NorthWestern Energy

BEFORE THE DEPARTMENT OF PUBLIC SERVICE REGULATION

MONTANA PUBLIC SERVICE COMMISSION

DOCKET NO. D2014.7.58

Electricity Supply Tracker

Colstrip Unit 4 Generation Asset
Variable Cost/Adjustment

Dave Gates Generating Station
Variable Cost/Credit Adjustments

Spion Kop Wind Generation
Variable Cost/Adjustments

Hydro Generation Assets
Variable Cost/Adjustments

Revenue Credits

July 1, 2015 to June 30, 2016

NorthWestern Energy
Delivering a Bright Future

May 29, 2015

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

RE: Docket No. D2014.7.58 – Monthly Electric Supply Cost Rate Adjustment for the period August 1, 2014 through June 30, 2015/ Application for (1) Approval of Deferred Cost Account Balances for Electricity Supply, CU4 Variable Costs, DGGS Variable Costs/Credits, and Spion Variable Costs; and (2) Projected Electricity Supply Cost Rates, CU4 Variable Rates, DGGS Variable Rates, Spion Variable Rates, and Hydro Variable Rates

Dear Ms. Whitney:

Pursuant to Montana law, the Montana Public Service Commission ("MPSC" or "Commission") rules, and 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, Order No. 6925f in Docket D2008.6.69, Order No. 7159i in Docket No. D2011.5.41, and Order No. 7323k in Docket No. D2013.12.85, NorthWestern Energy ("NorthWestern") hereby transmits an original and ten copies of its annual Application for approval of electric supply rates which:

- Reflects rate treatment for the net balance in the Electric Supply Deferred Cost Account for the 12-month period ending June 30, 2015, including electricity supply costs, Colstrip Unit No. 4 ("CU4") variable costs, the Dave Gates Generating Station ("DGGS") variable costs/credits, and the Spion Kop Wind Generation Project ("Spion") variable costs;

- Reflects the projected load, supply, and related electricity supply costs for the 12-month tracker period July 1, 2015 through June 30, 2016;

- Reflects the projected load and CU4 variable costs for the 12-month period July 1, 2015 through June 30, 2016;
- Reflects the projected load and DGGS net variable costs for the 12-month period July 1, 2015 through June 30, 2016;
- Reflects the projected load and Spion variable costs for the 12-month period July 1, 2015 through June 30, 2016;
- Reflects the projected load and Hydro Generation Assets ("Hydro") variable costs for the 12-month period July 1, 2015 through June 30, 2016; and

For purposes of determining the overall electric supply rate, this filing also includes:

- The CU4 fixed cost of service rate;
- The DGGS fixed cost of service rate;
- The Spion fixed cost of service rate;
- The Hydro fixed cost of service rate; and
- The Revenue Credit rate.

No rate treatment is requested for the fixed costs of service or revenue credit items.

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

1. Electricity Supply Tracker;
2. CU4 Variable Cost True-up;
3. DGGS net Variable Cost True-up;
4. Spion Variable Cost True-up;
5. Hydro Variable Cost True-up; and
6. Revenue Credits.

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 updated rolling 12-month forecast.

The CU4 fixed cost revenue requirement rate is unchanged from thethe last 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 updated 12-month forecast.

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 net variable cost section is the updated 12-month forecast.

The Spion fixed cost revenue requirement rate is unchanged from the January 1, 2014 monthly tracker filing reflecting Order No. 7159i in Docket No. D2011.5.41 and will remain the same until an order is issued in a future revenue requirement filing. The Spion variable cost section is the updated 12-month forecast.

The Hydro fixed cost revenue requirement rate is unchanged from the November 18, 2014 monthly tracker filing reflecting Order No. 7323k in Docket No. D2013.12.85 and will be updated later this year with a compliance filing that is required by Order No. 7323k. The Hydro variable cost section is the projected 12-month forecast.

The Revenue Credit rate is unchanged from the November 18, 2014 monthly tracker filing reflecting Order No. 7323k in Docket No. D2013.12.85 and will be updated later this year with a compliance filing that is required by Order No. 7323k.

The Electric Supply Deferred Cost Account Balance of $5,781,794 for the period ending June 30, 2015 includes an under-collection of $8,741,628 of electricity supply costs plus the under-collection of $777,601 in the DGGS Variable Cost/Credit Account Balance offset by an over-collection of $(13,878) in the Spion Variable Cost Account Balance and an over-collection of $(3,723,557) in the CU4 Variable Cost Account Balance.

The projected overall Electric Supply Cost and net Supply Deferred Cost in this filing result in a decrease for a typical residential customer using 750 kWh per month of $3.06 per month or $36.72 per year on the total bill. This will result in an overall 3.40% decrease for supply-related costs.

The typical residential bill calculation shows the combined effect of the proposed July 1, 2015 rate changes for the decreased Competitive Transition Charge for Qualifying Facilities (“CTC-QF”). The total effect of the decrease in the Total

Electric Supply rates, along with the CTC-QF adjustment on the typical residential customer's bill, is a projected decrease of $3.10 per month or $37.20 per year.

Including all July 1, 2015 rate adjustments, the total overall bill decrease for the typical residential customer is estimated to be 3.44%. The actual decrease 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 Kevin J. Markovich, Frank V. Bennett (five components), Joseph S. Janhunen (six components), and Danie L. Williams.

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

NorthWestern's next monthly tracking filing will be for rates effective August 1, 2015, unless electricity prices move dramatically in either direction prior to June 15, 2015. If this occurs, NorthWestern will file an updated electricity supply tracker filing for a July 1, 2015 monthly rate adjustment.

The NorthWestern 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
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Butte, MT 59701
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NorthWestern's attorneys in this matter are:

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Along with Joe Schwartzenberger, Al Brogan, and John Alke, please add Tracy Killoy to the official service list in this docket to receive copies of all documents. NorthWestern also requests that all electronic correspondence related to this filing be sent to tracy.killoy@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

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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	)	
Monthly Electric Supply Cost Rate Adjustment/	)	
Application for (1) Approval of Deferred Cost	)	REGULATORY DIVISION
Account Balances for Electricity Supply, CU4	)	
Variable Costs, DGGS Variable Costs/Credits,	)	
and Spion Variable Costs; and (2) Projected	)	DOCKET NO. D2014.7.58
Electricity Supply Cost Rates, CU4 Variable Rates,	)	
DGGS Variable Rates, Spion Variable Rates, and	)	
Hydro Variable Rates	)	

NorthWestern Energy's Application for Interim and Final Electricity Supply Rate Adjustment

NOW COMES, NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern" 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 No. 4 ("CU4") Variable Costs, Dave Gates Generating Station ("DGGS") Variable Costs/Credits, and Spion Kop Wind Generation Project ("Spion") Variable Costs; and (2) projected Electricity Supply Cost Rates, CU4 Variable Rates, DGGS

Variable Rates, Spion Variable Rates and Hydro Generation Assets ("Hydro") 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 a new tariff sheet for electric service upon approval by the Commission 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, Order No. 6943a in Docket No. D2008.8.95, and Order No. 7159i in Docket No. D2011.5.41, the balance in Account No. 191, Electric Supply Deferred Costs, for the 12-month period ending June 30, 2015 is an under-collection of $5,781,794. This balance consists of $8,741,628 for the under-collection of electricity supply costs from July 1, 2014 to June 30, plus an over-collection of $(3,723,557) for CU4 Variable Costs, plus an under-collection of $777,601 for DGGS Variable Costs/Credits, plus an over-collection of $(13,878) for Spion Variable Costs. NorthWestern proposes to amortize this under-collection balance of $5,781,794 in rates over the 12-month period ending June 2016. The net deferred electric supply rate per kilowatt hour ("kWh") is shown on Appendix A. The tracking market supply and electricity costs for the 12-month period, July 1, 2015 to June 30, 2016, produce an overall electricity supply rate per kWh also shown on Appendix A. This overall rate includes the following components: Electricity Supply Costs, CU4 Fixed Cost of Service, CU4 Variable Costs, DGGS Fixed Cost of Service, DGGS Variable Costs/Credits, Spion Fixed Cost of Service, Spion Variable Costs, Hydro Fixed Cost of Service, Hydro Variable Costs, and Revenue Credits. No adjustments are requested for the fixed costs of service or the revenue credits rates.

In addition, NorthWestern 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 with each subsequent monthly calculation 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 Account Balance, the DGGS Variable Cost/Credit Account Balance, and the Spion Variable Cost Account Balance described in Section No. V; and

2. The projected overall monthly market supply and costs – including electricity supply costs, CU4 costs, net DGGS costs, Spion costs, Hydro costs, and Revenue Credits as described in Section 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 Kevin J. Markovich, Frank V. Bennett (five components), Joseph S. Janhunen (six components), and Danie L. Williams.

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, 2015;
2. Grant such other and additional relief, as the Commission shall deem just and proper.

[Remainder of this page is blank – signature page to follow]

RESPECTFULLY SUBMITTED this 29th day of May 2015.

NORTHWESTERN ENERGY

By: John Alke

John Alke
Attorney for NorthWestern Corporation
d/b/a NorthWestern Energy

NorthWestern Energy
Electric Utility
Electricity Supply Costs, CU4 Fixed Cost of Service & Variable Costs, DGGS Fixed Cost of Service and Variable Costs/Credits, Spion Kop Fixed Cost of Service and Variable Costs, Hydro Fixed Cost of Service and Variable Costs & Deferred Electricity Supply, CU4 Variable Cost, DGGS Variable Cost/Credit, and Spion Variable Cost Rate Change Detail
Effective July 1, 2015

Overall Electric Supply Rate ($/kWh)	Current 6/1/2015	Proposed	Rate Change	Percentage Change
Residential	$ 0.067157	$ 0.067498	$ 0.000341	0.51%
Employee	$ 0.040294	$ 0.040499	$ 0.000205	0.51%
GS-1 Secondary Non-Demand	$ 0.065045	$ 0.065358	$ 0.000313	0.48%
GS-1 Secondary Demand	$ 0.067158	$ 0.067499	$ 0.000341	0.51%
GS-1 Primary Non-Demand	$ 0.065319	$ 0.065652	$ 0.000333	0.51%
GS-1 Primary Demand	$ 0.063446	$ 0.063754	$ 0.000308	0.49%
GS-2 Substation	$ 0.064754	$ 0.065085	$ 0.000331	0.51%
GS-2 Transmission	$ 0.064367	$ 0.064695	$ 0.000328	0.51%
Irrigation	$ 0.065045	$ 0.065358	$ 0.000313	0.48%
Lighting	$ 0.065045	$ 0.065358	$ 0.000313	0.48%

Net Deferred Electric Supply Rate ($/kWh)	Current 7/1/2014	Proposed	Rate Change	Percentage Change
Residential	$ 0.005369	$ 0.000960	$ (0.004409)	-82.12%
Employee	$ 0.003221	$ 0.000576	$ (0.002645)	-82.12%
GS-1 Secondary Non-Demand	$ 0.005369	$ 0.000960	$ (0.004409)	-82.12%
GS-1 Secondary Demand	$ 0.005369	$ 0.000960	$ (0.004409)	-82.12%
GS-1 Primary Non-Demand	$ 0.005222	$ 0.000934	$ (0.004288)	-82.11%
GS-1 Primary Demand	$ 0.005222	$ 0.000934	$ (0.004288)	-82.11%
GS-2 Substation	$ 0.005177	$ 0.000927	$ (0.004250)	-82.09%
GS-2 Transmission	$ 0.005146	$ 0.000921	$ (0.004225)	-82.10%
Irrigation	$ 0.005369	$ 0.000960	$ (0.004409)	-82.12%
Lighting	$ 0.005369	$ 0.000960	$ (0.004409)	-82.12%

NorthWestern Energy

Typical Bill Calculation

Electric Residential Service

				*CTC-QF and Overall Electric Supply		
	Current Rates			[1] *Proposed Rates*		
kWh per month	750	**Date**		**Date**		
		Effective	Total Bill	**Effective**	Total Bill	
		6/1/2015	Amount	**7/1/2015**	Amount	
Res. Dist.-Service Charge		$ 5.25	$ 5.25	$ 5.25	$ 5.25	
Plus:						
Res. Supply-Energy		$ 0.067157	$ 50.37	$ 0.067498	$ 50.62	
Res. Deferred Supply Costs		$ 0.005369	$ 4.03	$ 0.000960	$ 0.72	
Res. CTC-QF		$ 0.003325	$ 2.49	$ 0.003265	$ 2.45	
Res. Transmission-Energy		$ 0.009203	$ 6.90	$ 0.009203	$ 6.90	
Res. Distribution-Energy		$ 0.028648	$ 21.49	$ 0.028648	$ 21.49	
Res. USBC		$ 0.001334	$ 1.00	$ 0.001334	$ 1.00	
Res. BPA-Credit		$ (0.002032)	$ (1.52)	$ (0.002032)	$ (1.52)	
Total Kwh Charge		$ 0.113004	$ 84.76	$ 0.108876	$ 81.66	
Total Bill		**$ 0.120004**	**$ 90.01**	**$ 0.115876**	**$ 86.91**	
			Monthly Increase (Decrease)		$ (3.10)	
			Annual Increase (Decrease)		$ (37.20)	
			Percent Change		**-3.44%**	

[1]**Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 201**

NorthWestern Energy

Typical Bill Calculation

General Service - Secondary Non-Demand

		Current Rates		CTC-QF and Overall Electric Supply [1] Proposed Rates	
		Date Effective 6/1/2015	Total Bill Amount	**Date Effective 7/1/2015**	Total Bill Amount
kWh per month	**3500**				
GS-1 Dist.-Service Charge		$ 7.45	$ 7.45	$ 7.45	$ 7.45
Plus:					
GS-1 Supply-Energy		$ 0.065045	$ 227.66	$ 0.065358	$ 228.75
GS-1 Deferred Supply Costs		$ 0.005369	$ 18.79	$ 0.000960	$ 3.36
GS-1 CTC-QF		$ 0.003325	$ 11.64	$ 0.003265	$ 11.43
GS-1 Transmission-Energy		$ 0.008012	$ 28.04	$ 0.008012	$ 28.04
GS-1 Distribution-Energy		$ 0.037104	$ 129.86	$ 0.037104	$ 129.86
GS-1 USBC		$ 0.001143	$ 4.00	$ 0.001143	$ 4.00
Total Kwh Charge		$ 0.119998	$ 419.99	$ 0.115842	$ 405.44
Total Bill		**$ 0.122130**	**$ 427.44**	**$ 0.117970**	**$ 412.89**
			Monthly Increase (Decrease)		$ (14.55)
			Annual Increase (Decrease)		$ (174.60)
			Percent Change		**-3.40%**

[1]**Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2014.**

NorthWestern Energy

Typical Bill Calculation

General Service - Secondary Demand

					CTC-QF and Overall Electric Supply	
Kw	**11**		***Current Rates***		***Proposed Rates*** [1]	
kWh per month	**3500**		**Date Effective 6/1/2015**	Total Bill Amount	**Date Effective 7/1/2015**	Total Bill Amount
GS-1 Dist.-Service Charge			$ 9.30	$ 9.30	$ 9.30	$ 9.30
Plus:						
GS-1 Supply-Energy			$ 0.067158	$ 235.05	$ 0.067499	$ 236.25
GS-1 Deferred Supply Costs			$ 0.005369	$ 18.79	$ 0.000960	$ 3.36
GS-1 CTC-QF			$ 0.003325	$ 11.64	$ 0.003265	$ 11.43
GS-1 Transmission-Demand			$ 3.061539	$ 33.68	$ 3.061539	$ 33.68
GS-1 Distribution-Demand			$ 6.240882	$ 68.65	$ 6.240882	$ 68.65
GS-1 Distribution-Energy			$ 0.004951	$ 17.33	$ 0.004951	$ 17.33
GS-1 USBC			$ 0.001143	$ 4.00	$ 0.001143	$ 4.00
Subtotal				$ 389.14		$ 374.70
Total Bill			**$ 0.113840**	**$ 398.44**	**$ 0.109710**	**$ 384.00**
				Monthly Increase (Decrease)		$ (14.44)
				Annual Increase (Decrease)		$ (173.28)
				Percent Change		**-3.62%**

[1] **Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2014.**

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 6/1/2015**	Total Bill Amount	**Date Effective 7/1/2015**	Total Bill Amount	
GS-1 Dist.-Service Charge		$ 7.95	$ 7.95	$ 7.95	$ 7.95	
Plus:						
GS-1 Supply-Energy		$ 0.065319	$ 130.64	$ 0.065652	$ 131.30	
GS-1 Deferred Supply Costs		$ 0.005222	$ 10.44	$ 0.000934	$ 1.87	
GS-1 CTC-QF		$ 0.003234	$ 6.47	$ 0.003176	$ 6.35	
GS-1 Transmission-Energy		$ 0.008382	$ 16.76	$ 0.008382	$ 16.76	
GS-1 Distribution-Energy		$ 0.019218	$ 38.44	$ 0.019218	$ 38.44	
GS-1 USBC		$ 0.001143	$ 2.29	$ 0.001143	$ 2.29	
Total Kwh Charge		$ 0.102518	$ 205.04	$ 0.098505	$ 197.01	
Total Bill		**$ 0.106500**	**$ 212.99**	**$ 0.102480**	**$ 204.96**	
			Monthly Increase (Decrease)		$ (8.03)	
			Annual Increase (Decrease)		$ (96.36)	
			Percent Change		**-3.77%**	

[1]Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2014.

NorthWestern Energy

Typical Bill Calculation

General Service - Primary Demand

					CTC-QF and Overall Electric Supply	
Kw	**400**	***Current Rates***			***[1] Proposed Rates***	
kWh per month	**200000**	**Date Effective 6/1/2015**	Total Bill Amount		**Date Effective 7/1/2015**	Total Bill Amount
GS-1 Dist.-Service Charge		$ 25.00	$ 25.00		$ 25.00	$ 25.00
Plus:						
GS-1 Supply-Energy		$ 0.063446	$ 12,689.20		$ 0.063754	$ 12,750.80
GS-1 Deferred Supply Costs		$ 0.005222	$ 1,044.40		$ 0.000934	$ 186.80
GS-1 CTC-QF		$ 0.003234	$ 646.80		$ 0.003176	$ 635.20
GS-1 Transmission-Demand		$ 3.721122	$ 1,488.45		$ 3.721122	$ 1,488.45
GS-1 Distribution-Demand		$ 4.086007	$ 1,634.40		$ 4.086007	$ 1,634.40
GS-1 Distribution-Energy		$ 0.007158	$ 1,431.60		$ 0.007158	$ 1,431.60
GS-1 USBC		$ 0.001143	$ 228.60		$ 0.001143	$ 228.60
Subtotal			$ 19,163.45			$ 18,355.85
Total Bill		**$ 0.095940**	**$ 19,188.45**		**$ 0.091900**	**$ 18,380.85**
			Monthly Increase (Decrease)			$ (807.60)
			Annual Increase (Decrease)			$ (9,691.20)
			Percent Change			**-4.21%**

[1]Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2014.

NorthWestern Energy

Typical Bill Calculation

Irrigation & Sprinkling Service Non-Demand

						CTC-QF and Overall Electric Supply	
				Current Rates		***[1] Proposed Rates***	
kWh per month	**1342**			**Date Effective 6/1/2015**	Total Bill Amount	**Date Effective 7/1/2015**	Total Bill Amount
Irr. Dist.-Service Charge			**(a)**	$ 9.05	$ 9.05	$ 9.05	$ 9.05
Plus:							
Irr. Supply-Energy				$ 0.065045	$ 87.29	$ 0.065358	$ 87.71
Irr. Deferred Supply Costs				$ 0.005369	$ 7.21	$ 0.000960	$ 1.29
Irr. CTC-QF				$ 0.003325	$ 4.46	$ 0.003265	$ 4.38
Irr. Transmission-Energy				$ 0.011675	$ 15.67	$ 0.011675	$ 15.67
Irr. Distribution-Energy				$ 0.023791	$ 31.93	$ 0.023791	$ 31.93
Irr. USBC				$ 0.001144	$ 1.54	$ 0.001144	$ 1.54
Irr. BPA Credit				$ (0.002032)	$ (2.73)	$ (0.002032)	$ (2.73)
Total Kwh Charge				$ 0.108317	$ 145.37	$ 0.104161	$ 139.79
Total Bill				**$ 0.115070**	**$ 154.42**	**$ 0.110910**	**$ 148.84**
					Monthly Increase (Decrease)		$ (5.58)
					Season Incr (Decr) (6 Months)		$ (33.48)
					Percent Increase		**-3.61%**

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

[1]Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2014.

NorthWestern Energy

Typical Bill Calculation

Irrigation & Sprinkling Service Demand

						CTC-QF and Overall Electric Supply	
Kw	**41**		***Current Rates***			***Proposed Rates*** [1]	
kWh per month	**12260**		**Date**			**Date**	
			Effective	Total Bill		**Effective**	Total Bill
			6/1/2015	Amount		**7/1/2015**	Amount
Irr. Dist.-Service Charge		(a)	$ 21.34	$ 21.34		$ 21.34	$ 21.34
Plus:							
Irr. Supply-Energy			$ 0.065045	$ 797.45		$ 0.065358	$ 801.29
Irr. Deferred Supply Costs			$ 0.005369	$ 65.82		$ 0.000960	$ 11.77
Irr. CTC-QF			$ 0.003325	$ 40.76		$ 0.003265	$ 40.03
Irr. Transmission-Demand			$ 2.003150	$ 82.13		$ 2.003150	$ 82.13
Irr. Distribution-Demand			$ 7.300009	$ 299.30		$ 7.300009	$ 299.30
Irr. Distribution-Energy			$ 0.003953	$ 48.46		$ 0.003953	$ 48.46
Irr. USBC			$ 0.001144	$ 14.03		$ 0.001144	$ 14.03
Irr. BPA Credit			$ (0.002032)	$ (24.91)		$ (0.002032)	$ (24.91)
Subtotal				$ 1,323.04			$ 1,272.10
Total Bill			**$ 0.109660**	**$ 1,344.38**		**$ 0.105500**	**$ 1,293.44**
				Monthly Increase			$ (50.94)
				Season Increase (6 Months)			$ (305.64)
				Percent Increase			**-3.79%**

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

[1] Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2014.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of NorthWestern Energy's Application for (1) Approval of Deferred Cost Account Balances for Electricity Supply, CU4 Variable Costs, DGGS Variable Costs/Credits, and Spion Variable Costs; and (2) Projected Electricity Supply Cost Rates, CU4 Variable Rates, DGGS Variable Rates, Spion Variable Rates, and Hydro Variable Rates under Docket No. D2014.7.58 has been hand delivered to the PSC and MCC and e-filed with the PSC. It has also been served upon the attached service list.

Dated this 29th day of May 2015

Tracy Lowney Killoy

Tracy Lowney Killoy
Administrative Assistant

Docket No. D2014.7.58
Service List

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

IN THE MATTER OF NorthWestern Energy's Monthly Electric Supply Cost Rate Adjustment / Application for (1) Approval of Deferred Cost Account Balances for Electricity Supply, CU4 Variable Costs, DGGS Variable Costs/Credits, and Spion Variable Costs; and (2) Projected Electricity Supply Cost Rates, CU4 Variable Rates, DGGS Variable Rates, Spion Variable Rates, and Hydro Variable Rates	)	REGULATORY DIVISION DOCKET NO. D2014.7.58

Notice of Interim Rate Adjustment Request

NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern") 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 decrease 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, annual Colstrip Unit No. 4 ("CU4") Variable Cost true-ups, annual Dave Gates Generating Station ("DGGS") Variable Cost/Credit true-ups, annual Spion Kop Wind Generation Project ("Spion") Variable Cost true-ups, and annual Hydro Generation Assets ("Hydro") Variable Cost true-ups. Applicant requests that the proposed rates become effective for service on an interim basis on and after July 1, 2015 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, a decrease in the projected DGGS variable costs/credits, an increase in the Spion variable costs, and establishment of the Hydro variable costs; and 2) amortize the amounts in the Deferred Cost Account

Balances for Electricity Supply, CU4 Variable Costs, DGGS Variable Costs/Credits, and the Spion Variable Costs for the 12-month period ending June 30, 2015.

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

- Overall electric supply per kilowatt hour (“kWh”) rate increase as shown in the table below:

Overall Electric Supply Rate ($/kWh)	Current	Proposed	Rate Change	% Change
Residential	$ 0.067157	$ 0.067498	$ 0.000341	0.51%
Employee	$ 0.040294	$ 0.040499	$ 0.000205	0.51%
GS-1 Secondary Non-Demand	$ 0.065045	$ 0.065358	$ 0.000313	0.48%
GS-1 Secondary Demand	$ 0.067158	$ 0.067499	$ 0.000341	0.51%
GS-1 Primary Non-Demand	$ 0.065319	$ 0.065652	$ 0.000333	0.51%
GS-1 Primary Demand	$ 0.063446	$ 0.063754	$ 0.000308	0.49%
GS-2 Substation	$ 0.064754	$ 0.065085	$ 0.000331	0.51%
GS-2 Transmission	$ 0.064367	$ 0.064695	$ 0.000328	0.51%
Irrigation	$ 0.065045	$ 0.065358	$ 0.000313	0.48%
Lighting	$ 0.065045	$ 0.065358	$ 0.000313	0.48%

- The electric supply deferred costs balance for the 12-month period ending June 30, 2015 is an under-collection of $5,781,794. This balance consists of $8,741,628 for the under-collection of electricity supply costs plus the CU4 variable costs over-collection of $(3,723,557) plus the DGGS variable costs/credits under-collection of $777,601 plus the Spion variable costs over-collection of $(13,878) from July 1, 2014 to June 30, 2015. NorthWestern proposes to amortize the net under-collection in rates over the 12-month period ending June 2016. The resulting net electric deferred cost rates are shown below:

Net Electric Supply Deferred Charge Rate ($/kWh)	Current	Proposed	Rate Change	% Change
Residential	$0.005369	$ 0.000960	$(0.004409)	(82.12)%
Employee	$0.003221	$ 0.000576	$(0.002645)	(82.12)%
GS-1 Secondary Non-Demand	$0.005369	$ 0.000960	$(0.004409)	(82.12)%
GS-1 Secondary Demand	$0.005369	$ 0.000960	$(0.004409)	(82.12)%
GS-1 Primary Non-Demand	$0.005222	$ 0.000934	$(0.004288)	(82.11)%
GS-1 Primary Demand	$0.005222	$ 0.000934	$(0.004288)	(82.11)%
GS-2 Substation	$0.005177	$ 0.000927	$(0.004250)	(82.09)%
GS-2 Transmission	$0.005146	$ 0.000921	$(0.004225)	(82.10)%
Irrigation	$0.005369	$ 0.000960	$(0.004409)	(82.12)%
Lighting	$0.005369	$ 0.000960	$(0.004409)	(82.12)%

The interim request and supporting documents can be examined at NorthWestern's Montana 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 with respect to 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 (2013), 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 29, 2015

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

In the Matter of NorthWestern Energy's Monthly Electric Supply Cost Rate Adjustment / Application for (1) Approval of Deferred Cost Account Balances for Electricity Supply, CU4 Variable Costs, DGGS Variable Costs/Credits, and Spion Variable Costs; and (2) Projected Electricity Supply Cost Rates, CU4 Variable Rates, DGGS Variable Rates, Spion Variable Rates, and Hydro Variable Rates	)	Docket No. D2014.7.58

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 29, 2015

NorthWestern Energy

By: Claudia Rapkoch

Claudia Rapkoch
40 East Broadway
Butte, Montana 59701

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2014.7.58
Annual Electric Supply Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF KEVIN J. MARKOVICH

ON BEHALF OF NORTHWESTERN ENERGY

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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, Montana 59701.

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

A. I am employed by NorthWestern Energy ("NorthWestern" or "Company") 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 in Laramie where I earned a Master of Business Administration 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") 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 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. This involves 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. I also provide information and testimony on utility-related matters before the Montana Public Service Commission ("MPSC" or "Commission").

Q. Do you hold any professional certifications?

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

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The primary purposes of my testimony are to provide an overview of NorthWestern's request to implement its annual Electric Supply Tracking

Adjustment for 2014/2015 and to explain how NorthWestern has managed its electric supply portfolio during the tracking adjustment period covered by this filing. I describe the 2014/2015 tracker period activities, including a summary of the changes to our hedging program, and I provide the 2015/2016 tracker period forecast. Finally, I introduce the other NorthWestern witnesses who have submitted testimony in this filing and briefly describe the topic(s) covered by each.

Q. Please provide an overview of NorthWestern's request to implement its annual Electricity Supply Tracking Adjustment in this filing.

A. NorthWestern's filing in this docket reflects an overall decrease of $24.5 million as compared to the most current supply costs filed in the June 1, 2015 monthly tracker filing. As in prior filings, the primary cost drivers are power purchase costs and the associated hedging program costs, fixed cost recovery associated with NorthWestern-owned resources, and the Commission-authorized lost revenue adjustments associated with conservation.

The adjustment period covered by this filing straddles NorthWestern's acquisition of the hydroelectric generating facilities ("Hydros") from PPL Montana, LLC ("PPLM"). As a result, the generation resources NorthWestern has in place at the end of the adjustment period look much different than the resources it had in place at the beginning of the adjustment period.

At the end of this year NorthWestern will be filing with the Commission its 2015 Electricity Supply Resource Procurement Plan ("2015 Plan"). Because of the acquisition of the Hydros, the 2015 Plan will look different than the 2013 Plan which has shaped NorthWestern's electric supply choices – and the resulting costs – over the last few years, including the hedging program. It will also consider the soon-to-be-issued comments of the Commission on NorthWestern's 2013 Plan.

With the Hydros, both the need for open market purchases, and the need for hedging against the price volatility of such purchases, has declined. With two exceptions, NorthWestern does not foresee significant changes, in the near term, to its electricity supply portfolio. The exceptions relate to Community Renewable Energy Projects ("CREPs") and Public Utility Regulatory Policies Act of 1978 ("PURPA") compliance. First, NorthWestern is required by Montana law to acquire another 43 megawatts ("MW") of CREP generating capacity and currently has significant exposure to federally mandated purchases of power from qualifying facilities ("QFs") under PURPA. NorthWestern has the ability to map out a compliance plan for its CREP obligation. It does not have that ability with respect to PURPA compliance. Additionally, NorthWestern needs to make sure it has sufficient resources to integrate additional CREPs and QFs into the portfolio. NorthWestern is currently studying the optimization of its current resource mix, including Hydros. Once that study is complete, it should have a baseline upon which future integration needs and costs can be determined.

<u>NorthWestern's Electricity Supply Resource Procurement Plans</u>

Q. Please describe the general framework that guides NorthWestern's electricity supply planning and acquisition activities.

A. Montana statutes, particularly §§ 69-8-419 through 421, MCA, and Commission regulations, specifically ARM 38.5.8201 through 38.5.8301, provide the framework for NorthWestern's planning and acquisition decisions.

ARM 38.5.8226(1) requires NorthWestern to file a comprehensive long-term portfolio management and electricity supply resource procurement plan in December of odd-numbered years. NorthWestern's current plan was filed in December 2013 in Docket No. N2013.12.84. The 2013 Plan is a comprehensive analysis of NorthWestern's electricity load-serving obligations for its retail customers in Montana. Chapter 7 of the 2013 Plan identifies and discusses key initiatives and baseline activities that NorthWestern included in its action plan associated with the overall 2013 Plan. As these activities have progressed, NorthWestern has communicated the results to the MPSC and stakeholders.

Since 2003, NorthWestern has produced and filed six biennial electricity supply procurement plans ("Plans"). The Plans, and the accompanying MPSC and stakeholder comments, provide guidance to the resource planning and acquisition processes that NorthWestern follows in order to cost-effectively and reliably meet its retail load-serving obligations.

Q. Please briefly describe the status of the action plan items that were listed in NorthWestern's 2013 Plan.

During 2014 and the first part of 2015 NorthWestern has accomplished the following:

- Continued to purchase and sell energy, dispatch resources, schedule, and tag load and supply sources in order to reliably meet customer energy demands while effectively managing price and limiting customer risk. This included managing the supply portfolio in the period between the end of the 7-year contract with PPLM on July 1, 2014 and taking ownership of the Hydros on November 18, 2014.

- Successfully integrated the Hydros into the supply portfolio. This included developing communication and other operational processes and procedures involved with the resource coordination function that is part of managing the Hydros.

- Completed a study that addresses economic dispatch issues surrounding NorthWestern's Basin Creek generating facility. The MPSC ordered NorthWestern to provide a plan for conducting such a study in Docket No. D2012.5.49, the 2011/2012 electric tracker docket. The study was completed in 2014 and a final report has been prepared.

- Conducted a Request for Proposals ("RFP") for CREPs in 2014. As a result of the RFP process, purchase power agreements ("PPAs") were executed with Greycliff Wind Prime, LLC (20 MW) and New Colony Wind, LLC (25 MW) with the expectation that both projects would qualify as CREPs and allow NorthWestern to fully comply with annual CREP procurement obligations. Based upon recent open meetings of the Commission, it appears that both projects are in jeopardy over the issue of CREP certification.

- Continued to implement the Demand-Side Management ("DSM") plan included and described in the 2011 and 2013 Plans with the goal of achieving 6 average MW of incremental energy savings capability annually. NorthWestern continued its plan to help customers install energy conservation measures through voluntary programs using both internal and external resources (contractors) to achieve annual targets.

- Satisfied the Renewable Portfolio Standard (“RPS”) requirement for compliance year 2014 as prescribed in § 69-3-2004(3)(a), MCA. During 2014 and 2015, NorthWestern took ownership of bundled electricity and renewable energy credits (“RECs”) from eligible projects located in Montana including Gordon Butte (wind), Judith Gap (wind), Turnbull (hydro), Spion Kop (wind), Musselshell (wind), Musselshell Two (wind), Lower South Fork (hydro), Flint Creek (hydro), Fairfield Wind (wind), and Two Dot Wind Farm (wind). Using RECs carried over from previous years and a portion of the RECs from 2013 renewable production, NorthWestern retired 597,700 RECs from its Western Renewable Energy Generation Information System account to satisfy its 2014 RPS obligation. NorthWestern currently has 535,544 surplus RECs that will be carried over to meet future RPS obligations.

Hydros Integration

Q. Please explain how the Hydros were integrated into NorthWestern’s power supply portfolio.

A. In May 2013 NorthWestern Energy Supply issued an RFP seeking to purchase power from July 1, 2014 through December 31, 2017. Product #7 within the May 2013 RFP was a request for up to 300 MW of on-system, index-based, on-peak power for the period July 1, 2014 through December 31, 2014. The 7-year purchase from PPLM was set to expire on July 1, 2014, and NorthWestern felt it would be best to purchase a six-month product in order to move on-system power acquisitions from a mid-year to a calendar year basis. As a result of the May 2013 RFP, NorthWestern purchased 200 MW of on-peak, on-system, index-based power from PPLM for the period July 1, 2014 through December 31, 2014.

The 200 MW purchase from PPLM proved to be very beneficial. The Hydros acquisition was announced in September 2013, and this source of supply provided a much-needed bridge between the end of the PPLM 7-year contract in July 2014 and the Hydros closing in November 2014. Negotiated as part of the Hydros purchase, the 200 MW contract expired upon the Hydros closing, and NorthWestern was not obligated to purchase that power once it took ownership of the Hydros. Additional on-system monthly purchases were made in July and August 2014, and the rest of the on-system supply needs came from existing resources and day-ahead and hourly purchases.

Q. Has there been a change to the load/resource balance in the supply portfolio as a result of the Hydros acquisition?

A. Yes. Since July 1, 2002 when NorthWestern began default supply service to retail customers in Montana, the supply portfolio had been in a short position, meaning supply resources were generally less than load, both on a capacity and an energy basis. Energy Supply overcame that shortfall by entering into long-, medium-, and short-term PPAs, entering into long-term contracts for the rights to the output of specific physical resources, and by gradually acquiring its own resources. Prior to the Hydros acquisition, Energy Supply forecasted resource needs and utilized term, day-ahead, and hourly markets to purchase the energy needed to serve load. When serving load NorthWestern was predominately a market buyer; sales volumes were de minimis, and sales typically occurred as a result of changes in load or wind forecasts.

The Hydros acquisition has created a long physical on-system position in the supply portfolio. Energy Supply now uses term, day-ahead, and hourly markets to sell excess generation, and credit issues and transmission availability are more relevant. Term, day-ahead, and hourly roles and responsibilities are similar, but NorthWestern now must look to move and sell energy in addition to acquiring it to serve load.

Q. What will be the effect on the supply portfolio when Kerr Dam is transferred to the Confederated Salish and Kootenai Tribes ("CSKT")?

A. Kerr Dam, with a generation capacity of 194 MW and an average annual output of 125 MW, is expected to be transferred to the CSKT on September 5, 2015. This will reduce NorthWestern's physical supply portfolio by that amount, leaving it close to being balanced with load on an energy basis. NorthWestern will tend to be short during on-peak periods and long during off-peak hours. This will be a very manageable position, and NorthWestern will use term, day-ahead, and hourly markets to purchase energy when it is short and sell excess energy when it is long. The supply portfolio will be structurally sound with diverse fuel sources and appropriate levels of capacity, energy, and market exposure.

<u>2014/2015 Tracker Period Activities</u>

Q. What planning document guided electricity supply procurement and scheduling activities during the 2014/2015 tracker period?

A. The 2013 Plan, including the discussion by NorthWestern regarding its hedging strategy, is the planning document that guided electric supply procurement and scheduling activities during the 2014/2015 tracker period.

Q. Please provide an overview of the 2014/2015 tracker period.

A. As detailed in this testimony as well as in the Prefiled Direct Testimony of Frank V. Bennett ("Bennett Direct Testimony"), during the 2014/2015 tracker period a material change to the supply portfolio occurred when NorthWestern took ownership of the Hydros in November 2014. NorthWestern planned for this event and seamlessly integrated the hydro resources into the supply portfolio. This was a substantial undertaking that involved many functional areas within NorthWestern, and the preparation and upfront work proved beneficial as these resources have been fully functional since NorthWestern acquired them.

Q. How did NorthWestern's acquisition of the Hydros affect the hedging program?

A. My earlier testimony described how NorthWestern's acquisition of the Hydros changed the resulting portfolio from a short position in the market to a long position. However, until the acquisition of the Hydros was approved by the Commission and the deal closed, the Company had to actively manage a short position in the market. After the Hydros acquisition, the supply portfolio still contained a number of fixed price hedges at Mid C, all of which were put on in previous periods. These hedge transactions have been part of the supply portfolio since 2002, and a formalized hedging strategy was first introduced in the 2007 Electric Default Supply Procurement Plan. These transactions were never intended to serve load but rather to provide price stability and reduce volatility in the energy supply portfolio.

Q. Describe the management of the Mid C hedges after the Hydros acquisition.

A. The Mid C hedge transactions will continue to be managed and unwound at the Mid C market under the following protocols:

- All existing risk management policies and regulatory requirements will be adhered to including tenor limits, dollar thresholds, approved products, internal approvals, etc.
- No new Mid C fixed price term purchases will be executed. Only sales of existing Mid C positions will be considered.

Q. Since the Hydros closing have any of the Mid C hedges been unwound?

A. Yes. One hundred MW of on-peak and 50 MW of off-peak December 2014 Mid C hedges were unwound in November 2014, and 25 MW on-peak and 25 MW off-peak June 2015 Mid C hedges were unwound in May 2015. No other Mid C hedges have been unwound and no additional hedges have been put on since the Hydros closing.

2015/2016 Tracker Period Forecast

Q. What is the forecast for the 2015/2016 tracker period?

A. The forecast for the next tracker period is contained in the Bennett Direct Testimony. This is a forecast using the best information that is known at this time. Actual results in the next adjustment period will vary based upon the loads which actually materialize, and upon actual transactions and prices.

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 prefiled direct testimonies of the following:

- Frank V. Bennett, Contract and Regulatory Specialist. Mr. Bennett presents the following information:
  - Updated 12-month ended June 2015 electricity supply costs, CU4 variable costs, Dave Gates Generating Station ("DGGS") variable costs/credits, and Spion Kop Wind Generation Project ("Spion") variable costs; and
  - The forecasted 12-month ended June 2016 information for each of the segments listed above and for the Hydros variable costs.

- Joseph S. Janhunen, Senior Analyst in the Regulatory Affairs Department. Mr. Janhunen offers testimony that:
  - Presents the 2015/2016 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 2014/2015 periods for electricity supply costs, CU4 variable costs, DGGS variable costs/credits, and Spion variable costs;

- Presents the derivation of proposed electricity supply cost rates, CU4 variable rates, DGGS variable rates, Spion variable rates, Revenue Credits rates, and Hydros variable rates for the forecasted 2015/2016 tracker period; and
- Presents the all-in electricity supply rates incorporating all individual variable and fixed rate components.

- Danie L. Williams, Manager Regulatory Support Services. Ms. Williams offers testimony that:
  - Presents a review of the Electric Supply DSM energy efficiency programs administered by NorthWestern for Tracker Year 2014/2015 and the results from the Universal System Benefits program for the same period;
  - Provides updated numbers for DSM Program costs as well as Lost Revenues for Tracker Year 2014/2015; and
  - Provides forecasted numbers for DSM Program costs as well as Lost Revenues for Tracker Year 2015/2016.

Q. Does this conclude your testimony?

A. Yes, it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2014.7.58
Annual Electric Supply Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF DANIE L. WILLIAMS

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. My name is Danie L. Williams, 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") 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 Tech of the University of Montana with Bachelor of Science degrees in Mathematical Sciences and General Engineering. I joined NorthWestern in March 2009 in the capacity of Demand Side Management ("DSM") Engineer and assumed my present position as Manager of Regulatory Support Services in March 2015. 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 and related Universal System Benefits ("USB") programs. My duties also include preparing the information supporting NorthWestern's energy efficiency-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 Electric Supply DSM and USB energy efficiency programs conducted by NorthWestern for Tracker Year 2014-2015 and a description of the status of and plans for DSM and USB programs and related activities in the forthcoming tracker period;
2. Updated numbers for Tracker Year 2014-2015 and forecasted numbers for Tracker Year 2015-2016 for DSM Program costs and the Lost Revenues associated with DSM and USB program activities; and
3. The results of the NorthWestern Energy Compact Fluorescent Lamp ("CFL") Lighting Market Study completed in May 2015.

2014-2015 Electric E+ Program Results

Q. Please describe the activities and overall results of NorthWestern's Efficiency Plus (E+) Electric Programs during the 2014-2015 electric supply tracker period.

A. In the 2004-2005 time period, NorthWestern established an Energy Efficiency Acquisition Plan with DSM/USB 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 Tracker Year), then to 5.0 aMW in Program Year 3 (2007-2008 Tracker Year) and leveling at 5.0 aMW through the 2009-2010 Tracker Year. In its

2009 Electric Default Supply Procurement Plan, NorthWestern increased its annual DSM/USB goal to 6.0 aMW starting in the 2010-2011 time period. This 6.0 aMW target is still in place and will continue for the 2015-2016 Tracker Year.

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 energy savings and program costs for a portion of the end of the current tracking period.

The Electric Supply DSM Program Expenditures for Program Year 11 (2014-2015) of $5,119,097 are based on 10 months of actual costs and 2 months (May-June 2015) of estimated expenses. The estimated amount of 6.02 aMW of incremental new installed DSM/USB capability is based on 9 months of actual and 3 months (April, May and June 2015) 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 Electric Supply DSM Programs and USB 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 Lost Revenues, USB Programs are funded through a separate charge and USB spending is not reported or included in Exhibit__(DLW-2).

Q. Please provide additional details on energy savings of individual DSM and USB Programs in operation during the 2014-2015 Tracker Year.

A. Exhibit__(DLW-1) provides individual program details on reported energy savings and develops numbers used in the updated Lost Revenues computation. This exhibit presents the following two tables of tabulation and analysis: Table A: Reported Electricity Savings from 2014-2015 USB and DSM Program Activity and Table B: Residential and Commercial Electric Savings for Calculation of Lost Revenues.

Table A: Reported Electricity Savings from 2014-2015 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 2014 through June 2015 (actual through March 2015, estimates for April-June 2015) . 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 measure (also referred to as *deemed savings*) are used. Examples of the latter include residential and commercial audits and variable frequency motor drives. Reported energy savings represents the annual 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 2014-2015 tracker period (April - June 2015) 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.

Table B: Residential and Commercial Electric Savings for Calculation of Lost Revenues.

Consistent with previous years, NorthWestern's proposal for cost recovery in tracker period 2014-2015 includes calculations for Lost Revenues. Rates for NorthWestern's hydroelectric generation facilities ("Hydro") were effective November 18, 2014 and Lost Revenues associated with those facilities are included in the calculations from that point forward. Because the applicable transmission, distribution, Colstrip Unit No. 4 ("CU4"), Dave Gates Generating Station ("DGGS"), Spion Kop Wind Generation Project ("Spion"), and Hydro 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/USB savings that were acquired in the 2014-2015 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 excluding savings from NorthWestern's own facilities and including an adjustment to reflect 8.6% storage of CFLs in the E+ Residential Lighting, Northwest Energy Efficiency Alliance ("NEEA"), and Energy Star® New Homes programs to produce the overall percentage contribution by the residential (64.94%) and commercial (35.06%) customer classes to the total. These percentage splits are then used as inputs to the calculation of Lost Revenues (e.g., see Exhibit__(DLW-3) page 7, lines 17-18; page 16, lines 13-14; page 22, lines 14-15; page 26, lines 14-15; and page 33 lines 14-15).

<u>DSM/USB Program Status Report</u>

Q. What is the current status of electric supply DSM/USB programs and what actions are planned for the 2015-2016 tracker year?

A. NorthWestern intends to continue offering a full portfolio of programs to its customers in the forthcoming 2015-2016 tracker period. Exhibit__(DLW-2) presents DSM spending by program for 2014-2015 (actual through April 2015, estimates for May-June 2015) and estimated spending for Tracker Year 2015-2016.

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

<u>E+ Lighting Programs</u>: DNV GL (formerly known as KEMA Services, Inc. or KEMA) provided lighting program implementation services for both commercial and residential customers in the 2014-2015 tracker period. Through DNV GL, NorthWestern offered cash rebates for ENERGY STAR® qualified hard-wired CFL fixtures and occupancy sensors. The program included several mechanisms to either distribute or encourage purchase and use of ENERGY STAR® CFLs and fixtures, and other energy efficient lighting measures, including:

a. Free CFL with mail-in home audits;

b. Mail-in rebates for residential customers for ENERGY STAR hard-wired CFL fixtures and occupancy sensors (mail-in rebates for CFL bulbs were discontinued in July 2014);

c. Rebates to commercial customers for energy efficient lighting equipment and controls;

d. In-Store Instant Rebates with redeemed coupons for residential customers;

e. Simple Steps Program – buy-down of CFL prices for residential customers at retailers through a regional campaign facilitated by the Bonneville Power Administration; and

f. Non-Retailer Special Events for residential customers (trade shows).

Federal regulations relating to energy efficiency standards for lighting technologies began phasing in over a three-year period starting January 1, 2012. These new regulations apply to manufacturing of incandescent lighting products, not to retail sale of them. Manufacturers have ceased production of targeted lighting products as a result of the regulations, and halogen bulbs have been introduced and are becoming widely available in the market. Therefore, energy savings opportunities remain by persuading customers, through NorthWestern's E+ Lighting Rebate programs, to purchase CFLs or other lighting technologies instead of the less efficient bulbs. Low-cost resources will continue to be acquired in the same manner as in the past – through operation of the E+ Lighting Rebate programs.

Merely replacing a 100-watt incandescent lamp is not a qualified program measure but replacing it with a 23-watt CFL is a qualifying energy-saving measure. Incandescent lamps of 100 watts, 75 watts, 60 watts, or 40 watts are typically replaced with CFLs in ranges of size shown in Table 1.

Table 1: CFL Replacements for Incandescent Lamps

To Replace		
Incandescent Bulb Rating (Watts)	Necessary Light Output (lumens)	Typical CFL Replacement (Watts)
40 Watts	450	9-13 Watts
60 Watts	800	13-15 Watts
75 Watts	1,100	15-25 Watts
100 Watts	1,600	23-30 Watts
150 Watts	2,600	30-52 Watts

CFLs of 23 watts (or larger) are commonly used to replace 100-watt incandescent bulbs. In the past NorthWestern calculated the energy savings in this case as the wattage differential between the baseline lamp and the replacement lamp (e.g., 100 watts – 23 watts = 77 watts) multiplied by the assumed daily burn hours. Due to the phase-in of the federal regulations, beginning January 1, 2014, NorthWestern modified its assumption for the baseline lamp to 60 watts for CFLs of 13 watts or greater.

Lamp manufacturers have now made available to consumers halogen incandescent lamps that meet the federal requirements for lumen output per watt of electricity consumed. Beginning January 1, 2015

NorthWestern started using halogen incandescent lamps as the baseline lamps and provides customers with an incentive/rebate to purchase and install the higher cost but more efficient CFL. Halogen incandescent lamps to replace 100 watt, 75 watt, 60 watt, or 40 watt standard efficiency incandescent lamps are now readily available to consumers. Table 2 shows the halogen incandescent lamp wattages that correspond to the CFL replacement.

Table 2: CFL Replacements for Halogen Incandescent Lamps

To Replace		
Halogen Incandescent Bulb Rating (Watts)	Necessary Light Output (lumens)	Typical CFL Replacement (Watts)
29 Watts	450	9-13 Watts
43 Watts	800	13-15 Watts
53 Watts	1,100	15-30 Watts
72 Watts	1,600	23-30 Watts

NorthWestern is in the process of renewing its contract with DNV GL for services related to the E+ Lighting Programs and will be offering the following programs in 2015-2016:

a. Free CFL with mail-in home audits;

b. Mail-in rebates for residential customers for ENERGY STAR hard-wired CFL fixtures and occupancy sensors;

c. Rebates to commercial customers for energy efficient lighting equipment and controls;

d. In-Store Instant Rebates with redeemed coupons for residential customers;

e. Simple Steps Program – buy-down of CFL prices for residential customers at retailers through a regional campaign facilitated by the Bonneville Power Administration; and

f. Non-Retailer Special Events for residential customers (trade shows).

Q. NorthWestern has indicated in the past that it would likely eliminate CFLs from its programs in 2015. Why will CFLs continue to be a program offering during the 2015-16 program period?

A. In February 2015, NorthWestern contracted with Nexant, Inc. (“Nexant”) to conduct targeted comparison and market research designed to understand the current state of the market for energy efficient lighting products in Montana, with specific focus on awareness, installation, and saturation of CFLs in the residential sector for both general and specialty lighting.

Exhibit__(DLW-4) presents the results of Nexant’s research and summarizes the findings that conclude the residential CFL lighting market is not transformed and recommends that NorthWestern continue to include CFLs in its programs through at least the 2015-2016 tracker period. However, the residential lighting market is in a state of significant change and the change will require consideration and evaluation of the market during the next few years. Nexant used three sources to inform their conclusions: literature review of current market data, comparative research of energy efficiency program administrators in the Pacific Northwest, and a statistically significant survey of residential electric customers in NorthWestern's Montana service territory.

NorthWestern will continue to monitor developments in the lighting market in 2015-2016 and will be prepared to make program changes, if needed. More information will become available as remaining electric energy savings potential is evaluated (see DSM/USB Program Activities for 2015-2016 below).

Q. Please provide an update of and future plans for other electric E+ programs.

A. A summary follows:

1. E+ Commercial Programs and Contractors: NorthWestern has continued its focus on acquiring energy efficiency in the commercial sector by contracting with firms 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. There are currently five firms concentrating on the commercial and small industrial sectors:
    - CTA Architects Engineers
    - Energy Resource Management, Inc.
    - McKinstry Essention

- CLEAResult Consulting, Inc. (formerly Portland Energy Conservation, Inc.)
- National Center for Appropriate Technology ("NCAT")

NorthWestern compensates these contractors on a performance basis, with payment based on a percentage of the energy conservation resource value of each individual project that is completed with the contractor's involvement. Each contractor is expected to deliver to NorthWestern an estimated 0.25 aMW of incremental energy savings each year.

These contractors are supported by a two to three member team of DNV GL employees who have responsibility for direct contact, face-to-face marketing of E+ programs to commercial/small industrial customers in an effort to identify, qualify, and cultivate energy saving 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 energy savings 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

- One-year performance contract.
- During the 2014-2015 tracker period, the following have been or are expected to be completed, providing an estimated 0.30 aMW of energy savings:
  - 12 commercial custom incentive electric conservation projects.
  - 20 commercial lighting rebate projects.
  - 13 commercial electric rebate projects.

Energy Resource Management Inc.

- Second year of a two-year performance contract.
- During the 2014-2015 tracker period, the following have been or are expected to be completed, providing an estimated 0.21 aMW of energy savings:
  - 16 commercial custom incentive electric conservation projects.
  - 9 commercial lighting rebate projects.
  - 1 commercial electric rebate project.

McKinstry Essention

- One-year performance contract.
- During the 2014-2015 tracker period, the following have been or are expected to be completed, providing an estimated 0.08 aMW of energy savings:
  - 1 commercial custom incentive electric conservation project.
  - 8 commercial lighting rebate projects.

CLEAResult Consulting, Inc.

- First year of a two-year performance contract.
- During the 2014-2015 tracker period, the following have been or are expected to be completed, providing an estimated 0.04 aMW of energy savings:
  - 2 commercial custom incentive electric conservation projects.
  - 1 commercial lighting rebate project.
  - 4 commercial electric rebate projects.

NCAT

- One-year performance contract.
- During the 2014-2015 tracker period, the following have been or are expected to be completed, providing an estimated 0.73 aMW of energy savings:
  - – 43 commercial custom incentive electric conservation projects.
  - – 83 commercial lighting rebate projects.
  - – 22 commercial electric rebate projects.

2. 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 one of a five-year commitment that will continue its funding of and participation in NEEA activities and initiatives during the 2015-2019 time period. NorthWestern reported energy savings from NEEA activities totaling 1.47[1] aMW during the 2014-2015 tracker period. Information on NEEA’s numerous projects and initiatives that were in progress during 2014-2015 and are continuing into the future can be found at http://www.neea.org.

[1] Includes 1.36 aMW from general NEEA initiatives and 0.11 aMW from a NEEA sponsored Energy Star 80 Plus Program.

3. 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, no new electrically heated homes were certified in 2014-2015 but 68 new natural gas heated homes were certified. Current code requires 50% high efficiency lighting, but as a direct result of NorthWestern's support of the ENERGY STAR® Homes Northwest building standards through this program, an average of 85% of the lamps are ENERGY STAR® high efficiency products.

4. E+ Electric Motor Rewind Rebate: NorthWestern offers incentives for motor rewinding. Currently, only three electric motor service centers in 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, NorthWestern folded qualified motor rewinds into the Commercial Electric Rebate Program for Existing Facilities. Program marketing during 2014-2015 included sponsorship of motor management

seminars (see Green Motors Management details in the training section below).

5. E+ Residential Electric Programs: SBW Consulting, Inc. ("SBW") determined the residential electric existing and new construction rebate programs to be non-cost effective in its DSB/USB evaluation of Tracker Periods (2006-2010). Despite NorthWestern's subsequent attempts to modify these relatively small programs to be cost effective, it was unable to do so. Consequently, the programs were terminated as of July 1, 2014.

Additional information about all of NorthWestern's DSM/USB programs is available at NorthWestern's website at www.NorthWesternEnergy.com/Eplus.

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

A. Yes. NorthWestern 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 energy-consuming equipment efficiently and to promote the E+ programs, services, information resources, and incentives. Where practical or appropriate, Continuing Education Units ("CEUs") are offered. 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 2014-2015:

1. <u>NorthWestern Energy Lighting Trade Ally Network</u> – This activity was focused on commercial lighting and the trade allies supporting this key energy efficiency opportunity. Activities are focused on training regarding lighting design and technology, appropriate product promotion, and also review of NorthWestern's E+ program offerings. Meetings held in August of 2014 in Missoula focused on emerging lighting technologies and controls. Trade Allies receive a quarterly electronic newsletter with updates on technologies and case studies of NorthWestern customer projects. The Lighting Trade Allies are listed on the NorthWestern website. NorthWestern includes other resources for lighting professionals and trade allies associated with NorthWestern's E+ programs in the e-newsletter.

2. <u>Commercial Lighting Training</u> – October 21-24, 2014 in Billings, Bozeman, Helena, and Great Falls. NorthWestern partnered with Crescent Electric to focus on emerging lighting technologies and controls and information about NorthWestern's E+ programs.

3. <u>Green Motors Management Training</u> – Scheduled for June 1-5, 2015 in Billings, Bozeman, Great Falls, Butte, and Missoula. These one-day seminars are for commercial customers, facilities managers, electricians, and motor service shops to learn how to estimate operating costs for electric motor systems and to identify improvement in motors management practice to increase system reliability and reduce operating costs. This training is conducted by the Green Motors Management Group and sponsored by NorthWestern.

4. <u>Building Operator Certification</u> – This is targeted at public schools, non-profit hospitals, and state and local government; funding is provided for tuition and travel. Two Level I training classes were completed in the tracker period and a third Level I class is scheduled for June 2015. The first three-session class (8 days) was held in Bozeman (August 18-20, September 17-19, and October 6 & 7, 2014) with 10 attendees, and the second two-session class (8 days) was held in Great Falls (November 18-21 and December 16-19, 2014) with 9 attendees. One Level II training class was completed in the tracker period. The two-session class (7 days) was held in Missoula (January 13-16 and February 24-26, 2015) with 13 attendees.

5. <u>Montana Code Training</u> – In November of 2014, Montana adopted the 2012 International Energy Conservation Code (IECC). In advance of the code adoption and continuing forward, NorthWestern, in

partnership with NEEA, has provided training on the provisions of the updated residential and commercial codes. As an additional resource to guide the residential construction community, the "Montana Residential Energy Code Handbook—2012 International Energy Conservation Code (as amended)" was compiled by NCAT with input from the Montana Department of Labor and Industry and the Montana Department of Environmental Quality. Printing of this handbook was funded with USB and the handbook is being distributed at training and other venues as requested to further the adoption of the updated residential code. Training on the updated Montana Energy Code has been provided at trade association conferences targeting architects and engineers; at the state code conference; through special sessions with local building departments; and through the local homebuilding industry associations. Sessions were approved for CEUs by the Montana Society of Engineers, American Institute of Architects, and the International Codes Council. Additional training is planned for the 2015-2016 tracker period.

6. <u>Blower Door Testing Training</u> – The updated Montana Energy Code requires blower door testing to measure the air exchanges of a home as part of the residential code requirements. Through NEEA, blower doors have been provided to local homebuilding industry associations. During the tracker period, training sessions on the proper use of the

blower door have been provided to the associations and local code officials.

7. Performance Testing Training – This training was offered to local homebuilding and industry associations and was provided where requested. The training focused on the importance of tightness testing for building envelope and ducts and implications for mechanical ventilation.

8. ENERGY STAR® Home and Rating Certification Stipend Pilot Project – The objectives of the project were: 1) to encourage builders to obtain either an ENERGY STAR® certification or a Home Energy Rating System rating for their homes, 2) to encourage builders to take advantage of NorthWestern's new construction rebates, and 3) to encourage third-party energy inspections of homes built outside of local energy code jurisdictions. Twenty-nine certification stipends were submitted and paid in 2014, all for ENERGY STAR® homes. This was a continuation of a pilot started in 2013.

9. Efficiency of Chilled Water Systems and Cooling Towers – NEEA sponsored this training in Missoula on August 27, 2014. This course focuses on cooling for industrial and commercial facilities. The Cooling Tower course addresses efficiency measures and water treatment,

water conservation, and maintenance. This training equips attendees with the knowledge and tools needed to reduce energy usage and operating costs and improve the reliability of cooling systems.

10. Energy Efficiency for Air Cooled Refrigeration Systems – NorthWestern sponsored this NEEA facilitated training on November 19, 2014 in Billings. The course emphasis is on air cooled split refrigeration systems. Attendees developed the skills and knowledge to reduce the energy use and operating costs of their refrigeration systems while improving reliability. The training also addressed non-ammonia based refrigeration systems.

11. Preferred Contractor Training – This training was offered August 11-21, 2014 in Billings, Bozeman, Butte, Great Falls, Havre, Helena, Kalispell, and Missoula. In order to encourage participation, a live online webinar was also offered. Each year NorthWestern provides training to various contractors that install energy saving measures in the homes of consumers who participate in its E+ programs.

12. Webinars – To make training more accessible to commercial and industrial customers and trade allies, multiple energy management topic webinars sponsored by NEEA are posted on NorthWestern's

website and promoted in the electronic newsletter to commercial and industrial customers. These webinars are free to customers.

Q. Did NorthWestern make additional efforts during the 2014-2015 tracker period to promote its E+ programs?

A. Yes. To communicate information about NorthWestern's 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 E+ 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 2014-2015 to market its programs:

1. <u>Trade Shows</u> – In Fall 2014 and Spring 2015, NorthWestern staffed exhibits and educational display booths at eight home improvement trade shows around Montana providing educational materials and distributed four free CFLs each to eligible residential electric customers.

   a. Fall 2014 – Billings.

b. Spring 2015 – Missoula (2 shows), Billings, Bozeman, Great Falls, Helena, and Butte.

2. Montana Lodging and Hospitality Association Conference – NorthWestern hosted a display booth at this October 27-28, 2014 conference.

3. Montana Joint Engineers Conference – November 5-7, 2014 in Helena. NorthWestern provided training on the provisions of the updated Montana Energy Code and a display.

4. Montana Building Code Education Conference – March 30-April 2, 2015 in Bozeman. NorthWestern provided training on the updated residential and commercial Montana Energy Code provisions and staffed a display booth.

5. Montana Hospital Association Conference – September 24-26, 2014 in Billings and March 11-12, 2015 in Bozeman. NorthWestern provided a display booth.

6. Montana Compete Smart Manufacturer's Conference – October 9-10, 2014 in Billings. NorthWestern provided a sponsorship and a display booth.

7. Montana American Institute of Architects ("AIA") Conference – September 25-27, 2014 in Helena. NorthWestern provided a display booth and training on the provisions of the updated Montana Energy Code.

8. Montana Society of Health Care Engineers/ASHRAE[2] Conference – May 20-22, 2015 in Great Falls. NorthWestern provided a display booth and a presentation regarding Building Operator Certification training.

9. CFL Instant Savings Coupon Campaigns – October 2014 for Energy Awareness Month and in April 2015 to observe Earth Day with direct mail to all residential electric customers, point-of-purchase materials at participating retailers, and newspaper campaign.

10. "Simple Steps" Regional CFL Campaign – Upstream manufacturers' buy-down for CFLs with point-of-purchase materials at retailers.

11. E+ Audit for the Home – Direct mail in summer and winter 2014 and spring of 2015. NorthWestern funded spot placement of television, radio, and online promotion.

[2] 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.

12. E+ Tips and Commercial Lighting television spots – Spot placement during selected events.

13. Parade of Homes Sponsorships (Fall 2014) – Billings, Bozeman, Missoula, Helena, Kalispell, and Hamilton. These sponsorships are also included newspaper ad promotions.

14. Other Special Events:

a. NorthWestern sponsored Energy Corps members through NCAT who provided energy efficiency presentations, hands-on activities for youth, and supported display booths at events between October of 2014 and April of 2015. The following table summarizes Energy Corps activities associated with NorthWestern's programs:

Event	Location
Grade School Classroom Education	**West and Hillcrest Elementary and Silver Bow Montessori School (Butte)**
Service Groups	**Sunrise, Big Butte, and Anaconda Kiwanis (Butte and Anaconda)**
Middle School Classroom Education	**East Middle School (Butte)**
High School Classroom Education	**Butte High, Butte Central and Havre School (Butte and Havre)**
Renewable Energy and Energy Efficiency Non Profit	**National Center for Appropriate Technology and Alternative Energy Resources Organization (Butte and Red Lodge)**
Library Presentations	**Butte**

b. Home air-sealing installation and energy education targeted at customers over 50 years of age and/or low-income customers through direct mail. The Energy Corps members contacted eligible customers who had not received weatherization kits through distribution events or home energy audits prior to July 2014 and whose homes were identified as needing air-sealing. They scheduled site visits, installed air infiltration sealing materials, and provided energy efficiency education to 301 customers.

