GS-1 Primary and Secondary Non-demand customers do not include a demand charge. Demand reductions associated with such customers do not result in lost revenues.

Electric DSM Lost Revenues

Estimate Energy and Demand "Bill" Savings for Residential and C/I

	Tracker 2010-11				Tracker 2011-12		Tracker 2011-12	
	Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
1) Residential Savings (KWH)	8,853,306	14,412,563	17,706,613	29,106,935	75,920,484	80,234,534	119,961,810	119,961,810
2) C/I Savings								
Energy (KWH)	4,286,694	3,980,077	8,573,387	8,037,977	24,649,341	27,733,882	47,965,196	47,965,196
Demand (KW-Mths)	8,897	8,261	17,794	16,683	51,161	57,563	99,554	99,554

3) Disaggregate C&I Savings by service level (tariff)

C&I Savings is broken out as:*

GS-1 Secondary, non demand	1%	1%	1%	1%	1%	1%	1%	1%
GS-1 Secondary, demand	98%	98%	98%	98%	98%	98%	98%	98%
GS-1 Primary, non demand	0%	0%	0%	0%	0%	0%	0%	0%
GS-1 Primary, demand	1%	1%	1%	1%	1%	1%	1%	1%
Total C&I	100%	100%	100%	100%	100%	100%	100%	100%

4) C&I Reported Programmatic "Bill" Savings Based on Breakout in 3) Above:

	Tracker 2010-11							
	Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013	
Energy (KWh)	Target	Reported	Target	Reported	Target	Reported	Target	Reported
GS-1 Secondary, non demand	42,867	39,801	85,734	80,380	246,493	277,339	479,652	479,652
GS-1 Secondary, demand	4,200,960	3,900,476	8,401,919	7,877,217	24,156,354	27,179,204	47,005,892	47,005,892
GS-1 Primary, non demand	-	-	-	-	-	-	-	-
GS-1 Primary, demand	42,867	39,801	85,734	80,380	246,493	277,339	479,652	479,652
Check Total	4,286,694	3,980,077	8,573,387	8,037,977	24,649,341	27,733,882	47,965,196	47,965,196
Demand (KW-mth)								
GS-1 Secondary, demand	8,719	8,096	17,439	16,350	50,138	56,412	97,563	97,563
GS-1 Primary, demand	89	83	178	167	512	576	996	996
Total*	8,808	8,178	17,617	16,516	50,649	56,987	98,559	98,559

Totals are less than totals in row 12 above because non-demand C&I customers are not billed for demand.

File: Exhibit__(WMT-3) Electric DSM Lost Revenues 2010-13 final.xls
Tab: 5.Savings By Cust Class

Electric DSM Lost Revenues

Adjustment Factors (Net Savings Adjustment Ratios)

Residential	Net Savings Adjustment Ratio
Segment	
All	0.872

Commercial/Industrial	Net Savings Adjustment Ratio
Segment	
All	0.824

The Net Savings Adjustment Ratios for these tracker periods
are derived from the results of of NEXANT's DSM Evaluation.
These are sometimes referred to as Net-to-Gross Factors.

Electric DSM Lost Revenues - Montana T&D

July-December 2010

Residential								
			Gross					**Estimated**
			Program			**Net**		**Lost**
	Rate[1]		**Savings**		**Adjustment**	**Savings**		**Revenue**
Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
Transmission Energy	0.008918		14,412,563		0.872	12,570,237		112,101
Distribution Energy	0.027761		14,412,563		0.872	12,570,237		348,962
				Sub Total Residential:		**12,570,237**		**$ 461,064**
Commercial & Industrial								
			Gross	**Gross**				**Estimated**
			Program	**Program**		**Net**	**Net**	**Lost**
	Rate[1]	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
GS-1 Secondary, non demand, TX Energy	0.007765		39,801		0.824	32,792		255
GS-1 Secondary, non demand, Dist. Energy	0.035955		39,801		0.824	32,792		1,179
GS-1 Secondary, demand, TX Demand		2.966798		8,719	0.824		7,184	21,313
GS-1 Secondary, demand, Dist. Energy	0.004797		3,900,476		0.824	3,213,580		15,416
GS-1 Secondary, demand, Dist. Demand		6.047753		8,719	0.824		7,184	43,446
GS-1 Primary, non demand, TX Energy	0.008122		0		0.824	0		0
GS-1 Primary, non demand, Dist. Energy	0.018623		0		0.824	0		0
GS-1 Primary, demand, TX Demand		3.605969		89	0.824		73	264
GS-1 Primary, demand, Dist. Energy	0.006936		39,801		0.824	32,792		227
GS-1 Primary, demand, Dist. Demand		3.959563		89	0.824		73	290
			Sub Total Commercial & Industrial:			**3,279,164**		**$ 82,390**
		July-December 2010	**Estimated Totals:**			**15,849,401**		**$ 543,454**
Note 1: using rates in effect at the time (see Rates tab)								

Dkt. No. D2012.5.49
EXHIBIT__(WMT-3)

File: Exhibit__(WMT-3) Electric DSM Lost Revenues 2010-13 final.xls
Tab: 7.Calc Lost Revenues

Electric DSM Lost Revenues - Montana T&D

	A	B	C	D	E	F	G	H	I
39	**January-June 2011**								
40									
41									
42	**Residential**								
43				**Gross**					**Estimated**
44				**Program**			**Net**		**Lost**
45		**Rate[1]**		**Savings**		**Adjustment**	**Savings**		**Revenue**
46	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
47	Transmission Energy	0.009051		29,106,935		0.872	25,386,262		229,771
48	Distribution Energy	0.028176		29,106,935		0.872	25,386,262		715,283
49					**Sub Total Residential:**		**25,386,262**		**$ 945,054**
50									
51									
52	**Commercial & Industrial**			**Reported**	**Reported**				
53				**Gross**	**Gross**				**Estimated**
54				**Program**	**Program**		**Net**	**Net**	**Lost**
55		**Rate[1]**	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
56	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
57	GS-1 Secondary, non demand, TX Energy	0.007881		80,380		0.824	66,224		522
58	GS-1 Secondary, non demand, Dist. Energy	0.036493		80,380		0.824	66,224		2,417
59									
60	GS-1 Secondary, demand, TX Demand		3.011163		17,439	0.824		14,368	43,263
61	GS-1 Secondary, demand, Dist. Energy	0.004869		7,877,217		0.824	6,489,996		31,600
62	GS-1 Secondary, demand, Dist. Demand		6.138191		17,439	0.824		14,368	88,191
63									
64	GS-1 Primary, non demand, TX Energy	0.008244		0		0.824	0		0
65	GS-1 Primary, non demand, Dist. Energy	0.018902		0		0.824	0		0
66									
67	GS-1 Primary, demand, TX Demand		3.659893		178	0.824		147	537
68	GS-1 Primary, demand, Dist. Energy	0.00704		80,380		0.824	66,224		466
69	GS-1 Primary, demand, Dist. Demand		4.018774		178	0.824		147	589
70				**Sub Total Commercial & Industrial:**			**6,622,445**		**$ 167,584**
71									
72			**January-June 2011**	**Estimated Totals:**			**32,008,707**		**$ 1,112,639**
73	Note 1: using rates in effect at the time (see Rates tab)								
74									

File: Exhibit__(WMT-3) Electric DSM Lost Revenues 2010-13 final.xls
Tab: 7.Calc Lost Revenues

Electric DSM Lost Revenues - Montana T&D

	A	B	C	D	E	F	G	H	I
75	**July 2011-June 2012**								
76									
77									
78	**Residential**								
79				**Gross**					**Estimated**
80		**Average**		**Program**			**Net**		**Lost**
81		**Rate[1]**		**Savings**		**Adjustment**	**Savings**		**Revenue**
82	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
83	Transmission Energy	0.008972		80,234,534		0.872	69,978,334		627,846
84	Distribution Energy	0.027929		80,234,534		0.872	69,978,334		1,954,425
85					**Sub Total Residential:**		**69,978,334**		**$ 2,582,271**
86									
87									
88	**Commercial & Industrial**			**Reported**	**Reported**				
89				**Gross**	**Gross**				**Estimated**
90		**Average**	**Average**	**Program**	**Program**		**Net**	**Net**	**Lost**
91		**Rate[1]**	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
92	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
93	GS-1 Secondary, non demand, TX Energy	0.007812		277,339		0.824	228,498		1,785
94	GS-1 Secondary, non demand, Dist. Energy	0.036173		277,339		0.824	228,498		8,265
95									
96	GS-1 Secondary, demand, TX Demand		2.984713		56,412	0.824		46,477	138,722
97	GS-1 Secondary, demand, Dist. Energy	0.004826		27,179,204		0.824	22,392,797		108,068
98	GS-1 Secondary, demand, Dist. Demand		6.084272		56,412	0.824		46,477	282,781
99									
100	GS-1 Primary, non demand, TX Energy	0.008172		0		0.824	0		0
101	GS-1 Primary, non demand, Dist. Energy	0.018736		0		0.824	0		0
102									
103	GS-1 Primary, demand, TX Demand		3.627743		576	0.824		474	1,720
104	GS-1 Primary, demand, Dist. Energy	0.006979		277,339		0.824	228,498		1,595
105	GS-1 Primary, demand, Dist. Demand		3.983472		576	0.824		474	1,889
106				**Sub Total Commercial & Industrial:**			**22,849,793**		**$ 544,825**
107									
108			**July 2011-June 2012**	**Estimated Totals:**			**92,828,127**		**$ 3,127,095**
109									
110	**Note 1: Two sets of rates were used, each set was effective for 6 months of the 2011-12 tracker period**								
111									

Dkt. No. D2012.5.49
EXHIBIT__(WMT-3)
PAGE 9 OF 19

File: Exhibit__(WMT-3) Electric DSM Lost Revenues 2010-13 final.xls
Tab: 7.Calc Lost Revenues

Electric DSM Lost Revenues - Montana T&D

	A	B	C	D	E	F	G	H	I
112	**July 2012-June 2013**								
113									
114									
115	**Residential**			TARGET					
116				Gross					Estimated
117				Program			Net		Lost
118		Rate[1]		Savings		Adjustment	Savings		Revenue
119	Bill Line Item	($ per kwh)		(kwh)		Factor	(kwh)		($)
120	Transmission Energy	0.008866		119,961,810		0.872	104,627,362		927,626
121	Distribution Energy	0.027599		119,961,810		0.872	104,627,362		2,887,611
122					Sub Total Residential:		104,627,362		$ 3,815,237
123									
124				TARGET					
125	**Commercial & Industrial**			Reported	Reported				
126				Gross	Gross				Estimated
127				Program	Program		Net	Net	Lost
128		Rate[1]	Rate[1]	Savings	Savings	Adjustment	Savings	Savings	Revenue
129	Bill Line Item	($ per kwh)	($ per kw-mth)	(kwh)	(kw-mth)	Factor	(kwh)	(kw-mth)	($)
130	GS-1 Secondary, non demand, TX Energy	0.007719		479,652		0.824	395,183		3,050
131	GS-1 Secondary, non demand, Dist. Energy	0.035745		479,652		0.824	395,183		14,126
132									
133	GS-1 Secondary, demand, TX Demand		2.949439		97,563	0.824		80,382	237,081
134	GS-1 Secondary, demand, Dist. Energy	0.004769		47,005,892		0.824	38,727,897		184,693
135	GS-1 Secondary, demand, Dist. Demand		6.012368		97,563	0.824		80,382	483,284
136									
137	GS-1 Primary, non demand, TX Energy	0.008075		0		0.824	0		0
138	GS-1 Primary, non demand, Dist. Energy	0.018514		0		0.824	0		0
139									
140	GS-1 Primary, demand, TX Demand		3.58487		996	0.824		820	2,940
141	GS-1 Primary, demand, Dist. Energy	0.006896		479,652		0.824	395,183		2,725
142	GS-1 Primary, demand, Dist. Demand		3.936395		996	0.824		820	3,229
143				Sub Total Commercial & Industrial:			39,518,262		$ 931,129
144									
145			July 2012-June 2013	Estimated Totals:			144,145,624		$ 4,746,366
146									
147	Note 1: using rates expected to be in effect at the time (see Rates tab)								

Dkt. No. D2012.5.49
EXHIBIT__(WMT-3)
PAGE 10 OF 19

File: Exhibit__(WMT-3) Electric DSM Lost Revenues 2010-13 final.xls
Tab: 7.Calc Lost Revenues

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

DSM Targets and Results:

	January-June 2009		Tracker 2009-10		Tracker 2010-11		Tracker 2011-12		Tracker 2012-13	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Annual (Avg. MW)	2.50	3.34	5.00	8.33	6.00	8.56	6.00	7.69	6.00	6.00
Cumulative (Avg. MW)	2.50	3.34	8.34	11.67	17.67	20.24	26.24	27.93	33.93	33.93

Disaggregate Targets into Residential & Commercial/Industrial [1]

	January-June 2009		Tracker 2009-10		Tracker 2010-11		Tracker 2011-12		Tracker 2012-13	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
% Residential	66.5%	62.2%	66.5%	67.4%	67.4%	78.4%	67.4%	65.4%	67.4%	67.4%
% Commercial & Industrial	33.5%	37.8%	33.5%	32.6%	32.6%	21.6%	32.6%	34.6%	32.6%	32.6%
Incremental Res. (Avg. MW)	1.66	2.08	3.33	5.61	4.04	6.71	4.04	5.03	4.04	4.04
Cumulative Res. (Avg. MW)	1.66	2.08	4.99	7.69	11.74	14.40	18.44	19.43	23.47	23.47
Incremental C/I (Avg. MW)	0.84	1.26	1.68	2.72	1.96	1.85	1.96	2.66	1.96	1.96
Cumulative C/I (Avg. MW)	0.84	1.26	2.51	3.98	5.94	5.83	7.79	8.50	10.45	10.45
check fig:	2.50	3.34	5.00	8.33	6.00	8.56	6.00	7.69	6.00	6.00

1. Residential/commercial split based on DSM Program results

Cumulative Annual Energy Savings[2]	January-June 2009		Tracker 2009-10		Tracker 2010-11		Tracker 2011-12		Tracker 2012-13	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Residential (MWH)	7,282	9,113	32,789	42,806	85,093	96,775	143,870	148,184	187,911	187,911
C/I (MWH)	3,668	5,538	18,412	22,977	43,452	42,995	59,684	62,768	83,000	83,000
Total Savings (MWH)	10,950	14,651	51,201	65,783	128,545	139,769	203,554	210,953	270,911	270,911
Total Savings (Avg. MW)	1.25	1.67	5.84	7.51	14.67	15.96	23.24	24.08	30.93	30.93

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.

3) Disaggregate C&I Savings by service level (tariff)

C&I Savings is broken out as:*										
GS-1 Secondary, non demand	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
GS-1 Secondary, demand	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
GS-1 Primary, non demand	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
GS-1 Primary, demand	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Total C&I	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

File: Exhibit__(WMT-3) Electric DSM Lost Revenues 2010-13 final.xls
Tab: 8.CU-4 Related LRs

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Rates:
CU4 Fixed Rates: Docket D2009.12.155, Order No. 7075b

	01/01/09	01/01/10	01/01/11	01/01/12	01/01/13
Residential	$0.013273	$0.012734	0.012734	0.012734	0.012734
GS-1 Sec Non-Demand	$0.013273	$0.012734	0.012734	0.012734	0.012734
GS-1 Sec Demand	$0.013273	$0.012734	0.012734	0.012734	0.012734
GS-1 Pri Non-Demand	$0.012910	$0.012385	0.012385	0.012385	0.012385
GS-1 Pri Demand	$0.012910	$0.012385	0.012385	0.012385	0.012385
GS-2 Substation	$0.012798	$0.012278	0.012278	0.012278	0.012278
GS-2 Transmission	$0.012721	$0.012204	0.012204	0.012204	0.012204

Calculate CU-4 related DSM Lost Revenues
January - June 2009
Based on Cumulative DSM Savings Since January 2009

Residential Bill Line Item	Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Residential	$0.013273	9,112,652	0.87	7,947,802	105,491
				7,947,802	105,491

Commercial & Industrial Bill Line Item	Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
GS-1 Sec Non-Demand	$0.013273	55,379	0.82	45,627	606
GS-1 Sec Demand	$0.013273	5,427,155	0.82	4,471,404	59,349
GS-1 Pri Non-Demand	$0.012910	0	0.82	0	-
GS-1 Pri Demand	$0.012910	55,379	0.82	45,627	589
GS-2 Substation	$0.012798	0	0.82	0	-
GS-2 Transmission	$0.012721	0	0.82	0	-
		Sub Total General Service:		4,562,657	60,544

Note 1: using rates expected to be in effect at the time (see Rates tab)

Total CU-4-related DSM Lost Revenues Before Stipulation $ **166,035**

Stipulated CU-4-related DSM Lost Revenues $ **83,021**

File: Exhibit__(WMT-3) Electric DSM Lost Revenues 2010-13 final.xls
Tab: 8.CU-4 Related LRs

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Tracker 2009-10					
Based on Cumulative DSM Savings Since January 2009					
Residential		**Gross Program Savings (kwh)**		**Net Savings (kwh)**	**Estimated Lost Revenue ($)**
Bill Line Item	**Rate[1] ($ per kwh)**		**Adjustment Factor**		
Residential	$0.012734	42,805,614	0.87	37,333,869	475,409
				37,333,869	475,409
Commercial & Industrial		**Gross Program Savings (kwh)**		**Net Savings (kwh)**	**Estimated Lost Revenue ($)**
Bill Line Item	**Rate[1] ($ per kwh)**		**Adjustment Factor**		
GS-1 Sec Non-Demand	$0.012734	229,774	0.82	189,310	2,411
GS-1 Sec Demand	$0.012734	22,517,851	0.82	18,552,334	236,245
GS-1 Pri Non-Demand	$0.012385	0	0.82	0	-
GS-1 Pri Demand	$0.012385	229,774	0.82	189,310	2,345
GS-2 Substation	$0.012278	0	0.82	0	-
GS-2 Transmission	$0.012204	0	0.82	0	-
		Sub Total General Service:		18,930,953	241,001
Note 1: using rates expected to be in effect at the time (see Rates tab)					
		Total CU-4-related DSM Lost Revenues			**$ 716,410**

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Tracker 2010-11					
Based on Cumulative DSM Savings Since January 2009					
Residential		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
Residential	$0.012734	96,774,671	0.87	84,404,183	1,074,803
				84,404,183	1,074,803
Commercial & Industrial		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.012734	429,948	0.82	354,232	4,511
GS-1 Sec Demand	$0.012734	42,134,875	0.82	34,714,692	442,057
GS-1 Pri Non-Demand	$0.012385	0	0.82	0	-
GS-1 Pri Demand	$0.012385	429,948	0.82	354,232	4,387
GS-2 Substation	$0.012278	0	0.82	0	-
GS-2 Transmission	$0.012204	0	0.82	0	-
		Sub Total General Service:		**35,423,156**	450,955
Note 1: using rates expected to be in effect at the time (see Rates tab)					
		Total CU-4-related DSM Lost Revenues			**$ 1,525,758**

File: Exhibit__(WMT-3) Electric DSM Lost Revenues 2010-13 final.xls
Tab: 8.CU-4 Related LRs

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Tracker 2011-12					
Based on Cumulative DSM Savings Since January 2009					
Residential		Gross			Estimated
		Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
Residential	$0.012734	148,184,079	0.87	129,242,043	1,645,768
				129,242,043	1,645,768
Commercial & Industrial		Gross			Estimated
		Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
GS-1 Sec Non-Demand	$0.012734	627,685	0.82	517,146	6,585
GS-1 Sec Demand	$0.012734	61,513,128	0.82	50,680,329	645,363
GS-1 Pri Non-Demand	$0.012385	0	0.82	0	0
GS-1 Pri Demand	$0.012385	627,685	0.82	517,146	6,405
GS-2 Substation	$0.012278	0	0.82	0	0
GS-2 Transmission	$0.012204	0	0.82	0	0
		Sub Total General Service:		51,714,621	658,354
Note 1: using rates expected to be in effect at the time (see Rates tab)					
		Total CU-4-related DSM Lost Revenues			$ 2,304,122

Dkt. No. D2012.5.49
EXHIBIT__(WMT-3)
PAGE 15 OF 19

File: Exhibit__(WMT-3) Electric DSM Lost Revenues 2010-13 final.xls
Tab: 8.CU-4 Related LRs

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Row	B	C	D	E	F	G
172						
173	**Tracker 2012-13**					
174	**Based on Cumulative DSM Savings Since January 2009**					
175						
176	**Residential**		Gross			Estimated
177			Program		Net	Lost
178		Rate[1]	Savings	Adjustment	Savings	Revenue
179	Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
180	Residential	$0.012734	187,911,355	0.87	163,891,071	2,086,989
181					**163,891,071**	2,086,989
182						
183	**Commercial & Industrial**		Gross			Estimated
184			Program		Net	Lost
185		Rate[1]	Savings	Adjustment	Savings	Revenue
186	Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
187	GS-1 Sec Non-Demand	$0.012734	829,998	0.82	683,831	8,708
188	GS-1 Sec Demand	$0.012734	81,339,816	0.82	67,015,428	853,374
189	GS-1 Pri Non-Demand	$0.012385	0	0.82	0	0
190	GS-1 Pri Demand	$0.012385	829,998	0.82	683,831	8,469
191						
192	GS-2 Substation	$0.012278	0	0.82	0	0
193	GS-2 Transmission	$0.012204	0	0.82	0	0
194			**Sub Total General Service:**		68,383,090	870,552
195						
196	Note 1: using rates expected to be in effect at the time (see Rates tab)					
197						
198			**Total CU-4-related DSM Lost Revenues**			**$ 2,957,541**

Dkt. No. D2012.5.49
EXHIBIT__(WMT-3)

Electric DSM Lost Revenues - Dave Gates Generating Station

(fixed cost portion of DGGS)

DSM Targets and Results:	Tracker 2010-11				Tracker 2011-12		Tracker 2012-13	
	July-December 2010		January-June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Annual (Avg. MW)	N/A	N/A	3.00	4.28	6.00	7.69	6.00	6.00
Cumulative (Avg. MW)	N/A	N/A	3.00	4.28	10.28	11.97	17.97	17.97

Disaggregate Targets into Residential & Commercial/Industrial [1]	Tracker 2010-11							
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
% Residential	N/A	N/A	67.4%	78.4%	67.4%	65.4%	67.4%	67.4%
% Commercial & Industrial	N/A	N/A	32.6%	21.6%	32.6%	34.6%	32.6%	32.6%
Incremental Res. (Avg. MW)	N/A	N/A	2.02	3.35	4.04	5.03	4.04	4.04
Cumulative Res. (Avg. MW)	N/A	N/A	2.02	3.35	7.40	8.38	12.43	12.43
Incremental C/I (Avg. MW)	N/A	N/A	0.98	0.93	1.96	2.66	1.96	1.96
Cumulative C/I (Avg. MW)	N/A	N/A	0.98	0.93	2.88	3.59	5.55	5.55
check fig:	N/A	N/A	3.00	4.28	6.00	7.69	6.00	6.00

1. Residential/commercial split based on DSM Program results

Cumulative Annual Energy Savings[2]	Tracker 2010-11							
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Residential (MWH)	N/A	N/A	8,853	14,694	47,095	51,409	91,137	91,137
C/I (MWH)	N/A	N/A	4,287	4,058	16,689	19,774	40,005	40,005
Total Savings (MWH)	N/A	N/A	13,140	18,752	63,785	71,183	131,142	131,142
Total Savings (Avg. MW)	N/A	N/A	1.5	2.1	7.3	8.1	15.0	15.0

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.

Disaggregate C&I Savings by service level (tariff)						
C&I Savings is broken out as:						
GS-1 Secondary, non demand	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
GS-1 Secondary, demand	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
GS-1 Primary, non demand	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
GS-1 Primary, demand	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Total C&I	100%	100%	100%	100%	100%	100%

Rates: Source: Appendix E - 05/01/11 Rate Change Revised, Docket D2010.7.74, page 5 of 10		2011-12 Tracking Period		
DGGS Fixed Rate (after losses)				2012-13
	01/01/11	July-Dec 2011	Jan-June 2012	Tracking Period
Residential	0.004600	0.004018	0.004795	0.004795
GS-1 Sec Non-Demand	0.004600	0.004018	0.004795	0.004795
GS-1 Sec Demand	0.004600	0.004018	0.004795	0.004795
GS-1 Pri Non-Demand	0.004474	0.003908	0.004664	0.004664
GS-1 Pri Demand	0.004474	0.003908	0.004664	0.004664
GS-2 Substation	0.004435	0.003874	0.004624	0.004624
GS-2 Transmission	0.004409	0.003851	0.004596	0.004596

Electric DSM Lost Revenues - Dave Gates Generating Station

(fixed cost portion of DGGS)

January-June 2011

Based on INCREMENTAL DSM Savings Since January 2011

Residential		Gross			Estimated
		Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
Residential	$0.004600	14,694,373	0.87	12,816,024	58,954
				12,816,024	58,954

Commercial & Industrial		Gross			Estimated
		Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
GS-1 Sec Non-Demand	$0.004600	40,579	0.82	33,433	154
GS-1 Sec Demand	$0.004600	3,976,742	0.82	3,276,416	15,072
GS-1 Pri Non-Demand	$0.004474	0	0.82	0	-
GS-1 Pri Demand	$0.004474	40,579	0.82	33,433	150
GS-2 Substation	$0.004435	0	0.00	0	-
GS-2 Transmission	$0.004409	0	0.00	0	-
		Sub Total General Service:		3,343,281	15,375
	Total DGGS-related DSM Lost Revenues				$ 74,329

July 2011-June 2012

Based on INCREMENTAL DSM Savings Since January 2011

Residential		Gross			Estimated
	Average	Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
Residential	$0.004407	51,409,408	0.87	44,837,860	197,578
				44,837,860	197,578

Commercial & Industrial		Gross			Estimated
	Average	Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
GS-1 Sec Non-Demand	$0.004407	197,737	0.82	162,915	718
GS-1 Sec Demand	$0.004407	19,378,253	0.82	15,965,636	70,353
GS-1 Pri Non-Demand	$0.004286	0	0.82	0	-
GS-1 Pri Demand	$0.004286	197,737	0.82	162,915	698
GS-2 Substation	$0.004249	0	0.00	0	-
GS-2 Transmission	$0.004224	0	0.00	0	-
		Sub Total General Service:		16,291,465	71,769
	Total DGGS-related DSM Lost Revenues				$ 269,347

Note 1: Two sets of rates were used, each set was effective for 6 months of the 2011-12 tracker period

Dkt. No. D2012.5.49
EXHIBIT__(WMT-3
PAGE 18 OF 19)

Electric DSM Lost Revenues - Dave Gates Generating Station

(fixed cost portion of DGGS)

Row	Bill Line Item	Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
112	**July 2012-June 2013**					
113	Based on INCREMENTAL DSM Savings Since January 2011					
114						
115	**Residential**		Gross			Estimated
116			Program		Net	Lost
117		Rate[1]	Savings	Adjustment	Savings	Revenue
118	Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
119	Residential	$0.004795	91,136,684	0.87	79,486,888	381,140
120					79,486,888	381,140
121						
122	**Commercial & Industrial**		Gross			Estimated
123			Program		Net	Lost
124		Rate[1]	Savings	Adjustment	Savings	Revenue
125	Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
126	GS-1 Sec Non-Demand	$0.004795	400,050	0.82	329,599	1,580
127	GS-1 Sec Demand	$0.004795	39,204,941	0.82	32,300,736	154,882
128	GS-1 Pri Non-Demand	$0.004664	0	0.82	0	-
129	GS-1 Pri Demand	$0.004664	400,050	0.82	329,599	1,537
130						
131	GS-2 Substation	$0.004624	0	0.00	0	-
132	GS-2 Transmission	$0.004596	0	0.00	0	-
133			Sub Total General Service:		32,959,935	158,000
134						
135			Total DGGS-related DSM Lost Revenues			$ 539,139

Dkt. No. D2012.5.49
EXHIBIT__(WMT-3)
PAGE 19 OF 19

File: Exhibit__(WMT-3) Electric DSM Lost Revenues 2010-13 final.xls
Tab: 9.DGGS Related LRs

NorthWestern Energy

2012 DSM/USB Communications Plan

NorthWestern Energy offers a broad selection of energy efficiency, renewable energy, and low income programs and services funded by customers through electric and natural gas supply rates and the electric and natural gas Universal System Benefits Charges (USBC). The energy savings resulting from these programs are a key piece of NorthWestern Energy's supply portfolio.

The electric and natural gas resource acquisition targets for these programs are set forth in the supply portfolio plans filed with the Montana Public Service Commission (MPSC).

Program offerings have accelerated over the past several years. Findings of the electric DSM assessment and end use survey have been integrated into program offerings and this plan..

Compact Fluorescent Lights (CFLs) continue to contribute a significant portion of the electric savings in recent years. Savings from the commercial and industrial markets have not grown as rapidly.

A comprehensive independent evaluation of all NorthWestern Energy demand side management (DSM) and USB programs was completed in 2007. The evaluation concluded that NorthWestern Energy's programs deliver cost effective natural gas and electric savings, are well-run and follow many best practices. The evaluation provided specific recommendations for program changes, some of which relate to communication, education, and marketing. In 2012, such an independent evaluation will be conducted again. Results will be incorporated into future communication plans.

Nationally and locally, attention to energy efficiency, renewable energy, and "green" or sustainable has continued.

The DSM targets and the heightened awareness of "green" help frame the need and opportunities set forth in this communication plan. The plan is intended to be an active, adaptive product--one that can be filed with the MPSC as part of the implementation strategies to achieve the DSM targets and can be modified to meet current needs and opportunities.

The plan is implemented consistent with NorthWestern Energy E+ graphics and image standards and strategies.

When referring to DSM in this plan, both DSM activities funded with supply rates and Universal System Benefits (USB) activities funded with the USBC are included. Generally, DSM refers to both activities but where appropriate, USB has been specifically broken out.
The plan refines and sustains residential, low income, and renewable generation communications strategies and substantially increases the communication of the commercial/industrial programs. The following table lists the programs by customer sector addressed in the plan.

Table 1: DSM Programs

EFFICIENCY PLUS (E+) PROGRAM		
ELECTRIC PROGRAMS	**NATURAL GAS PROGRAMS**	**CUSTOMER SECTOR**
E+ Audit for the Home	E+ Audit for the Home	Residential
E+ Residential Lighting		Residential
E+ Residential Rebates Program—Existing Homes	E+ Residential Rebates Program—Existing Homes	Residential
E+ Residential New Homes Program	E+ Residential New Homes Program	Residential
E+ Free Weatherization/Fuel Switch	E+ Free Weatherization	Residential
E+ Appraisal for Small Business		Commercial
E+ Commercial Lighting Rebate		Commercial/Industrial

E+ Business Partners Electric	E+ Business Partners Natural Gas	Commercial/Industrial
E+ Business Partners –Irrigation		Agriculture
E+ Commercial Savings-New Construction	E+ Commercial Savings-New Construction	Commercial /Industrial
E+ Commercial Savings-Existing Facilities	E+ Commercial Savings-Existing Facilities	Commercial /Industrial
E+ Green Motor Rewind Instant Rebate		Commercial/Industrial /Agriculture
E+ Renewable Generation		All
E+ Green Power (Communications, not resource)		All
Northwest Energy Efficiency Alliance		All

The DSM programs are not offered to Large USB Electric Choice customers or to Natural Gas Choice customers so these customers are not targeted in the plan.

The DSM Communications Plan is intended as a guide to identify and direct the communications strategies associated with the implementation of NorthWestern Energy's DSM programs. The plan will be modified as needed to suit changing opportunities and conditions.

The 2009 American Recovery and Reinvestment Act (ARRA) has resulted in some new partnership opportunities for qualifying energy efficiency and renewable projects which are included.

GOAL

Effectively and efficiently market DSM programs to achieve defensible natural gas and electric resource acquisition results for the supply portfolios through NorthWestern Energy employees and its program contractors, and by generating increased public awareness of the programs and the opportunity to save energy.

OBJECTIVES

- Engage trade ally community and public entities to incorporate energy efficiency in their messages and marketing
- Engage customers to demand energy efficiency from service providers
- Build participation with emphasis on commercial/industrial DSM sector projects

AUDIENCES

- NorthWestern Energy employees
- NorthWestern Energy program contractors and partner contractors
- Commercial and industrial sector customers (electric and natural gas supply)
- Residential customers (gas and electric supply)
- Trade Allies: electrical vendors—i.e. Crescent Electric, Grainger, WesCo, CED; service providers—electricians, refrigeration, HVAC, motors, architects, engineers, insulation; distributors—lighting, equipment; retailers—of CFLs, building supplies, appliances, air sealing, and water measures; building contractors and general contractors; HVAC and insulation contractors; trade associations—i.e. AIA, ASHRAE, Montana Hospital Association, Innkeepers.
- Public officials and government departments
- Media—mass and trades
- Related organizations—Green Build, community climate change organizations

IMPLEMENTATION STRATEGIES

NorthWestern Energy will engage its employees, program implementation representatives, and program/partner contractors to utilize existing and new methods and tools to cultivate greater customer participation in the DSM programs.

Implementation tactics are targeted by customer sector and directed at defined audiences in most cases. Cross-marketing of programs within the customer sector is incorporated as appropriate. A general calendar of implementation tactics by quarter, sector, program and audience is provided.

TACTICS

Residential Programs

- Update program materials/resources (Web and Brochures)
- Coordinate display materials for Home Shows (Spring Shows run February – May; selected Fall Shows run September-October)
- Update and execute natural gas program campaign
- Develop updated program-at-a-glance summary
- CFL instant coupon offerings to increase installation of CFLs, incorporating the educational messages (4L's) and contest into various residential lighting messages for lighting activities (direct mail, tradeshows, events)
- Target direct mail and limited media for E+ Audits for the Home with cross marketing of Energy Appraisal
- Continue contacts by program contractors/community relations managers (CRMs)
- Update Customer Service Representative (CSR) training for new CSRs
- Messages in Energy Connections and news releases regarding saving energy.
- Participate in local events as appropriate
- Contact various program trade allies with updates and solicitations of new trade allies (Preferred Contractors, lighting retailers, homebuilding associations)
- Complete "Green Blocks" participation in targeted communities
- Target participation in Fall Weatherization events

Commercial/Industrial Programs

- Update existing program materials/resources (web and brochures) to incorporate program additions and changes.

- Develop new materials (brochure copy, case studies, feature articles, etc.) for targeted sectors—healthcare, grocery, and office. Execute new project case studies on commercial/industrial customers
- Integrate commercial program messages into tradeshow displays
- Continue customer and trade ally contacts by program/partner contractors and CRMs
- Participate in local events where appropriate
- Lead organization and coordination of the energy efficiency conference for commercial customers and energy service providers
- Targeted outreach for customer/trade ally training and partnership opportunities
- Review and update trade ally databases
- Update program-at-a-glance summary
- Update web resources with program changes and additions

METHODS/TOOLS

Residential Sector

Residential family of Program Brochures that describe individual program and cross-market same sector programs and highlight resources for more information directing customers to website or program contact phone numbers. GENERAL AUDIENCES

Web/interactive media tools— Efficiency Plus (E+) web section of www.northwesternenergy.com, Facebook, and Search Engine Marketing (SEM), GENERAL AUDIENCES

Internal Communications throughout the year such as FYI, TEAM, iConnect, emails, employee training sessions, etc. to inform all or targeted groups of employees of programs, featured projects/promotions, training, and events. EMPLOYEES

Billing messages in the message box of the NorthWestern Energy billing statement and in Energy Connections to encourage program participation. RESIDENTIAL CUSTOMERS

Direct Mail to Trade Allies and targeted customers of individual program offering and related trainings along with cross-marketing of other programs. TARGETED FOR INDIVIDUAL MAILING

One-on-one by program representatives, program contractors, CRMs, CSRs – communicate residential program offerings based upon opportunity and direct to appropriate resources. May include interactions during: E+ Audit for the Home, tradeshow discussions, customer care calls, or normal company interactions with the customer. OPPORTUNITY DRIVEN

One-to-Many through speakers' bureau, service organization presentations by program contractors and CRMs to increase awareness of programs and opportunities to save energy. COMPANY OR CUSTOMER INITIATED

Home Improvement Shows, Farmers' Markets, Parade of Homes, community events to reach targeted audiences with information about programs and opportunities and, as appropriate, distribute CFLs. COMPANY OR ORGANIZATION INITIATED

Trade association events, publications, and websites to target presentations, displays and messages about opportunities for customers to save energy and the programs that NorthWestern Energy offers. TARGETED TRADE ALLIES OR CUSTOMER GROUP

NorthWestern Energy Fall Home Energy Events to distribute starter weatherization kits, to educate residential customers on low cost ways to save energy, and to inform residential customers of the various programs and services offered by NorthWestern Energy. CFLs are also provided to residential electric customers who have not received free CFLs at a distribution event earlier in the year. TARGETED RESIDENTIAL CUSTOMERS THAT HAVE NOT PARTICIPATED IN THE PAST

Targeted media advertising tied to special campaigns, programs or events. TARGETED TO ELIGIBLE RESIDENTIAL AUDIENCE

Earned media feature stories on projects and opportunities in trade or mass media. GENERAL AUDIENCE WITH EMPHASIS ON ELIGIBLE AUDIENCE.

Customer contests provide customer awards tied to energy efficient products such as most efficient ENERGY STAR televisions for customer care contests.

Other Resources Coordinate activities and messages with remaining American Recovery and Reinvestment Act of 2009 (ARRA) initiatives and Montana Tax Credits where possible—i.e. Missoula Green Blocks, Tri-County Business Program.

Commercial/Industrial Sector

Commercial/Industrial family of Program Brochures that describe individual program and cross-market same sector programs and highlight resources for more information directing customers to website or program contact phone numbers. GENERAL AUDIENCES

Web/interactive media tools— Efficiency Plus (E+) web section of www.northwesternenergy.com, SEM, microsites as appropriate. GENERAL AUDIENCES

Internal Communications throughout the year such as FYI, TEAM, I-Connect, e-mails, CSR trainings, etc. to inform all or targeted groups of employees of programs, featured projects/promotions, training, and events. EMPLOYEES AND PROGRAM PARTNERS AS APPROPRIATE

Case Studies of E+ Business Partners and substantial E+ Commercial Lighting Rebate Program projects to demonstrate various types of customer participation and customer benefits. TARGETED TRADE ALLIES AND KEY CONTACTS AND TARGETED CUSTOMERS

Billing Messages in the message box of the NorthWestern Energy billing statement and in Energy Connections to encourage program participation COMMERCIAL/INDUSTRIAL CUSTOMERS

Direct Mail to trade allies and targeted customers of individual program offering and related trainings along with cross-marketing of other programs. TARGETED FOR INDIVIDUAL MAILING

Customer Care E-Newsletter to key customers will include information about programs, training, and case studies throughout the year

One-on-one by program representatives, program contractors, CRMs, and CSRs – communicate commercial and industrial program offerings based upon opportunity and direct to appropriate resources. May include interactions during: E+ Energy Appraisal, informal facility assessment, project completion review, cold calls, trade ally visits, or normal company interactions with the customer. OPPORTUNITY DRIVEN

One-to-Many through speakers' bureau, service organization presentations by program contractors and CRMs to increase awareness of programs and opportunities to save energy. COMPANY OR CUSTOMER INITIATED

Vendor breakfast/Brown Bags/After Hour events/Community Events to reach targeted audiences with information about programs and opportunities. COMPANY OR ORGANIZATION INITIATED

Commercial Conference on Energy Efficiency partner with others to offer conference to commercial customers, trade allies, and service providers to provide training and education conference in conjunction with the Montana BetterBricks Awards.

Trade Association Events, publications, and websites to target presentations, displays and messages about opportunities for customers to save energy and the programs that NorthWestern Energy offers. Northwestern Energy Lighting Trade Ally Network is an example of an activity that provides technical training and cultivates trade ally participation in programs. TARGETED TRADE ALLY OR CUSTOMER GROUP

Targeted media advertising tied to events, projects, or programs. Continuing E+ Commercial Lighting Rebate program advertising through television and radio to promote lighting as a universal way for businesses to save energy. GENERAL AUDIENCE WITH EMPHASIS ON COMMERCIAL LIGHTING OR OTHER SPECIFIC PROJECT-RELATED AUDIENCES

Earned media feature stories on projects and opportunities in trade or mass media. GENERAL AUDIENCE WITH EMPHASIS ON SPECIFIC PROJECT-RELATED AUDIENCES

Supporting commercial program contractors with consistent marketing materials to describe working relationship with NorthWestern Energy. GENERAL COMMERCIAL CUSTOMERS AND TRADE ALLIES AS IDENTIFIED BY PROGRAM CONTRACTORS.

Other Resources Coordinate activities and messages with the American Recovery and Reinvestment Act of 2009 (ARRA) initiatives and Montana Tax Credits where possible—i.e. Tri-County Small Business Program and International Code Council (ICC) training. .

NorthWestern Energy has defined an overall budget for marketing and communication for the electric and natural gas DSM programs of $1M. This includes mass media development and placement as well as all other marketing expenses.

MEASUREMENT

Measurement of this communications plan will be achieved through program participation in comparison to the resource acquisition goals set forth in the supply plans filed with the MPSC.

The DSM targets are based on a June 1 – May 31 year. USB programs operate on Calendar year.

Other supporting measurement will gathered through existing customer and employee survey tools, tracking of participation in comparison to past performance.

Attached is a calendar for 2012 which will be modified based upon opportunities and needs.

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	C	D	E	F	G	H	I	J	K	L	M
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	**Campaign/initiative**	**MO**	**Implement-ation Dates**	**E**	**G**	**Audience**	**Message**	**Media**	**Internal (includes employees and key contractors)**	**Web**	**Hard Materials**
2	R0x	**Residential**											
3	R0x	**Tips--electric (update)**	Spot media and Campaigns			x		Residential electric customers	Act to save electricity; check out programs	Television; radio		Tips	Brochure
4	R0x	**Tips--Natural Gas (update)**	Spot media and Campaigns				x	Residential natural gas customers	Act to save natural gas; check out programs	Television; radio		Tips	Brochure
5	R1x	***Residential Audits***			On-going	x	x	Residential space or water heating customers whose home has not previously been audit (home 5 yrs old or older), Residential electric baseload customers	Call to Action--Schedule an Audit; follow-up on recommendations	2 Xs /Year Energy Connections--more as needed; news releases as needed; bill statement messages; direct mail to targeted customers	CSR, CRM reminders of qualifications	*On-going description, contact, qualifications*	Tradeshow and event handouts/sign-ups/display/brochures of all residential programs/resources in audit packets
6	R1x	Outreach	Targeted Direct Mail	Jan	Jan,Feb, May more as needed		x	Residential natural gas customers who've not previously had an audit	Call to Action--Schedule an Audit; follow-up on recommendations	Direct Mail/ reinforcing press release	E-mail notice of mailing		Direct Mail
7	R1x	Electric Baseload	Targeted Direct Mail		On-going	x		Residential electric baseload customers	Call to Action--Complete Energy Usage survey; follow-up on recommendations	Direct Mail			Direct Mail Non-NWE production
8	R2x	***E+ Home Lighting -- CFLs***	*Campaign Focus on Education--opportunities to save electricity*		*On-going*	*x*		Residential electric customers	Call to Action--Install CFLs in High Use Locations (Educate--4L's)	Multiple Xs Energy Connections; Direct Mail, Radio, Newspaper, billboard, micro-web site, web advertising, events, Spot TV		*Mail-in offer, education messages, reinforce special offers/events, list participating retailers*	*Tradeshow Display/Retailer support & POP*
9	R2x	Mail-in Rebate Offer	Web, Audits, Distribution Events, Energy Connections		On-going	x		Residential electric customers	Call to Action--Install CFLs in High Use Locations (Educate--4L's) offer up to $2 off for up to 15 CFLs			on-line application	Brochure
10	R2a	Spring Trade Shows a)	CFL distribution (Missoula, Billings, Helena, Great Falls, Butte); Displays; promote all appropriate programs	Feb	Feb - May	x		Residential electric customers	Call to Action--Install CFLs in High Use Locations (Educate--4L's)	Spot Newspaper/TV	local market e-mail	List in events/training/ workshops?	Canvas Bags, Brochures/Signage
11	R2x	E+ Home Lighting -- CFLs Spring Intant Coupon Offer	Direct Mail to residential electric customers for up to $2 off on CFLs from Participating Retailers	Apr	Apr 22-Jun 13	x		Residential electric customers	Call to Action--Buy from participating retailers. Ltd time offer. Install CFLs in High Use Locations (Educate--4L's)	Multiple Xs Energy Connections; Direct Mail, Radio, Newspaper, billboard, micro-web site, web advertising, events, Spot TV, Retailer [illegible]	e-mail of mailing and qualifications	Reference, list of participating retailers	see media

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	C	D	E	F	G	H	I	J	K	L	M
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	**Campaign/initiative**	**MO**	**Implement-ation Dates**	**E**	**G**	**Audience**	**Message**	**Media**	**Internal (includes employees and key contractors)**	**Web**	**Hard Materials**
12	R2x	Farmers' Market	CFL Distribution Events	Jul	Jul- Aug	x		Residential electric customers who've not rec'd Free CFLs at event earlier in year	Call to Action--Install CFLs in High Use Locations (Educate--4L's)	Newspaper, spot Radio	local market e-mail	List in events/training/work shops?	
13	R2a	Fall Trade Shows a)	Displays, all programs, CFL distribution (Missoula, Billings, Bozeman?, Helena?, Great Falls, Butte)	Sep	Sep - Oct	x		Residential electric customers who've not rec'd Free CFLs at event earlier in year	Call to Action--Install CFLs in High Use Locations (Educate--4L's)	Spot Newspaper	local market e-mail	List in events/training/work shops?	Canvas Bags, Brochures/Signage
14	R2x	Regional Buy downs	Review POP/agreements for Regional efforts	Jan	Jan- Dec	x		Residential electric customers	Call to Action for specialty CFLs	POP/Retailer ed		Info on specialty CFLs and retailers	
15	R2x	E+ Home Lighting -- CFLs Fall Instant Coupon Offer	Direct Mail to residential electric customers for up to $2 off on CFLs from Participating Retailers	Oct	Tentative Oct 1 - Nov 15	x		Residential electric customers	Call to Action--Buy from participating retailers. Ltd time offer. Install CFLs in High Use Locations (Educate--4L's)	Multiple Xs Energy Connections; Direct Mail, Radio, Newspaper, billboard, micro-web site, web advertising, events, Spot TV, Retailer [illegible]	e-mail of mailing and qualifications	Reference, list of participating retailers	see media
16	R2b	Weatherization Events b)	CFL Distribution Events in conjunction with Gas/Customer Appreciation	Sep	Sep-Dec 15	x		Residential electric customers who've not rec'd Free CFLs at event earlier in year	Call to Action--Install CFLs in High Use Locations (Educate--4L's)	Direct Mail, Newspaper, Radio, bill insert, participating partners recognition, news release, mass and locals	e-mail of mailing and qualifications, schedule, request for help, I-connect, local e-mails at time of events	Schedule, event descriptions, how-to-info	Canvas Bags, how-to-DVDs, Brochures/Signage
17	R3x	***E+ Gas Savings for the Home***	Promote Rebates for homes with natural gas space or water heat		On-going		x	Residential natural gas space and water heating customers (New or Existing Homes)	Call to Action--Install qualifying measures for rebates (Insulation, Programmable Thermostats, High Efficiency heating or water Equipment replacements, heating system retrofit	2 Xs /Year Energy Connections--more as needed		Description of Rebate offers, forms, preferred contractor lists (Heating Contractors/Insula-tion Contractors)	General Brochure, description, application, preferred installers /Display materials / supporting Preferred Contractor advertising
18	R3x	Gas Savings Mass Media Campaign 1	Mass Media targeted at residential natural gas customers	Jan	Q 1-2		x	Residential natural gas space or water heating customers	Call to Action--Install qualifying measures for rebates	spot TV, Radio,		Call to Action	General description, application, preferred installers, supporting preferred Contractor advertising
19	R3x	Gas Savings Mass Media Campaign 2	Expanded messages?	Sep	Q 3-4		x	Residential natural gas space or water heating customers	Call to Action--Install qualifying measures for rebates	TV, Billboard, Radio, Newspaper; direct mail?	e-mail of campaign to CSRs, CRMs, key contractors	Call to Action	Update General Brochure, description, application, preferred installers / supporting Preferred Contractor advertising

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	C	D	E	F	G	H	I	J	K	L	M
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	**Campaign/initiative**	**MO**	**Implement-ation Dates**	**E**	**G**	**Audience**	**Message**	**Media**	**Internal (includes employees and key contractors)**	**Web**	**Hard Materials**
20	R3b	Weatherization Events b)	Distribute Air Sealing Measures to qualifying natural gas residential customers, educate on programs	Sep	Sep-Oct		x	Residential natural gas space or water heating customers--qualifications around past participation	Call to Action--Receive and Install air-sealing measures; learn about programs and saving energy	Direct Mail, bill insert, news release, wrap truck(s)	e-mail of mailing and qualifications, schedule, request for help, I-connect, local e-mails at time of events;	Schedule, event descriptions, how-to-info	Canvas Bags, how-to-DVDs, Brochures/Signage
21	R3a	Spring Tradeshows a)	Program Education in Natural Gas markets	Feb	Feb- May		x	Residential natural gas space or water heating customers	Call to Action--Install qualifying measures for rebates		local market e-mail	Call to Action	Displays/brochures program materials
22	R3a	Fall Tradeshows a)	Program Education in Natural Gas markets	Sep	Sep- Oct		x	Residential natural gas space or water heating customers	Call to Action--Install qualifying measures for rebates		local market e-mail	Call to Action	Displays/brochures program materials
23	R0x	Special Events--CSR Training, Game Days	Promote natural gas energy efficiency programs in existing homes, partners with local allies,		As needed	x	x	Residential natural gas space or water heating customers in existing homes; targeted Events	Call to Action--Participate in programs; priotitize measures; Install qualifying measures for rebates;	Spot newspaper; news releases as appropriate	CSR and local e-mails as appropriate	Schedule on site	Educational brochures; signage; displays; presentations
24	R4x	***E+ New Homes***	Promote energy efficiency in new homes, rebates for qualifying measures, rebates for Energy Star manufactured homes; Training/promote Northwest Energy Star Homes/builders; new MT Code			x	x	Residential customers building new homes		Energy Connections	E-mail of program qualifications and links; Training	Rebate forms, link to all Energy Star builders, Energy Star support; training events	Brochure
25	R4x	E+ New Homes Natural Gas	Promote natural gas energy efficiency in new homes, rebates for qualifying measures, training/promote Northwest Energy Star Homes; new MT Code	Sep	Sep		x	Residential natural gas customers building new homes	Call to Action--install high efficiency heating or water heating measures; Northwest Energy Star manufactured homes	Special Publication, Newspaper at Parade of Homes		Schedule/homes, Rebate forms, link to all Energy Star builders, Energy Star support	Brochures/Signage as needed
26	R4x	E+ New Homes Electric	Rebates for CFLs and Fixtures or Northwest Energy Star electrically heated manufactured homes, and information about Northwest Energy Star Homes; Train/promote NW Energy Star Homes/Builders; new	Sep	Sep and as approp.	x		Residential Electric Customers building new homes	Call to Action--Include ENERGY STAR lighting in new homes; Northwest Energy Star homes/builders	Special Publication, Newspaper at Parade of Homes		Schedule/homes, Rebate forms, link to all Energy Star builders, Energy Star support	Brochures/Signage as needed

DSM Program Communications Calendar

	A	B	C	D	E	F	G	H	I	J	K	L	M
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Campaign/initiative	MO	Implement-ation Dates	E	G	Audience	Message	Media	Internal (includes employees and key contractors)	Web	Hard Materials
27	R4x	***E+ Residential Electric Savings***	Promote energy efficiency in homes with electric space or water heat; efficient appliances; electronics		as needed	x		Residential Electric customers in existing homes	Call to Action--Install qualifying efficiency measures	trade ally		Description of Rebate offers, forms, preferred contractor lists (Heating Contractors/Insulation Contractors)	Brochure/forms/application as needed
28	R6x	**E+ Free Weatherization**	Supportive advertising for low income energy assistance--	Sep	Sep - Apr as needed	x	x	Income Qualified space or water heating customers for free Audit and installation of qualifying measures (LIEAP qualified) also receive NWE low income discount; may qualify for Energy Share	Call to Action--Apply for LIEAP as soon as possible to receive LIEAP and heating season discounts; and potentially qualify for free weatherization. Income Guidelines have been relaxed.	Energy Connections; Newspaper; radio , September? news release on NWE programs & funding		Description of program/discount and refer customers to Human Resource Councils to apply.	energy efficiency education materials

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	C	D	E	F	G	H	I	J	K	L	M
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	**Campaign/initiative**	**MO**	**Implement-ation Dates**	**E**	**G**	**Audience**	**Message**	**Media**	**Internal (includes employees and key contractors)**	**Web**	**Hard Materials**
29													
30	C0	**Commercial ***											PowerPoint presentation for internal and key contractor use: Messages for Commercial
31	C1	***E+ Commercial Lighting Rebates***	Promote rebates energy efficient lighting in commercial facilities		on-going	x		Commercial and industrial electric customers and the trade allies who serve them	Call to Action--Install high efficiency lighting products	Special Publications (display ads or articles); Case Studies; Lighting trade ally network; Association/Vendor Events; targeted direct mail; business Solutions E-newsletter; solicit features	e-mail to CRMs and key staff	Description of Rebate offers, forms, Lighting Trade Ally lists, case studies; schedule of training events; links to other resources as appropriate	Brochure/Case Studies/Display Signage
32	C1	***NWE Lighting Trade Ally Network***	Engage Lighting Trade Allies as Partners for program success		on-going	x		Lighting Trade Allies and key facility operators	Call to Action--technical training to improve ability to design, sell, install commercial/industrial energy efficient lighting equipment and to promote NWE Lighting Rebate Program	Qtrly Newsletters, e-mail Direct Mail, web	e-mail to CRMs and key staff	Schedule of training; Registration information; session description; "Qualified" List of Trade Ally Network Members for customers	Training invitation, Program brochure, Newsletter
33	C2	***E+ Energy Appraisal for Business***	Energy audits for commercial facilities under 300kW with emphasis on electric savings		on-going	x		Electric Commercial facilities under 300 kW	Call to Action--Schedule Appraisal and follow-up on recommendations	Targeted Direct Mail; Energy Connections; Business Solutions E-newsletter; Event Displays;		**Description of offer and contact information**	**Brochure**
34	C3	***E+ Business Partners***	Promote custom incentives for electric or natural gas cost effective energy efficiency measures in new or existing commercial/industrial facilities		on-going May- Jun & Fall emphasis	x	x	Commercial and industrial electric or natural gas customers and the trade allies who serve them	Call to Action--Install energy saving measures	Special Publications (display ads or articles); Case Studies; trade ally events; Association/Vendor Events; targeted direct mail; Business Solutions E-Newsletter, solicit feature articles		Description of program, application, case studies; Schedule of training events; links to other resources as appropriate	Brochure/Case Studies/Display Signage

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	C	D	E	F	G	H	I	J	K	L	M
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Campaign/initiative	MO	Implement-ation Dates	E	G	Audience	Message	Media	Internal (includes employees and key contractors)	Web	Hard Materials
35	C3a	***E+ Business Partners Natural Gas Measures***	Promote commercial natural gas offering custom incentives for new or existing facilities		May- Jun & Fall emphasis		x	Commercial and industrial natural gas customers and the trade allies who serve them	Call to Action--Install energy saving measures; explore offer	Special Publications (display ads or articles); Case Studies as they become available; trade ally events; Association/Vendor Events; targeted direct mail; Business Solutions E-Newsletter		Description of program, application, case studies as become available; Schedule of training events; links to other resources as appropriate	Brochure/Case Studies/Display Signage; presentations
36	C3b	***E+ Natural Gas Savings Rebates for Commercial Customers -- Existing Buildings***	Promote rebates for qualifying energy efficient equipment and improvements in existing commercial facilities		May-June & Fall emphasis		x	Commercial and industrial natural gas customers and the trade allies who serve them	Call to Action--Install energy saving measures for rebates	Special Publications (display ads or articles); Case Studies as they become available; trade ally events; Association/Vendor Events; targeted direct mail; Business Solutions E-Newsletter, solicit feature articles		Description of program, application, case studies as become available; Schedule of training events; links to other resources as appropriate	Brochure/Case Studies/Display Signage; presentations
37	C4a	***E+ Natural Gas Savings Rebates for Commercial Customers--New Construction***	Promote rebates for qualifying energy efficient equipment and improvements in new construction commercial facilities		May-June & (Fall?)		x	Commercial and industrial natural gas customers and the trade allies who serve them	Call to Action--Install energy saving measures for rebates	Special Publications (display ads or articles); Case Studies as they become available; trade ally events; Association/Vendor Events; targeted direct mail; Business Solutions E-Newsletter		Description of program, application, case studies as become available; Schedule of training events; links to other resources as appropriate	Brochure/Case Studies/Display Signage presentations
38	C4b	***E+ Commercial Gas Program***	Engage natural gas Trade Allies as Partners for program success		On-going		x	Commercial and industrial natural gas trade allies and key facility operators	Call to Action--Promote NWE natural gas commercial rebate programs to improve trade allies ability to design, sell, install commercial/industrial qualifying energy efficient natural gas	Multiple site Breakfast/Brown Bag. Direct Mail; e-mail; trade ally newsletters		Schedule of sessions; registration information; preferred contractors as available	Invitation to session; presentation; forms/ applications

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	C	D	E	F	G	H	I	J	K	L	M
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Campaign/initiative	MO	Implement-ation Dates	E	G	Audience	Message	Media	Internal (includes employees and key contractors)	Web	Hard Materials
39	C5b	***E+ Green Motor Rewind Rebates***	Promote instant rebates for motors rewond to Green Motors Standards in commercial/industrial facilities		as needed	x		Commercial and industrial electric customers with motors and the trade allies who serve them	Call to Action-- Demand GREEN motor standards when having motors rewond	Special Publications (display ads or articles); Case Studies as they become available; trade ally events; Association/Vendor Events; targeted direct mail; Business Solutions E-Newsletter		Description of program, application, case studies as become available; Schedule of training events; links to other resources as appropriate	Brochure/Case Studies/Display Signage; presentations
40	C5	***Motor Training***	Training/education/ CEU		May (Fall?)	x		Commercial and industrial electric customers with motors and the trade allies who serve them	Education on value of effective motor management techniques; information on NWE programs	Direct Mail; e-mail; trade ally newsletters	e-mail to CSRs, CRMs and key staff	Schedule of training events; course description; registration information	Direct Mail flyer and PDF of same; training manuals
41	C6	***E+ Irrigation***	Promote custom incentives for cost effective electric irrigation measures		Apr Sept	x		Irrigation customers	Call to Action--submit proposal for custom incentives for cost effective electric irrigation system improvements	Bi-annual mailing to irrigation customers through customer care	e-mail to CSRs, CRMs and key staff	Description of program, application,	Direct mail and Include in Business Partner brochure
42	C7	***Lighting Design Lab***	Promote energy efficient lighting design through training/education (CEUs)		Mar(Conference) Sep	x		Architects, Engineers, interested customers with lighting design and installation responsibilities	Improve energy efficiency of lighting with better knowledge; use NWE Rebates	Direct Mail; e-mail; trade ally newsletters;	e-mail to CSRs, CRMs and key staff	Schedule of training events; course description; registration information	
43	C8	***Commercial Conference on Energy/BetterBricks Awards***	Promote energy efficiency through conference and BetterBricks Awards by recognizing individuals who are energy efficiency champions for commercial facilities nominations/winners		Q-1	x	x	Architects, Engineers, facility managers, Public Buildings, others with commitment in developing/operating high performance commercial facilities	Encourage energy effciency and how it can improve bottom line to businesses	Direct Mail, newspaper, on-line, trade ally newsletters, e-mail, event booths	e-mail to CRMs and key staff	Schedule/Registration,Nomination process; BetterBricks Winners winners	
44	C9	***Building Operator Certification Training***	Training/education/ certification for facility managers; emphasis on schools, public buildings, non-profit hospitals		Apr maybe Fall as well	x	x	Facility managers with interest in reducing energy costs through operations and maintenance and incorporating energy efficiency in purchases and practices	Call to Action--enroll; scholarships for tuition and travel for public schools, public buildings, and non-profit hospitals	Direct Mail, trade ally newsletters, e-mail, event booths	e-mail to CSRs, CRMs and key staff	Schedule of training events; course description; registration information	Direct Mail flyer and PDF of same; training manuals
45	C10	***Tri--county Commercial Project***	Promote energy efficiency in existing buildings in partnership with L &C, Broadwater, Jefferson Counties	Mar	3 yr project	x	x	Target small businesses to increase adoption of energy efficiency improvements	Call to Action--Appraisal, recommendations, standard rebates (Fed. Grants)	Direct contact with targeted businesses			Description for targeted businesses

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	C	D	E	F	G	H	I	J	K	L	M
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	**Campaign/initiative**	**MO**	**Implement-ation Dates**	**E**	**G**	**Audience**	**Message**	**Media**	**Internal (includes employees and key contractors)**	**Web**	**Hard Materials**
46	C11	***New E+ Commercial Electric Rebates***	Promote prescriptive rebates for expanded commercial /industrial/irrigation energy efficiency opportunities in existing facilities and new construction			x		Promote opportunities to commercial/industrial/irrigation customers -- Target audiences as appropriate	Call to Action-- install qualifying measures, add to bottom line	Mix	e-mail to CSRs, CRMs and key staff;	Description of program; Add Program contractors; on-line forms; list of events/training;resources	Mix
47		**Renewables**											
48	G1	***E+ Renewable Energy***	Support education and development of small scale renewable generation			x		Residential and commercial electric customers and the renewable trade allies who support renewable generation	Educate electric customers on small scale renewables and direct them to resources to develop	Special NWE publications; ltd print ads; energy connections; montanagreenpower.com; trade allies & Associations		Description of program; NWE publications; Schedule of training events; List of events where NWE is present with display or speakers; links to other resources as	NWE publications and Brochures; Signage & presentations
49	G2	***E+ Green Power *****	Offer premium service option of green power product to electric customers		on-going	x		Residential and commercial electric customers who support renewable generation	Call to Action-- Opportunity to support renewable generation through premium on electric bill	Energy Connections; Public Radio Sponsorships; other events or sites as appropriate and available		Description of program; on-line enrollment	Brochure; signage
50													
51	O	***Northwest Energy Efficiency Alliance***	Promote		on-going	x		Residential, Commercial, Industrial, and agriculture customers and the trade allies and infrastructure that serve them	Varies with initiative	NWE supporting materials to NEEA messages	AS APPROPRIATE	Training Information; links to other resources	Varies with initiative
52													
53		*Large Universal System Benefits Choice (USBC) Customers are not eligible for electric programs. Natural gas commercial programs are not offered to natural gas Choice customers.											
54													
55		**E+ Green Power is not a DSM program but is part of NWE's renewable offerings.											
56													

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	P	Q	R	S	T	U	V	W	X	Y	Z	AA
1		DSM Communications Calendar subject to change based upon Need or Opportunity	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2	R0x	**Residential**												
3	R0x	**Tips--electric (update)**												
4	R0x	**Tips--Natural Gas (update)**												
5	R1x	***Residential Audits***												
6	R1x	Outreach												
7	R1x	Electric Baseload												
8	R2x	***E+ Home Lighting -- CFLs***												
9	R2x	Mail-in Rebate Offer												
10	R2a	Spring Trade Shows a)												
11	R2x	E+ Home Lighting -- CFLs Spring Intant Coupon Offer												

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	P	Q	R	S	T	U	V	W	X	Y	Z	AA
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12	R2x	Farmers' Market												
13	R2a	Fall Trade Shows a)												
14	R2x	Regional Buy downs												
15	R2x	E+ Home Lighting -- CFLs Fall Instant Coupon Offer												
16	R2b	Weatherization Events b)												
17	R3x	***E+ Gas Savings for the Home***												
18	R3x	Gas Savings Mass Media Campaign 1												
19	R3x	Gas Savings Mass Media Campaign 2												

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	P	Q	R	S	T	U	V	W	X	Y	Z	AA
1		**DSM Communications Calendar** **subject to change based upon Need or Opportunity**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
20	R3b	Weatherization Events b)												
21	R3a	Spring Tradeshows a)												
22	R3a	Fall Tradeshows a)												
23	R0x	Special Events--CSR Training, Game Days												
24	R4x	***E+ New Homes***												
25	R4x	E+ New Homes Natural Gas												
26	R4x	E+ New Homes Electric												

DSM Program Communications Calendar

	A	B	P	Q	R	S	T	U	V	W	X	Y	Z	AA
1		<u>DSM Communications Calendar</u> subject to change based upon Need or Opportunity	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
27	R4x	***E+ Residential Electric Savings***												
28	R6x	**E+ Free Weatherization**												

DSM Program Communications Calendar

	A	B	P	Q	R	S	T	U	V	W	X	Y	Z	AA
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
29														
30	C0	Commercial *												
31	C1	*E+ Commercial Lighting Rebates*												
32	C1	*NWE Lighting Trade Ally Network*												
33	C2	*E+ Energy Appraisal for Business*												
34	C3	*E+ Business Partners*												

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	P	Q	R	S	T	U	V	W	X	Y	Z	AA
1		DSM Communications Calendar subject to change based upon Need or Opportunity	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
35	C3a	*E+ Business Partners Natural Gas Measures*												
36	C3b	*E+ Natural Gas Savings Rebates for Commercial Customers -- Existing Buildings*												
37	C4a	*E+ Natural Gas Savings Rebates for Commercial Customers--New Construction*												
38	C4b	*E+ Commercial Gas Program*												

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	P	Q	R	S	T	U	V	W	X	Y	Z	AA
1		DSM Communications Calendar subject to change based upon Need or Opportunity	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
39	C5b	*E+ Green Motor Rewind Rebates*												
40	C5	*Motor Training*												
41	C6	*E+ Irrigation*												
42	C7	*Lighting Design Lab*												
43	C8	*Commercial Conference on Energy/BetterBricks Awards*												
44	C9	*Building Operator Certification Training*												
45	C10	*Tri--county Commercial Project*												

DSM Program Communications Calendar

Docket D2012.5.49
Exhibit__(WMT-4b)

	A	B	P	Q	R	S	T	U	V	W	X	Y	Z	AA
1		DSM Communications Calendar subject to change based upon Need or Opportunity	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
46	C11	*New E+ Commercial Electric Rebates*												
47		Renewables												
48	G1	*E+ Renewable Energy*												
49	G2	*E+ Green Power ***												
50														
51	O	*Northwest Energy Efficiency Alliance*												
52														
53														
54		*Large Universal System Benefits Choice (USE gas commercial programs are not offered to na												
55														
56		**E+ Green Power is not a DSM program but is												

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2012.5.49
Annual Electricity Supply Tracker
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF FRANK V. BENNETT

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL ELECTRICITY SUPPLY TRACKER

TABLE OF CONTENTS

Witness Information

Q. Please state your name and business address.

A. My name is Frank V. Bennett and my business address is 40 East Broadway, Butte, MT 59701.

Q. By whom and in what capacity are you employed?

A. I am employed by NorthWestern Energy ("NorthWestern") as a Contract and Regulatory Specialist.

Q. Please describe your employment history.

A. I have been working with NorthWestern's Energy Supply group since 1996. In this capacity, I administer energy supply contracts of NorthWestern's Montana utility and assist with various other supply matters. I am a regular participant in the preparation of testimony, exhibits, and work papers in supply-related proceedings before the Montana Public Service Commission ("MPSC" or "Commission"). From 1991 through 1996, I worked as a Landman for The Montana Power Company and North American Resources Company. During this time, I worked on Joint Operation contracts with other corporations and with land and mineral owners in an effort to explore and develop natural resources primarily in Montana, Wyoming, and Colorado. From 1984 through 1991, I worked in various capacities within the mineral industry, mainly for Altana Exploration Company and Roan Resources Ltd., in the Canadian provinces of Alberta and Saskatchewan with additional work in Montana and Colorado.

Q. Please describe your educational background.

A. I attended Montana Tech of the University of Montana where I received my Bachelor of Science degree in Business and Information Technology.

Purpose of Testimony

Q. Please describe your Annual Electricity Supply Tracker testimony.

A. In my testimony I present the following information:

- The tracker exhibits filed in this docket;
- Updates to the costs included in the 12-month ended June 2012 tracker period with 10 months of actual numbers and 2 months of estimated numbers;
- Components included within the 12-month electricity supply cost tracker for the period ended June 2012; and
- The forecast costs of the 12-month ended June 2013 tracker period.

Tracker Presentation in This Docket

Q. Please summarize the tracker presentation filed in this docket.

A. By statutory definition, “Electricity supply costs” means the actual costs incurred in providing electricity supply service through power purchase agreements, demand side management, and energy efficiency programs including…" § 69-8-103(8), MCA (2011). The electric tracker deals only with electricity supply costs. I will provide testimony and exhibits in this docket in three components: (1) Electricity Supply Tracker, (2) Colstrip Unit 4 ("CU4") True-up, and (3) Dave Gates Generating Station ("DGGS") True-up. All testimony is filed jointly to facilitate a retail customer total supply rate calculation.

Update to the 2011/2012 Electricity Supply Tracker Period

Q. Please summarize the estimated 12-month electricity supply tracker period ending June 2012, as it was filed in Docket D2011.5.38.

A. The tracker period ending June 2012 in Docket No. D2011.5.38 included 12 estimated months, July 2011 through June 2012. Interim Order No. 7154 in Docket No. D2011.5.38 authorized rates reflecting the 2011/2012 tracker period estimates effective on July 1, 2011. NorthWestern filed monthly rate adjustments for each month, from August 2011 through June 2012.

Q. How has NorthWestern incorporated the CU4 generation that is reflected in the 2011/2012 tracker?

A. NorthWestern has included the full rate-based volume of unit contingent energy associated with 222 megawatts ("MW") of capacity in the tracker.

Q. How has NorthWestern incorporated the DGGS regulation service in the 2011/2012 tracker?

A. NorthWestern replaced the historical third-party contracts for regulating service that are reflected in prior tracker periods with regulation service from DGGS, which began supplying this service on January 1, 2011. However, in early 2012, as noted below, there are costs for third-party-provided regulation service included in the 2011/2012 DGGS True-up. These costs, as well as other variable costs associated with the provision of regulation service by DGGS, are included in the DGGS True-up. NorthWestern has included 7 MW of energy output in the tracker from DGGS that is used to serve retail load. During early 2012 DGGS experienced an outage that required short-term replacement regulation service contracts that are discussed in the Prefiled Direct Testimony of Michael Cashell.

Q. How has the regulation cost associated with United Materials of Great Falls ("UMGF") been adjusted in this filing?

A. Consolidated Docket Nos. D2006.5.66 and D2007.5.46, Final Order No. 6836c, ¶160, directed NorthWestern to reduce regulation costs associated with UMGF from the 2005/2006 tracker period forward. Accordingly, NorthWestern has removed all associated wind regulation charges for the UMGF project from the 2005/2006 tracker period forward for the periods of time that NorthWestern Energy Supply was not purchasing the output from this facility. These removed regulation charges are not part of the Transmission Business Unit rate NorthWestern charges to its retail customers, but are absorbed by NorthWestern's equity holders.

Q. In addition to adjustments made for CU4 and DGGS as described above, how has the 12-month ended June 2012 electricity supply tracker period been updated from the forecasts originally filed in Docket No. D2011.5.38?

A. The 2011 electricity supply tracker filing, Docket No. D2011.5.38, was submitted under cover letter dated June 2, 2011. My Prefiled Direct Testimony in the 2011 filing included information for two tracker periods. Actual and estimated information was submitted for the first tracker period, July 2010 through June 2011. Forecast information was submitted for the second tracker period, July 2011 through June 2012. The first tracker period was updated for 12 months of actual information in response to Data Request PSC-001a in Docket No. D2011.5.38.

The forecast information for the July 2011 through June 2012 period has been updated in this filing with actual information[1] for July 2011 through April 2012 and estimates for May and June of 2012 and is included as Exhibit__(FVB-1)11_12. The actual numbers identify the realized load, specific monthly resource quantities bought and sold, and related costs for

[1] With the exception of transmission (e.g.: load following and imbalance costs) in which there is a lag of actual costs by a number of months.

each month in NorthWestern's electricity supply portfolio. Pages 3 and 4 show that during the 12-month tracker period ending June 2012, NorthWestern expects to purchase 6,469,325 megawatt hours ("MWh") of electricity at a cost of $222,495,986 for its electricity supply customers. The July 2011 beginning Deferred Account balance was a $24,426,468 under-collection for the market-based supply portion of this exhibit. Incorporating this under-collection with 10 months of actual and 2 months of estimated information, the 12 months ended June 2012 Deferred Account balance is forecasted to be an $11,496,428 under-collection (refer to Exhibit__(FVB-1)11_12, page 2). For further discussion of the Deferred Account, please refer to the Prefiled Direct Testimony of Cheryl Hansen – Electricity Supply Tracker.

<u>Components of 2011/2012 Electricity Supply Tracker Period</u>

Q. Has NorthWestern made changes to the exhibit for the 2011/2012 tracker period?

A. Yes. Based on requests from MPSC staff, NorthWestern has provided increased levels of detail to supplement the imbalance section of the tracker model that begins in this tracker period and will be carried forward for future tracker filings.

Q. What changes have been made to the imbalance information found in the tracker?

A. The imbalance was reported as a net expense on page 4 of the tracker in prior exhibits. NorthWestern, beginning with this tracker period, has separated the net value into the current month estimated imbalance, prior months supply true-up, and prior period accounting and Balancing Authority expenses on lines 98, 99, and 100, respectively. The volumes associated with the current month estimate and prior months supply true-up are shown on page 3, lines 48 and 49 of the tracker exhibit.

Q. Are any other changes reflected in the 2011/2012 tracker period?

A. Yes. In Docket No. D2011.5.38, Final Order No. 7154b, the MPSC authorized NorthWestern to include forecast lost revenues related to Demand-Side Management ("DSM") in future filings. Forecast lost transmission and distribution ("T&D") revenues resulting from DSM and Universal System Benefits ("USB") activities are included in both the 2011/2012 and 2012/2013 tracker period. Refer to the Prefiled Direct Testimony of William Thomas ("Thomas Direct Testimony") for support for the T&D lost revenues.

Q. Please explain the lost revenue changes reflected in the 2011/2012 tracker period.

A. The forecast and true-up lost revenues reflected in this tracker period have been shown on page 4 of Exhibit__(FVB-1)11_12 as adjustments in the months of April, May, and June to reflect the lost revenue calculation as discussed in the Thomas Direct Testimony.

Q. Describe the Electricity Supply cost components of the 12-month ended June 2012 tracker period as shown in Exhibit__(FVB-1)11-12.

A. There are four basic cost components that make up the Electric Supply portfolio for the 12-month tracker period July 2011 through June 2012:

1) <u>Electric Supply Expenses</u> – These expenses include the following:

a) A 275 MW peak and 150 MW off-peak contract with PPL Montana, LLC ("PPL") that is supplied seven days per week, 24 hours per day, on a firm basis. This is a declining volume contract that expires June 30, 2014.

b) A 25 MW peak firm energy contract with PPL secured through a May 2009 Request for Proposals ("RFP"). This contract expires June 30, 2017.

c) Approximately 100 MW of unit contingent Qualifying Facility ("QF") energy that comes from contracts entered into prior to 1999. Under Tier II settlements, only a portion of the costs of these contracts is recovered from retail customers through the tracker. The 10-months actual and 2-months estimate shows that the Tier II QFs under Stipulation will meet the 807,609 MWh per year target.

d) Approximately 14 MW of unit contingent QF-1 Tariff generation without renewable energy credits (“RECs”) (United Materials plus other small QFs) at Commission-determined rates. A recently signed QF-1 contract at 9.6 MW that conveys RECs to NorthWestern declared commercial operation on January 4, 2012. This contract expires on January 4, 2037.

e) Approximately 135 MW of unit contingent energy from the Judith Gap Energy, LLC wind turbine facility. Judith Gap Energy, LLC achieved commercial operation on February 16, 2006. This contract expires on December 31, 2026.

f) Approximately 50 MW of dispatchable capacity from Basin Creek Equity Partners, LLC. The Basin Creek plant achieved commercial operation on July 1, 2006. This contract will expire on July 1, 2026, unless extended for a five-year term in accordance with the contract.

g) Approximately 6 MW of unit contingent energy from Tiber Montana, LLC. Tiber Montana achieved commercial operation on June 1, 2004. This contract expires on June 1, 2024.

h) Approximately 13 MW of unit contingent energy from Turnbull Hydro, LLC for the Upper and Lower Turnbull facilities. Lower Turnbull achieved commercial operation on June 22, 2011 and Upper Turnbull achieved commercial operation on July 24, 2011. This contract expires December 31, 2031.

i) Approximately 25 MW of base load firm energy from Citigroup Energy Inc., secured through an October 2008 RFP. This contract expires June 30, 2020.

j) Short- and medium-term market power purchases and sales transacted with various suppliers to balance variable customer demand with electricity supply. The energy requirements vary in part due to customer use and seasonal weather impacts that affect demand. During the 2011/2012 electricity supply tracker period, the net non-base transaction purchase requirement, as shown on page 3 of Exhibit__(FVB-1)11_12, was 890,369 MWh or 13.8% of the annual supply requirements.

k) Expenses related to "wind other costs" incurred to fully incorporate wind supply contracts into NorthWestern's energy supply portfolio. These other wind costs include Judith Gap costs, wind modeling, 3TIER services, Fergus Electric service at the met tower site leases, WREGIS fees, and other direct wind costs.

l) Expenses related to system imbalance adjustments and operating reserves.

m) DSM program implementation costs directly involved with DSM programs and projects and T&D Lost Revenues related to DSM and USB programs, which are all included as expenses.