More details about the techniques, mechanisms, locations, forms of media, and calendar schedule are presented in Exhibit__(DLW-5a) which describes the goals, objectives, audiences, strategies, tactics, methods, and tools of the DSM/USB Communications Plan. Exhibit__(DLW-5b) 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 E+ programs, gain customer participation, and acquire cost-effective energy saving resources. The DSM/USB Communications Plan serves as a working plan that can and will be changed and adapted as conditions warrant or new knowledge is gained.

DSM/USB Program Activities for 2015-2016

Q. Does NorthWestern plan to offer electric E+ programs in the 2015-2016 tracker period?

A. Yes, the portfolio of E+ Electric programs will be continued through the 2015-2016 period. The mail-in rebates and custom incentives will continue uninterrupted throughout the tracker period from July 1, 2015 through June 30, 2016 subject to changes that may be dictated by the evolving lighting market.

NorthWestern will continue its contracts with outside service providers and will maintain its program rebates and incentives at a level approximately equal to 50% of the total resource value.

A coordinated and comprehensive marketing and communications effort that integrates USB and DSM funding for marketing and outreach has been developed and employed over the past several years, and many of the methods and techniques that have proven effective in the past will be repeated in the future (refer to Exhibit__(DLW-5a) and Exhibit__(DLW-5b)).

Q. What other actions are planned in 2015-2016 to continue development of NorthWestern's overall energy efficiency effort?

A. NorthWestern plans to hire an outside service provider in the 2015-2016 Tracker Period to perform an electric energy efficiency resource assessment and provide NorthWestern with updated estimates of remaining electric energy savings potential. The last assessment was completed by Nexant in April 2010.

Recovery of DSM Program Costs and Lost Revenues

Q. What are the DSM program costs for Tracker Year 2015-2016 and how does NorthWestern propose to recover them?

A. Exhibit__(DLW-2) presents budget figures for individual electric DSM programs that total $5,565,510 (refer to cell O35) for the 2015-2016 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 electricity supply expenses include recovery of $5,565,510 for 2015-2016 Tracker Year DSM program costs.

Q. Does NorthWestern propose to continue recovery of Transmission and Distribution ("T&D") Lost Revenues associated with DSM/USB program activity?

A. Yes. Electric Lost Revenues are a function of reduced T&D throughput caused by NorthWestern's DSM/USB program activity. Additional resource has been acquired in this tracker period, adding to the accumulated energy savings from NorthWestern's E+ program activities since the last reset of T&D rates, which became effective on January 1, 2011[3]. The accumulating energy savings further reduces the T&D throughput volumes compared to the prior tracking period. This, in turn, negatively affects NorthWestern's ability to recover fixed costs associated with the T&D system through volumetric rates.

Q. Does NorthWestern propose to continue recovery of Lost Revenues associated with CU4?

A. Yes. NorthWestern proposes to recover the Lost Revenues associated with the fixed cost portion of the revenue requirement of CU4. Similar to T&D rates, the CU4 fixed costs will be reset in a future CU4 revenue requirement proceeding. The Lost Revenues calculations associated with these fixed costs appear as a separate additional worksheet tab (pages 16-21 of Exhibit__(DLW-3)) in the Electric Lost Revenues spreadsheet described below.

Q. Does NorthWestern propose to continue 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 rates, the DGGS fixed costs will be reset in a future revenue requirement

[3] Refer to Docket No. D2009.9.129 Final Order No. 7046h.

proceeding. The Lost Revenue calculations associated with these fixed costs appear as a separate additional worksheet tab (pages 22-25 of Exhibit__(DLW-3)) in the Electric Lost Revenues spreadsheet described below.

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

A. Yes. NorthWestern proposes to recover the Lost Revenues associated with the fixed cost portion of the revenue requirement of Spion that was placed into commercial operation on December 1, 2012. Similar to T&D rates, the Spion fixed costs will be reset in a future revenue requirement proceeding. The Lost Revenue calculations associated with these fixed costs appear as a separate additional worksheet tab (pages 26-30 of Exhibit__(DLW-3)) in the Electric Lost Revenues spreadsheet described below.

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

A. Yes. NorthWestern proposes to recover the Lost Revenues associated with the fixed cost portion of the revenue requirement of Hydro that was placed into rates on November 18, 2014. Similar to T&D rates, the Hydro fixed costs will be reset in a future revenue requirement proceeding. The Lost Revenue calculations associated with these fixed costs appear as a separate additional worksheet tab (pages 33-35 of Exhibit__(DLW-3)) in the Electric Lost Revenues spreadsheet described below.

Q. Is there a difference in the Electric Lost Revenues numbers for the 2013-2014 tracker period in Exhibit__(DLW-3) as compared to the Lost Revenues presented for the 2013-2014 tracker period in NorthWestern's response to Data Request MCC-061 in consolidated Docket Nos. D2013.5.33/D2014.5.46?

A. Yes. While the 2013-2014 Lost Revenues are not an issue in this docket, there is a difference. The Lost Revenues for the 2013-2014 tracker period in the spreadsheet workbook Exhibit__(WMT-3) Electric DSM Lost Revenues_2014-2015_D2014.5.46_12+0_FINAL provided in response to Data Request MCC-061 were based on 12 months of actual energy savings. However, the savings in that workbook were not adjusted downward to reflect the 8.6% storage rate for residential CFLs as required in Final Order No. 7219h in Docket No. D2012.5.49. Exhibit__(DLW-3) correctly reflects that adjustment for the 2013-2014 tracker period.

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

A. The Electric Lost Revenues calculation is performed using a spreadsheet workbook model, included herein as Exhibit__(DLW-3), that is comprised of 12 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 Electric Lost Revenues. Additional notes and explanations are included on the individual spreadsheet tabs, identified as separate pages of Exhibit__(DLW-3).

1. **LR Summary** (Exhibit__(DLW-3), page 1) presents the results of the Lost Revenues computations for tracker periods starting with the 2011-2012 tracker period, including the calculations for Lost Revenues related to T&D, CU4, DGGS, Spion, and Hydro that are performed on the subsequent tabs.

2. **Rates** (Exhibit__(DLW-3), pages 2-6) details rates in effect for residential and GS-1 customers by line item. The Electric Lost Revenue calculations use T&D rates from this worksheet tab as inputs to Tab 7 Calc Lost Revenues. These rates are updated each time the Electric Lost Revenues exhibit is prepared for the Annual Electric Supply Tracker filing.

3. **Res and CI Energy Savings** (Exhibit__(DLW-3), page 7) uses the annual DSM/USB targets or reported amounts and disaggregates them into residential and commercial/industrial ("C&I") electric savings percentage splits. These percentage splits are updated each year as NorthWestern gains experience operating energy efficiency programs, collects program participation data, and observes the proportion of energy savings contributed by each customer segment toward annual DSM/USB targets. The residential and C&I electric savings are then disaggregated into cumulative annual residential and C&I energy savings using a 50% reduction factor. Use of this factor recognizes that first-year realized savings would be less than subsequent years, because energy efficiency measures are installed throughout the program year and are not in place and operating for a full year.

4. **C&I Demand Sav** (Exhibit__(DLW-3), page 8) 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__(DLW-3), page 9) 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 demand and GS-1 primary 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__(DLW-3), page 10) presents factors to be applied to residential and C&I program reported energy 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. The provisions of Final Order No. 7219h in Docket No. D2012.5.49 specified further adjustments (reductions) to the total net energy savings determined by SBW in its evaluation. Comparing the resulting total adjusted energy savings that incorporates this Commission-ordered change to the original SBW energy savings total results in an overall 9% (rounded) reduction from gross energy savings to net energy savings for use in Lost Revenue calculations. For the 2011-12 tracker period forward, an Adjustment Factor of 0.91 is used to de-rate gross reported energy savings to net adjusted energy savings used in Lost Revenue computations.

7. Calc Lost Revenues (Exhibit__(DLW-3), pages 11-15) calculates T&D 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__(DLW-3), pages 16-21) 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 CU4 that serves Montana jurisdictional loads. The same lost revenue calculation methodology used in tabs 2 through 7 is applied, and the time frame for energy savings relevant to the calculation reflects the fact that the CU4 rate became effective on January 1, 2009.

9. DGGS Related LRs (Exhibit__(DLW-3), pages 22-25) 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 energy savings relevant to the calculation reflects the fact that DGGS was placed in commercial service on January 1, 2011.

10. Spion Related LRs (Exhibit__(DLW-3), pages 26-30) calculates Lost Revenues that are specific to the portion of the energy supply rate associated with recovery of the fixed cost revenue requirement for Spion service to Montana jurisdictional loads. The same lost revenue calculation methodology used in tabs 2 through 7 is applied, and the time frame for energy savings relevant to the calculation reflects the fact that Spion was placed in commercial service on December 1, 2012.

11. Spion Kop Rates (Exhibit__(DLW-3), pages 31-32) presents a listing of the rates for each customer class and time period that are used for calculation of Spion Related lost revenues in Tab 10.

12. Hydro Related LRs (Exhibit__(DLW-3), pages 33-35) calculates Lost Revenues that are specific to the portion of the energy supply rate associated with recovery of the fixed cost revenue requirement for Hydro service to Montana jurisdictional loads. The same lost revenue calculation methodology used in tabs 2 through 7 is applied, and the time frame for energy savings relevant to the calculation reflects the fact that Hydro was included in rates on November 18, 2014.

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__(DLW-3) provides updated calculations of electric Lost Revenues. A true-up to the Lost Revenue calculations is required each time a new tracker is prepared because NorthWestern prepares and files a new annual tracker before the current tracking period ends. This schedule requires computation of 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 is updated to reflect 12 months of actual information in response to discovery or in rebuttal testimony in the current docket.

NorthWestern proposes that electric supply rates include recovery of the amount of $12,925,639 for total Electric Lost Revenues for the 2014-2015 Tracker Year (refer to cell G10 on page 1 of Exhibit__(DLW-3)).

The forecast Electric Lost Revenues for the 2015-2016 Tracker Year are $16,385,311 (refer to cell G12 on page 1 of Exhibit__(DLW-3)).

Q. Does this complete your testimony?

A. Yes, it does.

Table A: Reported Electricity Savings from 2014-15 USB and DSM Program Activity

Programs	Annualized Energy Savings[1]			
	USB		DSM	
	kWh	aMW	kWh	aMW
E+ Energy Audit for the Home or Business (Elec)	849,447	0.10	-	-
E+ Business Partners Program	-	-	2,979,214	0.34
E+ Irrigation	880,171	0.10	-	-
E+ Commercial Lighting Rebate Program	-	-	9,798,358	1.12
E+ Residential Lighting Programs	-	-	21,929,936	2.50
Builder Operator Certification	625,213	0.07	-	-
Northwest Energy Efficiency Alliance (NEEA)	-	-	11,957,207	1.36
Energy Star 80 Plus Program	-	-	952,749	0.11
E+ Free Weatherization Program & Fuel Switch	276,868	0.03	-	-
E+ Renewable Energy Program	731,749	0.08	-	-
Energy Star New Homes Program	25,315	0.003	-	-
E+ Residential NC Electric Rebate Program	-	-	-	-
E+ Residential EX Electric Rebate Program	-	-	777	0.00
E+ Commercial NC Electric Rebate Program	-	-	524,109	0.06
E+ Commercial EX Electric Rebate Program	-	-	1,188,283	0.14
Totals	**3,388,763**	**0.39**	**49,330,633**	**5.63**

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

USB + DSM savings acquired in 2014-15 Tracker Period (aMW):	6.02

Table B: Residential and Commercial Electric Savings for Calculation of Lost 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)	85%	718,747	15%	130,700	849,447		
E+ Business Partners Program	0%	-	100%	2,979,214	2,979,214		
E+ Irrigation	0%	-	100%	880,171	880,171		
E+ Commercial Lighting Rebate Program	0%	-	100%	9,798,358	9,798,358		
E+ Residential Lighting Programs	100%	21,929,936	0%	-	21,929,936		
Builder Operator Certification	0%	-	100%	625,213	625,213		
Northwest Energy Efficiency Alliance (NEEA)	96%	11,537,259	4%	419,948	11,957,207		
Energy Star 80 Plus Program	0%	-	100%	952,749	952,749		
E+ Free Weatherization Program & Fuel Switch	100%	276,868	0%	-	276,868		
E+ Renewable Energy Program	59%	432,565	41%	299,184	731,749		
Energy Star New Homes Program	100%	25,315	0%	-	25,315		
E+ Residential NC Electric Rebate Program	100%	-	0%	-	-		
E+ Residential EX Electric Rebate Program	100%	777	0%	-	777		
E+ Commercial NC Electric Rebate Program	0%	-	100%	524,109	524,109		
E+ Commercial EX Electric Rebate Program	0%	-	100%	1,188,283	1,188,283		
		34,921,467		**17,797,930**	**52,719,396**	**66.24%**	**33.76%**

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

	Residential kWh	Commercial kWh	Total kWh	Residential % of Total[2]	Commercial % of Total[2]
Subtract NorthWestern Energy Facilities from Commercial Totals[3]	**34,921,467**	**17,786,462**	**52,707,929**	**66.25%**	**33.75%**

Note 3: The savings from NorthWestern Energy facilities has been subtracted from the commercial kWh total, resulting in a reduction of Total kWh and a reduction of the Commercial Percentage of Total Savings.

	Residential kWh	Commercial kWh	Total kWh	Residential % of Total[2]	Commercial % of Total[2]
Subtract 8.6% for CFL Storage in E+ Residental Lighting, NEEA, and Energy Star New Homes[4]	**32,944,411**	**17,786,462**	**50,730,873**	**64.94%**	**35.06%**

Note 4: The savings from E+ Residental Lighting, NEEA, and Energy Star New Homes has been reduced by 8.6% for CFL storage per Order 7219h (paragraphs 67, 68, and 124). These amounts have been subtracted from the residential kWh total, resulting in a reduction of Total kWh and a reduction of the Residential Percentage of Total Savings.

Electric Supply DSM Program Spending and Budget

		2014-2015 Tracker Year												
		Actual Recorded Spending (July through April) - from SAP Records										Estimated		
Electric DSM Program Spending	**Order**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Total**
General Expenses Related to All DSM Programs	17054	$ 126	$ (3,180)	$ 1,052	$ 814	$ 147	$ 288	$ 1,898	$ 688	$ 659	$ 3,460	$ 595	$ 595	$ 7,142
E+ Residential Lighting Program	17055	$ 52,202	$ 89,153	$ 79,690	$ 60,638	$ 24,473	$ 192,445	$ 106,027	$ 62,016	$ 8,650	$ 232,563	$ 90,786	$ 90,786	$ 1,089,426
E+ Residential Electric Savings Program	17056	$ 1,686	$ 150	$ -	$ 66	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,902
E+ Residential New Construction Program	17059	$ 392	$ 231	$ -	$ 111	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 734
E+ Commercial Lighting Program	17060	$ 3,256	$ 142,984	$ 16,516	$ 279,504	$ 31,899	$ 337,155	$ 36,901	$ 269,835	$ 57,346	$ 96,714	$ 127,211	$ 127,211	$ 1,526,534
E+ Commercial New Construction Program	17062	$ 8,239	$ 498	$ -	$ 29,550	$ -	$ 12,614	$ -	$ 19,428	$ 17,271	$ 1,271	$ 8,887	$ 8,887	$ 106,644
E+ Business Partners Program	17063	$ 19,217	$ 83,970	$ 317	$ 195,789	$ 121,934	$ 167,285	$ 68,180	$ 95,128	$ 486	$ 51,457	$ 80,376	$ 80,376	$ 964,515
E+ Commercial Electric Rebate Program	17064	$ 15,732	$ 49,024	$ 1,537	$ 21,468	$ 17,479	$ 49,577	$ 6,662	$ 86,474	$ 29,347	$ 62,441	$ 33,974	$ 33,974	$ 407,690
Market Transformation (NEEA)	17067	$ -	$ 11	$ 229	$ 362,165	$ -	$ 54	$ -	$ 79	$ 325,706	$ 586	$ 325,678	$ -	$ 1,014,509
Monthly Total Spending		$ 100,849	$ 362,841	$ 99,341	$ 950,105	$ 195,932	$ 759,419	$ 219,667	$ 533,648	$ 439,465	$ 448,493	$ 667,507	$ 341,829	$ 5,119,097
Cumulative Total Spending (for 2014-15 Tracker Year 10+2)		$ 100,849	$ 463,690	$ 563,030	$ 1,513,135	$ 1,709,068	$ 2,468,487	$ 2,688,154	$ 3,221,802	$ 3,661,267	$ 4,109,760	$ 4,777,267	$ 5,119,097	**$ 5,119,097**

Note: Actual Program Expenses through April 30, 2015 as of May 7, 2015

		2015-2016 Tracker Year												
		Estimated												
Electric DSM Program Spending	**Order**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Total**
General Expenses Related to All DSM Programs	17054	$ 126	$ 11,404	$ 15,635	$ 15,397	$ 14,730	$ 14,872	$ 16,481	$ 15,271	$ 15,243	$ 18,043	$ 15,179	$ 15,179	$ 167,559
E+ Residential Lighting Program	17055	$ 52,202	$ 89,153	$ 79,690	$ 60,638	$ 24,473	$ 192,445	$ 106,027	$ 62,016	$ 8,650	$ 232,563	$ 90,786	$ 90,786	$ 1,089,426
E+ Commercial Lighting Program	17060	$ 3,256	$ 142,984	$ 16,516	$ 279,504	$ 31,899	$ 337,155	$ 36,901	$ 269,835	$ 57,346	$ 96,714	$ 127,211	$ 127,211	$ 1,526,534
E+ Commercial New Construction Program	17062	$ 8,239	$ 498	$ -	$ 29,550	$ -	$ 12,614	$ -	$ 19,428	$ 17,271	$ 1,271	$ 8,887	$ 8,887	$ 106,644
E+ Business Partners Program	17063	$ 19,217	$ 83,970	$ 317	$ 195,789	$ 121,934	$ 167,285	$ 68,180	$ 95,128	$ 486	$ 51,457	$ 80,376	$ 80,376	$ 964,515
E+ Commercial Electric Rebate Program	17064	$ 15,732	$ 49,024	$ 1,537	$ 21,468	$ 17,479	$ 49,577	$ 6,662	$ 86,474	$ 29,347	$ 62,441	$ 33,974	$ 33,974	$ 407,690
Market Transformation (NEEA)	17067	$ -	$ 79	$ 325,706	$ -	$ 79	$ 325,706	$ -	$ 79	$ 325,706	$ -	$ 79	$ 325,706	$ 1,303,142
Monthly Total Spending		$ 98,771	$ 377,111	$ 439,401	$ 602,346	$ 210,595	$ 1,099,655	$ 234,250	$ 548,232	$ 454,049	$ 462,490	$ 356,492	$ 682,119	$ 5,565,510
Estimated Total Spending (for 2015-16 Tracker Year)		$ 98,771	$ 475,882	$ 915,283	$ 1,517,629	$ 1,728,224	$ 2,827,879	$ 3,062,130	$ 3,610,361	$ 4,064,410	$ 4,526,899	$ 4,883,391	$ 5,565,510	**$ 5,565,510**

Electric Lost Revenues

Time Period	Montana T&D	Colstrip Unit #4	Dave Gates Mill Creek Station[1]	Spion Kop[2]	Hydro[3]	Total Lost Revenues
Tracker 2011-12	$ 2,307,045	$ 1,808,216	$ 215,603	$ -	$ -	$ 4,330,864
Tracker 2012-13	$ 4,079,918	$ 2,524,213	$ 504,221	$ 18,029	$ -	$ 7,126,381
Tracker 2013-14	$ 5,916,696	$ 3,233,963	$ 771,478	$ 75,837	$ -	$ 9,997,974
Tracker 2014-15	$ 7,518,502	$ 3,859,551	$ 1,007,044	$ 159,923	$ 380,619	$ 12,925,639
Tracker 2015-16	$ 9,067,752	$ 4,456,505	$ 1,231,827	$ 228,290	$ 1,400,936	$ 16,385,311

Notes:

The starting point for this 'Exhibit__(WMT-3) 2014-15 Elec Lost Revenues 9+3 FINAL 051115' in D2014.7.58 was the spreadsheet workbook *'Exhibit__(WMT-3) Electric DSM Lost Revenues_2014-2015_D2014.5.46_12+0_FINAL' and* was filed in response to MCC-061 in Docket D2014.5.46.

Tracker Period 2012-2013 based on 12 month actual reported energy savings (excluding NorthWestern Facilities DSM and 8.6% CFL storage calculation)
Tracker Period 2013-2014 based on 12 months actual reported energy savings (excluding NorthWestern Facilities DSM and 8.6% CFL storage calculation)
Tracker Period 2014-2015 based on 9 months of actual and 3 months of estimated savings (excluding NorthWestern Facilities DSM and 8.6% CFL storage calculation)
Tracker Period 2015-2016 based 6.0 aMW goal

Electric 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; and updated with Order on Remand No. 7046i effective July 8, 2011

1. DGGS began commercial service on January 1, 2011.

2. Spion Kop began commercial service on December 1, 2012.

3. Hydro was included in rates beginning on November 18, 2014.

Electric Lost Revenues

2011-12 Tracking Period

July 1, 2011 - December 31, 2011 Period			January 1, 2012 Forward			Averaged Rates used for 2011-12 Tracking Period		
Residential:			**Residential:**			**Residential:**		
Transmission Energy	0.009078	per kwh	Transmission Energy	0.008866	per kwh	Transmission Energy	0.008972	per kwh
Distribution Energy	0.028259	per kwh	Distribution Energy	0.027599	per kwh	Distribution Energy	0.027929	per kwh
GS 1 Secondary, non-demand			**GS 1 Secondary, non-demand**			**GS 1 Secondary, non-demand**		
Transmission Energy	0.007904	per kwh	Transmission Energy	0.007719	per kwh	Transmission Energy	0.007812	per kwh
Distribution Energy	0.036600	per kwh	Distribution Energy	0.035745	per kwh	Distribution Energy	0.036173	per kwh
GS 1 Secondary, demand			**GS 1 Secondary, demand**			**GS 1 Secondary, demand**		
Transmission Demand	3.019986	per kw	Transmission Demand	2.949439	per kw	Transmission Demand	2.984713	per kw
Distribution Energy	0.004883	per kwh	Distribution Energy	0.004769	per kwh	Distribution Energy	0.004826	per kwh
Distribution Demand	6.156176	per kw	Distribution Demand	6.012368	per kw	Distribution Demand	6.084272	per kw
General Service - 1 Primary, Non Demand:			**General Service - 1 Primary, Non Demand:**			**General Service - 1 Primary, Non Demand:**		
Transmission Energy	0.008268	per kwh	Transmission Energy	0.008075	per kwh	Transmission Energy	0.008172	per kwh
Distribution Energy	0.018957	per kwh	Distribution Energy	0.018514	per kwh	Distribution Energy	0.018736	per kwh
General Service - 1 Primary, Demand:			**General Service - 1 Primary, Demand:**			**General Service - 1 Primary, Demand:**		
Transmission Demand	3.670616	per kw	Transmission Demand	3.584870	per kw	Transmission Demand	3.627743	per kw
Distribution Energy	0.007061	per kwh	Distribution Energy	0.006896	per kwh	Distribution Energy	0.006979	per kwh
Distribution Demand	4.030549	per kw	Distribution Demand	3.936395	per kw	Distribution Demand	3.983472	per kw

2012-13 Tracking Period

July 1, 2012 - December 31, 2012 Period

Period July 2012-June 2013
Reference: 2012 Annual Tax Tracker Filing Application December 8, 2011,

Residential:		
Transmission Energy	0.008866	per kwh
Distribution Energy	0.027599	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.007719	per kwh
Distribution Energy	0.035745	per kwh
GS 1 Secondary, demand		
Transmission Demand	2.949439	per kw
Distribution Energy	0.004769	per kwh
Distribution Demand	6.012368	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008075	per kwh
Distribution Energy	0.018514	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.584870	per kw
Distribution Energy	0.006896	per kwh
Distribution Demand	3.936395	per kw

January 1, 2013 Forward

Period January 2013 forward (until next change)
Reference: 2013 Annual Tax Tracker; December 11, 2012; Docket No.

Residential:		
Transmission Energy	0.009188	per kwh
Distribution Energy	0.028601	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.007999	per kwh
Distribution Energy	0.037043	per kwh
GS 1 Secondary, demand		
Transmission Demand	3.056510	per kw
Distribution Energy	0.004942	per kwh
Distribution Demand	6.230629	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008368	per kwh
Distribution Energy	0.019186	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.715008	per kw
Distribution Energy	0.007146	per kwh
Distribution Demand	4.079294	per kw

Averaged Rates used for 2012-13 Tracking Period[1]

Residential:		
Transmission Energy	0.009027	per kwh
Distribution Energy	0.028100	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.007859	per kwh
Distribution Energy	0.036394	per kwh
GS 1 Secondary, demand		
Transmission Demand	3.002975	per kw
Distribution Energy	0.004856	per kwh
Distribution Demand	6.121499	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008222	per kwh
Distribution Energy	0.018850	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.649939	per kw
Distribution Energy	0.007021	per kwh
Distribution Demand	4.007845	per kw

2013-14 Tracking Period

July 1, 2013 - December 31, 2013 Period

Period July 2013-June 2014
Reference: 2013 Annual Tax Tracker; December 11, 2012; Docket No. D2012.12.124; Apprendix A (by operation of law)

Residential:		
Transmission Energy	0.009188	per kwh
Distribution Energy	0.028601	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.007999	per kwh
Distribution Energy	0.037043	per kwh
GS 1 Secondary, demand		
Transmission Demand	3.056510	per kw
Distribution Energy	0.004942	per kwh
Distribution Demand	6.230629	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008368	per kwh
Distribution Energy	0.019186	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.715008	per kw
Distribution Energy	0.007146	per kwh
Distribution Demand	4.079294	per kw

January 1, 2014 Forward

Period January 2014 forward (until next change)
Reference: 2014 Annual Tax Tracker; December 11, 2013; Docket No. D2013.12.83; Apprendix A (by operation of law)

Residential:		
Transmission Energy	0.009165	per kwh
Distribution Energy	0.028529	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.007979	per kwh
Distribution Energy	0.036950	per kwh
GS 1 Secondary, demand		
Transmission Demand	3.048835	per kw
Distribution Energy	0.004930	per kwh
Distribution Demand	6.214984	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008347	per kwh
Distribution Energy	0.019138	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.705680	per kw
Distribution Energy	0.007128	per kwh
Distribution Demand	4.069051	per kw

Averaged Rates used for 2013-14 Tracking Period[2]

Residential:		
Transmission Energy	0.009177	per kwh
Distribution Energy	0.028565	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.007989	per kwh
Distribution Energy	0.036997	per kwh
GS 1 Secondary, demand		
Transmission Demand	3.052673	per kw
Distribution Energy	0.004936	per kwh
Distribution Demand	6.222807	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008358	per kwh
Distribution Energy	0.019162	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.710344	per kw
Distribution Energy	0.007137	per kwh
Distribution Demand	4.074173	per kw

2014-15 Tracking Period

July 1, 2014 - December 31, 2014 Period			January 1, 2015 Forward			Averaged Rates used for 2014-15 Tracking Period[3]		
Period January 2014 forward (until next change)			Period January 2015 forward (until next change)					
Reference: 2014 Annual Tax Tracker; December 11, 2013; Docket No. D2013.12.83; Apprendix A (by operation of law)			Reference: 2015 Annual Tax Tracker; December 16, 2014; Docket D2014.12.xx; Apprendix A (by operation of law)					
Residential:			**Residential:**			**Residential:**		
Transmission Energy	0.009165	per kwh	Transmission Energy	0.009203	per kwh	Transmission Energy	0.009184	per kwh
Distribution Energy	0.028529	per kwh	Distribution Energy	0.028648	per kwh	Distribution Energy	0.028589	per kwh
GS 1 Secondary, non-demand			**GS 1 Secondary, non-demand**			**GS 1 Secondary, non-demand**		
Transmission Energy	0.007979	per kwh	Transmission Energy	0.008012	per kwh	Transmission Energy	0.007996	per kwh
Distribution Energy	0.036950	per kwh	Distribution Energy	0.037104	per kwh	Distribution Energy	0.037027	per kwh
GS 1 Secondary, demand			**GS 1 Secondary, demand**			**GS 1 Secondary, demand**		
Transmission Demand	3.048835	per kw	Transmission Demand	3.061539	per kw	Transmission Demand	3.055187	per kw
Distribution Energy	0.004930	per kwh	Distribution Energy	0.004951	per kwh	Distribution Energy	0.004941	per kwh
Distribution Demand	6.214984	per kw	Distribution Demand	6.240882	per kw	Distribution Demand	6.227933	per kw
General Service - 1 Primary, Non Demand:			**General Service - 1 Primary, Non Demand:**			**General Service - 1 Primary, Non Demand:**		
Transmission Energy	0.008347	per kwh	Transmission Energy	0.008382	per kwh	Transmission Energy	0.008365	per kwh
Distribution Energy	0.019138	per kwh	Distribution Energy	0.019218	per kwh	Distribution Energy	0.019178	per kwh
General Service - 1 Primary, Demand:			**General Service - 1 Primary, Demand:**			**General Service - 1 Primary, Demand:**		
Transmission Demand	3.705680	per kw	Transmission Demand	3.721122	per kw	Transmission Demand	3.713401	per kw
Distribution Energy	0.007128	per kwh	Distribution Energy	0.007158	per kwh	Distribution Energy	0.007143	per kwh
Distribution Demand	4.069051	per kw	Distribution Demand	4.086007	per kw	Distribution Demand	4.077529	per kw

2015-16 Tracking Period

July 1, 2015 - December 31, 2015 Period

Period January 2015 forward (until next change)
Reference: 2015 Annual Tax Tracker; December 16, 2014; Docket D2014.12.xx; Apprendix A (by operation of law)

Residential:		
Transmission Energy	0.009203	per kwh
Distribution Energy	0.028648	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.008012	per kwh
Distribution Energy	0.037104	per kwh
GS 1 Secondary, demand		
Transmission Demand	3.061539	per kw
Distribution Energy	0.004951	per kwh
Distribution Demand	6.240882	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008382	per kwh
Distribution Energy	0.019218	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.721122	per kw
Distribution Energy	0.007158	per kwh
Distribution Demand	4.086007	per kw

January 1, 2016 Forward

Period January 2015 forward (until next change)
Reference: 2015 Annual Tax Tracker; December 16, 2014; Docket D2014.12.xx; Apprendix A (by operation of law)

Residential:		
Transmission Energy	0.009203	per kwh
Distribution Energy	0.028648	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.008012	per kwh
Distribution Energy	0.037104	per kwh
GS 1 Secondary, demand		
Transmission Demand	3.061539	per kw
Distribution Energy	0.004951	per kwh
Distribution Demand	6.240882	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008382	per kwh
Distribution Energy	0.019218	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.721122	per kw
Distribution Energy	0.007158	per kwh
Distribution Demand	4.086007	per kw

Averaged Rates used for 2015-16 Tracking Period[4]

Residential:		
Transmission Energy	0.009203	per kwh
Distribution Energy	0.028648	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.008012	per kwh
Distribution Energy	0.037104	per kwh
GS 1 Secondary, demand		
Transmission Demand	3.061539	per kw
Distribution Energy	0.004951	per kwh
Distribution Demand	6.240882	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008382	per kwh
Distribution Energy	0.019218	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.721122	per kw
Distribution Energy	0.007158	per kwh
Distribution Demand	4.086007	per kw

Notes:

1. Rates were changed as a result of the Tax Tracker. The effective date of the revised rates was January 1, 2013. This date falls at the midpoint of the 2012-2013 tracker period, so Averaged rates for the full tracker period were calculated and used in Lost Revenue calculations for 2012-2013.

2. Rates were changed as a result of the Tax Tracker. The effective date of the revised rates was January 1, 2014. This date falls at the midpoint of the 2013-2014 tracker period, so Averaged rates for the full tracker period were calculated and used in Lost Revenue calculations for 2013-2014.

3. Rates were changed as a result of the Tax Tracker. The effective date of the revised rates was January 1, 2015. This date falls at the midpoint of the 2014-2015 tracker period, so Averaged rates for the full tracker period were calculated and used in Lost Revenue calculations for 2014-2015.

4. Rates effective January 1, 2015 were used for lost revenue calculation for the 2015-16 forecast period.

Electric Lost Revenues

Annual Energy Savings:

1) Targets and Results:

	Tracker 2011-2012		Tracker 2012-2013		Tracker 2013-2014		Tracker 2014-2015 (9+3)		Tracker 2015-2016	
	Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014		Period July 2014 – June 2015		Period July 2015 – June 2016	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Annual (Avg. MW)	6.00	6.69	6.00	7.45	6.00	6.57	6.00	5.79	6.00	
Cumulative (Avg. MW)	11.51	12.20	18.20	19.65	25.65	26.22	32.22	32.01	38.01	

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

	Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014		Period July 2014 – June 2015		Period July 2015 – June 2016	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
% Residential	67.4%	52.7%	69.7%	53.6%	69.7%	56.7%	55.2%	64.9%	58.4%	
% Commercial & Industrial	32.6%	49.9%	30.3%	46.4%	30.3%	43.3%	44.8%	35.1%	41.6%	
Incremental Res. (Avg. MW)	4.04	3.53	4.18	4.00	4.18	3.72	3.31	3.76	3.50	
Cumulative Res. (Avg. MW)	8.09	7.65	11.84	11.65	15.83	15.37	18.68	19.13	22.64	
Incremental C/I (Avg. MW)	1.96	3.34	1.82	3.46	1.82	2.84	2.69	2.03	2.50	
Cumulative C/I (Avg. MW)	3.91	4.72	6.54	8.18	10.00	11.02	13.71	13.05	15.55	
ck. fig.			OK	OK	OK	OK	OK	OK	OK	

2. Residential/commercial split based on E+ Program results

3) Cumulative Annual Energy Savings [3]

	Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014		Period July 2014 – June 2015		Period July 2015 – June 2016	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Residential (MWH)	53,843	51,591	85,368	84,544	120,364	118,350	149,151	151,130	182,953	
C/I (MWH)	20,703	26,740	49,310	56,501	79,608	84,100	108,336	105,443	125,265	
Total Savings (MWH)	74,546	78,332	134,677	141,045	199,972	202,450	257,487	256,573	308,218	
Total Savings (Avg. MW)	8.51	8.94	15.37	16.10	22.83	23.11	29.39	29.29	35.18	

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 Lost Revenues

Commercial/Industrial Reduction in Peak Demand:

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

2) Calculate Coincident Monthly Demand Reduction:

	Tracker 2011-2012		Tracker 2012-2013		Tracker 2013-2014		Tracker 2014-2015 (9+3)		Tracker 2015-2016	
	Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014		Period July 2014 – June 2015		Period July 2015 – June 2016	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
C/I Energy Savings (MWH)	20,703	26,740	49,310	56,501	79,608	84,100	108,336	105,443	125,265	-
C/I Energy Savings (Avg. MW)	2.4	3.1	5.6	6.4	9.1	9.6	12.4	12.0	14.3	-
C/I Avg. Monthly Demand Reduction (KW/Mth)*	3,581	4,625	8,529	9,773	13,769	14,546	18,738	18,238	21,666	-
C/I Annual Demand Reduction (KW-Mths)	42,970	55,501	102,345	117,270	165,231	174,554	224,857	218,853	259,994	-

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 2011-2012		Tracker 2012-2013		Tracker 2013-2014		Tracker 2014-2015 (9+3)		Tracker 2015-2016	
	Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014		Period July 2014 – June 2015		Period July 2015 – June 2016	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
4) C/I Annual Demand Reduction (KW-Mths)*	42,970	55,501	102,345	117,270	165,231	174,554	224,857	218,853	259,994	-

* 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 Lost Revenues

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

	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15 (9+3)		Tracker 2015-16	
	Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014		Period July 2014 – June 2015		Period July 2015 – June 2016	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
1) Residential Savings (KWH)	53,843,360	51,591,247	85,367,567	84,544,023	120,364,119	118,349,855	149,151,437	151,129,617	182,953,213	-
2) C/I Savings										
Energy (KWH)	20,702,882	26,740,472	49,309,629	56,500,810	79,608,351	84,100,067	108,335,938	105,443,194	125,265,035	-
Demand (KW-Mths)	42,970	55,501	102,345	117,270	165,231	174,554	224,857	218,853	259,994	-
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%	1%	1%
GS-1 Secondary, demand	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
GS-1 Primary, non demand	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
GS-1 Primary, demand	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Total C&I	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

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

	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15 (9+3)		Tracker 2015-16	
	Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014		Period July 2014 – June 2015		Period July 2015 – June 2016	
Energy (KWh)	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
GS-1 Secondary, non demand	207,029	267,405	493,096	565,008	796,084	841,001	1,083,359	1,054,432	1,252,650	-
GS-1 Secondary, demand	20,288,825	26,205,663	48,323,437	55,370,794	78,016,184	82,418,066	106,169,219	103,334,330	122,759,735	-
GS-1 Primary, non demand	-	-	-	-	-	-	-	-	-	-
GS-1 Primary, demand	207,029	267,405	493,096	565,008	796,084	841,001	1,083,359	1,054,432	1,252,650	-
Check Total	20,702,882	26,740,472	49,309,629	56,500,810	79,608,351	84,100,067	108,335,938	105,443,194	125,265,035	-
check fig (should = 0):	-	-	-	-	-	-	-	-	-	-
Demand (KW-mth)										
GS-1 Secondary, demand	42,110	54,391	100,298	114,925	161,926	171,063	220,360	214,476	254,794	-
GS-1 Primary, demand	430	555	1,023	1,173	1,652	1,746	2,249	2,189	2,600	-
Total*	42,540	54,946	101,321	116,098	163,579	172,808	222,608	216,664	257,394	-

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

Electric Lost Revenues

Adjustment Factors (Net Savings Adjustment Ratios)

For Lost Revenue calculations for the 2011-2012 tracker period forward, these values are used. SBW, Inc. Evalution Study Savings Realization rate for all Electric DSM & USB programs

Residential		**Net Savings Adjustment Ratio**
Segment		
All		0.91
Commercial/Industrial		**Net Savings Adjustment Ratio**
Segment		
All		0.91

Electric Lost Revenues - Montana T&D

July 2011-June 2012

Residential								
			Gross		**SBW's**			**Estimated**
	Average		**Program**		**NTG**	**Net**		**Lost**
	Rate[1]		**Savings**		**Adjustment**	**Savings**		**Revenue**
Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
Transmission Energy	0.008972		51,591,247		0.91	46,834,467		420,199
Distribution Energy	0.027929		51,591,247		0.91	46,834,467		1,308,040
				Sub Total Residential:		**46,834,467**		**$ 1,728,239**
Commercial & Industrial			**Reported**	**Reported**				
			Gross	**Gross**	**SBW's**			**Estimated**
	Average	**Average**	**Program**	**Program**	**NTG**	**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)**	**($)**
GS-1 Secondary, non demand, TX Energy	0.007812		267,405		0.91	242,750		1,896
GS-1 Secondary, non demand, Dist. Energy	0.036173		267,405		0.91	242,750		8,781
GS-1 Secondary, demand, TX Demand		2.984713		54,391	0.91		49,376	147,374
GS-1 Secondary, demand, Dist. Energy	0.004826		26,205,663		0.91	23,789,467		114,808
GS-1 Secondary, demand, Dist. Demand		6.084272		54,391	0.91		49,376	300,418
GS-1 Primary, non demand, TX Energy	0.008172		0		0.91	0		0
GS-1 Primary, non demand, Dist. Energy	0.018736		0		0.91	0		0
GS-1 Primary, demand, TX Demand		3.627743		555	0.91		504	1,828
GS-1 Primary, demand, Dist. Energy	0.006979		267,405		0.91	242,750		1,694
GS-1 Primary, demand, Dist. Demand		3.983472		555	0.91		504	2,007
			Sub Total Commercial & Industrial:			**24,274,966**		**$ 578,806**
		July 2011-June 2012	**Estimated Totals:**			**71,109,433**		**$ 2,307,045**

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

	A	B	C	D	E	F	G	H	I
1 2	**Electric Lost Revenues - Montana T&D**								
39									
40	**July 2012-June 2013**								
41									
42									
43	**Residential**			**Reported**					
44				**Gross**		**SBW's**			**Estimated**
45				**Program**		**NTG**	**Net**		**Lost**
46		**Rate[1]**		**Savings**		**Adjustment**	**Savings**		**Revenue**
47	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
48	Transmission Energy	0.009027		84,544,023		0.91	76,748,955		692,813
49	Distribution Energy	0.028100		84,544,023		0.91	76,748,955		2,156,646
50					**Sub Total Residential:**		**76,748,955**		**$ 2,849,458**
51									
52									
53	**Commercial & Industrial**			**Reported**	**Reported**				
54				**Gross**	**Gross**	**SBW's**			**Estimated**
55				**Program**	**Program**	**NTG**	**Net**	**Net**	**Lost**
56		**Rate[1]**	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
57	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
58	GS-1 Secondary, non demand, TX Energy	0.007859		565,008		0.91	512,914		4,031
59	GS-1 Secondary, non demand, Dist. Energy	0.036394		565,008		0.91	512,914		18,667
60									
61	GS-1 Secondary, demand, TX Demand		3.002975		114,925	0.91		104,329	313,296
62	GS-1 Secondary, demand, Dist. Energy	0.004856		55,370,794		0.91	50,265,535		244,064
63	GS-1 Secondary, demand, Dist. Demand		6.121499		114,925	0.91		104,329	638,648
64									
65	GS-1 Primary, non demand, TX Energy	0.008222		0		0.91	0		0
66	GS-1 Primary, non demand, Dist. Energy	0.018850		0		0.91	0		0
67									
68	GS-1 Primary, demand, TX Demand		3.649939		1,173	0.91		1,065	3,886
69	GS-1 Primary, demand, Dist. Energy	0.007021		565,008		0.91	512,914		3,601
70	GS-1 Primary, demand, Dist. Demand		4.007845		1,173	0.91		1,065	4,267
71				**Sub Total Commercial & Industrial:**			**51,291,362**		**$ 1,230,460**
72									
73			**July 2012-June 2013**	**Estimated Totals:**			**128,040,317**		**$ 4,079,918**
74									
75	**Note 1: Two sets of rates were used, each set was effective for 6 months of the 2012-13 tracker period**								

Electric Lost Revenues - Montana T&D

	A	B	C	D	E	F	G	H	I
76									
77	**July 2013-June 2014**								
78									
79									
80	**Residential**			**Reported**					
81				**Gross**		**SBW's**			**Estimated**
82				**Program**		**NTG**	**Net**		**Lost**
83		**Rate[1]**		**Savings**		**Adjustment**	**Savings**		**Revenue**
84	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
85	Transmission Energy	0.009177		118,349,855		0.91	107,437,845		985,903
86	Distribution Energy	0.028565		118,349,855		0.91	107,437,845		3,068,962
87					**Sub Total Residential:**		**107,437,845**		**$ 4,054,865**
88									
89									
90	**Commercial & Industrial**			**Reported**	**Reported**				
91				**Gross**	**Gross**	**SBW's**			**Estimated**
92				**Program**	**Program**	**NTG**	**Net**	**Net**	**Lost**
93		**Rate[1]**	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
94	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
95	GS-1 Secondary, non demand, TX Energy	0.007989		841,001		0.91	763,459		6,099
96	GS-1 Secondary, non demand, Dist. Energy	0.036997		841,001		0.91	763,459		28,245
97									
98	GS-1 Secondary, demand, TX Demand		3.052673		171,063	0.91		155,291	474,051
99	GS-1 Secondary, demand, Dist. Energy	0.004936		82,418,066		0.91	74,819,013		369,307
100	GS-1 Secondary, demand, Dist. Demand		6.222807		171,063	0.91		155,291	966,343
101									
102	GS-1 Primary, non demand, TX Energy	0.008358		0		0.91	0		0
103	GS-1 Primary, non demand, Dist. Energy	0.019162		0		0.91	0		0
104									
105	GS-1 Primary, demand, TX Demand		3.710344		1,746	0.91		1,585	5,879
106	GS-1 Primary, demand, Dist. Energy	0.007137		841,001		0.91	763,459		5,449
107	GS-1 Primary, demand, Dist. Demand		4.074173		1,746	0.91		1,585	6,456
108				**Sub Total Commercial & Industrial:**			**76,345,932**		**$ 1,861,830**
109									
110			**July 2013-June 2014**	**Estimated Totals:**			**183,783,777**		**$ 5,916,696**
111									
112	**Note 1: Two sets of rates were used, each set was effective for 6 months of the 2013-14 tracker period**								

Electric Lost Revenues - Montana T&D

	A	B	C	D	E	F	G	H	I
1-2	**Electric Lost Revenues - Montana T&D**								
113									
114	**July 2014-June 2015**								
115									
116									
117	**Residential**								
118				**Gross**		**SBW's**			**Estimated**
119				**Program**		**NTG**	**Net**		**Lost**
120		**Rate[1]**		**Savings**		**Adjustment**	**Savings**		**Revenue**
121	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
122	Transmission Energy	0.009184		151,129,617		0.91	137,195,270		1,260,001
123	Distribution Energy	0.028589		151,129,617		0.91	137,195,270		3,922,207
124					**Sub Total Residential:**		**137,195,270**		**$ 5,182,208**
125									
126									
127	**Commercial & Industrial**			**Reported**	**Reported**				
128				**Gross**	**Gross**	**SBW's**			**Estimated**
129				**Program**	**Program**	**NTG**	**Net**	**Net**	**Lost**
130		**Rate[1]**	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
131	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
132	GS-1 Secondary, non demand, TX Energy	0.007996		1,054,432		0.91	957,212		7,653
133	GS-1 Secondary, non demand, Dist. Energy	0.037027		1,054,432		0.91	957,212		35,443
134									
135	GS-1 Secondary, demand, TX Demand		3.055187		214,476	0.91		194,701	594,847
136	GS-1 Secondary, demand, Dist. Energy	0.004941		103,334,330		0.91	93,806,771		463,452
137	GS-1 Secondary, demand, Dist. Demand		6.227933		214,476	0.91		194,701	1,212,583
138									
139	GS-1 Primary, non demand, TX Energy	0.008365		0		0.91	0		0
140	GS-1 Primary, non demand, Dist. Energy	0.019178		0		0.91	0		0
141									
142	GS-1 Primary, demand, TX Demand		3.713401		2,189	0.91		1,987	7,378
143	GS-1 Primary, demand, Dist. Energy	0.007143		1,054,432		0.91	957,212		6,837
144	GS-1 Primary, demand, Dist. Demand		4.077529		2,189	0.91		1,987	8,101
145				**Sub Total Commercial & Industrial:**			**95,721,195**		**$ 2,336,294**
146									
147			**July 2014-June 2015**	**Estimated Totals:**			**232,916,465**		**$ 7,518,502**
148									
149	**Note 1: Two sets of rates were used, each set was effective for 6 months of the 2014-15 tracker period**								

Electric Lost Revenues - Montana T&D

Row	A	B	C	D	E	F	G	H	I
150									
151	**July 2015-June 2016**								
152									
153									
154	**Residential**			**TARGET**					
155				**Gross**		**SBW's**			**Estimated**
156				**Program**		**NTG**	**Net**		**Lost**
157		**Rate[1]**		**Savings**		**Adjustment**	**Savings**		**Revenue**
158	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
159	Transmission Energy	0.009203		182,953,213		0.91	166,084,689		1,528,477
160	Distribution Energy	0.028648		182,953,213		0.91	166,084,689		4,757,994
161					**Sub Total Residential:**		**166,084,689**		**$ 6,286,472**
162									
163				**TARGET**	**TARGET**				
164	**Commercial & Industrial**			**Reported**	**Reported**				
165				**Gross**	**Gross**	**SBW's**			**Estimated**
166				**Program**	**Program**	**NTG**	**Net**	**Net**	**Lost**
167		**Rate[1]**	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
168	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
169	GS-1 Secondary, non demand, TX Energy	0.008012		1,252,650		0.91	1,137,154		9,111
170	GS-1 Secondary, non demand, Dist. Energy	0.037104		1,252,650		0.91	1,137,154		42,193
171									
172	GS-1 Secondary, demand, TX Demand		3.061539		254,794	0.91		231,302	708,139
173	GS-1 Secondary, demand, Dist. Energy	0.004951		122,759,735		0.91	111,441,128		551,745
174	GS-1 Secondary, demand, Dist. Demand		6.240882		254,794	0.91		231,302	1,443,526
175									
176	GS-1 Primary, non demand, TX Energy	0.008382		0		0.91	0		0
177	GS-1 Primary, non demand, Dist. Energy	0.019218		0		0.91	0		0
178									
179	GS-1 Primary, demand, TX Demand		3.721122		2,600	0.91		2,360	8,783
180	GS-1 Primary, demand, Dist. Energy	0.007158		1,252,650		0.91	1,137,154		8,140
181	GS-1 Primary, demand, Dist. Demand		4.086007		2,600	0.91		2,360	9,644
182				**Sub Total Commercial & Industrial:**			**113,715,436**		**$ 2,781,280**
183									
184			**July 2015-June 2016**	**Estimated Totals:**			**279,800,125**		**$ 9,067,752**
185									
186	**Note 1: Two sets of rates were used, each set was effective for 6 months of the 2015-16 tracker period**								

Electric Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Targets and Results:

	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15 (9+3)		Tracker 2015-16	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Annual (Avg. MW)	6.00	6.69	6.00	7.45	6.00	6.57	6.00	5.79	6.00	
Cumulative (Avg. MW)	20.51	21.20	27.20	28.66	34.66	35.22	41.22	41.01	47.01	

Disaggregate Targets into Residential & Commercial/Industrial [1]

	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15 (9+3)		Tracker 2015-16	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
% Residential	67.4%	52.7%	69.7%	53.6%	69.7%	56.7%	55.2%	64.9%	58.4%	
% Commercial & Industrial	32.6%	49.9%	30.3%	46.4%	30.3%	43.3%	44.8%	35.1%	41.6%	
ck. fig.	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	
Incremental Res. (Avg. MW)	4.04	3.53	4.18	4.00	4.18	3.72	3.31	3.76	3.50	
Cumulative Res. (Avg. MW)	13.07	13.38	17.56	17.37	21.56	21.10	24.41	24.86	28.36	
Incremental C/I (Avg. MW)	1.96	3.16	1.82	3.46	1.82	2.84	2.69	2.03	2.50	
Cumulative C/I (Avg. MW)	6.43	7.82	9.64	11.28	13.10	14.12	16.82	16.15	18.65	
check fig:	6.00	6.69	6.00	7.45	6.00	6.57	6.00	5.79	6.00	

1. Residential/commercial split based on E+ Program results

	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15 (9+3)		Tracker 2015-16	
Cumulative Annual Energy Savings[2]	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Residential (MWH)	104,001	101,749	135,525	134,701	170,522	168,507	199,309	201,287	233,111	
C/I (MWH)	49,417	54,688	76,490	83,681	106,788	111,280	135,516	132,623	152,445	
Total Savings (MWH)	153,418	156,436	212,015	218,382	277,310	279,787	334,825	333,910	385,556	
Total Savings (Avg. MW)	17.51	17.86	24.20	24.93	31.66	31.94	38.22	38.12	44.01	

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%

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

	01/01/12	01/01/13	01/01/14	01/01/15	01/01/16
Residential	0.012734	0.012734	0.012734	0.012734	0.012734
GS-1 Sec Non-Demand	0.012734	0.012734	0.012734	0.012734	0.012734
GS-1 Sec Demand	0.012734	0.012734	0.012734	0.012734	0.012734
GS-1 Pri Non-Demand	0.012385	0.012385	0.012385	0.012385	0.012385
GS-1 Pri Demand	0.012385	0.012385	0.012385	0.012385	0.012385
GS-2 Substation	0.012278	0.012278	0.012278	0.012278	0.012278
GS-2 Transmission	0.012204	0.012204	0.012204	0.012204	0.012204

Electric Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Tracker 2011-12					
Based on Cumulative 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	$0.012734	101,748,654	0.91	92,367,296	1,176,205
				92,367,296	**$ 1,176,205**
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	546,877	0.91	496,454	6,322
GS-1 Sec Demand	$0.012734	53,593,911	0.91	48,652,483	619,541
GS-1 Pri Non-Demand	$0.012385	0	0.91	0	0
GS-1 Pri Demand	$0.012385	546,877	0.91	496,454	6,149
GS-2 Substation	$0.012278	0	0.91	0	0
GS-2 Transmission	$0.012204	0	0.91	0	0
		Sub Total General Service:		**49,645,391**	**$ 632,011**
Note 1: using rates expected to be in effect at the time (see Rates tab)					
		Total CU-4-related Lost Revenues			**$ 1,808,216**

Electric Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Tracker 2012-13					
Based on Cumulative Savings Since January 2009					
		Reported			
Residential		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
Residential	$0.012734	134,701,430	0.91	122,281,783	1,557,136
				122,281,783	**$ 1,557,136**
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	836,808	0.91	759,653	9,673
GS-1 Sec Demand	$0.012734	82,007,170	0.91	74,446,002	947,995
GS-1 Pri Non-Demand	$0.012385	0	0.91	0	0
GS-1 Pri Demand	$0.012385	836,808	0.91	759,653	9,408
GS-2 Substation	$0.012278	0	0.91	0	0
GS-2 Transmission	$0.012204	0	0.91	0	0
		Sub Total General Service:		75,965,309	**$ 967,077**
Note 1: using rates expected to be in effect at the time (see Rates tab)					
		Total CU-4-related Lost Revenues			**$ 2,524,213**

Electric Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Tracker 2013-14					
Based on Cumulative Savings Since January 2009					
		Reported			
Residential		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
Residential	$0.012734	168,507,262	0.91	152,970,673	1,947,929
				152,970,673	**$ 1,947,929**
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	1,112,800	0.91	1,010,199	12,864
GS-1 Sec Demand	$0.012734	109,054,442	0.91	98,999,481	1,260,659
GS-1 Pri Non-Demand	$0.012385	0	0.91	0	0
GS-1 Pri Demand	$0.012385	1,112,800	0.91	1,010,199	12,511
GS-2 Substation	$0.012278	0	0.91	0	0
GS-2 Transmission	$0.012204	0	0.91	0	0
		Sub Total General Service:		**101,019,878**	**$ 1,286,035**
Note 1: using rates expected to be in effect at the time (see Rates tab)					
		Total CU-4-related Lost Revenues			**$ 3,233,963**

Electric Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Row	B	C	D	E	F	G
144						
145	**Tracker 2014-15**					
146	**Based on Cumulative Savings Since January 2009**					
147						
148	**Residential**		**Gross**			**Estimated**
149			**Program**		**Net**	**Lost**
150		**Rate[1]**	**Savings**	**Adjustment**	**Savings**	**Revenue**
151	Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
152	Residential	$0.012734	201,287,023	0.91	182,728,098	2,326,860
153					**182,728,098**	**$ 2,326,860**
154						
155	**Commercial & Industrial**		**Gross**			**Estimated**
156			**Program**		**Net**	**Lost**
157		**Rate[1]**	**Savings**	**Adjustment**	**Savings**	**Revenue**
158	Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
159	GS-1 Sec Non-Demand	$0.012734	1,326,232	0.91	1,203,951	15,331
160	GS-1 Sec Demand	$0.012734	129,970,707	0.91	117,987,239	1,502,449
161	GS-1 Pri Non-Demand	$0.012385	0	0.91	0	0
162	GS-1 Pri Demand	$0.012385	1,326,232	0.91	1,203,951	14,911
163						
164	GS-2 Substation	$0.012278	0	0.91	0	0
165	GS-2 Transmission	$0.012204	0	0.91	0	0
166			**Sub Total General Service:**		**120,395,142**	**$ 1,532,692**
167						
168	Note 1: using rates expected to be in effect at the time (see Rates tab)					
169						
170			**Total CU-4-related Lost Revenues**			**$ 3,859,551**

Electric Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Tracker 2015-16					
Based on Cumulative Savings Since January 2009					
		TARGET			
Residential		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
Residential	$0.012734	233,110,619	0.91	211,617,517	2,694,737
				211,617,517	**$ 2,694,737**
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	1,524,450	0.91	1,383,894	17,623
GS-1 Sec Demand	$0.012734	149,396,111	0.91	135,621,595	1,727,005
GS-1 Pri Non-Demand	$0.012385	0	0.91	0	0
GS-1 Pri Demand	$0.012385	1,524,450	0.91	1,383,894	17,140
GS-2 Substation	$0.012278	0	0.91	0	0
GS-2 Transmission	$0.012204	0	0.91	0	0
		Sub Total General Service:		**138,389,383**	**$ 1,761,767**
Note 1: using rates expected to be in effect at the time (see Rates tab)					
		Total CU-4-related Lost Revenues			**$ 4,456,505**

Electric Lost Revenues - Dave Gates Generating Station

(fixed cost portion of DGGS)

Targets and Results:	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15 (9+3)		Tracker 2015-16	
	Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014		Period July 2014 – June 2015		Period July 2015 – June 2016	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Annual (Avg. MW)	6.00	6.69	6.00	7.45	6.00	6.57	6.00	5.79	6.00	-
Cumulative (Avg. MW)	8.81	9.50	15.50	16.95	22.95	23.52	29.52	29.31	35.31	

Disaggregate Targets into Residential & Commercial/Industrial [1]	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15 (9+3)		Tracker 2015-16	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
% Residential	67.4%	52.7%	69.7%	53.60%	69.7%	56.7%	55.2%	64.9%	58.4%	
% Commercial & Industrial	32.6%	47.3%	30.3%	46.40%	30.3%	43.3%	44.8%	35.1%	41.6%	
ck. fig.	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	0.0%
Incremental Res. (Avg. MW)	4.04	3.53	4.18	4.00	4.18	3.72	3.31	3.76	3.50	
Cumulative Res. (Avg. MW)	6.06	5.63	9.81	9.63	13.81	13.35	16.66	17.11	20.62	
Incremental C/I (Avg. MW)	1.96	3.16	1.82	3.46	1.82	2.84	2.69	2.03	2.50	
Cumulative C/I (Avg. MW)	2.94	3.87	5.68	7.33	9.14	10.17	12.86	12.20	14.69	
check fig:	6.00	6.69	6.00	7.45	6.00	6.57	6.00	5.79	6.00	0.00

1. Residential/commercial split based on E+ Program results

Cumulative Annual Energy Savings [2]	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15 (9+3)		Tracker 2015-16	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Residential (MWH)	36,128	33,876	67,652	66,829	102,649	100,635	131,436	133,415	165,238	
C/I (MWH)	14,757	20,027	41,829	49,020	72,128	76,619	100,855	97,963	117,784	
Total Savings (MWH)	50,885	53,903	109,482	115,849	174,777	177,254	232,292	231,377	283,023	
Total Savings (Avg. MW)	5.8	6.2	12.5	13.2	20.0	20.2	26.5	26.4	32.3	

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%	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	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%

Rates: Source: Appendix E - 05/01/11 Rate DGGS Fixed Rate (after losses)	**2011-12 Tracking Period**		**2012-13 Tracking Period**	**2013-14 Tracking Period**	**2014-15 Tracking Period**	**2015-16 Tracking Period**
	July-Dec 2011	**Jan-June 2012**				
Residential	0.004018	0.004795	0.004795	0.004795	0.004795	0.004795
GS-1 Sec Non-Demand	0.004018	0.004795	0.004795	0.004795	0.004795	0.004795
GS-1 Sec Demand	0.004018	0.004795	0.004795	0.004795	0.004795	0.004795
GS-1 Pri Non-Demand	0.003908	0.004664	0.004664	0.004664	0.004664	0.004664
GS-1 Pri Demand	0.003908	0.004664	0.004664	0.004664	0.004664	0.004664
GS-2 Substation	0.003874	0.004624	0.004624	0.004624	0.004624	0.004624
GS-2 Transmission	0.003851	0.004596	0.004596	0.004596	0.004596	0.004596

Electric Lost Revenues - Dave Gates Generating Station

(fixed cost portion of DGGS)

July 2011-June 2012

Residential	Average Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Bill Line Item					
Residential	$0.004407	33,876,166	0.91	30,752,739	135,512
				30,752,739	**$ 135,512**

Commercial & Industrial	Average Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Bill Line Item					
GS-1 Sec Non-Demand	$0.004407	200,271	0.91	181,806	801
GS-1 Sec Demand	$0.004407	19,626,551	0.91	17,816,957	78,510
GS-1 Pri Non-Demand	$0.004286	0	0.91	0	-
GS-1 Pri Demand	$0.004286	200,271	0.91	181,806	779
GS-2 Substation	$0.004249	0	0.91	0	-
GS-2 Transmission	$0.004224	0	0.91	0	-
		Sub Total General Service:		**18,180,569**	**$ 80,091**
		Total DGGS-related Lost Revenues			**$ 215,603**

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

July 2012-June 2013

Residential	Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Bill Line Item					
Residential	$0.004795	66,828,942	0.91	60,667,227	290,899
				60,667,227	**$ 290,899**

Commercial & Industrial	Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Bill Line Item					
GS-1 Sec Non-Demand	$0.004795	490,202	0.91	445,005	2,134
GS-1 Sec Demand	$0.004795	48,039,810	0.91	43,610,477	209,112
GS-1 Pri Non-Demand	$0.004664	0	0.91	0	-
GS-1 Pri Demand	$0.004664	490,202	0.91	445,005	2,076
GS-2 Substation	$0.004624	0	0.91	0	-
GS-2 Transmission	$0.004596	0	0.91	0	-
		Sub Total General Service:		**44,500,487**	**$ 213,322**
		Total DGGS-related Lost Revenues			**$ 504,221**

Electric Lost Revenues - Dave Gates Generating Station

(fixed cost portion of DGGS)

July 2013-June 2014

Bill Line Item	Rate[1] ($ per kwh)	Reported Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Residential					
Residential	$0.004795	100,634,774	0.91	91,356,117	438,053
				91,356,117	$ 438,053

Bill Line Item	Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Commercial & Industrial					
GS-1 Sec Non-Demand	$0.004795	766,195	0.91	695,551	3,335
GS-1 Sec Demand	$0.004795	75,087,082	0.91	68,163,955	326,846
GS-1 Pri Non-Demand	$0.004664	0	0.91	0	-
GS-1 Pri Demand	$0.004664	766,195	0.91	695,551	3,244
GS-2 Substation	$0.004624	0	0.91	0	-
GS-2 Transmission	$0.004596	0	0.91	0	-
		Sub Total General Service:		69,555,056	$ 333,425
		Total DGGS-related Lost Revenues			$ 771,478

July 2014-June 2015

Bill Line Item	Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Residential					
Residential	$0.004795	133,414,536	0.91	121,113,542	580,739
				121,113,542	$ 580,739

Bill Line Item	Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Commercial & Industrial					
GS-1 Sec Non-Demand	$0.004795	979,626	0.91	889,303	4,264
GS-1 Sec Demand	$0.004795	96,003,346	0.91	87,151,713	417,892
GS-1 Pri Non-Demand	$0.004664	0	0.91	0	-
GS-1 Pri Demand	$0.004664	979,626	0.91	889,303	4,148
GS-2 Substation	$0.004624	0	0.91	0	-
GS-2 Transmission	$0.004596	0	0.91	0	-
		Sub Total General Service:		88,930,320	$ 426,304
		Total DGGS-related Lost Revenues			$ 1,007,044

Electric Lost Revenues - Dave Gates Generating Station

(fixed cost portion of DGGS)