2) Generation Assets – This includes any energy contributed to the Supply Portfolio by NorthWestern's owned Generation Assets, described below. This energy reduces market purchases that would otherwise be made to balance loads with resources.

a) CU4 is a Generation Asset approved for inclusion in Docket No. D2008.6.69, Order No. 6925f at the volume of unit contingent energy associated with 222 MW of capacity. This asset was originally included as a rate-based facility in January 2009.

b) DGGS at Mill Creek is a Generation Asset approved for inclusion under Order No. 6943e in Docket No. D2008.8.95. NorthWestern includes 7 MW of base load energy as a result of minimum turndown from generating unit operations. This asset was included as a rate-based facility starting January 1, 2011.

3) Transmission Costs – These are costs associated with moving electricity off-system via point-to-point transmission service for resource balancing as well as other “ancillary services” required for system integrity and reliability.

Regulation and Frequency Response Service is an ancillary service which provides instantaneous voltage and energy regulation to balance load and resources. Because this service has been provided by the DGGS Generation Asset since January 1, 2011, these costs are now included in the DGGS portion of this filing.

Costs of the transmission facilities utilized to transmit and distribute energy to electric supply customers are included in delivery rates and, as such, no additional revenue is collected for these costs in the tracker.

As explained previously, Final Order No. 6836c provided direction for the removal of UMGF regulation costs from the electric tracker for periods when the power generation is not being purchased by NorthWestern for its retail customers.

4) Administrative Expenses – Incremental administrative and general costs above those recovered in the last general rate case filing of $1,649,719, or 0.73% of total electric supply expenses are also included in electricity supply costs. These costs include outside legal services, scheduling, software, broker costs, and other incremental expenses directly related to the electricity supply function (such as outside consultants used in conjunction with procurement activities).

Q. Please summarize the results of the 12-month ended June 2012 tracker period.

A. The results of the 2011/2012 tracker period are summarized in the following table:

Beginning Deferred Account		Balance ($)
Under-Collection		$ 24,426,468

Energy Supply/Service	MWh	Cost ($)	$ / MWh
Net Fixed Price Transactions	390,912	13,521,200	34.59
Net Market Transactions	499,457	8,592,315	17.20
PPL 7 Year Contract	1,933,600	100,447,640	51.95
PPL 2009 RFP	123,200	7,428,960	60.30
QF Tier II Contracts	818,890	29,463,662	35.98
QF Tier II Adjustments		108,087	
QF-1 Tariff Contracts	12,488	302,874	24.25

Energy Supply/Service	MWh	Cost ($)	$ / MWh
Gordon Butte Wind QF	21,400	1,438,160	67.20
Tiber	47,508	1,850,124	38.94
Turnbull	31,650	2,065,958	65.28
Judith Gap Energy (contract price only)	482,431	14,442,354	29.94
Wind Ancillary	NA	0	
Wind Other	NA	1,523,356	
Citigroup 2008 RFP	219,600	13,703,040	62.40
Basin Creek Fixed Capacity	12,587	5,865,982	
Basin Creek Operating Reserves	NA	(1,562,746)	
Basin Creek Wind Firming	0	0	
Basin Creek Fuel	NA	771,764	
Basin Creek Variable O&M	NA	55,455	
Basin Creek Gas Storage Capacity	NA	36,000	
Operating Reserves	NA	2,634,883	
DSM Program & Labor Costs	NA	8,771,493	
DSM Lost T & D Revenue	NA	521,183	
DSM Lost T & D Revenue Adjustment	NA	4,262,005	
Imbalance, Current Month	184,499	3,147,796	
Imbalance, Prior Months True-up	3,676	1,056,556	
Imbalance, Acct & BA Expense		2,047,885	
Transmission Costs	NA	682,976	
Administrative Expenses	NA	1,649,719	
Carrying Cost	NA	1,505,682	
Colstrip Unit 4 Generation Asset	1,630,824		
DGGS at Mill Creek Generation Asset	56,602		
Total Expenses:		$ 226,334,363	

Electricity Sales	MWh	Revenue ($)
Electric Cost Revenue		$ 219,443,106
Prior Deferred Expense		19,821,296
Total Revenue:		$ 239,264,403

Ending Deferred Account		Balance ($)
Under-Collection		$ 11,496,428

<u>2012/2013 Forecast Electricity Supply Tracker Period</u>

Q. Has NorthWestern made changes to the exhibit for the 2012/2013 tracker period?

A. Yes. Based on requests from MPSC staff, NorthWestern has provided increased levels of detail to support the supply sections of the tracker model that will begin in this forecast period and will be carried forward for future tracker filings.

Q. What changes have been made to the supply detail information found in the tracker?

A. The information supplied has been expanded to include detail regarding purchases and sales for both on-system and off-system transactions as explained in the Prefiled Direct Testimony of Kevin Markovich ("Markovich Direct Testimony").

Q. Are any other changes reflected in the 2012/2013 tracking period?

A. Yes. Under Final Order No. 7154b in Docket No. D2011.5.38, the MPSC authorized NorthWestern to include forecast lost T&D revenues in future filings. These forecast lost revenues are reflected in this forecast tracker period and are addressed in the Thomas Direct Testimony.

Q. Please summarize the 12-month electricity supply tracker period ending June 2013 as filed in this docket.

A. The June 2012 Deferred Account market-based supply under-collection ending balance of $11,496,428 as described above is the July 2012 beginning balance. July 2012 through June 2013 information is based on forecast numbers and includes the following existing electric supply base contracts: various QFs; Tiber Montana; Basin Creek Equity Partners, LLC; Judith Gap Energy, LLC; PPL EnergyPlus, LLC; Turnbull Hydro, LLC; and various Competitive Solicitation contracts. Please see Exhibit__(FVB-2)12_13 pages 3 and 4 for supply volume and cost details of the 12-month forecast tracker period.

Basin Creek plant output in this forecast has been modeled using recent operational experience and expectations of future dispatch based on forward market prices. The actual daily operation of the plant will take into consideration market conditions and the total Electric Supply Portfolio environment.

As described previously, NorthWestern was provided direction to remove a portion of regulation costs attributable to the UMGF wind project. This adjustment is reflected in the transmission cost section on page 1 of Exhibit__(FVB-2)12_13.

Q. How has NorthWestern treated regulation costs in the 2012/2013 tracker?

A. As of January 1, 2011, NorthWestern replaced the historical third-party contracts for regulating service with the DGGS Generation Asset. NorthWestern includes 7 MW of base load energy in the supply portfolio as an energy resource as a result of minimum turndown from generating unit operations as shown on page 3 of Exhibit__(FVB-2)12_13.

Q. How does the generation output from CU4 impact the 2012/2013 tracker period?

A. The unit contingent energy associated with 222 MW of capacity from the CU4 Generation Asset is included in this forecast period.

Q. Describe the Total Supply requirement for the 12-month period ending June 2013 as illustrated in Exhibit__(FVB-2)12_13.

A. NorthWestern's electricity supply forecasted Total Delivered Supply is estimated at 6,447,521 MWh, as shown on page 3 of Exhibit__(FVB-2)12_13.

Q. How is the projected 12-month ended June 2013 tracker organized?

A. As further discussed in the Markovich Direct Testimony, the supply detail is now categorized by off-system and on-system transactions. Please refer to that testimony for a more detailed explanation.

Q. Please summarize the 12-month ended June 2013 forecast tracker period.

A. The forecast tracker period is summarized in the following table:

Beginning Deferred Account		**Balance ($)**
Under-Collection		$ 11,496,428

Energy Supply/Service	**MWh**	**Cost ($)**	**$ / MWh**
System Transactions	6,447,521	202,692,309	31.44
Ancillary & Other		25,533,841	
Transmission Costs	NA	215,830	
Administrative Expenses	NA	1,291,243	
Carrying Cost	NA	219,987	
Total Expenses:		229,953,209	

Electricity Sales	**MWh**	**Revenue ($)**
Electric Cost Revenue		$229,953,209
Prior Deferred Expense		11,496,428
Total Revenue:		$ 241,449,638

Ending Deferred Account		**Balance ($)**
Even Collection		$ 0

Q. Describe the electric supply Revenue and Expense categories for the 12-month ended June 2013 forecast tracker period.

A. The electricity supply tracker revenue and expense details are reflected on page 1 of Exhibit__(FVB-2)12_13 under two main sections, Total Revenue and Total Expenses. Total Revenue is estimated to be $241,449,638. This includes the $11,496,428 under-collection for the 2011-2012 tracker period. The 12-month forecast tracker estimates Total Expenses of $229,953,209, reflecting an increase from the prior period. As discussed above, costs reflected in the forecast period include DSM costs and lost T&D revenues that are further explained in the Thomas Direct Testimony.

Q. Are there any additional updates anticipated for the first monthly tracker rate filing in this Docket?

A. Not at this time. Because a normal monthly filing would have been submitted on June 15, 2012, for July 2012 rates, this July tracker filed under this docket reflects the first monthly tracker rate filing under a yet-to-be-assigned monthly tracker docket number. The electric market forecast used in this filing was dated several weeks earlier than the forecasts normally used in monthly tracker rate filings. Therefore, if electric market prices decrease or increase dramatically prior to June 15, 2012, NorthWestern will file a monthly tracker rate filing update for a July 2012 rate adjustment.

Q. Does this conclude your Annual Electricity Supply Tracker testimony?

A. Yes, it does.

	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
3														
4		**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Total**
5		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
6	Total Sales and Unit Costs													
7	MWh	465,921	516,357	509,435	447,311	447,758	516,526	547,422	525,206	491,564	462,940	454,666	499,219	5,884,324
8	Supply Cost	$ 36.8201	$ 37.6133	$ 37.4485	$ 37.1819	$ 36.8201	$ 37.0059	$ 37.1942	$ 37.1669	$ 36.7363	$ 36.7092	$ 36.6049	$ 36.7923	$ 36.8201
9	YNP MWh	3,136	2,087	2,226	2,433	1,312	714	498	599	794	669	2,582	2,783	19,835
10	YNP Supply Rate	$ 60.4000	$ 60.4000	$ 60.4000	$ 60.4000	$ 60.4000	$ 60.4000	$ 60.4000	$ 60.4000	$ 60.4000	$ 60.4000	$ 60.4000	$ 60.4000	$ 60.4000
11	Prior Year(s) Deferred Expense	$ 3.5163	$ 3.5163	$ 3.5163	$ 3.5163	$ 3.5163	$ 3.5163	$ 3.5163	$ 3.5163	$ 3.5163	$ 3.5163	$ 3.5163	$ 3.5163	
12														
13														
14	Electric Cost Revenues													
15	NWE Electric Supply	$ 17,320,449	$ 19,291,341	$ 19,110,640	$ 16,700,444	$ 16,609,413	$ 19,078,936	$ 20,301,168	$ 19,554,419	$ 18,237,544	$ 17,030,333	$ 16,643,003	$ 18,367,408	$ 218,245,098
16	YNP Electric Supply	$ 189,415	$ 126,058	$ 134,475	$ 146,962	$ 79,264	$ 43,118	$ 30,084	$ 36,200	$ 47,978	$ 40,391	$ 155,976	$ 168,088	$ 1,198,008
17	Subtotal	$ 17,509,864	$ 19,417,399	$ 19,245,116	$ 16,847,406	$ 16,688,677	$ 19,122,053	$ 20,331,251	$ 19,590,619	$ 18,285,522	$ 17,070,723	$ 16,798,979	$ 18,535,496	$ 219,443,106
18	Prior Year(s) Deferred Expense	$ 760,815	$ 1,819,542	$ 1,792,407	$ 1,572,601	$ 1,574,093	$ 1,816,961	$ 1,925,978	$ 1,847,249	$ 1,729,307	$ 1,628,209	$ 1,598,737	$ 1,755,397	$ 19,821,296
19	Total Revenue	$ 18,270,679	$ 21,236,941	$ 21,037,522	$ 18,420,007	$ 18,262,770	$ 20,939,014	$ 22,257,229	$ 21,437,868	$ 20,014,829	$ 18,698,933	$ 18,397,716	$ 20,290,893	$ 239,264,403
20														
21														
22	Electric Supply Expenses													
23	Net Non-Base Transactions	$ 3,282,657	$ 3,494,900	$ 1,412,890	$ 620,442	$ 2,058,012	$ 2,839,243	$ 2,805,130	$ 2,081,049	$ 903,762	$ 884,678	$ 717,104	$ 1,013,648	$ 22,113,515
24														
25	Net Base Contracts	$ 15,949,666	$ 16,139,355	$ 14,900,207	$ 15,632,114	$ 17,872,526	$ 17,278,955	$ 17,499,161	$ 15,556,907	$ 16,627,840	$ 17,483,581	$ 19,507,723	$ 15,934,437	$ 200,382,471
26	Total Electric Supply Expenses	$ 19,232,323	$ 19,634,255	$ 16,313,098	$ 16,252,556	$ 19,930,538	$ 20,118,198	$ 20,304,290	$ 17,637,955	$ 17,531,602	$ 18,368,259	$ 20,224,827	$ 16,948,084	$ 222,495,986
27														
28	NWE Transmission Costs													
29														
30	Other Services (Wheeling)	$ 53,783	$ 71,640	$ 108,181	$ 81,697	$ 74,564	$ 100,807	$ 78,800	$ 42,338	$ 37,810	$ 36,342	$ 98,950	$ 67,598	$ 852,511
31	Ancillary Cost (Disallowed)	$ (13,781)	$ (13,781)	$ (13,781)	$ (13,781)	$ (13,781)	$ (13,781)	$ (13,781)	$ (13,781)	$ (13,781)	$ (13,781)	$ (15,863)	$ (15,863)	$ (169,535)
32	Total NWE Transmission	$ 40,002	$ 57,859	$ 94,400	$ 67,916	$ 60,783	$ 87,026	$ 65,019	$ 28,557	$ 24,029	$ 22,561	$ 83,088	$ 51,735	$ 682,976
33														
34	Administrative Expenses													
35	MCC Tax Collection (.0011)	$ 19,736	$ 23,075	$ 22,856	$ 21,789	$ 21,697	$ 24,915	$ 26,423	$ 25,415	$ 23,688	$ 22,122	$ 20,159	$ 22,130	$ 274,007
36	MPSC Tax Collection (.0042)	$ 75,355	$ 88,106	$ 87,269	$ 36,131	$ 36,162	$ 41,525	$ 44,039	$ 42,358	$ 39,481	$ 36,871	$ 33,598	$ 36,884	$ 597,779
37	Modeling	$ 114,251	$ 49,165	$ 31,667	$ -	$ 68,917	$ 5,625	$ 66,022	$ 31,855	$ 38,652	$ 188	$ 20,198	$ 20,198	$ 446,737
38	Trading & Marketing	$ 6,823	$ 6,373	$ 7,934	$ 21,423	$ 34,039	$ 7,098	$ 6,847	$ 6,337	$ 9,255	$ 8,420	$ 8,327	$ 8,327	$ 131,203
39	Administration	$ 5,620	$ 12,112	$ 4,400	$ 11,500	$ 14,411	$ 4,400	$ 14,816	$ 18,113	$ 80,825	$ 4,413	$ 14,692	$ 14,692	$ 199,993
40	Total Administrative Expenses	$ 221,785	$ 178,832	$ 154,127	$ 90,844	$ 175,226	$ 83,563	$ 158,146	$ 124,077	$ 191,901	$ 72,014	$ 96,974	$ 102,231	$ 1,649,719
41														
42	Carrying Cost Expense													
43	Carrying Costs	$ 167,711	$ 159,876	$ 131,656	$ 119,383	$ 132,611	$ 129,227	$ 118,762	$ 95,691	$ 81,492	$ 80,481	$ 96,364	$ 75,830	$ 1,389,085
44	Carrying Cost Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 116,597	$ -	$ 116,597
45	Total Carrying Costs	$ 167,711	$ 159,876	$ 131,656	$ 119,383	$ 132,611	$ 129,227	$ 118,762	$ 95,691	$ 81,492	$ 80,481	$ 212,961	$ 75,830	$ 1,505,682
46														
47														
48	Total Expenses	$ 19,661,822	$ 20,030,822	$ 16,693,280	$ 16,530,699	$ 20,299,158	$ 20,418,014	$ 20,646,217	$ 17,886,281	$ 17,829,024	$ 18,543,315	$ 20,617,849	$ 17,177,881	$ 226,334,363
49														
50	Deferred Cost Amortization	$ 760,815	$ 1,819,542	$ 1,792,407	$ 1,572,601	$ 1,574,093	$ 1,816,961	$ 1,925,978	$ 1,847,249	$ 1,729,307	$ 1,628,209	$ 1,598,737	$ 1,755,397	$ 19,821,296
51	(under collection)/over collection													
52	Monthly Deferred Cost	$ (2,151,957)	$ (613,424)	$ 2,551,835	$ 316,707	$ (3,610,481)	$ (1,295,961)	$ (314,966)	$ 1,704,338	$ 456,498	$ (1,472,592)	$ (3,818,871)	$ 1,357,615	$ (6,891,257)
53	Cumulative Deferred Cost	$ (2,151,957)	$ (2,765,381)	$ (213,545)	$ 103,162	$ (3,507,319)	$ (4,803,280)	$ (5,118,246)	$ (3,413,908)	$ (2,957,410)	$ (4,430,001)	$ (8,248,872)	$ (6,891,257)	

Electric Supply Cost Tracker
Electric Tracker Projection Excluding Generation Assets Cost of Service

	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate

Note: for supply cost expense positive value reflects an under collection, negative an (over collection).

Deferred Supply Cost Expense	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
Beginning Balance	$ 24,426,468	$ 25,817,610	$ 24,611,491	$ 20,267,249	$ 18,377,941	$ 20,414,329	$ 19,893,328	$ 18,282,317	$ 14,730,729	$ 12,544,924	$ 12,389,306	$ 14,609,440
Monthly Deferred Cost	$ 1,391,142	$ (1,206,119)	$ (4,344,242)	$ (1,889,308)	$ 2,036,388	$ (521,000)	$ (1,611,012)	$ (3,551,587)	$ (2,185,805)	$ (155,618)	$ 2,220,134	$ (3,113,012)
Ending Balance	$ 25,817,610	$ 24,611,491	$ 20,267,249	$ 18,377,941	$ 20,414,329	$ 19,893,328	$ 18,282,317	$ 14,730,729	$ 12,544,924	$ 12,389,306	$ 14,609,440	$ 11,496,428
Total Capital	$ 25,817,610	$ 24,611,491	$ 20,267,249	$ 18,377,941	$ 20,414,329	$ 19,893,328	$ 18,282,317	$ 14,730,729	$ 12,544,924	$ 12,389,306	$ 14,609,440	$ 11,496,428

Cost of Capital	Rate	% Capitalization	Rate of Return
Long-Term Debt	5.76%	52.00%	3.00%
Common Equity	10.25%	48.00%	4.92%
Average Cost of Capital			7.92%
Deferred Supply Expense			
Carrying Charge	7.92%	Prior Charge	7.80%

Electric Supply Cost Tracker
Electric Tracker Projection

Generation in MWh	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Total
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
Non-Base Transactions													
Net Fixed Price Transactions	60,000	64,800	10,000	10,416	10,000	52,000	60,000	20,000	21,600	20,000	31,216	30,880	390,912
Net Market Transactions	96,064	58,059	36,537	5,028	48,584	37,252	35,290	68,380	34,009	76,777	(8,905)	12,382	499,457
Total Non-Base Transactions	156,064	122,859	46,537	15,444	58,584	89,252	95,290	88,380	55,609	96,777	22,311	43,262	890,369
Rate Based Assets													
Colstrip Unit 4 MWh	101,915	143,318	137,169	156,328	146,791	154,634	147,724	149,866	125,253	72,069	150,303	145,454	1,630,824
Mill Creek Generating Station	5,208	5,208	5,040	5,208	5,047	5,208	5,201	0	5,194	5,040	5,208	5,040	56,602
Total Rate Based Assets	107,123	148,526	142,209	161,536	151,838	159,842	152,925	149,866	130,447	77,109	155,511	150,494	1,687,426
Net Base Fixed Price Contracts													
PPL 7 Year Contract	161,600	165,600	158,000	163,600	158,000	163,600	161,600	154,400	165,600	158,000	163,600	160,000	1,933,600
PPL 09 RFP	10,000	10,800	10,000	10,400	10,000	10,400	10,000	10,000	10,800	10,000	10,400	10,400	123,200
QF Tier II	44,296	53,845	70,056	58,217	74,815	77,001	71,321	71,227	73,805	75,027	74,400	74,880	818,890
QF Tier II Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
QF-1 Tariff Contracts	2,346	1,555	805	551	703	856	842	628	654	620	1,488	1,440	12,488
Gordon Butte Wind QF	-	-	-	-	-	-	5,926	3,501	4,525	3,055	2,232	2,160	21,400
Tiber	6,666	5,794	5,760	3,720	4,736	3,720	4,502	4,150	4,174	4,286	-	-	47,508
Turnbull	6,825	7,966	5,843	840	-	-	-	-	-	-	2,976	7,200	31,650
Judith Gap Energy	24,609	24,633	23,516	44,792	53,496	69,959	61,881	34,979	48,500	35,386	34,840	25,840	482,431
Wind Ancillary	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Other	-	-	-	-	-	-	-	-	-	-	-	-	-
Citigroup 08 RFP	18,600	18,600	18,000	18,600	18,000	18,600	18,600	17,400	18,600	18,000	18,600	18,000	219,600
Net Base Market Contracts													
Basin Creek Fixed Capacity	1,341	1,609	153	21	703	1,325	1,546	1,219	540	684	600	2,845	12,587
Basin Creek Operating Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Basin Creek Wind Firming	-	-	-	-	-	-	-	-	-	-	-	-	-
Basin Creek Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-
Basin Creek Variable O & M	-	-	-	-	-	-	-	-	-	-	-	-	-
Basin Creek Gas Storage Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM Program & Labor Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM Lost T& D Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
Imbalance Current Month Estimate	33,360	37,198	18,369	12,280	18,779	14,785	21,666	10,934	9,822	7,306	-	-	184,499
Imbalance Prior Months True-up	(3,491)	14,645	(1,925)	(9,969)	7,197	5,734	(12,145)	(1,248)	(5,211)	10,090	-	-	3,676
Imbalance, Accounting & BA Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Base Contract Transactions	306,153	342,244	308,576	303,052	346,430	365,980	345,739	307,191	331,809	322,454	309,136	302,765	3,891,530
Total Delivered Supply	569,340	613,629	497,322	480,032	556,852	615,074	593,954	545,437	517,865	496,340	486,958	496,521	6,469,325
Fixed price contracts (% of total)	77.23%	81.57%	89.15%	98.35%	86.36%	90.25%	92.05%	85.35%	92.31%	80.76%	101.40%	96.64%	88.98%
													11.02%

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**														
2	**Electric Tracker Projection**														
3															
57	**Electric Tracker Projection Excluding Generation Assets Cost of Service**														
58	**Total Supply Expense**														
59			**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Total**
60			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
61	Non-Base Transactions														
62		Net Fixed Price Transactions	$ 1,982,500	$ 2,543,400	$ 480,000	$ 143,220	$ 480,000	$ 1,954,160	$ 2,025,500	$ 718,500	$ 775,980	$ 718,500	$ 851,400	$ 848,040	$ 13,521,200
63		Net Market Transactions	$ 1,300,157	$ 951,500	$ 932,890	$ 477,222	$ 1,578,012	$ 885,083	$ 779,630	$ 1,362,549	$ 127,782	$ 166,178	$ (134,296)	$ 165,608	$ 8,592,315
64	Total Non-Base Transactions		$ 3,282,657	$ 3,494,900	$ 1,412,890	$ 620,442	$ 2,058,012	$ 2,839,243	$ 2,805,130	$ 2,081,049	$ 903,762	$ 884,678	$ 717,104	$ 1,013,648	$ 22,113,515
65															
66															
67															
68															
69															
70															
71															
72	Net Base Fixed Price Contracts														
73		PPL 7 Year Contract	$ 8,298,160	$ 8,503,560	$ 8,113,300	$ 8,466,300	$ 8,176,500	$ 8,466,300	$ 8,427,440	$ 8,051,960	$ 8,636,040	$ 8,302,900	$ 8,597,180	$ 8,408,000	$ 100,447,640
74		PPL 09 RFP	$ 603,000	$ 651,240	$ 603,000	$ 627,120	$ 603,000	$ 627,120	$ 603,000	$ 603,000	$ 651,240	$ 603,000	$ 627,120	$ 627,120	$ 7,428,960
75		QF Tier II	$ 1,593,770	$ 1,937,343	$ 2,520,615	$ 2,094,648	$ 2,691,844	$ 2,770,496	$ 2,566,130	$ 2,562,747	$ 2,655,504	$ 2,699,471	$ 2,676,912	$ 2,694,182	$ 29,463,662
76		QF Tier II Adjustment	$ 108,087	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 108,087
77		QF-1 Tariff Contracts	$ 82,473	$ 46,061	$ 26,349	$ 10,719	$ 14,138	$ 26,419	$ 22,699	$ 13,784	$ 7,805	$ 6,054	$ 22,518	$ 23,856	$ 302,874
78		Gordon Butte Wind QF	$ -	$ -	$ -	$ -	$ -	$ -	$ 367,178	$ 242,338	$ 313,204	$ 211,470	$ 154,477	$ 149,494	$ 1,438,160
79		Tiber	$ 257,208	$ 237,701	$ 213,340	$ 197,295	$ 157,430	$ 157,430	$ 157,430	$ 157,430	$ 157,430	$ 157,430	$ -	$ -	$ 1,850,124
80		Turnbull	$ 445,336	$ 519,808	$ 381,249	$ 55,582	$ -	$ -	$ -	$ -	$ -	$ -	$ 194,184	$ 469,800	$ 2,065,958
81		Judith Gap Energy	$ 732,935	$ 834,942	$ 795,826	$ 1,335,092	$ 1,701,072	$ 2,280,348	$ 2,002,202	$ 1,133,854	$ 1,454,916	$ 807,639	$ 783,820	$ 579,707	$ 14,442,354
82		Wind Ancillary	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
83		Wind Other	$ 23,864	$ 2,916	$ 2,956	$ 2,854	$ 701,803	$ 2,860	$ 37,927	$ 5,515	$ 2,968	$ 29,378	$ 704,681	$ 5,636	$ 1,523,356
84		Citigroup 08 RFP	$ 1,160,640	$ 1,160,640	$ 1,123,200	$ 1,160,640	$ 1,123,200	$ 1,160,640	$ 1,160,640	$ 1,085,760	$ 1,160,640	$ 1,123,200	$ 1,160,640	$ 1,123,200	$ 13,703,040
85															
86															
87	Net Base Market Contracts														
88		Basin Creek Fixed Capacity	$ 450,266	$ 450,266	$ 450,266	$ 450,266	$ 866,285	$ 455,346	$ 462,563	$ 459,005	$ 446,966	$ 452,985	$ 461,129	$ 460,641	$ 5,865,982
89		Basin Creek Operating Reserves	$ (156,835)	$ (156,835)	$ (151,776)	$ (156,835)	$ (138,600)	$ (143,220)	$ (143,220)	$ (101,338)	$ (108,326)	$ (100,800)	$ (104,160)	$ (100,800)	$ (1,562,746)
90		Basin Creek Wind Firming	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91		Basin Creek Fuel	$ 73,311	$ 85,099	$ 31,147	$ 22,590	$ 50,025	$ 67,722	$ 71,490	$ 54,515	$ 36,869	$ 39,613	$ 145,858	$ 93,523	$ 771,764
92		Basin Creek Variable O & M	$ 6,361	$ 7,859	$ 1,025	$ 80	$ 3,804	$ 6,376	$ 7,175	$ 6,020	$ 2,714	$ 3,450	$ 5,051	$ 5,539	$ 55,455
93		Basin Creek Gas Storage Capacity	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 36,000
94		Operating Reserves	$ 280,042	$ 280,542	$ 271,912	$ 195,987	$ 281,730	$ 143,220	$ 251,494	$ 202,634	$ 216,601	$ 100,800	$ 208,320	$ 201,600	$ 2,634,883
95		DSM Program & Labor Costs	$ 904,399	$ 747,559	$ 528,632	$ 626,320	$ 722,827	$ 783,516	$ 462,689	$ 533,330	$ 535,497	$ 996,891	$ 1,000,488	$ 929,347	$ 8,771,493
96		DSM Lost T&D Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 260,591	$ 260,591	$ 521,183
97		DSM Lost T&D Revenue Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,656,092	$ 2,605,913		$ 4,262,005
98		Imbalance, Current Month Estimate	$ 281,623	$ 670,877	$ 409,342	$ 219,263	$ 398,606	$ 319,956	$ 542,307	$ 231,870	$ 65,967	$ 7,985	$ -	$ -	$ 3,147,796
99		Imbalance, Prior Months True-up	$ (70,379)	$ 338,223	$ 256,087	$ (45,100)	$ 248,142	$ 171,520	$ (109,136)	$ 164,118	$ (125,236)	$ 228,317	$ -	$ -	$ 1,056,556
100		Imbalance, Accounting & BA Expense	$ 872,406	$ (181,446)	$ (679,261)	$ 366,293	$ 267,720	$ (20,095)	$ 606,153	$ 147,366	$ 514,042	$ 154,706	$ -	$ -	$ 2,047,885
101	Total Base Contract Transactions		$ 15,949,666	$ 16,139,355	$ 14,900,207	$ 15,632,114	$ 17,872,526	$ 17,278,955	$ 17,499,161	$ 15,556,907	$ 16,627,840	$ 17,483,581	$ 19,507,723	$ 15,934,437	$ 200,382,471
102															
103	Total Delivered Supply		$ 19,232,323	$ 19,634,255	$ 16,313,098	$ 16,252,556	$ 19,930,538	$ 20,118,198	$ 20,304,290	$ 17,637,955	$ 17,531,602	$ 18,368,259	$ 20,224,827	$ 16,948,084	$ 222,495,986
104															
105		Note:	Wind Other includes: Judith Gap impact fees and property tax charges, Global Energy fees, 3 Tier fees, electric service at met towers, and met tower site leases.												
106															

	A / B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection**													
3														
107	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
108	**Unit Costs**													
109		**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Average**
110		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
111	Non-Base Transactions													
112	Net Fixed Price Transactions	$ 33.042	$ 39.250	$ 48.000	$ 13.750	$ 48.000	$ 37.580	$ 33.758	$ 35.925	$ 35.925	$ 35.925	$ 27.274	$ 27.462	$ 34.589
113	Net Market Transactions	$ 13.534	$ 16.388	$ 25.533	$ 94.913	$ 32.480	$ 23.759	$ 22.092	$ 19.926	$ 3.757	$ 2.164	$ 15.081	$ 13.375	$ 17.203
114														
115	Total Non-Base Transactions	$ 21.034	$ 28.446	$ 30.361	$ 40.174	$ 35.129	$ 31.812	$ 29.438	$ 23.547	$ 16.252	$ 9.141	$ 32.141	$ 23.430	$ 24.836
116														
117														
118														
119														
120														
121														
122														
123	Net Base Fixed Price Contracts													
124	PPL 7 Year Contract	$ 51.350	$ 51.350	$ 51.350	$ 51.750	$ 51.750	$ 51.750	$ 52.150	$ 52.150	$ 52.150	$ 52.550	$ 52.550	$ 52.550	$ 51.949
125	PPL 09 RFP	$ 60.300	$ 60.300	$ 60.300	$ 60.300	$ 60.300	$ 60.300	$ 60.300	$ 60.300	$ 60.300	$ 60.300	$ 60.300	$ 60.300	$ 60.300
126	QF Tier II	$ 35.980	$ 35.980	$ 35.980	$ 35.980	$ 35.980	$ 35.980	$ 35.980	$ 35.980	$ 35.980	$ 35.980	$ 35.980	$ 35.980	$ 35.980
127	QF Tier II Adjustment	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
128	QF-1 Tariff Contracts	$ 35.148	$ 29.622	$ 32.748	$ 19.454	$ 20.111	$ 30.863	$ 26.958	$ 21.954	$ 11.934	$ 9.764	$ 15.133	$ 16.567	$ 24.253
129	Gordon Butte Wind QF	n/a	n/a	n/a	n/a	n/a	n/a	$ 61.961	$ 69.210	$ 69.210	$ 69.210	$ 69.210	$ 69.210	$ 67.203
130	Tiber	$ 38.585	$ 41.025	$ 37.038	$ 53.036	$ 33.241	$ 42.320	$ 34.969	$ 37.935	$ 37.713	$ 36.731	n/a	n/a	$ 38.943
131	Turnbull	$ 65.251	$ 65.253	$ 65.249	$ 66.169	n/a	n/a	n/a	n/a	n/a	n/a	$ 65.250	$ 65.250	$ 65.275
132	Judith Gap Energy	$ 29.783	$ 33.895	$ 33.842	$ 29.806	$ 31.798	$ 32.595	$ 32.356	$ 32.415	$ 29.999	$ 22.824	$ 22.498	$ 22.434	$ 29.937
133	Wind Ancillary	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
134	Wind Other	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
135	Citigroup 08 RFP	$ 62.400	$ 62.400	$ 62.400	$ 62.400	$ 62.400	$ 62.400	$ 62.400	$ 62.400	$ 62.400	$ 62.400	$ 62.400	$ 62.400	$ 62.400
136														
137														
138	Net Base Market Contracts													
139	Basin Creek Fixed Capacity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140	Basin Creek Operating Reserves	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
141	Basin Creek Wind Firming	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
142	Basin Creek Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
143	Basin Creek Variable O & M	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
144	Basin Creek Gas Storage Capacity	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
145	Operating Reserves	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
146	DSM Program & Labor Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
147	DSM Lost T& D Revenues	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
148	Imbalance, Current Month Estimate	$ 8.442	$ 18.036	$ 22.285	$ 17.855	$ 21.226	$ 21.641	$ 25.030	$ 21.206	$ 6.716	$ 1.093	n/a	n/a	$ 17.061
149	Imbalance, Prior Months True-up	$ 20.158	$ 23.095	$ (132.998)	$ 4.524	$ 34.477	$ 29.913	$ 8.986	$ (131.528)	$ 24.034	$ 22.628	n/a	n/a	$ 287.381
150	Imbalance, Accounting & BA Expense	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
151	Total Base Contract Transactions	$ 52.097	$ 47.157	$ 48.287	$ 51.582	$ 51.591	$ 47.213	$ 50.614	$ 50.642	$ 50.113	$ 54.220	$ 63.104	$ 52.630	$ 51.492
152														
153	Total Delivered Supply	$ 33.780	$ 31.997	$ 32.802	$ 33.857	$ 35.791	$ 32.709	$ 34.185	$ 32.337	$ 33.854	$ 37.007	$ 41.533	$ 34.134	$ 34.392

	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
3														
4		**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
5		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
6	Total Sales and Unit Costs													
7	MWh	498,023	530,930	487,991	463,159	482,393	528,410	561,395	526,009	496,981	471,801	449,669	450,484	5,947,244
8	Supply Cost	$ 38.4793	$ 38.4793	$ 38.4793	$ 38.4793	$ 38.4793	$ 38.4793	$ 38.4793	$ 38.4793	$ 38.4793	$ 38.4793	$ 38.4793	$ 38.4793	$ 38.4793
9	YNP MWh	2,494	2,405	2,376	1,769	954	768	889	901	821	890	1,694	2,495	18,457
10	YNP Supply Rate	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000
11	Prior Year(s) Deferred Expense	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	
12														
13														
14	Electric Cost Revenues													
15	NWE Electric Supply	$ 19,163,556	$ 20,429,802	$ 18,777,569	$ 17,822,022	$ 18,562,156	$ 20,332,858	$ 21,602,072	$ 20,240,441	$ 19,123,475	$ 18,154,560	$ 17,302,964	$ 17,334,296	$ 228,845,771
16	YNP Electric Supply	$ 149,669	$ 144,292	$ 142,579	$ 106,128	$ 57,225	$ 46,093	$ 53,328	$ 54,082	$ 49,279	$ 53,429	$ 101,639	$ 149,695	$ 1,107,438
17	Subtotal	$ 19,313,226	$ 20,574,094	$ 18,920,149	$ 17,928,149	$ 18,619,380	$ 20,378,951	$ 21,655,400	$ 20,294,523	$ 19,172,754	$ 18,207,990	$ 17,404,603	$ 17,483,991	$ 229,953,209
18	Prior Year(s) Deferred Expense	$ 962,711	$ 1,026,323	$ 943,321	$ 895,317	$ 932,499	$ 1,021,453	$ 1,085,214	$ 1,016,810	$ 960,698	$ 912,023	$ 869,242	$ 870,816	$ 11,496,428
19	Total Revenue	$ 20,275,937	$ 21,600,418	$ 19,863,470	$ 18,823,467	$ 19,551,880	$ 21,400,404	$ 22,740,614	$ 21,311,334	$ 20,133,452	$ 19,120,013	$ 18,273,844	$ 18,354,807	$ 241,449,638
20														
21	Electric Supply Expenses													
22	Net Base Purchases	$ 13,726,222	$ 13,426,268	$ 13,982,254	$ 15,213,608	$ 14,993,532	$ 15,673,993	$ 19,675,131	$ 17,463,349	$ 18,853,520	$ 17,878,030	$ 18,318,215	$ 17,306,437	$ 196,510,559
23	Net Base Sales	$ (693,550)	$ (841,722)	$ (776,940)	$ (767,340)	$ (850,559)	$ (988,130)	$ (975,560)	$ (856,152)	$ (844,332)	$ (668,252)	$ (638,290)	$ (530,880)	$ (9,431,706)
24	Net Term Purchases	$ 3,718,404	$ 3,664,035	$ 892,440	$ 901,260	$ 1,349,639	$ 1,486,870	$ 507,423	$ 443,681	$ 446,558	$ -	$ -	$ -	$ 13,410,310
25	Net Term Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,502,816)	$ (2,179,296)	$ (2,165,102)	$ (1,694,160)	$ (1,637,544)	$ (1,365,120)	$ (11,544,038)
26	Net Spot Purchases	$ 2,700,379	$ 3,020,489	$ 1,906,855	$ 1,083,516	$ 1,680,285	$ 3,956,579	$ 2,483,519	$ 2,260,301	$ 789,260	$ 159,257	$ 1,067,449	$ 1,654,265	$ 22,762,154
27	Net Spot Sales	$ (2,248,390)	$ (2,256,938)	$ (814,814)	$ (771,208)	$ (894,135)	$ (1,521,255)	$ (142,886)	$ (209,551)	$ (77,247)	$ (12,895)	$ (19,178)	$ (46,473)	$ (9,014,970)
28	Other Tracker Costs	$ 2,147,846	$ 2,069,740	$ 1,815,733	$ 1,862,575	$ 2,675,546	$ 2,112,030	$ 1,759,937	$ 1,793,896	$ 1,720,705	$ 2,557,710	$ 2,877,434	$ 2,140,688	$ 25,533,841
29	Total Electric Supply Expenses	$ 19,350,911	$ 19,081,872	$ 17,005,527	$ 17,522,411	$ 18,954,308	$ 20,720,086	$ 20,804,747	$ 18,716,229	$ 18,723,363	$ 18,219,689	$ 19,968,087	$ 19,158,917	$ 228,226,150
30														
31	NWE Transmission Costs													
32														
33	Other Services (Wheeling)	$ 25,136	$ 29,246	$ 74,844	$ 41,921	$ 49,890	$ 73,991	$ 22,741	$ 34,591	$ 14,194	$ 5,611	$ 8,919	$ 25,094	$ 406,180
34	Ancillary Cost (Disallowed)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (190,350)
35	Total NWE Transmission	$ 9,274	$ 13,384	$ 58,982	$ 26,059	$ 34,027	$ 58,129	$ 6,878	$ 18,729	$ (1,668)	$ (10,252)	$ (6,943)	$ 9,232	$ 215,830
36														
37	Administrative Expenses													
38	MCC Tax Collection (.0012)	$ 24,331	$ 25,921	$ 23,836	$ 22,588	$ 23,462	$ 25,680	$ 27,289	$ 25,574	$ 24,160	$ 22,944	$ 21,929	$ 22,026	$ 289,740
39	MPSC Tax Collection (.002)	$ 40,552	$ 43,201	$ 39,727	$ 37,647	$ 39,104	$ 42,801	$ 45,481	$ 42,623	$ 40,267	$ 38,240	$ 36,548	$ 36,710	$ 482,899
40	Modeling	$ 20,198	$ 20,198	$ 20,198	$ 20,198	$ 20,198	$ 20,198	$ 20,198	$ 20,198	$ 20,198	$ 20,198	$ 20,198	$ 20,198	$ 242,376
41	Trading & Marketing	$ 8,327	$ 8,327	$ 8,327	$ 8,327	$ 8,327	$ 8,327	$ 8,327	$ 8,327	$ 8,327	$ 8,327	$ 8,327	$ 8,327	$ 99,924
42	Administration	$ 14,692	$ 14,692	$ 14,692	$ 14,692	$ 14,692	$ 14,692	$ 14,692	$ 14,692	$ 14,692	$ 14,692	$ 14,692	$ 14,692	$ 176,304
43	Total Administrative Expenses	$ 108,100	$ 112,338	$ 106,780	$ 103,452	$ 105,783	$ 111,698	$ 115,987	$ 111,413	$ 107,644	$ 104,401	$ 101,693	$ 101,952	$ 1,291,243
44														
45	Carrying Cost Expense													
46	Carrying Costs	$ 70,971	$ 55,555	$ 38,048	$ 30,522	$ 27,685	$ 24,479	$ 12,604	$ (3,679)	$ (12,363)	$ (17,798)	$ (6,037)	$ 0	$ 219,987
47	Total Carrying Costs	$ 70,971	$ 55,555	$ 38,048	$ 30,522	$ 27,685	$ 24,479	$ 12,604	$ (3,679)	$ (12,363)	$ (17,798)	$ (6,037)	$ 0	$ 219,987
48														
49														
50	Total Expenses	$ 19,539,256	$ 19,263,149	$ 17,209,337	$ 17,682,444	$ 19,121,804	$ 20,914,393	$ 20,940,217	$ 18,842,692	$ 18,816,976	$ 18,296,041	$ 20,056,800	$ 19,270,101	$ 229,953,209
51														
52	Deferred Cost Amortization	$ 962,711	$ 1,026,323	$ 943,321	$ 895,317	$ 932,499	$ 1,021,453	$ 1,085,214	$ 1,016,810	$ 960,698	$ 912,023	$ 869,242	$ 870,816	$ 11,496,428
53	(under collection)/over collection													
54	Monthly Deferred Cost	$ (226,031)	$ 1,310,945	$ 1,710,811	$ 245,705	$ (502,424)	$ (535,442)	$ 715,183	$ 1,451,831	$ 355,778	$ (88,051)	$ (2,652,197)	$ (1,786,110)	$ 0
55	Cumulative Deferred Cost	$ (226,031)	$ 1,084,915	$ 2,795,726	$ 3,041,431	$ 2,539,008	$ 2,003,566	$ 2,718,749	$ 4,170,580	$ 4,526,358	$ 4,438,307	$ 1,786,110	$ 0	

Exhibit__(FVB-2)12_13

Docket D2012.5.49
Exhibit__(FVB-2)12_13

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	Electric Supply Cost Tracker													
2	Electric Tracker Projection Excluding Generation Assets Cost of Service													
3														
4														
5			Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
6			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate
7														
8			Note: for supply cost expense positive value reflects an under collection, negative an (over collection).											
9	Deferred Supply Cost Expense													
10		Beginning Balance	$ 11,496,428	$ 10,759,748	$ 8,422,479	$ 5,768,347	$ 4,627,324	$ 4,197,248	$ 3,711,237	$ 1,910,840	$ (557,802)	$ (1,874,278)	$ (2,698,250)	$ (915,294)
11		Monthly Deferred Cost	$ (736,681)	$ (2,337,269)	$ (2,654,132)	$ (1,141,023)	$ (430,076)	$ (486,011)	$ (1,800,397)	$ (2,468,642)	$ (1,316,476)	$ (823,972)	$ 1,782,955	$ 915,294
12		Ending Balance	$ 10,759,748	$ 8,422,479	$ 5,768,347	$ 4,627,324	$ 4,197,248	$ 3,711,237	$ 1,910,840	$ (557,802)	$ (1,874,278)	$ (2,698,250)	$ (915,294)	$ 0
13														
14														
15	Total Capital		$ 10,759,748	$ 8,422,479	$ 5,768,347	$ 4,627,324	$ 4,197,248	$ 3,711,237	$ 1,910,840	$ (557,802)	$ (1,874,278)	$ (2,698,250)	$ (915,294)	$ 0
16														
17														
18														
19	Cost of Capital		Rate	% Capitalization	Rate of Return									
20		Long-Term Debt	5.76%	52.00%	3.00%									
21		Common Equity	10.25%	48.00%	4.92%									
22														
23		Average Cost of Capital			7.92%									
24														
25	Deferred Supply Expense													
26		Carrying Charge	7.92%											
27														

	A B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection**													
3														
4	**Volumes in MWh**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
5		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
6	**Off System Transactions**													
7	**Fixed Price**													
8	Base Fixed Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Competitive Solicitations	28,600	29,400	27,600	29,400	28,025	28,600	103,400	93,600	103,275	100,400	103,400	100,000	775,700
10	Base Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Competitive Solicitations	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Term Fixed Price Purchases	90,000	75,600	19,200	21,600	20,000	20,000	-	-	-	-	-	-	246,400
13	Term Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
14	**Index Price**													
15	Base Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Base Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Competitive Solicitations	(28,600)	(29,400)	(27,600)	(29,400)	(28,025)	(28,600)	(29,000)	(26,400)	(28,975)	(28,400)	(29,000)	(28,000)	(341,400)
18	Term Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Index Price Sales	-	-	-	-	-	-	(74,400)	(67,200)	(74,300)	(72,000)	(74,400)	(72,000)	(434,300)
20	Spot Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Spot Sales	(90,000)	(75,600)	(19,200)	(21,600)	(20,000)	(20,000)	-	-	-	-	-	-	(246,400)
22														
23	**On System Transactions**													
24	**Fixed Price**													
25	Rate Based Assets													
26	Colstrip Unit 4	151,032	151,032	146,160	151,032	146,160	151,032	151,032	136,416	151,032	146,160	99,876	90,132	1,671,096
27	Dave Gates Generating Station	5,208	5,208	5,040	5,208	5,047	5,208	5,208	4,704	5,201	5,040	5,208	5,040	61,320
28	Spion Kop	-	-	-	7,752	14,400	11,904	17,856	10,752	11,888	11,520	8,928	8,640	103,640
29	Base Fixed Price Purchases													
30	PPL 7 Year Contract	124,200	125,400	120,000	125,400	121,325	124,200	124,200	112,800	124,075	121,200	124,200	120,000	1,467,000
31	Judith Gap	23,098	25,665	27,309	43,441	49,466	54,316	57,628	42,722	42,109	39,803	35,962	26,626	468,144
32	Competitive Solicitations	20,000	21,600	19,200	21,600	20,000	20,000	20,800	19,200	20,800	20,800	20,800	20,000	244,800
33	QF Tier II	56,629	37,248	67,118	72,110	69,667	73,022	72,371	66,880	74,590	68,123	74,697	75,155	807,610
34	QF-1 Tariff Contracts	2,928	2,952	2,880	2,976	2,884	3,684	14,508	11,760	11,517	9,829	10,695	8,641	85,253
35	Other Non-QF	13,344	13,224	12,960	13,392	12,978	13,392	13,392	12,096	13,374	12,960	13,392	12,960	157,464
36	Term Fixed Price Purchases	2,738	2,836	1,200	-	-	-	-	-	-	-	-	-	6,774
37	Term Fixed Price Sales	(1,250)	(1,350)	(1,200)	-	-	-	-	-	-	-	-	-	(3,800)
38	**Index Price**													
39	Base Index Price Purchases													
40	Basin Creek	2,103	5,362	4,050	2,371	2,802	4,452	3,807	2,727	1,405	772	571	262	30,684
41	Competitive Solicitations	28,600	29,400	27,600	29,400	28,025	28,600	45,400	40,800	45,325	43,600	45,400	44,000	436,150
42	Term Index Price Purchases	47,200	48,000	7,200	4,800	18,978	20,592	13,392	12,096	13,374	-	-	-	185,632
43	Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Spot Purchases	111,356	105,501	67,739	41,514	55,364	114,517	73,826	69,698	27,085	6,768	48,498	87,250	809,117
45	Spot Sales	(4,144)	(4,926)	(14,861)	(8,996)	(10,706)	(15,878)	(4,880)	(7,423)	(3,046)	(1,204)	(1,914)	(5,385)	(83,363)
46	Imbalance, Current Month Estimate	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Imbalance, Prior Months True-up	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Imbalance, Accounting & BA Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
49														
50	**Ancillary and Other**													
51	Basin Creek Fixed Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Basin Creek Variable Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Operating Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Wind Other Cost													
55	DSM Program & Labor Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
56	DSM Lost T& D Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
57	DSM Lost Revenue Adjustment													
58														
59	**Total Delivered Supply**	583,042	567,152	492,395	511,999	536,390	609,042	608,540	535,229	538,728	485,372	486,313	493,321	6,447,521
60														

	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection**													
3														
61	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
62	**Total Supply Expense**													
63														
64	**Energy Supply Revenue (Expense)**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
65		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
66	**Off System Transactions**													
67	**Fixed Price**													
68	Base Fixed Price Purchases													
69	Competitive Solicitations	$ 1,652,140	$ 1,691,460	$ 1,595,040	$ 1,691,460	$ 1,616,260	$ 1,652,140	$ 4,362,240	$ 3,959,040	$ 4,357,660	$ 4,252,320	$ 4,362,240	$ 4,215,600	$ 35,407,600
70	Base Fixed Price Sales													
71	Competitive Solicitations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	Term Fixed Price Purchases	$ 2,488,500	$ 2,204,280	$ 689,760	$ 775,980	$ 718,500	$ 718,500	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,595,520
73	Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	**Index Price**													
75	Base Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	Base Index Price Sales													
77	Competitive Solicitations	$ (693,550)	$ (841,722)	$ (776,940)	$ (767,340)	$ (850,559)	$ (988,130)	$ (975,560)	$ (856,152)	$ (844,332)	$ (668,252)	$ (638,290)	$ (530,880)	$ (9,431,706)
78	Term Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,502,816)	$ (2,179,296)	$ (2,165,102)	$ (1,694,160)	$ (1,637,544)	$ (1,365,120)	$ (11,544,038)
80	Spot Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	Spot Sales	$ (2,182,500)	$ (2,164,428)	$ (540,480)	$ (563,760)	$ (607,000)	$ (1,036,500)	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,094,668)
82														
83	**On System Transactions**													
84	**Fixed Price**													
85	Rate Based Assets													
86	Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87	Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	Spion Kop	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	Base Fixed Price Purchases													
90	PPL 7 Year Contract	$ 6,532,920	$ 6,596,040	$ 6,312,000	$ 6,602,310	$ 6,387,761	$ 6,539,130	$ 6,545,340	$ 5,944,560	$ 6,538,753	$ 6,393,300	$ 6,551,550	$ 6,330,000	$ 77,273,664
91	Judith Gap	$ 733,358	$ 814,852	$ 867,072	$ 1,379,250	$ 1,570,536	$ 1,724,530	$ 1,829,681	$ 1,356,432	$ 1,336,963	$ 1,263,750	$ 1,141,788	$ 845,372	$ 14,863,583
92	Competitive Solicitations	$ 1,080,500	$ 1,166,940	$ 1,037,280	$ 1,166,940	$ 1,080,500	$ 1,080,500	$ 1,123,720	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 13,225,320
93	QF Tier II	$ 2,076,585	$ 1,365,884	$ 2,461,217	$ 2,644,274	$ 2,554,689	$ 2,677,717	$ 2,653,845	$ 2,452,490	$ 2,735,215	$ 2,498,070	$ 2,739,139	$ 2,755,934	$ 29,615,059
94	QF-1 Tariff Contracts	$ 202,647	$ 204,308	$ 199,325	$ 205,969	$ 199,602	$ 254,180	$ 951,665	$ 773,412	$ 759,866	$ 659,041	$ 719,141	$ 585,871	$ 5,715,026
95	Other Non-QF	$ 774,522	$ 766,662	$ 752,580	$ 777,666	$ 753,625	$ 777,666	$ 780,084	$ 704,592	$ 779,036	$ 754,920	$ 780,084	$ 754,920	$ 9,156,357
96	Term Fixed Price Purchases	$ 81,304	$ 81,195	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 162,499
97	Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
98	**Index Price**													
99	Base Index Price Purchases													
100	Basin Creek	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
101	Competitive Solicitations	$ 673,550	$ 820,122	$ 757,740	$ 745,740	$ 830,559	$ 968,130	$ 1,428,556	$ 1,235,544	$ 1,222,308	$ 932,908	$ 900,554	$ 738,240	$ 11,253,951
102	Term Index Price Purchases	$ 1,148,600	$ 1,378,560	$ 202,680	$ 125,280	$ 631,139	$ 768,370	$ 507,423	$ 443,681	$ 446,558	$ -	$ -	$ -	$ 5,652,290
103	Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
104	Spot Purchases	$ 2,700,379	$ 3,020,489	$ 1,906,855	$ 1,083,516	$ 1,680,285	$ 3,956,579	$ 2,483,519	$ 2,260,301	$ 789,260	$ 159,257	$ 1,067,449	$ 1,654,265	$ 22,762,154
105	Spot Sales	$ (65,890)	$ (92,510)	$ (274,334)	$ (207,448)	$ (287,135)	$ (484,755)	$ (142,886)	$ (209,551)	$ (77,247)	$ (12,895)	$ (19,178)	$ (46,473)	$ (1,920,302)
106	Imbalance, Current Month Estimate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
107	Imbalance, Prior Months True-up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
108	Imbalance, Accounting & BA Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
109														
110	**Ancillary and Other**													
111	Basin Creek Fixed Costs	$ 449,333	$ 449,333	$ 452,693	$ 449,333	$ 452,693	$ 449,333	$ 449,333	$ 459,413	$ 449,333	$ 452,693	$ 449,333	$ 452,693	$ 5,415,510
112	Basin Creek Variable Costs	$ 53,501	$ 141,243	$ 109,668	$ 66,782	$ 88,101	$ 152,957	$ 134,706	$ 96,619	$ 49,677	$ 27,218	$ 20,331	$ 9,286	$ 950,089
113	Operating Reserves	$ 208,320	$ 208,320	$ 201,600	$ 208,320	$ 201,600	$ 208,320	$ 208,320	$ 188,160	$ 208,320	$ 201,600	$ 208,320	$ 201,600	$ 2,452,800
114	Wind Other Cost	$ 12,360	$ 12,360	$ 12,360	$ 12,360	$ 701,803	$ 12,360	$ 12,360	$ 12,360	$ 12,360	$ 12,360	$ 701,803	$ 12,360	$ 1,527,205
115	DSM Program & Labor Costs	$ 1,028,802	$ 862,954	$ 643,881	$ 730,250	$ 835,820	$ 893,531	$ 559,688	$ 641,814	$ 605,485	$ 1,468,309	$ 1,102,118	$ 1,069,220	$ 10,441,871
116	DSM Lost T& D Revenues	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 4,746,366
117	DSM Lost Revenue Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118														
119	**Total Delivered Supply**	$ 19,350,911	$ 19,081,872	$ 17,005,527	$ 17,522,411	$ 18,954,308	$ 20,720,086	$ 20,804,747	$ 18,716,229	$ 18,723,363	$ 18,219,689	$ 19,968,087	$ 19,158,917	$ 228,226,150
120		Wind Other Cost includes: Judith Gap impact fees and property tax charges, Global Energy fees, 3 Tier fees, electric service at met towers, and met tower site leases.												

	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection**													
3														
121	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
122	**Unit Costs**													
123														
124	**Energy Supply Unit Costs**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
125		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
126	**Off System Transactions**													
127	**Fixed Price**													
128	Base Fixed Price Purchases													
129	Competitive Solicitations	$ 57.77	$ 57.53	$ 57.79	$ 57.53	$ 57.67	$ 57.77	$ 42.19	$ 42.30	$ 42.19	$ 42.35	$ 42.19	$ 42.16	$ 45.65
130	Base Fixed Price Sales													
131	Competitive Solicitations	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
132	Term Fixed Price Purchases	$ 27.65	$ 29.16	$ 35.93	$ 35.93	$ 35.93	$ 35.93	n/a	n/a	n/a	n/a	n/a	n/a	$ 30.83
133	Term Fixed Price Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
134	**Index Price**													
135	Base Index Price Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
136	Base Index Price Sales													
137	Competitive Solicitations	$ 24.25	$ 28.63	$ 28.15	$ 26.10	$ 30.35	$ 34.55	$ 33.64	$ 32.43	$ 29.14	$ 23.53	$ 22.01	$ 18.96	$ 27.63
138	Term Index Price Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
139	Term Index Price Sales	n/a	n/a	n/a	n/a	n/a	n/a	$ 33.64	$ 32.43	$ 29.14	$ 23.53	$ 22.01	$ 18.96	$ 26.58
140	Spot Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
141	Spot Sales	$ 24.25	$ 28.63	$ 28.15	$ 26.10	$ 30.35	$ 51.83	n/a	n/a	n/a	n/a	n/a	n/a	$ 28.79
142														
143	**On System Transactions**													
144	**Fixed Price**													
145	Rate Based Assets													
146	Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
147	Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
148	Spion Kop	n/a	n/a	n/a	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
149	Base Fixed Price Purchases													
150	PPL 7 Year Contract	$ 52.60	$ 52.60	$ 52.60	$ 52.65	$ 52.65	$ 52.65	$ 52.70	$ 52.70	$ 52.70	$ 52.75	$ 52.75	$ 52.75	$ 52.67
151	Judith Gap	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75
152	Competitive Solicitations	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03
153	QF Tier II	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67
154	QF-1 Tariff Contracts	$ 69.21	$ 69.21	$ 69.21	$ 69.21	$ 69.21	$ 69.00	$ 65.60	$ 65.77	$ 65.98	$ 67.05	$ 67.24	$ 67.80	$ 67.04
155	Other Non-QF	$ 58.04	$ 57.98	$ 58.07	$ 58.07	$ 58.07	$ 58.07	$ 58.25	$ 58.25	$ 58.25	$ 58.25	$ 58.25	$ 58.25	$ 58.15
156	Term Fixed Price Purchases	$ 29.69	$ 28.63	$ -	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ 23.99
157	Term Fixed Price Sales	$ -	$ -	$ -	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ -
158	**Index Price**													
159	Base Index Price Purchases													
160	Basin Creek	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
161	Competitive Solicitations	$ 23.55	$ 27.90	$ 27.45	$ 25.37	$ 29.64	$ 33.85	$ 31.47	$ 30.28	$ 26.97	$ 21.40	$ 19.84	$ 16.78	$ 25.80
162	Term Index Price Purchases	$ 24.33	$ 28.72	$ 28.15	$ 26.10	$ 33.26	$ 37.31	$ 37.89	$ 36.68	$ 33.39	n/a	n/a	n/a	$ 30.45
163	Term Index Price Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
164	Spot Purchases	$ 24.25	$ 28.63	$ 28.15	$ 26.10	$ 30.35	$ 34.55	$ 33.64	$ 32.43	$ 29.14	$ 23.53	$ 22.01	$ 18.96	$ 28.13
165	Spot Sales	$ 15.90	$ 18.78	$ 18.46	$ 23.06	$ 26.82	$ 30.53	$ 29.28	$ 28.23	$ 25.36	$ 10.71	$ 10.02	$ 8.63	$ 23.04
166	Imbalance, Current Month Estimate	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
167	Imbalance, Prior Months True-up	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
168	Imbalance, Accounting & BA Expense													
169														
170	**Ancillary and Other**													
171	Basin Creek Fixed Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
172	Basin Creek Variable Costs	$ 25.43	$ 26.34	$ 27.08	$ 28.17	$ 31.44	$ 34.35	$ 35.39	$ 35.43	$ 35.37	$ 35.24	$ 35.61	$ 35.50	$ 30.96
173	Operating Reserves	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
174	Wind Other Cost													
175	DSM Program & Labor Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
176	DSM Lost T& D Revenues	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
177	DSM Lost Revenue Adjustment	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
178														
179														
180	**Total Delivered Supply**	$ 33.19	$ 33.65	$ 34.54	$ 34.22	$ 35.34	$ 34.02	$ 34.19	$ 34.97	$ 34.75	$ 37.54	$ 41.06	$ 38.84	$ 35.40
181														

Exhibit__(FVB-3)
Attached To Frank V. Bennett's
Pre-Filed Direct Testimony
Is Copyright Protected Information
And Therefore Has Not Been E-Filed

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2012.5.49
Annual Electricity Supply Tracker
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF CHERYL A. HANSEN

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL ELECTRICITY SUPPLY TRACKER

TABLE OF CONTENTS

Witness Information

Q. Please state your name and business address.

A. My name is Cheryl A. Hansen, and my business address is 40 East Broadway, Butte, Montana 59701.

Q. By whom are you employed and in what capacity?

A. I am employed by NorthWestern Energy ("NWE" or "NorthWestern") as a Senior Analyst in the Regulatory Affairs Department.

Q. Please summarize your educational and employment experiences.

A. I received a Bachelor of Arts degree in Anthropology from the University of Montana in 1974. I commenced my employment with NorthWestern Energy in 1978 and have worked in various positions within the Regulatory Affairs Department. I have attended various courses and/or seminars on a variety of utility and regulatory subjects, including rate design and marginal costing.

I am a regular participant in the preparation of rate case testimony, exhibits, and workpapers in proceedings before the Montana Public Service Commission ("MPSC" or "Commission") and the Federal Energy Regulatory Commission ("FERC"). I have provided rate design and cost of service support in several rate proceedings and have filed testimony before both the FERC and this Commission.

Purpose of Testimony

Q. What is the purpose of your Annual Electricity Supply Tracker testimony?

A. My testimony:

1. Presents the 2012-2013 tracker year billing statistics and explains how they are derived;
2. Presents the derivation of proposed electricity deferred supply rates resulting from the over/under collection reflected in the 2011-2012 tracker period;
3. Presents the derivation of proposed electricity supply rates for the forecasted 2012-2013 tracker period, and;
4. Presents the overall total supply rates incorporating all individual rate components.

2012-2013 Tracker Year Billing Statistics

Q. How were the tracker period usage and billing statistics developed?

A. The tracker period usage and billing statistics were developed using the same methodology as that presented in previous NWE filings. The methodology utilizes historical actual billing data, weather adjustments, known changes, and forecasted loads to derive the estimated usage for the July 2012 to June 2013 tracker period.

Q. Explain how cyclical and calendar usage are used in this filing.

A. Cyclical usage represents customer usage billed throughout a calendar month on each of 21 billing cycles that normally include usage for the current and prior month (e.g., a July 15 meter read includes 15 days of usage in July and 15 days of usage in June). Calendar usage, on the other hand, represents a customer's adjusted usage as if it was recorded for the calendar month.

Calendar data is used to determine the cost of energy supply, which is incurred on a calendar basis and is used in the analysis included in the Prefiled Direct Testimony of Frank Bennett ("Bennett Direct Testimony"). Cyclical data is used to establish rates for billing purposes.

Q. How was the tracker period usage presented in Exhibit__(CAH-1)_12-13 developed?

A. Table 1 of Exhibit__(CAH-1)_12-13 is actual billed usage for the period April 2011 through March 2012. The subsequent tables show a variety of changes that are made to arrive at July 2012 through June 2013 forecasted usage shown on Table 5. A brief description of Tables 1 through 3 in Exhibit__(CAH-1)_12-13 is as follows:

1. Table 1 is actual billed usage for 12 months ended March 2012.

2. Table 2 is the result of shifting data to calendar month, making known change adjustments and using forecast information. The Load Vision computer program shifts data to calendar month using

actual hourly metered data for the larger customers; individual meter read data for smaller GS-1 and Residential customers; monthly hours of darkness for lighting; and actual meter reads and historical load research shapes for irrigation.

3. Table 3 summarizes the changes made to Table 1 as described below:

- Column C shows the actual billed usage for the 12 months ended March 2012 as reflected on Table 1.
- Column D (with additional detail noted in Column J) shows changes in the operations of large customers. One change reflects two industrial customers returning to electric supply. There is also an additional 5,060 Megawatt hours ("MWh") representing increased load for two other industrial customers. Overall, the adjustment in Column D shows an increase of 10,207 MWh to electric supply usage and an increase of 24,290 MWh to choice usage.
- Column E replaces the actual Irrigation load with a six-year average resulting in an increase of 5,994 MWh.
- Column F shows changes to the Residential and General Service Secondary classes as a result of their forecasted usage for the 12 months ended June 2013. The changes reflect the effects of normal weather, customer growth, and demand-side management activities for these groups. The

total usage for each of these groups is based on regression models that predict annual usage for each group as a function of historical usage per customer, number of customers, heating degree days, and cooling degree days. The annual usage is shaped to calendar months using the average monthly shapes from prior test periods. The net impact of the forecast and calendar month adjustments as shown in Column F is a 105,812 MWh increase to electric supply usage and a 16,943 MWh decrease to choice usage.

- Column G is the resulting forecasted usage for the July 2012 through June 2013 time period.
- Column H reflects the sum of all changes (Columns D through F). The total result is a forecasted increase of 122,012 MWh to electric supply usage and a forecasted increase of 7,314 MWh to choice usage for a total increase of 129,326 MWh.

Q. Describe the additional adjustments made in Table 4 of Exhibit__(CAH-1)_12-13.

A. Table 2 is forecasted calendar month usage with the known change adjustments described above. Table 4 modifies Table 2 with two adjustments. First, the calendar usage data is shifted back to billed cyclical data. This cyclical adjustment is made to the Residential, GS-1

Secondary, GS-1 Primary, and Irrigation customer classes, as well as to Yellowstone National Park ("YNP"). The GS-2 customer class consists primarily of the large industrial customers, whose usage remains fairly constant throughout the year, and, therefore, a cyclical billing adjustment is unnecessary. Second, Lighting customers are billed a flat amount of kilowatt hours each month; therefore the total usage is spread evenly as one-twelfth in each month.

Q. Please describe Table 5 of Exhibit __ (CAH-1)_12-13.

A. Table 5 is a subset of Table 4 showing only those loads applicable to electric supply purchases. The total load information on Table 5 is used in the Bennett Direct Testimony and is shown on page 1 of Exhibit __ (FVB-2)12_13, page 2 of Exhibit__(FVB-5)12_13 and page 2 of Exhibit__(FVB-7)12_13.

It is necessary to make several adjustments to Table 4 in order to provide the appropriate loads for rate design purposes. These adjustments do not affect total load, but provide the detail required in the derivation of rates. The loads for the Residential class are allocated between Residential and Residential Employee using a ratio based on actual historical usage. The loads for the GS-1 Secondary and GS-1 Primary are allocated to Non Demand Metered and Demand Metered using a ratio based on actual historical usage. These changes are reflected on Table 5 of Exhibit__(CAH-1)_12-13 for use in the derivation of rates.

Q. Please explain how the YNP loads are treated in the derivation of rates process.

A. The loads for YNP are served by the utility and are included in the total delivered load shown in the tables discussed above. However, the costs for YNP are recovered through a separately negotiated contract rate; therefore, the loads and corresponding revenues are excluded from any rate design for MPSC jurisdictional rates. The loads for YNP are included only in the derivation of electricity supply rates. If the YNP rate were to include additional allocations related to Colstrip Unit 4 ("CU4") and the Dave Gates Generating Station ("DGGS"), the resulting revenue would be very small and not worth the administrative burden. Therefore, only the electricity supply rate derivation includes a revenue credit related to the YNP customer class.

<u>Derivation of Proposed Deferred Electricity Supply Rates</u>

Q. What is the electricity supply cost account balance for the 12-month period ending June 2012?

A. The electricity supply cost account balance for the 12-month period ending June 2012 is an under-collection of $11,496,428 as presented on page 1 of Exhibit__(CAH-2)_12-13. This includes the prior period balance for the

2010-2011 tracker period and the current period balance for the 2011-2012 tracker period as discussed below.

Q. Describe the status of the deferred electricity supply cost account balance associated with the 2010-2011 tracker period.

A. In the annual filing submitted on June 2, 2011, the net deferred account balance for the 2010-2011 tracker period was shown as an under-collection of $20,715,501. This amount becomes the starting balance in this filing. Added to this balance is the prior period true-up for the 2 months of estimated data included in the June 2, 2011 filing. Page 1 of Exhibit__(CAH-2)_12-13 shows the true-up of the estimated months of May and June 2011 with actual data. The resulting actual ending balance of $24,426,468 is the deferred account beginning balance for the 2011-2012 tracker period. This balance is then combined with the current year monthly activity shown on Exhibit__(CAH-2)_12-13, page 1, resulting in a net under-collected balance of $4,605,171 for the 2011-2012 tracker period.

Q. Describe the deferred electricity supply cost account balance associated with the 2011-2012 tracking period.

A. Page 2 of Exhibit__(CAH-2)_12-13 shows the monthly detail of the difference between the electricity supply cost revenues and expenses for the 2011-2012 tracker period, resulting in an under-collected amount of

$6,891,257. The months of May and June 2012 are estimated and will be trued-up in the next annual filing.

Q. What is the total deferred electricity supply cost account adjustment proposed for amortization in this filing?

A. The total deferred electricity supply cost account adjustment proposed in this filing is an under-collection of $11,496,428 shown below and on page 1, line 55 of Exhibit__(CAH-2)_12-13.

Total Electric Deferred Supply Cost Account Balance

2010-2011 Prior Period Supply Cost Account Balance	$4,605,171
2011-2012 Current Period Supply Cost Account Balance	$6,891,257
	$11,496,428

Derivation of the deferred electricity supply rates is shown on Exhibit__(CAH-2)_12-13, page 3 with the resulting rates and revenues shown in summarized format on page 4.

Derivation of Proposed Electricity Supply Rates

Q. Please describe the process used by NorthWestern to derive the proposed 2012-2013 electricity supply rates in this filing.

A. The rate design methodology used in this filing to derive the proposed 2012-2013 electricity supply rates is the same as that presented in previous electricity supply tracker filings. All forecasted costs are from Exhibit__(FVB-2)12_13 of the Bennett Direct Testimony and are discussed therein.

Derivation of the supply rates is shown on Exhibit__(CAH-2)_12-13, pages 5 and 6. The total proposed electricity supply cost of $229,953,209 from Exhibit__(FVB-2)12_13 (page 1, column O, line 50) is used as the starting point shown on page 5. This amount is then reduced for the supply revenues received from YNP. The forecasted loads from Exhibit__(CAH-1)_12-13 are adjusted for the employee discount and weighted by losses. A unit rate is calculated and then adjusted for losses by rate class to derive electricity supply base rates. These base rates are further adjusted on page 6, so that the percentage rate increase for each customer class is no greater than the Residential customer rate class increase. The resulting rates are the proposed electricity supply rates.

Page 7 of Exhibit__(CAH-2)_12-13 reflects the electricity supply rates and revenues in summarized format.

Proposed Total Deferred Supply Rates

Q. What is the net deferred supply cost account adjustment proposed for amortization in this filing?

A. The net deferred supply cost account adjustment proposed in this filing is an under-collection of $8,502,457. The adjustment consists of the following:

Net Deferred Supply Cost Account Balance

Total Deferred Electricity Supply Under-Collected Balance	$11,496,428
Total Deferred CU4 Variable Over-Collected Balance	$(2,993,971)
	$8,502,457

Because the total deferred DGGS Variable Cost Account Balance of $(161,231) is immaterial, NWE proposes to not request a deferred rate adjustment in this filing and carry forward the DGGS Variable Cost/Credit deferred account balance into the 2012-2013 true-up period. The computation of the DGGS balance is shown on Exhibit__(CAH-4)_12-13 page 1 that is addressed in, and included with, the Annual DGGS True-up section of my Testimony. The deferred electricity supply rate design as discussed above is shown on page 3 of Exhibit__(CAH-2)_12-13. The deferred CU4 variable rate design is shown on page 3 of Exhibit__(CAH-3)_12-13 that is addressed in, and included with, the Annual CU4 True-up section of my testimony. The individual rate components are then combined into a single deferred rate for use in billing the ratepayer. The total of net deferred supply rates is shown on page 1 of Exhibit__(CAH-5)_12-13. The total deferred supply revenue of $8,498,114 (including rounding) is shown on Exhibit__(CAH-5)_12-13, page 2, column N, line 40.

Proposed Total Supply Rates

Q. Please describe the process used by NorthWestern to derive the total proposed 2012-2013 electric supply rates in this filing.

A. The current total electric supply rate includes several separate rate components – an electricity supply tracker rate, a CU4 fixed cost of service rate, a CU4 variable rate, a DGGS fixed cost of service rate, a DGGS fixed cost of service rebate rate, and a DGGS variable rate. See page 7 of Exhibit__(CAH-2)_12-13 for proposed electricity supply rates; page 6 of Exhibit__(CAH-3)_12-13 for proposed CU4 fixed and variable rates; and page 4 of Exhibit__(CAH-4)_12-13 for proposed DGGS fixed and variable rates. Note that both the CU4 fixed and DGGS fixed rates remain unchanged from current rates. This is discussed in my Prefiled Direct Testimonies addressing CU4 and DGGS.

Q. Have you provided a summary of the unit rate adjustments and resulting rates proposed in this filing?

A. Yes. All of the separate rate components are bundled together into a single total supply rate for customer billing as shown on Exhibit__(CAH-5)_12-13, page 3. All rate components and resulting revenues are shown in summarized format on Exhibit__(CAH-5)_12-13, pages 4 and 5 and listed below:

Net Supply Revenue

Total Supply Revenue at Current Rates	$349,685,603
Electricity Supply Revenue at Proposed Rates	228,850,106
CU4 Fixed Revenue at Current Rates	75,408,426
CU4 Variable Revenue at Proposed Rates	24,925,255
DGGS Fixed Revenue at Current Rates	28,395,511
DGGS Fixed Rebate Revenue at Current Rates	(7,076,400)
DGGS Variable Revenue at Proposed Rates	7,503,384
Total Supply Revenue at Proposed Rates	$358,006,282
Net Proposed Total Supply Revenue Change	$8,320,679

Q. What is NWE's proposal for rate implementation?

A. NWE proposes an interim rate effective date for its proposed rate adjustments and implementation of monthly electric supply adjustments for service on and after July 1, 2012.