July 2015-June 2016

		TARGET			
Residential		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate1	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
Residential	$0.004795	165,238,131	0.91	150,002,961	719,264
				150,002,961	**$ 719,264**
Commercial & Industrial		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate1	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.004795	1,177,844	0.91	1,069,246	5,127
GS-1 Sec Demand	$0.004795	115,428,751	0.91	104,786,070	502,449
GS-1 Pri Non-Demand	$0.004664	0	0.91	0	-
GS-1 Pri Demand	$0.004664	1,177,844	0.91	1,069,246	4,987
GS-2 Substation	$0.004624	0	0.91	0	-
GS-2 Transmission	$0.004596	0	0.91	0	-
		Sub Total General Service:		**106,924,561**	**$ 512,563**
		Total DGGS-related Lost Revenues			**$ 1,231,827**

Electric Lost Revenues - Spion Kop

(fixed cost portion of Spion Kop)

	A	B	C	D	E	F	G	H	I	J	K
1				**Electric Lost Revenues - Spion Kop**							
2				**(fixed cost portion of Spion Kop)**							
3											
4				**Tracker 2012-13**		**Tracker 2013-14**		**Tracker 2014-15 (9+3)**		**Tracker 2015-16**	
5	Targets and Results:			**December 1, 2012 - June 30, 2013**		**Period July 2013 – June 2014**		**Period July 2014 – June 2015**		**Period July 2015 – June 2016**	
6				**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
7		Annual (Avg. MW)		6.00	4.33	6.00	6.57	6.00	5.79	6.00	-
8		Cumulative (Avg. MW)		6.00	4.33	10.33	10.89	16.89	16.69	22.69	
9											
10				Commercial online date for Spion Kop was							
11	Disaggregate Targets into Residential & Commercial/Industrial [1]										
12											
13				**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
14		% Residential		69.7%	53.6%	69.7%	56.7%	55.2%	64.9%	58.4%	
15		% Commercial & Industrial		30.3%	46.4%	30.3%	43.3%	44.8%	35.1%	41.6%	
16			ck. fig.	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%
17											
18		Incremental Res. (Avg. MW)		4.18	2.32	4.18	3.72	3.31	3.76	3.50	
19		Cumulative Res. (Avg. MW)		4.18	2.32	6.50	6.04	9.35	9.80	13.31	
20		Incremental C/I (Avg. MW)		1.82	2.01	1.82	2.84	2.69	2.03	2.50	
21		Cumulative C/I (Avg. MW)		1.82	2.01	3.83	4.85	7.54	6.88	9.38	
22											
23		1. Residential/commercial split based on E+ Program results									
24											
25											
26	Cumulative Annual Energy Savings[2]			**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
27		Residential (MWH)		18,322	10,163	38,649	36,634	67,436	69,414	101,238	
28		C/I (MWH)		7,958	8,799	25,556	30,048	54,284	51,391	71,213	
29		Total Savings (MWH)		26,280	18,962	64,205	66,682	121,720	120,805	172,451	
30		Total Savings (Avg. MW)		3.0	2.2	7.3	7.6	13.9	13.8	19.7	
31											
32		2. "Half-year convention":									
33		Savings resulting from the "Increment" in any year is reduced by 50% in that year as associated projects									
34		are completed and start generating savings at different times throughout the first year. This assumption contemplates that									
35		associated projects start generating savings half way through the year on average. In the second year and									
36		beyond, projects completed in the first year generate savings for the entire year so the "Increment" is credited at 100%									
37		for the second year and each successive year.									
38											
39		Disaggregate C&I Savings by service level (tariff)									
40											
41		C&I Savings is broken out as:									
42		GS-1 Secondary, non demand		1%	1%	1%	1%	1%	1%	1%	1%
43		GS-1 Secondary, demand		98%	98%	98%	98%	98%	98%	98%	98%
44		GS-1 Primary, non demand		0%	0%	0%	0%	0%	0%	0%	0%
45		GS-1 Primary, demand		1%	1%	1%	1%	1%	1%	1%	1%
46		Total C&I		100%	100%	100%	100%	100%	100%	100%	100%

Electric Lost Revenues - Spion Kop

(fixed cost portion of Spion Kop)

Spion Kop Rates Docket D2012.7.75	December 1, 2012 - June 30, 2013	Period July 2013 – June 2014	Period July 2014 – June 2015	Period July 2015 – June 2016
Residential	0.001047	$0.001253	$0.001458	$0.001458
GS-1 Sec Non-Demand	0.001048	$0.001254	$0.001459	$0.001459
GS-1 Sec Demand	0.001048	$0.001254	$0.001459	$0.001459
GS-1 Pri Non-Demand	0.001020	$0.001220	$0.001420	$0.001420
GS-1 Pri Demand	0.001020	$0.001220	$0.001420	$0.001420
GS-2 Substation	0.001011	$0.001209	$0.001407	$0.001407
GS-2 Transmission	0.001005	$0.001202	$0.001399	$0.001399
ck. fig. (average of rate string to observe year-to-year change)	$ 0.00102843	$ 0.00123007	$ 0.00143171	$ 0.00143171

December 1, 2012 - June 30, 2013

Residential Bill Line Item	Rate ($ per kwh)	Reported Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Residential	$0.001047	10,163,382	0.91	9,226,305	9,660
				9,226,305	**$ 9,660**

Commercial & Industrial Bill Line Item	Rate ($ per kwh)	Reported Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
GS-1 Sec Non-Demand	$0.001048	87,991	0.91	79,878	84
GS-1 Sec Demand	$0.001048	8,623,099	0.91	7,828,038	8,204
GS-1 Pri Non-Demand	$0.001020	0	0.91	0	-
GS-1 Pri Demand	$0.001020	87,991	0.91	79,878	81
GS-2 Substation	$0.001011	0	0.91	0	-
GS-2 Transmission	$0.001005	0	0.91	0	-
		Sub Total General Service:		**7,987,794**	**$ 8,369**
		Total Spion Kop-related Lost Revenues			**$ 18,029**

Electric Lost Revenues - Spion Kop

(fixed cost portion of Spion Kop)

July 2013-June 2014

		Reported			
Residential		**Gross**			**Estimated**
	Average	**Program**		**Net**	**Lost**
	Rate	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
Residential	$0.001253	36,634,320	0.91	33,256,589	41,654
				33,256,589	**$ 41,654**
		Reported			
Commercial & Industrial		**Gross**			**Estimated**
	Average	**Program**		**Net**	**Lost**
	Rate	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.001254	300,481	0.91	272,776	342
GS-1 Sec Demand	$0.001254	29,447,097	0.91	26,732,036	33,509
GS-1 Pri Non-Demand	$0.001220	0	0.91	0	-
GS-1 Pri Demand	$0.001220	300,481	0.91	272,776	333
GS-2 Substation	$0.001209	0	0.91	0	-
GS-2 Transmission	$0.001202	0	0.91	0	-
		Sub Total General Service:		**27,277,588**	**$ 34,183**
		Total Spion Kop-related Lost Revenues			**$ 75,837**

Electric Lost Revenues - Spion Kop
(fixed cost portion of Spion Kop)

July 2014-June 2015

Residential	Average Rate ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Bill Line Item					
Residential	$0.001458	69,414,082	0.91	63,014,014	91,874
				63,014,014	**$ 91,874**

Commercial & Industrial	Average Rate ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Bill Line Item					
GS-1 Sec Non-Demand	$0.001459	513,912	0.91	466,529	681
GS-1 Sec Demand	$0.001459	50,363,361	0.91	45,719,794	66,705
GS-1 Pri Non-Demand	$0.001420	-	0.91	0	-
GS-1 Pri Demand	$0.001420	513,912	0.91	466,529	662
GS-2 Substation	$0.001407	0	0.91	0	-
GS-2 Transmission	$0.001399	0	0.91	0	-
		Sub Total General Service:		**46,652,851**	**$ 68,048**
		Total Spion Kop-related Lost Revenues			**$ 159,923**

Electric Lost Revenues - Spion Kop
(fixed cost portion of Spion Kop)

July 2015-June 2016

		TARGET			
Residential		Gross			Estimated
	Average	Program		Net	Lost
	Rate	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
Residential	$0.001458	101,237,678	0.91	91,903,432	133,995
				91,903,432	**$ 133,995**
		TARGET			
Commercial & Industrial		Gross			Estimated
	Average	Program		Net	Lost
	Rate	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
GS-1 Sec Non-Demand	$0.001459	712,130	0.91	646,471	943
GS-1 Sec Demand	$0.001459	69,788,765	0.91	63,354,151	92,434
GS-1 Pri Non-Demand	$0.001420	0	0.91	0	-
GS-1 Pri Demand	$0.001420	712,130	0.91	646,471	918
GS-2 Substation	$0.001407	0	0.91	0	-
GS-2 Transmission	$0.001399	0	0.91	0	-
		Sub Total General Service:		**64,647,093**	**$ 94,295**
		Total Spion Kop-related Lost Revenues			**$ 228,290**

Appendix H - 12/01/12 Rate Change
Docket D2012.7.75
Page 1 of 2

NorthWestern Energy
Electric Utility Derivation of Rates
Spion Kop
Year 2013

Customer Rate Class	Loss Factor	Dec12 to Nov13 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Spion Kop Fixed Rate After Losses	Spion Kop Fixed Revenue Check
Residential	8.5100%	2,362,571,006	2,362,571,006	2,563,625,799	$ 0.001047	$ 2,473,612
Residential Employee	8.5100%	3,786,173	2,271,704	2,465,026	$ 0.000628	$ 2,378
GS 1 Secondary NonDemand	8.5100%	274,329,840	274,329,840	297,675,310	$ 0.001048	$ 287,498
GS 1 Secondary Demand	8.5100%	2,449,898,973	2,449,898,973	2,658,385,376	$ 0.001048	$ 2,567,494
GS 1 Primary NonDemand	5.5400%	561,768	561,768	592,889	$ 0.001020	$ 573
GS 1 Primary Demand	5.5400%	350,542,637	350,542,637	369,962,699	$ 0.001020	$ 357,553
General Service Substation	4.6300%	244,005,756	244,005,756	255,303,222	$ 0.001011	$ 246,690
General Service Transmission	4.0000%	132,300,021	132,300,021	137,592,022	$ 0.001005	$ 132,962
Irrigation	8.5100%	83,490,261	83,490,261	90,595,283	$ 0.001048	$ 87,498
Lighting	8.5100%	57,821,458	57,821,458	62,742,064	$ 0.001048	$ 60,597
		5,959,307,893	5,957,793,424	6,438,939,689	$ 0.001043	$ 6,216,854
YNP Contract		18,457,300			Rounding Adjustment	$ 506
Total Electric Supply Load		5,977,765,193				$ 6,217,360
		-				

Spion Kop First-year Revenue Requirement [1] $ 6,217,360

Total Spion Kop Fixed Rate Before Losses $ 0.000966
Total Spion Kop Fixed Rate After Losses $ 0.001043

[1] Source: Appendix G Dec 2012.
file name: Appendix H First Year 2013.xlsx

NorthWestern Energy
Electric Utility Derivation of Rates
Spion Kop Wind Generation
Second-Year Revenue Requirement
Order No. 7159l
12 Months Ended November 2014

Customer Rate Class	Loss Factor	Dec13 to Nov14 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Spion Kop Fixed Rate After Losses	Spion Kop Fixed Revenue Check
Residential	8.5100%	2,351,708,021	2,351,708,021	2,551,838,374	$ 0.001458	$ 3,428,790
Residential Employee	8.5100%	3,768,765	2,261,259	2,453,692	$ 0.000875	$ 3,298
GS 1 Secondary NonDemand	8.5100%	279,183,569	279,183,569	302,942,091	$ 0.001459	$ 407,329
GS 1 Secondary Demand	8.5100%	2,493,245,116	2,493,245,116	2,705,420,275	$ 0.001459	$ 3,637,645
GS 1 Primary NonDemand	5.5400%	572,442	572,442	604,156	$ 0.001420	$ 813
GS 1 Primary Demand	5.5400%	357,204,874	357,204,874	376,994,024	$ 0.001420	$ 507,231
General Service Substation	4.6300%	232,669,987	232,669,987	243,442,607	$ 0.001407	$ 327,367
General Service Transmission	4.0000%	135,701,068	135,701,068	141,129,111	$ 0.001399	$ 189,846
Irrigation	8.5100%	86,094,805	86,094,805	93,421,473	$ 0.001459	$ 125,612
Lighting	8.5100%	57,613,774	57,613,774	62,516,706	$ 0.001459	$ 84,058
		5,997,762,421	5,996,254,915	6,480,762,509	$ 0.001453	$ 8,711,988
YNP Contract		19,233,936			Rounding Adjustment	$ 2,749
Total Electric Supply Load		6,016,996,357				$ 8,714,738
		-				

2013-2014 Spion Kop AVERAGE Fixed Rate After Losses	
Residential	$ 0.001253
Residential Employee	$ 0.000752
GS 1 Secondary NonDemand	$ 0.001254
GS 1 Secondary Demand	$ 0.001254
GS 1 Primary NonDemand	$ 0.001220
GS 1 Primary Demand	$ 0.001220
General Service Substation	$ 0.001209
General Service Transmission	$ 0.001202
Irrigation	$ 0.001254
Lighting	$ 0.001254
	$ 0.001248

Spion Kop Second-year Revenue Requirement $ 8,714,738

Total Spion Kop Fixed Rate Before Losses $ 0.001345
Total Spion Kop Fixed Rate After Losses $ 0.001453

Rates effective January 1, 2014
source: Appendix F - 1/01/14 Rate Change, Docket D2013.7.53 from P. DiFronzo

NorthWestern Energy
Electric Utility Derivation of Rates
Spion Kop Wind Generation
Second-Year Revenue Requirement
Order No. 7159l
12 Months Ended November 2015

Row	B	D	F	H	J	L	N	P	Q
77									
78									
79–84									
85								2014-2015	
86						Spion Kop	Spion Kop	Spion Kop	
87			Dec13 to Nov14	Sales Adjusted		Fixed	Fixed	AVERAGE Fixed	
88		Loss	Supply Retail	for Employee	Sales Weighted	Rate	Revenue	Rate	
89		Factor	kWh Sales	Discount	by Losses	After Losses	Check	After Losses	
90	Customer Rate Class								
91	Residential	8.5100%	2,351,708,021	2,351,708,021	2,551,838,374	$ 0.001458	$ 3,428,790	Residential	$ 0.001458
92	Residential Employee	8.5100%	3,768,765	2,261,259	2,453,692	$ 0.000875	$ 3,298	Residential Employee	$ 0.000875
93	GS 1 Secondary NonDemand	8.5100%	279,183,569	279,183,569	302,942,091	$ 0.001459	$ 407,329	GS 1 Secondary NonDemand	$ 0.001459
94	GS 1 Secondary Demand	8.5100%	2,493,245,116	2,493,245,116	2,705,420,275	$ 0.001459	$ 3,637,645	GS 1 Secondary Demand	$ 0.001459
95	GS 1 Primary NonDemand	5.5400%	572,442	572,442	604,156	$ 0.001420	$ 813	GS 1 Primary NonDemand	$ 0.001420
96	GS 1 Primary Demand	5.5400%	357,204,874	357,204,874	376,994,024	$ 0.001420	$ 507,231	GS 1 Primary Demand	$ 0.001420
97	General Service Substation	4.6300%	232,669,987	232,669,987	243,442,607	$ 0.001407	$ 327,367	General Service Substation	$ 0.001407
98	General Service Transmission	4.0000%	135,701,068	135,701,068	141,129,111	$ 0.001399	$ 189,846	General Service Transmission	$ 0.001399
99	Irrigation	8.5100%	86,094,805	86,094,805	93,421,473	$ 0.001459	$ 125,612	Irrigation	$ 0.001459
100	Lighting	8.5100%	57,613,774	57,613,774	62,516,706	$ 0.001459	$ 84,058	Lighting	$ 0.001459
101			5,997,762,421	5,996,254,915	6,480,762,509	$ 0.001453	$ 8,711,988		
102	YNP Contract		19,233,936			Rounding Adjustment	$ 2,749		
103	Total Electric Supply Load		6,016,996,357				$ 8,714,738		
104			-						
105									
106									
107				**Spion Kop Second-year Revenue Requirement**	**$ 8,714,738**				
108									
109				**Total Spion Kop Fixed Rate Before Losses**	**$ 0.001345**				
110				**Total Spion Kop Fixed Rate After Losses**	**$ 0.001453**				
111									
112									
113	Rates effective January 1, 2014								
114	source: Appendix F - 1/01/14 Rate Change, Docket D2013.7.53 from P. DiFronzo								
115									

Electric Lost Revenues - Hydro

(fixed cost portion of Hydro)

	Tracker 2014-15		Tracker 2015-16	
Targets and Results:	November 18, 2014 - June 30, 2015		Period July 2015 – June 2016	
	Target	Reported	Target	Reported
Annual (Avg. MW)	6.00	3.57	6.00	-
Cumulative (Avg. MW)	6.00	3.57	9.57	

Commercial online date for Hydro was

Disaggregate Targets into Residential & Commercial/Industrial [1]

	Target	Reported	Target	Reported
% Residential	55.2%	64.9%	58.4%	
% Commercial & Industrial	44.8%	35.1%	41.6%	
ck. fig.	100.00%	100.00%	100.00%	0.00%
Incremental Res. (Avg. MW)	3.31	2.32	3.50	
Cumulative Res. (Avg. MW)	3.31	2.32	5.82	
Incremental C/I (Avg. MW)	2.69	1.25	2.50	
Cumulative C/I (Avg. MW)	2.69	1.25	3.75	

1. Residential/commercial split based on E+ Program results

Cumulative Annual Energy Savings[2]	Target	Reported	Target	Reported
Residential (MWH)	14,494	10,154	35,660	
C/I (MWH)	11,786	5,482	21,893	
Total Savings (MWH)	26,280	15,636	57,552	
Total Savings (Avg. MW)	3.0	1.8	6.6	

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

Electric Lost Revenues - Hydro

(fixed cost portion of Hydro)

Hydro		November 18, 2014 - June 30, 2015		Period July 2015 – June 2016	
Residential		$ 0.026817		$ 0.026817	
GS-1 Sec Non-Demand		$ 0.026817		$ 0.026817	
GS-1 Sec Demand		$ 0.026817		$ 0.026817	
GS-1 Pri Non-Demand		$ 0.026083		$ 0.026083	
GS-1 Pri Demand		$ 0.026083		$ 0.026083	
GS-2 Substation		$ 0.025858		$ 0.025858	
GS-2 Transmission		$ 0.025703		$ 0.025703	
	ck. fig. (average of rate string to observe year-to-year change)	$ 0.02631114		$ 0.02631114	

November 18, 2014 - June 30, 2015

Residential		Gross			Estimated
		Program		Net	Lost
	Rate	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
Residential	$0.026817	10,154,099	0.91	9,217,878	$ 247,196
				9,217,878	**$ 247,196**
Commercial & Industrial		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.026817	54,821	0.91	49,767	1,335
GS-1 Sec Demand	$0.026817	5,372,486	0.91	4,877,136	130,790
GS-1 Pri Non-Demand	$0.026083	0	0.91	0	-
GS-1 Pri Demand	$0.026083	54,821	0.91	49,767	1,298
GS-2 Substation	$0.025858	0	0.91	0	-
GS-2 Transmission	$0.025703	0	0.91	0	-
		Sub Total General Service:		**4,976,669**	**$ 133,423**
		Total Hydro-related Lost Revenues			**$ 380,619**

File: 14, Exhibit__(DLW-3) 2014-15 Elec Lost Revenues 9+3 FINAL 051115.xls
Tab: 12.Hydro Related LRs

Electric Lost Revenues - Hydro
(fixed cost portion of Hydro)

July 2015-June 2016

	Average Rate ($ per kwh)	TARGET Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Residential					
Bill Line Item					
Residential	$0.026817	35,659,589	0.91	32,371,728	868,113
				32,371,728	**$ 868,113**

	Average Rate ($ per kwh)	TARGET Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Commercial & Industrial					
Bill Line Item					
GS-1 Sec Non-Demand	$0.026817	218,929	0.91	198,743	5,330
GS-1 Sec Demand	$0.026817	21,455,010	0.91	19,476,830	522,310
GS-1 Pri Non-Demand	$0.026083	0	0.91	0	-
GS-1 Pri Demand	$0.026083	218,929	0.91	198,743	5,184
GS-2 Substation	$0.025858	0	0.91	0	-
GS-2 Transmission	$0.025703	0	0.91	0	-
		Sub Total General Service:		**19,874,317**	**$ 532,824**
		Total Hydro-related Lost Revenues			**$ 1,400,936**

Docket No. D2014.7.58
Exhibit__(DLW-4)

REPORT

NorthWestern Energy CFL Lighting Market Study

Submitted to NorthWestern Energy
May 15, 2015

Principal authors:

Dulane Moran, Managing Consultant

Patrick Burns, Principal Consultant

Contents

List of Tables and Figures

1 Executive Summary

NorthWestern Energy (NWE) has offered program options to promote energy efficient residential lighting under the E+ Residential Lighting program since 2005. Over the past 10 years, several program components have worked together to provide a variety of means through which customers could obtain free or discounted energy efficient lighting products, primarily Compact Fluorescent Lamps (or CFLs).

Substantial changes are currently occurring in the national lighting market, driven by implementation of the 2007 Energy Independence and Security Act (EISA), resultant shifts in lighting product mixes, declining costs for solid state Light Emitting Diode (LED) products, and emerging halogen lighting products. In February 2015, NWE contracted with Nexant, Inc. to conduct targeted comparison and market research designed to understand the current state of the market for energy efficient lighting products in Montana, with specific focus on awareness, installation, and saturation of CFLs.

This report presents the results of this rapidly-deployed research and summarizes the findings from three sources of information: a review of recent existing research on the national and regional lighting market; interviews with contacts from other Northwest program administrators; and a survey of over 300 NWE residential customers about their lighting product options.

1.1 Findings

1.1.1 Literature Review

A variety of indicators are used to assess the state of local markets for CFLs, including: sales volumes, shelf space shares, saturation estimates, and customer acceptance. While CFLs have become a commonly-stocked efficient lighting option and awareness of the product is high, new lighting products are entering the market. Recent studies have found that new lighting products may be creating confusion and causing lower levels of respondents to report ever purchasing a CFL. Two Northwest organizations, the Northwest Energy Efficiency Alliance (NEEA) and Energy Trust of Oregon, observed reduced shipments of CFLs after withdrawing retail incentives. Energy Trust returned to the retail program model to protect the shelf space that had been allocated to CFLs.

Without common agreement about the definition of a transformed market, we turned to the Diffusion of Innovations theory that underlies the concepts behind technology adoption. Using the adoption curve, we would expect a threshold of 50% sales and saturation, corresponding with the shift from “early majority” to “late majority” as an indicator that it is time to remove product incentives and market support. CFL sales and saturation are not at that 50% level. Nevertheless, as the baseline shifts to EISA-compliant incandescent and halogen bulbs and LEDs become a more viable product option, program planners may decide to allocate incentives to new lighting technologies or focus on subsidizing efficient alternatives for products that are exempt from EISA.

Our review of the current market data found evidence of substantial shifts in the mix of product shipments in 2014, indicating that halogen bulbs will likely command an increasing portion of retail shelf space in the near future.

1.1.2 Comparative Research

Retail lighting programs remain a major component of the residential energy efficiency efforts at all of the comparison organizations, all of whom were efficiency program administrators in the Pacific Northwest. Even with a changing baseline, CFLs remain a cost-effective offer for customers and utilities. All of the comparison organizations provided incentives for LEDs in 2014, representing between 12-50% of total product units.

There is no common framework or definition for determining market transformation among contacts at comparison organizations, a concept several contacts noted leaving for NEEA to assess. Contacts at Energy Trust were the most direct in recommending an overall shift from a point estimate (sales or saturation) toward using multiple indicators to determine the stability of the CFL market. Specialty lighting products are difficult to approach with a market transformation strategy; these products are too specialized and represent numerous niche applications appropriate for a small portion of overall sockets. Many specialty applications are exempt from EISA and driven by considerations of fit, appearance, and size. They can be expensive and remain a relatively low portion of the total bulbs incented, especially in Montana.

Consistent with evidence from data reflecting national lighting product shipments, contacts from all of the comparison organizations described a rapidly shifting residential lighting market reflecting the first year of full implementation of EISA and the increasing stock of halogen bulbs. Regional organizations responsible for determining regional baseline and unit energy savings values for CFLs have had to adjust and are reviewing their assumptions annually to obtain detailed sales data that will guide future programs. Because of the uncertainty associated with the volume of future halogen shipments and associated shelf space, contacts largely assume that they will continue to offer incentives for CFLs through 2016. Seattle City Light is an exception and the only organization to move to an LED-only residential lighting portfolio in 2015.

1.1.3 Customer Survey

Awareness and access. Ninety-six percent of the surveyed population is aware of CFLs. Eighty-five percent of the population has purchased at least one CFL, and respondents indicate CFLs are available on the shelves of large stores such as Home Depot/Lowe's Home Centers, discount or mass merchandise stores such as Walmart, K-Mart, and Target, or hardware stores. Seventy-seven percent reported having at least one CFL currently installed.

Satisfaction. Satisfaction rates for CFLs were very high for a third of the population, and moderately high for another third. Fifty-one percent of respondents stated they are very likely to purchase a CFL bulb for their home in the future. While NorthWestern Energy customers are familiar and largely satisfied with CFLs, nearly 20% indicated that they are unlikely to purchase CFLs, primarily because of the cost of the bulb and poor light quality. Several contacts spontaneously mentioned concerns about mercury in CFL lamps.

LED Awareness. Seventy-nine percent of respondents were aware of LED lamps, although far fewer households had an LED installed (24% reported having at least one LED installed, compared to 77% for CFL). Among households with an LED installed, satisfaction rates were higher than for CFLs, with 67% of contacts very satisfied with their LED. The top three reasons for not purchasing LEDs include the expense of the bulbs, not knowing enough about them, and not needing any.

Acquisition and Saturation. Sixty-three percent of respondents acquired a CFL bulb in 2014. On average 9 CFLs are installed per household, but this value ranges from zero to more than 40. The estimated CFL socket saturation rate is approximately 16%[1]. Awareness and installation rates of specialty CFLs are both lower than standard "twisters". It is challenging to estimate the saturation level of specialty bulbs because of the diverse products included and the variation of specific niche applications in a given home. Nearly a quarter of respondents purchased an LED in 2014. On average, 2 LEDs are installed per household, ranging from zero to forty-eight. The estimated LED saturation rate gleaned from survey respondents is 3%.

1.2 Conclusions

While awareness of CFLs is high, using estimates of sales and saturation we conclude that the CFL residential lighting market is not transformed. However, the residential lighting market is in the state of significant change and this change requires demand side management program providers to carefully consider and evaluate the market during the next few years.

1.2.1 CFLs will continue to need retail support

CFL saturation is between 16-25% in Montana, meaning that a substantial number of sockets continue to hold incandescent bulbs. The fact that CFL saturation appears to have plateaued in Montana and elsewhere in the Pacific Northwest could provide evidence of persistent barriers associated with putting CFLs in certain sockets. On the other hand, the current saturation estimates indicate that the approximately 60% of sockets that continue to hold incandescent lamps will contain a different product three years from now. Given the increasing shipments and availability of EISA-compliant halogen products, CFLs will continue to compete with a less efficient lighting product. If CFL shelf space shrinks or disappears, the likelihood that subsequent product choices reflect the most efficient options will be low.

As EISA continues to change the mix of available lighting, new choices will be available for consumers. Several recent studies have identified the continued need for retail level information

[1] Note that prior studies have found self-reported saturation to be approximately 30% lower than the saturation found on-site. A 30% increase would result in a saturation estimate of approximately 21%, consistent with the 2009 NorthWestern Energy End-use Study and only slightly lower than RBSA—both of which relied upon on-site counts.

about lighting products to help consumers navigate their next choice—which for some households will mean a break from all incandescent options for the first time.

1.2.2 Program adaptation will be necessary

Lighting remains a primary contributor to residential savings for many program administrators. However, EISA is affecting the efficiency of the lighting baseline and resulting in decreased average savings per bulb and a drop in overall savings. Thus, savings from energy efficient lighting are becoming more difficult, and more expensive to obtain cost effectively.

The dynamic changes occurring in the lighting market indicate a need for on-going monitoring and review of residential lighting as markets and prices and products continue to change. The resources required to track these shifts in supply and pricing and determining the timing for market exit indicate the value of leveraging research occurring at the regional and national level. While CFLs will need support to maintain retail shelf space in 2015 and 2016, it is unclear what the market will require post-2016. When it becomes clear that CFLs no longer require programmatic support, it will be necessary to plan for a staged, orderly withdrawal from the market in order to maintain long-established relationships with key market channel partners in residential lighting, manufacturing, and retailing. The next generation of products and programs will benefit from these successful relationships.

1.3 Recommendations

Maintain involvement in retail lighting programs through Fiscal Year (FY) 2015/16. The full effect of EISA is only now emerging and the dynamic shifts in lighting product assortment put the shelf space currently allotted to CFLs and LEDs at risk. If those products do not remain on the shelves, the least efficient option—an EISA-compliant incandescent/halogen—will become the default option.

Monitor market developments by tracking shelf studies, stock and flow research, and other evidence of structural changes in the lighting market. Limited resources for Montana-specific data require leveraging the research occurring elsewhere and tracking the adjustments occurring at the Regional Technical Forum. NorthWestern should consider purchasing available sales data, and/or track the manufacturer shipment data coming out in reports published by Northeast Energy Efficiency Partnerships, the Consortium for Energy Efficiency, the Department of Energy and/or others. If the market share of halogens continues to expand and/or shipments and shelf space associated with CFL and LEDs shrinks, additional market supports will likely be needed.

Prepare for rapid program adjustments and assume that lighting program activities will need to be reviewed every 12-18 months. Multiple competing forces are affecting the residential lighting market, many of which are hard to predict with certainty. Establishing a framework for tracking key indicators and adjusting programs annually will likely be necessary for the next 3-5 years.

Consider including LEDs in the next program year. LEDs are quickly becoming a viable lighting product, but many households have yet to obtain their first LED. Direct distribution and retail promotion can encourage consumers to try these new products. The performance advantages, once experienced, may push these products more rapidly up the adoption curve.

2 Background and Existing Research

This section summarizes relevant information from existing research, including a brief discussion of market transformation and the role of energy efficiency programs in promoting a marketplace of energy efficient products.

2.1 Summary

We found no commonly applied indicator of market transformation used to assess CFL program activities. While CFL programs are numerous and the research voluminous, multiple indicators are used in discussions about the extent to which the CFL market is transformed, including sales volume, shelf space, saturation estimates, and consumer acceptance. On one hand, CFLs have become a commonly-stocked efficient lighting option and awareness of the product is high. On the other hand, new lighting products are entering the market, creating confusion and causing lower levels of respondents to report ever purchasing a CFL.

Because the concept of market transformation is intertwined with the concepts around the theory of diffusion of innovations, a threshold of 50% sales and saturation offers a theoretically-grounded “bright line” indicator. This threshold corresponds with the shift from “early majority” to “late majority” and likely indicates that it is time to remove product incentives and market support. CFL sales and saturation are not at that 50% level. Nevertheless, as the baseline shifts to EISA-compliant incandescent and halogen bulbs and LEDs become a more viable product option, program planners may decide to allocate incentives to new lighting technologies or focus on subsidizing efficient alternatives for products that are exempt from EISA.

2.2 Methodology

CFL programs have been the subject of hundreds of studies over the past 10 to15 years. This low-cost, accessible source of residential energy savings has been an important component of energy efficiency programs throughout the country. A complete review of the data obtained about the residential lighting market is outside the scope of this study. Nevertheless, the research team reviewed numerous documents and recent reports in an effort to understand the current assumptions that underlie residential lighting programs. This section provides summary information from several of the most recent and directly relevant studies and is informed by the following sources:

Table 2-1: Secondary Research and Data Sources

Source
2009 NorthWestern Energy End Use and Load Profile Study (Nexant)
2013-2014 NEEA Residential Lighting Long-term Market Tracking Study (DNV GL)
2011 Residential Building Stock Assessment (Ecotope)
2014 Montana Single-family Homes. State Summary Statistics (NEEA)
2014 Northeast Residential Lighting Strategy, (Northeast Energy Efficiency Partnerships)
2014 ACEEE Summer Study Paper: Are LEDs the Next CFL: A Diffusion of Innovation Analysis (Holland, Christine)
2014 ACEEE Summer Study Paper: The Golden Goose that Keeps on Laying: Why there are still savings opportunities for CFL programs even after EISA. (Wood, Anders and Andrew Rietz)
2014 Process Evaluation of the 2013 Products Program (Research Into Action for Energy Trust of Oregon)
2010 ACEEE Summer Study Paper: Market Transformation and Resource Acquisition: Challenges and Opportunities in California's Residential Efficiency Lighting Program. (Ettenson, Lara and Noah Long)
2010 CFL Market Profile, Data Trends and Market Insights. (US Department of Energy)
2007 Puget Sound Area Residential Compact Fluorescent Lighting Market Saturation Study. (EMI Consulting)

2.3 Market Transformation

A primary finding from our literature review is the lack of a generally accepted bright line definition or indicator of transformation short of codes and standards that change the choice architecture for all consumers. The passage of the 2007 EISA standards seemed to create a logical off ramp for CFL programs, because there were no incandescent bulbs available at the time that would have met the EISA standard. In 2015, a year after the lower wattage requirements had phased in for all standard incandescent lamps, incandescents remain installed in many sockets and new EISA-compliant halogens are flooding into the market—threatening to displace CFLs from hard-won shelf space. At the same time, new LED products are becoming price competitive and providing new options for those specialty applications that have historically been challenging for CFL programs. In short, the dynamic nature of the current lighting market makes it difficult for any single metric to signify permanent change. Instead, program planners throughout the country are watching market trends and waiting for a preponderance of evidence to confirm permanent, structural change.

According to the American Council for an Energy Efficient Economy (ACEEE), "market transformation is the strategic process of intervening in a market to create lasting change in market behavior by removing identified barriers or exploiting opportunities to accelerate the adoption of all cost-effective energy efficiency as a matter of standard practice." This definition is rather expansive, and includes the assertion that the ultimate objective is the adoption of all cost-effective energy efficiency. The California Energy Efficiency Strategic Plan, adopted in September 2008, referenced prior definitions of market transformation as including "long-lasting sustainable changes in the structure of functioning of a market achieved by reducing barriers to the adoption of energy efficiency measures to the point where further publicly-funded intervention is no longer appropriate in that specific market."[2] Ettenson and Long assert that the lighting market is not transformed while a majority of available sockets do not contain an efficient lamp.

Regardless of the substantial changes in the residential lighting product mix, whether the CFL market can be declared transformed remains a difficult question.

At the core of understanding the energy efficiency framework for market transformation is the adoption model based on the work of Everett Rogers. According to this framework, adoption is a function of time and of specific attributes that can be applied to consumer behavior. In this model, the critical point occurs at 50% - when adoption tips from Early Majority to Late Majority, often because supply has changed and/or because new standards are being adopted. Holland[3] provides some nuance for how the adoption curve may apply to CFL and LED products, noting that earlier groups of adopters typically have higher disposable incomes, higher education, and higher risk tolerance than later groups. This means that an innovation (for our purposes CFLs or LEDs) may never reach full market saturation "if the benefits do not outweigh the risks for the later groups. The most commonly cited reason for failure of market adoption progress is inadequate price decline." (Holland) Reducing the perceived risk by lowering costs to consumers is a common rationale for programs that provide product subsidies to encourage consumers to choose the energy efficient option.

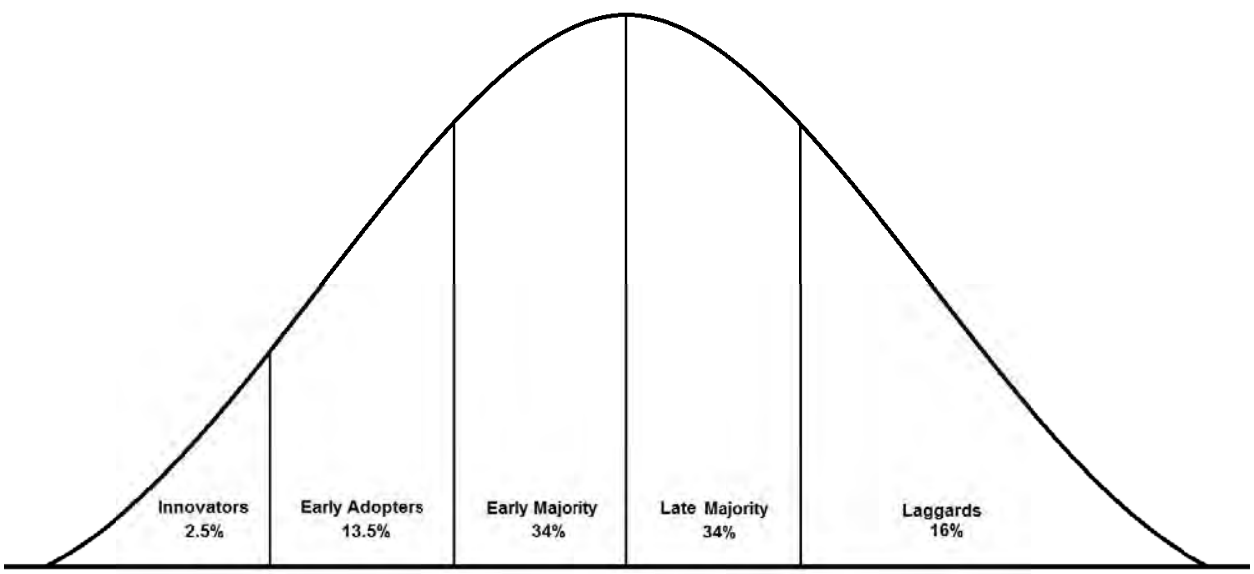


Figure 2-1: Rogers Diffusion of Innovations Model

[2] Ettenson and Long. Market Transformation and Resource Acquisition: Challenges and Opportunities in California's Residential Efficiency Lighting Programs

[3] Holland, Christine. Are LEDs the Next CFL: A Diffusion of Innovation Analysis

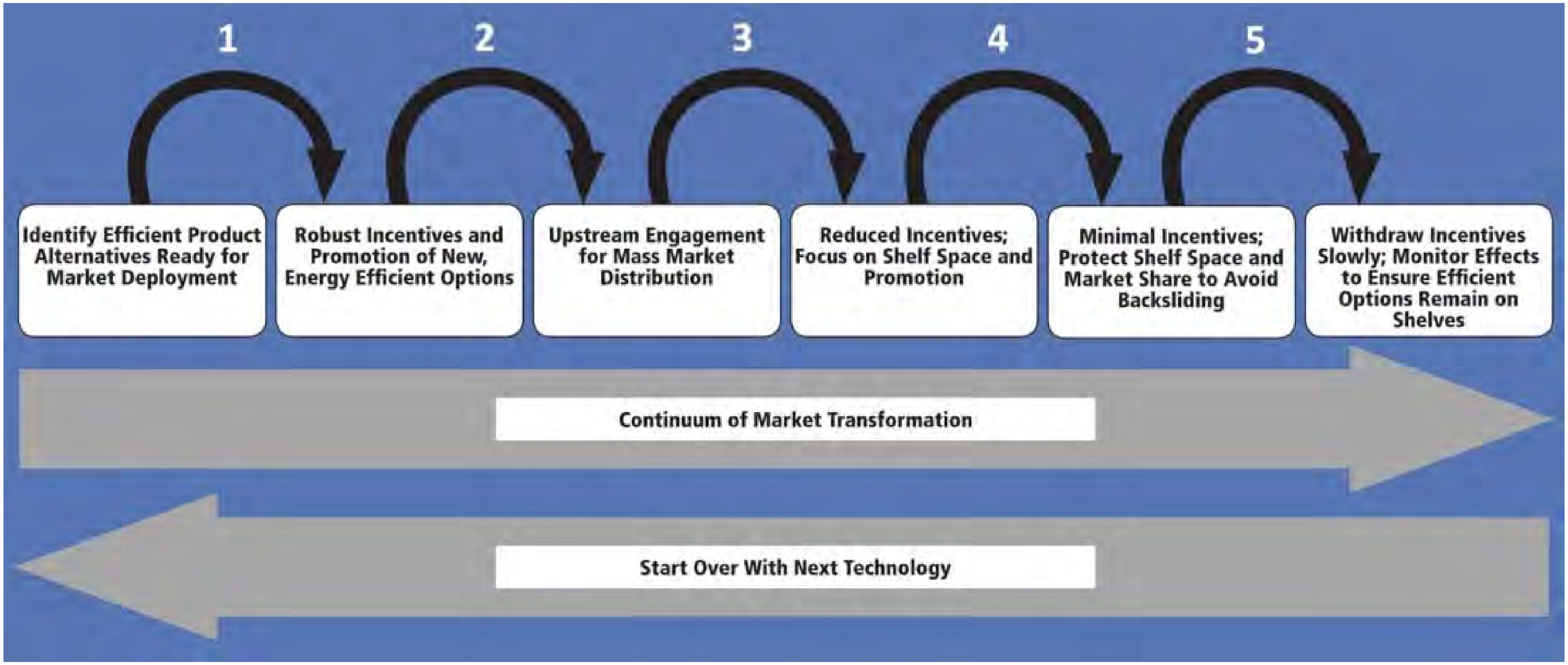
Ettenson & Long argue that utility efficiency programs have a natural role in the continuing process of market transformation as they pull more efficient products to market and thereby speed up the process of market acceptance. For this to work, efficiency programs must be regularly modified to address the ever changing market conditions and focus new program offerings on pulling the next generation of efficient products to market. From their perspective, market transformation should be viewed as a continuous process: research that supports innovation and demonstration; energy efficiency programs help efficient products gain (and keep) market share; and codes and standards ensure that efficiency level becomes mandatory.

"While some might call a market transformed when prices reach a certain level or most consumers know of a product, others might conclude that a market is not transformed unless a technology is widely adopted. There are a number of metrics used to determine various levels of market transformation. However, one critical metric that must be considered is the amount of remaining cost effective potential that can be reached by continuation or modification of a particular program." (Ettenson & Long)

2.3.1 Market Engagement Framework

Informed by the literature review, we developed a figure to represent a conceptual framework for market engagement and eventual transformation. (Figure 2-2) In this framework, market engagement and transformation is a continuum of activities to support wider deployment of energy efficient products. Rather than risking potential disruption of the market, this framework provides for different levels of engagement and monitoring progress to provide the appropriate level of support and avoid collapse or backsliding. Given the turbulence in the current lighting supply market and the expected but uneven implementation of EISA, staying engaged in the retail lighting market will likely make sense; perhaps at a lower incentive level, or with targeted promotions, but ensuring that the efficient option continues to be stocked.

Figure 2-2: Framework for Market Engagement and Transformation



2.3.2 The Northwest Lighting Market

Northwest efficiency programs have provided support for CFL development and deployment since the 1990s. These efforts have included give-away and coupon programs, large-scale upstream markdown programs, and quality verification programs (such as the Program for Evaluation and Analysis of Residential Lighting (PEARL).) In 2005, NEEA coordinated a regional manufacturer buydown designed to lower costs and increase accessibility by pushing discounted CFL products onto store shelves. This effort expanded in 2006 and 2007, when Energy Star CFL sales exceeded 18 million lamps.[4]

According to Holland, after 17 years of programmatic effort, households in the Northwest have a CFL socket saturation of 24% and reached peak market share of approximately 33% of all medium screw-based bulbs in 2008. This plateau in sales and saturation is intriguing and indicates that there remains a portion of the market that has yet to be reached with CFLs. This could reflect persistent barriers associated with cost and performance, or reflect consumer habit and inertia in product selection. As EISA continues to affect the product mix and choices for future purchases, the sockets that currently have incandescent lamps will eventually contain a different product. It remains unclear whether that will ultimately be an EISA-compliant incandescent or halogen bulb, a CFL, or even an LED.

The sections below provide several data points of interest to our inquiry from two recent major regional studies: the NEEA's Residential Building Stock Assessment and Residential Lighting Long-term Market Tracking study.

2.3.2.1 Residential Building Stock Assessment

The 2012 Residential Building Stock Assessment (RBSA) was sponsored by the Northwest Energy Efficiency Alliance and conducted by Ecotope, Inc. RBSA was designed to provide a regional baseline for residential homes in the Northwest. The study developed an inventory and profile of the existing residential building stock based on field data from a representative, random sample of existing homes.[5] The figures below present several of the Montana-specific RBSA findings relevant to the focus of this study.

RBSA found that over half of all sockets in all four states contained an incandescent lamp and that Montana had the highest percentage of incandescent lamps, statistically significant difference from the region as a whole.

[4] DNV GL. 2013-2014 Northwest Residential Lighting Long-term Market Tracking Study

[5] The RBSA used complex sampling approach and included oversamples added by some utilities to leverage the RBSA project to increase the sample sizes in their territories. A detailed discussion of the application of probability and sample weights can be found in Ecotope's report, available at http://neea.org/resource-center/regional-data-resources/residential-building-stock-assessment

Table 2-2: RBSA Data – Distribution of Lamps by Type and State *

Lamp Type	ID	MT	OR	WA
Compact Fluorescent	27%	25%	25%	32%
Halogen	2%	1%	5%	5%
Incandescent	63%	66%	62%	54%
Linear Fluorescent	8%	8%	8%	8%

* Estimates are taken from the state-specific RBSA summary reports; and exclude "other." The data for RBSA was collected in 2011 and 2012. LED residential products were too new to register at that point, but may emerge in the anticipated 2017 RBSA. State-specific summaries can be obtained at: http://neea.org/resource-center/regional-data-resources/residential-building-stock-assessment

The RBSA analysis also included estimates of the installed lighting equipment currently compliant with EISA requirements. As show in Table 2-3, 20-30% of the lamps installed in 2011/12 were exempt from EISA, and 30-40% of lamps were already compliant. The non-compliant lamps are of particular interest to program planners, because they will receive a different lighting product in the future as non-compliant bulbs disappear.

Table 2-3: RBSA Data – Distribution of Lamps by EISA Category and State

EISA Category	ID	MT	OR	WA	Region
Exempt	22.9%	21.2%	27.4%	28.6%	27.0%
Non-Compliant	40.9%	46.6%	39.9%	32.4%	36.7%
Compliant	36.3%	32.2%	32.7%	39.0%	36.3%

While the RBSA estimates are calculated differently, they are relatively consistent with the results of the 2009 End-use and Load Profile report prepared for NorthWestern Energy. The state-specific RBSA report contains higher CFL saturation estimates that the detailed regional single-family RBSA report (the regional report estimates 21.4% CFL saturation, lower than the saturation estimate in Table 2-4.)

Table 2-4: Montana Lighting Saturation – Comparison Studies

Bulb Type	2009 End-use Study	2012 RBSA *
Incandescent	66%	66%
CFL	23%	25%
Halogen	3%	1%
LED	.2%	NA
Linear Fluorescent	8%	8%

* State-Specific RBSA Report for Montana

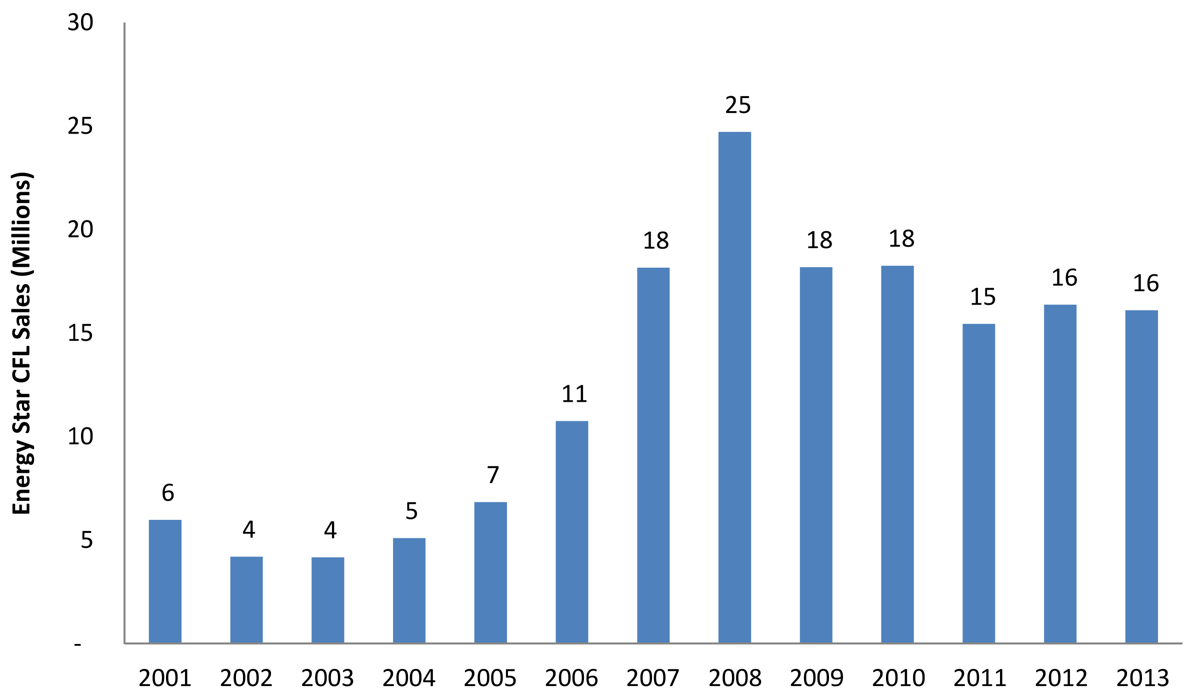
Using the RBSA estimate of 57 lamps per Montana home, this is approximately 14 CFLs per household and approximately 38 incandescent lamps.

2.3.2.2 Northwest Energy Efficiency Alliance's Long-term Market Tracking Study

The 2013-2014 Long-term Market Tracking (LTMT) report is the tenth assessment of the Northwest residential lighting market conducted by DNV GL. As such, these studies provide consistent longitudinal data on the health of the CFL market and sales trends.

Based in part on what appeared to be dramatic increases in CFL sales at the time, NEEA discontinued its support of the Northwest lighting market in 2008. Even with continued support of retail CFL programs by many regional program administrators, CFL sales have declined since 2008. By 2013 non-incentive sales of CFLs had declined to lowest levels since 2005, indicating that the market is continuing to rely on program incentives to encourage CFL purchases. Figure 2-3 contains NEEA's estimates of Northwest Energy Star CFL sales over the past 12 years.

Figure 2-3: NEEA LTMT Data – Estimated Northwest Energy Star CFL Sales (2001-2013) *



* As reported in the 2013-2014 Northwest Residential Lighting Long-term Market Tracking Study, includes NEEA incentive sales, other incentive sales, and non-incentive sales. Market information from PECI, 2006; Fluid Market Strategies, 2007-2013; CLEAResult, 2014

In addition to providing longitudinal sales data, the LTMT study provided several findings relative to the availability of bulbs in rural areas and the current levels of awareness.

The LTMT study found evidence that the portion of lighting products represented by LED lamps and EISA-qualifying incandescent lamps in retail stores is increasing.

Table 2-5: NEEA LTMT 2013 Portion of Lamps Stocked

Product	Urban	Rural	Region 2013	Region 2012
Incandescent			50%	61%
Incandescent Big Box	47%	54%		
Incandescent Non-Big Box	55%	48%		
General Purpose (GP) CFL	24%	27%	18%	18%
GPCFL Big Box	17%	23%		
GPCFL Non-Big Box	18%	19%		
Specialty CFLs			6%	6%
Specialty CFLs Big Box	8%	7%		
Specialty CFLs Non-Big Box	5%	7%		
Halogen			21%	12%
Halogen Big Box	20%	16%		
Halogen Non-Big Box	21%	24%		
LED	5%	2%	4%	2%
LED Big Box	8%	0%		
LED Non-Big Box	2%	2%		

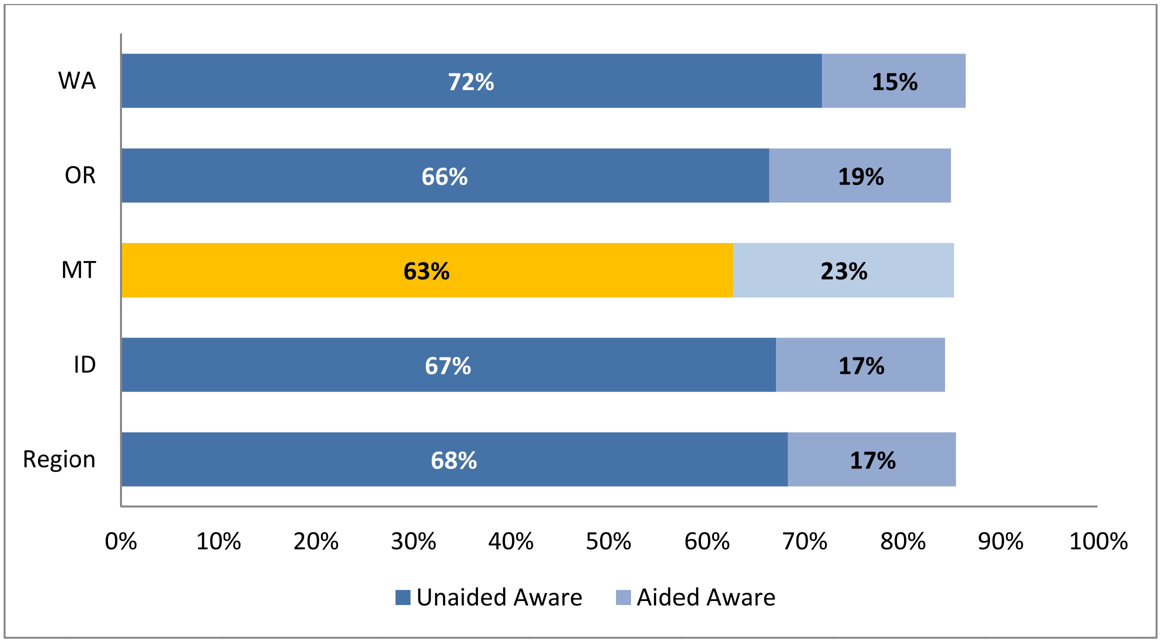
The LTMT survey results imply confusion among customers as findings indicate counterintuitive decreases in the portion of people reporting they had ever purchased CFLs (that portion should only increase with time). A recently completed evaluation of Energy Trust of Oregon's Retail Products Program noted that lighting purchases are typically made without the assistance of a sales associate--a potentially problematic situation given the "abundance of new lighting technologies," likely to require consumers to change the way they make lighting purchase decisions. As the product mix available on shelves changes, consumers have new questions about lighting levels, light quality, mercury in CFLs, costs and expected life, and reliability of new technologies. The information required to answer these questions is not always available or clear, leading consumers to make decisions based solely on price or habit.

The LTMT study data found no geographic differences in CFL awareness rates. Figure 2-4 shows that levels of CFL awareness are similar among the Northwest states. Eighty-six percent of Montana residents were aware of CFLs (including aided and unaided responses).[6] The LTMT also used phone survey data to estimate saturation (number of CFLs currently installed). Using

[6] CFL awareness in the survey conducted for this study was about 10 points higher.

the detailed survey data from banners contained in the appendix, the average number of CFLs installed among Montana respondents is approximately 6 bulbs (or 11%, using an average socket count of 57). The lower saturation estimate contained in the LTMT study is consistent with prior research indicating that respondents underestimate the number of CFLs installed in phone surveys by 30-40%. [7, 8]

Figure 2-4: NEEA LTMT Study – Unaided + Aided Awareness

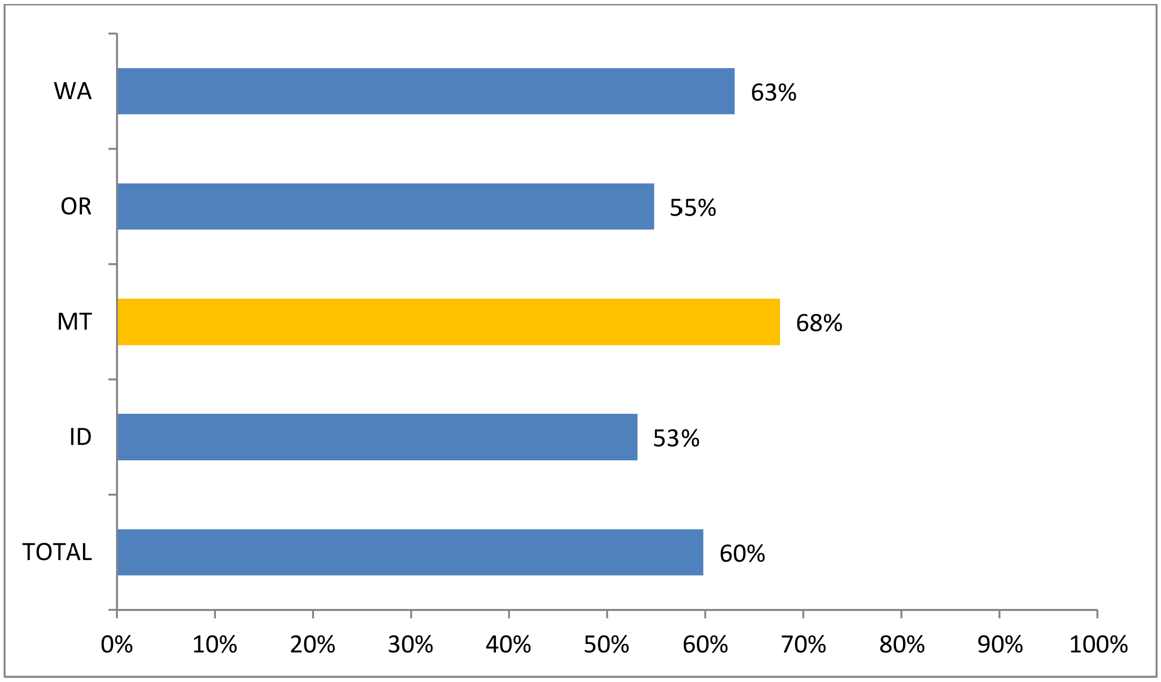


Montana respondents more commonly reported that they had "ever purchased" a CFL.

[7] The saturation estimate calculated from the survey conducted for this study is approximately 15%, five points higher, but still lower than the on-site saturation calculations, confirming expectations that a mail survey would result in more accurate estimates because respondents have the option to stop and look around their home before answering.

[8] For a more detailed discussion of sources and evidence of underreporting, see EMI's 2007 Puget Sound Area Residential Lighting Study, which included a detailed literature review.

Figure 2-5: NEEA LTMT Data – Portion "Ever Purchased" CFLs



The LTMT notes a declining portion of people reporting they had ever purchased a CFL. The higher portion of respondents in Montana reporting this could reflect the shift in emphasis in other states in the Northwest towards promoting LEDs.

2.4 Sales Data and Planning Considerations

Many evaluations use a code baseline approach to estimating the savings associated with choosing an efficient product. This approach assumes that a given customer will choose a replacement bulb from the specific products available on the shelf at the point of purchase. The baseline wattage is the least efficient option a consumer can find on the shelves.

2.4.1 Sales Data

A recent report published by the Northeast Energy Efficiency Partnership contained information from the National Electrical Manufacturers Association (NEMA), which tracks shipping data for all NEMA member manufacturers. As is visible in Table 2-6, 2014 ushered in a national increase in halogen and LED lamp shipments along with a substantial decline in market share for incandescent lamps. However, at the close of 2014, incandescent lamps remained the majority share of bulb purchases.

Table 2-6: 2013 & 2014 NEMA Shipping Data[9]

Lamp Type	Incandescent	Halogen	CFL	LED
Change from 2012 to 2013	-10.6%	+41.8%	-0.4%	+42.3%
Change from Q1 2014 to Q2 2014	-61.2%	+9.9%	-2.7%	+35.8%
Share of Shipments Year End 2013	51.5%	13.6%	33.8%	1.1%
Share of Shipments Q2 2014	34.7%	26%	36.4%	2.9%

During this time horizon from 2013 through 2014, CFL lamp shipments remained relatively unchanged.

In order to further evaluate the residential lighting market in NorthWestern Energy's service territory, we sought to identify and study sales data in a more regional way. Nexant was able to obtain sales dates in several states (Idaho, Oregon and Wyoming) proximate to Montana; however, no sales data in Montana was found during the study horizon. Additionally, we obtained market sales data from the state of California to serve as a comparison. Review of lighting sales in these regional states[10] mirrors that of the nation as a whole. Figure 2-6, Table 2-7, and Table 2-8 illustrates a few key points in the residential lighting market:

- Lighting sales for all lamp types were generally stable from 2009 through 2013 in the states of Idaho, Oregon, and Wyoming.

9 NEEP Residential Lighting Strategy http://www.neep.org/sites/default/files/resources/2014-2015%20RLS%20Update.pdf http://www.neep.org/blog/transformation-tactics-how-eisa-impacting-residential-lighting

10 Sales data was obtained from major retail channels included are grocery, drug, dollar, club, and mass merchandisers; however, sales data from two major do-it-yourself stores were not available. Despite the omission of sales data from these two retailers, Nexant believes the sales data to be representative of large share of market.

- Incandescent lamp sales commenced a dramatic decline in 2013 coincident with the implementation of EISA standards.
- Halogen lamp sales commenced a dramatic increase in 2013 coincident with the implementation of EISA standards and the decline of incandescent lamp sales.
- Lamp sales in the state of California commenced market shift in 2012, one year earlier than other states, because the state of California implemented EISA states one year earlier than the nation.
- CFL lamp sales remain relatively stable through throughout the time horizon.

Figure 2-6: 2009-2014 Lamp Sales by Bulb Type (CA, ID, OR and WY)[11]

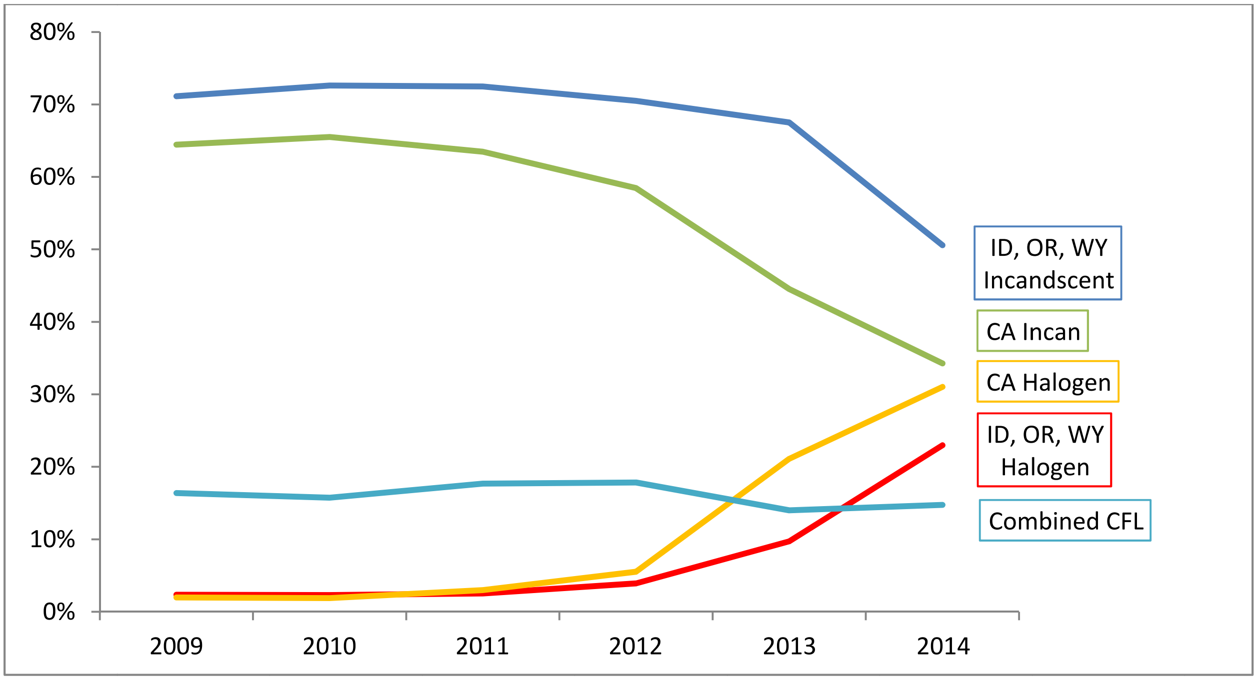


Table 2-7: 2009-2014 Lamp Sales by Bulb Type (ID, OR and WY only)

Lamp Type	2009	2010	2011	2012	2013	2014
CFL	14%	14%	15%	15%	11%	13%
Halogen	2%	2%	3%	4%	10%	23%
Incandescent	71%	73%	72%	70%	68% 51	%
LED	0%	0%	0%	0%	0%	1%
Other	12%	11%	10%	11%	12%	13%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

[11] LED market sales were not included in this figure for simplicity.

Table 2-8: 2009-2014 Lamp Sales by Bulb Type (CA only)

Lamp Type	2009	2010	2011	2012	2013	2014
CFL	19%	18%	20%	21%	17%	17%
Halogen	2%	2%	3%	6%	21% 31	%
Incandescent	64%	66%	63%	58%	45%	34%
LED	0%	0%	0%	0%	0%	1%
Other	15%	15%	13%	15%	17%	17%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

It is notable that in the state of California sales data, that there is subtle decline in the CFL sales share starting in 2013. This is understood to be partially caused by changes in the utility program sponsored CFL retail sales program, similar to those impacts noted by NEEA in 2009; refer to Figure 2-3.

2.4.2 Planning Considerations

EISA standards were phased in over a period of 2 years, from 2012 to 2014, by establishing a minimum lamp efficiency and not with a specific known technology. At the time of the rule passing in 2007, there was not a specific technology that met the exact EISA standard that could be considered the equivalent technology. Upon implementation of the EISA standard in 2012, many manufacturers introduced Halogen technologies that were specifically designed to meet the minimum standard. Table 2-9 illustrates the basic requirements of the EISA standard and savings estimates of energy efficiency measures, specifically CFL lamps.

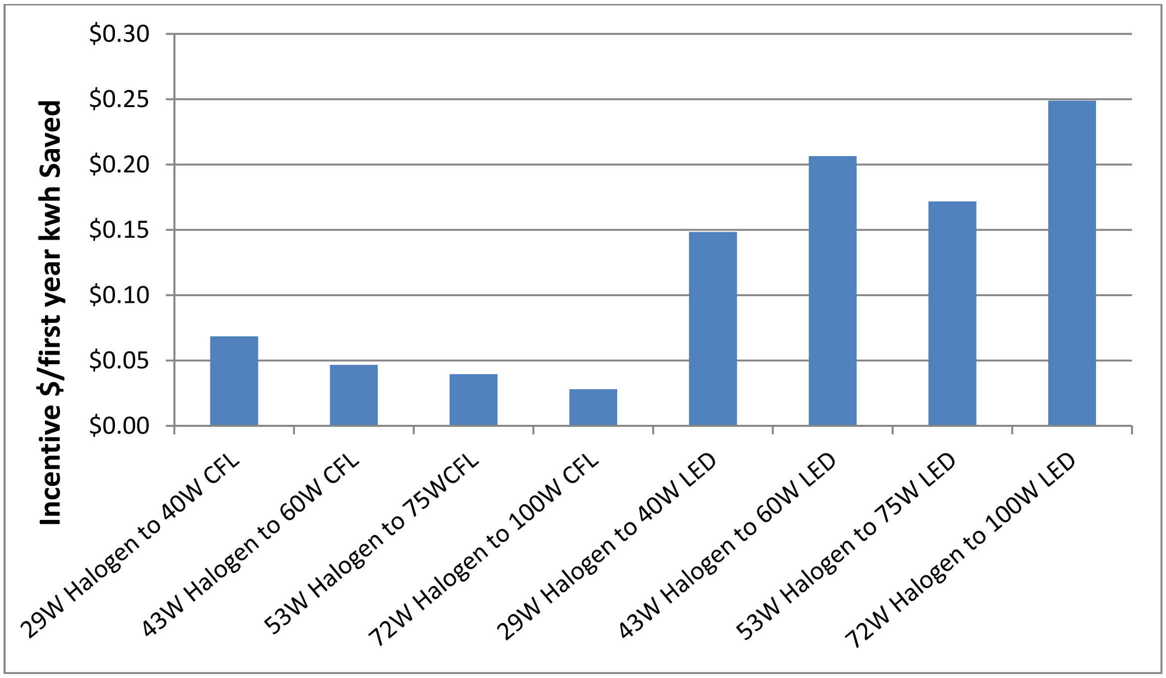
Table 2-9: Savings Estimates with Energy Star Qualified Lighting vs. EISA Baseline[12]

Standard Lamp Prior to EISA	EISA Effective Dates	EISA's Intended Replacement Lamps	Typical Energy Star Qualified Lighting Replacement Option	Savings Over New Baseline
100W Incandescent (approx. 1690 lumens)	2012	72W (1490 – 2600 lumens)	23 – 26W CFL (1600 – 1800 lumens)	46 – 49W
75W Incandescent (approx. 1190 lumens)	2013	53W (1050 – 1489 lumens)	18 – 20W CFL (1100 – 1300 lumens)	33 – 35W
60W Incandescent (approx. 840 lumens)	2014	43W (750 – 1049 lumens)	13 – 15W CFL (750 – 900 lumens)	28 – 30W
40W Incandescent (approx. 490 lumens)	2014	29W (310 – 749 lumens)	9 – 11W CFL (440 – 600 lumens)	18 – 20W

The implementation of the EISA standard also ushered in a new lighting technology, Light Emitting Diode (LED) lamps, which were also partially supported by a DOE competition initiative. Since the LED lamp was initially introduced to mass markets in 2011/2012, the cost of this technology has dramatically fallen. Costs for a 60W A-lamp equivalent in 2012 were often found to be in excess of $30, but as of the spring of 2015, costs of this lamp had declined to $10 per lamp (or less for multipacks). At this cost point, the LED lamp is marginally cost-effective using a total resource cost test (TRC) with a strong sensitivity to specific price, useful life, and avoided cost assumptions. Despite the lowered cost of the LED lamp, CFL lamps remain a more cost effective acquisition resource for utilities in the near term future with average costs around $0.05/first year saved as compared to LED lamps around $0.15/first year saved, as illustrated in Figure 2-7.

[12] EPA Residential Lighting Programs and Federal Minimum Lighting Standards
http://www.energystar.gov/ia/partners/manuf_res/LightingfactsheetFinal.pdf?873f-5a91

Figure 2-7: Comparison of CFL vs LED Lamp Technologies Incentive $/kWh[13]



[13] Considered incentive = 50% incremental cost of the technology cost – lamp cost research was conducted in spring, 2015 in Montana retailers.

3 Regional Comparisons

This section presents the findings obtained from in-depth interviews with representatives from five organizations currently engaged in residential energy efficiency programs that include residential lighting, most notably upstream retail programs.

3.1 Methodology

Working with NorthWestern Energy staff, we identified a list of seven regional program administrators with potentially valuable perspectives on the level of change occurring in the residential lighting market and programmatic adaptation. We completed interviews with five of the seven organizations. Table 3-1 lists the organizations that agreed to be interviewed and ultimately provided information on their current program activities as well as plans for the future.

Table 3-1: Comparison Cohort

Organization	Location
Avista	Eastern Washington
Bonneville Power Administration	Regional coverage
Energy Trust of Oregon	Oregon
Puget Sound Energy	Western Washington
Seattle City Light	Seattle

In addition to interviews, we reviewed publicly available data from integrated resource plans and other materials referenced in DSM Insights, a database of energy efficiency program information maintained by ESource. Our interviews focused on understanding the lighting products and incentives provided for in current programs, expectations for the next 12-24 months, and the definitions or indicators of market transformation used by each organization.

3.2 Summary

Retail lighting programs remain a major component of the residential energy efficiency efforts at all of the comparison organizations. Even with a changing baseline, CFLs remain a cost-effective offer for customers. Contacts from all of the comparison organizations described a rapidly shifting residential lighting market reflecting the first year of full implementation of EISA and the emerging halogen bulb market. All of the comparison organizations provided incentives for LEDs in 2014, typically representing between 12-50% of total product units.

There is no common framework or definition for determining market transformation, a concept several contact noted leaving for NEEA to assess. Contacts at Energy Trust were the most direct in recommending an overall shift from a point estimate (sales or saturation) toward using multiple indicators to determine the stability of the CFL market.

The organizations responsible for determining regional baseline and unit energy savings values for CFLs are reviewing their assumptions annually and working together to obtain detailed sales data that will guide future programs. Because of the uncertainty associated with the volume of future halogen shipments and associated shelf space, contacts largely assume that they will continue to offer incentives for CFLs through 2016. Seattle City Light is an exception and the only organization to move to an LED-only residential lighting portfolio in 2015.

3.3 Findings

Whenever possible we provide comparisons between the comparison cohort and NorthWestern Energy to provide context. Energy Trust of Oregon serves the largest number of residential customers, followed by Puget Sound Energy. Avista, Seattle City Light, and NorthWestern Energy all serve between 200,000 and 400,000 customers. Bonneville, as a regional marketer of wholesale electricity counts the regions utilities as customers.

Table 3-2: Comparison Cohort – Organizational Context

Organization	Residential Customers	Average Residential Rate	Organization Type
Avista	321,089	8.9¢	Investor-owned utility
Bonneville Power Administration	NA	NA	Regional Marketer
Energy Trust of Oregon *	1,205,537	10.6¢	Non-profit program administrator
Puget Sound Energy	956,783	10.4¢	Investor-owned utility
Seattle City Light	367,837	8.2¢	Municipal utility
NorthWestern Energy	276,171	11.2¢	Investor-owned utility

* Energy Trust customer counts include residential electric customers of Portland General Electric and PacifiCorp in Oregon
Residential customer counts and average residential retail rate from EIA data tables.
http://www.eia.gov/electricity/sales_revenue_price/

3.3.1 Residential Lighting Summaries

All of our comparison organizations obtain nearly all of their residential lighting savings through upstream retail programs that provide discounts on high volumes of bulbs sold at a variety of stores.

Avista

Avista began promoting CFL products during the West Coast energy crisis in 2001, relying largely on mail distribution and coupon promotions to get these new lighting products in customer hands. The role of CFLs in Avista's program portfolio varied for several years, including some years during which promotion activities were minimal. In the mid-2000s, Avista joined the regional upstream effort originally developed by NEEA and marketed under several labels including Savings with a Twist and Change a Light/Change the World. When NEEA stopped direct intervention in the upstream lighting market in 2008, the Bonneville Power Administration stepped in to manage the upstream, regionally-coordinated program currently known as Simple Steps/Smart Savings.

While Simple Steps is the primary programmatic effort for residential lighting, Avista has offered customers a variety of ways to obtain CFLs over the years including: outreach events, direct distribution by mail, and coupons. Avista provided incentives for LEDs in 2014, but does not currently include LEDs because the costs had not been updated at RTF in time for planning. LEDs were thus left out of the current program, but contacts expect that they will be included in 2016 as price declines have made them cost effective.

Table 3-3: Avista 2014 CFL Program Distribution

Program Component	Number of Units
Retail	
General Purpose CFL- Retail	522,692
Specialty CFL- Retail	103,059
LED Lamps- Retail	165,968
Retail Total *	**791,719**
Totals	
Portion of retail product GPCFL	66%
Portion of retail product LED	28%

* The bulk of CFLs are distributed through retail programs, Avista hosts outreach events but these represent only a small volume of product

Bonneville Power Administration

As a wholesale power marketer and system planner, Bonneville has a unique position in the region. Bonneville provides customer utilities with the BPA Implementation Manual that documents the payment rate available for specific energy efficiency measures. In addition, Bonneville played a key role in maintaining a regional upstream lighting program, operating the Change a Light/Change the World campaign from 2006 to 2010. Bonneville launched the Simple Steps, Smart Savings program in April 2010. Simple Steps is not designed to be a market transformation program. Rather, the program provides access to regionally-leveraged retail markdowns that reflect the current energy savings obtainable by promoting specific lighting products over a baseline choice. As the EISA baselines have become more efficient, the unit energy savings available per qualified product have diminished.

Table 3-4: Regional Product Flow – FY 2014 BPA Data

Item	All Simple Steps*	Participating BPA*	Non-participating utility sales*
GPCFL	4,769,932	1,148,801	822,926
Specialty CFL	1,477,303	295,853	176,520
LED	1,356,553	286,465	131,151
Total bulbs	7,603,788	1,731,119	1,130,597
CFL Fixtures	**24,199**	**21,973**	**14,009**
Portion of total sales specialty bulbs	19%	17%	16%
Portion of total sales LED bulbs	18%	17%	12%

* All Simple Steps participating utility sales, including IOUs
* Invoiced by participating BPA Simple Steps utilities. Because Seattle City Light, Tacoma Power, and SnoPUD also run their own programs next to Simple Steps, they claim non-program incentives.
* These are completely separate from the other figures, and are only claimed by BPA for the region. No incentives were paid.

Bonneville allows customer utilities to obtain energy savings for a variety of delivery methods, including direct install, mailed with request, mailed without request, and other distribution methods. Reflecting the lower cost and less certainty associated with high volume upstream programs, lighting products distributed through this channel have the lowest associated incentive. (Table 3-5)

Table 3-5: Bonneville Incentives – 2015 Implementation Manual *

Measure	Retail Markdown	By Request	Mailed Non-request	Direct Install
General Purpose CFL	$1.00	$2.50	$2.50 $4.	00
Decorative and Minibase; globe; three-way; reflector; outdoor CFLs (formerly specialty CFLs)	$2.25	$4.00	$4.00 $5.	50
LED Decorative and Minibase	$4.00	$4.00	$4.00 $6.	00
LED General purpose and dimmable, Globe, Three-way (Omnidirectional)	$4.00	$4.00	$4.00 $6.	00
LED Reflectors and Outdoor (Directional, includes PAR, BR, MR)	$4.00	$4.00	$4.00 $6.	00

* LED Savings are determined by bulb type and lumen category.

BPA works with the Regional Technical Forum to ensure that lighting savings estimates reflect the most accurate inputs and that the effects of EISA are incorporated in savings assumptions. The substantial changes in the residential lighting market observable as EISA is fully implemented and LEDs continue their rapid evolution in quality, supply, and price has caused BPA to plan for regular adjustments to the unit energy savings associated with residential lighting products. As the product mix continues to rapidly shift, BPA, NEEA, and other northwest utilities are launching a new effort to capture a wider range of retail lighting market data—allowing planners to look beyond CFL sales to see how the sales mix changes as EISA requirements are fully absorbed to include a new mix of incandescent[14], halogen, CFL and LED products.

According to contacts at BPA, LEDs are a small portion of the market now, but are growing as prices decline. Changes are occurring so rapidly that the standard timeframe for planning through RTF has been adjusted so that RTF is reviewing lighting every year and may still lack sufficient information to produce savings numbers on some LED products.

Energy Trust of Oregon

Energy Trust promotes energy efficient products and energy efficiency services throughout the service territories of Portland General Electric and PacifiCorp in Oregon. Energy Trust was one of many regional funders of NEEA's upstream residential lighting program and continued to provide access to discounted products for a year after NEEA ceased active interventions in the market in early 2008. Following NEEA's lead, Energy Trust stopped providing incentives for general purpose CFLs in 2009 and 2010. According to contacts at Energy Trust, CFL sales were stable for a while, but started declining as new halogen products absorbed shelf space and changed the product mix. Energy Trust provided incentives and product support for specialty bulbs consistently through the years during which they dropped general purpose. According to contacts at Energy Trust, the diversity and niche applications associated with specialty bulbs are difficult to build a market transformation around—the number of products and the size of the market for a given application require too many customized messages to support a cohesive market message. Energy Trust is currently providing incentives for general purpose CFLs, specialty CFLs and LEDs in an attempt to hold shelf space for quality, efficient, lighting products.

Energy Trust participated in Simple Steps until the end of 2014, and is now launching an Energy Trust branded retail program.

[14] Not all specialty applications are covered by EISA, so some incandescent products will continue in the product mix even as EISA-compliant incandescent and halogen lamps become the new baseline.

Table 3-6: Energy Trust of Oregon 2014 CFL Program Distribution

Program Component	Number of Units
Non-Retail	
General CFL- Direct Install	17,160
Specialty CFL- Direct Install	3,806
General CFL- Mail by Request	179,908
Specialty CFL- Mail by Request	96,015
Non-retail Subtotal	**296,889**
Retail	
General CFL- Retail	199,2673
Specialty CFL- Retail	486,868
LED Lamps- Retail	974,661
Retail Subtotal	**3,454,202**
Totals	
Total Product *	**3,751,091**
Portion of CFLs delivered through retail program	89%
Portion of retail product GPCFL	58%
Portion of retail product LED	28%

* Excludes fixtures and multifamily direct install

Puget Sound Energy

Puget Sound Energy (PSE) has supported CFL programs for more than 10 years and continues to provide incentives for general purpose and specialty CFLs as well as LED products. CFL incentives are relatively modest, at 50¢ per bulb for both standard and specialty lamps. In recent years, PSE held “Rock the Bulb” events to promote efficient lighting products, and has also provided thank you kits, and give-away events with coupon redemption. Going forward, PSE expects to tie these promotions with a new Energy Upgrades campaign likely to focus on LEDs in order to promote this new lighting technology and build familiarity with and exposure to LED products likely to get installed immediately.

While the promotional events will likely be exclusively LED, PSE does not have any firm indicators of when the organization might sunset CFL incentives. CFL products are available at a lower price point, making them more accessible to a wider range of incomes and providing a first step and they remain a cost-effective measure. One additional factor that might affect the overall sales and incentive levels going forward is a new requirement in Washington State levying a 25¢ disposal fee on every CFL. In 2014, nearly half of the bulbs discounted by PSE were LED.

Table 3-7: PSE 2014 Lighting Program Distribution

Program Component	Number of Units
Retail	
General CFL- Retail	1,739,414
Specialty CFL- Retail	645,422
LED Lamps- Retail	2,207,462
Retail Total	**4,592,298**
Totals	
Portion of retail product GPCFL	38%
Portion of retail product LED	48%

Seattle City Light

Seattle City Light (SCL) has supported or sponsored CFL programs since the mid-2000s, through NEEA-sponsored initiatives and through energy savings kits and other product promotions underway at the time. SCL is not a Simple Steps participant, instead managing their own retail program with some coordination with the other utilities operating in the populous Puget Sound region. At the end of 2014, SCL decided to shift program efforts to LED products exclusively, after finding that even among the relatively progressive and aware population in Seattle, CFL socket saturation had plateaued at 30-40% and held for several years. This decision was not made easily, but those involved noted that in continuing to promote CFL products, it had become difficult to get people excited about new lighting options and that the programs may not be able to overcome the persistent barriers for CFL installation in the remaining 60-70% of sockets. SCL staff are watching LED prices carefully, wanting to see price declines sufficient to allow incentives to bring LED products to a level that all households can afford.

Table 3-8: SCL 2014 Lighting Program Distribution

Program Component	Number of Units
Retail	
General CFL- Retail	644,000
Specialty CFL- Retail	118,000
LED Lamps- Retail	400,000
Retail Total *	**1,162,000**
Totals	
Portion of retail product GPCFL	55%
Portion of retail product LED	34%

* Excludes fixtures

NorthWestern Energy

NorthWestern has offered CFL promotions and programs since 2004, and is currently participating in the Simple Steps/Smart Savings Program, the regional retail CFL markdown program that represents the vast majority of bulbs provided or discounted for NorthWestern customers. In addition to this upstream buy-down program, NorthWestern currently offers four other program components that provide access to CFLs.[15] These program components include:

- **In-store Coupons.** Mailed twice a year (spring and fall) to all residential customers, coupons provide an instant rebate for up to ten CFLs at participating retailers. A bar code allows customer-specific tracking, and participating retailers submit the coupon and transaction information.
- **Trade Show.** Customers can receive up to four CFLs at special events (home and garden shows, farmers' markets, community fairs).
- **Mail-in.** Customers submit an application with purchase and product information to receive $5 per CFL fixture incentive, or the purchase price (whichever is less).
- **Mail-out.** Customers who complete a mail-in audit receive a CFL in the mail with their audit report.

NorthWestern has not included LED products in residential lighting efforts to-date. While the higher cost of LED products has historically made them non-cost-effective, recent price declines indicate that LEDs may be a viable option for future program years.

Table 3-9: NorthWestern Energy 2013-2014 CFL Program Distribution

Program Component	Number of Units
Non-Retail	
CFL Mail-out	1,591
CFL Mail-in	357
CFL In-store Coupon	10,731
Residential Direct Install	1,325
Trade Show Give-away	8,021
Non-retail Subtotal	**22,025**
Retail	
GPCFL Twister	585,422
Specialty CFL	143,833
Retail Subtotal	**729,255**
Totals	
Total Product	**751,280**
Portion of CFLs delivered through retail program	97%
Portion of retail product GPCFL	80%

[15] A CFL direct install option was discontinued at the end of 2013 because of high labor costs associated with installing the CFLs.

3.3.1.1 Program Elements: Summary Tables

Table 3-10 summarizes the length of time each organization has been involved in large scale retail CFL promotion (excluding kits and coupons distributed during the energy crisis.) Seattle is the only organization that had dropped CFLs completely in 2015, NorthWestern is the only one that had not offered LED incentives by 2015 (Avista dropped LEDs for Program Year (PY) 2015, but had them in 2014.)

Table 3-10: Age of Program and 2015 Lighting Program Components

Organization	Large scale promotion since	2015 Simple Steps Participant	2015 Incentives *		
			GPCFL	**Specialty**	**LED**
Avista *	2006	✓	$1.00 Va	ries $5.	00
Bonneville Power *	2006	NA	$1.00 $2.	25 $4.	00
Energy Trust of Oregon	2004		.75¢ .75	¢ $4.	00
Puget Sound Energy	2004		.50¢ .50	¢ $4.	00
Seattle City Light	2006		--	--	$4.00
NorthWestern Energy	2004	✓	.75¢ $1.	35 -	-

* Avista provided LED incentives in 2014, and plans to in 2016. 2015 LED incentives were excluded as an artifact of planning requirements and reflect uncertainty associated with unit energy savings values available. The incentive listed here was provided in 2014, and will likely be lower in 2016.

* Bonneville's incentives are the maximum customers can obtain through BPA, incentives in specific territories may be lower.

* Incentives can vary by lumen level and wattage. The incentives provided here are blended averages, based on the most common lumen levels. Specific, specialty products may have higher incentives.

Bulbs distributed through retail program efforts ranged from 2.5 to 4.8. Avista and NorthWestern distributed the lowest number of bulbs per ratepayer through retail programs in 2014.

Table 3-11: 2014 Retail Bulb Sales per Residential Customer

Organization	Residential Customers	2014 Retail Bulbs	Bulbs per Res Customer
Avista	321,089	791,719	2.5
Bonneville Power Administration	NA	NA	NA
Energy Trust of Oregon	1,205,537	3,454,202	2.9
Puget Sound Energy	956,783	4,592,298	4.8
Seattle City Light	367,783	1,162,000	3.2
NorthWestern Energy	276,171	729,255	2.6

The portion of total retail bulbs discounted in 2014 represented by general purpose CFLs (GPCFL) ranged from 38% to 80%. Nearly half of the retail bulbs discounted by PSE in 2014 were LED.

Table 3-12: Portion of 2014 Retail Sales GPCFL and LED

Organization	Portion GPCFL	Portion LED
Avista	66%	28%
Bonneville Power Administration	63%	18%
Energy Trust of Oregon	58%	28%
Puget Sound Energy	38%	48%
Seattle City Light	55%	34%
NorthWestern Energy	80%	--

3.3.2 Market Tracking

We asked contacts at each organization about whether they use specific indicators of market transformation in program planning. One contact noted that NEEA set up a projected baseline for CFLs years ago, but the implementation of federal standards and introduction of new halogen products "changed everything." CFL sales share did not continue to grow, and a large number of sockets continue to hold incandescent lamps. As it became apparent that bright line indicators were not working, program planners shifted to multiple indicators. Among the contacts we interviewed there was not consensus on the indicators of market transformation—the indicators offered included:

When the measure is no longer cost effective. Contacts noted that while the baselines have improved to account for the improved performance of EISA-compliant products, CFL products remain a cost effective program offer. Contacts described monitoring the RTF supply curves and RBSA data to track remaining technical potential and cost effectiveness.

- "We watch cost effectiveness and TRC for planning. RTF values will affect what we do. Even if some are dropped, there might be some bulbs that remain eligible."

When the technical potential disappears. If consumers are using CFLs to replace incandescent or halogen lamps, there are still energy savings to be had by encouraging CFL purchases to replace those bulbs. At some point, there may be no additional sockets for CFLs.

- "I f they are using CFLs to replace incandescent or halogen bulbs, there is still some delta wattage… some savings there."

When the efficient product outperforms the incumbent product and consumers have positive connections with the efficient choice. Market intervention has supported product improvement, but there are still low-quality versions of many products that may be kept in check by program-enforced labeling and quality standards.

- "We want to encourage quality light. It depends how low the market prices go, we'll watch to see if an incentive is needed."

When saturation plateaus. Seattle City Light contacts noted that the utility began focusing on LEDs after determining that CFL saturation was not increasing.

- “Over 50% of our potential assessment is in residential lighting, we want to get the remaining opportunity.”

When the market for halogens collapses and “stays collapsed.” Contacts described turbulence in the market as consumers are forced to choose a product other than a standard incandescent for the first time. With CFL saturation estimates hovering around 30% for the region, the 55-60% of sockets that currently contain incandescents will have a different product installed in the future. Whether consumers choose halogen, CFL or LED products for those sockets will be driven by the product mix and price points of products on store shelves in the future. Retail markdowns are a powerful tool for ensuring that efficient options continue to be stocked at attractive price points.

- “There is chaos on store shelves, the information is not stable. Halogen standards are hitting the shelves and we want shelf space for efficient products; CFLs are holding market share for energy efficient bulbs.”

When estimates of market share indicate that CFLs are stable or growing relative to halogens. Several regional organizations, including NEEA and BPA, are working on getting market sales data that covers the region and provides sufficient visibility to estimate new baselines.

- “Right now the CFL incentives are selling well, and LED is increasing rapidly. There may be a point where we go all-LED for some niches, including general use, but that doesn’t seem to be soon; the prices aren’t there yet and the product is not yet familiar enough. We’re definitely tracking market share as an indicator, but have not drawn a bright line in the sand.”
- “I track sales volume reported to us from retailers. We try to get every qualified product in every retailer, and have a pretty good handle on what’s happening in the market. In the last two years we’ve seen a big shift – in 2012/13 our program was 60% CFLs/40% LED, last year it was 50/50. This year will probably be more LEDs. We aren’t really tracking things at a household level; we use RBSA for socket counts.”

It is important to note that, while NEEA has a specific mission to focus on supporting market transformation, none of the program sponsors we interviewed operate with a similar mission. Rather, these organizations are charged with designing and implementing cost-effective energy efficiency programs and are thus focused on ensuring that their portfolio of programs remains cost-effective. As the retail lighting market evolves to reflect the full implementation of EISA requirements, contacts require up-to-date information on sales volumes, product prices, and shelf space. This information is difficult to obtain, which is why many are counting on regional partnerships to secure access and provide information about lighting baselines.

3.3.3 CFL Saturation

Contacts from Avista, Energy Trust, and Seattle all mentioned the NEEA Long Term Market Tracking study as a source of information about the state of the CFL market, particularly the data on sales and shelf studies. BPA also uses the NEEA study and sales data, but conducts its own stock and flow studies that include LEDs. These studies estimate the existing stock, model when that stock will turnover and then track the current flow of products. Saturation estimates are more difficult to estimate from sales and shelf studies, and can be expensive to obtain. Contacts from all of the comparison organizations mentioned the recently published Residential Building Stock Assessment (see description in Section 2), which provided saturation estimates for major lighting categories by state.

Current saturation estimates are most commonly obtained from the RBSA.[16] Puget Sound Energy and Seattle City Light operate with somewhat higher saturation estimates, informed by their own planning and reflecting the higher saturation estimates in urban areas and in the Puget Sound region (RBSA analysis of the Puget Sound sub-region found 31% CFL saturation.)[17] Contacts did not have saturation estimates for specialty bulbs by niche. According to one contact, the number and diversity of specialty products makes it difficult to build a market transformation model or to accurately estimate the potential, given the specific uses for which any given product might be appropriate.

Table 3-13: Current Estimate of CFL Saturation

Organization	Estimate	Source
Avista	24%	RBSA Eastern Washington
Bonneville Power Administration	27%	RBSA BPA Region
Energy Trust of Oregon	27%	RBSA Western Oregon
Puget Sound Energy	33%	2013 Integrated Resource Plan
Seattle City Light	30-40%	Interview
NorthWestern Energy	25%	RBSA Montana Specific

3.3.4 Baseline

The Regional Technical Forum (RTF) uses a blended market baseline that reflects the current overall sales mix and establishes a unit energy savings value that accounts for the improved efficiency of the EISA-compliant baseline. Comparison organizations use a variety of strategies to establish baseline values, including several that are tied to RTF. Table 3-14 describes the baseline used by each of the cohort organizations.

[16] The RBSA report was published in 2012, based on data collected in 2011 and early 2012. Plans are underway to begin a new RBSA with the intention that updated data be available every five years (in this case by 2017.)

[17] Research Into Action. Analysis of the Residential Building Stock Assessment. Prepared for Bonneville Power Administration. August 8, 2013.

Table 3-14: Current Baseline for Residential Lighting

Organization	Source
Avista	RTF
Bonneville Power Administration R	TF
Energy Trust of Oregon	Blended average of market sales
Puget Sound Energy	PSE-developed tool that uses blended baseline reflecting a mix of incandescent and halogens, using RBSA data
Seattle City Light	RTF; expected to adjust
NorthWestern Energy	EISA-compliant halogen

It is important to understand that all Washington utilities are required by I-937 law to utilize a RTF methodology or similar to estimate savings for energy efficiency measures. RTF considers a market baseline for some measure definitions to remove program attribution (net-to-gross) research.

3.3.5 Expectations for the Future

Contacts discussed their expectations for the 2015 and 2016 program years. Consistent with the overall theme of trying to operate in a dynamic market, nearly all expressed some uncertainty in exact product mixes and incentive levels, but none had immediate plans to drop general purpose CFLs (excluding Seattle, which dropped all CFLs at the end of 2014). All contacts expected that LEDs would be an increasing part of their residential lighting efforts, assuming that prices continued to decline.

Table 3-15: Plans for 2015-2016

Organization	Future Program Plans
Avista	More LEDs, less CFLs. Watch halogen shelf space.
Bonneville Power Administration R	educe reimbursement rate for GPCFL.
Energy Trust of Oregon	Watch LED prices and products. Stick with CFLs to protect shelf space for efficient products.
Puget Sound Energy	Adjust LED incentive levels to reflect price declines. Switch promotional events from CFL to LED. Watch cost-effectiveness of CFLs
Seattle City Light	In progress. Focused on providing first exposure to LED products through mail and retail outreach.

4 Customer Survey

This section presents the results of a mixed-mode survey fielded in March and April 2015 with NorthWestern residential customers. The survey focused on understanding the level of awareness, installation, and saturation of general service and specialty compact fluorescent lamps (CFLs) and LEDs, to inform estimates of the current state of the market for energy efficient lighting products in Montana.

4.1 Summary

Results from this survey indicate CFL awareness is high, with 96% of the surveyed population aware of CFLs. Eighty-five percent of the population has purchased at least one CFL, and respondents indicate CFLs are available on the shelves of large stores such as Home Depot/Lowe's Home Centers, discount or mass merchandise stores such as Walmart, K-Mart, and Target, or hardware stores. Seventy-seven percent reported having at least one CFL currently installed. Satisfaction rates for CFLs were very high for a third of the population, and moderately high for another third. Fifty-one percent of respondents stated they are very likely to purchase a CFL bulb for their home in the future. While NorthWestern Energy customers are familiar and largely satisfied with CFLs, nearly 20% indicated that they are unlikely to purchase CFLs, primarily because of the cost of the bulb and poor light quality. Several contacts spontaneously mentioned concerns about mercury in CFL lamps.

Seventy-nine percent of respondents were aware of LED lamps, although far fewer households had an LED installed (24% reported having at least one LED installed, compared to 77% for CFL.) Among households with an LED installed, satisfaction rates were higher than for CFLs, with 67% of contacts very satisfied with their LED. The top three reasons for not purchasing LEDs include the expense of the bulbs, not knowing enough about them, and not needing any.

Sixty-three percent of respondents acquired a CFL bulb in 2014. On average 9 CFLs are installed per household, but this value ranges from zero to more than 40. The estimated CFL socket saturation rate is approximately 16%[18].

Nearly a quarter of respondents purchased an LED in 2014. On average, 2 LEDs are installed per household, ranging from zero to forty-eight. The estimated LED saturation rate gleaned from survey respondents is 3%.

[18] Note that prior studies have found self-reported saturation to be approximately 30% lower than the saturation found on-site. A 30% increase would result in a saturation estimate of approximately 21%, consistent with the 2009 End-use Study and only slightly lower than RBSA—both of which relied upon on-site counts.

4.2 Methodology

Nexant developed and deployed a mixed-mode survey that collected data via web through direct mail recruitment. All contacts in the sample frame received a letter on NorthWestern letterhead containing a pre-incentive of $2, information about the study, and a survey URL encouraging recipients to log in and complete the survey online. The recruitment letter also included a toll-free phone number that customers could use to complete the survey by phone. Customers with email addresses received a reminder by email with a live link to the survey URL.[19] We then followed up with non-responders with a survey formatted for completion by mail.

To facilitate comparison, the questions were largely adapted from a consumer survey conducted as part of NEEA's 2013-2014 NEEA LTMT study and included similarly worded questions on awareness, prior purchase, currently installed bulbs, and storage. In order to keep the survey short and focused, not all questions were matched. The following topics covered in the NEEA study were not included:

- Questions about general considerations in light bulb purchases (importance of various bulb attributes: quality, life, environmental attributes, price, familiarity)
- Probes about pin-based CFLs
- Questions about overall satisfaction with the features of CFLs (general satisfaction is included)
- Questions designed to probe about awareness of EISA changes (including probes about shopping for incandescent lamps and incandescent purchases)
- Questions about bulb removal

4.2.1 Disposition

We mailed 1,000 letters to randomly selected residential customers and ultimately completed the survey with 361 respondents for a response rate of 37%. Approximately half of this sample completed the web-based survey, 32% completed the paper version and returned it in the mail, and 10% completed the survey using an in-bound telephone option.

We also received incomplete surveys in the mail. For surveys that were returned incomplete, we checked to see if the respondent had at least answered the awareness questions. If so, we recorded their answers and counted them as partial completes. Using this screen, 80 of the 102 partially completed surveys were considered usable.[20].

[19] Email addresses were available for approximately 17% of the population.

[20] Including partial completes increases the total sample to 441, for a response rate of 45%. However, we excluded partial completes from the analysis in this chapter.

Table 4-1: Survey Disposition

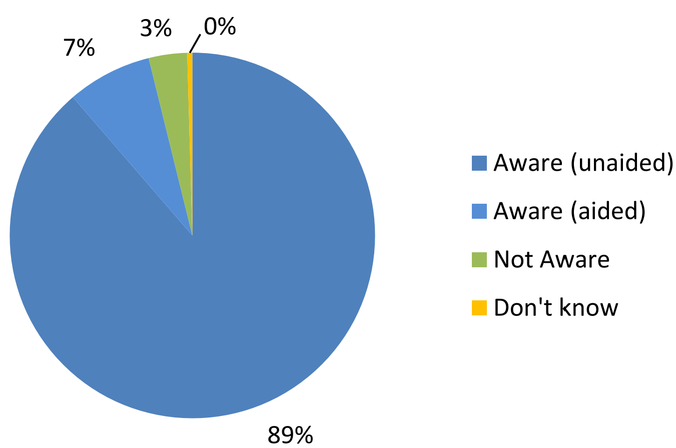
Mode	Count	Percent
Incompletes		
Undeliverable	5	0.5%
No response	514	51%
Returned, Unusable	40	4%
Partial Completes	80	8%
Completes		
Web-based Survey URL	208	21% (47% of sample)
Mail/Paper Survey	116	12% (26% of sample)
In-bound Phone	37	8% (4% of sample)
Total Completes (Excludes partials)	**361**	36% (100% of sample)
Total Sample Frame	**1,000**	**100%**

4.3 Survey Findings

4.3.1 CFL Awareness

Nearly 90% (322 of 361) of respondents reported that they had heard of CFLs without needing any description or assistance. Those reporting that they had not heard of CFLs received a brief description of CFLs and were then asked again about awareness. Twenty-five of the 39 contacts provided additional information subsequently indicated that they were aware of CFLs, for a combined awareness level of 96%.

Figure 4-1: CFL Awareness (n=361)

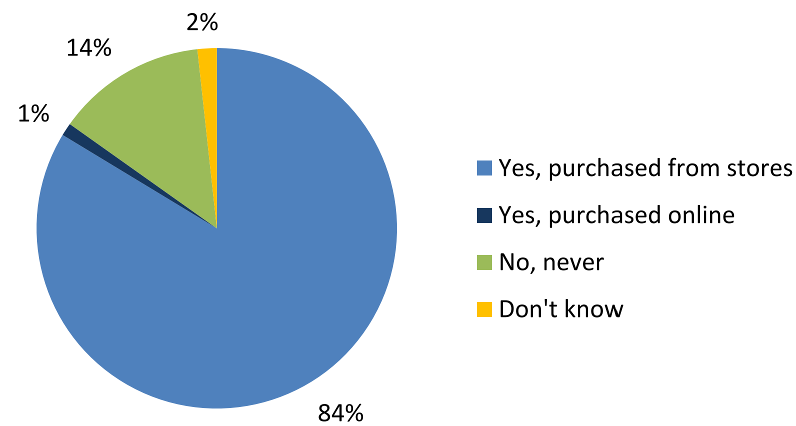


Respondents were provided a list of specially-shaped CFLs including reflectors, candelabras and globes. Awareness of specialty (non-twister) CFLs was lower, at 64% (231 of 361).

4.3.2 Purchase & Storage

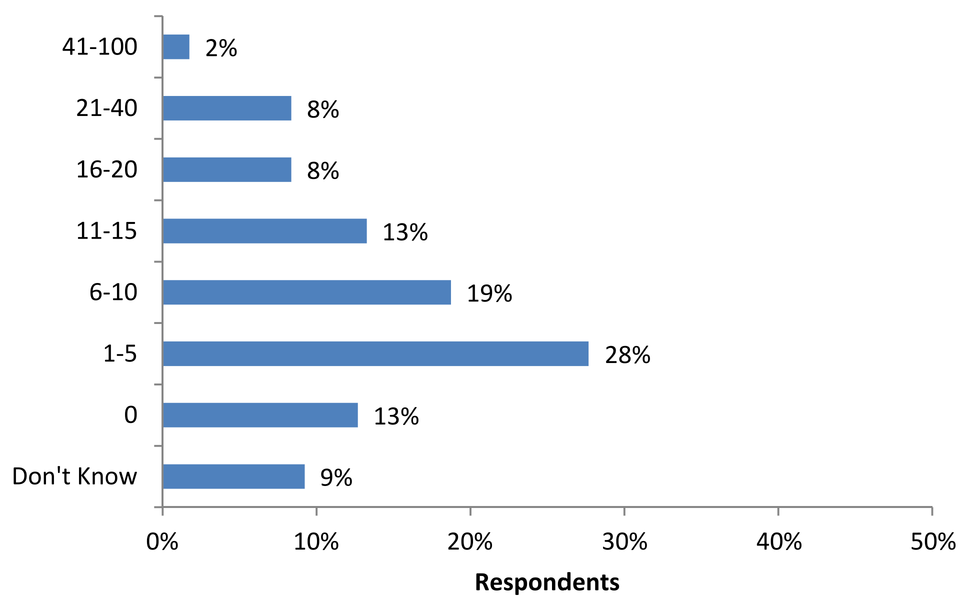
CFL-aware respondents answered follow up questions about prior purchases and experience with CFLs. Eighty-five percent of respondents reported previously purchasing a CFL, nearly all of whom purchased them in stores. Only 1% (4 contacts) had purchased CFLs online.

Figure 4-2: CFL Purchasing (n=347)



Respondents reported the number of CFLs currently installed in their homes. A majority, 77%, reported having at least one CFL installed in their home. Thirteen percent of contacts (44 individuals) did not have any CFLs installed in their homes, and 9% were unsure. The average number of bulbs installed among respondent households is nine. [21]

Figure 4-3: Quantity of CFLs Currently Installed (n=347)

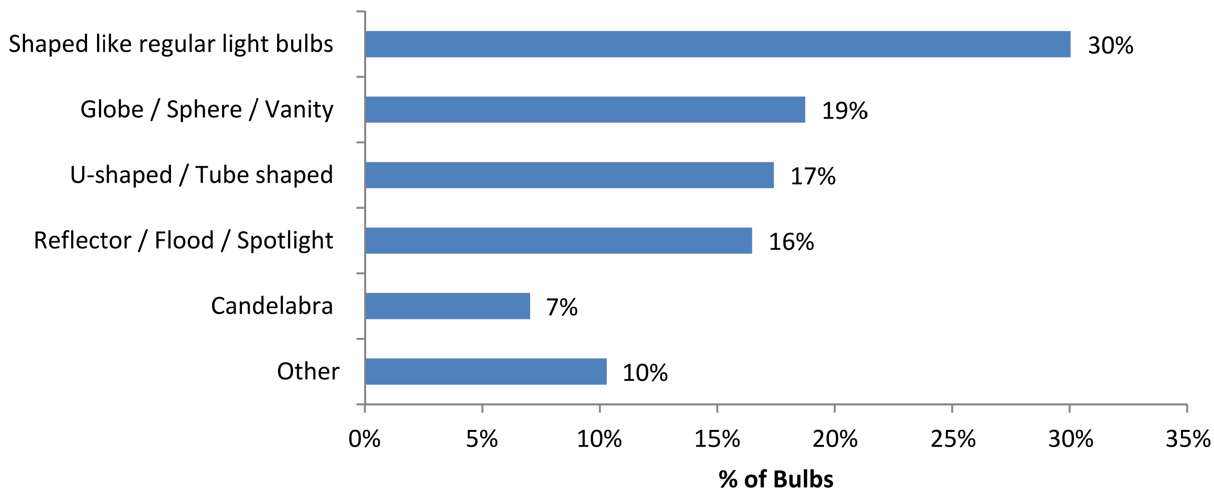


[21] Excluding "don't knows"

The total number of CFLs currently installed in respondent homes is 3,151, 83% of which are spiral or twisty shaped. Assuming 57 sockets per Montana home,[22] we estimate the current saturation to be approximately 16%. Note that this estimate is somewhat lower than the 22-25% CFL saturation estimates from on-site studies occurring in 2009 and 2011, but is consistent with other studies that have found households underestimate the number of CFLs they have installed in their homes by about 30%.

Respondents were asked separately about specialty (non-twist) CFLs currently installed. About one-half reported having at least one specialty lamp installed. The most commonly installed types are A-lamps (shaped like regular light bulbs,) followed by globes then U-or tube shapes. Reflectors and candelabras were the least commonly installed specialty CFLs.

Figure 4-4: Distribution of Specialty CFLs Installed (Multiple Responses Allowed)*

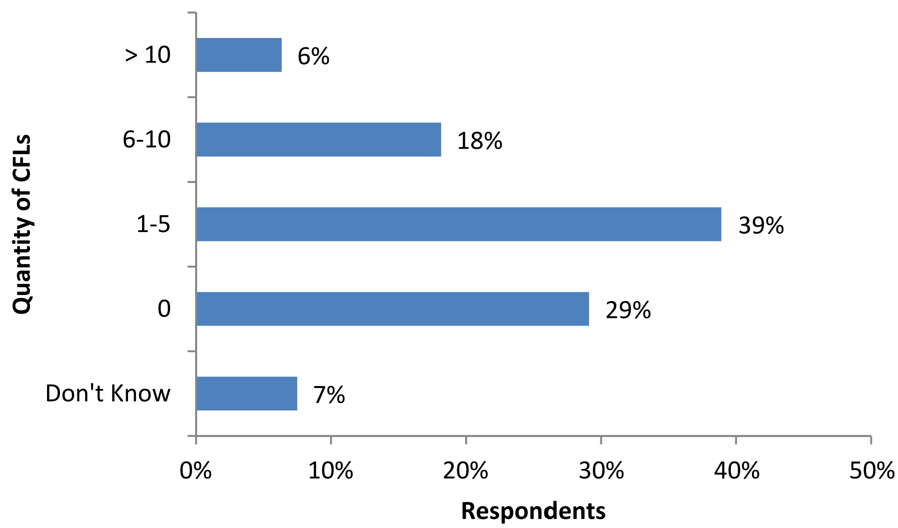


* Other responses included additional mentions of spiral or twisty CFLs and linear fluorescent lamps.

We sought to understand the portion of customers with CFLs in storage for later use. Among the 347 contacts asked how many CFLs they were storing for use as spares or to be installed at a later date, 29% reported not storing any CFLs, 39% were storing 1-5 CFLs, and the remainder were storing over 6 CFLs. Of the CFL bulbs in storage, 84% are spiral or twist CFLs.

22 Estimate taken from RBSA Single Family Characteristics and Energy Use Report prepared by Ecotope, Inc.

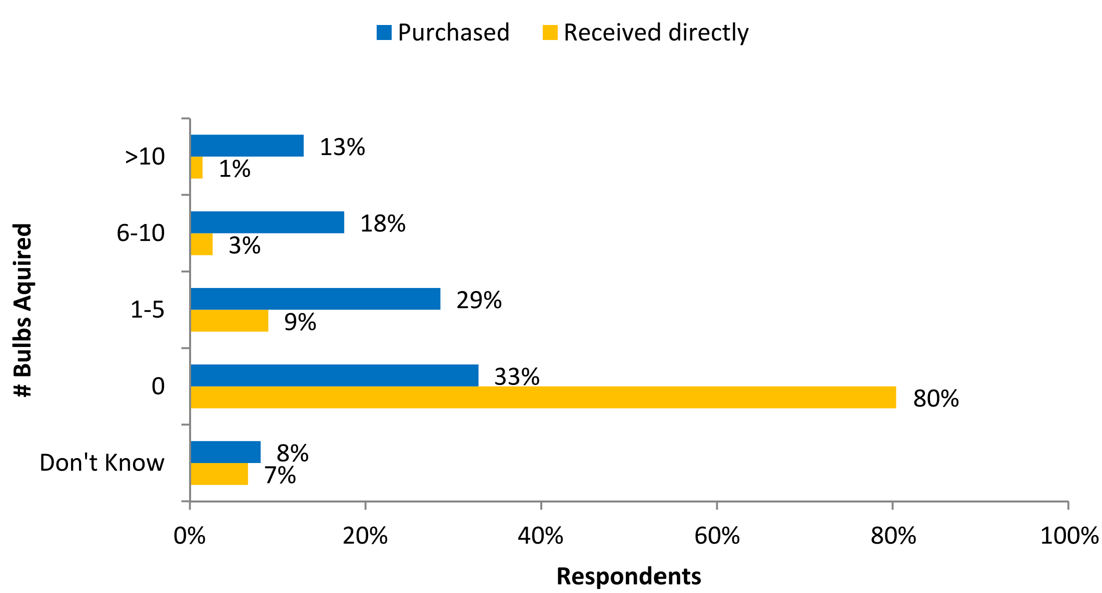
Figure 4-5: Quality of CFLs in Storage (n=347)



4.3.2.1 2014 Purchases

To understand consumers' recent purchases, we asked respondents about the bulbs they acquired in 2014. Sixty-three percent of respondents reported acquiring at least one CFL in 2014. Fifty-nine percent reported purchasing a CFL in 2014, while 13% reported receiving one directly through an outreach event or direct distribution. Respondents reported acquiring between zero and 45, with an average of six.

Figure 4-6: Number of 2014 CFLs Acquired CFL by Method (n=347)

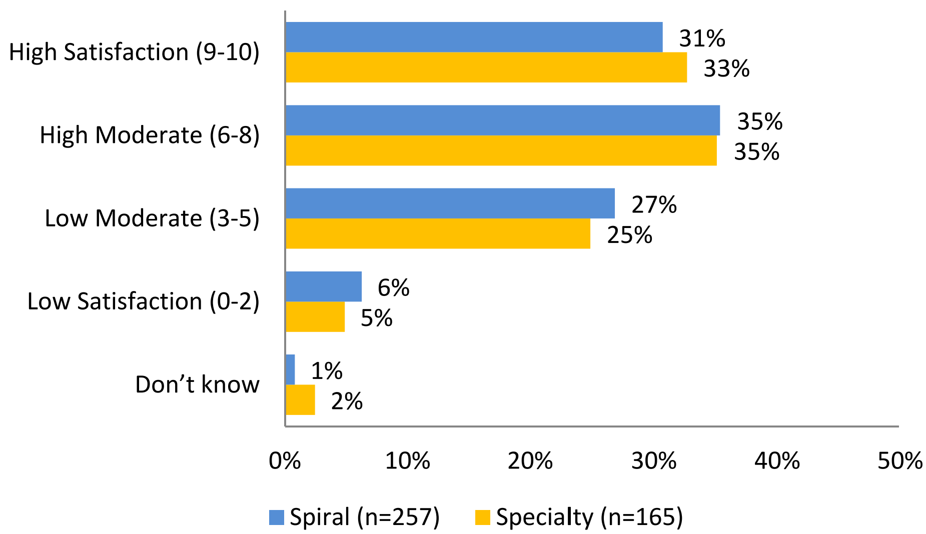


Of the bulbs acquired in 2014, 83% were spiral/ twisty shaped. Fifty-five percent of acquired bulbs are installed, while 43% are stored for later use.

4.3.3 CFL Satisfaction

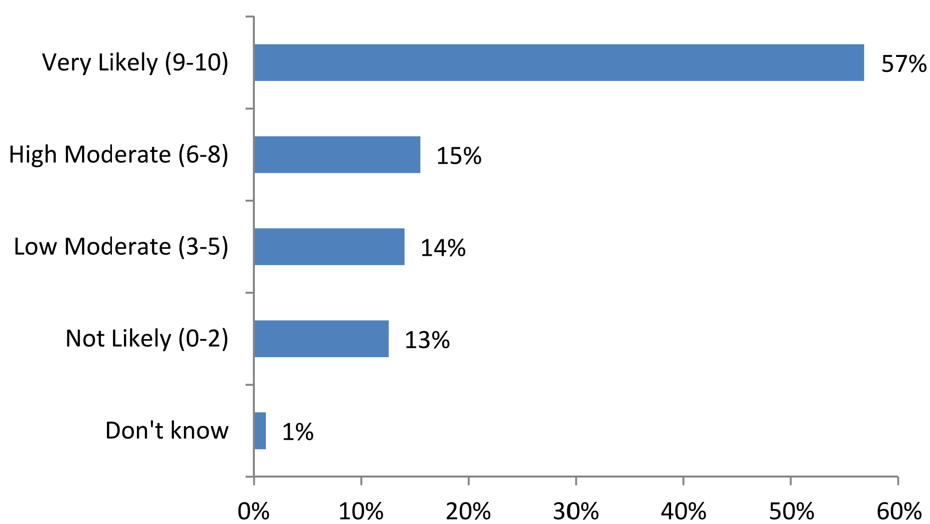
Satisfaction with spiral CFL products was mixed. Thirty-one percent reported high satisfaction, 19% moderate satisfaction, and 27% moderately low satisfaction. Six percent of respondents reported low satisfaction with their twisty CFL bulbs. Specialty CFLs received slightly higher satisfaction ratings.

Figure 4-7: CFL Satisfaction Rates (0-10 Scale)



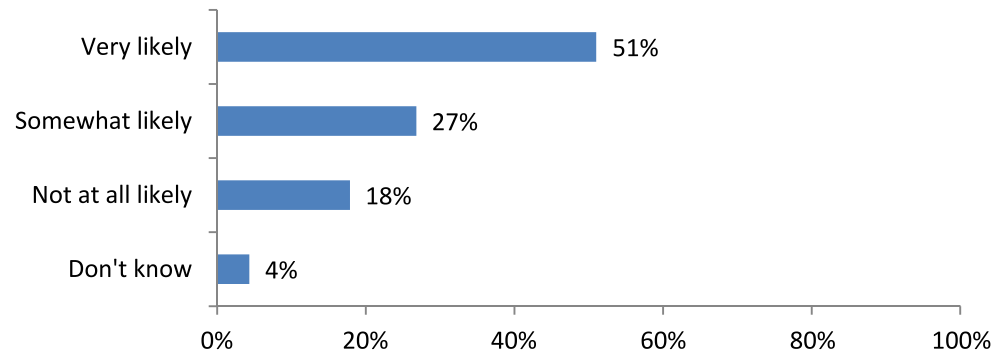
When a currently installed CFLs burns out, nearly 60% of respondents report they will be very likely to replace it with another CFL.

Figure 4-8: Likelihood of Replacing CFL with another CFL (0-10 Scale) (n=271)



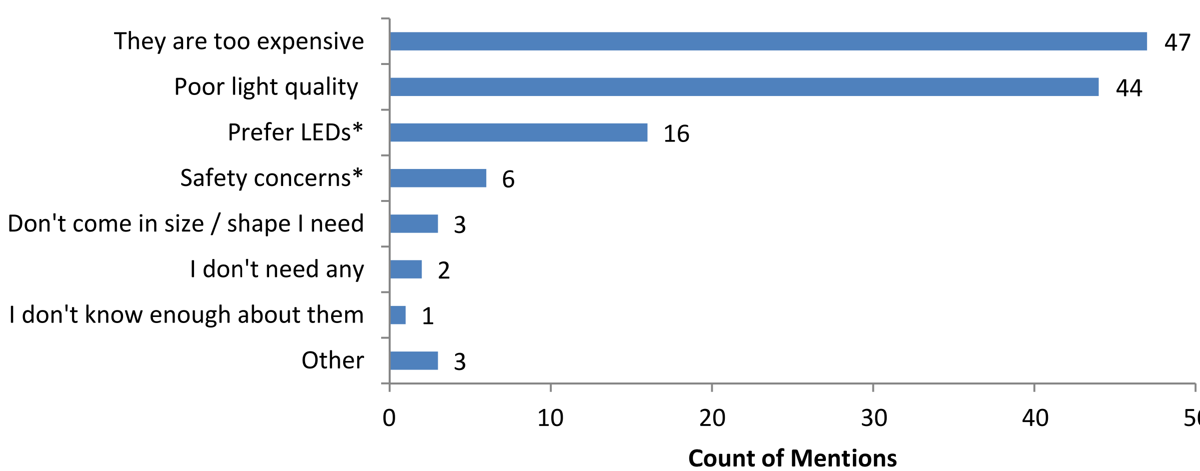
Fifty-one percent of respondents stated they are very likely to purchase a CFL bulb for their home in the future.

Figure 4-9: Likelihood of Future CFL Purchase (n=347)



The 62 contacts (18%) reporting they would not likely purchase a CFL for their home in the future provided their rationale. Thirty-five respondents provided open-ended responses that were re-coded and are reflected below. The most common reason for not purchasing CFLs in the future is perception that they are too expensive (provided by 47 of 62, or 76% of those unlikely to purchase in the future) followed closely by concerns about poor light quality (mentioned by 44 of 62, or 71%). Indicating widespread availability, no respondents checked the pre-coded options *"I can't find them"* or *"I don't know where to buy them."* In the open-ended "other" category, two primary reasons emerged: a preference for LEDs and concerns about the safety of CFLs. Topics related to safety included concerns about disposal, mercury, and radiation. The remaining mentions included in the "other category" are: a renter who has little incentive to purchase bulbs, a contact that resents government interference, and a contact that prefers incandescent lamps.

Figure 4-10: Reason Unlikely to Buy CFLs in Future * (Multiple Mentions Allowed)



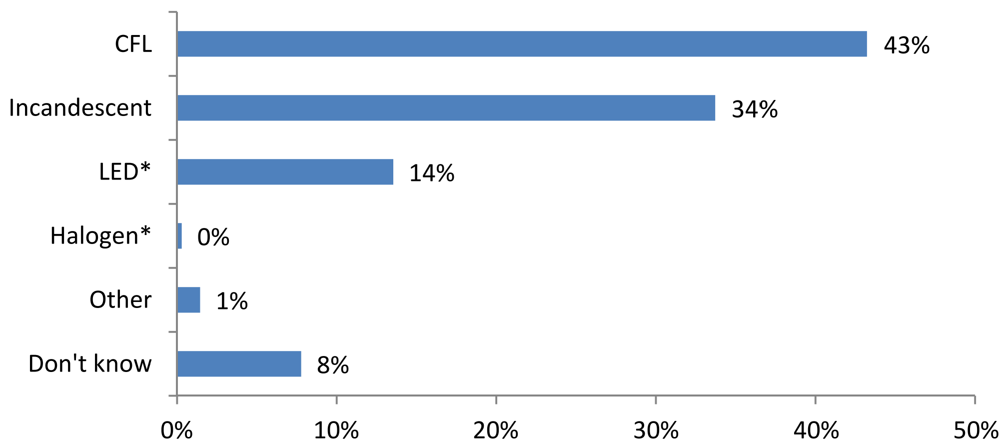
* Categories with an asterisk indicate recoded open ended responses. Respondents clicked all reasons that applied, and the graphic above summarizes count of mentions, so total count may exceed number of respondents.

Open ended responses included:

- *"Need HAZMAT if one [CFL] breaks"*
- *"I'm afraid they may be harmful. Too much hassle to dispose properly"*
- *"They are obsolete, because of LEDs. LEDs should be the issue with this survey"*
- *"They contain mercury and LED lights work better"*
- *"They take too long to light up"*

When faced with a choice between CFL and regular incandescent light bulbs, respondents indicated a slight preference of CFLs over incandescent lamps. Coded open-ended responses indicate 14% prefer LEDs. Other responses included the cheapest option and 'it depends.'

Figure 4-11: Preference – CFL vs. Incandescent (n=347)



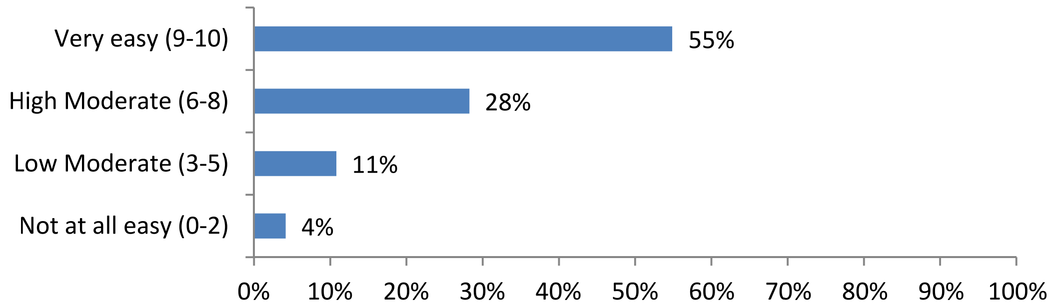
* Indicates a coded "other" open-ended response.

Open-ended responses included:

- *"It depends. I prefer some lights to be bright instantly rather than warming up before they're at their brightest."*
- *"Regular old-fashioned light bulb is preferred"*
- *"LED, but they're currently too expensive"*
- *"Whatever is cheaper and I believe CFLs are more expensive"*
- *"LED because they don't get hot and also low energy"*

Over half of respondents found it very easy to identify energy efficient bulbs where they purchase light bulbs. Of the 361 responses, seven "don't know" responses (2%) were removed from analysis for a total of 354 respondents.

Figure 4-12: Ease of Finding Energy Efficient Lightbulbs (0-10 Scale) (n=354)



Respondents most commonly reported shopping at discount and mass merchandise stores, such as Walmart, K-Mart, or Target. The majority of respondents indicated they had seen CFLs and LEDs at home centers and hardware stores, with fewer people indicating that these bulbs are available at supermarkets or drug stores.

Table 4-2: Shopping Options and CFL and LED Availability (n=361)

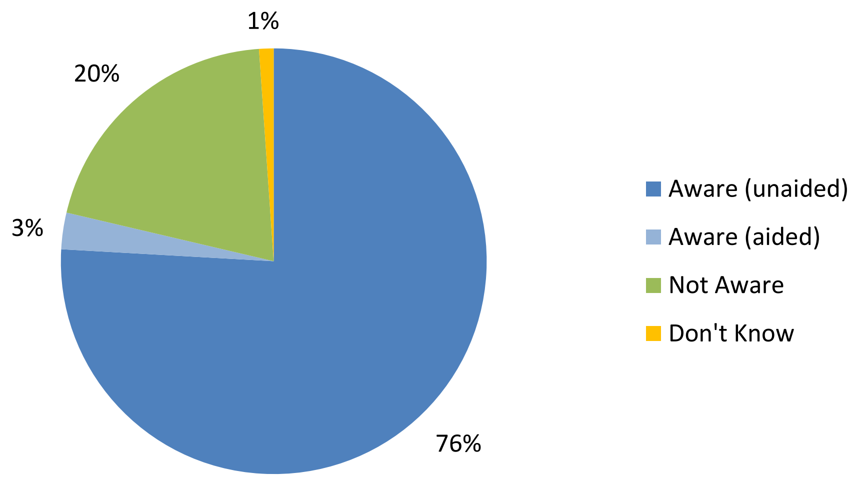
Store	Frequenting Store	Seen CFLs here?	Seen LEDs here?
Discount or mass merchandise store (Walmart, K-Mart, Target)	75%	74%	39%
Home center (Home Depot, Lowe's)	73%	82%	62%
Hardware stores (ACE, True Value, Do it Best)	71%	78%	49%
Buying clubs (Costco, Sam's Club)	58%	58%	36%
Supermarket or food store (Albertson's, Safeway, Rosauers)	55%	40%	12%
Drug stores (Walgreens, CVS)	34%	27%	9%
Lighting supply store or lighting showroom *	9%	64%	61%

* Note only 33 respondents reported frequenting lighting supply stores or show rooms.

4.4 LED Awareness

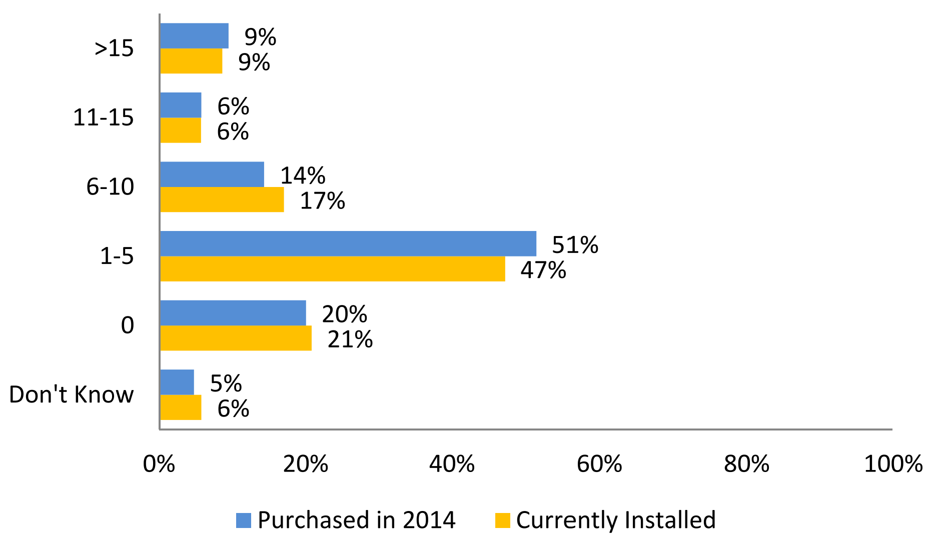
Awareness of LEDs is relatively high given how recently these products have become available. (Figure 4-13) Seventy-six percent of respondents had heard of LEDs unaided. When prompted with a verbal or written description of the definition of an LED, an additional 3% said they had heard of LEDs for a total of 79% awareness.