Q. Does this conclude your Annual Electricity Supply Tracker testimony?

A. Yes, it does.

TABLE 1 - Actual billed data

NorthWestern Energy Revenue Month Sales (MWh)

Class	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Total
Residential Non-Choice	202,646	176,219	162,307	172,331	188,775	186,373	158,828	177,187	225,517	246,939	228,813	212,626	2,338,561
Residential Choice	10	9	8	10	14	12	9	9	10	12	10	10	123
Total Residential	**202,656**	**176,228**	**162,315**	**172,341**	**188,789**	**186,385**	**158,837**	**177,196**	**225,527**	**246,951**	**228,823**	**212,636**	**2,338,684**
GS Secondary Non-Choice	219,877	203,630	206,845	222,699	236,060	242,190	214,265	205,039	226,654	235,459	229,006	218,728	2,660,454
GS Secondary Choice	6,575	6,162	6,600	6,984	7,737	7,701	7,154	6,441	6,591	6,947	6,972	6,663	82,525
GS Primary Non-Choice	28,637	25,614	24,995	25,412	29,432	29,983	28,206	30,176	31,107	31,310	31,164	27,714	343,751
GS Primary Choice	7,163	6,559	6,725	6,811	6,051	5,557	5,387	5,873	5,550	6,202	6,102	5,749	73,728
Total General Service - 1	**262,252**	**241,966**	**245,164**	**261,906**	**279,280**	**285,431**	**255,012**	**247,529**	**269,901**	**279,918**	**273,244**	**258,855**	**3,160,458**
GS Substation Non-Choice	18,073	16,642	16,231	15,974	17,888	16,442	21,739	19,100	17,755	18,401	19,259	18,090	215,592
GS Substation Choice	136,482	125,607	136,537	134,501	138,024	134,650	125,186	136,301	134,150	135,221	138,837	131,472	1,606,967
GS Transmission Non-Choice	11,749	10,926	12,151	11,336	12,224	9,840	10,030	10,903	10,738	10,450	12,114	9,597	132,057
GS Transmission Choice	7,115	7,654	8,096	7,381	9,097	10,911	10,419	9,068	10,368	10,500	9,886	10,068	110,562
Total General Service - 2	**173,418**	**160,828**	**173,014**	**169,192**	**177,233**	**171,842**	**167,373**	**175,372**	**173,010**	**174,572**	**180,096**	**169,227**	**2,065,178**
Irrigation Non-Choice	28	1,061	5,989	13,421	27,221	19,834	9,471	535	-85	7	14	0	77,496
Irrigation Choice	0	14	11	17	68	39	21	11	0	0	0	0	182
Total Irrigation	**28**	**1,075**	**6,000**	**13,438**	**27,289**	**19,873**	**9,492**	**546**	**-85**	**7**	**14**	**0**	**77,678**
Lighting Non-Choice	4,799	4,768	4,769	4,749	4,758	4,772	4,773	4,819	4,840	4,855	4,836	4,808	57,546
Lighting Choice	365	365	365	370	364	365	362	365	365	266	365	453	4,372
Total Lighting	**5,165**	**5,133**	**5,134**	**5,119**	**5,122**	**5,137**	**5,135**	**5,184**	**5,205**	**5,121**	**5,201**	**5,261**	**61,918**
Yellowstone Contract	712	968	2,753	3,136	2,087	2,226	2,433	1,312	714	498	599	794	18,234
Total Yellowstone	**712**	**968**	**2,753**	**3,136**	**2,087**	**2,226**	**2,433**	**1,312**	**714**	**498**	**599**	**794**	**18,234**
REC Silicon	67,937	64,232	62,737	64,138	67,183	0	132,433	69,617	66,958	72,110	70,831	66,188	804,364
Special Contract	**67,937**	**64,232**	**62,737**	**64,138**	**67,183**	**0**	**132,433**	**69,617**	**66,958**	**72,110**	**70,831**	**66,188**	**804,364**
Total Distribution	**712,168**	**650,430**	**657,117**	**689,270**	**746,983**	**670,895**	**730,715**	**676,755**	**741,231**	**779,178**	**758,809**	**712,961**	**8,526,513**
Total Electric Supply Usage	486,522	439,828	436,038	469,057	518,445	511,661	449,744	449,070	517,240	547,920	525,806	492,358	5,843,689
Total Choice Usage	225,646	210,602	221,078	220,213	228,539	159,234	280,971	227,685	223,991	231,258	233,004	220,603	2,682,823
	712,168	**650,430**	**657,117**	**689,270**	**746,983**	**670,895**	**730,715**	**676,755**	**741,231**	**779,178**	**758,809**	**712,961**	**8,526,513**

TABLE 2 - Table 1 normalized

NorthWestern Energy Calendar Month Sales (MWh) - With Forecast and Known Change Adjustments

Class	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Total
Residential Non-Choice	195,103	184,158	161,171	183,772	210,642	255,032	251,405	214,835	203,880	176,456	167,250	163,589	2,367,291
Residential Choice	10	9	8	9	11	13	13	11	10	9	9	8	120
Total Residential	**195,113**	**184,167**	**161,179**	**183,782**	**210,653**	**255,045**	**251,417**	**214,846**	**203,890**	**176,465**	**167,258**	**163,597**	**2,367,411**
GS Secondary Non-Choice	251,155	246,411	217,093	218,617	217,320	236,897	238,633	213,425	225,835	210,007	214,885	220,953	2,711,231
GS Secondary Choice	7,775	7,628	6,720	6,767	6,727	7,333	7,387	6,607	6,991	6,501	6,652	6,840	83,927
GS Primary Non-Choice	28,879	30,189	27,657	30,225	31,253	32,392	32,279	30,298	29,828	27,024	25,733	25,349	351,104
GS Primary Choice	6,084	5,578	5,345	5,825	5,610	6,260	6,008	5,821	7,205	6,531	6,756	6,803	73,825
Total General Service - 1	**293,892**	**289,806**	**256,815**	**261,435**	**260,910**	**282,882**	**284,306**	**256,150**	**269,858**	**250,062**	**254,026**	**259,944**	**3,220,087**
GS Substation Non-Choice	19,286	21,098	21,109	21,287	20,092	21,288	21,321	20,773	20,887	19,393	19,661	17,810	244,006
GS Substation Choice	139,002	135,594	125,990	136,853	133,999	134,662	138,487	131,099	138,119	126,937	136,443	135,539	1,612,726
GS Transmission Non-Choice	11,858	10,712	9,937	10,622	10,346	10,511	11,925	9,973	12,190	10,905	12,370	10,950	132,300
GS Transmission Choice	9,154	10,918	10,419	9,068	10,367	10,500	9,886	10,068	7,115	7,654	8,096	7,381	110,626
Total General Service - 2	**179,299**	**178,322**	**167,455**	**177,831**	**174,805**	**176,961**	**181,619**	**171,914**	**178,312**	**164,889**	**176,570**	**171,680**	**2,099,658**
Irrigation Non-Choice	27,056	25,653	11,923	2,404	39	11	11	2	67	272	4,013	12,038	83,490
Irrigation Choice	48	46	21	4	0	0	0	0	0	1	7	22	149
Total Irrigation	**27,104**	**25,699**	**11,944**	**2,409**	**39**	**11**	**11**	**2**	**67**	**273**	**4,020**	**12,060**	**83,640**
Lighting Non-Choice	3,553	4,068	4,470	5,753	5,921	6,408	6,427	5,085	5,066	4,149	3,781	3,140	57,821
Lighting Choice	276	304	346	443	454	476	487	389	380	316	292	239	4,401
Total Lighting	**3,829**	**4,372**	**4,816**	**6,196**	**6,375**	**6,883**	**6,914**	**5,474**	**5,446**	**4,465**	**4,073**	**3,379**	**62,222**
Yellowstone Contract	2,401	2,409	2,344	1,194	714	823	955	848	795	986	2,402	2,588	18,457
Total Yellowstone	**2,401**	**2,409**	**2,344**	**1,194**	**714**	**823**	**955**	**848**	**795**	**986**	**2,402**	**2,588**	**18,457**
REC Silicon	67,183	68,025	64,408	69,617	66,957	72,110	70,831	66,188	67,937	64,232	62,737	64,138	804,364
Special Contract	**67,183**	**68,025**	**64,408**	**69,617**	**66,957**	**72,110**	**70,831**	**66,188**	**67,937**	**64,232**	**62,737**	**64,138**	**804,364**
Total Distribution	**768,821**	**752,800**	**668,960**	**702,463**	**720,453**	**794,716**	**796,055**	**715,422**	**726,305**	**661,372**	**671,086**	**677,387**	**8,655,839**
Total Electric Supply Usage	539,289	524,698	455,703	473,875	496,327	563,362	562,956	495,239	498,548	449,192	450,095	456,417	5,965,702
Total Choice Usage	229,532	228,102	213,257	228,588	224,126	231,354	233,099	220,183	227,757	212,180	220,992	220,969	2,690,138
	768,821	**752,800**	**668,960**	**702,463**	**720,453**	**794,716**	**796,055**	**715,422**	**726,305**	**661,372**	**671,086**	**677,387**	**8,655,839**

TABLE 3 - Comparison of Tables 1 & 2

NorthWestern Energy Sales (MWh)

Class	Table 1	Large Cust Known Changes	Irrigation Normalization	Res/GS-1 Forecasts & Shift to Calendar Mth	Table 2	Diff MWH	% Diff	Changes
Residential Non-Choice	2,338,561			28,731	2,367,291	28,731	1.23%	Replaced actual with forecast 12MEJun13.
Residential Choice	123			-3	120	-3	-2.50%	
Total Residential	**2,338,684**	**0**	**0**	**28,728**	**2,367,411**	**28,728**	**1.23%**	
GS Secondary Non-Choice	2,660,454			50,777	2,711,231	50,777	1.91%	Replaced actual with forecast 12MEJun13.
GS Secondary Choice	82,525			1,402	83,927	1,402	1.70%	
GS Primary Non-Choice	343,751			7,354	351,104	7,354	2.14%	Shift to calendar(7354 Mwh)
GS Primary Choice	73,728			96	73,825	96	0.13%	Shift to Calendar
Total General Service - 1	**3,160,458**	**0**	**0**	**59,629**	**3,220,087**	**59,629**	**1.89%**	
GS Substation Non-Choice	215,592	10,207		18,207	244,006	28,414	13.18%	Two customers returned to supply (5,147), increased load (5,060) & shift to calendar/acct adj (18,207).
GS Substation Choice	1,606,967	24,290		-18,531	1,612,726	5,759	0.36%	Two customers moved from choice to supply (-7,322), increased loads (14,092 + 17,520) & acct adj (-18,531).
GS Transmission Non-Choice	132,057			243	132,300	243	0.18%	Shift to Calendar Month
GS Transmission Choice	110,562			64	110,626	64	0.06%	
Total General Service - 2	**2,065,178**	**34,497**	**0**	**-17**	**2,099,658**	**34,480**	**1.67%**	
Irrigation Non-Choice	77,496		5,994		83,490	5,994	7.74%	Replaced actuals with 6 year average
Irrigation Choice	182				149	-32	-17.85%	
Total Irrigation	**77,678**	**0**	**5,994**	**0**	**83,640**	**5,962**	**7.68%**	
Lighting Non-Choice	57,546			276	57,821	276	0.48%	Shift to calendar month.
Lighting Choice	4,372			29	4,401	29	0.66%	
Total Lighting	**61,918**	**0**	**0**	**305**	**62,222**	**304**	**0.49%**	
Yellowstone Contract	18,234			224	18,457	224	1.23%	
Total Yellowstone	**18,234**	**0**	**0**	**224**	**18,457**	**224**	**1.23%**	
REC Silicon	804,364				804,364	-1	0.00%	
Special Contract	**804,364**	**0**	**0**	**0**	**804,364**	**-1**	**0.00%**	
Total Distribution	**8,526,513**	**34,497**	**5,994**	**88,869**	**8,655,839**	**129,326**	**1.52%**	
Total Electric Supply Usage	5,843,689	10,207	5,994	105,812	5,965,702	122,012		
Total Choice Usage	2,682,823	24,290	0	-16,943	2,690,138	7,314		
	8,526,513	34,497	5,994	88,869	8,655,839	129,326		
	-	-	-	-	-	-		

TABLE 4: Table 2 w/cyclical adj

NorthWestern Energy Revenue Month Sales (MWh)

Class	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Total
Residential Non-Choice	179,346	189,630	172,664	172,472	197,207	232,837	253,218	233,120	209,358	190,168	171,853	165,419	2,367,291
Residential Choice	9	10	9	9	10	12	13	12	11	10	9	8	120
Total Residential	**179,355**	**189,640**	**172,673**	**172,480**	**197,217**	**232,849**	**253,231**	**233,132**	**209,368**	**190,178**	**171,861**	**165,428**	**2,367,411**
GS Secondary Non-Choice	236,054	248,783	231,752	217,855	217,969	227,109	237,765	226,029	219,630	217,921	212,446	217,919	2,711,231
GS Secondary Choice	7,307	7,701	7,174	6,744	6,747	7,030	7,360	6,997	6,799	6,746	6,576	6,746	83,927
GS Primary Non-Choice	27,114	29,534	28,923	28,941	30,739	31,822	32,335	31,288	30,063	28,426	26,379	25,541	351,104
GS Primary Choice	6,443	5,831	5,461	5,585	5,718	5,935	6,134	5,914	6,513	6,868	6,643	6,779	73,825
Total General Service - 1	**276,918**	**291,849**	**273,310**	**259,125**	**261,173**	**271,896**	**283,594**	**270,228**	**263,004**	**259,960**	**252,044**	**256,985**	**3,220,087**
GS Substation Non-Choice	19,286	21,098	21,109	21,287	20,092	21,288	21,321	20,773	20,887	19,393	19,661	17,810	244,006
GS Substation Choice	139,002	135,594	125,990	136,853	133,999	134,662	138,487	131,099	138,119	126,937	136,443	135,539	1,612,726
GS Transmission Non-Choice	11,858	10,712	9,937	10,622	10,346	10,511	11,925	9,973	12,190	10,905	12,370	10,950	132,300
GS Transmission Choice	9,154	10,918	10,419	9,068	10,367	10,500	9,886	10,068	7,115	7,654	8,096	7,381	110,626
Total General Service - 2	**179,299**	**178,322**	**167,455**	**177,831**	**174,805**	**176,961**	**181,619**	**171,914**	**178,312**	**164,889**	**176,570**	**171,680**	**2,099,658**
Irrigation Non-Choice	19,547	26,354	18,788	7,164	1,222	25	11	7	34	169	2,143	8,026	83,490
Irrigation Choice	35	47	34	13	2	0	0	0	0	0	4	14	149
Total Irrigation	**19,582**	**26,402**	**18,822**	**7,176**	**1,224**	**25**	**11**	**7**	**34**	**170**	**2,147**	**8,040**	**83,640**
Lighting Non-Choice	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	57,821
Lighting Choice	367	367	367	367	367	367	367	367	367	367	367	367	4,401
Total Lighting	**5,185**	**5,185**	**5,185**	**5,185**	**5,185**	**5,185**	**5,185**	**5,185**	**5,185**	**5,185**	**5,185**	**5,185**	**62,222**
Yellowstone Contract	2,494	2,405	2,376	1,769	954	768	889	901	821	890	1,694	2,495	18,457
Total Yellowstone	**2,494**	**2,405**	**2,376**	**1,769**	**954**	**768**	**889**	**901**	**821**	**890**	**1,694**	**2,495**	**18,457**
REC Silicon	67,183	68,025	64,408	69,617	66,957	72,110	70,831	66,188	67,937	64,232	62,737	64,138	804,364
Special Contract	**67,183**	**68,025**	**64,408**	**69,617**	**66,957**	**72,110**	**70,831**	**66,188**	**67,937**	**64,232**	**62,737**	**64,138**	**804,364**
Total Distribution	**730,017**	**761,828**	**704,229**	**693,183**	**707,515**	**759,795**	**795,361**	**747,555**	**724,662**	**685,505**	**672,238**	**673,951**	**8,655,839**
													-
Total Electric Supply Usage	500,517	533,335	490,368	464,928	483,347	529,179	562,283	526,910	497,802	472,691	451,363	452,979	5,965,702
Total Choice Usage	229,500	228,493	213,861	228,256	224,168	230,616	233,078	220,645	226,860	212,813	220,875	220,973	2,690,138
	730,017	**761,828**	**704,229**	**693,183**	**707,515**	**759,795**	**795,361**	**747,555**	**724,662**	**685,505**	**672,238**	**673,951**	**8,655,839**

TABLE 5 - Table 4 modified for rate design

NorthWestern Energy Revenue Month Sales (MWh) - Electric Supply Rate Design Load

Class	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Total
Residential Non-Choice	179,050	189,318	172,380	172,187	196,882	232,454	252,801	232,736	209,013	189,855	171,570	165,147	2,363,392
Residential Employee	295	312	284	284	325	383	417	384	345	313	283	272	3,899
Total Residential	**179,346**	**189,630**	**172,664**	**172,472**	**197,207**	**232,837**	**253,218**	**233,120**	**209,358**	**190,168**	**171,853**	**165,419**	**2,367,291**
	-	-	-	-	-	-	-	-	-	-	-	-	-
GS Secondary Non-Demand	21,275	22,216	20,659	19,275	21,206	25,284	27,633	25,950	24,919	22,372	21,609	20,394	272,791
GS Secondary Demand	214,779	226,568	211,093	198,580	196,763	201,824	210,132	200,079	194,711	195,549	190,837	197,525	2,438,440
Total GS-1 Secondary	**236,054**	**248,783**	**231,752**	**217,855**	**217,969**	**227,109**	**237,765**	**226,029**	**219,630**	**217,921**	**212,446**	**217,919**	**2,711,231**
	-	-	-	-	-	-	-	-	-	-	-	-	-
GS Primary Non-Demand	95	75	64	55	56	38	19	24	21	24	31	49	552
GS Primary Demand	27,018	29,458	28,859	28,886	30,683	31,784	32,316	31,265	30,042	28,402	26,347	25,492	350,553
Total GS-1 Primary	**27,114**	**29,534**	**28,923**	**28,941**	**30,739**	**31,822**	**32,335**	**31,288**	**30,063**	**28,426**	**26,379**	**25,541**	**351,104**
	-	-	-	-	-	-	-	-	-	-	-	-	-
Total GS-2 Substation	**19,286**	**21,098**	**21,109**	**21,287**	**20,092**	**21,288**	**21,321**	**20,773**	**20,887**	**19,393**	**19,661**	**17,810**	**244,006**
Total GS-2 Transmission	**11,858**	**10,712**	**9,937**	**10,622**	**10,346**	**10,511**	**11,925**	**9,973**	**12,190**	**10,905**	**12,370**	**10,950**	**132,300**
Total Irrigation	**19,547**	**26,354**	**18,788**	**7,164**	**1,222**	**25**	**11**	**7**	**34**	**169**	**2,143**	**8,026**	**83,490**
Total Lighting	**4,818**	**4,818**	**4,818**	**4,818**	**4,818**	**4,818**	**4,818**	**4,818**	**4,818**	**4,818**	**4,818**	**4,818**	**57,821**
MPSC Electric Supply Load	**498,023**	**530,930**	**487,991**	**463,159**	**482,393**	**528,410**	**561,395**	**526,009**	**496,981**	**471,801**	**449,669**	**450,484**	**5,947,244**
Yellowstone Park Load	**2,494**	**2,405**	**2,376**	**1,769**	**954**	**768**	**889**	**901**	**821**	**890**	**1,694**	**2,495**	**18,457**
Total Electric Supply Load	**500,517**	**533,335**	**490,368**	**464,928**	**483,347**	**529,179**	**562,283**	**526,910**	**497,802**	**472,691**	**451,363**	**452,979**	**5,965,702**
													-

Exhibit__(CAH-2)_12-13
Docket No. D2012.5.49

NorthWestern Energy
Electric Utility
Deferred Electricity Supply Cost Account Balance
July 2011 - June 2012

Month	Monthly Collection	Collection to-date	Balance Remaining
Jul10-Jun11 under-collected balance as filed in D2011.5.38			**$ 20,715,501**
Prior Period Tracker Year True-up - Deferred:			
May11: Estimated as filed in D2011.5.38		$ -	
May11: Actual		$ (5)	$ (5)
Jun11: Estimated as filed in D2011.5.38		$ -	
Jun11: Actual		$ (8)	$ (8)
Prior Period Tracker Year True-up - Supply:			
May11: Est as filed in D2011.5.38 - Revenue	$ 17,279,791		
May11: Est as filed in D2011.5.38 - Expense	$ 17,117,642	$ (162,149)	
May11: Actual - Revenue	$ 16,905,850		
May11: Actual - Expense	$ 17,744,345	$ 838,496	$ 1,000,645
Jun11: Est as filed in D2011.5.38 - Revenue	$ 18,802,045		
Jun11: Est as filed in D2011.5.38 - Expense	$ 16,691,515	$ (2,110,530)	
Jun11: Actual - Revenue	$ 16,423,607		
Jun11: Actual - Expense	$ 17,023,412	$ 599,805	$ 2,710,335
Actual Jul10-Jun11 under-collected balance [1]			**$ 24,426,468**
			-
Deferred Jul11-Jun12 Monthly Activity [2]:			
July 2011	$ 760,815	$ 760,815	$ 23,665,653
August 2011	$ 1,819,542	$ 2,580,357	$ 21,846,110
September 2011	$ 1,792,407	$ 4,372,764	$ 20,053,704
October 2011	$ 1,572,601	$ 5,945,365	$ 18,481,103
November 2011	$ 1,574,093	$ 7,519,458	$ 16,907,010
December 2011	$ 1,816,961	$ 9,336,419	$ 15,090,049
January 2012	$ 1,925,978	$ 11,262,397	$ 13,164,071
February 2012	$ 1,847,249	$ 13,109,646	$ 11,316,822
March 2012	$ 1,729,307	$ 14,838,953	$ 9,587,514
April 2012	$ 1,628,209	$ 16,467,163	$ 7,959,305
May 2012 - Estimated	$ 1,598,737	$ 18,065,899	$ 6,360,568
June 2012 - Estimated	$ 1,755,397	$ 19,821,296	$ 4,605,171
Prior Period Electricity Supply Cost Ending Balance			**$ 4,605,171**
Current Period Electricity Supply Cost Ending Balance (see page 2)			**$ 6,891,257**
Total Electricity Supply Cost Balance Jul11-Jun12 [3]			**$ 11,496,428**
			-

[1] Source: Exhibit_(FVB-1)11-12, page 2, line 10.
[2] Source: Exhibit_(FVB-1)11-12, page 1, line 52.
[3] Source: Exhibit_(FVB-1)11-12, page 2, line 15.

NorthWestern Energy
Electric Utility
Electricity Supply Cost Account Balance
July 2011 - June 2012

Month		Supply Cost Revenues		Supply Cost Expense		Supply Cost Balance
July 2011	$	17,509,864	$	19,661,822	$	2,151,957
August 2011	$	19,417,399	$	20,030,822	$	613,424
September 2011	$	19,245,116	$	16,693,280	$	(2,551,835)
October 2011	$	16,847,406	$	16,530,699	$	(316,707)
November 2011	$	16,688,677	$	20,299,158	$	3,610,481
December 2011	$	19,122,053	$	20,418,014	$	1,295,961
January 2012	$	20,331,251	$	20,646,217	$	314,966
February 2012	$	19,590,619	$	17,886,281	$	(1,704,338)
March 2012	$	18,285,522	$	17,829,024	$	(456,498)
April 2012	$	17,070,723	$	18,543,315	$	1,472,592
May 2012 - Estimated	$	16,798,979	$	20,617,849	$	3,818,871
June 2012 - Estimated	$	18,535,496	$	17,177,881	$	(1,357,615)
Supply Cost Balance Jul11-Jun12	**$**	**219,443,106**	**$**	**226,334,363**	**$**	**6,891,257**
		-		-		-

Source:
Revenues: Exhibit_(FVB-1)11-12, page 1, line 17.
Expense: Exhibit_(FVB-1)11-12, page 1, line 48.

NorthWestern Energy
Electric Utility Derivation of Rates
Deferred Electricity Supply
July 2012 - June 2013

Customer Rate Class	Loss Factor	Jul12 - Jun13 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Deferred Supply Cost Rate After Losses	Deferred Supply Cost Revenue Check
Residential	8.5100%	2,363,392,484	2,363,392,484	2,564,517,184	$ 0.001941	$ 4,587,345
Residential Employee	8.5100%	3,898,778	2,339,267	2,538,338	$ 0.001165	$ 4,542
GS 1 Secondary NonDemand	8.5100%	272,790,804	272,790,804	296,005,301	$ 0.001941	$ 529,487
GS 1 Secondary Demand	8.5100%	2,438,440,251	2,438,440,251	2,645,951,516	$ 0.001941	$ 4,733,013
GS 1 Primary NonDemand	5.5400%	551,733	551,733	582,300	$ 0.001888	$ 1,042
GS 1 Primary Demand	5.5400%	350,552,671	350,552,671	369,973,289	$ 0.001888	$ 661,843
General Service Substation	4.6300%	244,005,756	244,005,756	255,303,222	$ 0.001872	$ 456,779
General Service Transmission	4.0000%	132,300,021	132,300,021	137,592,022	$ 0.001861	$ 246,210
Irrigation	8.5100%	83,490,261	83,490,261	90,595,283	$ 0.001941	$ 162,055
Lighting	8.5100%	57,821,458	57,821,458	62,742,064	$ 0.001941	$ 112,231
		5,947,244,217	5,945,684,706	6,425,800,519	$ 0.001933	$ 11,494,547
YNP Contract		18,457,300			Rounding Adjustment	$ 1,882
Total Electric Supply Load		5,965,701,517				$ 11,496,428
		-				

2011-12 Deferred Electricity Supply Cost Under Collection	$	11,496,428
Total Deferred Electricity Supply Rate Before Losses	**$**	**0.001789**
Total Deferred Electricity Supply Rate After Losses	**$**	**0.001933**

NorthWestern Energy
Electric Utility
Deferred Electricty Supply Revenue ($000) Summary
July 2012 - June 2013

	Jul12 - Jun13 Supply Retail kWh Sales	Current Deferred Supply Rates 7/1/2011	Current Deferred Supply Revenue	Proposed Deferred Supply Rates 7/1/2012	Proposed Deferred Supply Revenue	Revenue Diff Proposed vs Current
Residential						
Residential	2,363,392	$ 0.003532	$ 8,348	$ 0.001941	$ 4,587	$ (3,760)
Residential Employee	3,899	$ 0.002119	$ 8	$ 0.001165	$ 5	$ (4)
Total Residential			$ 8,356		$ 4,592	$ (3,764)
General Service 1						
GS-1 Sec Non-Demand	272,791	$ 0.003532	$ 963	$ 0.001941	$ 529	$ (434)
GS-1 Sec Demand	2,438,440	$ 0.003532	$ 8,613	$ 0.001941	$ 4,733	$ (3,880)
GS-1 Pri Non-Demand	552	$ 0.003435	$ 2	$ 0.001888	$ 1	$ (1)
GS-1 Pri Demand	350,553	$ 0.003435	$ 1,204	$ 0.001888	$ 662	$ (542)
Total GS-1			$ 10,782		$ 5,925	$ (4,857)
General Service 2						
GS-2 Substation	244,006	$ 0.003406	$ 831	$ 0.001872	$ 457	$ (374)
GS-2 Transmission	132,300	$ 0.003385	$ 448	$ 0.001861	$ 246	$ (202)
Total GS-2			$ 1,279		$ 703	$ (576)
Irrigation						
Irrigation	83,490	$ 0.003532	$ 295	$ 0.001941	$ 162	$ (133)
Total Irrigation			$ 295		$ 162	$ (133)
Lighting						
Lighting	57,821	$ 0.003532	$ 204	$ 0.001941	$ 112	$ (92)
Total Lighting			$ 204		$ 112	$ (92)
Total Rate Schedule	**5,947,244**		**$ 20,916**		**$ 11,495**	**$ (9,421.361)**
	-					

Northwestern Energy
Electric Utility Derivation of Rates
Electricity Supply Excluding Generation Assets - Prior to Cap Adjustment
July 2012 - June 2013

Customer Rate Class	Loss Factor	Jul12 - Jun13 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Electricity Supply Rate After Losses	Electricity Supply Revenue Check
Residential	8.5100%	2,363,392,484	2,363,392,484	2,564,517,184	$ 0.038645	$ 91,333,303
Residential Employee	8.5100%	3,898,778	2,339,267	2,538,338	$ 0.023187	$ 90,401
GS 1 Secondary NonDemand	8.5100%	272,790,804	272,790,804	296,005,301	$ 0.038645	$ 10,542,001
GS 1 Secondary Demand	8.5100%	2,438,440,251	2,438,440,251	2,645,951,516	$ 0.038645	$ 94,233,523
GS 1 Primary NonDemand	5.5400%	551,733	551,733	582,300	$ 0.037587	$ 20,738
GS 1 Primary Demand	5.5400%	350,552,671	350,552,671	369,973,289	$ 0.037587	$ 13,176,223
General Service Substation	4.6300%	244,005,756	244,005,756	255,303,222	$ 0.037263	$ 9,092,386
General Service Transmission	4.0000%	132,300,021	132,300,021	137,592,022	$ 0.037039	$ 4,900,260
Irrigation	8.5100%	83,490,261	83,490,261	90,595,283	$ 0.038645	$ 3,226,481
Lighting	8.5100%	57,821,458	57,821,458	62,742,064	$ 0.038645	$ 2,234,510
		5,947,244,217	5,945,684,706	6,425,800,519	$ 0.038490	$ 228,849,827
YNP Contract		18,457,300			Rounding Adjustment	$ (4,056)
Total Electricity Supply Load		5,965,701,517				$ 228,845,771
		-				

Electricity Supply Excluding Generation Assets Costs	$ 229,953,209
less: YNP Contract Revenues	$ (1,107,438)
Electricity Supply Excluding Generation Assets Rate Design Revenues	$ 228,845,771
Electricity Supply Cost Rate Before Losses	**$ 0.035614**
Electricity Supply Cost Rate After Losses	**$ 0.038480**

YNP Contract Load	18,457,300
YNP May12-Apr13 Contract Supply Rate	0.060000
YNP Supply Revenue	$ 1,107,438

NorthWestern Energy
Electric Utility Derivation of Rates
Electricity Supply Excluding Generation Assets Capped at Residential Increase
Revenues ($000)
July 2012 - June 2013

CAPPED RATES	Jul12 - Jun13 Energy (mWh)	Current Revenue	Proposed Rates	Proposed Revenue	$ Change	% Change	$ at Res Cap 3.34%	Capped $ Change	Capped % Change	Capped kWh Rates
Residential										
Residential	2,363,392	$ 88,381	$ 0.038645	$ 91,333	$ 2,952	3.34%	$ 91,333	$ 92,413	4.56%	$ 0.039102
Res Employee	3,899	$ 87	$ 0.023187	$ 90	$ 3	3.34%	$ 90	$ 91	4.56%	$ 0.023462
Total Residential	2,367,291	$ 88,469		$ 91,424	$ 2,955	3.34%	$ 91,424	$ 92,505	4.56%	
General Service 1										
GS1 Sec NonDmd	272,791	$ 9,229	$ 0.038645	$ 10,542	$ 1,313	14.23%	$ 9,537	$ 9,650	4.56%	$ 0.035374
GS1 Sec Dmd	2,438,440	$ 91,185	$ 0.038645	$ 94,234	$ 3,048	3.34%	$ 94,231	$ 95,345	4.56%	$ 0.039101
GS1 Prim NonDmd	552	$ 20	$ 0.037587	$ 21	$ 1	3.35%	$ 21	$ 21	4.56%	$ 0.038027
GS1 Prim Dmd	350,553	$ 11,642	$ 0.037587	$ 13,176	$ 1,534	13.18%	$ 12,031	$ 12,173	4.56%	$ 0.034726
Total GS-1	3,062,335	$ 112,077		$ 117,972	$ 5,896	5.26%	$ 115,820	$ 117,189	4.56%	
General Service 2										
GS2 Substation	244,006	$ 8,798	$ 0.037263	$ 9,092	$ 295	3.35%	$ 9,092	$ 9,199	4.56%	$ 0.037701
GS2 Transmission	132,300	$ 4,742	$ 0.037039	$ 4,900	$ 159	3.35%	$ 4,900	$ 4,958	4.56%	$ 0.037474
Total GS-2	376,306	$ 13,539		$ 13,993	$ 453	3.35%	$ 13,992	$ 14,157	4.56%	
Irrigation										
Irrigation	83,490	$ 2,825	$ 0.038645	$ 3,226	$ 402	14.23%	$ 2,919	$ 2,953	4.56%	$ 0.035374
Total Irrigation	83,490	$ 2,825		$ 3,226	$ 402	14.23%	$ 2,919	$ 2,953	4.56%	
Lighting										
Lighting	57,821	$ 1,956	$ 0.038645	$ 2,235	$ 278	14.23%	$ 2,021	$ 2,045	4.56%	$ 0.035374
Total Lighting	57,821	$ 1,956		$ 2,235	$ 278	14.23%	$ 2,021	$ 2,045	4.56%	
Total Rate Schedule	5,947,244	$ 218,866		$ 228,850	$ 9,984	4.56%	$ 226,175	$ 228,850		
	-									
Capped Rate Adjustment Factor							0.011824			

NorthWestern Energy
Electric Utility
Electricity Supply Excluding Generation Assets Revenue ($000) Summary
July 2012 - June 2013

	Jul12 - Jun13 Supply Retail kWh Sales	Current Rates 6/1/2012 [1]	Current Supply Revenue	Proposed Rates 7/1/2012	Proposed Supply Revenue	Revenue Diff Proposed vs Current
Residential						
Residential	2,363,392	$ 0.037396	$ 88,381	$ 0.039102	$ 92,413	$ 4,032
Residential Employee	3,899	$ 0.022438	$ 87	$ 0.023462	$ 91	$ 4
Total Residential			$ 88,469		$ 92,505	$ 4,036
General Service 1						
GS-1 Sec Non-Demand	272,791	$ 0.033831	$ 9,229	$ 0.035374	$ 9,650	$ 421
GS-1 Sec Demand	2,438,440	$ 0.037395	$ 91,185	$ 0.039101	$ 95,345	$ 4,160
GS-1 Pri Non-Demand	552	$ 0.036368	$ 20	$ 0.038027	$ 21	$ 1
GS-1 Pri Demand	350,553	$ 0.033211	$ 11,642	$ 0.034726	$ 12,173	$ 531
Total GS-1			$ 112,077		$ 117,189	$ 5,113
General Service 2						
GS-2 Substation	244,006	$ 0.036056	$ 8,798	$ 0.037701	$ 9,199	$ 401
GS-2 Transmission	132,300	$ 0.035839	$ 4,742	$ 0.037474	$ 4,958	$ 216
Total GS-2			$ 13,539		$ 14,157	$ 618
Irrigation						
Irrigation	83,490	$ 0.033831	$ 2,825	$ 0.035374	$ 2,953	$ 129
Total Irrigation			$ 2,825		$ 2,953	$ 129
Lighting						
Lighting	57,821	$ 0.033831	$ 1,956	$ 0.035374	$ 2,045	$ 89
Total Lighting			$ 1,956		$ 2,045	$ 89
Total Rate Schedule	**5,947,244**		**$ 218,866**		**$ 228,850**	**$ 9,984.582**
	-					

[1] Source: Appendix F - June 2012 Monthly Electric Supply Tracker filing.

NorthWestern Energy Electric Utility
Deferred Supply Derivation of Rates
Total Proposed Deferred Supply Rate
July 2012 to June 2013

Rates Effective July 1, 2012

	Deferred Electricity Supply Rates [1]	Deferred CU4 Rates [2]	Total Deferred Supply Rates
Residential			
Residential	0.001941	(0.000506)	0.001435
Residential Employee	0.001165	(0.000304)	0.000861
Total Residential			
General Service 1			
GS-1 Sec Non-Demand	0.001941	(0.000506)	0.001435
GS-1 Sec Demand	0.001941	(0.000506)	0.001435
GS-1 Pri Non-Demand	0.001888	(0.000492)	0.001396
GS-1 Pri Demand	0.001888	(0.000492)	0.001396
Total GS-1			
General Service 2			
GS-2 Substation	0.001872	(0.000488)	0.001384
GS-2 Transmission	0.001861	(0.000485)	0.001376
Total GS-2			
Irrigation			
Irrigation	0.001941	(0.000506)	0.001435
Total Irrigation			
Lighting			
Lighting	0.001941	(0.000506)	0.001435
Total Lighting			
Average Billed Rate	**0.001933**	**(0.000504)**	**0.001429**
Total Supply Rate	**1.933**	**(0.504)**	**1.429**
			-

[1] Source: Exhibit_(CAH-2)_12-13
[2] Source: Exhibit_(CAH-3)_12-13

Exhibit__(CAH-5)_12-13
Docket No. D2012.5.49

NorthWestern Energy Electric Utility
Deferred Supply Derivation of Rates
Total Revenue Summary
July 2012 to June 2013
Rates Effective July 1, 2012

	Current Deferred Revenue			Proposed Deferred Revenue			
	Deferred Supply Revenue	Deferred CU4 Revenue	Total Deferred Revenue 7/1/2011	Deferred Supply Revenue	Deferred CU4 Revenue	Total Deferred Revenue 7/1/2012	Revenue Difference Proposed vs Current
Residential							
Residential	$ 8,348	$ (9,860)	$ (1,513)	$ 4,587	$ (1,196)	$ 3,391	$ 4,904
Residential Employee	$ 8	$ (10)	$ (1)	$ 5	$ (1)	$ 3	$ 5
Total Residential	$ 8,356	$ (9,870)	$ (1,514)	$ 4,592	$ (1,197)	$ 3,395	$ 4,909
General Service 1							
GS-1 Sec Non Demand	$ 963	$ (1,138)	$ (175)	$ 529	$ (138)	$ 391	$ 566
GS-1 Sec Demand	$ 8,613	$ (10,173)	$ (1,561)	$ 4,733	$ (1,234)	$ 3,499	$ 5,060
GS-1 Pri Non Demand	$ 2	$ (2)	$ (0)	$ 1	$ (0)	$ 1	$ 1
GS-1 Pri Demand	$ 1,204	$ (1,423)	$ (218)	$ 662	$ (172)	$ 489	$ 708
Total GS-1	$ 10,782	$ (12,736)	$ (1,954)	$ 5,925	$ (1,545)	$ 4,381	$ 6,335
General Service 2							
GS-2 Substation	$ 831	$ (982)	$ (151)	$ 457	$ (119)	$ 338	$ 488
GS-2 Transmission	$ 448	$ (529)	$ (81)	$ 246	$ (64)	$ 182	$ 263
Total GS-2	$ 1,279	$ (1,511)	$ (232)	$ 703	$ (183)	$ 520	$ 752
Irrigation							
Irrigation	$ 295	$ (348)	$ (53)	$ 162	$ (42)	$ 120	$ 173
Total Irrigation	$ 295	$ (348)	$ (53)	$ 162	$ (42)	$ 120	$ 173
Lighting							
Lighting	$ 204	$ (241)	$ (37)	$ 112	$ (29)	$ 83	$ 120
Total Lighting	$ 204	$ (241)	$ (37)	$ 112	$ (29)	$ 83	$ 120
Total Rate Schedule	$ 20,916	$ (24,706)	$ (3,790)	$ 11,495	$ (2,996)	$ 8,498.114	$ 12,288.332
	-	-	-	-	-	-	-

NorthWestern Energy
Electric Utility
Total Proposed Supply Rate
July 1, 2012

	Proposed Electricity Supply Rates [1]	Colstrip Unit 4 [2]		Dave Gates Gen Station [3]			Proposed Total Supply Rates
		Current Fixed Rates	Proposed Variable Rates	Current Fixed Rates	Current Fixed Rebate Rates	Proposed Variable Rates	
Residential							
Residential	0.039102	0.012734	0.004209	0.004795	(0.001195)	0.001267	0.060912
Residential Employee	0.023462	0.007640	0.002525	0.002877	(0.000717)	0.000760	0.036547
Total Residential							
General Service 1							
GS-1 Sec Non-Demand	0.035374	0.012734	0.004209	0.004795	(0.001195)	0.001267	0.057184
GS-1 Sec Demand	0.039101	0.012734	0.004209	0.004795	(0.001195)	0.001267	0.060911
GS-1 Pri Non-Demand	0.038027	0.012385	0.004094	0.004664	(0.001162)	0.001233	0.059241
GS-1 Pri Demand	0.034726	0.012385	0.004094	0.004664	(0.001162)	0.001233	0.055940
Total GS-1							
General Service 2							
GS-2 Substation	0.037701	0.012278	0.004059	0.004624	(0.001152)	0.001222	0.058732
GS-2 Transmission	0.037474	0.012204	0.004034	0.004596	(0.001145)	0.001215	0.058378
Total GS-2							
Irrigation							
Irrigation	0.035374	0.012734	0.004209	0.004795	(0.001195)	0.001267	0.057184
Total Irrigation							
Lighting							
Lighting	0.035374	0.012734	0.004209	0.004795	(0.001195)	0.001267	0.057184
Total Lighting							
Average Billed Rate	**0.038480**	**0.012680**	**0.004191**	**0.004775**	**(0.001190)**	**0.001262**	**0.060197**
Total Supply Rate	**38.480**		**16.871**			**4.846**	**60.197**

[1] Source: Exhibit_(CAH-2)_12-13
[2] Source: Exhibit_(CAH-3)_12-13
[3] Source: Exhibit_(CAH-4)_12-13

NorthWestern Energy
Electric Utility
Total Supply Revenue Summary by Rate Component
Tracker Period July 2011 to June 2012

	Total Supply Revenue Current Rate 6/1/2012	Proposed Supply Revenue						
		Electricity Supply Revenue	CU4 Fixed Revenue	CU4 Variable Revenue	DGGS Fixed Revenue	DGGS Fixed Rebate Revenue	DGGS Variable Revenue	Total Supply Revenue 7/1/2012
Residential								
Residential	$ 140,591	$ 92,413	$ 30,095	$ 9,948	$ 11,332	$ (2,824)	$ 2,994	$ 143,959
Residential Employee	$ 139	$ 91	$ 30	$ 10	$ 11	$ (3)	$ 3	$ 142
Total Residential	$ 140,730	$ 92,505	$ 30,125	$ 9,957	$ 11,344	$ (2,827)	$ 2,997	$ 144,101
General Service 1								
GS-1 Sec Non Demand	$ 15,255	$ 9,650	$ 3,474	$ 1,148	$ 1,308	$ (326)	$ 346	$ 15,599
GS-1 Sec Demand	$ 145,053	$ 95,345	$ 31,051	$ 10,263	$ 11,692	$ (2,914)	$ 3,090	$ 148,528
GS-1 Pri Non Demand	$ 32	$ 21	$ 7	$ 2	$ 3	$ (1)	$ 1	$ 33
GS-1 Pri Demand	$ 19,175	$ 12,173	$ 4,342	$ 1,435	$ 1,635	$ (407)	$ 432	$ 19,610
Total GS-1	$ 179,515	$ 117,189	$ 38,873	$ 12,849	$ 14,638	$ (3,648)	$ 3,868	$ 183,770
General Service 2								
GS-2 Substation	$ 13,996	$ 9,199	$ 2,996	$ 990	$ 1,128	$ (281)	$ 298	$ 14,331
GS-2 Transmission	$ 7,543	$ 4,958	$ 1,615	$ 534	$ 608	$ (151)	$ 161	$ 7,723
Total GS-2	$ 21,538	$ 14,157	$ 4,610	$ 1,524	$ 1,736	$ (433)	$ 459	$ 22,054
Irrigation								
Irrigation	$ 4,669	$ 2,953	$ 1,063	$ 351	$ 400	$ (100)	$ 106	$ 4,774
Total Irrigation	$ 4,669	$ 2,953	$ 1,063	$ 351	$ 400	$ (100)	$ 106	$ 4,774
Lighting								
Lighting	$ 3,233	$ 2,045	$ 736	$ 243	$ 277	$ (69)	$ 73	$ 3,306
Total Lighting	$ 3,233	$ 2,045	$ 736	$ 243	$ 277	$ (69)	$ 73	$ 3,306
Total Rate Schedule	$ 349,686	$ 228,850	$ 75,408	$ 24,925	$ 28,396	$ (7,076)	$ 7,503	$ 358,006
	-	-	-	-	-	-	-	-

NorthWestern Energy
Electric Utility
Total Supply Revenue ($000) Summary
Tracker Period July 2011 to June 2012

	Jul11 to Jun12 Supply Retail kWh Sales	Current Total Supply Rates 6/1/2012	Current Total Supply Revenue	Proposed Total Supply Rates 7/1/2012	Proposed Total Supply Revenue	Revenue Difference Proposed vs Current	% Change
Residential							
Residential	2,363,392	0.059487	$ 140,591	0.060912	$ 143,959	$ 3,368	2.40%
Residential Employee	3,899	0.035692	$ 139	0.036547	$ 142	$ 3	2.40%
Total Residential			$ 140,730		$ 144,101	$ 3,371	
General Service 1							
GS-1 Sec Non-Demand	272,791	0.055922	$ 15,255	0.057184	$ 15,599	$ 344	2.26%
GS-1 Sec Demand	2,438,440	0.059486	$ 145,053	0.060911	$ 148,528	$ 3,475	2.40%
GS-1 Pri Non-Demand	552	0.057855	$ 32	0.059241	$ 33	$ 1	2.40%
GS-1 Pri Demand	350,553	0.054698	$ 19,175	0.055940	$ 19,610	$ 435	2.27%
Total GS-1			$ 179,515		$ 183,770	$ 4,255	
General Service 2							
GS-2 Substation	244,006	0.057358	$ 13,996	0.058732	$ 14,331	$ 335	2.40%
GS-2 Transmission	132,300	0.057012	$ 7,543	0.058378	$ 7,723	$ 181	2.40%
Total GS-2			$ 21,538		$ 22,054	$ 516	
Irrigation							
Irrigation	83,490	0.055922	$ 4,669	0.057184	$ 4,774	$ 105	2.26%
Total Irrigation			$ 4,669		$ 4,774	$ 105	
Lighting							
Lighting	57,821	0.055922	$ 3,233	0.057184	$ 3,306	$ 73	2.26%
Total Lighting			$ 3,233		$ 3,306	$ 73	
Total Rate Schedule	**5,947,244**		**$ 349,686**		**$ 358,006**	**$ 8,320.679**	2.38%
	-		-		-	-	

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2012.5.49
Annual CU4 True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF FRANK V. BENNETT

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL COLSTRIP UNIT 4 ("CU4") TRUE-UP

TABLE OF CONTENTS

Witness Information

Q. Are you the same Frank V. Bennett who filed Prefiled Direct Testimony in the Electricity Supply Tracker portion of this docket?

A. Yes.

Purpose of Testimony

Q. Please describe your Annual CU4 True-up testimony.

A. In my testimony I present the following information:

- The updated CU4 costs for the 12-month ended June 2012 true-up period with 10 months of actual numbers and 2 months of estimated numbers, and
- The forecast CU4 costs for the 12-month ended June 2013 true-up period.

Update to CU4 Values in the 2011/2012 True-up Period

Q. How has NorthWestern updated the CU4 generation that is reflected in the 2011/2012 electricity supply tracker?

A. NorthWestern has included the full rate-based volume of unit contingent energy associated with 222 MW of capacity from July 1, 2011 through June 30, 2012.

Q. How are the CU4 variable costs treated in the 2011/2012 true-up period?

A. The CU4 costs are treated the same as they were in NorthWestern's 2011 annual CU4 true-up filing. The variable CU4 cost of service includes fuel costs and incremental property taxes. These variable costs are tracked in a manner similar to the market-based supply costs. In addition, CU4 property taxes were updated to reflect changes in the 2011 Annual Property Tax Tracker Filing. The CU4 variable cost was updated in January 2012 to reflect the CU4 property tax changes submitted in the 2012 Annual Property Tax Tracker filing.

Q. Have any adjustments been made to the CU4 fixed cost of service in the 2011/2012 or 2012/2013 true-up periods?

A. No. The CU4 fixed cost of service presented in this filing includes the costs which were approved in Docket No. D2008.6.69. They will remain unchanged until such time that an order is issued in a subsequent revenue requirement filing.

Q. Are any other changes reflected in the 2011/2012 true-up period?

A. Yes. Under Final Order No. 7154b in Docket No. D2011.5.38, the Montana Public Service Commission ("MPSC") authorized NorthWestern to include forecast lost revenues related to Demand-Side Management ("DSM") in future filings. Forecast lost CU4 fixed cost revenues resulting from DSM and Universal System Benefits activities are included in both the 2011/2012 and 2012/2013 true-up periods. Refer to the Prefiled Direct

Testimony of William Thomas (“Thomas Direct Testimony”) for support for the CU4 fixed cost lost revenues.

Q. Please explain the lost revenue changes reflected in the 2011/2012 true-up period.

A. The forecast and true-up lost revenues reflected in the 2011/2012 period have been shown on page 2 of Exhibit__(FVB-4)11_12 as an adjustment in the months of April, May, and June to reflect the lost revenue calculation as discussed in the Thomas Direct Testimony.

Q. Please summarize the 12-month ended June 2012 CU4 deferred balance.

A. The June 2011 deferred balance of $(25,950,940) over-collection shown on page 2 of Exhibit__(FVB-4)10_11 from Docket No. D2011.5.38 is the July 2011 beginning deferred balance. With 10 months actual values and 2 months estimated values, the June 2012 estimated ending deferred account balance is a $(2,993,971) over-collection. Please refer to the Prefiled Direct Testimony of Cheryl Hansen - CU4 True-up for further discussion of the Deferred Account.

Q. Please summarize the 12-month ended June 2012 CU4 true-up period variable costs.

A. The CU4 true-up period is summarized in the following table:

Beginning Deferred CU4		**Balance ($)**
Over-Collection		(25,950,940)

Variable Costs CU4		**Cost ($)**
Fuel Cost		19,701,158
Property Tax Adjustments		(213,381)
DSM Lost Revenue		384,020
DSM Lost Revenue Adjustment		3,445,858
Subtotal Variable CU4 Cost of Service:		23,317,656

Carrying Costs		(1,116,029)
Total Variable Costs		22,201,626

Variable Revenues CU4		**Revenue ($)**
Revenues		22,620,911
Prior Deferred Expense		(23,376,254)
Subtotal Revenues:		(755,343)

Ending Deferred CU4		**Balance ($)**
Over-Collection		(2,993,971)

Forecast of CU4 in the 2012/2013 True-up Period

Q. Are any changes reflected in the 2012/2013 tracking period?

A. Yes. Under Final Order No. 7154b in Docket No. D2011.5.38, the MPSC authorized NorthWestern to include forecast lost revenues in future filings. Forecast lost CU4 fixed cost revenues are reflected in this forecast tracker period and are addressed in the Thomas Direct Testimony

Q. Please summarize the 12-month CU4 true-up period ending June 2013.

A. The June 2012 Deferred Account over-collection ending balance of $(2,993,971) as described above is the July 2012 beginning balance. July

2012 through June 2013 information is based on forecast numbers. Please see Exhibit__(FVB-5)12_13 for supply volume and cost details of the 12-month forecast tracker period.

Q. Describe the changes within the CU4 variable Revenue and Expense categories for the 12-month ended June 2013 forecast true-up period.

A. The CU4 Generation Asset true-up variable cost revenue and expense details are reflected on page 2 of Exhibit__(FVB-5)12_13 under two main sections, Total Revenue and Total Variable Expenses. Total Net Revenue is estimated to be $21,931,791. This includes the current year revenue of $24,925,762 offset by the deferred balance carry forward of $(2,993,971) over-collection from the prior true-up period as shown on Exhibit__(FVB-4)11_12. The 12-month forecast true-up estimates Total Variable CU4 Expenses of $24,925,762.

Q. Please provide a summary table of the 12-month ended June 2013 CU4 true-up period.

A. The CU4 true-up period is summarized in the following table:

Beginning Deferred CU4		**Balance ($)**
Over-Collection		(2,993,971)

Variable Costs CU4		**Cost ($)**
Fuel Expense		22,589,151
Property Tax Adjustments		(446,243)
DSM Lost Revenue		2,957,541
DSM Lost Revenue Adjustment		0
Subtotal Variable CU4 Cost of Service:		25,100,448

Carrying Costs		(174,686)
Total Variable Costs		24,925,762

Variable Revenues CU4		**Revenue ($)**
Revenues		24,925,762
Prior Year Deferred		(2,993,971)
Subtotal Revenues:		21,931,791

Ending Deferred CU4		**Balance ($)**
Even Collection		0

Q. Does this conclude your Annual CU4 True-up testimony?

A. Yes, it does.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1		**Colstrup Unit 4 Generation Asset Component**														
2				**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Total**
3				Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
4		**Colstrip Unit 4 Fixed Cost Revenue Requirement -- Per Final Order 6925f**														
5		Colstrip 4 Plant In Service														
6		Electric Generation Plant		$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$407,000,000
7		Accumulated Depreciation (Book Life 34 Yrs)		$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (11,970,588)
8		Deferred Income Taxes		$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (1,152,169)
9		Total Year End Rate Base		$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$393,877,243
10																
11		Average Annual Rate Base		$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$400,438,621
12																
13		Fixed Return (Avg Rate Base * Cost of Capital)	8.25%	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 33,036,186
14																
15		Fixed Cost of Service														
16		Steam Power Generation Operation		$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 8,874,144
17		Purchase Power		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Administrative and General Expenses		$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 2,968,654
19		Depreciation		$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 11,970,588
20		Property Taxes		$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 2,431,458
21		Taxes Other than Income		$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 529,037
22		MCC/MPSC Taxes	0.45%	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 234,907
23		Deferred Income Taxes		$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 1,152,169
24		Current Income Taxes		$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 11,620,288
25		Miscellaneous Revenues (Rent)		$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (71,887)
26		Fixed Cost of Service		$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 39,709,358
27																
28		Total CU4 Fixed Cost Revenue Requirement		$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 72,745,544
29																
30																

	A / B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
31	**Colstrup Unit 4 Generation Asset Component**														
32			**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Total**
33			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
34	**Colstrip Unit 4 Variable Cost -- Per Final Order 6925f**														
35	Total Forecast Sales														
36	2011/12 Tracker Sales MWh		465,921	516,357	509,435	447,311	447,758	516,526	547,422	525,206	491,564	462,940	454,666	499,219	5,884,325
37	CU4 Cost		$ 3.8343	$ 3.8343	$ 3.8343	$ 3.8343	$ 3.8343	$ 3.8343	$ 3.7559	$ 3.7559	$ 3.7559	$ 3.7559	$ 3.7559	$ 3.7559	
38	Prior Year Deferred Expense		$ (4.1540)	$ (4.1540)	$ (4.1540)	$ (4.1540)	$ (4.1540)	$ (4.1540)	$ (4.1540)	$ (4.1540)	$ (4.1540)	$ (4.1540)	$ (4.1540)	$ (4.1540)	
39															
40	Colstrip Unit 4 Variable Cost Revenues														
41	NWE Electric Supply		$ 1,787,127	$ 1,980,514	$ 1,954,393	$ 1,714,628	$ 1,716,299	$ 1,981,123	$ 2,134,869	$ 2,047,604	$ 1,916,877	$ 1,804,809	$ 1,707,667	$ 1,875,001	$ 22,620,911
42															
43	Subtotal		$ 1,787,127	$ 1,980,514	$ 1,954,393	$ 1,714,628	$ 1,716,299	$ 1,981,123	$ 2,134,869	$ 2,047,604	$ 1,916,877	$ 1,804,809	$ 1,707,667	$ 1,875,001	$ 22,620,911
44	Prior Year(s) Deferred Expense		$ (864,477)	$ (2,145,631)	$ (2,117,329)	$ (1,857,581)	$ (1,859,386)	$ (2,146,284)	$ (2,275,043)	$ (2,182,052)	$ (2,042,738)	$ (1,923,318)	$ (1,888,673)	$ (2,073,744)	$ (23,376,254)
45	Total Revenue		$ 922,650	$ (165,117)	$ (162,936)	$ (142,953)	$ (143,088)	$ (165,161)	$ (140,174)	$ (134,448)	$ (125,861)	$ (118,508)	$ (181,006)	$ (198,743)	$ (755,343)
46															
47	Colstrip Unit 4 Fuel Cost		$ 1,664,731	$ 1,886,663	$ 1,864,674	$ 1,773,239	$ 1,573,613	$ 1,861,028	$ 1,081,603	$ 1,861,756	$ 1,639,714	$ 584,990	$ 1,954,573	$ 1,954,573	$ 19,701,158
48															
49	Incremental Property Tax Adjustment		$ 1,623	$ 1,623	$ 1,623	$ 1,623	$ 1,623	$ 1,623	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (213,381)
50															
51	DSM Lost Revenue												$ 192,010	$ 192,010	$ 384,020
52	DSM Lost Revenue Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,525,757	$ 1,920,101		$ 3,445,858
53															
54	Subtotal Colstrip Unit 4 Variable Cost		$ 1,666,354	$ 1,888,287	$ 1,866,297	$ 1,774,862	$ 1,575,237	$ 1,862,651	$ 1,044,416	$ 1,824,569	$ 1,602,527	$ 2,073,560	$ 4,029,498	$ 2,109,396	$ 23,317,656
55															
56															
57	**Carrying Cost Expense**														
58	Carry Cost	7.80%	$ (164,817)	$ (152,468)	$ (140,197)	$ (128,574)	$ (118,180)	$ (105,694)	$ (98,639)	$ (86,475)	$ (75,740)	$ (61,902)	$ (34,316)	$ (19,449)	$ (1,186,452)
59	Carry Cost Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 70,422	$ -	$ 70,422
60	Total Carrying Cost		$ (164,817)	$ (152,468)	$ (140,197)	$ (128,574)	$ (118,180)	$ (105,694)	$ (98,639)	$ (86,475)	$ (75,740)	$ (61,902)	$ 36,106	$ (19,449)	$ (1,116,029)
61															
62	Total Variable CU4 Expenses		$ 1,501,537	$ 1,735,819	$ 1,726,100	$ 1,646,288	$ 1,457,057	$ 1,756,958	$ 945,777	$ 1,738,094	$ 1,526,787	$ 2,011,658	$ 4,065,604	$ 2,089,947	$ 22,201,626
63															
64	Deferred Cost Amortization (Under)/Over		$ (864,477)	$ (2,145,631)	$ (2,117,329)	$ (1,857,581)	$ (1,859,386)	$ (2,146,284)	$ (2,275,043)	$ (2,182,052)	$ (2,042,738)	$ (1,923,318)	$ (1,888,673)	$ (2,073,744)	$ (23,376,254)
65	Monthly Deferred Cost		$ 285,589	$ 244,695	$ 228,292	$ 68,340	$ 259,242	$ 224,165	$ 1,189,092	$ 309,510	$ 390,090	$ (206,849)	$ (2,357,937)	$ (214,946)	$ 419,284
66	Cumulative Deferred Cost		$ 285,589	$ 530,285	$ 758,577	$ 826,917	$ 1,086,159	$ 1,310,324	$ 2,499,416	$ 2,808,926	$ 3,199,016	$ 2,992,167	$ 634,231	$ 419,284	
67															
68	Variable Rate Base Deferred														
69	Beginning Balance		$(25,950,940)	$(25,372,053)	$(23,471,118)	$(21,582,082)	$(19,792,841)	$(18,192,696)	$(16,270,578)	$(15,184,627)	$(13,312,085)	$(11,659,437)	$ (9,529,270)	$ (5,282,661)	
70	Monthly Deferred Cost		$ 578,887	$ 1,900,935	$ 1,889,036	$ 1,789,241	$ 1,600,145	$ 1,922,118	$ 1,085,951	$ 1,872,542	$ 1,652,648	$ 2,130,166	$ 4,246,609	$ 2,288,690	
71	Ending Balance Under/(Over)		$(25,372,053)	$(23,471,118)	$(21,582,082)	$(19,792,841)	$(18,192,696)	$(16,270,578)	$(15,184,627)	$(13,312,085)	$(11,659,437)	$ (9,529,270)	$ (5,282,661)	$ (2,993,971)	
72															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1		**Colstrup Unit 4 Generation Asset Component**														
2				**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
3				Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
4		**Colstrip Unit 4 Fixed Cost Revenue Requirement -- Per Final Order 6925f**														
5		Colstrip 4 Plant In Service														
6		Electric Generation Plant		$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$407,000,000
7		Accumulated Depreciation (Book Life 34 Yrs)		$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (11,970,588)
8		Deferred Income Taxes		$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (1,152,169)
9		Total Year End Rate Base		$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$393,877,243
10																
11		Average Annual Rate Base		$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$400,438,621
12																
13		Fixed Return (Avg Rate Base * Cost of Capital)	8.25%	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 33,036,186
14																
15		Fixed Cost of Service														
16		Steam Power Generation Operation		$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 8,874,144
17		Purchase Power		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Administrative and General Expenses		$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 2,968,654
19		Depreciation		$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 11,970,588
20		Property Taxes		$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 2,431,458
21		Taxes Other than Income		$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 529,037
22		MCC/MPSC Taxes	0.45%	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 234,907
23		Deferred Income Taxes		$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 1,152,169
24		Current Income Taxes		$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 11,620,288
25		Miscellaneous Revenues (Rent)		$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (71,887)
26		Fixed Cost of Service		$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 39,709,358
27																
28		Total CU4 Fixed Cost Revenue Requirement		$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 72,745,544
29																
30																

	A/B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
31	**Colstrup Unit 4 Generation Asset Component**														
32			**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
33			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
34	**Colstrip Unit 4 Variable Cost -- Per Final Order 6925f**														
35	Total Forecast Sales														
36	2011/12 Tracker Sales MWh		536,889	522,289	453,359	472,682	495,613	562,539	562,001	494,391	497,753	448,206	447,693	453,829	5,947,244
37	CU4 Cost		$ 4.6065	$ 4.6065	$ 4.6065	$ 4.6065	$ 4.6065	$ 4.6065	$ 3.7559	$ 3.7559	$ 3.7559	$ 3.7559	$ 3.7559	$ 3.7559	
38	Prior Year Deferred Expense		$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	
39															
40	Colstrip Unit 4 Variable Cost Revenues														
41	NWE Electric Supply		$ 2,473,161	$ 2,405,907	$ 2,088,383	$ 2,177,394	$ 2,283,024	$ 2,591,317	$ 2,110,804	$ 1,856,870	$ 1,869,497	$ 1,683,405	$ 1,681,478	$ 1,704,524	$ 24,925,762
42															
43	Subtotal		$ 2,473,161	$ 2,405,907	$ 2,088,383	$ 2,177,394	$ 2,283,024	$ 2,591,317	$ 2,110,804	$ 1,856,870	$ 1,869,497	$ 1,683,405	$ 1,681,478	$ 1,704,524	$ 24,925,762
44	Prior Year(s) Deferred Expense		$ (270,282)	$ (262,932)	$ (228,231)	$ (237,958)	$ (249,502)	$ (283,194)	$ (282,923)	$ (248,887)	$ (250,580)	$ (225,637)	$ (225,378)	$ (228,467)	$ (2,993,971)
45	Total Revenue		$ 2,202,879	$ 2,142,975	$ 1,860,152	$ 1,939,435	$ 2,033,522	$ 2,308,123	$ 1,827,881	$ 1,607,983	$ 1,618,917	$ 1,457,768	$ 1,456,100	$ 1,476,057	$ 21,931,791
46															
47	Colstrip Unit 4 Fuel Cost		$ 1,882,429	$ 1,882,429	$ 1,882,429	$ 1,882,429	$ 1,882,429	$ 1,882,429	$ 1,882,429	$ 1,882,429	$ 1,882,429	$ 1,882,429	$ 1,882,429	$ 1,882,429	$ 22,589,151
48															
49	Incremental Property Tax Adjustment		$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (446,243)
50															
51	DSM Lost Revenue		$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 2,957,541
52	DSM Lost Revenue Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53															
54	Subtotal Colstrip Unit 4 Variable Cost		$ 2,091,704	$ 2,091,704	$ 2,091,704	$ 2,091,704	$ 2,091,704	$ 2,091,704	$ 2,091,704	$ 2,091,704	$ 2,091,704	$ 2,091,704	$ 2,091,704	$ 2,091,704	$ 25,100,448
55															
56															
57	**Carrying Cost Expense**														
58	Carrying Costs	7.80%	$ (20,303)	$ (20,771)	$ (19,393)	$ (18,524)	$ (18,265)	$ (19,799)	$ (18,204)	$ (15,160)	$ (12,168)	$ (8,102)	$ (3,999)	$ 0	$ (174,686)
59															
60	Total Variable CU4 Expenses		$ 2,071,401	$ 2,070,933	$ 2,072,311	$ 2,073,180	$ 2,073,439	$ 2,071,905	$ 2,073,501	$ 2,076,544	$ 2,079,536	$ 2,083,602	$ 2,087,705	$ 2,091,704	$ 24,925,762
61															
62	Deferred Cost Amortization (Under)/Over		$ (270,282)	$ (262,932)	$ (228,231)	$ (237,958)	$ (249,502)	$ (283,194)	$ (282,923)	$ (248,887)	$ (250,580)	$ (225,637)	$ (225,378)	$ (228,467)	$ (2,993,971)
63	Monthly Deferred Cost		$ 401,760	$ 334,973	$ 16,071	$ 104,213	$ 209,585	$ 519,412	$ 37,304	$ (219,675)	$ (210,040)	$ (400,197)	$ (406,227)	$ (387,180)	$ (0)
64	Cumulative Deferred Cost		$ 401,760	$ 736,733	$ 752,805	$ 857,018	$ 1,066,603	$ 1,586,015	$ 1,623,319	$ 1,403,644	$ 1,193,604	$ 793,407	$ 387,180	$ (0)	
65															
66	Variable Rate Base Deferred														
67	Beginning Balance		$ (2,993,971)	$ (3,125,449)	$ (3,197,491)	$ (2,985,332)	$ (2,851,587)	$ (2,811,670)	$ (3,047,887)	$ (2,802,267)	$ (2,333,706)	$ (1,873,086)	$ (1,247,253)	$ (615,647)	
68	Monthly Deferred Cost		$ (131,478)	$ (72,042)	$ 212,159	$ 133,745	$ 39,917	$ (236,218)	$ 245,620	$ 468,562	$ 460,619	$ 625,834	$ 631,605	$ 615,647	
69	Ending Balance Under/(Over)		$ (3,125,449)	$ (3,197,491)	$ (2,985,332)	$ (2,851,587)	$ (2,811,670)	$ (3,047,887)	$ (2,802,267)	$ (2,333,706)	$ (1,873,086)	$ (1,247,253)	$ (615,647)	$ 0	
70															

PREFILED DIRECT TESTIMONY

OF CHERYL A. HANSEN

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL COLSTRIP UNIT 4 ("CU4") TRUE-UP

TABLE OF CONTENTS

Witness Information

Q. Are you the same Cheryl A. Hansen who filed Prefiled Direct Testimony in the Electricity Supply Tracker portion of this docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your Annual CU4 True-up testimony?

A. My testimony:

1. Presents the derivation of proposed deferred CU4 variable rates resulting from the over/under collection reflected in the 2011-2012 true-up period;
2. Presents the derivation of proposed CU4 variable rates for the forecasted 2012-2013 true-up period; and
3. Discusses the overall total supply rates incorporating all individual rate components.

Derivation of Proposed Deferred CU4 Variable Rates

Q. What is the CU4 variable cost account balance for the 12-month period ending June 2012?

A. The CU4 variable cost account balance for the 12-month period ending June 2012 is an over-collection of $(2,993,971) as presented on page 1 of Exhibit__(CAH-3)_12-13. As discussed below, this includes the prior period balance for the 2010-2011 true-up period and the current period balance for the 2011-2012 true-up period.

Q. Describe the status of the deferred CU4 variable cost account balance associated with the 2010-2011 true-up period.

A. In the annual filing submitted on June 2, 2011, the net deferred account balance for the 2010-2011 true-up period was shown as an over-collection of $(24,472,321). This amount becomes the starting balance in this filing. Added to this balance is the prior period true-up for the 2 months of estimated data included in the June 2, 2011 filing. Page 1 of Exhibit__(CAH-3)_12-13 shows the true-up of the estimated months of May and June 2011 with actual data. The resulting actual ending balance of $(25,950,940) is the deferred account beginning balance for the 2011-2012 true-up period. This balance is then combined with the current year monthly activity shown on Exhibit__(CAH-3)_12-13, page 1, resulting in a net over-collected balance of $(2,574,686) for the 2011-2012 true-up period.

Q. Describe the deferred CU4 variable cost account balance associated with the 2011-2012 true-up period.

A. Page 2 of Exhibit__(CAH-3)_12-13 shows the monthly detail of the difference between the CU4 variable cost revenues and expenses for the 2011-2012 true-up period, resulting in an over-collected amount of

$(419,284). The months of May and June 2012 are estimated and will be trued-up in the next annual filing.

Q. What is the total deferred CU4 variable cost account adjustment proposed for amortization in this filing?

A. The total deferred CU4 variable cost account adjustment proposed in this filing is an over-collection of $(2,993,971) shown below and on page 1, line 55 of Exhibit__(CAH-3)_12-13.

Total Deferred CU4 Variable Cost Account Balance

2010-2011 Prior Period CU4 Variable Account Balance	$(2,574,686)
2011-2012 Current Period CU4 Variable Account Balance	<u>$(419,284)</u>
	$(2,993,971)

Derivation of the deferred CU4 variable rates is shown on Exhibit__(CAH-3)_12-13, page 3 with the resulting rates and revenues shown in summarized format on page 4.

<u>Derivation of Proposed CU4 Variable Rates</u>

Q. Please describe the process used by NorthWestern to derive the proposed 2012-2013 CU4 variable rates in this filing.

A. The rate design methodology used in this filing to derive the proposed 2012-2013 CU4 variable rates is the same as that presented in previous

CU4 filings. All forecasted costs are from Exhibit__(FVB-5)12_13 of the Prefiled Direct Testimony of Frank Bennett and are discussed in his testimony.

The derivation of CU4 variable rates is shown on Exhibit__(CAH-3)_12-13, page 5. The total CU4 variable cost of $24,925,762 is the sum of forecasted fuel costs, incremental property taxes, DSM Lost Revenues, and carrying costs from Exhibit__(FVB-5)12-13, page 2, column P, line 60. This sum is the amount used to derive the CU4 variable rates. The forecasted loads used in the derivation are from Exhibit__(CAH-1)_12-13.

Q. Please describe the 2012-2013 CU4 fixed rates included in this filing.

A. The CU4 fixed cost of service rate components presented in this filing remain unchanged and will not change until an order is issued in any subsequent CU4 revenue requirement filing.

The CU4 fixed and variable rates and revenues are shown in summarized format on Exhibit__(CAH-3)_12-13, page 6.

Proposed Total Supply Rates

Q. Please describe the process used by NorthWestern to derive the total proposed 2012-2013 electric supply rates in this filing.

A. With the introduction of Dave Gates Generating Station ("DGGS") rates in 2011, the total electric supply rate currently includes several separate rate components – an electricity supply tracker rate, a CU4 fixed cost of service rate, a CU4 variable rate, a DGGS fixed cost of service rate, a DGGS fixed cost of service rebate rate, and a DGGS variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(CAH-5)_12-13, page 3.

The total deferred supply rate also includes two separate rate components – a deferred electricity supply rate and a deferred CU4 variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(CAH-5)_12-13, page 1. Because the deferred DGGS balance is immaterial, NWE proposes to not request a deferred rate adjustment in this filing and carry forward the DGGS Variable Cost/Credit deferred account balance into the 2012-2013 true-up period.

Q. Does this conclude your Annual CU4 True-up testimony?

A. Yes, it does.

Exhibit__(CAH-3)_12-13
Docket No. D2012.5.49

NorthWestern Energy
Electric Utility
Deferred CU4 Variable Cost Account Balance
July 2011 - June 2012

Month	Monthly Collection	Collection to-date	Balance Remaining
Jul10-Jun11 over-collected balance as filed in D2011.5.38			**$ (24,472,321)**
Prior Period Tracker Year True-up - Deferred:			
May11: Estimated as filed in D2011.5.38		$ -	
May11: Actual		$ -	$ -
Jun11: Estimated as filed in D2011.5.38		$ -	
Jun11: Actual		$ -	$ -
Prior Period Tracker Year True-up - Variable:			
May11: Est as filed in D2011.5.38 - Revenue	$ 1,646,774		
May11: Est as filed in D2011.5.38 - Expense	$ 1,239,890	$ (406,884)	
May11: Actual - Revenue	$ 1,582,348		
May11: Actual - Expense	$ 459,503	$ (1,122,845)	$ (715,961)
Jun11: Est as filed in D2011.5.38 - Revenue	$ 1,803,415		
Jun11: Est as filed in D2011.5.38 - Expense	$ 1,718,099	$ (85,316)	
Jun11: Actual - Revenue	$ 1,562,125		
Jun11: Actual - Expense	$ 714,150	$ (847,975)	$ (762,659)
Actual Jul10-Jun11 over-collected balance [1]			**$ (25,950,940)**
			-
Jul11-Jun12 Monthly Activity [2]:			
July 2011	$ (864,477)	$ (864,477)	$ (25,086,464)
August 2011	$ (2,145,631)	$ (3,010,107)	$ (22,940,833)
September 2011	$ (2,117,329)	$ (5,127,436)	$ (20,823,504)
October 2011	$ (1,857,581)	$ (6,985,017)	$ (18,965,924)
November 2011	$ (1,859,386)	$ (8,844,403)	$ (17,106,537)
December 2011	$ (2,146,284)	$ (10,990,687)	$ (14,960,253)
January 2012	$ (2,275,043)	$ (13,265,730)	$ (12,685,211)
February 2012	$ (2,182,052)	$ (15,447,782)	$ (10,503,159)
March 2012	$ (2,042,738)	$ (17,490,520)	$ (8,460,421)
April 2012	$ (1,923,318)	$ (19,413,837)	$ (6,537,103)
May 2012 - Estimated	$ (1,888,673)	$ (21,302,510)	$ (4,648,430)
June 2012 - Estimated	$ (2,073,744)	$ (23,376,254)	$ (2,574,686)
Prior Period CU4 Variable Cost Ending Balance			**$ (2,574,686)**
Current Period CU4 Variable Cost Ending Balance (see page 2)			**$ (419,284)**
Total CU4 Variable Cost Balance Jul11-Jun12 [3]			**$ (2,993,971)**
			-

[1] Source: Exhibit_(FVB-4)11-12, page 2, line 69.
[2] Source: Exhibit_(FVB-4)11-12, page 2, line 65.
[3] Source: Exhibit_(FVB-4)11-12, page 2, line 71.

NorthWestern Energy
Electric Utility
CU4 Variable Cost Account Balance
July 2011 - June 2012

Month	CU4 Variable Cost Revenues	CU4 Variable Cost Expense	CU4 Variable Cost Balance
July 2011	$ 1,787,127	$ 1,501,537	$ (285,589)
August 2011	$ 1,980,514	$ 1,735,819	$ (244,695)
September 2011	$ 1,954,393	$ 1,726,100	$ (228,292)
October 2011	$ 1,714,628	$ 1,646,288	$ (68,340)
November 2011	$ 1,716,299	$ 1,457,057	$ (259,242)
December 2011	$ 1,981,123	$ 1,756,958	$ (224,165)
January 2012	$ 2,134,869	$ 945,777	$ (1,189,092)
February 2012	$ 2,047,604	$ 1,738,094	$ (309,510)
March 2012	$ 1,916,877	$ 1,526,787	$ (390,090)
April 2012	$ 1,804,809	$ 2,011,658	$ 206,849
May 2012 - Estimated	$ 1,707,667	$ 4,065,604	$ 2,357,937
June 2012 - Estimated	$ 1,875,001	$ 2,089,947	$ 214,946
CU4 Variable Balance Jul11-Jun12	**$ 22,620,911**	**$ 22,201,626**	**$ (419,284)**
	-	-	-

Source:
Revenues: Exhibit_(FVB-4)11-12, page 2, line 41.
Expense: Exhibit_(FVB-4)11-12, page 2, line 62.