Figure 4-13: LED Awareness (n=361)



Thirty-two percent of LED-aware respondents (111 of 350) have purchased at least one LED bulb, 76% of whom did so in 2014.[23] Ninety-six percent of LED bulbs acquired in 2014 were installed, indicating that few customers are storing LEDs for later use.

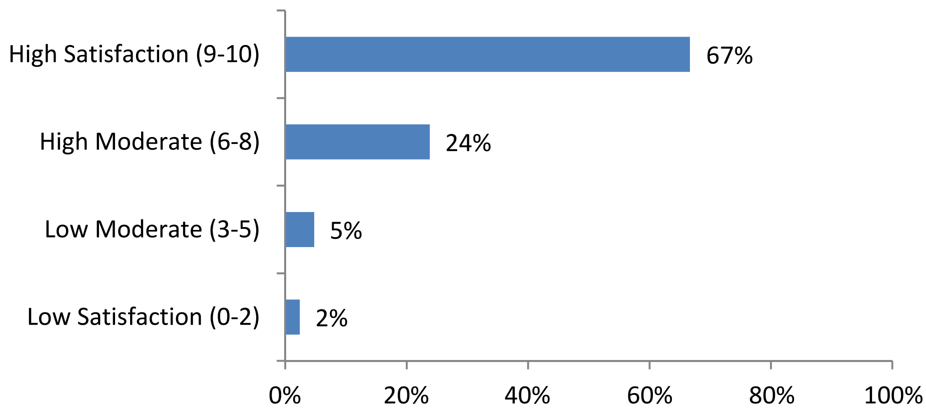
Figure 4-14: Quantity of LEDs Purchased in 2014 and Currently Installed



[23] Indicating that 24% of the sample reported purchasing an LED in 2014.

Eighty four (of 111) contacts currently have at least one LED installed in their home, all of whom answered questions about their satisfaction with these products. Satisfaction ratings were higher for LEDs than both standard spiral CFLs and specialty CFLs, with 67% of respondents offering ratings of 9 or higher on a 0-10 scale.

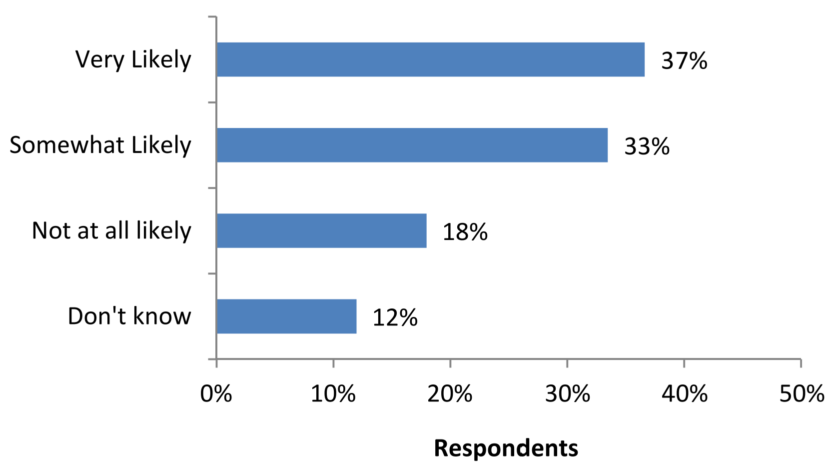
Figure 4-15: LED Satisfaction (0-10 Scale) (n=84*)



* Excludes two “Don’t know” responses.

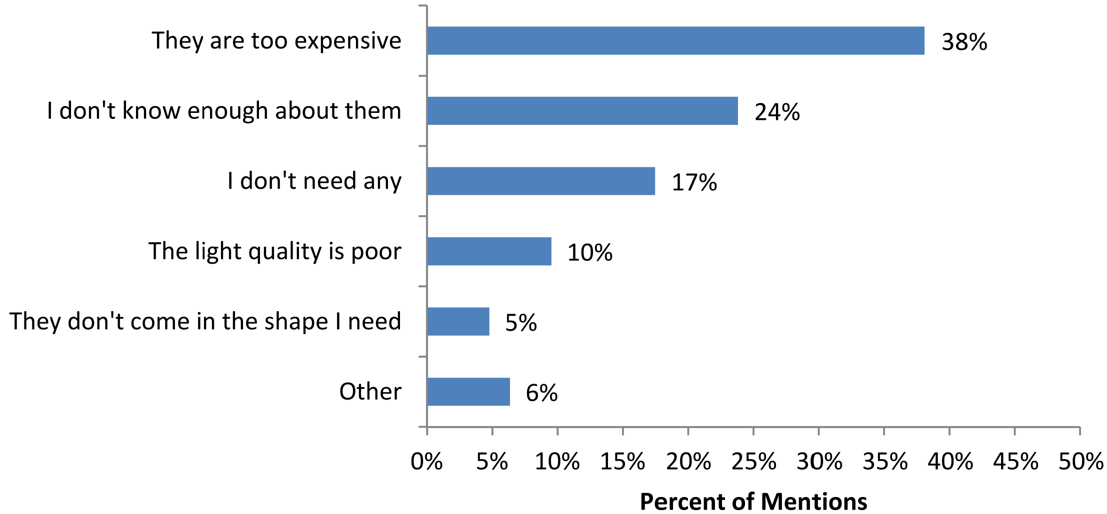
Thirty-seven percent reported they would very likely purchase an LED bulb for their home in the future, one-third were somewhat likely, while 18% indicated they were not at all likely. Twelve percent responded “don’t know”.

Figure 4-16: Likelihood of Future LED Purchase (n=284)



Among those unlikely to purchase an LED in the future, the most common reason, given by 38% of respondents, was the price of LED products. Another 24% of respondents indicated that they did not know enough about LEDs. “Other” responses were recoded and categorized. Most of these comments related to a perception of LEDs having poor light quality and included comments about color, longevity, and a comment about the bulbs being too bright.

Figure 4-17: Reasons Unlikely to Purchase an LED (n=51, Multiple Responses)

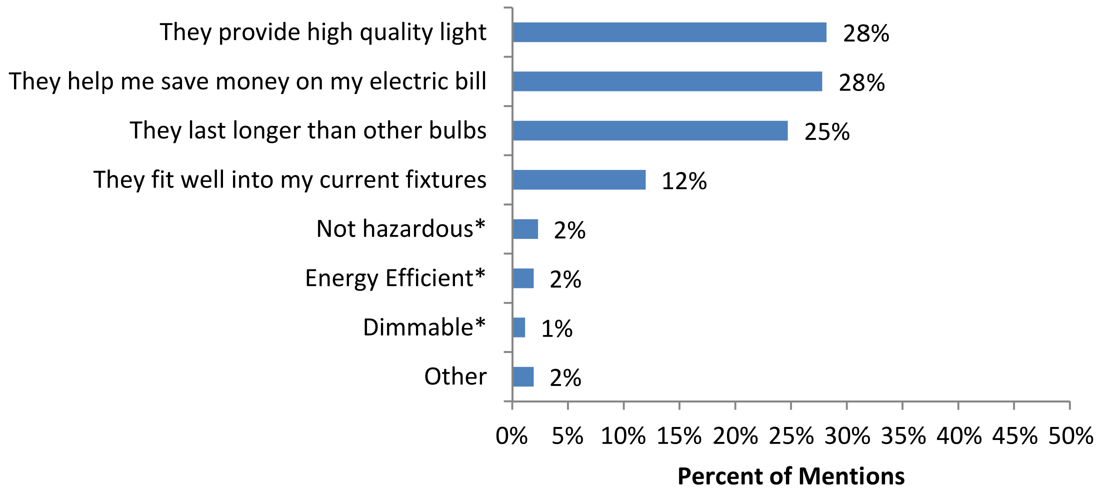


Open-ended responses included:

- *"Not enough incentives over CFLs to warrant the price"*
- *"We both had cataract surgery, and afterwards the LED bulbs were too bright"*
- *"Not suitable in table lamp applications since majority of light is projected up"*
- *"Don't like the type of light emitted"*
- *"They did not last and/or put out adequate lighting"*
- *"They are for a rental unit, not our home"*

Reasons contacts were likely to purchase an LED in the future included LEDs are perceived to provide a high quality light (28%), and they help save money on the electric bill (28%). Other reasons included the expected life of the bulb, and that it fits well into current fixtures.

Figure 4-18: Reasons Very Likely to Purchase and LED (n=104, Multiple Responses)



Representative open-ended responses:

- *"Does not have mercury that CFLs have"*
- *"Easy to dispose of"*
- *"I prefer the color of light"*
- *"Good for the environment"*
- *"Low energy use and better light, less maintenance"*
- *"They work on dimmers"*

4.5 Demographics

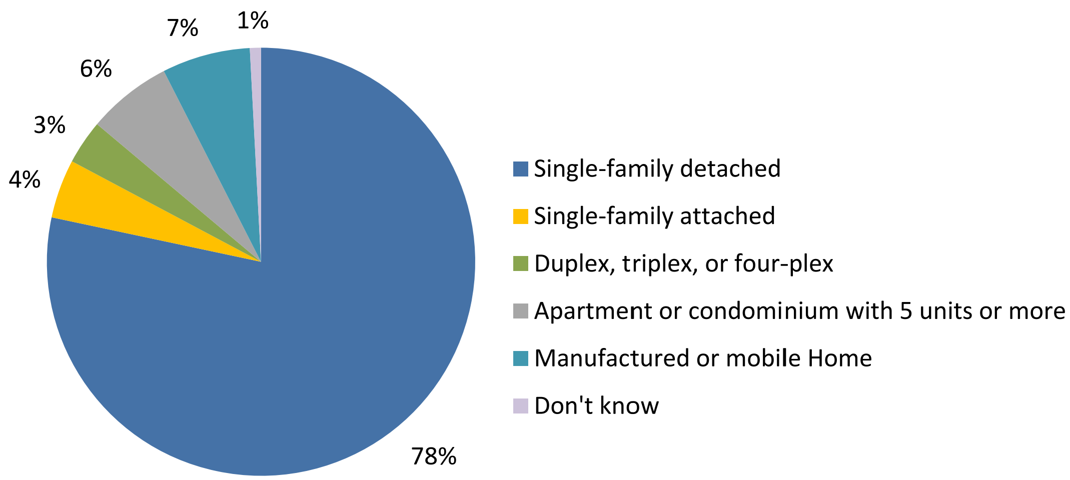
Respondents were fairly evenly distributed, although those 55 and older were overrepresented relative to the census representation. Just over half of respondents had a landline (59%).

Table 4-3: Respondent Age

Age Group	Frequency	Percent	Census
>75	43	12%	9%
65-74	86	24%	11%
55-64	92	25%	18%
45-54	32	9%	19%
35-44	39	11%	15%
25-34	36	10%	16%
18-24	6	2%	11%
Prefer not to answer	27	7%	

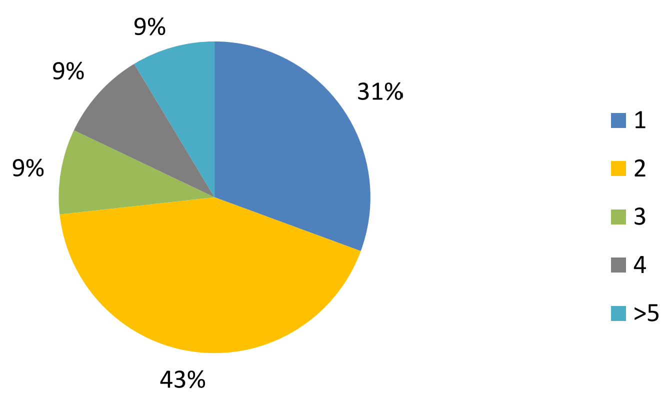
The majority of respondents live in a single-family detached home (76%). Eighty-three percent owned their home.

Figure 4-19: Type of Home (n=441)



Most respondent households contained two occupants (43%).

Figure 4-20: Size of Household (n=361)



5 Conclusions

NorthWestern Energy (NWE) has offered program options to promote energy efficient residential lighting under the E+ Residential Lighting program since 2005. Over the past 10 years, several program components have worked together to provide a variety of means through which customers could obtain free or discounted energy efficient lighting products, primarily Compact Fluorescent Lamps (or CFLs).

Substantial changes are occurring in the national lighting market, driven by implementation of the 2007 Energy Independence and Security Act (EISA), resultant shifts in lighting product mixes, declining costs for solid state LED products, and emerging halogen lighting products. In February 2015, NWE contracted with Nexant, Inc. to conduct targeted comparison and market research designed to understand the current state of the market for energy efficient lighting products in Montana, with specific focus on awareness, installation, and saturation of CFLs.

This report presents the results of this rapidly-deployed research and summarizes the findings from three sources of information: a review of recent existing research on the national and regional lighting market; interviews with contacts from other Northwest program administrators; and a survey of over 300 NWE residential customers about their lighting product options.

5.1 Findings

5.1.1 Literature Review

A variety of indicators are used to assess the state of local markets for CFLs, including: sales volumes, shelf space, saturation estimates, and customer acceptance. While CFLs have become a commonly-stocked efficient lighting option and awareness of the product is high, new lighting products are entering the market. Recent studies have found that new lighting products may be creating confusion and causing lower levels of respondents to report ever purchasing a CFL. Two Northwest organizations, the Northwest Energy Efficiency Alliance and Energy Trust of Oregon, observed reduced shipments of CFLs after withdrawing retail incentives. Energy Trust returned to the retail program model to protect the shelf space that had been allocated to CFLs.

Without common agreement about the definition of a transformed market, we turned to the Diffusion of Innovations theory that underlies the concepts behind technology adoption. Using the adoption curve, we would expect a threshold of 50% sales and saturation, corresponding with the shift from “early majority” to “late majority” as an indicator that it is time to remove product incentives and market support. CFL sales and saturation are not at that 50% level. Nevertheless, as the baseline shifts to EISA-compliant incandescent and halogen bulbs and LEDs become a more viable product option, program planners may decide to allocate incentives to new lighting technologies or focus on subsidizing efficient alternatives for products that are exempt from EISA.

Our review of the current market data found evidence of substantial shifts in the mix of product shipments in 2014, indicating that halogen bulbs will likely command an increasing portion of retail shelf space in the near future.

5.1.2 Comparative Research

Retail lighting programs remain a major component of the residential energy efficiency efforts at all of the comparison organizations, all of whom were efficiency program administrators in the Pacific Northwest. Even with a changing baseline, CFLs remain a cost-effective offer for customers and utilities. All of the comparison organizations provided incentives for LEDs in 2014, representing between 12-50% of total product units.

There is no common framework or definition for determining market transformation among contacts at comparison organizations, a concept several contacts noted leaving for NEEA to assess. Contacts at Energy Trust were the most direct in recommending an overall shift from a point estimate (sales or saturation) toward using multiple indicators to determine the stability of the CFL market. Specialty lighting products are difficult to approach with a market transformation strategy; these products are too specialized and represent numerous niche applications appropriate for a small portion of overall sockets. Many specialty applications are exempt from EISA and driven by considerations of fit, appearance, and size. They can be expensive and remain a relatively low portion of the total bulbs incented, especially in Montana.

5.1.3 Customer Survey

Awareness and access. Ninety-six percent of the surveyed population is aware of CFLs. Eighty-five percent of the population has purchased at least one CFL, and respondents indicate CFLs are available on the shelves of large stores such as Home Depot/Lowe's Home Centers, discount or mass merchandise stores such as Walmart, K-Mart, and Target, or hardware stores. Seventy-seven percent reported having at least one CFL currently installed.

Satisfaction. Satisfaction rates for CFLs were very high for a third of the population, and moderately high for another third. Fifty-one percent of respondents stated they are very likely to purchase a CFL bulb for their home in the future. While NorthWestern Energy customers are familiar and largely satisfied with CFLs, nearly 20% indicated that they are unlikely to purchase CFLs, primarily because of the cost of the bulb and poor light quality. Several contacts spontaneously mentioned concerns about mercury in CFL lamps.

LED Awareness. Seventy-nine percent of respondents were aware of LED lamps, although far fewer households had an LED installed (24% reported having at least one LED installed, compared to 77% for CFL). Among households with an LED installed, satisfaction rates were higher than for CFLs, with 67% of contacts very satisfied with their LED. The top three reasons for not purchasing LEDs include the expense of the bulbs, not knowing enough about them, and not needing any.

Acquisition and Saturation. Sixty-three percent of respondents acquired a CFL bulb in 2014. On average 9 CFLs are installed per household, but this value ranges from zero to more than

40. The estimated CFL socket saturation rate is approximately 16%[24]. Nearly a quarter of respondents purchased an LED in 2014. On average, 2 LEDs are installed per household, ranging from zero to forty-eight. The estimated LED saturation rate gleaned from survey respondents is 3%.

5.2 Conclusions

5.2.1 CFLs will continue to need retail support

CFL saturation is between 16-25% in Montana, meaning that a substantial number of sockets continue to hold incandescent bulbs. The fact that CFL saturation appears to have plateaued in Montana and elsewhere in the Pacific Northwest could provide evidence of persistent barriers associated with putting CFLs in certain sockets. On the other hand, the current saturation estimates indicate that the approximately 60% of sockets that continue to hold incandescent lamps will contain a different product three years from now. Given the increasing shipments and availability of EISA-compliant halogen products, CFLs will continue to compete with a less efficient lighting product. If CFL shelf space shrinks or disappears, the likelihood that subsequent product choices reflect the most efficient options will be low.

As EISA continues to change the mix of available lighting, new choices will be available for consumers. Several recent studies have identified the continued need for retail level information about lighting products to help consumers navigate their next choice—which for some households will mean a break from all incandescent options for the first time.

5.2.2 Program adaptation will be necessary

Lighting remains a primary contributor to residential savings for many program administrators. However, EISA is affecting the efficiency of the lighting baseline and resulting in decreased average savings per bulb and a drop in overall savings. Thus, savings from energy efficient lighting are becoming more difficult, and more expensive to obtain cost effectively.

The dynamic changes occurring in the lighting market indicate a need for on-going monitoring and review of residential lighting as markets and prices and products continue to change. The resources required to track these shifts in supply and pricing and determining the timing for market exit indicate the value of leveraging research occurring at the regional and national level. While CFLs will need support to maintain retail shelf space in 2015 and 2016, it is unclear what the market will require post-2016. When it becomes clear that CFLs no longer require programmatic support, it will be necessary to plan for a staged, orderly withdrawal from the market in order to maintain long-established relationships with key market channel partners in residential lighting, manufacturing, and retailing. The next generation of products and programs will benefit from these successful relationships.

[24] Note that prior studies have found self-reported saturation to be approximately 30% lower than the saturation found on-site. A 30% increase would result in a saturation estimate of approximately 21%, consistent with the 2009 NorthWestern Energy End-use Study and only slightly lower than RBSA—both of which relied upon on-site counts.

5.3 Recommendations

Maintain involvement in retail lighting programs through Fiscal Year (FY) 2015/16. The full effect of EISA is only now emerging and the dynamic shifts in lighting product assortment put the shelf space currently allotted to CFLs and LEDs at risk. If those products do not remain on the shelves, the least efficient option—an EISA-compliant incandescent/halogen—will become the default option.

Monitor market developments by tracking shelf studies, stock and flow research, and other evidence of structural changes in the lighting market. Limited resources for Montana-specific data mean leveraging the research occurring elsewhere and tracking the adjustments occurring at the Regional Technical Forum. NorthWestern should consider purchasing CREED data, and/or track the manufacturer shipment data coming out in reports published by Northeast Energy Efficiency Partnerships, the Consortium for Energy Efficiency, the Department of Energy and others. If the market share of halogens continues to expand and/or shipments and shelf space associated with CFL and LEDs shrinks, additional market supports will likely be needed.

Prepare for rapid program adjustments and assume that lighting program activities will need to be reviewed every 12-18 months. Multiple competing forces are affecting the residential lighting market, many of which are hard to predict with certainty. Establishing a framework for tracking key indicators and adjusting programs annually will likely be necessary for the next 3-5 years.

Consider including LEDs in the FY 2015 program. LEDs are quickly becoming a viable lighting product, but many households have yet to obtain their first LED. Direct distribution and retail promotion can encourage consumers to try these new products. The performance advantages, once experienced, may push these products more rapidly up the adoption curve.

Appendix A Customer Survey

Q1. Have you ever heard of compact fluorescent light bulbs or CFLs?

Yes – **Skip to Q3** No

Q2. Compact fluorescent light bulbs, or CFLs, are small fluorescent bulbs that fit in regular light bulb sockets. The most common CFLs look different from standard bulbs. They are often made out of thin tubes of twisted or swirled glass. Some CFLs look more like regular light bulbs. Do you know of light bulbs like these?

Yes No

Q3. Compact fluorescent light bulbs, or CFLs, also come in special shapes such as reflectors, candelabras and globes. Do you know of these special-shaped CFLs?

Yes No

If you answered "No" to Q1, Q2 and Q3, skip to Q17

Q4. Have you **EVER** purchased any CFLs? Check all that apply.

No, never
Yes, purchased online
Yes, purchased from stores

Q5. How many CFLs do you currently have installed in your home? __________ **If none, skip to Q9**

Q6a. Of those CFLs installed in your home, how many are spiral or twisty shape? If none, write "0".

Q6b. If you have at least one spiral or twisty shape CFL installed, please rate your satisfaction with it/them. (0-10 Scale – Not at all Satisfied to Extremely Satisfied.)

Q7a. How many of each of the following types of specialty CFLs are installed in your home? If none, write "0". Shaped like regular light bulbs; U-shaped or Tube shaped; Globe, Sphere or Vanity; Reflector, Flood, or Spotlight; Candelabra; Other - please specify:

Q7b. If you have at least one (of any type) installed, please rate your satisfaction with it/them. (0-10 Scale. Not at all Satisfied to Extremely Satisfied.)

Q8. When one of the CFLs you have installed burns out, how likely are you to replace it with another CFL? (0-10 Scale. Not at all likely to Very likely)

Q9. How many CFLs are you storing for use as spares or to be installed at a later date? ______ **If none, skip to Q11**

Q10. Of those you are storing (mentioned above), how many are spiral or twisty shape? ______

Q11. Specifically in 2014, how many CFL light bulbs have you acquired? Please list the quantity you **purchased** separately from the quantity you **received directly** (for example, through an event)? If a package contained more than one bulb, please count each bulb separately. **If none, skip to Q14**

__________ Purchased

__________ Received directly

Q12. Of those you purchased and/or received in 2014, how many were spiral or twisty shape? ______

Q13. Of those you purchased and/or received in 2014, how many were installed and how many were stored for later?

Q14. How likely are you to purchase a CFL bulb for your home in the future?
- Not at all likely
- Somewhat likely – **Skip to Q16**
- Very likely – **Skip to Q16**

Q15. Why do you think you will not likely buy CFLs in the future? Check all that apply.
- They are too expensive
- I can't find them
- I don't know where to buy them
- I don't know enough about them
- I don't need any
- They don't come in the size or shape I need
- The light quality is poor
- Other reason - please specify: ____

25

25

Q16. When faced with a choice between CFL and regular incandescent light bulbs, would you say that you prefer CFLs, prefer incandescent, or prefer some other type of bulb? Check only one.

CFL
Incandescent
Other - please specify: ___________________________

Q17. Have you heard of light emitting diodes or LED light bulbs?

Yes – **Skip to Q19** No

Q18. LED light bulbs can be used in the same types of fixtures as regular incandescent bulbs but are shaped somewhat differently. They produce light using semiconductor chips and use a lot less energy than regular incandescent bulbs. Do you know of light bulbs like these?

Yes No

If you answered "No" to Q17 and Q18, skip to Q24

Q19. Have you **EVER** purchased any LED bulbs, other than LED nightlights or holiday light strings?

Yes No – **Skip to Q22**

Q20. Specifically in 2014, how many LED bulbs did you purchase? If a package contained more than one bulb, please count each bulb separately. If none, write "0". _______

Q21a. How many LED bulbs are currently installed in your home? If none, write "0". _______

Q21b. If you have at least one LED bulb installed, please rate your satisfaction with it/them. (0-10 Scale. Not at all satisfied to extremely satisfied.)

Q22. How likely are you to purchase an LED bulb for your home in the future?

Not at all likely Somewhat likely (Skip to Q23) Very likely

Q22a. Why do you say **Not at all likely**?

They are too expensive
I can't find them
I don't know where to buy them
I don't know enough about them
I don't need any
They don't come in the size or shape I need
The light quality is poor
Another reason: ______________________

Q22b. Why do you say **Very likely?**

They last longer than other bulbs
They provide high quality light
They help me save money on my electric bill
They fit well into my current fixtures
Another reason: ______________________

Q23. When faced with a choice between CFL and LED lightbulbs would you say that you prefer CFLs, prefer LEDs or prefer some other type of bulb?

Q24. Thinking about where you purchase light bulbs, how easy is it for you to identify energy efficient light bulbs?

Q25. Below are different types of stores that may exist in your area. First, please indicate if you shop at that type of store. If you do, please also indicate if you have seen CFL or LED bulbs (not including LED holiday light strings) for sale in those stores?

To help understand how well NorthWestern Energy programs are serving all types of customers, we have a few questions about your household. Please be assured that all responses will be kept

Q26. What type of home do you live in?
- Single-family detached house
- Single-family attached home (such as a townhouse)
- Duplex, triplex, or four-plex
- Apartment or condominium with 5 units or more
- Manufactured or mobile home
- Other – please specify: ______________________________

Q27. Do you own your home or rent? Own Rent

Q28. Including yourself, how many people live in your home? ______

Q29. In what year were you born? ______

Q30. Do you live in a household that has a landline telephone? Yes No

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NorthWestern Energy

2015 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.

Lighting in both the commercial and residential sectors continues to contribute a significant portion of the electric savings as in recent years.

A comprehensive independent evaluation of all NorthWestern Energy Demand Side Management (DSM) and Universal Systems Benefits (USB) programs was completed in 2012. The evaluation concluded that NorthWestern Energy's programs deliver cost effective natural gas and electric savings, are well-run and follow more than 50 best practices. The evaluation provided specific recommendations for program changes, some of which relate to communication, education, and marketing. Recommendations continue to be incorporated into the communications plan as appropriate and applicable.

Nationally and locally, there is continued focus on energy efficiency, renewable energy, and "green" or sustainability efforts.

The energy efficiency targets and the continued awareness of "green" help frame the need and opportunities set forth in this communications plan. The plan is intended to be an active, adaptive product--one that establishes the framework for communications strategies designed to help achieve energy efficiency targets and can be modified to meet changing needs and opportunities.

The plan is implemented consistent with NorthWestern Energy Efficiency Plus (E+) graphics and image standards and strategies. The section of NorthWestern Energy's website related to E+ Programs continues to be updated as part of continuing web redesign and to reflect current program offerings.

The plan refines and sustains communication strategies for the residential, low income, small-scale renewable generation, and commercial/industrial programs. The following table lists the programs by customer sector addressed in the plan.

Table 1: E+ Programs

ELECTRIC PROGRAMS	NATURAL GAS PROGRAMS	CUSTOMER SECTOR
E+ Audit for the Home	E+ Audit for the Home	Residential
E+ Free Weatherization/Fuel Switch	E+ Free Weatherization	Residential
E+ Residential Lighting		Residential
	E+ Residential Rebates Program—Existing Homes	Residential
	E+ Residential New Homes Program	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 (NEEA)		All

Because the E+ programs are not offered to Large USB Electric Choice customers or to Natural Gas Choice customers, these customers are not targeted in the plan. Choice customers are transmission and/or distribution customers who purchase their supplies of electricity or natural gas in the wholesale market.

GOAL

Effectively and efficiently market E+ programs to achieve 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 sector projects

AUDIENCES

- NorthWestern Energy employees
- NorthWestern Energy program contractors and partner contractors
- Residential, commercial and industrial customers eligible for participation in NorthWestern's programs (electric and natural gas supply)
- Trade Allies: electrical vendors—i.e. Crescent Electric, Grainger, WesCo, CED; service providers—electricians, refrigeration, HVAC, motors, architects, engineers, and insulation; distributors— of lighting, equipment; retailers—of CFLs, building supplies, appliances, air sealing, and water measures; building contractors and general contractors; HVAC and insulation contractors; and trade associations—i.e. AIA, ASHRAE, Montana Hospital Association, Montana Hospitality and Lodging Association.
- Public officials and government departments

- Media—mass and trades
- Related 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 customer participation in the E+ 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 (see Exhibit__(DLW-5b)).

TACTICS

<u>Residential Programs</u>

- Update program materials/resources (Web and Brochures)
- Coordinate display materials for Home Shows (Spring Shows run February – May; selected Fall Shows run September-October)
- Execute natural gas program campaign
- Develop updated program-at-a-glance summary
- Provide CFL In-Store instant coupon offerings to increase installation of CFLs, and incorporate educational messages into various residential lighting communications used 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 for Small Businesses
- Continue contacts by program contractors/community relations managers (CRMs)
- Update Customer Service Representative (CSR) training for new CSRs

- Include energy saving messages in Energy Connections and news releases Incorporate energy efficient products into contest offerings for customers
- Participate in local events as appropriate
- Contact various program trade allies regarding informational updates and solicit new trade allies (Preferred Contractors, lighting retailers, homebuilding associations)

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.) and execute new project case studies on commercial/industrial customers
- Integrate commercial program messages into tradeshow displays
- Continue customer and trade ally contacts through program/partner contractors and CRMs
- Participate in local events where appropriate
- Conduct 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 programs, cross-market same sector programs, and highlight resources for more information by directing customers to website or program contact phone numbers. GENERAL AUDIENCES

Web/interactive media tools including Efficiency Plus (E+) web section of www.NorthWesternEnergy.com/EPlus, Facebook, YouTube, Twitter, 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 regarding individual program offerings 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, 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

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.

Commercial/Industrial Sector

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

Web/interactive media tools including Efficiency Plus (E+) web section of www.NorthWesternEnergy.com/EPlus, SEM, YouTube, and Twitter as appropriate. GENERAL AUDIENCES

Internal Communications throughout the year such as FYI, TEAM, iConnect, 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, E+ Commercial Lighting Rebate Program, or other E+ Rebate projects to demonstrate various types of customer participation and customer benefits. TARGETED TRADE ALLIES AND KEY CONTACTS AND TARGETED CUSTOMERS

Direct Mail to Trade Allies and targeted customers regarding individual program offerings 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. COMMERCIAL CUSTOMERS AND TRADE ALLIES

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

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

Support of 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.

NorthWestern Energy has defined an overall budget for marketing and communication for the electric and natural gas E+ programs of approximately $500,000. This includes mass media development and placement as well as all other marketing expenses.

MEASUREMENT

Program participation compared to resource acquisition targets will be used as one measure of the effectiveness of this communications plan.

The energy efficiency targets are based on a July 1 – June 30 year. USB programs operate on Calendar year.

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

Attached is a calendar for 2015 which will also be modified to meet changing opportunities and needs (see Exhibit__(DLW-5b)).

DSM/USB Communications Plan

		DSM/USB 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**	**Jan**
	R0x	**Residential**												
	R0x	**Tips--Electric (USB/DSM)**	Spot media and Campaigns			x		Residential electric customers	Act to save electricity; check out programs	Television; radio		Tips	Brochure	
	R0x	**Tips--Natural Gas (USB/DSM)**	Spot media and Campaigns				x	Residential natural gas customers	Act to save natural gas; check out programs	Television; radio		Tips	Brochure	
	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; Facebook/Twitter outreach*	Tradeshow and event handouts/sign-ups/display/brochures of all residential programs/resources in audit packets	
	R1x	Outreach	Targeted Direct Mail	Jan May Sep	January May Sep -- 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	Email notice of mailing		Direct Mail	
	R1x	Electric Baseload	Targeted Direct Mail	Oct	Fall	x		Residential electric baseload customers	Call to Action--Complete Energy Usage survey; follow-up on recommendations	Direct Mail	Email notice of mailing		Direct Mail Non-NWE production	
	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*	
	R2x	Mail-in Fixture/Sensor Rebate Offer	Web, Audits, Energy Connections		On-going	x		Residential electric customers	Call to Action--Install CFLs in High Use Locations (Educate--4L's) $ off for qualifying CFL fixtures and occupancy wall switch sensors			on-line application	Brochure	

DSM/USB Communications Plan

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10	R2a	Spring Trade Shows a)	CFL distribution (Missoula, Billings,Bozeman, 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 Email of event; CSR/CRM notice of mailing	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 coupon for $1 off on CFLs from Participating Retailers	Apr	Apr 22-Jun 14	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, Newspaper, web advertising, events, Retailer POP/Education	Email of mailing and qualifications	Reference, list of participating retailers	see media	
12	R2a	Fall Trade Shows a)	Displays, all programs, CFL distribution (Billings)	Sep	Sep	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/ workshops	Canvas Bags, Brochures/Signage	
13	R2x	Regional Buy downs- Simple Steps	Review POP/agreements for Regional efforts	Jan	Jan- Dec	x		Residential electric customers	Call to Action for CFLs	POP/Retailer ed		Info on CFLs and retailers		
14	R2x	E+ Home Lighting -- CFLs Fall Instant Coupon Offer	Direct Mail to residential electric customers for up to $1 off on CFLs from Participating Retailers	Oct	Tentative Oct 4 - 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; Direct Mail, Newspaper, billboard, web advertising, events, Retailer POP/Education	e-mail of mailing and qualifications	Reference, list of participating retailers	see media	
15	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 upgrades)	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	
16	R3x	Gas Savings Mass Media Campaign 1	Mass Media targeted at residential natural gas customers	Aug	Q 3-4		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	

DSM/USB Communications Plan

		<u>DSM/USB Communications Calendar</u> 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**	**Jan**
17	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	
18	R3a	Fall Tradeshows a)	Program Education in Natural Gas markets	Sep	Sep		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	
19	R0x	Special Events--CSR Training, Game Days	Promote natural gas energy efficiency programs in existing homes, partners with local trade allies		As needed	x	x	Residential natural gas space or water heating customers in existing homes; targeted Events	Call to Action--Participate in programs; prioritize 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	
20	R4x	***New Homes***	Promote energy efficiency in new homes, Training/promote high efficiency builders; train on new MT Code			x	x	Residential customers building new homes and construction trade allies		Energy Connections	E-mail of program qualifications and links; Training	Rebate forms, training events	Guide to new MT Code Publications for Trade Associations	
21	R4x	New Homes Natural Gas	Promote energy efficiency in new homes, Training/promote high efficiency builders; train on new MT Code	Sep	Sep and as approp.		x	Residential natural gas customers building new homes	Call to Action--install high efficiency heating or water heating measures; know the new MT code; explore going beyond code	Special Publication, Newspaper at Parade of Homes		Schedule/homes, link to all high efficiency builders	Brochures/New code handbook/Signage as needed	
22	R4x	New Homes Electric	Promote energy efficiency in new homes, Training/promote high efficiency builders; train on new MT Code	Sep	Sep and as approp.	x		Residential Electric Customers building new homes	Call to Action--install high efficiency heating or water heating measures; know the new MT code; explore going beyond code	Special Publication, Newspaper at Parade of Homes		Schedule/homes, link to all high efficiency builders	Brochures/New code handbook/Signage as needed	
23	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, Fall news release on NWE programs & funding		Description of program/discount and refer customers to Human Resource Councils to apply.	energy efficiency education materials	

DSM/USB Communications Plan

		DSM/USB 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	Jan
24														
25	C0	**Commercial ***											PowerPoint presentation for internal and key contractor use: Messages for Commercial Cust/Trade Allies	
26	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 and articles	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	
27	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 (on-line/special events) 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 notices, Program brochure, Newsletter	
28	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; presentations		**Description of offer and contact information**	**Brochure**	

DSM/USB Communications Plan

		DSM/USB 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	Jan
29	C3	***E+ Business Partners Electric Measures***	Promote custom incentives for electric cost effective energy efficiency measures in new or existing commercial/industrial facilities		On-going May- Jun & Fall emphasis	x	x	Commercial and industrial electric 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	
30	C3a	***E+ Business Partners Natural Gas Measures***	Promote commercial natural gas offering custom incentives for new or existing facilities		On-going 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	
31	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; Add Program contractors; on-line forms; list of events/training; resources	Brochure/Case Studies/Display Signage; presentations	

DSM/USB Communications Plan

		<u>DSM/USB Communications Calendar</u> 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	Jan
32	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 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; Add Program contractors; on-line forms; list of events/training; resources	Brochure/Case Studies/Display Signage presentations	
33	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 measures.	Direct Mail; e-mail; trade ally newsletters		Description of program, application, case studies as become available; Schedule of training events; links to other resources as appropriate	Direct mail, one-on-one, Web	
34	C5	***Motor Training***	Training/education/ CEU		Jun	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	
35	C6	***E+ Irrigation***	Promote custom incentives for cost effective electric irrigation measures		Apr Sep	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	
36	C9	***Building Operator Certification Training***	Training/education/ certification for facility managers; emphasis on schools, public buildings, non-profit hospitals		Mulitple pts	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	

DSM/USB Communications Plan

		DSM/USB 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	Jan
37	C10	***City of Bozeman Business Energy Project***	Promote energy efficiency in existing buildings in partnership with City of Bozeman, L &C, Broadwater, Jefferson Counties		On-going	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	
38	C11a	***E+ Commercial Electric Rebates -- Existing Buildings***	Promote rebates for qualifying energy efficient equipment and improvements in existing commercial facilities			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	
39	C11b	***E+ Commercial Electric Rebates -- New Construction***	Promote rebates for qualifying energy efficient equipment and improvements in new commercial facilities			x		Promote opportunities to commercial/industrial -- 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	
40		**Renewables**												
41	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; trade allies & Associations		Description of program; NWE publications; Qualified Installer list; Schedule of training events; List of events where NWE is present with display or speakers; links to other resources as appropriate	NWE publications and Brochures; Signage & presentations	
42	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; Spot Newspaper		Description of program; on-line enrollment	Brochure; signage	
43														

DSM/USB Communications Plan

		DSM/USB 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	Jan
44	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	
45														
46		*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.												
47														
48		**E+ Green is not a DSM program but is part of NWE's renewable offerings.												
49														

DSM/USB Communications Plan

			Q	R	S	T	U	V	W	X	Y	Z	AA
		<u>DSM/USB Communications Calendar</u> subject to change based upon need or opportunity	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	R0x	**Residential**											
	R0x	**Tips--Electric (USB/DSM)**											
	R0x	**Tips--Natural Gas (USB/DSM)**											
	R1x	***Residential Audits***											
	R1x	Outreach											
	R1x	Electric Baseload											
	R2x	***E+ Home Lighting -- CFLs***											
	R2x	Mail-in Fixture/Sensor Rebate Offer											

DSM/USB Communications Plan

			Q	R	S	T	U	V	W	X	Y	Z	AA
		<u>DSM/USB Communications Calendar</u> subject to change based upon need or opportunity	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
10	R2a	Spring Trade Shows a)											
11	R2x	E+ Home Lighting -- CFLs Spring Intant Coupon Offer											
12	R2a	Fall Trade Shows a)											
13	R2x	Regional Buy downs- Simple Steps											
14	R2x	E+ Home Lighting -- CFLs Fall Instant Coupon Offer											
15	R3x	***E+ Gas Savings for the Home***											
16	R3x	Gas Savings Mass Media Campaign 1											

DSM/USB Communications Plan

			Q	R	S	T	U	V	W	X	Y	Z	AA
		DSM/USB Communications Calendar subject to change based upon need or opportunity	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
17	R3a	Spring Tradeshows a)											
18	R3a	Fall Tradeshows a)											
19	R0x	Special Events--CSR Training, Game Days											
20	R4x	***New Homes***											
21	R4x	New Homes Natural Gas											
22	R4x	New Homes Electric											
23	R6x	**E+ Free Weatherization**											

DSM/USB Communications Plan

			Q	R	S	T	U	V	W	X	Y	Z	AA
		DSM/USB Communications Calendar subject to change based upon need or opportunity	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
24													
25	C0	**Commercial ***											
26	C1	***E+ Commercial Lighting Rebates***											
27	C1	***NWE Lighting Trade Ally Network***											
28	C2	***E+ Energy Appraisal for Business***											

DSM/USB Communications Plan

			Q	R	S	T	U	V	W	X	Y	Z	AA
		DSM/USB Communications Calendar subject to change based upon need or opportunity	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
29	C3	***E+ Business Partners Electric Measures***											
30	C3a	***E+ Business Partners Natural Gas Measures***											
31	C3b	***E+ Natural Gas Savings Rebates for Commercial Customers -- Existing Buildings***											

DSM/USB Communications Plan

			Q	R	S	T	U	V	W	X	Y	Z	AA
		<u>DSM/USB Communications Calendar</u> subject to change based upon need or opportunity	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
32	C4a	***E+ Natural Gas Savings Rebates for Commercial Customers--New Construction***											
33	C4b	***E+ Commercial Gas Program***											
34	C5	***Motor Training***											
35	C6	***E+ Irrigation***											
36	C9	***Building Operator Certification Training***											

DSM/USB Communications Plan

			Q	R	S	T	U	V	W	X	Y	Z	AA
		DSM/USB Communications Calendar subject to change based upon need or opportunity	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
37	C10	***City of Bozeman Business Energy Project***											
38	C11a	***E+ Commercial Electric Rebates -- Existing Buildings***											
39	C11b	***E+ Commercial Electric Rebates -- New Construction***											
40		**Renewables**											
41	G1	***E+ Renewable Energy***											
42	G2	***E+ Green Power *****											
43													

DSM/USB Communications Plan

			Q	R	S	T	U	V	W	X	Y	Z	AA
		<u>DSM/USB Communications Calendar</u> subject to change based upon need or opportunity	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
44	O	***Northwest Energy Efficiency Alliance***											
45													
46		*Large Universal System Benefits Choice (USB											
47		gas commercial programs are not offered to na											
48													
49		**E+ Green is not a DSM program but is part of											

PREFILED DIRECT TESTIMONY

OF FRANK V. BENNETT

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL ELECTRICITY SUPPLY TRACKER

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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 Supply group since 1996. In this capacity, I administer energy supply contracts for 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 attached to my testimony that are filed in this docket;
- Updates to the costs included in the 12-month ended June 2015 tracker period with 9 months of actual numbers and 3 months of estimated numbers;
- Components included in the 12-month electricity supply cost tracker for the period ended June 2015; and
- The forecast costs of the 12-month ended June 2016 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…" § 69-8-103(8), MCA. The electric tracker deals only with electricity supply and related costs. I provide testimony and exhibits in this docket separated into five components: (1) Electricity Supply Tracker, (2) Colstrip Unit 4 ("CU4") True-up, (3) Dave Gates Generating Station ("DGGS") True-up, (4) Spion Kop Wind Generation Asset ("Spion") True-up, and (5) Hydro Asset True-up. All testimony is filed jointly to facilitate a retail customer total supply rate calculation.

Update to the 2014/2015 Electricity Supply Tracker Period

Q. Please summarize the estimated 12-month electricity supply tracker period ending June 2015, as it was filed in Docket Nos. D2013.5.33 and D2014.5.46.

A. The tracker period ending June 2015 in Docket Nos. D2013.5.33 and D2014.5.46 ("Consolidated Dockets") included 12 estimated months, July 2014 through June 2015. Interim Order No. 7283a in the Consolidated Dockets authorized rates reflecting the 2014/2015 tracker period estimates effective on July 1, 2014. NorthWestern filed monthly rate adjustments for each month, from August 2014 through June 2015 in this Docket No. D2014.7.58.

Q. How has NorthWestern incorporated the CU4 generation that is reflected in the 2014/2015 tracker?

A. NorthWestern has included the full rate-based volume of unit contingent energy associated with 222 megawatts ("MW") of capacity in the tracker. The variable costs associated with CU4 are included in the CU4 True-up.

Q. How has NorthWestern incorporated the DGGS regulation service in the 2014/2015 tracker?

A. The variable costs associated with the provision of regulation service by DGGS are included in the DGGS True-up. NorthWestern has included 7 MW of baseload energy from DGGS in the tracker to serve retail load.

Q. How has NorthWestern incorporated the Spion generation that is reflected in the 2014/2015 tracker?

A. NorthWestern has included the variable energy volumes generated by Spion's 40 MW of capacity in the tracker. The variable costs associated with Spion are included in the Spion True-up.

Q. How has NorthWestern incorporated the Hydro generation that is reflected in the 2014/2015 tracker?

A. NorthWestern has included the unit contingent energy associated with 439 MW of capacity in the tracker after the November 18, 2014 Hydro Compliance filing.

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

A. Consistent with consolidated Docket Nos. D2006.5.66 and D2007.5.46, Final Order No. 6836c, in this tracker filing, NorthWestern reduced regulation costs associated with wind energy contracts that do not serve retail load. Accordingly, NorthWestern removed all associated wind regulation charges for the UMGF project from the 2005/2006 tracker period forward for the periods of time that NorthWestern was not purchasing the output from this facility. The removed regulation charges are not part of the Transmission Business Unit rate NorthWestern charges its retail customers, but are instead collected from NorthWestern's equity shareholders.

Q. How has the 12-month ended June 2015 electricity supply tracker period been updated from the forecasts originally filed in Docket No. D2014.5.46?

A. The 2014 electricity supply tracker filing, Docket No. D2014.5.46, was submitted under cover letter dated May 29, 2014. My prefiled direct testimony in the 2014 filing included information for two tracker periods. Actual and estimated information was submitted for the first tracker period, July 2013 through June 2014. Forecast information was submitted for the second tracker period, July 2014 through June 2015. The first tracker period was updated for 12 months of actual information and was provided in response to Data Request PSC-022 in the Consolidated Dockets.

The forecast information for the July 2014 through June 2015 period has been updated in this filing with actual information[1] for July 2014 through March 2015, and estimates[2] for April, May, and June of 2015, and is included as Exhibit__(FVB-1)14-15. The actual numbers identify the load, specific monthly resource quantities bought and sold, and related costs for each month in NorthWestern's electricity supply portfolio. Pages 3 and 4 of Exhibit__(FVB-1)14-15 show that during the 12-month tracker period ending June 2015, NorthWestern expects Total Delivered Supply to be 6,577,411 megawatt hours ("MWh") of electricity. A total of 4,306,184 MWh of this electricity is attributable to NorthWestern's rate-based assets. The remaining 2,271,227 MWh of electricity is projected to be purchased at a cost of $167,092,609 to NorthWestern's electricity supply customers. The July 2014 beginning Deferred Account balance was a $37,220,708 under-collection for the market-based supply portion of this exhibit. Incorporating this under-collection with 9 months of actual and 3 months of estimated information, the 12 months ended June 2015 Deferred Account balance is forecasted to be a $8,741,628 under-collection (refer to Exhibit__(FVB-1)14-15, page 2). For further discussion of the Deferred Account, please refer to the Prefiled Direct Testimony of Joseph S. Janhunen – Electricity Supply Tracker.

[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.
[2] With the exception of DSM Program and Labor Costs which includes actual values for April from Exhibit__(DLW-2) page 1.

<u>Components of the 2014/2015 Electricity Supply Tracker Period</u>

Q. Describe the Electricity Supply cost components of the 12-month ended June 2015 tracker period as shown in Exhibit__(FVB-1)14-15.

A. NorthWestern's tracker exhibits in this filing reflect the expanded data analysis requested by the Commission staff and initially incorporated for the 2011/2012 tracker period with my testimony in Docket No. D2012.5.49. There are three basic cost components that make up the Electric Supply portfolio for the 12-month tracker period of July 2014 through June 2015: Electric Supply Expenses, Transmission Costs, and Administrative Expenses.

I. Electric Supply Expenses

A. <u>Off System Transactions</u> – These fixed and indexed price transactions have a delivery point outside of NorthWestern's service territory. Most of these transactions are at the Mid-Columbia trading hub and are used for hedging purposes.

B. <u>On System Transactions</u> – These fixed and indexed price transactions have a delivery point on or within NorthWestern's service territory and include the following:

1. Fixed Price Transactions

   a. Rate-Based 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.

i) CU4 is a generation asset approved for inclusion in rates 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.

ii) DGGS is a generation asset approved for inclusion in rates by Order No. 6943e in Docket No. D2008.8.95. NorthWestern includes 7 MW of baseload energy as a result of minimum turndown from generating unit operations. This asset was included as a rate-based facility starting January 1, 2011.

iii) Spion is a generation asset approved for inclusion in rates by Order No. 7159l in Docket No. D2011.5.41. NorthWestern includes the variable energy volumes generated by Spion’s 40 MW of capacity. This asset was included as a rate-based facility starting December 1, 2012.

iv) Hydro includes generation assets approved for inclusion in rates by Order No. 7323k in Docket No. D2013.12.85, at the volume of unit contingent energy associated with 439 MW of capacity. These assets were originally included as rate-based facilities on November 18, 2014.

b. Base Fixed Price Purchases

i.) The variable energy generated from the Judith Gap Energy, LLC ("Judith Gap") wind turbine facility with 135 MW of capacity. Judith Gap achieved commercial operation on February 16, 2006. This contract expires on December 31, 2026.

ii.) The energy generated by two hydroelectric power purchase agreements totaling approximately 20 MW of capacity.

iii.) The energy associated with approximately 100 MW of capacity from Qualifying Facility ("QF") 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 9-months actual and 3-months estimate shows that these Tier II QFs will meet the 807,337 MWh per year target included in the Stipulation attached to Final Orders 5986w and 6353c under combined Docket Nos. D97.7.90 and D2001.1.5.

iv.) The variable energy generated by approximately 75 MW of capacity under various QF supply agreements in two primary groups. The first group includes agreements for approximately 52 MW of capacity that convey renewable energy credits ("RECs") to NorthWestern, which then uses them to meet its renewable energy requirements. The second group includes approximately 23 MW of generation under which the associated RECs remain with the QF (UMGF, plus other small QFs).

v.) 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.

2. Index Price Transactions

a. Base, short-term, 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.

b. Imbalance charges in three categories, including current month estimates of purchases and sales, prior month true-ups of the earlier estimated values, and accounting and Balancing Authority Area (“BAA”) expenses that adjust accounts not tied directly with a specific meter or customer.

C. Ancillary and Other – The following are portfolio supply-related costs that are not actual energy-based power purchase agreements but are required to address the needs of the retail supply portfolio:

1. Approximately 50 MW of dispatchable capacity from Basin Creek Equity Partners, LLC (“Basin Creek”). 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 terms.

2. Operating Reserves which are the contingency reserves required to be in place under NorthWestern’s BAA transmission tariff. This line item includes the actual costs of operating reserves that are not supplied by the portfolio of resources.

3. Expenses related to “wind other costs” incurred by NorthWestern 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, Western Renewable Energy Generation Information System fees, and other direct wind costs.

4. Demand-Side Management ("DSM") program implementation costs directly involved with DSM programs and projects and Transmission and Distribution Lost Revenues related to DSM and Universal System Benefits programs, which are all included as expenses.

II. Transmission Costs

These are costs of network transmission service and those 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 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 this tracker filing.

As explained previously, Final Order No. 6836c reduced regulation costs associated with wind energy contracts that do not serve retail load.

III. Administrative Expenses

Incremental administrative and general costs which are in addition to those recovered in the last general rate case filing (Docket No. D2009.9.129), $1,608,725 or 0.93% of total electric supply expenses, are also included in electricity supply costs. These costs include MPSC and Montana Consumer Counsel taxes, 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 2015 tracker period.

A. The results of the 2014/2015 tracker period are summarized in the following table:

Beginning Deferred Account		**Balance ($)**
Under-Collection		$37,220,708

Energy Supply/Service	**MWh**	**Cost ($)**	**$/MWh**
Off System Transactions			
Fixed Price	1,475,839	$67,279,555	$45.59
Index Price	(1,474,592)	($39,168,995)	$26.56
On System Transactions			
Rate Based Assets	4,306,184		
Base Fixed Price Purchase	1,832,261	$73,064,641	$39.88
Index Price	1,441,986	$42,827,335	$29.70
Revenue Credits	(1,102,000)		
Imbalance		$283,410	
Ancillary and Other	97,733	$22,806,663	
Transmission Costs		$1,689,057	
Administrative Expenses		$1,608,725	
Carrying Cost		$1,811,476	
Total Expenses:		$172,201,867	

Electricity Sales	**MWh**	**Revenue ($)**
Electric Cost Revenue		$168,580,285
Prior Deferred Expense		$32,100,662
Total Revenue:		$200,680,947

Ending Deferred Account		**Balance ($)**
Under-Collection		$8,741,628

<u>2015/2016 Forecast Electricity Supply Tracker Period</u>

Q. Please summarize the 12-month electricity supply tracker period ending June 2016 as filed in this docket.

A. The June 2015 Deferred Account market-based supply under-collection ending balance of $8,741,628 as described above is the July 2015 beginning balance. July 2015 through June 2016 information is based on forecast numbers and includes the following sources of existing electric supply: multiple off-system and on-system fixed and index priced transactions that are comprised of certain rate-based assets, QFs, various base purchase contracts, as well as term and competitive solicitation contracts. Please see Exhibit__(FVB-2)15-16 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 explained previously, Final Order No. 6836c reduced regulation costs associated with wind energy contracts that do not serve retail load. NorthWestern removes 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)15-16.

Q. How has NorthWestern treated regulation costs in the 2015/2016 tracker period?

A. The variable costs associated with the provision of regulation service by DGGS are included in the DGGS section of this filing. NorthWestern has included the 7 MW of DGGS baseload energy in the supply portfolio as an energy resource as shown on page 3 of Exhibit__(FVB-2)15-16.

Q. How does the generation output from rate-based generation assets impact the 2015/2016 tracker period?

A. As in the prior tracker period, there are four rate-based generation assets that contribute energy to the electricity supply tracker in this forecast period. They include 222 MW of unit contingent energy associated with CU4, 40 MW of variable energy associated with Spion, 7 MW of baseload energy associated with DGGS, and 439 MW of unit contingent energy associated with the Hydro assets.

Q. Describe the Total Supply requirement for the 12-month period ending June 2016 as illustrated in Exhibit__(FVB-2)15-16.

A. NorthWestern's electricity supply forecasted Total Delivered Supply is estimated at 6,550,618 MWh, as shown on page 3 of Exhibit__(FVB-2)15-16.

Q. Please summarize the 12-month ended June 2016 forecast tracker period.

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

Beginning Deferred Account		**Balance ($)**
Under-Collection		$8,741,628

Energy Supply/Service	**MWh**	**Cost ($)**	**$/MWh**
Off System Transactions			
Fixed Price	1,138,825	$52,272,216	$45.90
Index Price	(1,138,825)	($34,616,704)	$30.40
On System Transactions			
Rate Based Assets	4,442,266		
Base Fixed Price Purchase	1,822,190	$77,066,226	$42.29
Index Price	402,832	$12,811,616	$31.80
Revenue Credits	(203,370)		
Imbalance		$0	
Ancillary and Other	86,699	$26,024,476	
Transmission Costs		($17,010)	
Administrative Expenses		$1,233,464	
Carrying Cost		$172,580	
Total Expenses:		$134,946,865	

Electricity Sales	**MWh**	**Revenue ($)**
Electric Cost Revenue		$134,946,865
Prior Deferred Expense		$8,741,628
Total Revenue:		$143,688,493

Ending Deferred Account		**Balance ($)**
Under-Collection		($0)

Q. Describe the electric supply Revenue and Expense categories for the 12-month ended June 2016 forecast tracker period.

A. The electricity supply tracker revenue and expense details are reflected on page 1 of Exhibit__(FVB-2)15-16 under two main sections, Total Revenue and Total Expenses. Total Revenue is estimated to be $143,688,493. This includes the $8,741,628 under-collection for the 2014-2015 tracker period. The 12-month forecast tracker period estimates the Total Expenses as $134,946,865, reflecting a decrease from the prior period. The costs shown above reflected in the forecast period include DSM costs and lost T&D revenues that are further explained in the Prefiled Direct Testimony of Danie L. Williams.

Q. Are there any additional updates anticipated for the first month of this tracker rate filing?

A. No, not at this time. Because a regular monthly filing would have been submitted on June 15, 2015, for rates effective July 1, 2015, this tracker 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, 2015, NorthWestern will file a monthly tracker rate filing update for a July 2015 rate adjustment.