Northwestern Energy
Electric Utility Derivation of Rates
Deferred CU4 Variable
Tracker Period July 2012 to June 2013

Customer Rate Class	Loss Factor	Jul12 to Jun13 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Deferred CU4 Variable Rate After Losses	Deferred CU4 Variable Revenue Check
Residential	8.5100%	2,363,392,484	2,363,392,484	2,564,517,184	$ (0.000506)	$ (1,195,877)
Residential Employee	8.5100%	3,898,778	2,339,267	2,538,338	$ (0.000304)	$ (1,185)
GS 1 Secondary NonDemand	8.5100%	272,790,804	272,790,804	296,005,301	$ (0.000506)	$ (138,032)
GS 1 Secondary Demand	8.5100%	2,438,440,251	2,438,440,251	2,645,951,516	$ (0.000506)	$ (1,233,851)
GS 1 Primary NonDemand	5.5400%	551,733	551,733	582,300	$ (0.000492)	$ (271)
GS 1 Primary Demand	5.5400%	350,552,671	350,552,671	369,973,289	$ (0.000492)	$ (172,472)
General Service Substation	4.6300%	244,005,756	244,005,756	255,303,222	$ (0.000488)	$ (119,075)
General Service Transmission	4.0000%	132,300,021	132,300,021	137,592,022	$ (0.000485)	$ (64,166)
Irrigation	8.5100%	83,490,261	83,490,261	90,595,283	$ (0.000506)	$ (42,246)
Lighting	8.5100%	57,821,458	57,821,458	62,742,064	$ (0.000506)	$ (29,258)
		5,947,244,217	5,945,684,706	6,425,800,519	$ (0.000504)	$ (2,996,432)
YNP Contract		18,457,300			Rounding Adjustment	$ 2,461
Total Electric Supply Load		5,965,701,517				$ (2,993,971)
		-				

2011-12 Deferred CU4 Variable Cost Over Collection $ (2,993,971)

Total Deferred Electric CU4 Variable Rate Before Losses $ (0.000466)
Total Deferred Electric CU4 Variable Rate After Losses $ (0.000504)

Exhibit__(CAH-3)_12-13
Docket No. D2012.5.49

NorthWestern Energy
Electric Utility
Deferred CU4 Variable Revenue ($000) Summary
Tracker Period July 2012 to June 2013

	Jul12-Jun13 Load Statistics	Current Deferred CU4 Rates 7/1/2011	Current Deferred CU4 Revenue	Proposed Deferred CU4 Rates 7/1/2012	Proposed Deferred CU4 Revenue	Revenue Diff Proposed vs Current
Residential						
Residential	2,363,392	$ (0.004172)	$ (9,860)	$ (0.000506)	$ (1,196)	$ 8,664
Residential Employee	3,899	$ (0.002503)	$ (10)	$ (0.000304)	$ (1)	$ 9
Total Residential			$ (9,870)		$ (1,197)	$ 8,673
General Service 1						
GS-1 Sec Non Demand	272,791	$ (0.004172)	$ (1,138)	$ (0.000506)	$ (138)	$ 1,000
GS-1 Sec Demand	2,438,440	$ (0.004172)	$ (10,173)	$ (0.000506)	$ (1,234)	$ 8,939
GS-1 Pri Non Demand	552	$ (0.004058)	$ (2)	$ (0.000492)	$ (0)	$ 2
GS-1 Pri Demand	350,553	$ (0.004058)	$ (1,423)	$ (0.000492)	$ (172)	$ 1,250
Total GS-1			$ (12,736)		$ (1,545)	$ 11,191
General Service 2						
GS-2 Substation	244,006	$ (0.004023)	$ (982)	$ (0.000488)	$ (119)	$ 863
GS-2 Transmission	132,300	$ (0.003999)	$ (529)	$ (0.000485)	$ (64)	$ 465
Total GS-2			$ (1,511)		$ (183)	$ 1,327
Irrigation						
Irrigation	83,490	$ (0.004172)	$ (348)	$ (0.000506)	$ (42)	$ 306
Total Irrigation			$ (348)		$ (42)	$ 306
Lighting						
Lighting	57,821	$ (0.004172)	$ (241)	$ (0.000506)	$ (29)	$ 212
Total Lighting			$ (241)		$ (29)	$ 212
Total Rate Schedule	**5,947,244**		**$ (24,706)**		**$ (2,996)**	**$ 21,709.693**
	-				-	

Northwestern Energy
Electric Utility Derivation of Rates
CU4 Variable
Tracker Period July 2012 to June 2013

Customer Rate Class	Loss Factor	Jul12 to Jun13 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	CU4 Variable After Losses kWh Charges	CU4 Variable Revenue/Cost Check
Residential	8.5100%	2,363,392,484	2,363,392,484	2,564,517,184	$ 0.004209	$ 9,947,519
Residential Employee	8.5100%	3,898,778	2,339,267	2,538,338	$ 0.002525	$ 9,844
GS 1 Secondary NonDemand	8.5100%	272,790,804	272,790,804	296,005,301	$ 0.004209	$ 1,148,176
GS 1 Secondary Demand	8.5100%	2,438,440,251	2,438,440,251	2,645,951,516	$ 0.004209	$ 10,263,395
GS 1 Primary NonDemand	5.5400%	551,733	551,733	582,300	$ 0.004094	$ 2,259
GS 1 Primary Demand	5.5400%	350,552,671	350,552,671	369,973,289	$ 0.004094	$ 1,435,163
General Service Substation	4.6300%	244,005,756	244,005,756	255,303,222	$ 0.004059	$ 990,419
General Service Transmission	4.0000%	132,300,021	132,300,021	137,592,022	$ 0.004034	$ 533,698
Irrigation	8.5100%	83,490,261	83,490,261	90,595,283	$ 0.004209	$ 351,411
Lighting	8.5100%	57,821,458	57,821,458	62,742,064	$ 0.004209	$ 243,371
MPSC System Average	7.4717%	5,947,244,217	5,945,684,706	6,425,800,519	$ 0.004192	$ 24,925,255
YNP Contract		18,457,300			Rounding Adjustment	$ 507
Total Supply Load		5,965,701,517				$ 24,925,762
		-				

Colstrip Unit 4 Variable Cost of Service	$	24,925,762
Total CU4 Variable COS Rate Before Losses	**$**	**0.003879**
Total CU4 Variable COS Rate After Losses	**$**	**0.004191**

NorthWestern Energy
Electric Utility
Total Colstrip Unit 4 Revenue ($000) Summary
Tracker Period July 2012 to June 2013

		CU4 Fixed		CU4 Variable				
	Jul12-Jun13 Load Statistics	Current Rates [1] 4/1/2010	Current Rate Revenue	Current Rates [2] 1/1/2012	Current Rate Revenue	Proposed Rates 7/1/2012	Proposed Rate Revenue	Revenue Diff Proposed vs Current
Residential								
Residential	2,363,392	0.012734	$ 30,095	0.003915	$ 9,253	0.004209	$ 9,948	$ 695
Residential Employee	3,899	0.007640	$ 30	0.002349	$ 9	0.002525	$ 10	$ 1
Total Residential			$ 30,125		$ 9,262		$ 9,957	$ 696
General Service 1								
GS-1 Sec Non Demand	272,791	0.012734	$ 3,474	0.003915	$ 1,068	0.004209	$ 1,148	$ 80
GS-1 Sec Demand	2,438,440	0.012734	$ 31,051	0.003915	$ 9,546	0.004209	$ 10,263	$ 717
GS-1 Pri Non Demand	552	0.012385	$ 7	0.003808	$ 2	0.004094	$ 2	$ 0
GS-1 Pri Demand	350,553	0.012385	$ 4,342	0.003808	$ 1,335	0.004094	$ 1,435	$ 100
Total GS-1			$ 38,873		$ 11,951		$ 12,849	$ 898
General Service 2								
GS-2 Substation	244,006	0.012278	$ 2,996	0.003775	$ 921	0.004059	$ 990	$ 69
GS-2 Transmission	132,300	0.012204	$ 1,615	0.003752	$ 496	0.004034	$ 534	$ 37
Total GS-2			$ 4,610		$ 1,418		$ 1,524	$ 107
Irrigation								
Irrigation	83,490	0.012734	$ 1,063	0.003915	$ 327	0.004209	$ 351	$ 25
Total Irrigation			$ 1,063		$ 327		$ 351	$ 25
Lighting								
Lighting	57,821	0.012734	$ 736	0.003915	$ 226	0.004209	$ 243	$ 17
Total Lighting			$ 736		$ 226		$ 243	$ 17
Total Rate Schedule	**5,947,244**		**$ 75,408**		**$ 23,184**		**$ 24,925**	**$ 1,741.193**
	-						-	

[1] Colstrip Unit 4 Fixed Rates approved in Docket No. D2010.5.50 Order No. 7093c effective 4/1/2010.
[2] Colstrip Unit 4 Variable Rates updated for property taxes January 2012 Electric Supply Monthly filing effective 1/1/2012.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2012.5.49
Annual Electric Supply Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF MICHAEL R. CASHELL

ON BEHALF OF NORTHWESTERN ENERGY

TABLE OF CONTENTS

Exhibits

Witness Information

Q. Please state your name and business address.

A. My name is Michael R. Cashell, and my business address is 40 East Broadway, Butte, Montana 59701.

Q. By whom are you employed and in what capacity?

A. I am NorthWestern Energy's ("NWE" or "NorthWestern") Vice President - Transmission.

Q. Please summarize your education and employment experience.

A. I graduated from the Montana Tech of the University of Montana, receiving a Bachelor of Science degree in Engineering Science in 1986. I also attended the University of Idaho's Public Utilities Executive Course in 1997. I have been certified as a North American Electric Reliability Corporation ("NERC") System Operator. I have worked in the electric and natural gas utility industry for nearly 26 years, first employed by the Montana Power Company ("MPC") and now by NorthWestern. My experience is primarily in the areas of transmission operations, control area operation, tariff and contract administration, bulk power supply and operations, hydro-electric and thermal electric generation plant optimization, and independent power production.

Q. What are your responsibilities as Vice President - Transmission?

A. I am responsible for all aspects of NorthWestern's electric and natural gas transmission systems, including the systems' safe, reliable and efficient operation, transmission services, operations, planning, engineering and maintenance. I am responsible for the activities related to transmission and transportation contracts, interconnection agreements, procurement of ancillary services products, and compliance activities related to Federal Energy Regulatory Commission ("FERC") regulation and NERC reliability and security standards.

<u>Purpose of Testimony</u>

Q. Please describe your testimony.

A. I offer testimony that 1) describes the variable costs and revenue credits that are being trued-up related to the Dave Gates Generating Station ("DGGS"); 2) describes how the outage of DGGS impacts the true-up process; 3) explains what NorthWestern has done to minimize the impacts of the outage of DGGS; and 4) explains, as set forth in Exhibit__(MRC-1), the methodology by which NorthWestern proposes to true-up DGGS-related costs and revenue credits for the January 2011 through June 2012 period.

DGGS Cost/Revenue Credit Items Included in Annual True-up

Q. Under normal circumstances, what DGGS cost and revenue items did NorthWestern intend to include and true-up in the DGGS portion of its electricity supply annual filing?

A. In Docket No. D2008.8.95, Patrick Corcoran, NWE Vice President of Government and Regulatory Affairs, indicated that variable costs that include fuel costs, as well as revenue credits from energy produced by DGGS, would be reflected and trued-up in the DGGS portion of the annual filing. Variable Fuel Costs include natural gas and diesel fuel. Variable Revenue Credits associated with the energy produced at DGGS in the process of providing regulation service were not intended to include the baseload energy of 7 average MW delivered to retail customers from the plant.

Q. Is NorthWestern obligated to investigate the availability of sources of regulation other than DGGS?

A. Yes. Pursuant to Order No. 6943a, ¶ 262, NorthWestern is obligated to periodically test the market for available alternatives for regulation services and use economic dispatch criteria to determine whether the total cost of such alternatives would be more cost effective than the variable operating costs of DGGS.

Q. What impact would use of regulation service alternatives have on the DGGS true-up portion of the annual electric supply filing?

A. If NWE made an economic decision to reduce or eliminate the operation of DGGS for a period of time, the costs of the alternate regulation source, such as a third-party regulation contract, would replace all or a portion of the DGGS variable fuel costs. As a result, the costs of the alternative service would be included as variable cost in the DGGS true-up portion of the annual filing.

<u>DGGS Turbine Outage and NorthWestern Response</u>

Q. Was there a recent outage at DGGS that caused NorthWestern to utilize third-party regulation contracts?

A. Yes. DGGS experienced a forced outage starting on January 31, 2012, and the plant was not available to fully meet NWE's regulation needs until May 1, 2012. NorthWestern was able to arrange for regulation service contracts with Powerex and Avista during this period.

Q. Please provide more information regarding the regulation service contracts with Powerex and Avista.

A. NorthWestern entered into contracts with Powerex and Avista shortly after January 31, 2012 due to damage to the power turbines of each of the three units at DGGS. NorthWestern was able to negotiate agreements in substantially the same form as the previous agreements for regulation service that were in place prior to DGGS going into commercial operation. Each agreement included a regulating reserve capacity component and a regulating reserve energy component. The agreements were structured to simulate a generating resource, consistent with past regulation contracts, so that NorthWestern could regulate both up and down. This is the same service DGGS provides, and it is critical to the reliable operation of the NorthWestern Balancing Authority Area and transmission system.

NorthWestern's Actions to Reduce Impacts of the Turbine Outage

Q. What additional flexibility was NorthWestern able to negotiate in the Powerex and Avista contracts?

A. NorthWestern negotiated the contractual ability to reduce its regulating reserve capacity requirements and related regulating reserve energy, with resulting lower costs, as DGGS was brought back into service. For example, NWE's contracted service with Powerex and Avista began on February 3, 2012, just over two days after the full outage of DGGS.[1] On February 3, NorthWestern contracted for 76 MW of regulating reserve capacity from Powerex and 15 MW from Avista. Through the efforts of Pratt & Whitney Power Systems ("PWPS"), the turbine vendor, and NorthWestern's employees, DGGS was brought back online in increments using loaned and/or DGGS power turbines which had been repaired by PWPS. Using this staged approach, NorthWestern was able to rapidly reduce the regulation service required under the regulation service

[1] DGGS was forced out of service on January 31, 2012 at 8:10 p.m.

contracts. The table below shows how the regulation service taken under the contracts with Avista and Powerex was reduced as DGGS became operational.

Regulation Contract Services

	Avista MW	Powerex MW
2/3/2012	15	76
3/1/2012	15	50
4/1/2012	15	24
4/15/2012	15	10
5/1/2012	0	0

As of May 1, 2012, NorthWestern is no longer incurring costs under either the Powerex or Avista regulating reserve contract.

Q. What is the current status of DGGS?

A. At this time, two and one-half DGGS units (5 power turbines) are available to provide regulation service. This is through a combination of loaned power turbines and DGGS power turbines that have been repaired at PWPS's Connecticut maintenance facility and returned to service.

Q. Are the repairs that have been made to the DGGS power turbines final?

A. No. PWPS still must complete the root cause analysis for the damaged turbines and design the final changes required for a permanent solution. Ultimately, each of the DGGS power turbines will need to be taken out of service again and have the final design changes implemented.

Effect of Turbine Outage on Tracker Costs

Q. How does the outage of DGGS, and the subsequent need to enter into third-party regulation service contracts, impact the DGGS true-up process?

A. There is no substantial impact to the true-up process as a result of the DGGS outage and the use of third-party contracts. As described above, these contract costs replace the fuel costs that would have been included as variable costs in the DGGS true-up process, just as they would have if NorthWestern had entered into third-party contracts in the normal course of business.

Q. Have you prepared an analysis that illustrates the DGGS true-up that would have been proposed had DGGS not been taken off-line?

A. Yes. Pages 1 and 2 of Exhibit__(MRC-1) present this analysis for January 2011 through June 2012, with May and June estimated. Because no adjustments were made to monthly DGGS variable costs during the period of the outage, rates paid by customers reflected forecasted variable fuel costs and forecasted revenue credits as though DGGS was in operation.

Pages 1 and 2 of this exhibit set forth what this 18-month true-up analysis would have looked like had no third-party regulation contracts been needed. Importantly, I note that this analysis includes estimated fuel costs and energy production at DGGS assuming that there had been no outage. Line 8 on pages 1 and 2 shows Variable Fuel Cost Revenues, by month, that have been collected as part of the rates associated with DGGS. Next, the actual fuel costs, by month, including natural gas, diesel, and related transportation costs, appear on lines 10 and 11 with the total on line 13. Finally, the over- or under-collection of revenues is tracked on line 15. Without considering the costs associated with the third-party regulation agreements – in other words, assuming no outage at DGGS – line 15 would indicate an over-collection from customers of $(4,306,373).

Q. How are revenue credits related to the energy produced at DGGS as a by-product of the regulation process handled?

A. Line 18 of pages 1 and 2 of Exhibit__(MRC-1) shows the monthly values of revenue credits provided to customers, based upon annual energy production of 27 average MW, valued at projected Mid-C monthly market prices minus $7/MWH. Customers received a credit for this 18-month time period of $7,159,264. However, the true value of the energy produced (at the actual Mid-C monthly price minus $7/MWH) was $4,714,052 as shown on line 24. This means that customers received a credit that was $2,445,212 too high as shown on line 26, and NorthWestern must collect this amount from customers.

Q. What is the result of a DGGS true-up computation for the 18-month period from January 2011 through June 2012, assuming no DGGS outage and no regulation market purchases were made?

A. As shown on line 28 on page 1 of Exhibit__(MRC-1), with full production from DGGS and no third-party regulation contracts, NorthWestern would have over-collected from customers a net amount of $(1,861,161).

Q. Since there was an outage at DGGS, is this number relevant to what NorthWestern is proposing in this DGGS true-up filing?

A. It is relevant only as a comparison to illustrate the difference between what was expected to occur in the true-up and how that had to be modified as a result of the outage. However, as described above, Order No. 6943a contemplated that NorthWestern may at some time enter into third-party contracts if the comparison of economic alternatives to the operation of DGGS showed that option to be a more cost-effective source of regulation services. As a result, in testimony that follows, I will explain how NorthWestern's proposal for this DGGS true-up period is consistent with this philosophy.

<u>NorthWestern's Proposal (includes true-up of 7 average MW supply)</u>

Q. Please explain the impact of the DGGS outage and the inclusion of the costs of the third-party contracts for regulation service on the DGGS true-up computation?

A. Pages 3 and 4 of Exhibit__(MRC-1) show this analysis. Lines 15 through 17 include the capacity and energy charges associated with the Powerex and Avista contracts that were required as a result of the DGGS outage for the months of February through April. As shown on line 19, these capacity and energy costs total $2,946,886 for this 3-month period. Line 23 makes it evident that inclusion of the costs of the regulation contracts significantly decreases the over-collection from customers as compared to pages 1 and 2. The over-collection from customers declines from $4.3 million to $1.5 million as shown on line 23 of page 3. Similarly, when including the cost of the energy associated with the regulation contracts in the revenue credit calculation, $1,859,386 is due from customers for this 18-month period, as shown on line 40 of page 3.

Q. Does DGGS also provide 7 average MW of minimum generation baseload energy to the electricity supply portfolio for use by Energy Supply retail customers?

A. Yes it does. This energy is also priced at an estimated Mid-C monthly price minus $7/MWH, but it is not included in the annual DGGS true-up computation. It was determined in Docket No. D2008.8.95 that the value of this energy would remain constant until an updated value was determined as part of a future DGGS general filing. NorthWestern is now proposing a change in this treatment, which is discussed in more detail below.

Q. Have you made any additional adjustments to the DGGS annual true-up computation that is presented on pages 3 and 4 of Exhibit__(MRC-1)?

A. Yes. As described above, DGGS provides 7 average MW of baseload generation to serve retail customers. When DGGS is operating, this energy is always scheduled to Energy Supply and provides an offset to energy that would otherwise need to be procured for retail customers. The revenue in the 18-month period associated with this 7 average MW baseload supply from DGGS to retail customers is shown on line 43 of page 3 and is $2,322,459. This amount was based on a projected Mid-C price of $32.93 minus $7/MWH, as approved in Docket No. D2008.8.95.

Q. You stated above that the value of the 7 average MW of baseload minimum generation is not part of the DGGS annual true-up, but is adjusted only at the time of an electric general rate filing. What impact would a true-up of this value to actual prices have on the analysis?

A. The inclusion of a true-up of the value of the 7 average MW of baseload energy provided to retail customers has been reflected on page 3 of my exhibit. The value of the 7 average MW using actual monthly Mid-C prices minus $7 per MWH is $1,330,423 as shown on Line 47. Line 49 shows that a true-up of the approved Mid-C price minus $7 per MWH to actual values results in a difference of $(992,036) over-collected from customers.

Q. What is NorthWestern Energy proposing in regard to this over-collection?

A. While it was contemplated in Docket No. D2008.8.95 that the value of the 7 average MW of minimum generation baseload energy would be adjusted only when NorthWestern Energy filed an electric general rate filing, NorthWestern has concluded that to true-up on an annual basis is more appropriate because it is consistent with the treatment of other energy produced as part of the regulation process at DGGS. The true-up of this value, as with all true-ups, can result in an over- or under-collection from customers on an annual basis going forward.

Q. With the inclusion of this additional true-up, what is the final result of the DGGS cost and revenue credit true-up, reflecting the outage of DGGS and the purchase of regulation through third-party contracts for three months in 2012?

A. The net result is an over-collection from customers of $(590,694) as shown on line 51 of page 3 of Exhibit__(MRC-1).

Q. Does this conclude your testimony?

A. Yes, it does.

Assumes no Plant Outage with no Regulation Purchase Contracts Tracking Variable Cost and Credits as required by MPSC Order 6943b

	A	B	C	D	E	F	G	H	I	J	K	L
1	NorthWestern Energy											
2	Dave Gates Generating Station (DGGS)											
3	MPSC - Variable Costs & Credits Analysis											
4	May 2012											
5												
6		Total	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11
7	*Variable Fuel Cost:*											
8	Natural Gas Fuel Cost Revenues	$ 20,234,227	$ 591,444	$ 1,189,654	$ 1,186,138	$ 1,071,572	$ 1,069,481	$ 1,037,183	$ 1,115,702	$ 1,236,428	$ 1,220,116	$ 1,070,442
9	*Less Actual Fuel Costs:*											
10	Natural Gas Costs (Incl Tran/Compressor)	$ 15,694,022	$ 1,028,565	$ 874,872	$ 1,097,527	$ 1,070,650	$ 1,076,822	$ 1,169,384	$ 1,108,354	$ 1,290,254	$ 1,045,796	$ 919,418
11	Diesel	233,833	6,242	115,329	104,284	-	1,775	-	4,284	-	487	-
12	Regulation Contracts	-	-	-	-	-	-	-	-	-	-	-
13	Total Fuel Costs & Contracts	$ 15,927,855	$ 1,034,807	$ 990,201	$ 1,201,811	$ 1,070,650	$ 1,078,598	$ 1,169,384	$ 1,112,638	$ 1,290,254	$ 1,046,283	$ 919,418
14												
15	**Difference (Over) / Under Collect**	$ (4,306,373)	443,363	(199,453)	15,673	(922)	9,117	132,201	(3,064)	53,826	(173,832)	(151,024)
16												
17	*Variable Revenue Credit:*											
18	Revenue Credits 27MW Revenues	$ (7,159,264)	$ (224,363)	$ (451,265)	$ (449,929)	$ (406,468)	$ (391,377)	$ (359,035)	$ (386,213)	$ (427,998)	$ (422,349)	$ (370,543)
19	*Less Actual Revenue Credits:*											
20	Actual MWH Generation		(20,713)	(18,999)	(25,211)	(22,113)	(22,259)	(23,813)	(23,345)	(30,111)	(22,432)	(21,739)
21	Mid-C minus $7		$ 18.46	$ 15.04	$ 9.63	$ 13.30	$ 9.52	$ 8.45	$ 15.23	$ 21.27	$ 24.72	$ 19.21
22	Total Actual Revenue Credits	$ (5,892,566)	$ (382,443)	$ (285,751)	$ (242,836)	$ (294,133)	$ (211,935)	$ (201,250)	$ (355,541)	$ (640,318)	$ (554,538)	$ (417,635)
23	MPSC Allocation	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
24	MPSC Revenue Credits	$ (4,714,052)	$ (305,955)	$ (228,601)	$ (194,269)	$ (235,306)	$ (169,548)	$ (161,000)	$ (284,433)	$ (512,255)	$ (443,630)	$ (334,108)
25												
26	**Difference (Over) / Under Collect**	$ 2,445,212	(81,591)	222,664	255,661	171,162	221,829	198,035	101,780	(84,257)	(21,282)	36,435
27												
28	**Total Difference (Over) / Under Collect**	$ (1,861,161)										
29												

Dkt. No. D2012.5.49
EXHIBIT__(MRC-1)
PAGE 1 OF 4

Assumes no Plant Outage with no Regulation Purchase Contracts Tracking Variable Cost and Credits as required by MPSC Order 6943b

	A	M	N	O	P	Q	R	S	T
1	NorthWestern Energy								
2	Dave Gates Generating Station (DGGS)								
3	MPSC - Variable Costs & Credits Analysis								
4	May 2012								
5					Estimates/Forecast				
6		Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
7	*Variable Fuel Cost:*								
8	Natural Gas Fuel Cost Revenues	$ 1,071,491	$ 1,236,824	$ 1,311,028	$ 1,257,433	$ 1,177,152	$ 1,108,328	$ 1,088,510	$ 1,195,301
9	*Less Actual Fuel Costs:*								
10	Natural Gas Costs (Incl Tran/Compressor)	$ 893,687	$ 736,264	$ 723,572	$ 498,895	$ 548,728	$ 461,924	$ 550,480	$ 598,831
11	Diesel	-	1,345	-	86	-	-	-	-
12	Regulation Contracts	-	-	-	-	-	-	-	-
13	**Total Fuel Costs & Contracts**	$ 893,687	$ 737,609	$ 723,572	$ 498,981	$ 548,728	$ 461,924	$ 550,480	$ 598,831
14									
15	**Difference (Over) / Under Collect**	(177,805)	(499,215)	(587,457)	(758,452)	(628,424)	(646,404)	(538,031)	(596,470)
16									
17	*Variable Revenue Credit:*								
18	Revenue Credits 27MW Revenues	$ (370,916)	$ (428,154)	$ (453,847)	$ (435,284)	$ (407,493)	$ (383,663)	$ (376,636)	$ (413,730)
19	*Less Actual Revenue Credits:*								
20	Actual MWH Generation	(23,000)	(19,207)	(23,276)	(19,677)	(25,211)	(22,113)	(22,259)	(23,813)
21	Mid-C minus $7	$ 24.04	$ 23.86	$ 18.01	$ 19.15	$ 9.55	$ 2.26	$ 3.35	$ 5.61
22	Total Actual Revenue Credits	$ (552,831)	$ (458,364)	$ (419,288)	$ (376,815)	$ (240,765)	$ (49,975)	$ (74,557)	$ (133,591)
23	MPSC Allocation	80%	80%	80%	80%	80%	80%	80%	80%
24	**MPSC Revenue Credits**	$ (442,264)	$ (366,691)	$ (335,430)	$ (301,452)	$ (192,612)	$ (39,980)	$ (59,645)	$ (106,873)
25									
26	**Difference (Over) / Under Collect**	(71,349)	61,463	118,417	133,833	214,881	343,683	316,991	306,857
27									
28	**Total Difference (Over) / Under Collect**								
29									

Dkt. No. D2012.5.49
EXHIBIT__(MRC-1)
PAGE 2 OF 4

Plant Outage with Regulation Purchase Contracts Tracking Variable Cost and Credits as required by MPSC Order No. 6943b with 7MW Variable Energy Adjustment

	A	B	C	D	E	F	G	H	I	J	K
1	NorthWestern Energy										
2	Dave Gates Generating Station (DGGS)										
3	MPSC - Variable Costs & Credits Analysis										
4	May 2012										
5											
6		Total	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11
7	*Variable Fuel Cost:*										
8	Natural Gas Fuel Cost Revenues	$ 20,234,227	$ 591,444	$ 1,189,654	$ 1,186,138	$ 1,071,572	$ 1,069,481	$ 1,037,183	$ 1,115,702	$ 1,236,428	$ 1,220,116
9	*Less Actual Fuel Costs:*										
10	Natural Gas Costs (Incl Tran/Compressor)	$ 15,595,464	$ 1,057,619	$ 924,254	$ 1,163,377	$ 1,123,000	$ 1,143,134	$ 1,241,290	$ 1,150,882	$ 1,307,636	$ 1,052,103
11	Diesel	$ 233,833	$ 6,242	$ 115,329	$ 104,284	$ -	$ 1,775	$ -	$ 4,284	$ -	$ 487
12	Subtotal MPSC-Related Fuel Cost	$ 15,829,297	$ 1,063,861	$ 1,039,583	$ 1,267,661	$ 1,123,000	$ 1,144,910	$ 1,241,290	$ 1,155,166	$ 1,307,636	$ 1,052,590
13											
14	*Less Regulation Contracts:*										
15	Capacity	$ 2,392,728	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Energy	$ 1,290,880	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Subtotal	$ 3,683,607	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	MPSC Allocation	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
19	Subtotal Regulation Contract Cost	$ 2,946,886	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											
21	Total Fuel Costs & Contracts	$ 18,776,183	$ 1,063,861	$ 1,039,583	$ 1,267,661	$ 1,123,000	$ 1,144,910	$ 1,241,290	$ 1,155,166	$ 1,307,636	$ 1,052,590
22											
23	Difference (Over) / Under Collect	$ (1,458,045)	$ 472,417	$ (150,071)	$ 81,523	$ 51,429	$ 75,429	$ 204,107	$ 39,464	$ 71,208	$ (167,525)
24		-									
25	*Variable Revenue Credit:*										
26	Revenue Credits 27MW Revenues	$ (7,159,264)	$ (224,363)	$ (451,265)	$ (449,929)	$ (406,468)	$ (391,377)	$ (359,035)	$ (386,213)	$ (427,998)	$ (422,349)
27	*Less Actual Revenue Credits:*										
28	Actual MWH Generation		(20,713)	(18,999)	(25,211)	(22,113)	(22,259)	(23,813)	(23,345)	(30,111)	(22,432)
29	Mid-C minus $7		$ 18.46	$ 15.04	$ 9.63	$ 13.30	$ 9.52	$ 8.45	$ 15.23	$ 21.27	$ 24.72
30	Total Actual Revenue Credits	$ (5,333,968)	$ (382,443)	$ (285,751)	$ (242,836)	$ (294,133)	$ (211,935)	$ (201,250)	$ (355,541)	$ (640,318)	$ (554,538)
31	MPSC Allocation	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
32	Actual Revenue Credits	$ (4,267,174)	$ (305,955)	$ (228,601)	$ (194,269)	$ (235,306)	$ (169,548)	$ (161,000)	$ (284,433)	$ (512,255)	$ (443,630)
33	*Less Contract Revenue Credits:*										
34	Revenue Credits	$ (1,290,880)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	MPSC Allocation	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
36	Contract Revenue Credits	$ (1,032,704)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37											
38	Total Actual Revenue & Contract Credits	$ (5,299,878)	$ (305,955)	$ (228,601)	$ (194,269)	$ (235,306)	$ (169,548)	$ (161,000)	$ (284,433)	$ (512,255)	$ (443,630)
39											
40	Difference (Over) / Under Collect	$ 1,859,386	$ (81,591)	$ 222,664	$ 255,661	$ 171,162	$ 221,829	$ 198,035	$ 101,780	$ (84,257)	$ (21,282)
41											
42	*Variable Energy 7MW:*										
43	Energy Supply Costs 7MW Revenues	$ 2,322,459	$ 72,663	$ 146,153	$ 145,719	$ 131,648	$ 126,864	$ 116,532	$ 125,352	$ 138,915	$ 137,081
44	*Less Actual Energy Costs 7MW:*										
45	*Energy Costs 7MW Adj. to Market Price*										
46	Monthly 7MW		5,208	4,704	5,208	5,040	5,208	5,040	5,208	5,208	5,040
47	Energy Supply Costs at Market Price	$ 1,330,423	$ 96,160	$ 70,750	$ 50,164	$ 67,039	$ 49,587	$ 42,594	$ 79,317	$ 110,750	$ 124,593
48											
49	Difference (Over) / Under Collect	$ (992,036)	$ 23,497	$ (75,403)	$ (95,555)	$ (64,609)	$ (77,277)	$ (73,938)	$ (46,035)	$ (28,166)	$ (12,488)
50											
51	Total Difference (Over) / Under Collect	$ (590,694)									

Dkt. No. D2012.5.49
EXHIBIT__(MRC-1)
PAGE 3 OF 4

Plant Outage with Regulation Purchase Contracts Tracking Variable Cost and Credits as required by MPSC Order No. 6943b with 7MW Variable Energy Adjustment

	A	L	M	N	O	P	Q	R	S	T
1	NorthWestern Energy									
2	Dave Gates Generating Station (DGGS)									
3	MPSC - Variable Costs & Credits Analysis									
4	May 2012									
5									Forecast	
6		Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
7	*Variable Fuel Cost:*									
8	Natural Gas Fuel Cost Revenues	$ 1,070,442	$ 1,071,491	$ 1,236,824	$ 1,311,028	$ 1,257,433	$ 1,177,152	$ 1,108,328	$ 1,088,510	$ 1,195,301
9	*Less Actual Fuel Costs:*									
10	Natural Gas Costs (Incl Tran/Compressor)	$ 945,357	$ 902,755	$ 742,817	$ 754,501	$ 69,530	$ 279,893	$ 412,616	$ 642,506	$ 682,193
11	Diesel	$ -	$ -	$ 1,345	$ -	$ 86	$ -	$ -	$ -	$ -
12	Subtotal MPSC-Related Fuel Cost	$ 945,357	$ 902,755	$ 744,162	$ 754,501	$ 69,616	$ 279,893	$ 412,616	$ 642,506	$ 682,193
13										
14	*Less Regulation Contracts:*									
15	Capacity	$ -	$ -	$ -	$ -	$ 1,113,078	$ 888,828	$ 390,822	$ -	$ -
16	Energy	$ -	$ -	$ -	$ -	$ 768,176	$ 401,242	$ 121,461	$ -	$ -
17	Subtotal	$ -	$ -	$ -	$ -	$ 1,881,254	$ 1,290,070	$ 512,283	$ -	$ -
18	MPSC Allocation	80%	80%	80%	80%	80%	80%	80%	80%	80%
19	Subtotal Regulation Contract Cost	$ -	$ -	$ -	$ -	$ 1,505,003	$ 1,032,056	$ 409,827	$ -	$ -
20										
21	Total Fuel Costs & Contracts	$ 945,357	$ 902,755	$ 744,162	$ 754,501	$ 1,574,619	$ 1,311,949	$ 822,443	$ 642,506	$ 682,193
22										
23	Difference (Over) / Under Collect	$ (125,084)	$ (168,737)	$ (492,662)	$ (556,528)	$ 317,186	$ 134,797	$ (285,885)	$ (446,004)	$ (513,108)
24										
25	*Variable Revenue Credit:*									
26	Revenue Credits 27MW Revenues	$ (370,543)	$ (370,916)	$ (428,154)	$ (453,847)	$ (435,284)	$ (407,493)	$ (383,663)	$ (376,636)	$ (413,730)
27	*Less Actual Revenue Credits:*									
28	Actual MWH Generation	(21,739)	(23,000)	(19,207)	(23,276)	(214)	(8,134)	(12,003)	(22,259)	(23,813)
29	Mid-C minus $7	$ 19.21	$ 24.04	$ 23.86	$ 18.01	$ 19.15	$ 9.55	$ 2.26	$ 3.35	$ 5.61
30	Total Actual Revenue Credits	$ (417,635)	$ (552,831)	$ (458,364)	$ (419,288)	$ (4,098)	$ (77,712)	$ (27,147)	$ (74,557)	$ (133,591)
31	MPSC Allocation	80%	80%	80%	80%	80%	80%	80%	80%	80%
32	Actual Revenue Credits	$ (334,108)	$ (442,264)	$ (366,691)	$ (335,430)	$ (3,278)	$ (62,170)	$ (21,718)	$ (59,645)	$ (106,873)
33	*Less Contract Revenue Credits:*									
34	Revenue Credits	$ -	$ -	$ -	$ -	$ (768,176)	$ (401,242)	$ (121,461)	$ -	$ -
35	MPSC Allocation	80%	80%	80%	80%	80%	80%	80%	80%	80%
36	Contract Revenue Credits	$ -	$ -	$ -	$ -	$ (614,541)	$ (320,994)	$ (97,169)	$ -	$ -
37										
38	Total Actual Revenue & Contract Credits	$ (334,108)	$ (442,264)	$ (366,691)	$ (335,430)	$ (617,819)	$ (383,163)	$ (118,887)	$ (59,645)	$ (106,873)
39										
40	Difference (Over) / Under Collect	$ 36,435	$ (71,349)	$ 61,463	$ 118,417	$ (182,535)	$ 24,330	$ 264,776	$ 316,991	$ 306,857
41										
42	*Variable Energy 7MW:*									
43	Energy Supply Costs 7MW Revenues	$ 120,271	$ 120,392	$ 138,966	$ 147,305	$ 141,281	$ 132,260	$ 124,526	$ 122,247	$ 134,285
44	*Less Actual Energy Costs 7MW:*									
45	*Energy Costs 7MW Adj. to Market Price*									
46	Monthly 7MW	5,208	5,040	5,208	5,208	4,872	5,208	5,040	5,208	5,040
47	Energy Supply Costs at Market Price	$ 100,053	$ 121,142	$ 124,286	$ 93,816	$ 93,299	$ 49,757	$ 11,399	$ 17,444	$ 28,274
48										
49	Difference (Over) / Under Collect	$ (20,218)	$ 750	$ (14,681)	$ (53,489)	$ (47,982)	$ (82,503)	$ (113,128)	$ (104,803)	$ (106,010)
50										
51	Total Difference (Over) / Under Collect									

Dkt. No. D2012.5.49
EXHIBIT__(MRC-1)
PAGE 4 OF 4

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2012.5.49
Annual DGGS True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF FRANK V. BENNETT

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL DAVE GATES GENERATING STATION ("DGGS") TRUE-UP

TABLE OF CONTENTS

Witness Information

Q. Are you the same Frank V. Bennett who filed Prefiled Direct Testimony in the Electricity Supply Tracker portion of this docket?

A. Yes.

Purpose of Testimony

Q. Please describe your Annual DGGS True-up testimony.

A. In my testimony I present the following information:

- The updated DGGS costs for the 12-month ended June 2012 true-up period with 10 months of actual numbers and 2 months of estimated numbers, and
- The forecast DGGS costs for the 12-month ended June 2013 true-up period.

Update to DGGS Values in the 2011/2012 True-up Period

Q. How has NorthWestern updated the DGGS generation values reflected in the 2011/2012 tracker?

A. NorthWestern includes the contribution of 7 MW of base load energy from the DGGS asset in the Electricity Supply Tracker.

Q. How are the DGGS variable costs of service treated in the 2011/2012 true-up period?

A. The DGGS costs are treated the same as they were in NorthWestern's 2011 annual true-up filing. The variable DGGS cost of service includes 10 months of actual values and 2 months of estimated information. During early 2012, DGGS experienced an outage that required short-term replacement regulation service contracts that are discussed in the Prefiled Direct Testimony of Michael Cashell ("Cashell Direct Testimony"). The variable cost of service on page 2 of Exhibit__(FVB-6)11_12 includes fuel cost offset by costs allocated to choice customers and net revenue credits to derive the variable DGGS costs and the true-up values discussed in the Cashell Direct Testimony. These variable costs are tracked in a manner similar to the market-based supply costs.

Q. Are any other changes reflected in the 2011/2012 true-up period?

A. Yes. Under Final Order No. 7154b in Docket No. D2011.5.38, the Montana Public Service Commission ("MPSC") authorized NorthWestern to include forecast lost revenues related to Demand-Side Management ("DSM") in future filings. Forecast lost DGGS fixed cost revenues resulting from DSM and Universal System Benefits activities are included in both the 2011/2012 and 2012/2013 true-up period. Refer to the Prefiled Direct Testimony of William Thomas ("Thomas Direct Testimony") for support for the DGGS fixed cost lost revenues.

Q. Please explain the lost revenue changes reflected in the 2011/2012 true-up period.

A. The forecast and true-up lost revenues reflected in the 2011/2012 period have been shown on page 2 of Exhibit__(FVB-6)11_12 as an adjustment in the months of April, May, and June to reflect the lost revenue calculation as discussed in the Thomas Direct Testimony.

Q. Have any adjustments been made to the DGGS fixed cost of service in the 2011/2012 or 2012/2013 true-up periods?

A. Yes. The DGGS fixed cost of service presented in this filing has been updated from what was approved in Docket No. D2008.8.95, Order No. 6943c. The fixed cost of service and associated fixed cost rates were updated in compliance with Order No. 6943e in NorthWestern's May 1, 2012 monthly electric tracker filing. They will remain unchanged until such time that an order is issued in a subsequent revenue requirement filing.

Q. Please summarize the 12-month ended June 2012 DGGS deferred balance.

A. The June 2011 deferred balance of $1,476,330 under-collection shown on page 2 of Exhibit__(FVB-6)10_11 from Docket No. D2011.5.38 is the July 2011 beginning deferred balance. With 10 months of actual values and 2 months of estimated values, the June 2012 ending deferred account balance is a $(161,231) over-collection. Please refer to the Prefiled Direct Testimony of Cheryl A. Hansen – Annual DGGS True-up for further discussion of the Deferred Account.

Q. Please summarize the 12-month ended June 2012 DGGS true-up period variable costs.

A. The DGGS true-up period is summarized in the following table:

Beginning Deferred DGGS		**Balance ($)**
Under-Collection		1,476,330

Variable Costs DGGS		**Cost ($)**
Fuel Cost		14,533,096
Fuel Adjustment		(2,392,728)
Less Energy Supply 7 MW		(1,374,928)
7 MW Cost Adjustment		420,798
Less Transmission Service @ 20%		(2,237,248)
Energy Supply 7 MW		1,374,928
7 MW Cost Adjustment		(420,798)
Reg. Contract Capacity		2,392,728
Reg. Contract Energy		1,290,880
Less Transmission Service @ 20%		(736,721)
DGGS – Fuel Cost Allocation:		12,850,006

Revenue Credits 27 MW		(3,715,620)
Less Transmission Service @ 20%		743,124
Reg. Contract Revenue Credit		(1,290,880)
Less Transmission Service @ 20%		258,176
DGGS – Revenue Credit Allocation:		(4,005,200)

DSM Lost Revenue		44,891
DSM Lost Revenue Adjustment		298,784
Subtotal DGGS Variable Cost Allocation		9,188,462

Carrying Cost		54,586
Carry Cost Adjustment		165
Prior Period Deferred Adjustment		(85,985)
Total DGGS Variable Cost Allocation		$ 9,157,248

Variable Revenues DGGS		**Revenue ($)**
Revenues		10,794,809

Ending Deferred DGGS		**Balance ($)**
Over-Collection		(161,231)

Forecast of DGGS in the 2012/2013 True-up Period

Q. Are any changes reflected in the 2012/2013 tracking period?

A. Yes, under Final Order No. 7154b in Docket No. D2011.5.38, the MPSC authorized NorthWestern to include forecast lost revenues associated with DSM in future filings. Forecast lost DGGS fixed cost revenues are reflected in this forecast true-up period and are addressed in the Thomas Direct Testimony.