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

A. Yes, it does.

	A 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-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Total**
5		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
6	Total Sales and Unit Costs													
7	MWh	482,388	546,211	496,510	442,674	449,232	540,528	601,160	515,060	488,212	447,321	458,167	466,568	5,934,031
8	Supply Cost	$ 35.4916	$ 36.2978	$ 36.0640	$ 35.8384	$ 35.4916	$ 21.7438	$ 21.9824	$ 22.9258	$ 22.6010	$ 22.1837	$ 22.2140	$ 21.8070	$ 35.4916
9	YNP MWh	3,580	2,595	2,455	2,704	1,670	616	589	547	565	543	2,044	2,483	20,390
10	YNP Supply Rate	$ 64.3000	$ 64.3000	$ 64.3000	$ 64.3000	$ 64.3000	$ 64.3000	$ 64.3000	$ 64.3000	$ 64.3000	$ 64.3000	$ 64.3000	$ 64.3000	$ 64.3000
11	Prior Year(s) Deferred Expense	$ 5.7268	$ 5.7268	$ 5.7268	$ 5.7268	$ 5.7268	$ 5.7268	$ 5.7268	$ 5.7268	$ 5.7268	$ 5.7268	$ 5.7268	$ 5.7268	
12														
13														
14	Electric Cost Revenues													
15	NWE Electric Supply	$ 17,248,208	$ 19,834,334	$ 17,966,021	$ 15,921,856	$ 12,306,260	$ 10,818,570	$ 20,065,666	$ 11,567,418	$ 11,137,298	$ 10,053,805	$ 10,177,700	$ 10,174,464	$ 167,271,601
16	YNP Electric Supply	$ 230,128	$ 166,765	$ 157,729	$ 173,711	$ 107,249	$ 39,223	$ 37,379	$ 34,800	$ 35,998	$ 34,631	$ 131,434	$ 159,637	$ 1,308,684
17	Subtotal	$ 17,478,336	$ 20,001,099	$ 18,123,750	$ 16,095,567	$ 12,413,509	$ 10,857,793	$ 20,103,045	$ 11,602,218	$ 11,173,296	$ 10,088,435	$ 10,309,134	$ 10,334,101	$ 168,580,285
18	Prior Year(s) Deferred Expense	$ 954,516	$ 3,061,930	$ 2,842,559	$ 2,533,239	$ 2,569,980	$ 3,094,594	$ 3,443,663	$ 2,948,768	$ 2,795,414	$ 2,560,224	$ 2,623,831	$ 2,671,943	$ 32,100,662
19	Total Revenue	$ 18,432,851	$ 23,063,030	$ 20,966,309	$ 18,628,806	$ 14,983,489	$ 13,952,387	$ 23,546,709	$ 14,550,986	$ 13,968,710	$ 12,648,660	$ 12,932,965	$ 13,006,044	$ 200,680,947
20														
21	Electric Supply Expenses													
22	Net Base Purchases	$ 11,021,924	$ 11,797,828	$ 11,319,225	$ 11,987,470	$ 12,614,968	$ 12,638,767	$ 10,082,085	$ 8,616,611	$ 9,341,427	$ 9,163,728	$ 9,112,979	$ 8,480,571	$ 126,177,582
23	Net Base Sales	$ (465,630)	$ (492,156)	$ (452,572)	$ (410,876)	$ (379,791)	$ (372,136)	$ (295,520)	$ (231,172)	$ (248,201)	$ (655,696)	$ (628,900)	$ (896,580)	$ (5,529,230)
24	Net Term Purchases	$ 10,984,664	$ 8,933,724	$ 4,298,123	$ 4,011,808	$ 2,621,632	$ 2,931,592	$ 2,390,810	$ 2,173,800	$ 2,388,569	$ 2,337,020	$ 2,362,990	$ 2,337,020	$ 47,771,752
25	Net Term Sales	$ (5,737,808)	$ (5,876,004)	$ (4,273,119)	$ (3,760,200)	$ (3,585,883)	$ (5,673,724)	$ (1,685,864)	$ (1,137,740)	$ (1,336,101)	$ -	$ -	$ (514,800)	$ (33,581,243)
26	Net Spot Purchases	$ 2,967,678	$ 2,970,598	$ 3,093,861	$ 1,791,369	$ 2,251,678	$ 1,195,874	$ 554,233	$ 414,786	$ 375,518	$ -	$ -	$ -	$ 15,615,594
27	Net Spot Sales	$ (321,840)	$ (220,726)	$ (96,827)	$ (139,606)	$ (104,758)	$ (2,278)	$ (230)	$ (679)	$ 15,256	$ (1,828,860)	$ (1,845,730)	$ (1,905,640)	$ (6,451,919)
28	Other Tracker Costs	$ 1,696,259	$ 1,818,174	$ 1,020,696	$ 1,697,927	$ 3,356,223	$ 2,351,775	$ 1,393,724	$ 1,745,693	$ 1,592,751	$ 1,719,816	$ 3,146,835	$ 1,550,200	$ 23,090,073
29	Total Electric Supply Expenses	$ 20,145,246	$ 18,931,437	$ 14,909,388	$ 15,177,893	$ 16,774,069	$ 13,069,869	$ 12,439,237	$ 11,581,299	$ 12,129,219	$ 10,736,008	$ 12,148,173	$ 9,050,771	$ 167,092,609
30														
31	NWE Transmission Costs													
32														
33	Other Services (Wheeling)	$ 65,581	$ 51,850	$ 60,363	$ 39,115	$ 152,886	$ 294,818	$ 374,820	$ 252,407	$ 414,631	$ -	$ -	$ -	$ 1,706,472
34	Ancillary Cost (Disallowed)	$ (1,013)	$ (2,228)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (17,415)
35	Total NWE Transmission	$ 64,569	$ 49,623	$ 58,946	$ 37,697	$ 151,469	$ 293,401	$ 373,403	$ 250,990	$ 413,213	$ (1,418)	$ (1,418)	$ (1,418)	$ 1,689,057
36														
37	Administrative Expenses													
38	MPSC Tax Collection (.0042/.002)	$ 75,998	$ 95,638	$ 86,952	$ 36,715	$ 29,534	$ 27,437	$ 46,517	$ 28,980	$ 27,094	$ 20,177	$ 20,618	$ 20,668	$ 516,330
39	MCC Tax Collection (.0011/.001)	$ 19,904	$ 25,048	$ 22,773	$ 18,358	$ 14,767	$ 13,719	$ 23,258	$ 14,490	$ 13,547	$ 10,088	$ 10,309	$ 10,334	$ 196,596
40	Modeling	$ 10,438	$ 18,208	$ 149,338	$ 15,543	$ 27,860	$ 125,976	$ -	$ -	$ 22,376	$ 27,083	$ 27,083	$ 27,083	$ 450,988
41	Trading & Marketing	$ 9,802	$ 8,396	$ 7,304	$ 7,304	$ 6,794	$ 10,094	$ 7,973	$ 8,378	$ 7,654	$ 7,732	$ 7,732	$ 7,732	$ 96,895
42	Administration	$ 6,322	$ 2,802	$ 18,928	$ 56,530	$ (1,331)	$ 8,955	$ 19,201	$ 4,922	$ 190,031	$ 13,852	$ 13,852	$ 13,852	$ 347,916
43	Total Administrative Expenses	$ 122,464	$ 150,093	$ 285,295	$ 134,449	$ 77,625	$ 186,181	$ 96,949	$ 56,770	$ 260,702	$ 78,933	$ 79,595	$ 79,670	$ 1,608,725
44														
45	Carrying Cost Expense													
46	Carrying Costs	$ 259,750	$ 235,368	$ 198,999	$ 178,550	$ 193,146	$ 191,753	$ 122,398	$ 105,536	$ 98,498	$ 86,967	$ 82,852	$ 57,660	$ 1,811,476
47	Total Carrying Costs	$ 259,750	$ 235,368	$ 198,999	$ 178,550	$ 193,146	$ 191,753	$ 122,398	$ 105,536	$ 98,498	$ 86,967	$ 82,852	$ 57,660	$ 1,811,476
48														
49														
50	Total Expenses	$ 20,592,028	$ 19,366,521	$ 15,452,628	$ 15,528,589	$ 17,196,309	$ 13,741,204	$ 13,031,987	$ 11,994,594	$ 12,901,631	$ 10,900,490	$ 12,309,203	$ 9,186,683	$ 172,201,867
51														
52	Deferred Cost Amortization	$ 954,516	$ 3,061,930	$ 2,842,559	$ 2,533,239	$ 2,569,980	$ 3,094,594	$ 3,443,663	$ 2,948,768	$ 2,795,414	$ 2,560,224	$ 2,623,831	$ 2,671,943	$ 32,100,662
53	(under collection)/over collection													
54	Monthly Deferred Cost	$ (3,113,693)	$ 634,579	$ 2,671,122	$ 566,978	$ (4,782,799)	$ (2,883,412)	$ 7,071,059	$ (392,376)	$ (1,728,335)	$ (812,055)	$ (2,000,069)	$ 1,147,418	$ (3,621,582)
55	Cumulative Deferred Cost	$ (3,113,693)	$ (2,479,114)	$ 192,008	$ 758,986	$ (4,023,813)	$ (6,907,225)	$ 163,834	$ (228,542)	$ (1,956,877)	$ (2,768,931)	$ (4,769,000)	$ (3,621,582)	

Electric Supply Cost Tracker

Electric Tracker Projection Excluding Generation Assets Cost of Service

	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate

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

	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
Deferred Supply Cost Expense												
Beginning Balance	**$ 37,220,708**	$ 39,379,885	$ 35,683,376	$ 30,169,695	$ 27,069,478	$ 29,282,297	$ 29,071,114	$ 18,556,392	$ 16,000,000	$ 14,932,921	$ 13,184,752	$ 12,560,989
Monthly Deferred Cost	$ 2,159,177	$ (3,696,509)	$ (5,513,681)	$ (3,100,217)	$ 2,212,819	$ (211,183)	$ (10,514,722)	$ (2,556,392)	$ (1,067,079)	$ (1,748,170)	$ (623,762)	$ (3,819,362)
Ending Balance	$ 39,379,885	$ 35,683,376	$ 30,169,695	$ 27,069,478	$ 29,282,297	$ 29,071,114	$ 18,556,392	$ 16,000,000	$ 14,932,921	$ 13,184,752	$ 12,560,989	$ 8,741,628
Total Capital	$ 39,379,885	$ 35,683,376	$ 30,169,695	$ 27,069,478	$ 29,282,297	$ 29,071,114	$ 18,556,392	$ 16,000,000	$ 14,932,921	$ 13,184,752	$ 12,560,989	$ 8,741,628

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%

	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-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Total**
5		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
6	**Off System Transactions**													
7	**Fixed Price**													
8	Base Fixed Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Competitive Solicitations	113,598	113,800	110,000	125,399	109,283	113,799	39,400	26,400	39,375	38,800	38,600	38,800	907,254
10	Base Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Competitive Solicitations	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Term Fixed Price Purchases	72,800	62,400	30,000	32,460	28,800	31,200	66,200	60,000	66,125	64,400	65,800	64,400	644,585
13	Term Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	(18,000)	(18,000)
14	**Index Price**													
15	Base Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Base Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Competitive Solicitations	(29,000)	(29,000)	(28,000)	(29,400)	(27,625)	(29,000)	(29,000)	(26,400)	(28,975)	(28,400)	(28,600)	(28,400)	(341,800)
18	Term Index Price Purchases	-	-	-	-	-	58,000	-	-	-	-	-	-	58,000
19	Term Index Price Sales	(157,393)	(147,200)	(112,000)	(117,600)	(110,475)	(115,999)	(76,600)	(69,600)	(76,525)	-	-	-	(983,392)
20	Spot Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Spot Sales	-	-	-	-	-	-	-	-	-	(74,800)	(75,800)	(56,800)	(207,400)
22														
23	**On System Transactions**													
24	**Fixed Price**													
25	Rate-Based Assets													
26	Colstrip Unit 4	134,341	151,002	151,114	143,695	145,002	130,667	154,793	92,539	119,053	111,360	115,072	145,440	1,594,078
27	Dave Gates Generating Station	5,208	5,208	5,040	5,208	5,047	6,003	5,208	4,704	5,201	5,040	5,208	5,040	62,115
28	Spion Kop	6,742	5,546	8,479	13,736	16,105	13,305	16,428	13,308	16,361	11,520	8,928	8,640	139,097
29	Hydro Assets	-	-	-	-	123,580	331,190	352,720	337,952	350,636	297,360	389,856	327,600	2,510,894
30														
31	Base Fixed Price Purchases													
32	Judith Gap	22,306	22,720	25,206	37,387	57,438	49,080	60,455	43,045	54,028	40,524	35,180	28,766	476,135
33	Other Non-QF	4,339	608	3,898	93	3,605	3,720	3,720	3,660	3,715	3,600	3,147	6,928	41,033
34	Competitive Solicitations	20,800	20,800	20,000	21,600	19,200	20,800	20,800	19,200	20,800	20,800	20,000	20,800	245,600
35	QF Tier II	55,018	75,621	73,119	74,862	74,167	75,768	75,311	68,916	69,918	74,522	75,031	57,153	849,407
36	QF Tier II Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
37	QF-1 Tariff Contracts	17,606	10,474	12,975	16,865	20,329	18,363	21,381	16,932	20,727	12,709	13,671	10,800	192,832
38	Term Fixed Price Purchases	26,550	-	1,875	2,025	1,800	1,950	-	-	-	-	-	-	34,200
39	Term Fixed Price Sales	(1,950)	(1,950)	(1,875)	-	(1,050)	(58,000)	-	-	-	-	-	-	(64,825)
40	**Index Price**													
41	Base Index Price Purchases													
42	Competitive Solicitations	45,400	45,400	44,000	34,200	44,475	45,400	29,000	36,000	28,975	28,400	28,600	28,400	438,250
43	Term Index Price Purchases	193,074	159,800	80,000	86,400	44,800		-	-	-	-	-	-	564,074
44	Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
45	Spot Purchases	91,105	73,342	84,988	62,858	64,144	42,353	22,439	25,982	15,842	-	-	-	483,053
46	Spot Sales	(13,419)	(7,819)	(7,620)	(10,998)	(3,535)	(120)	-	-	-	-	-	-	(43,511)
47	Revenue Credits	-	-	-	-	(58,091)	(134,838)	(151,144)	(121,660)	(191,949)	(117,070)	(196,620)	(130,628)	(1,102,000)
48	Imbalance, Current Month Estimate	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Imbalance, Prior Months True-up	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Imbalance, Accounting & BA Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
51														
52	**Ancillary and Other**													
53	Basin Creek Fixed Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Basin Creek Variable Costs	5,028	6,406	2,742	591	2,972	3,551	2,525	1,293	4,050	1,258	835	1,132	32,383
55	Operating Reserves	11,160	11,160	10,800	16,368	15,862	-	-	-	-	-	-	-	65,350
56	Wind Other Cost													
57	DSM Program & Labor Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
58	T & D Lost Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-
59	T & D Lost Revenue Adjustment													
60														
61	**Total Delivered Supply**	623,313	578,318	514,740	515,749	575,833	607,192	613,636	532,271	517,357	490,023	498,908	510,071	6,577,411
62														

	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														
63	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
64	**Total Supply Expense**													
65														
66	**Energy Supply Expense**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Total**
67		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
68	**<u>Off System Transactions</u>**													
69	**Fixed Price**													
70	Base Fixed Price Purchases													
71	Competitive Solicitations	$ 4,993,796	$ 5,004,440	$ 4,833,100	$ 5,399,306	$ 4,773,855	$ 5,004,410	$ 2,314,000	$ 1,520,160	$ 2,312,440	$ 2,276,560	$ 2,269,640	$ 2,276,560	$ 42,978,266
72	Base Fixed Price Sales													
73	Competitive Solicitations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Term Fixed Price Purchases	$ 3,226,080	$ 2,627,040	$ 1,230,000	$ 1,313,760	$ 1,165,920	$ 1,263,080	$ 2,390,810	$ 2,173,800	$ 2,388,569	$ 2,337,020	$ 2,362,990	$ 2,337,020	$ 24,816,089
75	Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (514,800)	$ (514,800)
76	**Index Price**													
77	Base Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Base Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	Competitive Solicitations	$ (465,630)	$ (492,156)	$ (452,572)	$ (410,876)	$ (379,791)	$ (372,136)	$ (295,520)	$ (231,172)	$ (248,201)	$ (655,696)	$ (628,900)	$ (896,580)	$ (5,529,230)
80	Term Index Price Purchases	$ -	$ -	$ 11,550	$ -	$ -	$ 1,668,512	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,680,062
81	Term Index Price Sales	$ (5,737,808)	$ (5,876,004)	$ (4,273,119)	$ (3,760,200)	$ (3,585,883)	$ (3,329,123)	$ (1,685,864)	$ (1,137,740)	$ (1,336,101)	$ -	$ -	$ -	$ (30,721,842)
82	Spot Purchases	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
83	Spot Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,828,860)	$ (1,845,730)	$ (1,905,640)	$ (5,580,230)
84														
85	**<u>On System Transactions</u>**													
86	**Fixed Price**													
87	<u>Rate-Based Assets</u>													
88	Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	Spion Kop	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	Hydro Assets													
92														
93	Base Fixed Price Purchases													
94	Judith Gap	$ 675,297	$ 778,051	$ 793,782	$ 1,132,991	$ 1,853,742	$ 1,618,751	$ 1,984,593	$ 1,418,526	$ 1,646,181	$ 1,286,618	$ 1,116,985	$ 913,326	$ 15,218,843
95	Other Non-QF	$ 601,691	$ 357,187	$ 257,278	$ 6,142	$ 136,106	$ 136,106	$ 136,106	$ 136,106	$ 136,106	$ 139,500	$ 247,996	$ 374,362	$ 2,664,686
96	Competitive Solicitations	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 1,166,940	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 1,123,720	$ 13,268,540
97	QF Tier II	$ 2,183,066	$ 2,879,648	$ 2,784,372	$ 2,850,745	$ 2,824,279	$ 2,885,245	$ 2,867,843	$ 2,624,321	$ 2,662,477	$ 2,837,803	$ 2,857,191	$ 2,176,390	$ 32,433,380
98	QF Tier II Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -	$ -
99	QF-1 Tariff Contracts	$ 715,841	$ 778,303	$ 724,349	$ 1,043,490	$ 1,271,847	$ 1,252,630	$ 1,436,903	$ 1,125,846	$ 1,288,826	$ 864,631	$ 931,767	$ 740,433	$ 12,174,865
100	Term Fixed Price Purchases	$ 633,450	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 633,450
101	Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ (2,344,601)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,344,601)
102	**Index Price**													
103	Base Index Price Purchases													
104	Competitive Solicitations	$ 728,514	$ 876,480	$ 845,845	$ 387,856	$ 717,859	$ 617,904	$ 218,920	$ 754,372	$ 171,676	$ 634,896	$ 608,900	$ 875,780	$ 7,439,001
105	Term Index Price Purchases	$ 7,125,134	$ 6,306,684	$ 3,056,573	$ 2,698,048	$ 1,455,712	$ -	$ -	$ -		$ -	$ -	$ -	$ 20,642,151
106	Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
107	Spot Purchases	$ 2,967,678	$ 2,970,598	$ 3,093,861	$ 1,791,369	$ 2,251,678	$ 1,195,874	$ 554,233	$ 414,786	$ 375,518	$ -	$ -	$ -	$ 15,615,594
108	Spot Sales	$ (321,840)	$ (220,726)	$ (96,827)	$ (139,606)	$ (104,758)	$ (2,278)	$ (230)	$ (679)	$ 15,256	$ -	$ -	$ -	$ (871,689)
109	Revenue Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110	Imbalance, Current Month Estimate	$ (145,257)	$ (271,653)	$ (113,019)	$ (2,497)	$ 145,453	$ 164,279	$ (126,425)	$ (83,261)	$ 88,059	$ -	$ -	$ -	$ (344,321)
111	Imbalance, Prior Months True-up	$ 219,403	$ 200,474	$ (363,251)	$ (187,583)	$ 390,261	$ 167,048	$ 208,965	$ 125,855	$ (133,442)	$ -	$ -	$ -	$ 627,731
112	Imbalance, Accounting & BA Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
113														
114	**<u>Ancillary and Other</u>**													
115	Basin Creek Fixed Costs	$ 346,275	$ 346,275	$ 350,235	$ (118,168)	$ 370,057	$ 469,035	$ 293,973	$ 466,155	$ 466,155	$ 356,450	$ 777,549	$ 354,039	$ 4,478,028
116	Basin Creek Variable Costs	$ 273,950	$ 303,965	$ 161,056	$ 65,209	$ 540,792	$ 159,533	$ 131,324	$ 71,486	$ 68,133	$ 48,448	$ 31,675	$ 42,907	$ 1,898,477
117	Operating Reserves	$ 245,520	$ 245,520	$ 237,600	$ 360,096	$ 273,460	$ -	$ -	$ 924	$ -	$ 221,760	$ 229,152	$ 221,760	$ 2,035,792
118	Wind Other Cost	$ 25,133	$ 366	$ 18,349	$ 379	$ 809,883	$ 2,076	$ 35,833	$ 500	$ 33,995	$ 14,279	$ 833,631	$ 14,279	$ 1,788,702
119	DSM Program & Labor Costs	$ 100,849	$ 362,841	$ 99,341	$ 950,105	$ 195,932	$ 759,419	$ 219,667	$ 533,648	$ 439,465	$ 448,493	$ 667,507	$ 341,829	$ 5,119,097
120	T & D Lost Revenue	$ 630,386	$ 630,386	$ 630,386	$ 630,386	$ 630,386	$ 630,386	$ 630,386	$ 630,386	$ 630,386	$ 630,386	$ 607,321	$ 607,321	$ 7,518,502
121	T & D Lost Revenue Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (31,934)	$ (31,934)
122														
123	**Total Delivered Supply**	$ 20,145,246	$ 18,931,437	$ 14,909,388	$ 15,177,893	$ 16,774,069	$ 13,069,869	$ 12,439,237	$ 11,581,299	$ 12,129,219	$ 10,736,008	$ 12,148,173	$ 9,050,771	$ 167,092,609
124		Wind Other Cost includes: Judith Gap impact fees and property tax charges, consulting work on met towers, 3 TIER forecasting fees, electric service at met towers, and WREGIS charges.												

	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														
125	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
126	**Unit Costs**													
127														
128	**Energy Supply Unit Costs**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Total**
129		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
130	**Off System Transactions**													
131	**Fixed Price**													
132	Base Fixed Price Purchases													
133	Competitive Solicitations	$ 43.96	$ 43.98	$ 43.94	$ 43.06	$ 43.68	$ 43.98	$ 58.73	$ 57.58	$ 58.73	$ 58.67	$ 58.80	$ 58.67	$ 47.37
134	Base Fixed Price Sales													
135	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
136	Term Fixed Price Purchases	$ 44.31	$ 42.10	$ 41.00	$ 40.47	$ 40.48	$ 40.48	$ 36.11	$ 36.23	$ 36.12	$ 36.29	$ 35.91	$ 36.29	$ 38.50
137	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	$ 28.60	$ 28.60
138	**Index Price**													
139	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
140	Base Index Price Sales													
141	Competitive Solicitations	$ 16.06	$ 16.97	$ 16.16	$ 13.98	$ 13.75	$ 12.83	$ 10.19	$ 8.76	$ 8.57	$ 23.09	$ 21.99	$ 31.57	$ 16.18
142	Term Index Price Purchases	n/a	n/a	n/a	n/a	n/a	$ 28.77	n/a	n/a	n/a	n/a	n/a	n/a	$ 28.97
143	Term Index Price Sales	$ 36.46	$ 39.92	$ 38.15	$ 31.97	$ 32.46	$ 28.70	$ 22.01	$ 16.35	$ 17.46	n/a	n/a	n/a	$ 31.24
144	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
145	Spot Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ 24.45	$ 24.35	$ 33.55	$ 26.91
146														
147	**On System Transactions**													
148	**Fixed Price**													
149	Rate-Based Assets													
150	Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
151	Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152	Spion Kop	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
153	Hydro Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
154														
155	Base Fixed Price Purchases													
156	Judith Gap	$ 30.27	$ 34.25	$ 31.49	$ 30.30	$ 32.27	$ 32.98	$ 32.83	$ 32.95	$ 30.47	$ 31.75	$ 31.75	$ 31.75	$ 31.96
157	Other Non-QF	$ 138.67	$ 587.48	$ 66.00	$ 66.04	$ 37.75	$ 36.59	$ 36.59	$ 37.19	$ 36.64	$ 38.75	$ 78.80	$ 54.04	$ 64.94
158	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
159	QF Tier II	$ 39.68	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.18
160	QF Tier II Adjustments	$ -	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	QF-1 Tariff Contracts	$ 26.96	$ 74.31	$ 55.83	$ 61.87	$ 62.56	$ 68.21	$ 67.20	$ 66.49	$ 62.18	$ 68.03	$ 68.16	$ 68.56	$ 63.14
162	Term Fixed Price Purchases	$ 23.86	n/a	$ -	$ -	$ -	$ -	n/a	n/a	n/a	n/a	n/a	n/a	$ 18.52
163	Term Fixed Price Sales	$ -	$ -	$ -	n/a	$ -	$ 40.42	n/a	n/a	n/a	n/a	n/a	n/a	$ 36.17
164	**Index Price**													
165	Base Index Price Purchases													
166	Competitive Solicitations	$ 16.05	$ 19.31	$ 19.22	$ 11.34	$ 16.14	$ 13.61	$ 7.55	$ 20.95	$ 5.92	$ 22.36	$ 21.29	$ 30.84	$ 16.97
167	Term Index Price Purchases	$ 36.90	$ 39.47	$ 38.21	$ 31.23	$ 32.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ 36.59
168	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
169	Spot Purchases	$ 32.57	$ 40.50	$ 36.40	$ 28.50	$ 35.10	$ 28.24	$ 24.70	$ 15.96	$ 23.70	n/a	n/a	n/a	$ 32.33
170	Spot Sales	$ 23.98	$ 28.23	$ 12.71	$ 12.69	$ 29.63	$ 18.98	n/a	n/a	n/a	n/a	n/a	n/a	$ 20.03
171	Revenue Credits	n/a	n/a	n/a	n/a	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
172	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
173	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
174	Imbalance, Accounting & BA Expense													
175														
176	**Ancillary and Other**													
177	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
178	Basin Creek Variable 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
179	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
180	Wind Other Cost													
181	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
182	T & D Lost Revenue	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
183	T & D 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
184														
185														
186	**Total Delivered Supply**	$ 32.32	$ 32.74	$ 28.96	$ 29.43	$ 29.13	$ 21.53	$ 20.27	$ 21.76	$ 23.44	$ 21.91	$ 24.35	$ 17.74	$ 25.40
187														

	A/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-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Total**
5		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
6	Total Sales and Unit Costs													
7	MWh	516,208	541,697	492,397	468,897	489,975	535,138	566,841	530,208	500,071	476,340	456,744	465,627	6,040,143
8	Supply Cost	$ 22.1098	$ 22.1098	$ 22.1098	$ 22.1098	**$ 22.1098**	$ 22.1098	$ 22.1098	$ 22.1098	$ 22.1098	$ 22.1098	$ 22.1098	$ 22.1098	$ 22.1098
9	YNP MWh	2,648	2,559	2,493	1,971	1,283	1,025	1,092	1,109	1,001	1,093	1,829	2,590	20,691
10	YNP Supply Rate	$ 67.7000	$ 67.7000	$ 67.7000	$ 67.7000	$ 67.7000	$ 67.7000	$ 67.7000	$ 67.7000	$ 67.7000	$ 67.7000	$ 67.7000	$ 67.7000	$ 67.7000
11	Prior Year(s) Deferred Expense	$ 1.4473	$ 1.4473	$ 1.4473	$ 1.4473	$ 1.4473	$ 1.4473	$ 1.4473	$ 1.4473	$ 1.4473	$ 1.4473	$ 1.4473	$ 1.4473	
12														
13														
14	Electric Cost Revenues													
15	NWE Electric Supply	$ 11,413,234	$ 11,976,796	$ 10,886,780	$ 10,367,195	$ 10,833,225	$ 11,831,773	$ 12,532,708	$ 11,722,766	$ 11,056,439	$ 10,531,766	$ 10,098,499	$ 10,294,891	$ 133,546,074
16	YNP Electric Supply	$ 179,253	$ 173,216	$ 168,751	$ 133,407	$ 86,884	$ 69,420	$ 73,923	$ 75,068	$ 67,761	$ 73,971	$ 123,823	$ 175,314	$ 1,400,790
17	Subtotal	$ 11,592,488	$ 12,150,012	$ 11,055,531	$ 10,500,602	$ 10,920,109	$ 11,901,193	$ 12,606,632	$ 11,797,834	$ 11,124,200	$ 10,605,737	$ 10,222,322	$ 10,470,205	$ 134,946,865
18	Prior Year(s) Deferred Expense	$ 747,085	$ 783,974	$ 712,624	$ 678,613	$ 709,119	$ 774,481	$ 820,363	$ 767,346	$ 723,730	$ 689,386	$ 661,025	$ 673,881	$ 8,741,628
19	Total Revenue	$ 12,339,573	$ 12,933,986	$ 11,768,156	$ 11,179,216	$ 11,629,228	$ 12,675,675	$ 13,426,995	$ 12,565,181	$ 11,847,930	$ 11,295,123	$ 10,883,347	$ 11,144,086	$ 143,688,493
20														
21	Electric Supply Expenses													
22	Net Base Purchases	$ 7,969,403	$ 8,472,289	$ 8,057,173	$ 9,103,028	$ 9,112,776	$ 9,924,940	$ 10,301,824	$ 8,935,253	$ 9,366,192	$ 9,157,523	$ 9,215,564	$ 8,269,202	$ 107,885,166
23	Net Base Sales	$ (405,912)	$ (400,192)	$ (326,500)	$ (291,816)	$ (289,920)	$ (355,056)	$ (310,300)	$ (285,200)	$ (287,496)	$ (269,464)	$ (234,100)	$ (243,464)	$ (3,699,420)
24	Net Term Purchases	$ 2,390,810	$ 2,390,810	$ 2,309,200	$ 2,418,630	$ 2,283,621	$ 2,390,810	$ 1,796,240	$ 1,720,160	$ 1,844,015	$ 1,782,880	$ 1,796,240	$ 1,782,880	$ 24,906,296
25	Net Term Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Net Spot Purchases	$ 1,995,452	$ 2,364,196	$ 551,895	$ 196,425	$ 759,690	$ 1,437,091	$ 826,353	$ 447,041	$ -	$ -	$ -	$ 780,451	$ 9,358,596
27	Net Spot Sales	$ (3,715,656)	$ (3,663,296)	$ (3,003,800)	$ (2,593,920)	$ (2,757,260)	$ (3,250,128)	$ (2,352,074)	$ (2,059,144)	$ (2,058,392)	$ (1,938,068)	$ (1,774,478)	$ (1,751,068)	$ (30,917,284)
28	Other Tracker Costs	$ 1,779,975	$ 2,094,879	$ 2,105,906	$ 2,061,686	$ 2,896,324	$ 2,684,617	$ 1,701,276	$ 1,937,214	$ 1,835,322	$ 1,878,906	$ 2,959,099	$ 2,089,273	$ 26,024,476
29	Total Electric Supply Expenses	$ 10,014,072	$ 11,258,686	$ 9,693,874	$ 10,894,034	$ 12,005,231	$ 12,832,274	$ 11,963,319	$ 10,695,324	$ 10,699,642	$ 10,611,777	$ 11,962,324	$ 10,927,274	$ 133,557,831
30														
31	NWE Transmission Costs													
32														
33	Other Services (Wheeling)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Ancillary Cost (Disallowed)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (17,010)
35	Total NWE Transmission	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (17,010)
36														
37	Administrative Expenses													
38	MPSC Tax Collection (.0020)	$ 24,679	$ 25,868	$ 23,536	$ 22,358	$ 23,258	$ 25,351	$ 26,854	$ 25,130	$ 23,696	$ 22,590	$ 21,767	$ 22,288	$ 287,377
39	MCC Tax Collection (.0010)	$ 12,340	$ 12,934	$ 11,768	$ 11,179	$ 11,629	$ 12,676	$ 13,427	$ 12,565	$ 11,848	$ 11,295	$ 10,883	$ 11,144	$ 143,688
40	Modeling	$ 35,453	$ 35,453	$ 35,453	$ 35,453	$ 35,453	$ 35,453	$ 35,453	$ 35,453	$ 35,453	$ 35,453	$ 35,453	$ 35,453	$ 425,436
41	Trading & Marketing	$ 2,017	$ 2,017	$ 2,017	$ 2,017	$ 2,017	$ 2,017	$ 2,017	$ 2,017	$ 2,017	$ 2,017	$ 2,017	$ 2,017	$ 24,201
42	Administration	$ 29,397	$ 29,397	$ 29,397	$ 29,397	$ 29,397	$ 29,397	$ 29,397	$ 29,397	$ 29,397	$ 29,397	$ 29,397	$ 29,397	$ 352,761
43	Total Administrative Expenses	$ 103,885	$ 105,668	$ 102,171	$ 100,404	$ 101,754	$ 104,894	$ 107,148	$ 104,562	$ 102,410	$ 100,752	$ 99,517	$ 100,299	$ 1,233,464
44														
45	Carrying Cost Expense													
46	Carrying Costs	$ 43,282	$ 33,138	$ 20,254	$ 19,152	$ 22,442	$ 24,318	$ 15,463	$ 3,835	$ (3,093)	$ (6,991)	$ 778	$ (0)	$ 172,580
47	Total Carrying Costs	$ 43,282	$ 33,138	$ 20,254	$ 19,152	$ 22,442	$ 24,318	$ 15,463	$ 3,835	$ (3,093)	$ (6,991)	$ 778	$ (0)	$ 172,580
48														
49														
50	Total Expenses	$ 10,159,822	$ 11,396,075	$ 9,814,882	$ 11,012,173	$ 12,128,010	$ 12,960,068	$ 12,084,512	$ 10,802,304	$ 10,797,541	$ 10,704,120	$ 12,061,201	$ 11,026,156	$ 134,946,865
51														
52	Deferred Cost Amortization	$ 747,085	$ 783,974	$ 712,624	$ 678,613	$ 709,119	$ 774,481	$ 820,363	$ 767,346	$ 723,730	$ 689,386	$ 661,025	$ 673,881	$ 8,741,628
53	(under collection)/over collection													
54	Monthly Deferred Cost	$ 1,432,666	$ 753,937	$ 1,240,649	$ (511,570)	$ (1,207,901)	$ (1,058,875)	$ 522,119	$ 995,530	$ 326,658	$ (98,383)	$ (1,838,879)	$ (555,951)	$ (0)
55	Cumulative Deferred Cost	$ 1,432,666	$ 2,186,602	$ 3,427,252	$ 2,915,681	$ 1,707,780	$ 648,905	$ 1,171,024	$ 2,166,555	$ 2,493,213	$ 2,394,830	$ 555,950	$ (0)	

Electric Supply Cost Tracker

Electric Tracker Projection Excluding Generation Assets Cost of Service

	Jul-15 Estimate	Aug-15 Estimate	Sep-15 Estimate	Oct-15 Estimate	Nov-15 Estimate	Dec-15 Estimate	Jan-16 Estimate	Feb-16 Estimate	Mar-16 Estimate	Apr-16 Estimate	May-16 Estimate	Jun-16 Estimate
Deferred Supply Cost Expense												
Beginning Balance	$ 8,741,628	$ 6,561,877	$ 5,023,966	$ 3,070,693	$ 2,903,650	$ 3,402,432	$ 3,686,825	$ 2,344,343	$ 581,467	$ (468,922)	$ (1,059,924)	$ 117,930
Monthly Deferred Cost	$ (2,179,750)	$ (1,537,911)	$ (1,953,274)	$ (167,043)	$ 498,782	$ 284,394	$ (1,342,482)	$ (1,762,876)	$ (1,050,388)	$ (591,003)	$ 1,177,854	$ (117,930)
Ending Balance	$ 6,561,877	$ 5,023,966	$ 3,070,693	$ 2,903,650	$ 3,402,432	$ 3,686,825	$ 2,344,343	$ 581,467	$ (468,922)	$ (1,059,924)	$ 117,930	$ (0)
Total Capital	$ 6,561,877	$ 5,023,966	$ 3,070,693	$ 2,903,650	$ 3,402,432	$ 3,686,825	$ 2,344,343	$ 581,467	$ (468,922)	$ (1,059,924)	$ 117,930	$ (0)

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

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%

Electric Supply Cost Tracker
Electric Tracker Projection

Volumes in MWh	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
Off System Transactions													
Fixed Price													
Base Fixed Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Competitive Solicitations	39,400	39,400	38,000	40,200	37,225	39,400	38,600	37,400	40,175	38,800	38,600	38,800	466,000
Base Fixed Price Sales													-
Competitive Solicitations	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Fixed Price Purchases	66,200	66,200	64,000	66,600	63,675	66,200	47,200	44,800	47,950	46,400	47,200	46,400	672,825
Term Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Index Price													
Base Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Base Index Price Sales													-
Competitive Solicitations	(10,400)	(10,400)	(10,000)	(10,800)	(9,600)	(10,400)	(10,000)	(10,000)	(10,800)	(10,400)	(10,000)	(10,400)	(123,200)
Term Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Sales	(95,200)	(95,200)	(92,000)	(96,000)	(91,300)	(95,200)	(75,800)	(72,200)	(77,325)	(74,800)	(75,800)	(74,800)	(1,015,625)
On System Transactions													
Fixed Price													
Rate-Based Assets													
Colstrip Unit 4	150,288	150,288	145,440	150,288	145,440	150,288	150,288	140,592	150,086	145,440	89,688	82,416	1,650,542
Dave Gates Generating Station	5,208	5,208	5,040	5,208	5,040	5,208	5,208	4,704	5,208	5,040	5,208	5,040	61,320
Spion Kop	8,184	8,184	9,360	14,136	14,400	11,904	17,856	11,136	11,888	11,520	8,928	8,640	136,136
Hydro Assets	271,560	209,808	180,991	179,388	189,958	207,034	209,419	201,835	221,945	226,011	251,997	244,322	2,594,268
Base Fixed Price Purchases													
Judith Gap	22,785	25,190	27,632	42,916	48,041	55,493	59,351	44,721	42,829	40,524	35,180	28,766	473,428
Other Non-QF	7,195	5,594	1,704	282	3,605	3,720	3,720	3,480	3,715	3,600	8,355	11,968	56,938
Competitive Solicitations	20,800	20,800	20,000	21,600	19,200	20,800	20,000	20,000	21,600	20,800	20,000	20,800	246,400
QF Tier II	58,376	69,644	69,722	77,434	73,638	75,603	73,522	64,788	67,497	71,898	69,469	46,485	818,076
QF Tier II Adjustments													-
QF-1 Tariff Contracts	11,414	12,201	11,475	14,225	16,204	26,412	28,644	21,228	23,405	20,629	21,855	19,656	227,348
Term Fixed Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Index Price													
Base Index Price Purchases													
Competitive Solicitations	10,400	10,400	10,000	10,800	9,600	10,400	10,000	10,000	10,800	10,400	10,000	10,400	123,200
Term Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Purchases	51,126	61,440	16,903	7,270	25,155	42,094	26,631	15,675	-	-	-	33,338	279,632
Spot Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Credits	(29,653)	(21,453)	(12,275)	(10,920)	(13,480)	-	-	-	(23,773)	(65,958)	(25,858)	-	(203,370)
Imbalance, Current Month Estimate	-	-	-	-	-	-	-	-	-	-	-	-	-
Imbalance, Prior Months True-up	-	-	-	-	-	-	-	-	-	-	-	-	-
Imbalance, Accounting & BA Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
Ancillary and Other													
Basin Creek Fixed Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Basin Creek Variable Costs	14,408	14,280	11,178	6,745	6,407	10,164	7,012	4,980	4,202	3,903	1,729	1,693	86,699
Operating Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Other Cost	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM Program & Labor Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
T & D Lost Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-
T & D Lost Revenue Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Delivered Supply	602,092	571,583	497,170	519,372	543,209	619,120	611,650	543,138	539,401	493,808	496,551	513,524	6,550,618

	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														
63	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
64	**Total Supply Expense**													
65														
66	**Energy Supply Expense**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Total**
67		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
68	**Off System Transactions**													
69	**Fixed Price**													
70	Base Fixed Price Purchases													
71	Competitive Solicitations	$ 2,314,000	$ 2,314,000	$ 2,232,200	$ 2,358,360	$ 2,189,400	$ 2,314,000	$ 2,269,640	$ 2,194,760	$ 2,356,800	$ 2,276,560	$ 2,269,640	$ 2,276,560	$ 27,365,920
72	Base Fixed Price Sales													
73	Competitive Solicitations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Term Fixed Price Purchases	$ 2,390,810	$ 2,390,810	$ 2,309,200	$ 2,418,630	$ 2,283,621	$ 2,390,810	$ 1,796,240	$ 1,720,160	$ 1,844,015	$ 1,782,880	$ 1,796,240	$ 1,782,880	$ 24,906,296
75	Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	**Index Price**													
77	Base Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	Base Index Price Sales													
79	Competitive Solicitations	$ (405,912)	$ (400,192)	$ (326,500)	$ (291,816)	$ (289,920)	$ (355,056)	$ (310,300)	$ (285,200)	$ (287,496)	$ (269,464)	$ (234,100)	$ (243,464)	$ (3,699,420)
80	Term Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	Spot Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
83	Spot Sales	$ (3,715,656)	$ (3,663,296)	$ (3,003,800)	$ (2,593,920)	$ (2,757,260)	$ (3,250,128)	$ (2,352,074)	$ (2,059,144)	$ (2,058,392)	$ (1,938,068)	$ (1,774,478)	$ (1,751,068)	$ (30,917,284)
84														
85	**On System Transactions**													
86	**Fixed Price**													
87	Rate-Based Assets													
88	Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	Spion Kop	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	Hydro Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92														
93	Base Fixed Price Purchases													
94	Judith Gap	$ 723,447	$ 799,775	$ 877,289	$ 1,362,569	$ 1,525,322	$ 1,761,904	$ 1,884,400	$ 1,419,885	$ 1,359,803	$ 1,286,618	$ 1,116,985	$ 913,326	$ 15,031,323
95	Other Non-QF	$ 389,340	$ 338,035	$ 75,812	$ (21,828)	$ 139,694	$ 144,150	$ 144,150	$ 134,850	$ 143,956	$ 139,500	$ 464,627	$ 718,111	$ 2,810,398
96	Competitive Solicitations	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 1,166,940	$ 1,037,280	$ 1,123,720	$ 1,080,500	$ 1,080,500	$ 1,166,940	$ 1,123,720	$ 1,080,500	$ 1,123,720	$ 13,311,760
97	QF Tier II	$ 2,264,991	$ 2,702,183	$ 2,705,209	$ 3,004,455	$ 2,857,166	$ 2,933,393	$ 2,852,635	$ 2,513,782	$ 2,618,864	$ 2,789,655	$ 2,695,400	$ 1,803,607	$ 31,741,341
98	QF Tier II Adjustments													$ -
99	QF-1 Tariff Contracts	$ 768,792	$ 815,184	$ 779,664	$ 962,316	$ 1,093,194	$ 1,313,517	$ 1,780,199	$ 1,326,277	$ 1,453,932	$ 1,292,806	$ 1,374,311	$ 1,211,214	$ 14,171,404
100	Term Fixed Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
101	Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
102	**Index Price**													
103	Base Index Price Purchases													
104	Competitive Solicitations	$ 385,112	$ 379,392	$ 306,500	$ 270,216	$ 270,720	$ 334,256	$ 290,300	$ 265,200	$ 265,896	$ 248,664	$ 214,100	$ 222,664	$ 3,453,020
105	Term Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
106	Term Index Price Sales													$ -
107	Spot Purchases	$ 1,995,452	$ 2,364,196	$ 551,895	$ 196,425	$ 759,690	$ 1,437,091	$ 826,353	$ 447,041	$ -	$ -	$ -	$ 780,451	$ 9,358,596
108	Spot Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
109	Revenue Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110	Imbalance, Current Month Estimate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111	Imbalance, Prior Months True-up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
112	Imbalance, Accounting & BA Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
113														
114	**Ancillary and Other**													
115	Basin Creek Fixed Costs	$ 515,687	$ 554,445	$ 549,237	$ 507,918	$ 922,514	$ 517,514	$ 486,042	$ 473,746	$ 487,518	$ 475,181	$ 900,874	$ 489,968	$ 6,880,645
116	Basin Creek Variable Costs	$ 398,828	$ 396,634	$ 307,134	$ 184,733	$ 183,067	$ 300,758	$ 211,249	$ 148,547	$ 122,803	$ 108,067	$ 47,010	$ 46,321	$ 2,455,149
117	Operating Reserves	$ -	$ -	$ 43,445	$ -	$ -	$ -	$ 3,046	$ -	$ 4,263	$ 66,480	$ 74,574	$ 104,177	$ 295,986
118	Wind Other Cost	$ 11,043	$ 11,043	$ 11,043	$ 11,043	$ 824,502	$ 11,043	$ 11,043	$ 11,043	$ 11,043	$ 11,043	$ 824,502	$ 11,043	$ 1,759,434
119	DSM Program & Labor Costs	$ 98,771	$ 377,111	$ 439,401	$ 602,346	$ 210,595	$ 1,099,655	$ 234,250	$ 548,232	$ 454,049	$ 462,490	$ 356,492	$ 682,119	$ 5,565,510
120	T & D Lost Revenue	$ 755,646	$ 755,646	$ 755,646	$ 755,646	$ 755,646	$ 755,646	$ 755,646	$ 755,646	$ 755,646	$ 755,646	$ 755,646	$ 755,646	$ 9,067,752
121	T & D Lost Revenue Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122														
123	**Total Delivered Supply**	$ 10,014,072	$ 11,258,686	$ 9,693,874	$ 10,894,034	$ 12,005,231	$ 12,832,274	$ 11,963,319	$ 10,695,324	$ 10,699,642	$ 10,611,777	$ 11,962,324	$ 10,927,274	$ 133,557,831
124		Wind Other Cost includes: Judith Gap impact fees and property tax charges, consulting work on met towers, 3 TIER forecasting fees, electric service at met towers, and WREGIS charges.												

	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														
125	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
126	**Unit Costs**													
127														
128	**Energy Supply Unit Costs**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Total**
129		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
130	**Off System Transactions**													
131	**Fixed Price**													
132	Base Fixed Price Purchases													
133	Competitive Solicitations	$ 58.73	$ 58.73	$ 58.74	$ 58.67	$ 58.82	$ 58.73	$ 58.80	$ 58.68	$ 58.66	$ 58.67	$ 58.80	$ 58.67	$ 58.73
134	Base Fixed Price Sales													
135	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
136	Term Fixed Price Purchases	$ 36.11	$ 36.11	$ 36.08	$ 36.32	$ 35.86	$ 36.11	$ 38.06	$ 38.40	$ 38.46	$ 38.42	$ 38.06	$ 38.42	$ 37.02
137	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
138	**Index Price**													
139	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
140	Base Index Price Sales													
141	Competitive Solicitations	$ 39.03	$ 38.48	$ 32.65	$ 27.02	$ 30.20	$ 34.14	$ 31.03	$ 28.52	$ 26.62	$ 25.91	$ 23.41	$ 23.41	$ 30.03
142	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
143	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
144	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
145	Spot Sales	$ 39.03	$ 38.48	$ 32.65	$ 27.02	$ 30.20	$ 34.14	$ 31.03	$ 28.52	$ 26.62	$ 25.91	$ 23.41	$ 23.41	$ 30.44
146														
147	**On System Transactions**													
148	**Fixed Price**													
149	Rate-Based Assets													
150	Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
151	Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152	Spion Kop	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
153	Hydro Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
154														
155	Base Fixed Price Purchases													
156	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
157	Other Non-QF	$ 54.11	$ 60.43	$ 44.49	$ (77.40)	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 55.61	$ 60.00	$ 49.36
158	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
159	QF Tier II	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80
160	QF Tier II Adjustments	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	QF-1 Tariff Contracts	$ 67.36	$ 66.81	$ 67.94	$ 67.65	$ 67.46	$ 49.73	$ 62.15	$ 62.48	$ 62.12	$ 62.67	$ 62.88	$ 61.62	$ 62.33
162	Term Fixed 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
163	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
164	**Index Price**													
165	Base Index Price Purchases													
166	Competitive Solicitations	$ 37.03	$ 36.48	$ 30.65	$ 25.02	$ 28.20	$ 32.14	$ 29.03	$ 26.52	$ 24.62	$ 23.91	$ 21.41	$ 21.41	$ 28.03
167	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
168	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
169	Spot Purchases	$ 39.03	$ 38.48	$ 32.65	$ 27.02	$ 30.20	$ 34.14	$ 31.03	$ 28.52	n/a	n/a	n/a	$ 23.41	$ 33.47
170	Spot Sales	$ 30.89	$ 35.11	$ 33.83	$ 31.65	$ 28.95	$ 16.89	$ 15.65	$ 14.54	$ 26.21	$ 28.24	$ 27.12	$ 30.12	$ 28.28
171	Revenue Credits													
172	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
173	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
174	Imbalance, Accounting & BA Expense													
175														
176	**Ancillary and Other**													
177	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
178	Basin Creek Variable 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
179	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
180	Wind Other Cost													
181	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
182	T & D Lost Revenue	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
183	T & D 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
184														
185														
186	**Total Delivered Supply**	$ 16.63	$ 19.70	$ 19.50	$ 20.98	$ 22.10	$ 20.73	$ 19.56	$ 19.69	$ 19.84	$ 21.49	$ 24.09	$ 21.28	$ 20.39
187														

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Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2014.7.58
Annual Electricity Supply Tracker
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF JOSEPH S. JANHUNEN

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 Joseph S. Janhunen, 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 ("NorthWestern") as a Senior Analyst in the Regulatory Affairs Department.

Q. Please summarize your educational and employment experiences.

A. I received a Bachelor of Science degree in Accounting from Montana State University in 1985. In January 1989, I completed the requirements to become a Certified Public Accountant. I began my employment with Montana Power Company and NorthWestern in 1986. I started in the Income Tax Department and worked there for five years. In 1991, I moved to the General Accounting Department. While in General Accounting, I recorded regulatory assets, regulatory liabilities, and the amortization associated with these assets and liabilities. In 2000, I transferred to the Financial Reporting Department. My major duties focused on the income statement. I prepared schedules for the Montana Public Service Commission ("MPSC" or "Commission") Annual Report and for FERC Form 1. In 2009, I moved into my current position in the Regulatory Affairs Department. My duties include conducting cost of service analyses, preparing workpapers and exhibits for the cost of service portion of proceedings before this Commission, preparing property tax tracker exhibits, and preparing exhibits and testimony for the electric supply tracker filings.

Purpose of Testimony

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

A. This testimony:

1. Presents the 2015-2016 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 both the 2013-2014 true-up period and the 2014-2015 true-up period;
3. Presents the derivation of proposed electricity supply rates for the forecasted 2015-2016 tracker period; and
4. Presents the overall total supply rates incorporating all individual rate components.

2015-2016 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 NorthWestern filings.

The methodology utilizes historical actual billed data, weather adjustments, known changes, and forecasted loads to derive the estimated usage for the July 2015 to June 2016 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 yearly 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 V. Bennett ("Bennett Direct Testimony"). Cyclical data is used to establish rates for billing purposes and calculate forecasted revenues.

Q. How was the tracker period usage presented in Exhibit__(JSJ-1)15-16 developed?

A. Table 1 of Exhibit__(JSJ-1)15-16 is actual billed usage for the period April 2014 through March 2015. The subsequent tables show a variety of changes that are made to arrive at the July 2015 through June 2016 forecasted usage shown on Table 5 of the exhibit. A brief description of Tables 1 through 4 in Exhibit__(JSJ-1)15-16 is as follows:

1. Table 1 is actual billed usage for 12 months ended March 2015.

2. Table 2 is the result of shifting data to a calendar month primarily using the Energy Vision computer program. Energy Vision shifts data to a calendar month by using actual hourly metered data for the larger customers, individual meter read data for smaller General Service – 1 ("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 is Table 2 adjusted for known changes and forecast information for the Residential and GS-1 customer classes.

4. Table 4 summarizes the changes shown on Table 3 as described below:

   - Column C shows the actual billed usage for the 12 months ended March 2015 as reflected on Table 1.
   - Column D shows changes in the operations of large customers. Changes include increases in load for four choice customers. Overall, the adjustment in Column D shows no increase in megawatt-hours ("MWh") in electric supply usage.

- Column E replaces the actual irrigation load with a three-year average resulting in an increase of 9,950 MWh to non-choice usage.
- Column F shows changes to the Residential and GS-1 Secondary classes as a result of their forecasted usage for the 12 months ended June 2016. The changes reflect the effects of normal weather, customer growth, and Demand-Side Management ("DSM") 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 97,787 MWh increase to electric supply usage.
- Column G is the resulting forecasted usage for the July 2015 through June 2016 time period.
- Column H reflects the sum of all changes (Columns D through F). The total result is a forecasted increase of 107,737 MWh to electric supply usage for the 2015-2016 tracker period.

Q. Describe the adjustments made in Table 5 of Exhibit__(JSJ-1)15-16.

A. Again, Table 3 is forecasted calendar month usage with the known change adjustments described above. Table 5 modifies Table 3 by making 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 (Substation and Transmission) 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 6 of Exhibit__(JSJ-1)15-16.

A. Table 6 is a subset of Table 5 showing only those loads applicable to electric supply purchases and that are used in the Bennett Direct Testimony.

It is necessary to make several adjustments to Table 5 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 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 6 of Exhibit__(JSJ-1)15-16 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 associated with YNP 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"), the Dave Gates Generating Station ("DGGS"), the Spion Kop Wind Generation Asset ("Spion"), the Hydro Generation Asset ("Hydro") fixed costs, and the Revenue Credits, the resulting calculations would be an administrative burden. In addition, the inclusion of adjustments to all components would not change the total overall supply rate charged to ratepayers. Therefore, only the electricity supply rate derivation includes a revenue credit related to the YNP customer class.

Derivation of Proposed Deferred Electricity Supply Rates

Q. What is the electricity supply cost account balance for the 12-month period ending June 2015?

A. The electricity supply cost account balance for the 12-month period ending June 2015 is an under-collection of $8,741,628 as presented on page 1 of Exhibit__(JSJ-2)15-16. As discussed below, this includes the prior period balance for the 2013-2014 tracker period and the current period balance for the 2014-2015 tracker period.

Q. Describe the status of the deferred electricity supply cost account balance associated with the 2013-2014 tracker period.

A. In the annual filing submitted on May 29, 2014, the net deferred account balance for the 2013-2014 tracker period was shown as an under-collection of $34,320,720. This amount becomes the starting balance in this filing. Added to this balance is the prior period true-up for the 3 months of estimated data included in the May 2014 filing. Page 1 of Exhibit__(JSJ-2)15-16 shows the true-up of the previously estimated months of April, May and June 2014 with actual data for these months. The resulting actual under-collected ending balance of $37,220,708 is the deferred account beginning balance associated with the 2013-2014 tracker period. This balance is then combined with the current year monthly activity shown on Exhibit__(JSJ-2)15-16, page 1, resulting in a net under-collected balance of $5,120,046 for the 2013-2014 tracker period. The months of April, May and June 2015 are estimated and will be trued-up in the next annual electric supply filing.

Q. Describe the electricity supply cost account balance associated with the 2014-2015 tracking period.

A. Page 2 of Exhibit__(JSJ-2)15-16 shows the monthly detail of the difference between the electricity supply cost revenues and expenses for the 2014-2015 tracker period, resulting in an under-collected amount of $3,621,582. The months of April, May and June 2015 are estimated and will be trued-up in the next annual electric supply 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 $8,741,628 shown below and on page 1, line 64 of Exhibit__(JSJ-2)15-16.

Total Electric Deferred Supply Cost Account Balance	
2013-2014 Prior Period Supply Cost Account Balance	$5,120,046
2014-2015 Current Period Supply Cost Account Balance	$3,621,582
	$8,741,628

Derivation of the deferred electricity supply rates is shown on Exhibit__(JSJ-2)15-16, page 3 with the resulting rates and revenues shown on page 4.

Derivation of Proposed Electricity Supply Rates

Q. Please describe the process NorthWestern used to derive the proposed 2015-2016 forecasted electricity supply rates in this filing.

A. The rate design methodology used in this filing to derive the proposed 2015-2016 forecasted electricity supply rates is the same as that presented in previous electricity supply tracker filings. All forecasted costs are from Exhibit__(FVB-2)15-16 of the Bennett Direct Testimony and are discussed therein.

Derivation of the electricity supply rates is shown on Exhibit__(JSJ-2)15-16, pages 5 and 6. The total proposed electricity supply cost of $134,946,865 from Exhibit__(FVB-2)15-16 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__(JSJ-1)15-16 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 electricity supply rates proposed in this filing.

Page 7 of Exhibit__(JSJ-2)15-16 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 $5,781,794. The adjustment consists of the following:

Net Deferred Supply Cost Account Balance

Total Deferred Electricity Supply Under-Collected Balance	$8,741,628
Total Deferred CU4 Variable Over-Collected Balance	$(3,723,557)
Total Deferred DGGS Variable Under-Collected Balance	$777,601
Total Deferred Spion Variable Over-Collected Balance	$(13,878)
	$5,781,794

The deferred CU4 variable rate design is shown on page 3 of Exhibit__(JSJ-3)15-16 and is addressed in, and included with, the Annual CU4 True-up section of my testimony. The deferred DGGS variable rate design is shown on page 3 of Exhibit__(JSJ-4)15-16 and is addressed in, and included with, the Annual DGGS True-up section of my testimony. The deferred Spion variable rate design is shown on page 3 of Exhibit__(JSJ-5)15-16 and is addressed in, and included with, the Annual Spion True-up section of my testimony. The individual rate components are then combined into a single deferred rate for use in billing. The net total deferred supply rate is shown on page 1 of Exhibit__(JSJ-8)15-16. The total deferred supply revenue of $5,774,792, including rounding, is shown on Exhibit__(JSJ-8)15-16, page 2, column X, line 39.

Proposed Total Supply Rates

Q. Please describe the process NorthWestern used to derive the total 2015-2016 electric supply rates proposed in this filing.

A. 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 variable rate, a Spion fixed cost of service rate, a Spion variable rate, a Hydro fixed cost of service rate, a Hydro variable rate, and a Revenue Credits rate. See page 7 of Exhibit__(JSJ-2)15-16 for proposed electricity supply rates; page 6 of Exhibit__(JSJ-3)15-16 for proposed CU4 fixed and variable rates; page 6 of Exhibit__(JSJ-4)15-16 for proposed DGGS fixed and variable rates; page 6 of Exhibit__(JSJ-5)15-16 for proposed Spion fixed and variable rates; page 2 of Exhibit__(JSJ-6)15-16 for proposed Hydro fixed and variable rates; and page 1 of Exhibit__(JSJ-7)15-16 for Revenue Credits rates. Note that the CU4, DGGS, Spion, and Hydro fixed rates and the Revenue Credits rates remain unchanged from current rates. All of the individual fixed and variable rate components are bundled together into a single rate for customer billing as shown on Exhibit__(JSJ-8)15-16, page 3 with the resulting revenues by rate component shown on page 4 and listed below:

Net Supply Revenue

Total Supply Revenue at Current Rates	$402,378,861
Electricity Supply Revenue at Proposed Rates	133,545,516
CU4 Fixed Revenue at Current Rates	76,592,496
CU4 Variable Revenue at Proposed Rates	28,882,922
DGGS Fixed Revenue at Current Rates	28,841,376
DGGS Variable Revenue at Proposed Rates	8,192,177
Spion Fixed Revenue at Current Rates	8,773,698
Spion Variable Revenue at Proposed Rates	108,699
Hydro Fixed Revenue at Current Rates	161,299,913
Hydro Variable Revenue at Proposed Rates	1,792,692
Revenue Credits at Current Rates	(43,619,165)
Total Supply Revenue at Proposed Rates	$404,410,325
Net Proposed Total Supply Revenue Change	$2,031,464

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

A. Yes. The total supply rates (the summation of all the individual rate components) and total supply revenues are shown on Exhibit__(JSJ-8)15-16, page 5.

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

A. NorthWestern 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, 2015.

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

A. Yes, it does.

TABLE 1 - Actual billing cycle data

NorthWestern Energy Actual Revenue Month Sales in MWH

	Class	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Total
8	Residential Non-Choice	196,669	174,410	160,864	172,548	203,950	178,441	159,106	173,204	238,096	275,476	221,446	206,952	2,361,162
9	Residential Choice	0	0	1	1	1	1	1	1	1	1	0	0	9
10	**Total Residential**	**196,669**	**174,410**	**160,865**	**172,549**	**203,951**	**178,442**	**159,107**	**173,205**	**238,097**	**275,477**	**221,446**	**206,952**	**2,361,171**
11	GS Secondary Non-Choice	215,410	211,990	212,321	226,391	249,675	238,719	213,899	206,562	235,045	256,788	225,711	219,211	2,711,722
12	GS Secondary Choice	5,009	3,884	5,980	6,096	6,526	6,029	5,600	5,336	5,197	5,470	5,355	5,000	65,482
13	GS Primary Non-Choice	27,655	26,912	26,965	26,992	29,764	30,016	29,358	30,141	30,133	31,120	29,574	27,312	345,942
14	GS Primary Choice	5,993	6,162	6,432	5,947	3,159	5,697	5,608	6,221	5,501	5,304	6,112	5,586	67,721
15	**Total General Service - 1**	**254,067**	**248,949**	**251,698**	**265,425**	**289,124**	**280,461**	**254,466**	**248,260**	**275,875**	**298,682**	**266,751**	**257,109**	**3,190,867**
16	GS Substation Non-Choice	19,931	18,422	17,771	17,008	19,483	19,520	19,533	20,956	20,653	21,639	20,850	18,955	234,721
17	GS Substation Choice	143,913	133,012	139,218	134,010	145,203	147,815	140,584	129,836	144,647	148,061	148,112	132,779	1,687,189
18	GS Transmission Non-Choice	11,179	10,349	10,675	11,348	10,833	10,826	10,703	11,803	11,871	11,208	12,704	10,953	134,452
19	GS Transmission Choice	13,370	11,938	12,776	13,222	13,223	15,925	15,705	16,044	15,564	15,477	15,339	13,359	171,944
20	**Total General Service - 2**	**188,394**	**173,721**	**180,440**	**175,587**	**188,741**	**194,086**	**186,526**	**178,639**	**192,735**	**196,385**	**197,005**	**176,047**	**2,228,306**
21	Irrigation Non-Choice	-9	3,032	11,723	23,302	27,748	14,153	5,300	1,733	-86	-16	-82	11	86,810
22	Irrigation Choice	0	6	17	21	39	55	15	6	1	0	0	0	159
23	**Total Irrigation**	**-9**	**3,037**	**11,741**	**23,323**	**27,787**	**14,209**	**5,315**	**1,739**	**-85**	**-16**	**-82**	**11**	**86,969**
24	Lighting Non-Choice	4,828	4,793	4,663	4,800	4,758	4,835	4,774	4,832	4,816	4,945	4,858	4,818	57,721
25	Lighting Choice	359	358	355	365	356	359	359	359	359	359	358	358	4,305
26	**Total Lighting**	**5,187**	**5,152**	**5,019**	**5,165**	**5,115**	**5,194**	**5,133**	**5,191**	**5,175**	**5,303**	**5,216**	**5,176**	**62,025**
27	Yellowstone Contract	520	906	3,821	3,580	2,595	2,455	2,704	1,670	616	589	547	565	20,568
28	**Total Yellowstone**	**520**	**906**	**3,821**	**3,580**	**2,595**	**2,455**	**2,704**	**1,670**	**616**	**589**	**547**	**565**	**20,568**
29	REC Silicon	66,242	61,689	50,314	59,037	60,467	41,831	54,140	52,256	59,828	59,024	57,256	50,830	672,915
30	**Special Contract**	**66,242**	**61,689**	**50,314**	**59,037**	**60,467**	**41,831**	**54,140**	**52,256**	**59,828**	**59,024**	**57,256**	**50,830**	**672,915**
31	**Total Distribution**	**711,069**	**667,864**	**663,897**	**704,667**	**777,780**	**716,677**	**667,390**	**660,961**	**772,242**	**835,443**	**748,140**	**696,690**	**8,622,821**
34	**Total Electric Supply Usage**	476,183	450,815	448,804	485,968	548,806	498,965	445,378	450,902	541,145	601,748	515,607	488,777	5,953,097
35	**Total Choice Usage**	234,886	217,050	215,093	218,699	228,974	217,712	222,013	210,059	231,097	233,695	232,533	207,913	2,669,724
36		711,069	667,864	663,897	704,667	777,780	716,677	667,390	660,961	772,242	835,443	748,140	696,690	8,622,821

TABLE 2 - Calendar month sales from Energy Vision

NorthWestern Energy Calendar Month Sales (MWh)

Class	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Total
Residential Non-Choice	216,676	175,461	165,420	156,789	203,977	190,791	159,513	171,762	228,467	251,159	244,752	201,060	2,365,827
Residential Choice	1	0	0	1	1	1	1	0	0	0	0	0	5
Total Residential	**216,677**	**175,461**	**165,420**	**156,790**	**203,978**	**190,792**	**159,514**	**171,762**	**228,467**	**251,159**	**244,752**	**201,060**	**2,365,832**
GS Secondary Non-Choice	230,148	212,075	219,434	217,272	255,400	245,510	219,027	219,629	225,316	243,123	240,767	212,627	2,740,328
GS Secondary Choice	5,013	4,824	5,297	5,235	6,226	6,103	5,393	5,386	5,080	5,322	5,363	4,761	64,002
GS Primary Non-Choice	28,206	26,400	26,510	26,004	29,434	29,249	29,099	30,072	29,574	30,031	30,050	27,141	341,771
GS Primary Choice	5,993	6,162	6,431	5,948	3,158	5,697	5,608	6,222	5,501	5,304	6,111	5,586	67,721
Total General Service - 1	**269,361**	**249,461**	**257,672**	**254,458**	**294,218**	**286,559**	**259,127**	**261,309**	**265,471**	**283,780**	**282,291**	**250,115**	**3,213,823**
GS Substation Non-Choice	21,904	20,527	19,298	18,252	20,303	20,353	20,710	21,594	22,750	23,064	22,410	20,665	251,830
GS Substation Choice	141,956	131,501	138,057	132,747	144,114	146,633	139,234	128,768	142,759	146,249	146,503	131,229	1,669,748
GS Transmission Non-Choice	10,989	10,767	10,741	10,556	10,897	11,461	10,881	11,484	11,712	11,327	12,803	11,019	134,637
GS Transmission Choice	13,370	11,938	12,776	13,222	13,223	15,925	15,705	16,044	15,564	15,477	15,339	13,359	171,944
Total General Service - 2	**188,218**	**174,733**	**180,872**	**174,778**	**188,536**	**194,372**	**186,530**	**177,890**	**192,786**	**196,117**	**197,054**	**176,272**	**2,228,159**
Irrigation Non-Choice	125	526	8,564	22,764	30,925	17,786	6,450	1,691	61	7	3	8	88,912
Irrigation Choice	0	0	0	21	38	30	15	4	0	0	0	0	109
Total Irrigation	**125**	**526**	**8,564**	**22,764**	**30,925**	**17,786**	**6,450**	**1,691**	**61**	**7**	**3**	**8**	**89,020**
Lighting Non-Choice	5,459	4,385	3,884	3,192	3,612	4,322	4,819	6,028	6,483	6,731	6,958	5,413	61,285
Lighting Choice	382	318	277	226	267	306	340	427	437	477	491	366	4,314
Total Lighting	**5,841**	**4,702**	**4,160**	**3,418**	**3,879**	**4,628**	**5,160**	**6,455**	**6,921**	**7,208**	**7,448**	**5,779**	**65,599**
Yellowstone Contract	954	1,231	2,427	2,752	2,543	2,574	2,412	1,530	1,037	1,014	1,170	1,047	20,691
Total Yellowstone	**954**	**1,231**	**2,427**	**2,752**	**2,543**	**2,574**	**2,412**	**1,530**	**1,037**	**1,014**	**1,170**	**1,047**	**20,691**
REC Silicon	66,242	61,689	50,314	59,037	60,467	41,831	54,140	52,256	59,828	59,024	57,256	50,830	672,915
Special Contract	**66,242**	**61,689**	**50,314**	**59,037**	**60,467**	**41,831**	**54,140**	**52,256**	**59,828**	**59,024**	**57,256**	**50,830**	**672,915**
Total Distribution	**747,418**	**667,803**	**669,430**	**673,998**	**784,547**	**738,541**	**673,333**	**672,892**	**754,571**	**798,309**	**789,976**	**685,111**	**8,656,038**
Total Electric Supply Usage	514,462	451,371	456,279	457,582	557,091	522,045	452,911	463,789	525,402	566,456	558,913	478,980	6,005,281
Total Choice Usage	232,957	216,432	213,151	216,437	227,494	216,526	220,437	209,107	229,170	231,853	231,063	206,132	2,650,757
	747,418	667,803	669,430	674,019	784,585	738,571	673,348	672,896	754,571	798,309	789,976	685,111	8,656,038

TABLE 3: Table 2 adjusted for known changes & forecast information.

NorthWestern Energy Sales in MWH - With Forecast and Known Change Adjustments

Class	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
Residential Non-Choice	201,064	189,821	163,659	186,375	211,317	258,962	251,019	219,180	203,019	179,095	168,862	165,870	2,398,243
Residential Choice	0	0	0	0	0	1	1	1	0	0	0	0	5
Total Residential	**201,064**	**189,822**	**163,659**	**186,376**	**211,318**	**258,963**	**251,019**	**219,180**	**203,020**	**179,095**	**168,863**	**165,870**	**2,398,248**
GS Secondary Non-Choice	255,349	251,616	221,562	221,787	219,776	241,545	241,424	218,009	228,442	214,009	218,439	223,661	2,755,617
GS Secondary Choice	5,964	5,877	5,175	5,180	5,133	5,641	5,639	5,092	5,335	4,998	5,102	5,224	64,359
GS Primary Non-Choice	29,434	29,249	29,099	30,072	29,574	30,031	30,050	27,141	28,206	26,400	26,510	26,004	341,771
GS Primary Choice	3,158	5,697	5,608	6,222	5,501	5,304	6,111	5,586	5,993	6,162	6,431	5,948	67,721
Total General Service - 1	**293,905**	**292,439**	**261,443**	**263,261**	**259,984**	**282,522**	**283,223**	**255,828**	**267,977**	**251,569**	**256,483**	**260,836**	**3,229,469**
GS Substation Non-Choice	20,303	20,353	20,710	21,594	22,750	23,064	22,410	20,665	21,904	20,527	19,298	18,252	251,830
GS Substation Choice	144,114	146,633	139,234	128,768	142,759	146,249	146,503	131,565	142,739	132,622	139,578	134,581	1,675,344
GS Transmission Non-Choice	10,897	11,461	10,881	11,484	11,712	11,327	12,803	11,019	10,989	10,767	10,741	10,556	134,637
GS Transmission Choice	13,223	15,925	15,705	25,716	24,937	25,149	25,011	22,095	25,091	23,676	25,117	24,395	266,041
Total General Service - 2	**188,536**	**194,372**	**186,530**	**187,562**	**202,159**	**205,789**	**206,726**	**185,344**	**200,724**	**187,591**	**194,734**	**187,785**	**2,327,852**
Irrigation Non-Choice	33,655	19,365	7,027	1,843	66	8	4	9	136	572	9,309	24,767	96,760
Irrigation Choice	41	24	9	2	0	0	0	0	0	1	11	30	118
Total Irrigation	**33,696**	**19,389**	**7,036**	**1,845**	**67**	**8**	**4**	**9**	**136**	**573**	**9,320**	**24,797**	**96,878**
Lighting Non-Choice	3,612	4,322	4,819	6,028	6,483	6,731	6,958	5,413	5,459	4,385	3,884	3,192	61,285
Lighting Choice	267	306	340	427	437	477	491	366	382	318	277	226	4,314
Total Lighting	**3,879**	**4,628**	**5,160**	**6,455**	**6,921**	**7,208**	**7,448**	**5,779**	**5,841**	**4,702**	**4,160**	**3,418**	**65,599**
Yellowstone Contract	2,543	2,574	2,412	1,530	1,037	1,014	1,170	1,047	954	1,231	2,427	2,752	20,691
Total Yellowstone	**2,543**	**2,574**	**2,412**	**1,530**	**1,037**	**1,014**	**1,170**	**1,047**	**954**	**1,231**	**2,427**	**2,752**	**20,691**
REC Silicon	60,467	41,831	54,140	52,256	59,828	59,024	57,256	50,830	66,242	61,689	50,314	59,037	672,915
Special Contract	**60,467**	**41,831**	**54,140**	**52,256**	**59,828**	**59,024**	**57,256**	**50,830**	**66,242**	**61,689**	**50,314**	**59,037**	**672,915**
Total Distribution	**784,091**	**745,053**	**680,379**	**699,283**	**741,313**	**814,527**	**806,848**	**718,017**	**744,894**	**686,450**	**686,301**	**704,495**	**8,811,652**
Total Electric Supply Usage	556,856	528,761	460,168	480,712	502,717	572,682	565,837	502,482	499,110	456,985	459,471	475,054	6,060,834
Total Choice Usage	227,235	216,293	220,211	218,571	238,596	241,845	241,012	215,535	245,784	229,465	226,831	229,441	2,750,817
	784,091	745,053	680,379	699,283	741,313	814,527	806,848	718,017	744,894	686,450	686,301	704,495	8,811,652

TABLE 4 - Comparison of Tables 1 & 3

NorthWestern Energy Sales (MWh)

Class	Table 1	Lg Cust Known Changes	Irrig Adj & Choice/ NonChoice Movement	Res/GS-1 Forecasts & Shift to Calendar Month	Table 3	Diff MWH	% Diff	Changes
Residential Non-Choice	2,361,162			37,081	2,398,243	37,081	1.57%	Replaced actual with forecast for 12 months ended June 2016.
Residential Choice	9			-4	5	-4	-43.31%	Only two residential choice account as of 2015.
Total Residential	**2,361,171**	**0**	**0**	**37,077**	**2,398,248**	**37,077**	**1.57%**	
GS Secondary Non-Choice	2,711,722			43,895	2,755,617	43,895	1.62%	Replaced actual with forecast for 12 months ended June 2016.
GS Secondary Choice	65,482			-1,123	64,359	-1,123	-1.71%	Replaced with forecast.
GS Primary Non-Choice	345,942			-4,171	341,771	-4,171	-1.21%	Shift to calendar (4,171).
GS Primary Choice	67,721			0	67,721	0	0.00%	
Total General Service - 1	**3,190,867**	**0**	**0**	**38,602**	**3,229,469**	**38,602**	**1.21%**	
GS Substation Non-Choice	234,721			17,109	251,830	17,109	7.29%	Shift to calendar/part of 1 cust choice in Tbl 2 (17,109).
GS Substation Choice	1,687,189	5,596		-17,441	1,675,344	-11,845	-0.70%	Shift to calendar/part of 1 cust choice in Tbl 2 (-17,441). Increase 2 cust (5,596)
GS Transmission Non-Choice	134,452			185	134,637	185	0.14%	Shift to calendar (185).
GS Transmission Choice	171,944	94,097		0	266,041	94,097	54.73%	Increase 2 customers (94,097).
Total General Service - 2	**2,228,306**	**99,693**	**0**	**-147**	**2,327,852**	**99,546**	**4.47%**	
Irrigation Non-Choice	86,810		9,950		96,760	9,950	11.46%	Replaced actuals with 3 year average
Irrigation Choice	159			-41	118	-41	-25.71%	
Total Irrigation	**86,969**	**0**	**9,950**	**-41**	**96,878**	**9,909**	**11.39%**	
Lighting Non-Choice	57,721			3,564	61,285	3,564	6.18%	Shift to calendar month.
Lighting Choice	4,305			9	4,314	9	0.21%	
Total Lighting	**62,025**	**0**	**0**	**3,573**	**65,599**	**3,573**	**5.76%**	
Yellowstone Contract	20,568			123	20,691	123	0.60%	
Total Yellowstone	**20,568**	**0**	**0**	**123**	**20,691**	**123**	**0.60%**	
REC Silicon	672,915			0	672,915	0	0.00%	
Special Contract	**672,915**	**0**	**0**	**0**	**672,915**	**0**	**0.00%**	
Total Distribution	**8,622,821**	**99,693**	**9,950**	**79,187**	**8,811,652**	**188,831**	**2.19%**	
Total Electric Supply Usage	5,953,097	0	9,950	97,787	6,060,834	107,737	1.81%	
Total Choice Usage	2,669,724	99,693	0	-18,599	2,750,817	81,094	3.04%	
	8,622,821	**99,693**	**9,950**	**79,187**	**8,811,652**	**188,831**	**2.19%**	
		-	-	-	-			

TABLE 5: Table 3 shifted for cyclical billing.

NorthWestern Energy Sales in MWH - Shifted to Cyclical Month

Class	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
Residential Non-Choice	183,467	195,443	176,740	175,017	198,846	235,140	254,991	235,099	211,099	191,057	173,978	167,366	2,398,243
Residential Choice	0	0	0	0	0	0	1	1	0	0	0	0	5
Total Residential	**183,467**	**195,443**	**176,740**	**175,017**	**198,847**	**235,140**	**254,991**	**235,100**	**211,100**	**191,057**	**173,979**	**167,366**	**2,398,248**
GS Secondary Non-Choice	239,505	253,483	236,589	221,674	220,782	230,660	241,484	229,716	223,226	221,225	216,224	221,050	2,755,617
GS Secondary Choice	5,594	5,920	5,526	5,177	5,156	5,387	5,640	5,365	5,214	5,167	5,050	5,163	64,359
GS Primary Non-Choice	27,719	29,341	29,174	29,586	29,823	29,803	30,041	28,595	27,673	27,303	26,455	26,257	341,771
GS Primary Choice	4,553	4,428	5,652	5,915	5,861	5,402	5,708	5,849	5,790	6,078	6,297	6,189	67,721
Total General Service - 1	**277,371**	**293,172**	**276,941**	**262,352**	**261,622**	**271,253**	**282,873**	**269,526**	**261,902**	**259,773**	**254,026**	**258,659**	**3,229,469**
GS Substation Non-Choice	20,303	20,353	20,710	21,594	22,750	23,064	22,410	20,665	21,904	20,527	19,298	18,252	251,830
GS Substation Choice	144,114	146,633	139,234	128,768	142,759	146,249	146,503	131,565	142,739	132,622	139,578	134,581	1,675,344
GS Transmission Non-Choice	10,897	11,461	10,881	11,484	11,712	11,327	12,803	11,019	10,989	10,767	10,741	10,556	134,637
GS Transmission Choice	13,223	15,925	15,705	25,716	24,937	25,149	25,011	22,095	25,091	23,676	25,117	24,395	266,041
Total General Service - 2	**188,536**	**194,372**	**186,530**	**187,562**	**202,159**	**205,789**	**206,726**	**185,344**	**200,724**	**187,591**	**194,734**	**187,785**	**2,327,852**
Irrigation Non-Choice	29,211	26,510	13,196	4,435	954	37	6	6	72	354	4,940	17,038	96,760
Irrigation Choice	36	32	16	5	1	0	0	0	0	0	6	21	118
Total Irrigation	**29,246**	**26,542**	**13,212**	**4,440**	**956**	**37**	**6**	**6**	**72**	**354**	**4,947**	**17,059**	**96,878**
Lighting Non-Choice	5,107	5,107	5,107	5,107	5,107	5,107	5,107	5,107	5,107	5,107	5,107	5,107	61,285
Lighting Choice	359	359	359	359	359	359	359	359	359	359	359	359	4,314
Total Lighting	**5,467**	**5,467**	**5,467**	**5,467**	**5,467**	**5,467**	**5,467**	**5,467**	**5,467**	**5,467**	**5,467**	**5,467**	**65,599**
Yellowstone Contract	2,648	2,559	2,493	1,971	1,283	1,025	1,092	1,109	1,001	1,093	1,829	2,590	20,691
Total Yellowstone	**2,648**	**2,559**	**2,493**	**1,971**	**1,283**	**1,025**	**1,092**	**1,109**	**1,001**	**1,093**	**1,829**	**2,590**	**20,691**
REC Silicon	60,467	41,831	54,140	52,256	59,828	59,024	57,256	50,830	66,242	61,689	50,314	59,037	672,915
Special Contract	**60,467**	**41,831**	**54,140**	**52,256**	**59,828**	**59,024**	**57,256**	**50,830**	**66,242**	**61,689**	**50,314**	**59,037**	**672,915**
Total Distribution	**747,202**	**759,385**	**715,523**	**689,065**	**730,161**	**777,735**	**808,411**	**747,381**	**746,507**	**707,024**	**685,295**	**697,962**	**8,811,652**
													-
Total Electric Supply Usage	518,856	544,256	494,890	470,867	491,258	536,164	567,933	531,317	501,072	477,433	458,573	468,216	6,060,834
Total Choice Usage	228,346	215,129	220,633	218,197	238,903	241,571	240,478	216,065	245,436	229,591	226,722	229,746	2,750,817
	747,202	759,385	715,523	689,065	730,161	777,735	808,411	747,381	746,507	707,024	685,295	697,962	8,811,652

TABLE 6 - Table 5 modified for rate design

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

Class	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
Residential Non-Choice	183,208	195,167	176,491	174,770	198,566	234,808	254,631	234,768	210,802	190,788	173,733	167,130	2,394,863
Residential Employee	259	275	249	247	280	331	359	331	298	269	245	236	3,380
Total Residential	**183,467**	**195,443**	**176,740**	**175,017**	**198,846**	**235,140**	**254,991**	**235,099**	**211,099**	**191,057**	**173,978**	**167,366**	**2,398,243**
	-	-	-	-	-	-	-	-	-	-	-	-	-
GS Secondary Non-Demand	24,227	25,641	23,932	22,424	22,333	23,333	24,428	23,237	22,581	22,378	21,872	22,361	278,748
GS Secondary Demand	215,277	227,841	212,656	199,251	198,448	207,328	217,056	206,479	200,645	198,847	194,351	198,689	2,476,869
Total GS-1 Secondary	**239,505**	**253,483**	**236,589**	**221,674**	**220,782**	**230,660**	**241,484**	**229,716**	**223,226**	**221,225**	**216,224**	**221,050**	**2,755,617**
	-	-	-	-	-	-	-	-	-	-	-	-	-
GS Primary Non-Demand	38	41	40	41	41	41	42	40	38	38	37	36	473
GS Primary Demand	27,681	29,301	29,134	29,545	29,782	29,761	29,999	28,556	27,635	27,265	26,418	26,221	341,298
Total GS-1 Primary	**27,719**	**29,341**	**29,174**	**29,586**	**29,823**	**29,803**	**30,041**	**28,595**	**27,673**	**27,303**	**26,455**	**26,257**	**341,771**
	-	-	-	-	-	-	-	-	-	-	-	-	-
Total GS-2 Substation	**20,303**	**20,353**	**20,710**	**21,594**	**22,750**	**23,064**	**22,410**	**20,665**	**21,904**	**20,527**	**19,298**	**18,252**	**251,830**
Total GS-2 Transmission	**10,897**	**11,461**	**10,881**	**11,484**	**11,712**	**11,327**	**12,803**	**11,019**	**10,989**	**10,767**	**10,741**	**10,556**	**134,637**
Total Irrigation	**29,211**	**26,510**	**13,196**	**4,435**	**954**	**37**	**6**	**6**	**72**	**354**	**4,940**	**17,038**	**96,760**
Total Lighting	**5,107**	**5,107**	**5,107**	**5,107**	**5,107**	**5,107**	**5,107**	**5,107**	**5,107**	**5,107**	**5,107**	**5,107**	**61,285**
MPSC Electric Supply Load	**516,208**	**541,697**	**492,397**	**468,897**	**489,975**	**535,138**	**566,841**	**530,208**	**500,071**	**476,340**	**456,744**	**465,627**	**6,040,143**
Yellowstone Park Load	**2,648**	**2,559**	**2,493**	**1,971**	**1,283**	**1,025**	**1,092**	**1,109**	**1,001**	**1,093**	**1,829**	**2,590**	**20,691**
Total Electric Supply Load	**518,856**	**544,256**	**494,890**	**470,867**	**491,258**	**536,164**	**567,933**	**531,317**	**501,072**	**477,433**	**458,573**	**468,216**	**6,060,834**
													-

NorthWestern Energy
Electric Utility
Deferred Supply Cost Account Balance
July 2014 - June 2015

Month	Monthly Collection	Collection to-date	Balance Remaining
Jul13-Jun14 under collected balance as filed in D2014.5.46			**$ 34,320,720**
Prior Period Tracker Year True-up - Deferred:			
Apr14: Estimated as filed in D2014.5.46		$ (276,487)	
Apr14: Actual		$ (276,487)	$ -
May14: Estimated as filed in D2014.5.46		$ (268,267)	
May14: Actual		$ (261,515)	$ (6,751)
Jun14: Estimated as filed in D2014.5.46		$ (294,474)	
Jun14: Actual		$ (258,625)	$ (35,849)
Prior Period Tracker Year True-up - Supply:			
Apr14: Est as filed in D2014.5.46 - Revenue	$ 18,522,121		
Apr14: Est as filed in D2014.5.46 - Expense	$ 18,861,038	$ 338,917	
Apr14: Actual - Revenue	$ 18,522,121		
Apr14: Actual - Expense	$ 19,494,988	$ 972,867	$ 633,950
May14: Est as filed in D2014.5.46 - Revenue	$ 17,707,490		
May14: Est as filed in D2014.5.46 - Expense	$ 22,337,226	$ 4,629,735	
May14: Actual - Revenue	$ 17,355,094		
May14: Actual - Expense	$ 21,197,124	$ 3,842,030	$ (787,705)
Jun14: Est as filed in D2014.5.46 - Revenue	$ 18,867,277		
Jun14: Est as filed in D2014.5.46 - Expense	$ 20,490,370	$ 1,623,093	
Jun14: Actual - Revenue	$ 16,987,462		
Jun14: Actual - Expense	$ 21,706,898	$ 4,719,436	$ 3,096,343
Actual Jul13-Jun14 under collected balance [1]			**$ 37,220,708**
			-
Deferred Jul14-Jun15 Monthly Activity [2]:			
July 2014	$ 954,516	$ 954,516	$ 36,266,192
August 2014	$ 3,061,930	$ 4,016,446	$ 33,204,262
September 2014	$ 2,842,559	$ 6,859,005	$ 30,361,703
October 2014	$ 2,533,239	$ 9,392,244	$ 27,828,464
November 2014	$ 2,569,980	$ 11,962,224	$ 25,258,484
December 2014	$ 3,094,594	$ 15,056,818	$ 22,163,890
January 2015	$ 3,443,663	$ 18,500,481	$ 18,720,226
February 2015	$ 2,948,768	$ 21,449,249	$ 15,771,458
March 2015	$ 2,795,414	$ 24,244,663	$ 12,976,045
April 2015 - Estimated	$ 2,560,224	$ 26,804,887	$ 10,415,820
May 2015 - Estimated	$ 2,623,831	$ 29,428,718	$ 7,791,989
June 2015 - Estimated	$ 2,671,943	$ 32,100,662	$ 5,120,046
Deferred Supply Ending Balance			**$ 5,120,046**
Current Year Ending Balance (see page 2)			**$ 3,621,582**
Total Supply Cost Balance Jul14-Jun15 [3]			**$ 8,741,628**
			-

[1] Exhibit__(FVB-1)14-15, page 2, line 10, col C.
[2] Exhibit__(FVB-1)14-15, page 1, line 18.
[3] Exhibit__(FVB-1)14-15, page 2, line 15, col N.

NorthWestern Energy
Electric Utility
Supply Cost Account Balance
July 2014 - June 2015

Month	Supply Cost Revenue[1]	Supply Cost Expense[2]	Supply Cost Balance
July 2014	$ 17,478,336	$ 20,592,028	$ 3,113,693
August 2014	$ 20,001,099	$ 19,366,521	$ (634,579)
September 2014	$ 18,123,750	$ 15,452,628	$ (2,671,122)
October 2014	$ 16,095,567	$ 15,528,589	$ (566,978)
November 2014	$ 12,413,509	$ 17,196,309	$ 4,782,799
December 2014	$ 10,857,793	$ 13,741,204	$ 2,883,412
January 2015	$ 20,103,045	$ 13,031,987	$ (7,071,059)
February 2015	$ 11,602,218	$ 11,994,594	$ 392,376
March 2015	$ 11,173,296	$ 12,901,631	$ 1,728,335
April 2015 -Estimated	$ 10,088,435	$ 10,900,490	$ 812,055
May 2015 - Estimated	$ 10,309,134	$ 12,309,203	$ 2,000,069
June 2015 - Estimated	$ 10,334,101	$ 9,186,683	$ (1,147,418)
Supply Cost Balance Jul14-Jun15	**$ 168,580,285**	**$ 172,201,867**	**$ 3,621,582**
	-	-	-

[1]Revenue: Exhibit__(FVB-1)14-15, page 1, line 17.
[2]Expense: Exhibit__(FVB-1)14-15, page 1, line 50.

NorthWestern Energy
Electric Utility Derivation of Rates
Deferred Electricity Supply
Tracker Period July 2015 to June 2016

Customer Rate Class	**Loss Factor**	**Jul15 to Jun16 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%	2,394,862,903	2,394,862,903	2,598,665,736	$ 0.001453	$ 3,479,736
Residential Employee	8.5100%	3,379,973	2,027,984	2,200,565	$ 0.000873	$ 2,951
GS 1 Secondary NonDemand	8.5100%	278,748,374	278,748,374	302,469,861	$ 0.001453	$ 405,021
GS 1 Secondary Demand	8.5100%	2,476,869,018	2,476,869,018	2,687,650,572	$ 0.001453	$ 3,598,891
GS 1 Primary NonDemand	5.5400%	473,438	473,438	499,666	$ 0.001413	$ 669
GS 1 Primary Demand	5.5400%	341,297,734	341,297,734	360,205,628	$ 0.001413	$ 482,254
General Service Substation	4.6300%	251,830,078	251,830,078	263,489,810	$ 0.001401	$ 352,814
General Service Transmission	4.0000%	134,636,802	134,636,802	140,022,274	$ 0.001393	$ 187,549
Irrigation	8.5100%	96,759,889	96,759,889	104,994,156	$ 0.001453	$ 140,592
Lighting	8.5100%	61,285,015	61,285,015	66,500,369	$ 0.001453	$ 89,047
		6,040,143,224	6,038,791,235	6,526,698,638	$ 0.001447	$ 8,739,524
YNP Contract		20,691,140			Rounding Adjustment	$ 2,104
Total Electric Supply Load		6,060,834,364				$ 8,741,628
		-				

2014-15 Deferred Electricity Supply Cost Under-Collection $ 8,741,628

Total Deferred Electricity Supply Rate Before Losses $ 0.001339
Total Deferred Electricity Supply Rate After Losses $ 0.001447

NorthWestern Energy
Electric Utility
Deferred Electricty Supply Revenue ($000) Summary
Tracker Period July 2015 to June 2016

	Jul15 to Jun16 Supply Retail MWh Sales	Current Deferred Supply Rates[1] 7/1/2014	Current Deferred Supply Revenue	Proposed Deferred Supply Rates 7/1/2015	Proposed Deferred Supply Revenue	Revenue Diff Proposed vs Current
Residential						
Residential	2,394,863	$ 0.005751	$ 13,773	$ 0.001453	$ 3,480	$ (10,293)
Residential Employee	3,380	$ 0.003451	$ 12	$ 0.000873	$ 3	$ (9)
Total Residential			$ 13,785		$ 3,483	$ (10,302)
General Service 1						
GS-1 Sec Non-Demand	278,748	$ 0.005751	$ 1,603	$ 0.001453	$ 405	$ (1,198)
GS-1 Sec Demand	2,476,869	$ 0.005751	$ 14,244	$ 0.001453	$ 3,599	$ (10,646)
GS-1 Pri Non-Demand	473	$ 0.005594	$ 3	$ 0.001413	$ 1	$ (2)
GS-1 Pri Demand	341,298	$ 0.005594	$ 1,909	$ 0.001413	$ 482	$ (1,427)
Total GS-1			$ 17,759		$ 4,487	$ (13,273)
General Service 2						
GS-2 Substation	251,830	$ 0.005545	$ 1,396	$ 0.001401	$ 353	$ (1,044)
GS-2 Transmission	134,637	$ 0.005512	$ 742	$ 0.001393	$ 188	$ (555)
Total GS-2			$ 2,139		$ 540	$ (1,598)
Irrigation						
Irrigation	96,760	$ 0.005751	$ 556	$ 0.001453	$ 141	$ (416)
Total Irrigation			$ 556		$ 141	$ (416)
Lighting						
Lighting	61,285	$ 0.005751	$ 352	$ 0.001453	$ 89	$ (263)
Total Lighting			$ 352		$ 89	$ (263)
Total Rate Schedule	**6,040,143**		**$ 34,591**		**$ 8,740**	**$ (25,851.853)**
	-					

[1]Docket No. D2014.5.46, Interim Order No. 7283a, effective 7/1/2014.

NorthWestern Energy
Electric Utility Derivation of Rates
Electricity Supply Excluding Generation Assets - Prior to Cap Adjustment
Tracker Period July 2015 to June 2016

Customer Rate Class	Loss Factor	Jul15 to Jun16 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%	2,394,862,903	2,394,862,903	2,598,665,736	$ 0.022203	$ 53,173,141
Residential Employee	8.5100%	3,379,973	2,027,984	2,200,565	$ 0.013322	$ 45,028
GS 1 Secondary NonDemand	8.5100%	278,748,374	278,748,374	302,469,861	$ 0.022203	$ 6,189,050
GS 1 Secondary Demand	8.5100%	2,476,869,018	2,476,869,018	2,687,650,572	$ 0.022203	$ 54,993,923
GS 1 Primary NonDemand	5.5400%	473,438	473,438	499,666	$ 0.021596	$ 10,224
GS 1 Primary Demand	5.5400%	341,297,734	341,297,734	360,205,628	$ 0.021596	$ 7,370,666
General Service Substation	4.6300%	251,830,078	251,830,078	263,489,810	$ 0.021409	$ 5,391,430
General Service Transmission	4.0000%	134,636,802	134,636,802	140,022,274	$ 0.021280	$ 2,865,071
Irrigation	8.5100%	96,759,889	96,759,889	104,994,156	$ 0.022203	$ 2,148,360
Lighting	8.5100%	61,285,015	61,285,015	66,500,369	$ 0.022203	$ 1,360,711
		6,040,143,224	6,038,791,235	6,526,698,638	$ 0.022115	$ 133,547,605
YNP Contract		20,691,140			Rounding Adjustment	$ (1,530)
Total Electricity Supply Load		6,060,834,364				$ 133,546,075
		-				

Electricity Supply Excluding Generation Assets Costs	$ 134,946,865
less: YNP Contract Revenues	$ (1,400,790)
Electricity Supply Excluding Generation Assets Rate Design Revenues	**$ 133,546,075**
Electricity Supply Cost Rate Before Losses	$ 0.020462
Electricity Supply Cost Rate After Losses	$ 0.022110

YNP Contract Load	20,691,140
YNP May15-Apr16 Contract Supply Rate	0.067700
YNP Supply Revenue	$ 1,400,790

NorthWestern Energy
Electric Utility Derivation of Rates
Electricity Supply Excluding Generation Assets Capped at Residential Increase
Revenues ($000)
Tracker Period July 2015 to June 2016

CAPPED RATES	Jul15 to Jun16 Supply Retail MWh Sales	Current Revenue	Proposed Rates	Proposed Revenue	$ Change	% Change	$ at Res Cap 0.17%	Capped $ Change	Capped % Change	Capped kWh Rates
Residential										
Residential	2,394,863	$ 53,082	$ 0.022203	$ 53,173	$ 91	0.17%	$ 53,173	$ 53,804	1.36%	$ 0.022466
Res Employee	3,380	$ 45	$ 0.013322	$ 45	$ 0	0.17%	$ 45	$ 46	1.36%	$ 0.013478
Total Residential	2,398,243	$ 53,127		$ 53,218	$ 91	0.17%	$ 53,218	$ 53,850	1.36%	
General Service 1										
GS1 Sec NonDmd	278,748	$ 5,589	$ 0.022203	$ 6,189	$ 600	10.73%	$ 5,599	$ 5,665	1.36%	$ 0.020325
GS1 Sec Dmd	2,476,869	$ 54,900	$ 0.022203	$ 54,994	$ 94	0.17%	$ 54,994	$ 55,647	1.36%	$ 0.022466
GS1 Prim NonDmd	473	$ 10	$ 0.021596	$ 10	$ 0	0.18%	$ 10	$ 10	1.36%	$ 0.021850
GS1 Prim Dmd	341,298	$ 6,718	$ 0.021596	$ 7,371	$ 653	9.71%	$ 6,730	$ 6,809	1.36%	$ 0.019952
Total GS-1	3,097,389	$ 67,218		$ 68,564	$ 1,346	2.00%	$ 67,333	$ 68,132	1.36%	
General Service 2										
GS2 Substation	251,830	$ 5,382	$ 0.021409	$ 5,391	$ 10	0.18%	$ 5,391	$ 5,455	1.36%	$ 0.021661
GS2 Transmission	134,637	$ 2,860	$ 0.021280	$ 2,865	$ 5	0.17%	$ 2,865	$ 2,899	1.36%	$ 0.021532
Total GS-2	386,467	$ 8,242		$ 8,257	$ 15	0.18%	$ 8,256	$ 8,354	1.36%	
Irrigation										
Irrigation	96,760	$ 1,940	$ 0.022203	$ 2,148	$ 208	10.73%	$ 1,944	$ 1,967	1.36%	$ 0.020325
Total Irrigation	96,760	$ 1,940		$ 2,148	$ 208	10.73%	$ 1,944	$ 1,967	1.36%	
Lighting										
Lighting	61,285	$ 1,229	$ 0.022203	$ 1,361	$ 132	10.73%	$ 1,231	$ 1,246	1.36%	$ 0.020325
Total Lighting	61,285	$ 1,229		$ 1,361	$ 132	10.73%	$ 1,231	$ 1,246	1.36%	
Total Rate Schedule	6,040,143	$ 131,755		$ 133,548	$ 1,792	1.36%	$ 131,981	$ 133,548		
	-							-		
Capped Rate Adjustment Factor							0.011867			

NorthWestern Energy
Electric Utility
Electricity Supply Excluding Generation Assets Revenue ($000) Summary
Tracker Period July 2015 to June 2016

		Supply				Total
	Jul15 to Jun16 Supply Retail MWh Sales	Current Rates[1] 6/1/2015	Current Supply Revenue	Proposed Rates 7/1/2015	Proposed Supply Revenue	Revenue Diff Proposed vs Current
Residential						
Residential	2,394,863	$ 0.022165	$ 53,082	$ 0.022466	$ 53,803	$ 721
Residential Employee	3,380	$ 0.013299	$ 45	$ 0.013478	$ 46	$ 1
Total Residential			$ 53,127		$ 53,849	$ 721
General Service 1						
GS-1 Sec Non-Demand	278,748	$ 0.020052	$ 5,589	$ 0.020325	$ 5,666	$ 76
GS-1 Sec Demand	2,476,869	$ 0.022165	$ 54,900	$ 0.022466	$ 55,645	$ 746
GS-1 Pri Non-Demand	473	$ 0.021557	$ 10	$ 0.021850	$ 10	$ 0
GS-1 Pri Demand	341,298	$ 0.019684	$ 6,718	$ 0.019952	$ 6,810	$ 91
Total GS-1			$ 67,218		$ 68,131	$ 913
General Service 2						
GS-2 Substation	251,830	$ 0.021370	$ 5,382	$ 0.021661	$ 5,455	$ 73
GS-2 Transmission	134,637	$ 0.021243	$ 2,860	$ 0.021532	$ 2,899	$ 39
Total GS-2			$ 8,242		$ 8,354	$ 112
Irrigation						
Irrigation	96,760	$ 0.020052	$ 1,940	$ 0.020325	$ 1,967	$ 26
Total Irrigation			$ 1,940		$ 1,967	$ 26
Lighting						
Lighting	61,285	$ 0.020052	$ 1,229	$ 0.020325	$ 1,246	$ 17
Total Lighting			$ 1,229		$ 1,246	$ 17
Total Rate Schedule	**6,040,143**		**$ 131,755**		**$ 133,546**	**$ 1,790.040**
	-					

[1]Appendix F in June 2015 Electric Supply monthly filing, effective June 1, 2015.

NorthWestern Energy
Electric Utility
Total Proposed Deferred Supply Rates
Effective July 1, 2015

	Deferred Electricity Supply Rates[1]	Deferred CU4 Rates[2]	Deferred DGGS Rates[3]	Deferred Spion Rate[4]	Total Deferred Supply Rates
Residential					
Residential	0.001453	(0.000620)	0.000129	(0.000002)	0.000960
Residential Employee	0.000873	(0.000373)	0.000077	(0.000001)	0.000576
Total Residential					
General Service 1					
GS-1 Sec Non-Demand	0.001453	(0.000620)	0.000129	(0.000002)	0.000960
GS-1 Sec Demand	0.001453	(0.000620)	0.000129	(0.000002)	0.000960
GS-1 Pri Non-Demand	0.001413	(0.000603)	0.000126	(0.000002)	0.000934
GS-1 Pri Demand	0.001413	(0.000603)	0.000126	(0.000002)	0.000934
Total GS-1					
General Service 2					
GS-2 Substation	0.001401	(0.000597)	0.000125	(0.000002)	0.000927
GS-2 Transmission	0.001393	(0.000594)	0.000124	(0.000002)	0.000921
Total GS-2					
Irrigation					
Irrigation	0.001453	(0.000620)	0.000129	(0.000002)	0.000960
Total Irrigation					
Lighting					
Lighting	0.001453	(0.000620)	0.000129	(0.000002)	0.000960
Total Lighting					
Average Billed Rate	**0.001447**	**(0.000617)**	**0.000129**	**(0.000002)**	**0.000956**
Total Supply Rate	**1.447**	**(0.617)**	**0.129**	**(0.002)**	**0.957**

[1]Source: Exhibit_(JSJ-2)15-16
[2]Source: Exhibit_(JSJ-3)15-16
[3]Source: Exhibit_(JSJ-4)15-16
[4]Source: Exhibit_(JSJ-5)15-16

NorthWestern Energy
Electric Utility
Total Deferred Supply Revenue ($000) Summary
Tracker Period July 2015 to June 2016

		Current Deferred Revenue					Proposed Deferred Revenue					Revenue
	Jul15 to Jun16 Supply Retail MWh Sales	Deferred Supply Revenue	Deferred CU4 Revenue	Deferred DGGS Revenue	Deferred Spion Revenue	Total Deferred Revenue	Deferred Supply Revenue	Deferred CU4 Revenue	Deferred DGGS Revenue	Deferred Spion Revenue	Total Deferred Revenue	Difference Proposed vs Current
Residential												
Residential	2,394,863	$ 13,773	$ (1,071)	$ 151	$ 5	$ 12,858	$ 3,480	$ (1,485)	$ 309	$ (5)	$ 2,299	$ (10,559)
Residential Employee	3,380	$ 12	$ (1)	$ 0	$ 0	$ 11	$ 3	$ (1)	$ 0	$ (0)	$ 2	$ (9)
Total Residential		$ 13,785	$ (1,071)	$ 151	$ 5	$ 12,869	$ 3,483	$ (1,486)	$ 309	$ (5)	$ 2,301	$ (10,568)
General Service 1												
GS-1 Sec Non Demand	278,748	$ 1,603	$ (125)	$ 18	$ 1	$ 1,497	$ 405	$ (173)	$ 36	$ (1)	$ 268	$ (1,229)
GS-1 Sec Demand	2,476,869	$ 14,244	$ (1,107)	$ 156	$ 5	$ 13,298	$ 3,599	$ (1,536)	$ 320	$ (5)	$ 2,378	$ (10,921)
GS-1 Pri Non Demand	473	$ 3	$ (0)	$ 0	$ 0	$ 2	$ 1	$ (0)	$ 0	$ (0)	$ 0	$ (2)
GS-1 Pri Demand	341,298	$ 1,909	$ (148)	$ 21	$ 1	$ 1,782	$ 482	$ (206)	$ 43	$ (1)	$ 319	$ (1,463)
Total GS-1		$ 17,759	$ (1,380)	$ 194	$ 6	$ 16,580	$ 4,487	$ (1,915)	$ 399	$ (6)	$ 2,965	$ (13,615)
General Service 2												
GS-2 Substation	251,830	$ 1,396	$ (109)	$ 15	$ 1	$ 1,304	$ 353	$ (150)	$ 31	$ (1)	$ 233	$ (1,070)
GS-2 Transmission	134,637	$ 742	$ (58)	$ 8	$ 0	$ 693	$ 188	$ (80)	$ 17	$ (0)	$ 124	$ (569)
Total GS-2		$ 2,139	$ (166)	$ 23	$ 1	$ 1,997	$ 540	$ (230)	$ 48	$ (1)	$ 357	$ (1,639)
Irrigation												
Irrigation	96,760	$ 556	$ (43)	$ 6	$ 0	$ 520	$ 141	$ (60)	$ 12	$ (0)	$ 93	$ (427)
Total Irrigation		$ 556	$ (43)	$ 6	$ 0	$ 520	$ 141	$ (60)	$ 12	$ (0)	$ 93	$ (427)
Lighting												
Lighting	61,285	$ 352	$ (27)	$ 4	$ 0	$ 329	$ 89	$ (38)	$ 8	$ (0)	$ 59	$ (270)
Total Lighting		$ 352	$ (27)	$ 4	$ 0	$ 329	$ 89	$ (38)	$ 8	$ (0)	$ 59	$ (270)
Total Rate Schedule	**6,040,143**	**$ 34,591**	**$ (2,689)**	**$ 379**	**$ 12**	**$ 32,294**	**$ 8,740**	**$ (3,729)**	**$ 776**	**$ (12)**	**$ 5,775**	**$ (26,518.861)**
	-	-	-	-	-	-	-	-	-	-	-	-

NorthWestern Energy
Electric Utility
Total Proposed Supply Rates
Effective July 1, 2015

	Proposed Electricity Supply Rates[1]	Colstrip Unit 4[2]		Dave Gates Gen Station[3]		Spion Kop[4]		Hydro[5]		Rev Credits[6]	Proposed Total Supply Rates
		Current Fixed Rates	Proposed Variable Rates	Current Fixed Rates	Proposed Variable Rates	Current Fixed Rates	Proposed Variable Rates	Current Fixed Rates	Proposed Variable Rates	Current Rates	
Residential											
Residential	0.022466	0.012734	0.004802	0.004795	0.001362	0.001458	0.000018	0.026817	0.000298	(0.007252)	0.067498
Residential Employee	0.013478	0.007640	0.002882	0.002877	0.000818	0.000875	0.000011	0.016090	0.000179	(0.004351)	0.040499
Total Residential											
General Service 1											
GS-1 Sec Non-Demand	0.020325	0.012734	0.004802	0.004795	0.001362	0.001459	0.000018	0.026817	0.000298	(0.007252)	0.065358
GS-1 Sec Demand	0.022466	0.012734	0.004802	0.004795	0.001362	0.001459	0.000018	0.026817	0.000298	(0.007252)	0.067499
GS-1 Pri Non-Demand	0.021850	0.012385	0.004670	0.004664	0.001325	0.001420	0.000018	0.026083	0.000290	(0.007053)	0.065652
GS-1 Pri Demand	0.019952	0.012385	0.004670	0.004664	0.001325	0.001420	0.000018	0.026083	0.000290	(0.007053)	0.063754
Total GS-1											
General Service 2											
GS-2 Substation	0.021661	0.012278	0.004630	0.004624	0.001313	0.001407	0.000018	0.025858	0.000288	(0.006992)	0.065085
GS-2 Transmission	0.021532	0.012204	0.004602	0.004596	0.001305	0.001399	0.000018	0.025703	0.000286	(0.006950)	0.064695
Total GS-2											
Irrigation											
Irrigation	0.020325	0.012734	0.004802	0.004795	0.001362	0.001459	0.000018	0.026817	0.000298	(0.007252)	0.065358
Total Irrigation											
Lighting											
Lighting	0.020325	0.012734	0.004802	0.004795	0.001362	0.001459	0.000018	0.026817	0.000298	(0.007252)	0.065358
Total Lighting											
Average Billed Rate	**0.022110**	**0.012681**	**0.004782**	**0.004775**	**0.001356**	**0.001453**	**0.000018**	**0.026705**	**0.000297**	**(0.007222)**	**0.066955**
Total Supply Rate	**22.110**		**17.463**		**6.131**		**1.471**		**27.002**	**(7.222)**	**66.955**
											-

[1]Source: Exhibit_(JSJ-2)15-16
[2]Source: Exhibit_(JSJ-3)15-16
[3]Source: Exhibit_(JSJ-4)15-16
[4]Source: Exhibit_(JSJ-5)15-16
[5]Source: Exhibit_(JSJ-6)15-16
[6]Source: Exhibit_(JSJ-7)15-16

NorthWestern Energy
Electric Utility
Total Supply Revenue ($000) Summary by Rate Component
Tracker Period July 2015 to June 2016

	Total Supply Revenue Current Rate 6/1/2015	Proposed Supply Revenue: Electricity Supply Revenue	CU4 Fixed Revenue	CU4 Variable Revenue	DGGS Fixed Revenue	DGGS Variable Revenue	Spion Fixed Revenue	Spion Variable Revenue	Hydro Fixed Revenue	Hydro Variable Revenue	Revenue Credits Revenue	Total Supply Revenue 7/1/2015
Residential												
Residential	$ 160,832	$ 53,803	$ 30,496	$ 11,500	$ 11,483	$ 3,262	$ 3,492	$ 43	$ 64,223	$ 714	$ (17,368)	$ 161,648
Residential Employee	$ 136	$ 46	$ 26	$ 10	$ 10	$ 3	$ 3	$ 0	$ 54	$ 1	$ (15)	$ 137
Total Residential	$ 160,968	$ 53,849	$ 30,522	$ 11,510	$ 11,493	$ 3,265	$ 3,495	$ 43	$ 64,277	$ 714	$ (17,382)	$ 161,785
General Service 1												
GS-1 Sec Non Demand	$ 18,131	$ 5,666	$ 3,550	$ 1,339	$ 1,337	$ 380	$ 407	$ 5	$ 7,475	$ 83	$ (2,021)	$ 18,218
GS-1 Sec Demand	$ 166,342	$ 55,645	$ 31,540	$ 11,894	$ 11,877	$ 3,373	$ 3,614	$ 45	$ 66,422	$ 738	$ (17,962)	$ 167,186
GS-1 Pri Non Demand	$ 31	$ 10	$ 6	$ 2	$ 2	$ 1	$ 1	$ 0	$ 12	$ 0	$ (3)	$ 31
GS-1 Pri Demand	$ 21,654	$ 6,810	$ 4,227	$ 1,594	$ 1,592	$ 452	$ 485	$ 6	$ 8,902	$ 99	$ (2,407)	$ 21,759
Total GS-1	$ 206,158	$ 68,131	$ 39,323	$ 14,829	$ 14,807	$ 4,206	$ 4,506	$ 56	$ 82,812	$ 920	$ (22,394)	$ 207,195
General Service 2												
GS-2 Substation	$ 16,307	$ 5,455	$ 3,092	$ 1,166	$ 1,164	$ 331	$ 354	$ 5	$ 6,512	$ 73	$ (1,761)	$ 16,390
GS-2 Transmission	$ 8,666	$ 2,899	$ 1,643	$ 620	$ 619	$ 176	$ 188	$ 2	$ 3,461	$ 39	$ (936)	$ 8,710
Total GS-2	$ 24,973	$ 8,354	$ 4,735	$ 1,786	$ 1,783	$ 506	$ 543	$ 7	$ 9,972	$ 111	$ (2,697)	$ 25,101
Irrigation												
Irrigation	$ 6,294	$ 1,967	$ 1,232	$ 465	$ 464	$ 132	$ 141	$ 2	$ 2,595	$ 29	$ (702)	$ 6,324
Total Irrigation	$ 6,294	$ 1,967	$ 1,232	$ 465	$ 464	$ 132	$ 141	$ 2	$ 2,595	$ 29	$ (702)	$ 6,324
Lighting												
Lighting	$ 3,986	$ 1,246	$ 780	$ 294	$ 294	$ 83	$ 89	$ 1	$ 1,643	$ 18	$ (444)	$ 4,005
Total Lighting	$ 3,986	$ 1,246	$ 780	$ 294	$ 294	$ 83	$ 89	$ 1	$ 1,643	$ 18	$ (444)	$ 4,005
Total Rate Schedule	$ 402,379	$ 133,546	$ 76,592	$ 28,883	$ 28,841	$ 8,192	$ 8,774	$ 109	$ 161,300	$ 1,793	$ (43,619)	$ 404,410
	-	-	-	-	-	-	-	-	-	-	-	-

NorthWestern Energy
Electric Utility
Total Supply Revenue ($000) Summary
Tracker Period July 2015 to June 2016

	Jul15 to Jun16 Supply Retail MWh Sales	Current Total Supply Rates[1] 6/1/2015	Current Total Supply Revenue	Proposed Total Supply Rates 7/1/2015	Proposed Total Supply Revenue	Revenue Difference Proposed vs Current	% Change
Residential							
Residential	2,394,863	0.067157	$ 160,832	0.067498	$ 161,648	$ 817	0.51%
Residential Employee	3,380	0.040294	$ 136	0.040499	$ 137	$ 1	0.51%
Total Residential			$ 160,968		$ 161,785	$ 817	
General Service 1							
GS-1 Sec Non-Demand	278,748	0.065045	$ 18,131	0.065358	$ 18,218	$ 87	0.48%
GS-1 Sec Demand	2,476,869	0.067158	$ 166,342	0.067499	$ 167,186	$ 845	0.51%
GS-1 Pri Non-Demand	473	0.065319	$ 31	0.065652	$ 31	$ 0	0.51%
GS-1 Pri Demand	341,298	0.063446	$ 21,654	0.063754	$ 21,759	$ 105	0.49%
Total GS-1			$ 206,158		$ 207,195	$ 1,037	
General Service 2							
GS-2 Substation	251,830	0.064754	$ 16,307	0.065085	$ 16,390	$ 83	0.51%
GS-2 Transmission	134,637	0.064367	$ 8,666	0.064695	$ 8,710	$ 44	0.51%
Total GS-2			$ 24,973		$ 25,101	$ 128	
Irrigation							
Irrigation	96,760	0.065045	$ 6,294	0.065358	$ 6,324	$ 30	0.48%
Total Irrigation			$ 6,294		$ 6,324	$ 30	
Lighting							
Lighting	61,285	0.065045	$ 3,986	0.065358	$ 4,005	$ 19	0.48%
Total Lighting			$ 3,986		$ 4,005	$ 19	
Total Rate Schedule	**6,040,143**		**$ 402,379**		**$ 404,410**	**$ 2,031.464**	0.50%
	-				-	-	
						-	

[1]Appendix F in June 2015 Electric Supply monthly filing, effective June 1, 2015.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2014.7.58
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 the purpose of this testimony.

A. In this testimony, I present the following information:

- The updated CU4 costs for the 12-month ended June 2015 true-up period with 9 months of actual numbers and 3 months of estimated numbers, and
- The forecast CU4 costs for the 12-month ended June 2016 true-up period.

Update to CU4 Values in the 2014/2015 True-up Period

Q. How has NorthWestern updated the CU4 generation that is reflected in the 2014/2015 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, 2014 through June 30, 2015.

Q. How are the CU4 variable costs treated in the 2014/2015 true-up period?

A. The CU4 costs are treated the same as they have been treated in previous annual CU4 true-up filings. The variable CU4 cost of service includes fuel costs, incremental property taxes, and Lost Revenues. These variable costs are tracked in a manner similar to the market-based supply costs. The CU4 variable cost was updated in January 2015 to reflect the CU4 property tax changes submitted in the 2015 Annual Property Tax Tracker filing.

Q. Have any adjustments been made to the CU4 fixed cost of service in the 2014/2015 or 2015/2016 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. Please summarize the 12-month ended June 2015 CU4 deferred account balance.

A. The June 2014 deferred account balance of $(5,008,086) over-collection shown on page 2 of Exhibit__(FVB-4)13-14 Updated from Docket Nos. D2013.5.33 and D2014.5.46 ("Consolidated Dockets") is the July 2014 beginning deferred account balance. This updated exhibit was provided electronically in response to Data Request MCC-076 in the Consolidated Dockets. With 9 months actual values and 3 months estimated values, the June 2015 estimated ending deferred account balance is a $(3,723,557) over-collection. Please refer to the Prefiled Direct Testimony of Joseph S. Janhunen - CU4 True-up for further discussion of the Deferred Account.

Q. Please summarize the 12-month ended June 2015 CU4 true-up period variable costs.

A. The CU4 true-up period is summarized in the following table (rounded from tracker values):

Beginning Deferred CU4		**Balance ($)**
Over-Collection		($5,008,086)

Variable Costs CU4		**Cost ($)**
Fuel Cost		21,450,327
Property Tax Adjustment		(219,502)
MPSC/MCC Tax Adjustment		(127,140)
Lost Revenue		3,859,551
Lost Revenue Adjustment		(11,170)
Subtotal CU4 Variable Cost of Service:		24,952,065

Carrying Costs		(298,388)
Carry Cost Adjustment		0
Total Variable Costs		$24,653,678

Variable Revenues CU4		**Revenue ($)**
Revenues		26,010,609
Prior Deferred Expense		(2,641,461)
Total Revenues:		$23,369,148

Ending Deferred CU4		**Balance ($)**
Over-Collection		($3,723,557)

Forecast of CU4 in the 2015/2016 True-up Period

Q. Please summarize the 12-month CU4 true-up period ending June 2016.

A. The June 2015 Deferred Account over-collection ending balance of $(3,723,557) as described above is the July 2015 beginning balance. July 2015 through June 2016 information is based on forecasted numbers. Please see Exhibit__(FVB-5)15-16 for supply volume and cost details of the 12-month forecast true-up period.

Q. Describe the changes within the CU4 variable Revenue and Expense categories for the 12-month ended June 2016 forecast true-up period.

A. The CU4 generation asset true-up variable revenue and cost details are reflected on page 2 of Exhibit__(FVB-5)15-16 under two main sections, Total Revenue and Total Variable Costs. Total Net Revenue is estimated to be $25,160,111. This includes the current year revenue of $28,883,668 offset by the deferred balance carry forward of the $(3,723,557) over-collection from the prior true-up period as shown on Exhibit__(FVB-4)14-15. The 12-month forecast true-up estimates Total CU4 Variable Costs of $28,883,668.

Q. Please provide a summary table of the 12-month ended June 2016 CU4 true-up period.

A. The CU4 true-up period is summarized in the following table (rounded from tracker values):

Beginning Deferred CU4		**Balance ($)**
Over-Collection		($3,723,557)

Variable Costs CU4		**Cost ($)**
Fuel Cost		24,600,595
Property Tax Adjustment		(48,569)
Lost Revenue		4,456,505
Lost Revenue Adjustment		0
Subtotal CU4 Variable Cost of Service:		29,008,531

Carrying Costs		(124,863)
Carry Cost Adjustment		0
Total Variable Costs		$28,883,668

Variable Revenues CU4		**Revenue ($)**
Revenues		28,883,668
Prior Deferred Expense		(3,723,557)
Total Revenues:		$25,160,111

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		**Colstrip Unit 4 Generation Asset Component**														
2				**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Total**
3				Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	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		**Colstrip Unit 4 Generation Asset Component**														
32				**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Total**
33				Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
34		**Colstrip Unit 4 Variable Cost**														
35		Total Forecast Sales														
36		2011/12 Tracker Sales MWh		482,388	546,211	496,510	442,674	449,232	540,528	601,160	515,060	488,212	447,321	458,167	466,568	5,934,031
37		CU4 Cost		$ 4.3559	$ 4.3559	$ 4.3559	$ 4.3559	$ 4.3559	$ 4.3559	$ 4.4110	$ 4.4110	$ 4.4110	$ 4.4110	$ 4.4110	$ 4.4110	
38		Prior Year Deferred Expense		$ (0.4451)	$ (0.4451)	$ (0.4451)	$ (0.4451)	$ (0.4451)	$ (0.4451)	$ (0.4451)	$ (0.4451)	$ (0.4451)	$ (0.4451)	$ (0.4451)	$ (0.4451)	
39																
40		Colstrip Unit 4 Variable Cost Revenues														
41		NWE CU4 Revenues		$ 2,101,569	$ 2,380,049	$ 2,162,676	$ 1,927,332	$ 1,955,461	$ 2,354,684	$ 2,652,616	$ 2,271,465	$ 2,153,484	$ 1,972,243	$ 2,020,987	$ 2,058,045	$ 26,010,609
42																
43		Subtotal		$ 2,101,569	$ 2,380,049	$ 2,162,676	$ 1,927,332	$ 1,955,461	$ 2,354,684	$ 2,652,616	$ 2,271,465	$ 2,153,484	$ 1,972,243	$ 2,020,987	$ 2,058,045	$ 26,010,609
44		Prior Year(s) Deferred Expense		$ (214,774)	$ (243,234)	$ (221,019)	$ (196,968)	$ (199,842)	$ (240,641)	$ (267,720)	$ (229,251)	$ (217,344)	$ (199,052)	$ (203,938)	$ (207,678)	$ (2,641,461)
45		Total Revenue		$ 1,886,795	$ 2,136,815	$ 1,941,656	$ 1,730,364	$ 1,755,619	$ 2,114,043	$ 2,384,895	$ 2,042,214	$ 1,936,140	$ 1,773,191	$ 1,817,049	$ 1,850,367	$ 23,369,148
46																
47		Colstrip Unit 4 Fuel Cost		$ 1,904,993	$ 2,605,943	$ 2,238,413	$ 2,042,038	$ 1,969,922	$ 985,705	$ 1,419,506	$ 1,458,747	$ 1,833,471	$ 1,719,325	$ 1,552,938	$ 1,719,325	$ 21,450,327
48																
49		Incremental Property Tax Adjustment		$ (32,536)	$ (32,536)	$ (32,536)	$ (32,536)	$ (32,536)	$ (32,536)	$ (4,047)	$ (4,047)	$ (4,047)	$ (4,047)	$ (4,047)	$ (4,047)	$ (219,502)
50		MPSC/MCC Tax Adjustment		$ (127,140)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (127,140)
51																
52		Lost Revenue		$ 324,371	$ 324,371	$ 324,371	$ 324,371	$ 324,371	$ 324,371	$ 324,371	$ 324,371	$ 324,371	$ 324,371	$ 307,920	$ 307,920	$ 3,859,551
53		Lost Revenue Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,170)	$ (11,170)
54																
55		Subtotal Colstrip Unit 4 Variable Cost		$ 2,069,688	$ 2,897,778	$ 2,530,248	$ 2,333,873	$ 2,261,757	$ 1,277,540	$ 1,739,830	$ 1,779,071	$ 2,153,794	$ 2,039,649	$ 1,856,810	$ 2,012,027	$ 24,952,065
56																
57																
58		**Carrying Cost Expense**														
59		Carrying Costs	7.92%	$ (32,038)	$ (27,198)	$ (23,471)	$ (19,620)	$ (16,389)	$ (22,052)	$ (26,482)	$ (28,405)	$ (27,148)	$ (25,559)	$ (25,465)	$ (24,561)	$ (298,388)
60																
61		Total CU4 Variable Cost		$ 2,037,650	$ 2,870,580	$ 2,506,777	$ 2,314,253	$ 2,245,368	$ 1,255,487	$ 1,713,348	$ 1,750,666	$ 2,126,646	$ 2,014,090	$ 1,831,345	$ 1,987,467	$ 24,653,678
62																
63		Deferred Cost Amortization (Under)/Over		$ (214,774)	$ (243,234)	$ (221,019)	$ (196,968)	$ (199,842)	$ (240,641)	$ (267,720)	$ (229,251)	$ (217,344)	$ (199,052)	$ (203,938)	$ (207,678)	$ (2,641,461)
64		Monthly Deferred Cost		$ 63,919	$ (490,531)	$ (344,102)	$ (386,921)	$ (289,906)	$ 1,099,196	$ 939,268	$ 520,799	$ 26,838	$ (41,847)	$ 189,641	$ 70,578	$ 1,356,932
65		Cumulative Deferred Cost		$ 63,919	$ (426,612)	$ (770,713)	$ (1,157,634)	$ (1,447,541)	$ (348,345)	$ 590,923	$ 1,111,722	$ 1,138,559	$ 1,096,713	$ 1,286,354	$ 1,356,932	
66																
67		Variable Rate-Base Deferred														
68		Beginning Balance		$ (5,008,086)	$ (4,857,232)	$ (4,123,467)	$ (3,558,346)	$ (2,974,457)	$ (2,484,708)	$ (3,343,264)	$ (4,014,811)	$ (4,306,358)	$ (4,115,852)	$ (3,874,953)	$ (3,860,656)	
69		Monthly Deferred Cost		$ 150,854	$ 733,765	$ 565,121	$ 583,889	$ 489,749	$ (858,556)	$ (671,547)	$ (291,547)	$ 190,507	$ 240,898	$ 14,297	$ 137,100	
70		Ending Balance Under/(Over)		$ (4,857,232)	$ (4,123,467)	$ (3,558,346)	$ (2,974,457)	$ (2,484,708)	$ (3,343,264)	$ (4,014,811)	$ (4,306,358)	$ (4,115,852)	$ (3,874,953)	$ (3,860,656)	$ (3,723,557)	
71																

	A / B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Colstrip Unit 4 Generation Asset Component**														
2			**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**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	**Colstrip Unit 4 Generation Asset Component**														
32			**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Total**
33			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
34	**Colstrip Unit 4 Variable Cost**														
35	Total Forecast Sales														
36	2011/12 Tracker Sales MWh		516,208	541,697	492,397	468,897	489,975	535,138	566,841	530,208	500,071	476,340	456,744	465,627	6,040,143
37	CU4 Cost		$ 4.7820	$ 4.7820	$ 4.7820	$ 4.7820	$ 4.7820	$ 4.7820	$ 4.7820	$ 4.7820	$ 4.7820	$ 4.7820	$ 4.7820	$ 4.7820	
38	Prior Year Deferred Expense		$ (0.6165)	$ (0.6165)	$ (0.6165)	$ (0.6165)	$ (0.6165)	$ (0.6165)	$ (0.6165)	$ (0.6165)	$ (0.6165)	$ (0.6165)	$ (0.6165)	$ (0.6165)	
39															
40	Colstrip Unit 4 Variable Cost Revenues														
41	NWE CU4 Revenues		$ 2,468,482	$ 2,590,370	$ 2,354,619	$ 2,242,242	$ 2,343,036	$ 2,559,005	$ 2,710,605	$ 2,535,428	$ 2,391,313	$ 2,277,836	$ 2,184,128	$ 2,226,604	$ 28,883,668
42															
43	Subtotal		$ 2,468,482	$ 2,590,370	$ 2,354,619	$ 2,242,242	$ 2,343,036	$ 2,559,005	$ 2,710,605	$ 2,535,428	$ 2,391,313	$ 2,277,836	$ 2,184,128	$ 2,226,604	$ 28,883,668
44	Prior Year(s) Deferred Expense		$ (318,226)	$ (333,939)	$ (303,547)	$ (289,060)	$ (302,054)	$ (329,896)	$ (349,439)	$ (326,856)	$ (308,278)	$ (293,649)	$ (281,568)	$ (287,044)	$ (3,723,557)
45	Total Revenue		$ 2,150,256	$ 2,256,431	$ 2,051,072	$ 1,953,182	$ 2,040,982	$ 2,229,109	$ 2,361,165	$ 2,208,572	$ 2,083,036	$ 1,984,187	$ 1,902,560	$ 1,939,560	$ 25,160,111
46															
47	Colstrip Unit 4 Fuel Cost		$ 2,264,943	$ 2,053,159	$ 2,035,524	$ 2,044,880	$ 1,972,008	$ 2,083,588	$ 2,230,719	$ 2,018,327	$ 2,230,719	$ 2,872,736	$ 1,419,307	$ 1,374,685	$ 24,600,595
48															
49															
50	Incremental Property Tax Adjustment		$ (4,047)	$ (4,047)	$ (4,047)	$ (4,047)	$ (4,047)	$ (4,047)	$ (4,047)	$ (4,047)	$ (4,047)	$ (4,047)	$ (4,047)	$ (4,047)	$ (48,569)
51															
52	Lost Revenue		$ 371,375	$ 371,375	$ 371,375	$ 371,375	$ 371,375	$ 371,375	$ 371,375	$ 371,375	$ 371,375	$ 371,375	$ 371,375	$ 371,375	$ 4,456,505
53	Lost Revenue Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54															
55	Subtotal Colstrip Unit 4 Variable Cost		$ 2,632,271	$ 2,420,487	$ 2,402,852	$ 2,412,208	$ 2,339,336	$ 2,450,916	$ 2,598,047	$ 2,385,655	$ 2,598,047	$ 3,240,064	$ 1,786,635	$ 1,742,013	$ 29,008,531
56															
57															
58	**Carrying Cost Expense**														
59	Carrying Costs	7.92%	$ (21,523)	$ (20,577)	$ (18,378)	$ (15,452)	$ (13,573)	$ (12,191)	$ (10,699)	$ (9,594)	$ (6,238)	$ 2,059	$ 1,303	$ (0)	$ (124,863)
60															
61	Total CU4 Variable Cost		$ 2,610,747	$ 2,399,910	$ 2,384,474	$ 2,396,756	$ 2,325,763	$ 2,438,726	$ 2,587,348	$ 2,376,061	$ 2,591,809	$ 3,242,123	$ 1,787,938	$ 1,742,013	$ 28,883,668
62															
63	Deferred Cost Amortization (Under)/Over		$ (318,226)	$ (333,939)	$ (303,547)	$ (289,060)	$ (302,054)	$ (329,896)	$ (349,439)	$ (326,856)	$ (308,278)	$ (293,649)	$ (281,568)	$ (287,044)	$ (3,723,557)
64	Monthly Deferred Cost		$ (142,266)	$ 190,460	$ (29,855)	$ (154,514)	$ 17,274	$ 120,279	$ 123,256	$ 159,367	$ (200,496)	$ (964,288)	$ 396,189	$ 484,591	$ 0
65	Cumulative Deferred Cost		$ (142,266)	$ 48,195	$ 18,340	$ (136,174)	$ (118,900)	$ 1,379	$ 124,635	$ 284,003	$ 83,507	$ (880,780)	$ (484,591)	$ 0	
66															
67	Variable Rate-Base Deferred														
68	Beginning Balance		$ (3,723,557)	$ (3,263,065)	$ (3,119,586)	$ (2,786,184)	$ (2,342,610)	$ (2,057,830)	$ (1,848,213)	$ (1,622,030)	$ (1,454,541)	$ (945,768)	$ 312,168	$ 197,547	
69	Monthly Deferred Cost		$ 460,491	$ 143,479	$ 333,402	$ 443,574	$ 284,781	$ 209,617	$ 226,183	$ 167,489	$ 508,773	$ 1,257,936	$ (114,621)	$ (197,547)	
70	Ending Balance Under/(Over)		$ (3,263,065)	$ (3,119,586)	$ (2,786,184)	$ (2,342,610)	$ (2,057,830)	$ (1,848,213)	$ (1,622,030)	$ (1,454,541)	$ (945,768)	$ 312,168	$ 197,547	$ (0)	
71															

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2014.7.58
Annual CU4 True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY
OF JOSEPH S. JANHUNEN
ON BEHALF OF NORTHWESTERN ENERGY
ANNUAL COLSTRIP UNIT 4 (“CU4”) TRUE-UP

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Witness Information

Q. Are you the same Joseph S. Janhunen 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. This testimony:

1. Presents the derivation of proposed deferred CU4 variable rates resulting from the over/under-collection reflected in both the 2013-2014 true-up period and the 2014-2015 true-up period;
2. Presents the derivation of proposed CU4 variable rates for the forecasted 2015-2016 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 2015?

A. The CU4 variable cost account balance for the 12-month period ending June 2015 is an over-collection of $(3,723,557) as presented on page 1 of Exhibit__(JSJ-3)15-16. As discussed below, this includes the prior period

balance for the 2013-2014 true-up period and the current period balance for the 2014-2015 true-up period.

Q. Describe the status of the deferred CU4 variable cost account balance associated with the 2013-2014 true-up period.

A. In the annual filing submitted on May 29, 2014, the net deferred account balance for the 2013-2014 true-up period was shown as an over-collection of $(2,667,589). This amount becomes the starting balance in this filing. Added to this balance is the prior period true-up for the 3 months of estimated data included in the May 2014 filing. Page 1 of Exhibit__(JSJ-3)15-16 shows the true-up of the estimated months of April, May and June 2014 with actual data for these months. The resulting actual ending balance of $(5,008,086) is the deferred account beginning balance associated with the 2013-2014 true-up period. This balance is then combined with the current year deferred monthly activity shown on Exhibit__(JSJ-3)15-16, page 1, resulting in a net over-collected balance of $(2,366,625) for the 2013-2014 true-up period. The months of April, May and June 2015 are estimated and will be trued-up in the next annual filing.

Q. Describe the CU4 variable cost account balance associated with the 2014-2015 true-up period.

A. Page 2 of Exhibit__(JSJ-3)15-16 shows the monthly detail of the difference between the CU4 variable cost revenues and expenses for the

2014-2015 true-up period, resulting in an over-collected amount of $(1,356,932). The months of April, May and June 2015 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 $(3,723,557) shown below and on page 1, line 64 of Exhibit__(JSJ-3)15-16.

Total Deferred CU4 Variable Cost Account Balance

2013-2014 Prior Period CU4 Variable Account Balance	$(2,366,625)
2014-2015 Current Period CU4 Variable Account Balance	$(1,356,932)
	$(3,723,557)

Derivation of the deferred CU4 variable rates is shown on Exhibit__(JSJ-3)15-16, page 3 with the resulting rates and revenues shown on page 4.

Derivation of Proposed CU4 Variable Rates

Q. Please describe the process NorthWestern used to derive the proposed 2015-2016 forecasted CU4 variable rates in this filing.

A. The rate design methodology used in this filing to derive the proposed 2015-2016 forecasted CU4 variable rates is the same as that presented in previous annual CU4 true-up filings. All forecasted costs are from Exhibit__(FVB-5)15-16 of the Prefiled Direct Testimony of Frank V. Bennett and are discussed therein.

Derivation of the CU4 variable rates is shown on Exhibit__(JSJ-3)15-16, page 5. The total CU4 variable cost of $28,883,668 is the sum of forecasted fuel costs, incremental property taxes, Lost Revenues, and carrying costs from Exhibit__(FVB-5)15-16. This sum is the amount used to derive the CU4 variable rates. The forecasted loads used in the derivation are from Exhibit__(JSJ-1)15-16. The resulting rates are the CU4 variable rates proposed in this filing.

Q. Please describe the 2015-2016 CU4 fixed rates included in this filing.

A. The CU4 fixed cost of service rate component presented in this filing remains unchanged and will not change until an order is issued in any subsequent revenue requirement filing that deals with CU4.

Page 6 of Exhibit__(JSJ-3)15-16 reflects the CU4 fixed and variable rates and revenues in summarized format.

Proposed Total Deferred Supply and Total Supply Rates

Q. Please describe the process NorthWestern used to derive the total 2015-2016 deferred supply rates proposed in this filing.