Q. Please summarize the 12-month DGGS true-up period ending June 2013.

A. The June 2012 Deferred Account over-collection ending balance of $(161,231) as described above is the July 2012 beginning balance. July 2012 through June 2013 information is based on forecast numbers. Please see Exhibit__(FVB-7)12_13 for supply volume and cost details of the 12-month forecast tracking period.

Q. Describe the changes within the DGGS variable Revenue and Cost categories for the 12-month ended June 2013 forecast true-up period.

A. The DGGS Generation Asset variable cost revenue and expense details are reflected on page 2 of Exhibit__(FVB-7)12_13 under two main sections, Total Revenue and Total Variable Cost Allocation. Total Revenue is estimated to be $7,345,934, reflecting a decrease from the prior true-up period in Exhibit__(FVB-6)11_12. The 12-month forecast true-up estimates a Total DGGS Variable Cost Allocation of $7,507,165, reflecting a decrease from the prior period.

Q. Please provide a summary table of the 12-month ended June 2013 DGGS true-up period.

A. The DGGS true-up period is summarized in the following table:

Beginning Deferred DGGS		**Balance ($)**
Over-Collection		(161,231)

Variable Costs DGGS		**Cost ($)**
Fuel Cost		14,141,769
Fuel Adjustment		0
Less Energy Supply 7 MW		(1,501,727)
Less Transmission Service @ 20%		(2,528,009)
Energy Supply 7 MW		1,501,727
Reg. Contract Capacity		0
Reg. Contract Energy		0
Less Transmission Service @ 20%		0
DGGS – Fuel Cost Allocation:		11,613,761

Revenue Credits 27 MW		(5,792,375)
Less Transmission Service @ 20%		1,158,475
Reg. Contract Revenue Credit		0
Less Transmission Service @ 20%		0
DGGS – Revenue Credit Allocation:		(4,633,900)

DSM Lost Revenue		539,139
DSM Lost Revenue Adjustment		0
Subtotal DGGS Variable Cost Allocation		7,519,000

Carrying Cost		(11,836)
Total DGGS Variable Cost Allocation		7,507,165

Variable Revenues DGGS		**Revenue ($)**
Revenues		7,345,934

Ending Deferred DGGS		**Balance ($)**
Even Collection		0

Q. Does this conclude your Annual DGGS True-up testimony?

A. Yes, it does.

	A B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Dave Gates Generating Station at Mill Creek Asset Component**														
2			**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Total**
3			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
4	**Dave Gates Generating Station Fixed Cost Revenue Requirement -- Per Interim Order 6943b ***														
5	DGGS Plant in Service														
6	Electric Generation Plant		$ 15,391,857	$ 15,391,857	$ 15,391,857	$ 15,391,857	$ 15,391,857	$ 15,391,857	$ 15,391,857	$ 15,391,857	$ 15,391,857	$ 15,391,857	$ 15,391,857	$ 15,391,857	$ 184,702,288
7	Accumulated Depreciation (Book Life 30 Yrs)		$ (252,996)	$ (252,996)	$ (252,996)	$ (252,996)	$ (252,996)	$ (252,996)	$ (252,996)	$ (252,996)	$ (252,996)	$ (252,996)	$ (252,996)	$ (252,996)	$ (3,035,952)
8	DGGS Project Costs		$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 231,716
9	Customer Contributed Capital		$ 447	$ 447	$ 447	$ 447	$ 447	$ 447	$ 447	$ 447	$ 447	$ 447	$ 447	$ 447	$ 5,358
10	Working Capital		$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 1,980,537
11	Total Year End Rate Base		$ 15,323,662	$ 15,323,662	$ 15,323,662	$ 15,323,662	$ 15,323,662	$ 15,323,662	$ 15,323,662	$ 15,323,662	$ 15,323,662	$ 15,323,662	$ 15,323,662	$ 15,323,662	$ 183,883,947
12															
13	Fixed Return (Avg RB * Cost of Capital)	8.16%	$ 1,250,411	$ 1,250,411	$ 1,250,411	$ 1,250,411	$ 1,250,411	$ 1,250,411	$ 1,250,411	$ 1,250,411	$ 1,250,411	$ 1,250,411	$ 1,250,411	$ 1,250,411	$ 15,004,930
14															
15	Fixed Cost of Service														
16	Operation & Maintenance Expenses		$ 563,583	$ 563,583	$ 563,583	$ 563,583	$ 563,583	$ 563,583	$ 563,583	$ 563,583	$ 563,583	$ 563,583	$ 563,583	$ 563,583	$ 6,763,000
17	Depreciation		$ 505,992	$ 505,992	$ 505,992	$ 505,992	$ 505,992	$ 505,992	$ 505,992	$ 505,992	$ 505,992	$ 505,992	$ 505,992	$ 505,992	$ 6,071,904
18	Amortization of DGGS Project Cost		$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 154,477
19	Property Taxes		$ 481,036	$ 481,036	$ 481,036	$ 481,036	$ 481,036	$ 481,036	$ 481,036	$ 481,036	$ 481,036	$ 481,036	$ 481,036	$ 481,036	$ 5,772,435
20	MPSC & MCC Revenue Tax		$ 16,706	$ 16,706	$ 16,706	$ 16,706	$ 16,706	$ 16,706	$ 16,706	$ 16,706	$ 16,706	$ 16,706	$ 16,706	$ 16,707	$ 200,475
21	Deferred Income Taxes		$ (21,175)	$ (21,175)	$ (21,175)	$ (21,175)	$ (21,175)	$ (21,175)	$ (21,175)	$ (21,175)	$ (21,175)	$ (21,175)	$ (21,175)	$ (21,175)	$ (254,096)
22	Current Income Taxes		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Fixed Cost of Service		$ 1,559,016	$ 1,559,016	$ 1,559,016	$ 1,559,016	$ 1,559,016	$ 1,559,016	$ 1,559,016	$ 1,559,016	$ 1,559,016	$ 1,559,016	$ 1,559,016	$ 1,559,017	$ 18,708,195
24															
25	Subtotal Fixed Cost Revenue Requirement		$ 2,809,427	$ 2,809,427	$ 2,809,427	$ 2,809,427	$ 2,809,427	$ 2,809,427	$ 2,809,427	$ 2,809,427	$ 2,809,427	$ 2,809,427	$ 2,809,427	$ 2,809,428	$ 33,713,125
26															
27	Less: Transmission Service @ 20%		$ (561,885)	$ (561,885)	$ (561,885)	$ (561,885)	$ (561,885)	$ (561,885)	$ (561,885)	$ (561,885)	$ (561,885)	$ (561,885)	$ (561,885)	$ (561,886)	$ (6,742,625)
28															
29	DGGS Fixed Cost Allocation		$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 26,970,500
30															
31															
32	Total DGGS Fixed Cost Revenue Requirement		$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,642	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 2,247,542	$ 26,970,500
33	* Order No. 6943e was effective on May 2012. The true-up of Interim rates to Final rates is reflected in the Prefiled Direct Testimony of Cheryl Hansen.														

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
34	**Dave Gates Generating Station at Mill Creek Asset Component**														
35			Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Total
36			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	
37	**Dave Gates Generating Station at Mill Creek Variable Cost -- Per Interim Order 6943b**														
38	Total Forecast Sales														
39	2011/12 Tracker Sales MWh		465,921	516,357	509,435	447,311	447,758	516,526	547,422	525,206	491,564	462,940	454,666	499,219	5,884,324
40	DGGS Cost		$ 1.8346	$ 1.8346	$ 1.8346	$ 1.8346	$ 1.8346	$ 1.8346	$ 1.8346	$ 1.8346	$ 1.8346	$ 1.8346	$ 1.8346	$ 1.8346	
41	Prior Year Deferred Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
42															
43	DGGS Variable Cost Revenues														
44	NWE Electric Supply		$ 854,841	$ 947,345	$ 934,848	$ 820,170	$ 820,967	$ 947,636	$ 1,004,486	$ 963,430	$ 901,919	$ 849,191	$ 834,121	$ 915,856	$ 10,794,809
45	Prior Year(s) Deferred Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	Total Revenue		$ 854,841	$ 947,345	$ 934,848	$ 820,170	$ 820,967	$ 947,636	$ 1,004,486	$ 963,430	$ 901,919	$ 849,191	$ 834,121	$ 915,856	$ 10,794,809
47															
48	DGGS Fuel Cost														
49	DGGS Fuel Cost		$ 1,523,274	$ 1,745,294	$ 1,440,331	$ 1,281,749	$ 1,249,585	$ 1,054,488	$ 1,036,942	$ 1,293,396	$ 1,288,451	$ 917,991	$ 820,577	$ 881,016	$ 14,533,096
50	DGGS Fuel Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,392,728)	$ -	$ (2,392,728)
51	Less: Energy Supply Cost (7 MW)		$ (132,921)	$ (132,921)	$ (132,921)	$ (132,921)	$ (132,921)	$ (132,921)	$ (132,921)	$ (132,921)	$ (132,921)	$ (132,921)	$ (17,444)	$ (28,274)	$ (1,374,928)
52	7 MW Cost Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 420,798	$ -	$ 420,798
53	Subtotal		$ 1,390,353	$ 1,612,373	$ 1,307,410	$ 1,148,828	$ 1,116,664	$ 921,567	$ 904,021	$ 1,160,475	$ 1,155,530	$ 785,070	$ (1,168,797)	$ 852,742	$ 10,765,440
54	Less: Transmission Service @ 20%		$ (278,071)	$ (322,475)	$ (261,482)	$ (229,766)	$ (223,333)	$ (184,313)	$ (180,804)	$ (232,095)	$ (231,106)	$ (157,014)	$ 233,759	$ (170,548)	$ (2,237,248)
55	MPSC-Related Supply Cost		$ 1,112,283	$ 1,289,899	$ 1,045,928	$ 919,063	$ 893,331	$ 737,254	$ 723,216	$ 928,380	$ 924,424	$ 628,056	$ (935,038)	$ 682,194	$ 8,948,991
56	Energy Supply Cost (7 MW)		$ 132,921	$ 132,921	$ 132,921	$ 132,921	$ 132,921	$ 132,921	$ 132,921	$ 132,921	$ 132,921	$ 132,921	$ 17,444	$ 28,274	$ 1,374,928
57	7 MW Cost Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (420,798)	$ -	$ (420,798)
58	Subtotal MPSC-Related Fuel Cost		$ 1,245,204	$ 1,422,820	$ 1,178,849	$ 1,051,984	$ 1,026,252	$ 870,175	$ 856,137	$ 1,061,301	$ 1,057,345	$ 760,977	$ (1,338,392)	$ 710,468	$ 9,903,121
59															
60	Regulation Contracts														
61	Capacity		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,392,728	$ -	$ 2,392,728
62	Energy		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,290,880	$ -	$ 1,290,880
63	Subtotal		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,683,607	$ -	$ 3,683,607
64	Less: Transmission Service @ 20%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (736,721)	$ -	$ (736,721)
65	Subtotal MPSC-Related Regulation Contract Cost		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,946,886	$ -	$ 2,946,886
66	DGGS Cost Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	DGGS Fuel Cost Allocation		$ 1,245,204	$ 1,422,820	$ 1,178,849	$ 1,051,984	$ 1,026,252	$ 870,175	$ 856,137	$ 1,061,301	$ 1,057,345	$ 760,977	$ 1,608,494	$ 710,468	$ 12,850,006
68															
69	DGGS Revenue Credits														
70	Revenue Credits (27 MW Supply/Tran)		$ (355,541)	$ (640,318)	$ (554,538)	$ (417,635)	$ (552,831)	$ (458,364)	$ (419,288)	$ (4,097)	$ (77,712)	$ (27,147)	$ (74,557)	$ (133,591)	$ (3,715,620)
71	Less: Transmission Service @ 20%		$ 71,108	$ 128,064	$ 110,908	$ 83,527	$ 110,566	$ 91,673	$ 83,858	$ 819	$ 15,542	$ 5,429	$ 14,911	$ 26,718	$ 743,124
72	Subtotal MPSC-Related Revenue Credits		$ (284,433)	$ (512,255)	$ (443,630)	$ (334,108)	$ (442,264)	$ (366,691)	$ (335,430)	$ (3,278)	$ (62,170)	$ (21,718)	$ (59,646)	$ (106,873)	$ (2,972,496)
73															
74	Regulation Contracts Revenue Credits														
75	Revenue Credits		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,290,880)	$ -	$ (1,290,880)
76	Less: Transmission Service @ 20%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 258,176	$ -	$ 258,176
77	Subtotal MPSC-Related Revenue Credits		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,032,704)	$ -	$ (1,032,704)
78															
79	DGGS Revenue Credit Allocation		$ (284,433)	$ (512,255)	$ (443,630)	$ (334,108)	$ (442,264)	$ (366,691)	$ (335,430)	$ (3,278)	$ (62,170)	$ (21,718)	$ (1,092,349)	$ (106,873)	$ (4,005,200)
80															
81	DSM Lost Revenue		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,446	$ 22,446	$ 44,891
82	DSM Lost Revenue Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 74,329	$ 224,456	$ -	$ 298,784
83	Subtotal DGGS Variable Cost Allocation		$ 960,771	$ 910,565	$ 735,218	$ 717,876	$ 583,988	$ 503,484	$ 520,707	$ 1,058,023	$ 995,175	$ 813,588	$ 763,046	$ 626,040	$ 9,188,482
84															
85	**Carrying Cost Expense**														
86	Carry Cost	7.80%	$ 10,346	$ 10,173	$ 8,934	$ 8,324	$ 6,828	$ 3,969	$ 832	$ 1,456	$ 2,075	$ 1,856	$ 842	$ (1,047)	$ 54,586
87	Carry Cost Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 165	$ -	$ 165
88	Prior Period Deferred Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (85,985)	$ -	$ (85,985)
89	Total Carrying Costs		$ 10,346	$ 10,173	$ 8,934	$ 8,324	$ 6,828	$ 3,969	$ 832	$ 1,456	$ 2,075	$ 1,856	$ (84,978)	$ (1,047)	$ (31,234)
90															
91	Total DGGS Variable Cost Allocation		$ 971,116	$ 920,738	$ 744,152	$ 726,199	$ 590,816	$ 507,453	$ 521,539	$ 1,059,479	$ 997,250	$ 815,444	$ 678,068	$ 624,993	$ 9,157,248
92															
93	Deferred Cost Amortization (Under)/Over		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
94	Monthly Deferred Cost		$ (116,275)	$ 26,607	$ 190,696	$ 93,970	$ 230,151	$ 440,183	$ 482,947	$ (96,050)	$ (95,331)	$ 33,747	$ 156,053	$ 290,863	$ 1,637,561
95	Cumulative Deferred Cost		$ (116,275)	$ (89,667)	$ 101,028	$ 194,999	$ 425,149	$ 865,332	$ 1,348,279	$ 1,252,229	$ 1,156,898	$ 1,190,646	$ 1,346,698	$ 1,637,561	
96															
97	Variable Rate Base Deferred														
98	Beginning Balance		$ 1,476,330	$ 1,592,605	$ 1,565,997	$ 1,375,301	$ 1,281,331	$ 1,051,181	$ 610,998	$ 128,051	$ 224,100	$ 319,432	$ 285,684	$ 129,632	
99	Monthly Deferred Cost		$ 116,275	$ (26,607)	$ (190,696)	$ (93,970)	$ (230,151)	$ (440,183)	$ (482,947)	$ 96,050	$ 95,331	$ (33,747)	$ (156,053)	$ (290,863)	
100	Ending Balance Under/(Over)		$ 1,592,605	$ 1,565,997	$ 1,375,301	$ 1,281,331	$ 1,051,181	$ 610,998	$ 128,051	$ 224,100	$ 319,432	$ 285,684	$ 129,632	$ (161,231)	

	A B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Dave Gates Generating Station at Mill Creek Asset Component**														
2			**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
3			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
4	**Dave Gates Generating Station Fixed Cost Revenue Requirement – Per Order 6943e**														
5	DGGS Plant in Service														
6	Electric Generation Plant		$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 182,537,625
7	Accumulated Depreciation (Book Life 30 Yrs)		$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (8,953,885)
8	DGGS Project Costs		$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 231,716
9	Customer Contributed Capital		$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (3,115,352)
10	Working Capital		$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 1,980,537
11	Total Year End Rate Base		$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 172,680,641
12															
13	Fixed Return (Avg RB * Cost of Capital)	8.16%	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 14,090,740
14															
15	Fixed Cost of Service														
16	Operation & Maintenance Expenses		$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 4,849,385
17	Depreciation		$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 5,969,257
18	Amortization of DGGS Project Cost		$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 154,477
19	Property Taxes		$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 3,804,214
20	MPSC & MCC Revenue Tax		$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 125,086
21	Deferred Income Taxes		$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 6,300,004
22	Current Income Taxes		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Fixed Cost of Service		$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 21,202,423
24															
25	Subtotal Fixed Cost Revenue Requirement		$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 35,293,163
26															
27	Less: Transmission Service @ 20%		$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (7,058,633)
28															
29	DGGS Fixed Cost Allocation		$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 28,234,531
30															
31															
32	Total DGGS Fixed Cost Revenue Requirement		$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 28,234,531
33															

Row	B	C	Jul-12 Estimate	Aug-12 Estimate	Sep-12 Estimate	Oct-12 Estimate	Nov-12 Estimate	Dec-12 Estimate	Jan-13 Estimate	Feb-13 Estimate	Mar-13 Estimate	Apr-13 Estimate	May-13 Estimate	Jun-13 Estimate	Total
34	**Dave Gates Generating Station at Mill Creek Asset Component**														
37	**Dave Gates Generating Station at Mill Creek Variable Cost – Per Interim Order 6943b**														
38	Total Forecast Sales														
39	2011/12 Tracker Sales MWh		536,889	522,289	453,359	472,682	495,613	562,539	562,001	494,391	497,753	448,206	447,693	453,829	5,947,244
40	DGGS Cost		$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	
41	Prior Year Deferred Expense		$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	
42															
43	DGGS Variable Cost Revenues														
44	NWE Electric Supply		$ 677,711	$ 659,282	$ 572,272	$ 596,663	$ 625,609	$ 710,089	$ 709,410	$ 624,067	$ 628,310	$ 565,767	$ 565,120	$ 572,865	$ 7,507,165
45	Prior Year(s) Deferred Expense		$ (14,555)	$ (14,159)	$ (12,291)	$ (12,814)	$ (13,436)	$ (15,251)	$ (15,236)	$ (13,403)	$ (13,494)	$ (12,151)	$ (12,137)	$ (12,303)	$ (161,231)
46	Total Revenue		$ 663,156	$ 645,123	$ 559,982	$ 583,848	$ 612,173	$ 694,838	$ 694,174	$ 610,664	$ 614,816	$ 553,616	$ 552,983	$ 560,562	$ 7,345,934
47															
48	DGGS Fuel Cost														
49	DGGS Fuel Cost		$ 1,178,481	$ 1,178,481	$ 1,178,481	$ 1,178,481	$ 1,178,481	$ 1,178,481	$ 1,178,481	$ 1,178,481	$ 1,178,481	$ 1,178,481	$ 1,178,481	$ 1,178,481	$ 14,141,769
50	DGGS Fuel Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	Less: Energy Supply Cost (7 MW)		$ (125,144)	$ (125,144)	$ (125,144)	$ (125,144)	$ (125,144)	$ (125,144)	$ (125,144)	$ (125,144)	$ (125,144)	$ (125,144)	$ (125,144)	$ (125,144)	$ (1,501,727)
52	Subtotal		$ 1,053,337	$ 1,053,337	$ 1,053,337	$ 1,053,337	$ 1,053,337	$ 1,053,337	$ 1,053,337	$ 1,053,337	$ 1,053,337	$ 1,053,337	$ 1,053,337	$ 1,053,337	$ 12,640,043
53	Less: Transmission Service @ 20%		$ (210,667)	$ (210,667)	$ (210,667)	$ (210,667)	$ (210,667)	$ (210,667)	$ (210,667)	$ (210,667)	$ (210,667)	$ (210,667)	$ (210,667)	$ (210,667)	$ (2,528,009)
54	MPSC-Related Supply Cost		$ 842,670	$ 842,670	$ 842,670	$ 842,670	$ 842,670	$ 842,670	$ 842,670	$ 842,670	$ 842,670	$ 842,670	$ 842,670	$ 842,670	$ 10,112,034
55	Energy Supply Cost (7 MW)		$ 125,144	$ 125,144	$ 125,144	$ 125,144	$ 125,144	$ 125,144	$ 125,144	$ 125,144	$ 125,144	$ 125,144	$ 125,144	$ 125,144	$ 1,501,727
56	Subtotal MPSC-Related Fuel Cost		$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 11,613,761
57															
58	Regulation Contracts														
59	Capacity		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	Energy		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	Subtotal		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Less: Transmission Service @ 20%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Subtotal MPSC-Related Regulation Contract Cost		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64															
65	DGGS Fuel Cost Allocation		$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 967,813	$ 11,613,761
66															
67	DGGS Revenue Credits														
68	Revenue Credits (27 MW Supply/Tran)		$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (5,792,375)
69	Less: Transmission Service @ 20%		$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 1,158,475
70	Subtotal MPSC-Related Revenue Credits		$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (4,633,900)
71															
72	Regulation Contracts Revenue Credits														
73	Revenue Credits		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Less: Transmission Service @ 20%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	Subtotal MPSC-Related Revenue Credits		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76															
77	DGGS Revenue Credit Allocation		$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (4,633,900)
78															
79	DSM Lost Revenue		$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 539,139
80	DSM Lost Revenue Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81															
82															
83	Subtotal DGGS Variable Cost Allocation		$ 626,583	$ 626,583	$ 626,583	$ 626,583	$ 626,583	$ 626,583	$ 626,583	$ 626,583	$ 626,583	$ 626,583	$ 626,583	$ 626,583	$ 7,519,000
84															
85	**Carrying Cost Expense**														
86	Carrying Costs	7.80%	$ (1,293)	$ (1,423)	$ (997)	$ (724)	$ (634)	$ (1,085)	$ (1,534)	$ (1,440)	$ (1,372)	$ (904)	$ (429)	$ (0)	$ (11,836)
87															
88	Total DGGS Variable Cost Allocation		$ 625,290	$ 625,160	$ 625,587	$ 625,859	$ 625,949	$ 625,498	$ 625,049	$ 625,144	$ 625,211	$ 625,679	$ 626,154	$ 626,583	$ 7,507,165
89															
90	Deferred Cost Amortization (Under)/Over		$ (14,555)	$ (14,159)	$ (12,291)	$ (12,814)	$ (13,436)	$ (15,251)	$ (15,236)	$ (13,403)	$ (13,494)	$ (12,151)	$ (12,137)	$ (12,303)	$ (161,231)
91	Monthly Deferred Cost		$ 52,421	$ 34,122	$ (53,314)	$ (29,197)	$ (340)	$ 84,590	$ 84,361	$ (1,077)	$ 3,099	$ (59,912)	$ (61,035)	$ (53,718)	$ 0
92	Cumulative Deferred Cost		$ 52,421	$ 86,542	$ 33,228	$ 4,031	$ 3,691	$ 88,282	$ 172,642	$ 171,565	$ 174,665	$ 114,753	$ 53,718	$ 0	
93															
94	Variable Rate Base Deferred														
95	Beginning Balance		$ (161,231)	$ (199,097)	$ (219,059)	$ (153,454)	$ (111,443)	$ (97,667)	$ (167,007)	$ (236,131)	$ (221,652)	$ (211,257)	$ (139,194)	$ (66,022)	
96	Monthly Deferred Cost		$ (37,866)	$ (19,962)	$ 65,605	$ 42,011	$ 13,776	$ (69,340)	$ (69,125)	$ 14,480	$ 10,395	$ 72,063	$ 73,172	$ 66,022	
97	Ending Balance Under/(Over)		$ (199,097)	$ (219,059)	$ (153,454)	$ (111,443)	$ (97,667)	$ (167,007)	$ (236,131)	$ (221,652)	$ (211,257)	$ (139,194)	$ (66,022)	$ (0)	

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2012.5.49
Annual DGGS True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF CHERYL A. HANSEN

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL DAVE GATES GENERATING STATION ("DGGS") TRUE-UP

TABLE OF CONTENTS

Witness Information

Q. Are you the same Cheryl A. Hansen who filed Prefiled Direct Testimony in the Electricity Supply Tracker portion of this Docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your Annual DGGS True-up testimony?

A. My testimony:

1. Presents the over/under collection reflected in both the 2010-2011 true-up period and the 2011-2012 true-up period;
2. Presents the derivation of proposed DGGS variable rates for the forecasted 2012-2013 true-up period; and
3. Discusses the overall total supply rates incorporating all individual rate components.

Deferred DGGS Variable Cost Account Balance

Q. What is the DGGS variable cost account balance for the 12-month period ending June 2012?

A. The DGGS variable cost account balance for the 12-month period ending June 2012 is an over-collection of $(161,231) as presented on page 1 of Exhibit__(CAH-4)_12-13. As discussed below, this includes the prior period balance for the 2010-2011 true-up period and the current period balance for the 2011-2012 true-up period.

Q. Describe the status of the deferred DGGS variable cost account balance associated with the 2010-2011 true-up period.

A. In the annual filing submitted on June 2, 2011, the net deferred account balance for the 2010-2011 true-up period was shown as an under-collection of $942,215. This amount becomes the starting balance in this filing. Added to this balance is the prior period true-up for the 2 months of estimated data included in the June 2, 2011 filing. Page 1 of Exhibit__(CAH-4)_12-13 shows the true-up of the estimated months of May and June 2011 with actual data. The resulting actual ending balance of $1,476,330 is the deferred account balance for the 2011-2012 true-up period shown on Exhibit__(CAH-4)_12-13, page 1. As proposed in the June 2011 filing, there were no deferred DGGS rate components established and the deferred account balance was carried forward to the 2011-2012 tracking period. As a result, there is no monthly deferred activity for the July 2011 to June 2012 tracking period.

Q. Describe the deferred DGGS variable cost account balance associated with the 2011-2012 true-up period.

A. Page 2 of Exhibit__(CAH-4)_12-13 shows the monthly detail of the difference between the DGGS variable cost revenues and expenses for the 2011-2012 true-up period, resulting in an over-collected amount of $(1,637,561). The months of May and June 2012 are estimated and will be trued-up in the next annual filing.

Q. What is the total deferred DGGS variable cost account balance?

A. The total deferred DGGS variable cost account balance is an over-collection of $(161,231) shown below and on page 1, line 57 of Exhibit__(CAH-4)_12-13. Since this amount is immaterial, NWE proposes to carry the over-collected balance forward to the 2012-2013 true-up period and not seek a rate adjustment in this filing.

Total Deferred DGGS Variable Cost Account Balance

2010-2011 Prior Period DGGS Variable Account Balance	$1,476,330
2011-2012 Current Period DGGS Variable Account Balance	$(1,637,561)
	$(161,231)

Derivation of Proposed DGGS Variable Rates

Q. Please describe the process used by NorthWestern to derive the proposed 2012-2013 DGGS variable rates in this filing.

A. The rate design methodology used in this filing to derive the proposed 2012-2013 DGGS variable rates is the same as that presented in previous DGGS filings. All forecasted costs are from Exhibit__(FVB-7)12_13 of the Prefiled Direct Testimony of Frank Bennett and are discussed in his testimony.

The derivation of DGGS variable rates is shown on Exhibit__(CAH-4)_12-13, page 3. The total DGGS variable cost of $7,507,165 is the sum of forecasted fuel costs, revenue credits, DSM Lost Revenues, carrying costs, and the energy supply 7MW costs from Exhibit__(FVB-7)12-13, page 1, column P, line 88. This sum is the amount used to derive the DGGS variable rates. The forecasted loads used in the derivation are from Exhibit__(CAH-1)_12-13.

Q. Please describe the 2012-2013 DGGS fixed cost rates included in this filing.

A. The DGGS fixed cost of service rate components presented in this filing are those submitted in compliance with Docket No. D2008.8.95 Order No. 6943e. The DGGS fixed rate components include rates effective January 1, 2012 reflecting the second year revenue requirement and the rebate rates effective May 1, 2012 to refund the over-collection of DGGS revenue from the inception of DGGS fixed rates on January 1, 2011.

The DGGS fixed and variable rates and revenues are shown in summarized format on Exhibit__(CAH-4)_12-13, page 4.

Proposed Total Supply Rates

Q. Please describe the process used by NorthWestern to derive the total proposed 2012-2013 electric supply rates in this filing.

A. With the introduction of DGGS rates in 2011, the total electric supply rate currently includes several separate rate components – an electricity supply tracker rate, a CU4 fixed cost of service rate, a CU4 variable rate, a DGGS fixed cost of service rate, a DGGS fixed cost of service rebate rate, and a DGGS variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(CAH-5)_12-13, page 3.

The total deferred supply rate also includes two separate rate components – a deferred electricity supply rate and a deferred CU4 variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(CAH-5)_12-13, page 1. Because the deferred DGGS balance is immaterial, NWE proposes to not request a deferred rate adjustment in this filing and carry forward the DGGS Variable Cost/Credit deferred account balance into the 2012-2013 true-up period.

Q. **Does this conclude your Annual DGGS True-up testimony?**

A. Yes, it does.

NorthWestern Energy
Electric Utility
DGGS Variable Cost Account Balance
July 2011 - June 2012

Month	DGGS Variable Cost Revenues	DGGS Variable Cost Expense	DGGS Variable Cost Balance
Jul10-Jun11 under-collected balance as filed in D2011.5.38			**$ 942,215**
Prior Period Tracker Year True-up - Deferred:			
May11: Estimated as filed in D2011.5.38		$ -	
May11: Actual		$ -	$ -
Jun11: Estimated as filed in D2011.5.38		$ -	
Jun11: Actual		$ -	$ -
Prior Period Tracker Year True-up - Variable:			
May11: Est as filed in D2011.5.38 - Revenue	$ 838,013		
May11: Est as filed in D2011.5.38 - Expense	$ 910,728	$ 72,714	
May11: Actual - Revenue	$ 804,968		
May11: Actual - Expense	$ 1,048,894	$ 243,926	$ 171,212
Jun11: Est as filed in D2011.5.38 - Revenue	$ 917,725		
Jun11: Est as filed in D2011.5.38 - Expense	$ 910,682	$ (7,043)	
Jun11: Actual - Revenue	$ 794,681		
Jun11: Actual - Expense	$ 1,150,540	$ 355,860	$ 362,903
Actual Jul10-Jun11 under-collected balance [1]			**$ 1,476,330**
			-
Deferred Jul11-Jun12 Monthly Activity [2]:			
July 2011	$ -	$ -	$ 1,476,330
August 2011	$ -	$ -	$ 1,476,330
September 2011	$ -	$ -	$ 1,476,330
October 2011	$ -	$ -	$ 1,476,330
November 2011	$ -	$ -	$ 1,476,330
December 2011	$ -	$ -	$ 1,476,330
January 2012	$ -	$ -	$ 1,476,330
February 2012	$ -	$ -	$ 1,476,330
March 2012	$ -	$ -	$ 1,476,330
April 2012	$ -	$ -	$ 1,476,330
May 2012	$ -	$ -	$ 1,476,330
June 2012	$ -	$ -	$ 1,476,330
Prior Period DGGS Variable Cost Ending Balance			**$ 1,476,330**
Current Period DGGS Variable Cost Ending Balance (see page 2)			**$ (1,637,561)**
Total DGGS Variable Cost Balance Jul11-Jun12 [3]			**$ (161,231)**
			-

Source:
[1] Source: Exhibit_(FVB-6)11-12, page 2, line 98.
[2] Source: Exhibit_(FVB-6)11-12, page 2, line 94.
[3] Source: Exhibit_(FVB-6)11-12, page 2, line 100.

NorthWestern Energy
Electric Utility
DGGS Variable Cost Account Balance
July 2011 - June 2012

Month	DGGS Variable Cost Revenue	DGGS Variable Cost Expense	DGGS Variable Cost Balance
July 2011	$ 854,841	$ 971,116	$ 116,275
August 2011	$ 947,345	$ 920,738	$ (26,607)
September 2011	$ 934,848	$ 744,152	$ (190,696)
October 2011	$ 820,170	$ 726,199	$ (93,970)
November 2011	$ 820,967	$ 590,816	$ (230,151)
December 2011	$ 947,636	$ 507,453	$ (440,183)
January 2012	$ 1,004,486	$ 521,539	$ (482,947)
February 2012	$ 963,430	$ 1,059,479	$ 96,050
March 2012	$ 901,919	$ 997,250	$ 95,331
April 2012	$ 849,191	$ 815,444	$ (33,747)
May 2012 - Estimated	$ 834,121	$ 678,068	$ (156,053)
June 2012 - Estimated	$ 915,856	$ 624,993	$ (290,863)
DGGS Variable Balance Jul11-Jun12	**$ 10,794,809**	**$ 9,157,248**	**$ (1,637,561)**
	-	-	-

Source:
Revenue: Exhibit_(FVB-6)11-12, page 2, line 44.
Expense: Exhibit_(FVB-6)11-12, page 2, line 91.

Northwestern Energy
Electric Utility Derivation of Rates
DGGS Variable
Tracker Period July 2012 to June 2013

Customer Rate Class	Loss Factor	Jul112 to Jun13 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	DGGS Variable After Losses kWh Charges	DGGS Variable Revenue/Cost Check
Residential	8.5100%	2,363,392,484	2,363,392,484	2,564,517,184	$ 0.001267	$ 2,994,418
Residential Employee	8.5100%	3,898,778	2,339,267	2,538,338	$ 0.000760	$ 2,963
GS 1 Secondary NonDemand	8.5100%	272,790,804	272,790,804	296,005,301	$ 0.001267	$ 345,626
GS 1 Secondary Demand	8.5100%	2,438,440,251	2,438,440,251	2,645,951,516	$ 0.001267	$ 3,089,504
GS 1 Primary NonDemand	5.5400%	551,733	551,733	582,300	$ 0.001233	$ 680
GS 1 Primary Demand	5.5400%	350,552,671	350,552,671	369,973,289	$ 0.001233	$ 432,231
General Service Substation	4.6300%	244,005,756	244,005,756	255,303,222	$ 0.001222	$ 298,175
General Service Transmission	4.0000%	132,300,021	132,300,021	137,592,022	$ 0.001215	$ 160,745
Irrigation	8.5100%	83,490,261	83,490,261	90,595,283	$ 0.001267	$ 105,782
Lighting	8.5100%	57,821,458	57,821,458	62,742,064	$ 0.001267	$ 73,260
MPSC System Average	7.4717%	5,947,244,217	5,945,684,706	6,425,800,519	$ 0.001262	$ 7,503,384
YNP Contract		18,457,300			Rounding Adjustment	$ 3,780
Total Supply Load		5,965,701,517				$ 7,507,165
		-				

DGGS Variable Cost of Service	$	7,507,165
Total DGGS Variable COS Rate Before Losses	**$**	**0.001168**
Total DGGS Variable COS Rate After Losses	**$**	**0.001262**

Exhibit__(CAH-4)_12-13
Docket No. D2012.5.49

NorthWestern Energy
Electric Utility
Total Dave Gates Generating Station Revenue ($000) Summary
Tracker Period July 2011 to June 2012

		DGGS Fixed		DGGS Fixed Rebate		DGGS Variable				
	Jun11-Jun12 Load Statistics	Current Rates [1] 1/1/2012	Current Rate Revenue	Current Rates [2] 5/1/2012	Current Rate Revenue	Current Rates 7/1/2011	Current Rate Revenue	Proposed Rates 7/1/2012	Proposed Rate Revenue	Revenue Diff Proposed vs Current
Residential										
Residential	2,363,392	0.004795	$ 11,332	(0.001195)	$ (2,824)	0.001842	$ 4,353	0.001267	$ 2,994	$ (1,359)
Residential Employee	3,899	0.002877	$ 11	(0.000717)	$ (3)	0.001105	$ 4	0.000760	$ 3	$ (1)
Total Residential			$ 11,344		$ (2,827)		$ 4,358		$ 2,997	$ (1,360)
General Service 1										
GS-1 Sec Non Demand	272,791	0.004795	$ 1,308	(0.001195)	$ (326)	0.001842	$ 502	0.001267	$ 346	$ (157)
GS-1 Sec Demand	2,438,440	0.004795	$ 11,692	(0.001195)	$ (2,914)	0.001842	$ 4,492	0.001267	$ 3,090	$ (1,402)
GS-1 Pri Non Demand	552	0.004664	$ 3	(0.001162)	$ (1)	0.001792	$ 1	0.001233	$ 1	$ (0)
GS-1 Pri Demand	350,553	0.004664	$ 1,635	(0.001162)	$ (407)	0.001792	$ 628	0.001233	$ 432	$ (196)
Total GS-1			$ 14,638		$ (3,648)		$ 5,623		$ 3,868	$ (1,755)
General Service 2										
GS-2 Substation	244,006	0.004624	$ 1,128	(0.001152)	$ (281)	0.001777	$ 434	0.001222	$ 298	$ (135)
GS-2 Transmission	132,300	0.004596	$ 608	(0.001145)	$ (151)	0.001766	$ 234	0.001215	$ 161	$ (73)
Total GS-2			$ 1,736		$ (433)		$ 667		$ 459	$ (208)
Irrigation										
Irrigation	83,490	0.004795	$ 400	(0.001195)	$ (100)	0.001842	$ 154	0.001267	$ 106	$ (48)
Total Irrigation			$ 400		$ (100)		$ 154		$ 106	$ (48)
Lighting										
Lighting	57,821	0.004795	$ 277	(0.001195)	$ (69)	0.001842	$ 107	0.001267	$ 73	$ (33)
Total Lighting			$ 277		$ (69)		$ 107		$ 73	$ (33)
Total Rate Schedule	**5,947,244**		**$ 28,396**		**$ (7,076)**		**$ 10,908**		**$ 7,503**	**$ (3,405.096)**
	-									

[1] DGGS Rates (based on 2nd yr rev req) approved in Docket No. D2008.8.95 Order No.6943e, effective 1/1/2012.
[2] DGGS Rebate Rates submitted in Docket No. D2008.8.95 Order No.6943e compliance filing, effective 5/1/2012.