A. The total deferred supply rate includes four separate rate components – a deferred electricity supply rate, a deferred CU4 variable rate, a deferred Dave Gates Generating Station ("DGGS") variable rate, and a deferred Spion Kop Wind Generation Asset ("Spion") variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(JSJ-8)15-16, page 1.

Q. Please describe the process NorthWestern used to derive the total 2015-2016 supply rates proposed in this filing.

A. 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 variable rate, a Spion fixed cost of service rate, a Spion variable rate, a Hydro Generation Asset ("Hydro") fixed cost of service rate, a Hydro variable rate, and a Revenue Credits rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(JSJ-8)15-16, page 3.

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

A. Yes, it does.

NorthWestern Energy
Electric Utility
Deferred CU4 Variable Cost Account Balance
July 2014 - June 2015

Month	Monthly Collection	Collection to-date	Balance Remaining
Jul13-Jun14 over collected balance as filed in D2014.5.46			**$ (2,667,589)**
Prior Period Tracker Year True-up - Deferred:			
Apr14: Estimated as filed in D2014.5.46		$ 148,691	
Apr14: Actual		$ 148,691	$ -
May14: Estimated as filed in D2014.5.46		$ 144,002	
May14: Actual		$ 140,643	$ (3,360)
Jun14: Estimated as filed in D2014.5.46		$ 158,070	
Jun14: Actual		$ 139,102	$ (18,968)
Prior Period Tracker Year True-up - Variable:			
Apr14: Est as filed in D2014.5.46 - Revenue	$ 1,926,207		
Apr14: Est as filed in D2014.5.46 - Expense	$ 2,089,879	$ 163,672	
Apr14: Actual - Revenue	$ 1,926,207		
Apr14: Actual - Expense	$ 1,152,403	$ (773,804)	$ (937,476)
May14: Est as filed in D2014.5.46 - Revenue	$ 1,870,900		
May14: Est as filed in D2014.5.46 - Expense	$ 2,044,431	$ 173,531	
May14: Actual - Revenue	$ 1,821,950		
May14: Actual - Expense	$ 1,244,129	$ (577,821)	$ (751,352)
Jun14: Est as filed in D2014.5.46 - Revenue	$ 2,053,668		
Jun14: Est as filed in D2014.5.46 - Expense	$ 2,121,207	$ 67,539	
Jun14: Actual - Revenue	$ 1,801,982		
Jun14: Actual - Expense	$ 1,240,179	$ (561,803)	$ (629,342)
Actual Jul13-Jun14 over collected balance [1]			**$ (5,008,086)**
			-
Deferred Jul14-Jun15 Monthly Activity [2]:			
July 2014	$ (214,774)	$ (214,774)	$ (4,793,313)
August 2014	$ (243,234)	$ (458,007)	$ (4,550,079)
September 2014	$ (221,019)	$ (679,027)	$ (4,329,060)
October 2014	$ (196,968)	$ (875,995)	$ (4,132,091)
November 2014	$ (199,842)	$ (1,075,837)	$ (3,932,249)
December 2014	$ (240,641)	$ (1,316,478)	$ (3,691,608)
January 2015	$ (267,720)	$ (1,584,198)	$ (3,423,888)
February 2015	$ (229,251)	$ (1,813,449)	$ (3,194,637)
March 2015	$ (217,344)	$ (2,030,794)	$ (2,977,293)
April 2015 - Estimated	$ (199,052)	$ (2,229,845)	$ (2,778,241)
May 2015 - Estimated	$ (203,938)	$ (2,433,783)	$ (2,574,303)
June 2015 - Estimated	$ (207,678)	$ (2,641,461)	$ (2,366,625)
Deferred CU4 Variable Ending Balance			**$ (2,366,625)**
Current Year CU4 Variable Ending Balance (see page 2)			**$ (1,356,932)**
Total CU4 Variable Cost Balance Jul14-Jun15 [3]			**$ (3,723,557)**
			-

[1] Exhibit__(FVB-4)14-15, page 2, line 68, col D.
[2] Exhibit__(FVB-4)14-15, page 2, line 44.
[3] Exhibit__(FVB-4)14-15, page 2, line 70, col O.

NorthWestern Energy
Electric Utility
CU4 Variable Cost Account Balance
July 2014 - June 2015

Month	CU4 Variable Cost Revenue[1]	CU4 Variable Cost Expense[2]	CU4 Variable Cost Balance
July 2014	$ 2,101,569	$ 2,037,650	$ (63,919)
August 2014	$ 2,380,049	$ 2,870,580	$ 490,531
September 2014	$ 2,162,676	$ 2,506,777	$ 344,102
October 2014	$ 1,927,332	$ 2,314,253	$ 386,921
November 2014	$ 1,955,461	$ 2,245,368	$ 289,906
December 2014	$ 2,354,684	$ 1,255,487	$ (1,099,196)
January 2015	$ 2,652,616	$ 1,713,348	$ (939,268)
February 2015	$ 2,271,465	$ 1,750,666	$ (520,799)
March 2015	$ 2,153,484	$ 2,126,646	$ (26,838)
April 2015 - Estimated	$ 1,972,243	$ 2,014,090	$ 41,847
May 2015 - Estimated	$ 2,020,987	$ 1,831,345	$ (189,641)
June 2015 - Estimated	$ 2,058,045	$ 1,987,467	$ (70,578)
CU4 Cost Balance Jul14-Jun15	**$ 26,010,609**	**$ 24,653,678**	**$ (1,356,932)**
	-	-	-

[1]Revenue: Exhibit__(FVB-4)14-15, page 2, line 43.
[2]Expense: Exhibit__(FVB-4)14-15, page 2, line 61.

Exhibit_(JSJ-3)15-16
Docket No. D2014.7.58

NorthWestern Energy
Electric Utility Derivation of Rates
Deferred CU4 Variable
Tracker Period July 2015 to June 2016

Customer Rate Class	Loss Factor	Jul15 to Jun16 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%	2,394,862,903	2,394,862,903	2,598,665,736	$ (0.000620)	$ (1,484,815)
Residential Employee	8.5100%	3,379,973	2,027,984	2,200,565	$ (0.000373)	$ (1,261)
GS 1 Secondary NonDemand	8.5100%	278,748,374	278,748,374	302,469,861	$ (0.000620)	$ (172,824)
GS 1 Secondary Demand	8.5100%	2,476,869,018	2,476,869,018	2,687,650,572	$ (0.000620)	$ (1,535,659)
GS 1 Primary NonDemand	5.5400%	473,438	473,438	499,666	$ (0.000603)	$ (285)
GS 1 Primary Demand	5.5400%	341,297,734	341,297,734	360,205,628	$ (0.000603)	$ (205,803)
General Service Substation	4.6300%	251,830,078	251,830,078	263,489,810	$ (0.000597)	$ (150,343)
General Service Transmission	4.0000%	134,636,802	134,636,802	140,022,274	$ (0.000594)	$ (79,974)
Irrigation	8.5100%	96,759,889	96,759,889	104,994,156	$ (0.000620)	$ (59,991)
Lighting	8.5100%	61,285,015	61,285,015	66,500,369	$ (0.000620)	$ (37,997)
		6,040,143,224	6,038,791,235	6,526,698,638	$ (0.000617)	$ (3,728,951)
YNP Contract		20,691,140			Rounding Adjustment	$ 5,394
Total Supply Load		6,060,834,364				$ (3,723,557)
		-				

2014-15 Deferred CU4 Variable Cost Over-Collection	**$**	**(3,723,557)**
Total Deferred CU4 Variable Rate Before Losses	$	(0.000571)
Total Deferred CU4 Variable Rate After Losses	$	(0.000617)

Exhibit_(JSJ-3)15-16
Docket No. D2014.7.58

NorthWestern Energy
Electric Utility
Deferred CU4 Variable Revenue ($000) Summary
Tracker Period July 2015 to June 2016

	Jul15 to Jun16 Supply Retail MWh Sales	Current Deferred CU4 Rates[1]	Current Deferred CU4 Revenue	Proposed Deferred CU4 Rates 7/1/2015	Proposed Deferred CU4 Revenue	Revenue Diff Proposed vs Current
Residential						
Residential	2,394,863	$ (0.000447)	$ (1,071)	$ (0.000620)	$ (1,485)	$ (414)
Residential Employee	3,380	$ (0.000269)	$ (1)	$ (0.000373)	$ (1)	$ (0)
Total Residential			$ (1,071)		$ (1,486)	$ (415)
General Service 1						
GS-1 Sec Non Demand	278,748	$ (0.000447)	$ (125)	$ (0.000620)	$ (173)	$ (48)
GS-1 Sec Demand	2,476,869	$ (0.000447)	$ (1,107)	$ (0.000620)	$ (1,536)	$ (428)
GS-1 Pri Non Demand	473	$ (0.000435)	$ (0)	$ (0.000603)	$ (0)	$ (0)
GS-1 Pri Demand	341,298	$ (0.000435)	$ (148)	$ (0.000603)	$ (206)	$ (57)
Total GS-1			$ (1,380)		$ (1,915)	$ (534)
General Service 2						
GS-2 Substation	251,830	$ (0.000431)	$ (109)	$ (0.000597)	$ (150)	$ (42)
GS-2 Transmission	134,637	$ (0.000428)	$ (58)	$ (0.000594)	$ (80)	$ (22)
Total GS-2			$ (166)		$ (230)	$ (64)
Irrigation						
Irrigation	96,760	$ (0.000447)	$ (43)	$ (0.000620)	$ (60)	$ (17)
Total Irrigation			$ (43)		$ (60)	$ (17)
Lighting						
Lighting	61,285	$ (0.000447)	$ (27)	$ (0.000620)	$ (38)	$ (11)
Total Lighting			$ (27)		$ (38)	$ (11)
Total Rate Schedule	**6,040,143**		**$ (2,689)**		**$ (3,729)**	**$ (1,040.297)**
	-				-	

[1]Docket No. D2014.5.46, Interim Order No. 7283a, effective 7/1/2014.

NorthWestern Energy
Electric Utility Derivation of Rates
CU4 Variable Cost of Service
Tracker Period July 2015 to June 2016

Customer Rate Class	**Loss Factor**	**Jul15 to Jun16 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%	2,394,862,903	2,394,862,903	2,598,665,736	$ 0.004802	$ 11,500,132
Residential Employee	8.5100%	3,379,973	2,027,984	2,200,565	$ 0.002882	$ 9,741
GS 1 Secondary NonDemand	8.5100%	278,748,374	278,748,374	302,469,861	$ 0.004802	$ 1,338,550
GS 1 Secondary Demand	8.5100%	2,476,869,018	2,476,869,018	2,687,650,572	$ 0.004802	$ 11,893,925
GS 1 Primary NonDemand	5.5400%	473,438	473,438	499,666	$ 0.004670	$ 2,211
GS 1 Primary Demand	5.5400%	341,297,734	341,297,734	360,205,628	$ 0.004670	$ 1,593,860
General Service Substation	4.6300%	251,830,078	251,830,078	263,489,810	$ 0.004630	$ 1,165,973
General Service Transmission	4.0000%	134,636,802	134,636,802	140,022,274	$ 0.004602	$ 619,599
Irrigation	8.5100%	96,759,889	96,759,889	104,994,156	$ 0.004802	$ 464,641
Lighting	8.5100%	61,285,015	61,285,015	66,500,369	$ 0.004802	$ 294,291
		6,040,143,224	6,038,791,235	6,526,698,638	$ 0.004783	$ 28,882,922
YNP Contract		20,691,140			Rounding Adjustment	$ 746
Total Supply Load		6,060,834,364				$ 28,883,668
		-				

2015-16 Colstrip Unit 4 Variable Cost of Service $ 28,883,668

Total CU4 Variable COS Rate Before Losses $ 0.004425
Total CU4 Variable COS Rate After Losses $ 0.004782

NorthWestern Energy
Electric Utility
Total CU4 Revenue ($000) Summary
Tracker Period July 2015 to June 2016

		CU4 Fixed		CU4 Variable				Total
	Jul15 to Jun16 Supply Retail MWh Sales	**Current Rates[1]**	**Current Rate Revenue**	**Current Rates[2]**	**Current Rate Revenue**	**Proposed Rates 7/1/2015**	**Proposed Rate Revenue**	**Revenue Diff Proposed vs Current**
Residential								
Residential	2,394,863	0.012734	$ 30,496	0.004429	$ 10,607	0.004802	$ 11,500	$ 893
Residential Employee	3,380	0.007640	$ 26	0.002657	$ 9	0.002882	$ 10	$ 1
Total Residential			$ 30,522		$ 10,616		$ 11,510	$ 894
General Service 1								
GS-1 Sec Non Demand	278,748	0.012734	$ 3,550	0.004429	$ 1,235	0.004802	$ 1,339	$ 104
GS-1 Sec Demand	2,476,869	0.012734	$ 31,540	0.004429	$ 10,970	0.004802	$ 11,894	$ 924
GS-1 Pri Non Demand	473	0.012385	$ 6	0.004308	$ 2	0.004670	$ 2	$ 0
GS-1 Pri Demand	341,298	0.012385	$ 4,227	0.004308	$ 1,470	0.004670	$ 1,594	$ 124
Total GS-1			$ 39,323		$ 13,677		$ 14,829	$ 1,152
General Service 2								
GS-2 Substation	251,830	0.012278	$ 3,092	0.004271	$ 1,076	0.004630	$ 1,166	$ 90
GS-2 Transmission	134,637	0.012204	$ 1,643	0.004245	$ 572	0.004602	$ 620	$ 48
Total GS-2			$ 4,735		$ 1,647		$ 1,786	$ 138
Irrigation								
Irrigation	96,760	0.012734	$ 1,232	0.004429	$ 429	0.004802	$ 465	$ 36
Total Irrigation			$ 1,232		$ 429		$ 465	$ 36
Lighting								
Lighting	61,285	0.012734	$ 780	0.004429	$ 271	0.004802	$ 294	$ 23
Total Lighting			$ 780		$ 271		$ 294	$ 23
Total Rate Schedule	**6,040,143**		**$ 76,592**		**$ 26,640**		**$ 28,883**	**$ 2,243.034**
	-						-	

[1]CU4 Fixed Rates approved in Docket No. D2010.5.50 Order No. 7093c, effective 4/1/2010.
[2]CU4 Variable Rates updated for property taxes in January 2015 Electric Supply monthly filing, effective 1/1/2015.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2014.7.58
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

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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 this portion of your testimony.

A. In this testimony, I present the following information:

- The updated DGGS costs for the 12-month ended June 2015 true-up period with 9 months of actual numbers and 3 months of estimated numbers, and
- The forecast DGGS costs for the 12-month ended June 2016 true-up period.

Update to DGGS Values in the 2014/2015 True-up Period

Q. Does NorthWestern continue to utilize 7 MW of generation from DGGS within the 2014/2015 electric supply tracker?

A. Yes, NorthWestern includes the contribution of 7 MW of baseload energy from the DGGS asset in the Electricity Supply Tracker.

Q. How are the DGGS variable costs of service treated in the 2014/2015 true-up period?

A. NorthWestern has incorporated the 7 aMW baseload energy at actual energy market prices in this true-up filing. This change is consistent with the Prefiled Direct Testimony of Michael Cashell in Docket No. D2012.5.49 and was approved in Final Order No. 7219h. The variable DGGS cost of service includes 9 months of actual values and 3 months of estimated information. The variable cost of service on page 2 of Exhibit__(FVB-6)14-15 includes fuel cost offset by costs allocated to choice customers and net revenue credits in addition to incremental property taxes and Lost Revenues to derive the variable DGGS costs. These variable costs are tracked in a manner similar to the market-based supply costs. In addition, the DGGS variable cost was updated in January 2015 to reflect the DGGS property tax changes submitted in the 2015 Annual Property Tax Tracker filing.

Q. Have any adjustments been made to the DGGS fixed cost of service in the 2014/2015 or 2015/2016 true-up periods?

A. No. The DGGS fixed cost of service and associated fixed cost rates presented in this filing are the same as approved in Docket No. D2008.8.95, Order No. 6943e. The fixed costs 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 2015 DGGS deferred account balance.

A. The June 2014 deferred account balance of $2,501,228 under-collection shown on page 2 of Exhibit__(FVB-6)13-14 Updated from Docket Nos. D2013.5.33 and D2014.5.46 (“Consolidated Dockets”) is the July 2014 beginning deferred balance. This updated exhibit was provided electronically in response to Data

Request MCC-076 in the Consolidated Dockets. With 9 months of actual values and 3 months of estimated values, the June 2015 ending deferred account balance is a $777,601 under-collection. Please refer to the Prefiled Direct Testimony of Joseph S. Janhunen – Annual DGGS True-up for further discussion of the Deferred Account.

Q. Please summarize the 12-month ended June 2015 DGGS true-up period variable costs.

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

Beginning Deferred DGGS		**Balance ($)**
Under-Collection		$2,501,228

Variable Costs DGGS		**Cost ($)**
Fuel Cost		18,250,583
Fuel Adjustment		0
Less Energy Supply 7 MW		(894,837)
Less Transmission Service @ 20%		(3,471,149)
Energy Supply 7 MW		894,837
Regulation Contracts		0
Less Transmission Service @ 20%		0
DGGS – Fuel Cost Allocation:		14,779,434

Revenue Credits 27 MW		(7,048,507)
Less Transmission Service @ 20%		1,409,701
Reg. Contract Revenue Credit		0
Less Transmission Service @ 20%		0
DGGS – Revenue Credit Allocation:		(5,638,805)

MPSC/MCC Tax Adjustments		124,341
Incremental Property Tax Adjustment		112,343
Lost Revenue		1,007,044
Lost Revenue Adjustment		(4,206)
Subtotal DGGS Variable Cost Allocation		10,380,150

Carrying Cost		148,939
Carrying Cost Adjustment		0
Total DGGS Variable Cost Allocation		$10,529,089

Variable Revenues DGGS		**Revenue ($)**
Revenues		$11,880,622
Prior Deferred Expense		$372,096
Total Revenues:		$12,252,717

Ending Deferred DGGS		**Balance ($)**
Under-Collection		$777,601

Forecast of DGGS in the 2015/2016 True-up Period

Q. Please summarize the 12-month DGGS true-up period ending June 2016.

A. The June 2015 Deferred Account under-collection ending balance of $777,601 as described above is the July 2015 beginning balance. July 2015 through June 2016 information is based on forecast numbers. Please see Exhibit__(FVB-7)15-16 for supply volume and cost details of the 12-month forecast true-up period.

Q. Describe the changes within the DGGS variable Revenue and Cost categories for the 12-month ended June 2016 forecast true-up period.

A. The DGGS generation asset variable cost revenue and expense details are reflected on page 2 of Exhibit__(FVB-7)15-16 under two main sections: Total Revenue and Total Variable Cost Allocation. Total Revenue is estimated to be $8,968,896. The 12-month forecast true-up period estimates a Total DGGS Variable Cost Allocation of $8,191,297.

Q. Please provide a summary table of the 12-month ended June 2016 DGGS true-up period.

A. The DGGS true-up period is summarized in the following table (rounded from true-up values):

Beginning Deferred DGGS		**Balance ($)**
Under-Collection		$777,601

Variable Costs DGGS		**Cost ($)**
Fuel Cost		13,061,763
Fuel Adjustment		0
Less Energy Supply 7 MW		(1,234,218)
Less Transmission Service @ 20%		(2,365,509)
Energy Supply 7 MW		1,234,218
Regulation Contracts		0
Less Transmission Service @ 20%		0
DGGS – Fuel Cost Allocation:		10,696,254

Revenue Credits 27 MW		(4,760,550)
Less Transmission Service @ 20%		952,110
Reg. Contract Revenue Credit		0
Less Transmission Service @ 20%		0
DGGS – Revenue Credit Allocation:		(3,808,440)

MPSC/MCC Tax Adjustments		0
Incremental Property Tax Adjustment		69,942
Lost Revenue		1,231,827
Lost Revenue Adjustment		0
Subtotal DGGS Variable Cost Allocation		8,189,583

Carrying Cost		1,714
Carrying Cost Adjustment		0
Total DGGS Variable Cost Allocation		$8,191,297

Variable Revenues DGGS		**Revenue ($)**
Revenues		$8,191,296
Prior Deferred Expense		$777,601
Total Revenues:		$8,968,896

Ending Deferred DGGS		**Balance ($)**
Even-Collection		$0

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

A. Yes, it does.

	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-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Total**
3			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	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															

	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-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Total**
36			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
37	**Dave Gates Generating Station at Mill Creek Variable Cost**														
38	Total Forecast Sales														
39	2011/12 Tracker Sales MWh		482,388	546,211	496,510	442,674	449,232	540,528	601,160	515,060	488,212	447,321	458,167	466,568	5,934,031
40	DGGS Cost		$ 2.0100	$ 2.0100	$ 2.0100	$ 2.0100	$ 2.0100	$ 2.0100	$ 1.9949	$ 1.9949	$ 1.9949	$ 1.9949	$ 1.9949	$ 1.9949	
41	Prior Year Deferred Expense		$ 0.0626	$ 0.0626	$ 0.0626	$ 0.0626	$ 0.0626	$ 0.0626	$ 0.0626	$ 0.0626	$ 0.0626	$ 0.0626	$ 0.0626	$ 0.0626	
42															
43	DGGS Variable Cost Revenues														
44	NWE DGGS Revenues		$ 969,594	$ 1,098,076	$ 997,788	$ 889,209	$ 902,187	$ 1,086,373	$ 1,199,618	$ 1,027,245	$ 973,890	$ 891,925	$ 913,978	$ 930,737	$ 11,880,622
45	Prior Year(s) Deferred Expense		$ 30,263	$ 34,274	$ 31,143	$ 27,753	$ 28,158	$ 33,908	$ 37,725	$ 32,303	$ 30,625	$ 28,047	$ 28,686	$ 29,212	$ 372,096
46	Total Revenue		$ 999,857	$ 1,132,349	$ 1,028,931	$ 916,962	$ 930,345	$ 1,120,281	$ 1,237,343	$ 1,059,548	$ 1,004,515	$ 919,972	$ 942,664	$ 959,949	$ 12,252,717
47															
48	DGGS Fuel Cost														
49	DGGS Fuel Cost		$ 2,065,268	$ 2,048,881	$ 1,600,521	$ 1,371,247	$ 1,533,596	$ 1,313,376	$ 968,387	$ 1,128,190	$ 1,253,264	$ 1,663,243	$ 1,679,936	$ 1,624,673	$ 18,250,583
50	DGGS Fuel Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	Less: Energy Supply Cost (7 MW)		$ (111,660)	$ (142,387)	$ (135,425)	$ (118,794)	$ (108,612)	$ (98,275)	$ (79,891)	$ (34,904)	$ (50,622)	$ (4,981)	$ (4,720)	$ (4,568)	$ (894,837)
52	Subtotal		$ 1,953,608	$ 1,906,494	$ 1,465,096	$ 1,252,452	$ 1,424,984	$ 1,215,101	$ 888,496	$ 1,093,287	$ 1,202,642	$ 1,658,262	$ 1,675,217	$ 1,620,106	$ 17,355,746
53	Less: Transmission Service @ 20%		$ (390,722)	$ (381,299)	$ (293,019)	$ (250,490)	$ (284,997)	$ (243,020)	$ (177,699)	$ (218,657)	$ (240,528)	$ (331,652)	$ (335,043)	$ (324,021)	$ (3,471,149)
54	MPSC-Related Supply Cost		$ 1,562,887	$ 1,525,195	$ 1,172,077	$ 1,001,962	$ 1,139,987	$ 972,081	$ 710,797	$ 874,629	$ 962,114	$ 1,326,609	$ 1,340,173	$ 1,296,085	$ 13,884,596
55	Energy Supply Cost (7 MW)		$ 111,660	$ 142,387	$ 135,425	$ 118,794	$ 108,612	$ 98,275	$ 79,891	$ 34,904	$ 50,622	$ 4,981	$ 4,720	$ 4,568	$ 894,837
56	Subtotal MPSC-Related Fuel Cost		$ 1,674,546	$ 1,667,582	$ 1,307,501	$ 1,120,756	$ 1,248,599	$ 1,070,356	$ 790,688	$ 909,533	$ 1,012,736	$ 1,331,591	$ 1,344,893	$ 1,300,652	$ 14,779,434
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		$ 1,674,546	$ 1,667,582	$ 1,307,501	$ 1,120,756	$ 1,248,599	$ 1,070,356	$ 790,688	$ 909,533	$ 1,012,736	$ 1,331,591	$ 1,344,893	$ 1,300,652	$ 14,779,434
66															
67	DGGS Revenue Credits														
68	Revenue Credits (27 MW Supply/Tran)		$ (699,907)	$ (954,329)	$ (655,407)	$ (509,753)	$ (544,055)	$ (486,062)	$ (307,757)	$ (211,781)	$ (305,672)	$ (791,261)	$ (791,261)	$ (791,261)	$ (7,048,507)
69	Less: Transmission Service @ 20%		$ 139,981	$ 190,866	$ 131,081	$ 101,951	$ 108,811	$ 97,212	$ 61,551	$ 42,356	$ 61,134	$ 158,252	$ 158,252	$ 158,252	$ 1,409,701
70	Subtotal MPSC-Related Revenue Credits		$ (559,925)	$ (763,463)	$ (524,325)	$ (407,803)	$ (435,244)	$ (388,850)	$ (246,206)	$ (169,425)	$ (244,537)	$ (633,009)	$ (633,009)	$ (633,009)	$ (5,638,805)
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		$ (559,925)	$ (763,463)	$ (524,325)	$ (407,803)	$ (435,244)	$ (388,850)	$ (246,206)	$ (169,425)	$ (244,537)	$ (633,009)	$ (633,009)	$ (633,009)	$ (5,638,805)
78															
79	MCC Tax adjustment		$ (21,810)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (21,810)
80	MPSC Tax Adjustment		$ 146,151	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 146,151
81	Incremental Property Tax Adjustment		$ 12,895	$ 12,895	$ 12,895	$ 12,895	$ 12,895	$ 12,895	$ 5,829	$ 5,829	$ 5,829	$ 5,829	$ 5,829	$ 5,829	$ 112,343
82	Lost Revenue		$ 84,953	$ 84,953	$ 84,953	$ 84,953	$ 84,953	$ 84,953	$ 84,953	$ 84,953	$ 84,953	$ 84,953	$ 78,757	$ 78,757	$ 1,007,044
83	Lost Revenue Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,206)	$ (4,206)
84															
85	Subtotal DGGS Variable Cost Allocation		$ 1,336,810	$ 1,001,967	$ 881,024	$ 810,802	$ 911,204	$ 779,355	$ 635,264	$ 830,890	$ 858,980	$ 789,363	$ 796,470	$ 748,023	$ 10,380,150
86															
87	**Carrying Cost Expense**														
88	Carrying Costs	7.92%	$ 18,845	$ 18,104	$ 17,243	$ 16,652	$ 16,636	$ 14,482	$ 10,581	$ 9,133	$ 8,227	$ 7,415	$ 6,493	$ 5,129	$ 148,939
89															
90	Total DGGS Variable Cost Allocation		$ 1,355,655	$ 1,020,071	$ 898,267	$ 827,454	$ 927,839	$ 793,837	$ 645,845	$ 840,023	$ 867,207	$ 796,777	$ 802,963	$ 753,152	$ 10,529,089
91															
92	Deferred Cost Amortization (Under)/Over		$ 30,263	$ 34,274	$ 31,143	$ 27,753	$ 28,158	$ 33,908	$ 37,725	$ 32,303	$ 30,625	$ 28,047	$ 28,686	$ 29,212	$ 372,096
93	Monthly Deferred Cost		$ (386,060)	$ 78,004	$ 99,521	$ 61,755	$ (25,652)	$ 292,536	$ 553,774	$ 187,223	$ 106,683	$ 95,147	$ 111,015	$ 177,585	$ 1,351,532
94	Cumulative Deferred Cost		$ (386,060)	$ (308,056)	$ (208,535)	$ (146,780)	$ (172,432)	$ 120,104	$ 673,878	$ 861,101	$ 967,784	$ 1,062,931	$ 1,173,947	$ 1,351,532	
95															
96	Variable Rate Base Deferred														
97	Beginning Balance		$ 2,501,228	$ 2,857,026	$ 2,744,748	$ 2,614,084	$ 2,524,576	$ 2,522,070	$ 2,195,626	$ 1,604,128	$ 1,384,602	$ 1,247,293	$ 1,124,099	$ 984,398	
98	Monthly Deferred Cost		$ 355,798	$ (112,278)	$ (130,664)	$ (89,508)	$ (2,506)	$ (326,444)	$ (591,499)	$ (219,526)	$ (137,308)	$ (123,194)	$ (139,701)	$ (206,797)	
99	Ending Balance Under/(Over)		$ 2,857,026	$ 2,744,748	$ 2,614,084	$ 2,524,576	$ 2,522,070	$ 2,195,626	$ 1,604,128	$ 1,384,602	$ 1,247,293	$ 1,124,099	$ 984,398	$ 777,601	

	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-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**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															

	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-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Total**
36			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
37	**Dave Gates Generating Station at Mill Creek Variable Cost**														
38	Total Forecast Sales														
39	2011/12 Tracker Sales MWh		516,208	541,697	492,397	468,897	489,975	535,138	566,841	530,208	500,071	476,340	456,744	465,627	6,040,143
40	DGGS Cost		$ 1.3561	$ 1.3561	$ 1.3561	$ 1.3561	$ 1.3561	$ 1.3561	$ 1.3561	$ 1.3561	$ 1.3561	$ 1.3561	$ 1.3561	$ 1.3561	
41	Prior Year Deferred Expense		$ 0.1287	$ 0.1287	$ 0.1287	$ 0.1287	$ 0.1287	$ 0.1287	$ 0.1287	$ 0.1287	$ 0.1287	$ 0.1287	$ 0.1287	$ 0.1287	
42															
43	DGGS Variable Cost Revenues														
44	NWE DGGS Revenues		$ 700,052	$ 734,619	$ 667,761	$ 635,891	$ 664,476	$ 725,724	$ 768,717	$ 719,038	$ 678,167	$ 645,985	$ 619,410	$ 631,456	$ 8,191,296
45	Prior Year(s) Deferred Expense		$ 66,456	$ 69,737	$ 63,391	$ 60,365	$ 63,079	$ 68,893	$ 72,974	$ 68,258	$ 64,378	$ 61,323	$ 58,801	$ 59,944	$ 777,601
46	Total Revenue		$ 766,508	$ 804,356	$ 731,151	$ 696,256	$ 727,555	$ 794,617	$ 841,691	$ 787,296	$ 742,546	$ 707,309	$ 678,211	$ 691,400	$ 8,968,896
47															
48	DGGS Fuel Cost														
49	DGGS Fuel Cost		$ 1,038,382	$ 1,043,041	$ 1,010,855	$ 1,070,648	$ 1,090,129	$ 1,158,690	$ 1,191,042	$ 1,074,416	$ 1,166,885	$ 1,068,922	$ 1,087,428	$ 1,061,325	$ 13,061,763
50	DGGS Fuel Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	Less: Energy Supply Cost (7 MW)		$ (139,210)	$ (138,429)	$ (115,769)	$ (97,546)	$ (107,251)	$ (127,388)	$ (113,586)	$ (94,955)	$ (92,286)	$ (75,701)	$ (67,131)	$ (64,966)	$ (1,234,218)
52	Subtotal		$ 899,172	$ 904,612	$ 895,086	$ 973,102	$ 982,878	$ 1,031,302	$ 1,077,456	$ 979,461	$ 1,074,599	$ 993,221	$ 1,020,297	$ 996,359	$ 11,827,545
53	Less: Transmission Service @ 20%		$ (179,834)	$ (180,922)	$ (179,017)	$ (194,620)	$ (196,576)	$ (206,260)	$ (215,491)	$ (195,892)	$ (214,920)	$ (198,644)	$ (204,059)	$ (199,272)	$ (2,365,509)
54	MPSC-Related Supply Cost		$ 719,337	$ 723,689	$ 716,069	$ 778,482	$ 786,302	$ 825,041	$ 861,965	$ 783,569	$ 859,680	$ 794,577	$ 816,238	$ 797,087	$ 9,462,036
55	Energy Supply Cost (7 MW)		$ 139,210	$ 138,429	$ 115,769	$ 97,546	$ 107,251	$ 127,388	$ 113,586	$ 94,955	$ 92,286	$ 75,701	$ 67,131	$ 64,966	$ 1,234,218
56	Subtotal MPSC-Related Fuel Cost		$ 858,547	$ 862,118	$ 831,838	$ 876,028	$ 893,553	$ 952,429	$ 975,551	$ 878,524	$ 951,966	$ 870,278	$ 883,369	$ 862,053	$ 10,696,254
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		$ 858,547	$ 862,118	$ 831,838	$ 876,028	$ 893,553	$ 952,429	$ 975,551	$ 878,524	$ 951,966	$ 870,278	$ 883,369	$ 862,053	$ 10,696,254
66															
67	DGGS Revenue Credits														
68	Revenue Credits (27 MW Supply/Tran)		$ (536,952)	$ (533,939)	$ (446,537)	$ (376,248)	$ (413,683)	$ (491,352)	$ (438,119)	$ (366,256)	$ (355,959)	$ (291,989)	$ (258,934)	$ (250,582)	$ (4,760,550)
69	Less: Transmission Service @ 20%		$ 107,390	$ 106,788	$ 89,307	$ 75,250	$ 82,737	$ 98,270	$ 87,624	$ 73,251	$ 71,192	$ 58,398	$ 51,787	$ 50,116	$ 952,110
70	Subtotal MPSC-Related Revenue Credits		$ (429,562)	$ (427,151)	$ (357,230)	$ (300,998)	$ (330,946)	$ (393,082)	$ (350,495)	$ (293,005)	$ (284,767)	$ (233,591)	$ (207,147)	$ (200,466)	$ (3,808,440)
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		$ (429,562)	$ (427,151)	$ (357,230)	$ (300,998)	$ (330,946)	$ (393,082)	$ (350,495)	$ (293,005)	$ (284,767)	$ (233,591)	$ (207,147)	$ (200,466)	$ (3,808,440)
78															
79	Incremental Property Tax Adjustment		$ 5,829	$ 5,829	$ 5,829	$ 5,829	$ 5,829	$ 5,829	$ 5,829	$ 5,829	$ 5,829	$ 5,829	$ 5,829	$ 5,829	$ 69,942
80															
81	Lost Revenue		$ 102,652	$ 102,652	$ 102,652	$ 102,652	$ 102,652	$ 102,652	$ 102,652	$ 102,652	$ 102,652	$ 102,652	$ 102,652	$ 102,652	$ 1,231,827
82	Lost Revenue Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
83															
84	Subtotal DGGS Variable Cost Allocation		$ 537,467	$ 543,448	$ 583,089	$ 683,510	$ 671,088	$ 667,828	$ 733,536	$ 694,000	$ 775,679	$ 745,168	$ 784,702	$ 770,068	$ 8,189,583
85															
86	**Carrying Cost Expense**														
87	Carrying Costs	7.92%	$ 3,642	$ 1,934	$ 964	$ 886	$ 517	$ (322)	$ (1,042)	$ (1,668)	$ (1,460)	$ (1,218)	$ (519)	$ 0	$ 1,714
88															
89	Total DGGS Variable Cost Allocation		$ 541,109	$ 545,382	$ 584,053	$ 684,396	$ 671,604	$ 667,507	$ 732,494	$ 692,331	$ 774,220	$ 743,950	$ 784,183	$ 770,068	$ 8,191,297
90															
91	Deferred Cost Amortization (Under)/Over		$ 66,456	$ 69,737	$ 63,391	$ 60,365	$ 63,079	$ 68,893	$ 72,974	$ 68,258	$ 64,378	$ 61,323	$ 58,801	$ 59,944	$ 777,601
92	Monthly Deferred Cost		$ 158,943	$ 189,237	$ 83,708	$ (48,504)	$ (7,128)	$ 58,217	$ 36,223	$ 26,706	$ (96,052)	$ (97,964)	$ (164,773)	$ (138,611)	$ (0)
93	Cumulative Deferred Cost		$ 158,943	$ 348,180	$ 431,888	$ 383,383	$ 376,255	$ 434,472	$ 470,695	$ 497,401	$ 401,349	$ 303,384	$ 138,611	$ (0)	
94															
95	Variable Rate Base Deferred														
96	Beginning Balance		$ 777,601	$ 552,202	$ 293,227	$ 146,129	$ 134,268	$ 78,318	$ (48,793)	$ (157,990)	$ (252,954)	$ (221,280)	$ (184,639)	$ (78,667)	
97	Monthly Deferred Cost		$ (225,399)	$ (258,974)	$ (147,098)	$ (11,861)	$ (55,950)	$ (127,110)	$ (109,197)	$ (94,965)	$ 31,674	$ 36,641	$ 105,972	$ 78,667	
98	Ending Balance Under/(Over)		$ 552,202	$ 293,227	$ 146,129	$ 134,268	$ 78,318	$ (48,793)	$ (157,990)	$ (252,954)	$ (221,280)	$ (184,639)	$ (78,667)	$ 0	

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2014.7.58
Annual DGGS True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF JOSEPH S. JANHUNEN

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL DAVE GATES GENERATING STATION (“DGGS”) TRUE-UP

TABLE OF CONTENTS

Witness Information

Q. Are you the same Joseph S. Janhunen 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. This testimony:

1. Presents the derivation of proposed deferred DGGS variable rates resulting from the over/under collection reflected in both the 2013-2014 true-up period and the 2014-2015 true-up period;
2. Presents the derivation of proposed DGGS variable rates for the forecasted 2015-2016 true-up period; and
3. Discusses the overall total supply rates incorporating all individual rate components.

Derivation of Proposed Deferred DGGS Variable Rates

Q. What is the DGGS variable cost account balance for the 12-month period ending June 2015?

A. The DGGS variable cost account balance for the 12-month period ending June 2015 is an under-collection of $777,601 as presented on page 1 of Exhibit__(JSJ-4)15-16. As discussed below, this includes the prior period

balance for the 2013-2014 true-up period and the current period balance for the 2014-2015 true-up period.

Q. Describe the status of the deferred DGGS variable cost account balance associated with the 2013-2014 true-up period.

A. In the annual filing submitted on May 29, 2014, the net deferred account balance for the 2013-2014 true-up period was shown as an under-collection of $375,220. This amount becomes the starting balance in this filing. Added to this balance is the prior period true-up for the 3 months of estimated data included in the May 2014 filing. Page 1 of Exhibit__(JSJ-4)15-16 shows the true-up of the previously estimated months of April, May and June 2014 with actual data for these months. This results in an actual under-collected ending balance of $2,501,228.

Next, this amount is combined with the current year monthly activity shown on Exhibit__(JSJ-4)15-16, page 1, resulting in an under-collected balance of $2,129.133 for the 2013-2014 true-up period. The months of April, May and June 2015 are estimated and will be trued-up in the next annual filing.

Q. Describe the DGGS variable cost account balance associated with the 2014-2015 true-up period.

A. Page 2 of Exhibit__(JSJ-4)15-16 shows the monthly detail of the difference between the DGGS variable cost revenues and expenses for the 2014-2015 true-up period, resulting in an over-collected amount of $(1,351,532). The months of April, May and June 2015 are estimated and will be trued-up in the next annual filing.

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

A. The total deferred DGGS variable cost account adjustment proposed in this filing is an under-collection of $777,601 shown below and on page 1, line 64 of Exhibit__(JSJ-4)15-16.

Total Deferred DGGS Variable Cost Account Balance	
2013-2014 Prior Period DGGS Variable Account Balance	$2,129,133
2014-2015 Current Period DGGS Variable Account Balance	$(1,351,532)
	$777,601

Derivation of the deferred DGGS variable rates is shown on Exhibit__(JSJ-4)15-16, page 3 with the resulting rates and revenues shown on page 4.

Derivation of Proposed DGGS Variable Rates

Q. Please describe the process NorthWestern used to derive the proposed 2015-2016 forecasted DGGS variable rates in this filing.

A. The rate design methodology used in this filing to derive the proposed 2015-2016 forecasted DGGS variable rates is the same as that presented in previous annual DGGS true-up filings. All forecasted costs are from Exhibit__(FVB-7)15-16 of the Prefiled Direct Testimony of Frank V. Bennett and are discussed therein.

Derivation of the DGGS variable rates is shown on Exhibit__(JSJ-4)15-16, page 5. The total DGGS variable cost of $8,191,297 is the sum of forecasted fuel costs, revenue credits, Lost Revenues, incremental property taxes, carrying costs, and the energy supply costs for the 7MW from Exhibit__(FVB-7)15-16. This sum is the amount used to derive the DGGS variable rates. The forecasted loads used in the derivation of rates are from Exhibit__(JSJ-1)15-16, page 6. The resulting rates are the DGGS variable rates proposed in this filing.

Q. Please describe the 2015-2016 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 will not change until an order is issued in any subsequent revenue requirement filing that deals with DGGS.

Page 6 of Exhibit__(JSJ-4)15-16 reflects the DGGS fixed and variable rates and revenues in summarized format.

Proposed Total Deferred Supply and Total Supply Rates

Q. Please describe the process NorthWestern used to derive the total 2015-2016 deferred supply rates proposed in this filing.

A. The total deferred supply rate includes four separate rate components – a deferred electricity supply rate, a deferred Colstrip Unit 4 ("CU4") variable rate, a deferred DGGS variable rate, and a deferred Spion Kop Wind Generation Asset ("Spion") variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(JSJ-8)15-16, page 1.

Q. Please describe the process NorthWestern used to derive the total 2015-2016 supply rates proposed in this filing.

A. 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 variable rate, a Spion fixed cost of service rate, a Spion variable rate, a Hydro Generation Asset (“Hydro”) fixed cost of service rate, a Hydro variable rate, and a Revenue Credits rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(JSJ-8)15-16, page 3.

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

A.	Yes, it does.

NorthWestern Energy
Electric Utility
Deferred DGGS Variable Cost Account Balance
July 2014 - June 2015

Month	Monthly Collection	Collection to-date	Balance Remaining
Jul13-Jun14 under collected balance as filed in D2014.5.46			**$ 375,220**
Prior Period Tracker Year True-up - Deferred:			
Apr14: Estimated as filed in D2014.5.46		$ 252,431	
Apr14: Actual		$ 252,431	$ -
May14: Estimated as filed in D2014.5.46		$ 354,772	
May14: Actual		$ 238,768	$ 116,005
Jun14: Estimated as filed in D2014.5.46		$ 389,430	
Jun14: Actual		$ 236,151	$ 153,279
Prior Period Tracker Year True-up - Variable:			
Apr14: Est as filed in D2014.5.46 - Revenue	$ 1,027,768		
Apr14: Est as filed in D2014.5.46 - Expense	$ (420,649)	$ (1,448,417)	
Apr14: Actual - Revenue	$ 1,027,768		
Apr14: Actual - Expense	$ 99,844	$ (927,924)	$ 520,493
May14: Est as filed in D2014.5.46 - Revenue	$ 998,148		
May14: Est as filed in D2014.5.46 - Expense	$ 1,008,760	$ 10,611	
May14: Actual - Revenue	$ 972,139		
May14: Actual - Expense	$ 1,663,782	$ 691,643	$ 681,031
Jun14: Est as filed in D2014.5.46 - Revenue	$ 1,095,658		
Jun14: Est as filed in D2014.5.46 - Expense	$ 1,075,941	$ (19,717)	
Jun14: Actual - Revenue	$ 961,485		
Jun14: Actual - Expense	$ 1,596,969	$ 635,484	$ 655,201
Actual Jul13-Jun14 under collected balance [1]			**$ 2,501,228**
			-
Deferred Jul14-Jun15 Monthly Activity [2]:			
July 2014	$ 30,263	$ 30,263	$ 2,470,966
August 2014	$ 34,274	$ 64,536	$ 2,436,692
September 2014	$ 31,143	$ 95,679	$ 2,405,550
October 2014	$ 27,753	$ 123,432	$ 2,377,796
November 2014	$ 28,158	$ 151,590	$ 2,349,638
December 2014	$ 33,908	$ 185,498	$ 2,315,730
January 2015	$ 37,725	$ 223,223	$ 2,278,006
February 2015	$ 32,303	$ 255,526	$ 2,245,703
March 2015	$ 30,625	$ 286,151	$ 2,215,077
April 2015- Estimated	$ 28,047	$ 314,198	$ 2,187,030
May 2015 - Estimated	$ 28,686	$ 342,884	$ 2,158,344
June 2015 - Estimated	$ 29,212	$ 372,096	$ 2,129,133
Deferred DGGS Variable Ending Balance			**$ 2,129,133**
Current Year DGGS Variable Ending Balance (see page 2)			**$ (1,351,532)**
Total DGGS Variable Cost Balance Jul14-Jun15 [3]			**$ 777,601**
			-

[1] Exhibit__(FVB-6)14-15, page 2, line 97, col D.
[2] Exhibit__(FVB-6)14-15, page 2, line 45.
[3] Exhibit__(FVB-6)14-15, page 2, line 99, col O.

Exhibit__(JSJ-4)15-16
Docket No. D2014.7.58
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NorthWestern Energy
Electric Utility
DGGS Variable Cost Account Balance
July 2014 - June 2015

Month	DGGS Variable Cost Revenue[1]	DGGS Variable Cost Expense[2]	DGGS Variable Cost Balance
July 2014	$ 969,594	$ 1,355,655	$ 386,060
August 2014	$ 1,098,076	$ 1,020,071	$ (78,004)
September 2014	$ 997,788	$ 898,267	$ (99,521)
October 2014	$ 889,209	$ 827,454	$ (61,755)
November 2014	$ 902,187	$ 927,839	$ 25,652
December 2014	$ 1,086,373	$ 793,837	$ (292,536)
January 2015	$ 1,199,618	$ 645,845	$ (553,774)
February 2015	$ 1,027,245	$ 840,023	$ (187,223)
March 2015	$ 973,890	$ 867,207	$ (106,683)
April 2015 - Estimated	$ 891,925	$ 796,777	$ (95,147)
May 2015 - Estimated	$ 913,978	$ 802,963	$ (111,015)
June 2015 - Estimated	$ 930,737	$ 753,152	$ (177,585)
DGGS Cost Balance Jul14-Jun15	**$ 11,880,622**	**$ 10,529,089**	**$ (1,351,532)**
	-	-	-

[1]Revenue: Exhibit__(FVB-6)14-15, page 2, line 44.
[2]Expense: Exhibit__(FVB-6)14-15, page 2, line 90.

NorthWestern Energy
Electric Utility Derivation of Rates
Deferred DGGS Variable
Tracker Period July 2015 to June 2016

Customer Rate Class	**Loss Factor**	**Jul15 to Jun16 Supply Retail kWh Sales**	**Sales Adjusted for Employee Discount**	**Sales Weighted by Losses**	**Deferred DGGS Variable Rate After Losses**	**Deferred DGGS Variable Revenue Check**
Residential	8.5100%	2,394,862,903	2,394,862,903	2,598,665,736	$ 0.000129	$ 308,937
Residential Employee	8.5100%	3,379,973	2,027,984	2,200,565	$ 0.000077	$ 260
GS 1 Secondary NonDemand	8.5100%	278,748,374	278,748,374	302,469,861	$ 0.000129	$ 35,959
GS 1 Secondary Demand	8.5100%	2,476,869,018	2,476,869,018	2,687,650,572	$ 0.000129	$ 319,516
GS 1 Primary NonDemand	5.5400%	473,438	473,438	499,666	$ 0.000126	$ 60
GS 1 Primary Demand	5.5400%	341,297,734	341,297,734	360,205,628	$ 0.000126	$ 43,004
General Service Substation	4.6300%	251,830,078	251,830,078	263,489,810	$ 0.000125	$ 31,479
General Service Transmission	4.0000%	134,636,802	134,636,802	140,022,274	$ 0.000124	$ 16,695
Irrigation	8.5100%	96,759,889	96,759,889	104,994,156	$ 0.000129	$ 12,482
Lighting	8.5100%	61,285,015	61,285,015	66,500,369	$ 0.000129	$ 7,906
		6,040,143,224	6,038,791,235	6,526,698,638	$ 0.000129	$ 776,297
YNP Contract		20,691,140			Rounding Adjustment	$ 1,304
Total Supply Load		6,060,834,364				$ 777,601
		-				

2014-15 Deferred DGGS Variable Cost Under-Collection $ 777,601

Total Deferred DGGS Variable Rate Before Losses $ 0.000119
Total Deferred DGGS Variable Rate After Losses $ 0.000129

NorthWestern Energy
Electric Utility
Deferred DGGS Variable Revenue ($000) Summary
Tracker Period July 2015 to June 2016

	Jul15 to Jun16 Supply Retail MWh Sales	Current Deferred DGGS Rates[1]	Current Deferred DGGS Revenue	Proposed Deferred DGGS Rates 7/1/2015	Proposed Deferred DGGS Revenue	Revenue Diff Proposed vs Current
Residential						
Residential	2,394,863	$ 0.000063	$ 151	$ 0.000129	$ 309	$ 158
Residential Employee	3,380	$ 0.000038	$ 0	$ 0.000077	$ 0	$ 0
Total Residential			$ 151		$ 309	$ 158
General Service 1						
GS-1 Sec Non Demand	278,748	$ 0.000063	$ 18	$ 0.000129	$ 36	$ 18
GS-1 Sec Demand	2,476,869	$ 0.000063	$ 156	$ 0.000129	$ 320	$ 163
GS-1 Pri Non Demand	473	$ 0.000061	$ 0	$ 0.000126	$ 0	$ 0
GS-1 Pri Demand	341,298	$ 0.000061	$ 21	$ 0.000126	$ 43	$ 22
Total GS-1			$ 194		$ 399	$ 204
General Service 2						
GS-2 Substation	251,830	$ 0.000061	$ 15	$ 0.000125	$ 31	$ 16
GS-2 Transmission	134,637	$ 0.000060	$ 8	$ 0.000124	$ 17	$ 9
Total GS-2			$ 23		$ 48	$ 25
Irrigation						
Irrigation	96,760	$ 0.000063	$ 6	$ 0.000129	$ 12	$ 6
Total Irrigation			$ 6		$ 12	$ 6
Lighting						
Lighting	61,285	$ 0.000063	$ 4	$ 0.000129	$ 8	$ 4
Total Lighting			$ 4		$ 8	$ 4
Total Rate Schedule	**6,040,143**		**$ 379**		**$ 776**	**$ 397.443**
	-				-	

[1]Docket No. D2014.5.46, Interim Order No. 7283a, effective 7/1/2014.

NorthWestern Energy
Electric Utility Derivation of Rates
DGGS Variable Cost of Service
Tracker Period July 2015 to June 2016

Customer Rate Class	**Loss Factor**	**Jul15 to Jun16 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%	2,394,862,903	2,394,862,903	2,598,665,736	$ 0.001362	$ 3,261,803
Residential Employee	8.5100%	3,379,973	2,027,984	2,200,565	$ 0.000818	$ 2,765
GS 1 Secondary NonDemand	8.5100%	278,748,374	278,748,374	302,469,861	$ 0.001362	$ 379,655
GS 1 Secondary Demand	8.5100%	2,476,869,018	2,476,869,018	2,687,650,572	$ 0.001362	$ 3,373,496
GS 1 Primary NonDemand	5.5400%	473,438	473,438	499,666	$ 0.001325	$ 627
GS 1 Primary Demand	5.5400%	341,297,734	341,297,734	360,205,628	$ 0.001325	$ 452,219
General Service Substation	4.6300%	251,830,078	251,830,078	263,489,810	$ 0.001313	$ 330,653
General Service Transmission	4.0000%	134,636,802	134,636,802	140,022,274	$ 0.001305	$ 175,701
Irrigation	8.5100%	96,759,889	96,759,889	104,994,156	$ 0.001362	$ 131,787
Lighting	8.5100%	61,285,015	61,285,015	66,500,369	$ 0.001362	$ 83,470
		6,040,143,224	6,038,791,235	6,526,698,638	$ 0.001357	$ 8,192,177
YNP Contract		20,691,140			Rounding Adjustment	$ (880)
Total Supply Load		6,060,834,364				$ 8,191,297
		-				

2015-16 DGGS Variable Cost of Service	**$**	**8,191,297**
Total DGGS Variable COS Rate Before Losses	$	0.001255
Total DGGS Variable COS Rate After Losses	$	0.001356

NorthWestern Energy
Electric Utility
Total DGGS Revenue ($000) Summary
Tracker Period July 2015 to June 2016

	Jul15 to Jun16 Supply Retail MWh Sales	DGGS Fixed: Current Rates[1]	DGGS Fixed: Current Rate Revenue	DGGS Variable: Current Rates[2]	DGGS Variable: Current Rate Revenue	DGGS Variable: Proposed Rates 7/1/2015	DGGS Variable: Proposed Rate Revenue	Total Revenue Diff Proposed vs Current
Residential								
Residential	2,394,863	0.004795	$ 11,483	0.002003	$ 4,797	0.001362	$ 3,262	$ (1,535)
Residential Employee	3,380	0.002877	$ 10	0.001202	$ 4	0.000818	$ 3	$ (1)
Total Residential			$ 11,493		$ 4,801		$ 3,265	$ (1,536)
General Service 1								
GS-1 Sec Non Demand	278,748	0.004795	$ 1,337	0.002003	$ 558	0.001362	$ 380	$ (179)
GS-1 Sec Demand	2,476,869	0.004795	$ 11,877	0.002003	$ 4,961	0.001362	$ 3,373	$ (1,588)
GS-1 Pri Non Demand	473	0.004664	$ 2	0.001948	$ 1	0.001325	$ 1	$ (0)
GS-1 Pri Demand	341,298	0.004664	$ 1,592	0.001948	$ 665	0.001325	$ 452	$ (213)
Total GS-1			$ 14,807		$ 6,185		$ 4,206	$ (1,979)
General Service 2								
GS-2 Substation	251,830	0.004624	$ 1,164	0.001931	$ 486	0.001313	$ 331	$ (156)
GS-2 Transmission	134,637	0.004596	$ 619	0.001920	$ 259	0.001305	$ 176	$ (83)
Total GS-2			$ 1,783		$ 745		$ 506	$ (238)
Irrigation								
Irrigation	96,760	0.004795	$ 464	0.002003	$ 194	0.001362	$ 132	$ (62)
Total Irrigation			$ 464		$ 194		$ 132	$ (62)
Lighting								
Lighting	61,285	0.004795	$ 294	0.002003	$ 123	0.001362	$ 83	$ (39)
Total Lighting			$ 294		$ 123		$ 83	$ (39)
Total Rate Schedule	**6,040,143**		**$ 28,841**		**$ 12,048**		**$ 8,192**	**$ (3,855.419)**
	-						-	

[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 Variable Rates updated for property taxes in January 2015 Electric Supply monthly filing, effective 1/1/2015.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2014.7.58
Annual Spion True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF FRANK V. BENNETT

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL SPION KOP WIND GENERATION ASSET ("SPION") 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 this portion of your testimony.

A. In my testimony, I present the following information:

- The updated Spion costs for the 12-month ended June 2015 true-up period with 9 months of actual numbers and 3 months of estimated numbers, and
- The forecast Spion costs for the 12-month ended June 2016 true-up period.

Update to Spion Values in the 2014/2015 True-up Period

Q. How has NorthWestern updated the Spion generation that is reflected in the 2014/2015 electric supply tracker?

A. NorthWestern has included the full rate-based volume of unit contingent energy associated with the 40 MW of capacity from July 1, 2014 through June 30, 2015.

Q. How are the Spion variable costs treated in the 2014/2015 true-up period?

A. The Spion costs are treated the same as they have been treated in previous annual true-up filings. The variable Spion cost of service includes 9 months of actual values and 3 months of estimated information. The variable cost of service on page 2 of Exhibit__(FVB-8)14-15 includes incremental property taxes and lost revenues. These variable costs are tracked in a manner similar to the market-based supply costs. In addition, the Spion variable cost was updated in January 2015 to reflect the Spion property tax changes submitted in the 2015 Annual Property Tax Tracker filing.

Q. Have any adjustments been made to the Spion fixed cost of service in the 2014/2015 or 2015/2016 true-up periods?

A. Yes. The Spion fixed cost of service and associated fixed cost rates presented in this filing have been updated to reflect the second year approved revenue requirement effective on January 1, 2014 in Docket No. D2011.5.41, Order No. 7159l. The fixed costs 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 2015 Spion deferred account balance.

A. The June 2014 deferred account balance of $15,574 under-collection shown on page 2 of Exhibit__(FVB-8)13-14 Updated from Docket Nos. D2013.5.33 and D2014.5.46 (“Consolidated Dockets”) is the July 2014 beginning deferred account balance. This updated exhibit was provided electronically in response to Data Request MCC-076 in the Consolidated Dockets. With 9 months of actual values and 3 months of estimated values, the June 2015 ending deferred account balance is a $(13,878) over-collection. Please refer to the Prefiled Direct Testimony of Joseph S. Janhunen – Annual Spion True-up for further discussion of the Deferred Account.

Q. Please summarize the 12-month ended June 2015 Spion true-up period variable costs.

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

Beginning Deferred Spion		**Balance ($)**
Under-Collection		$15,574

Variable Costs Spion		**Cost ($)**
Incremental Property Tax Adjustment		(131,830)
MPSC/MCC Tax Adjustment		(11,251)
Lost Revenue		159,923
Lost Revenue Adjustment		(1,099)
Subtotal Variable Spion Cost of Service:		15,744

Carrying Cost		(291)
Total Spion Variable Cost Allocation		$15,453

Variable Revenues Spion		**Revenue ($)**
Revenues		32,443
Prior Deferred Expense		$12,461
Total Revenues:		$44,904

Ending Deferred Spion		**Balance ($)**
Over-Collection		($13,878)

Forecast for Spion Values in the 2015/2016 Period

Q. Please summarize the 12-month Spion true-up period ending June 2016.

A. The June 2015 Deferred Account over-collection ending balance of $(13,878) as described above is the July 2015 beginning balance. July 2015 through June 2016 information is based on forecast numbers. Please see Exhibit__(FVB-9)15-16 for supply volume and cost details of the 12-month forecast true-up period.

Q. Describe the changes within the Spion variable Revenue and Cost categories for the 12-month ended June 2016 forecast true-up period.

A. The Spion generation asset true-up variable cost revenue and expense details are reflected on page 2 of Exhibit__(FVB-9)15-16 under two main sections: Total Revenue and Total Variable Cost. Total Revenue is estimated to be $97,591. Total variable cost is estimated to be $111,469.

Q. Please provide a summary table of the 12-month ended June 2016 Spion period.

A. The Spion period is summarized in the following table (rounded from tracker values):

Beginning Deferred Spion		Balance ($)
Over-Collection		($13,878)

Variable Costs Spion		Cost ($)
Incremental Property Tax Adjustment		(116,251)
MPSC/MCC Tax Adjustment		0
Lost Revenue		228,290
Lost Revenue Adjustment		0
Subtotal Variable Spion Cost of Service:		112,039

Carrying Cost		(570)
Total Spion Variable Cost Allocation		$111,469

Variable Revenues Spion		Revenue ($)
Revenues		111,468
Prior Deferred Expense		($13,878)
Total Revenues:		$97,591

Ending Deferred Spion		Balance ($)
Even-Collection		$0

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

A. Yes, it does.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1		**Spion Kop Asset Component**														
2				**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Total**
3				Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
4		**Spion Kop Fixed Cost Revenue Requirement -- Per Order 7159l**														
5		Spion Kop Plant In Service														
6		Electric Generation Plant		$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 83,900,949
7		Accumulated Depreciation		$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (5,004,126)
8		Total Net Plant		$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 78,896,823
9																
10		Accelerated Tax Depreciation		$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 18,126,024
11		NOL Deferred Tax Asset		$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (20,951,616)
12		Total Customer Contributed Capital		$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (2,825,592)
13																
14		Total Year End Rate Base		$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 81,722,415
15																
16		Fixed Return (Avg RB * Cost of Capital)	7.00%	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 5,720,569
17																
18		Fixed Cost of Service														
19		Operation & Maintenance Turbine Expense		$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 1,742,500
20		Landowner Maintenance Expense		$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 12,000
21		Landowner Right of Way Expense		$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 12,280
22		Royalty Fee		$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 186,521
23		Administrative and General Expense		$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 237,000
24		Depreciation		$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 3,336,078
25		Wind Generation Facility Impact Fee		$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 157,314
26		Property & Other Taxes		$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 439,798
27		MPSC & MCC Revenue Tax	0.53%	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 46,188
28		Deferred Income Taxes		$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (139,511)
29		Current Income Taxes		$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (3,036,000)
30		Fixed Cost of Service		$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 2,994,168
31																
32		Total Spion Kop Fixed Cost Revenue Requirement		$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 8,714,737
33																

Row	A/B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
34	**Spion Kop Asset Component**														
35			**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jan-00**
36			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
37	**Spion Kop Variable Cost**														
38	Total Forecast Sales														
39	2011/12 Tracker Sales MWh		482,388	546,211	496,510	442,674	449,232	540,528	601,160	515,060	488,212	447,321	458,167	466,568	5,934,031
40	Spion Kop Cost		$ 0.0028	$ 0.0028	$ 0.0028	$ 0.0028	$ **0.0028**	$ 0.0028	$ 0.0080	$ 0.0080	$ 0.0080	$ 0.0080	$ 0.0080	$ 0.0080	
41	Prior Year Deferred Expense		$ 0.0026	$ 0.0026	$ 0.0026	$ 0.0026	$ 0.0026	$ 0.0026	$ 0.0026	$ 0.0026	$ 0.0026	$ 0.0026	$ 0.0026	$ 0.0026	
42															
43	Spion Kop Variable Cost Revenues														
44	NWE Spion Kop Revenues		$ 1,447	$ 1,638	$ 1,489	$ 1,328	$ 1,347	$ 1,621	$ 4,744	$ 4,056	$ 3,848	$ 3,520	$ 3,668	$ 3,736	$ 32,443
45															
46	Subtotal		$ 1,447	$ 1,638	$ 1,489	$ 1,328	$ 1,347	$ 1,621	$ 4,744	$ 4,056	$ 3,848	$ 3,520	$ 3,668	$ 3,736	$ 32,443
47	Prior Year(s) Deferred Expense		$ 965	$ 1,092	$ 993	$ 885	$ 898	$ 1,081	$ 1,202	$ 1,030	$ 976	$ 894	$ 1,212	$ 1,234	$ 12,461
48	Total Revenue		$ 2,411	$ 2,730	$ 2,482	$ 2,213	$ 2,246	$ 2,702	$ 5,946	$ 5,086	$ 4,824	$ 4,414	$ 4,880	$ 4,970	$ 44,904
49															
50	Incremental Property Tax Adjustment		$ (12,284)	$ (12,284)	$ (12,284)	$ (12,284)	$ (12,284)	$ (12,284)	$ (9,688)	$ (9,688)	$ (9,688)	$ (9,688)	$ (9,688)	$ (9,688)	$ (131,830)
51	MPSC/MCC Tax Adjustment		$ (11,251)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,251)
52															
53	Lost Revenue		$ 13,641	$ 13,641	$ 13,641	$ 13,641	$ 13,641	$ 13,641	$ 13,641	$ 13,641	$ 13,641	$ 13,641	$ 11,756	$ 11,756	$ 159,923
54	Lost Revenue Adjustment			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,099)	$ (1,099)
55															
56	Subtotal Spion Kop Variable Cost		$ (9,894)	$ 1,357	$ 1,357	$ 1,357	$ 1,357	$ 1,357	$ 3,954	$ 3,954	$ 3,954	$ 3,954	$ 2,069	$ 970	$ 15,744
57															
58	**Carrying Cost Expense**														
59	Carrying Costs	7.92%	$ 22	$ 13	$ 5	$ (0)	$ (6)	$ (15)	$ (29)	$ (36)	$ (42)	$ (46)	$ (65)	$ (92)	$ (291)
60															
61	Total Variable Costs		$ (9,872)	$ 1,370	$ 1,362	$ 1,357	$ 1,351	$ 1,342	$ 3,925	$ 3,917	$ 3,911	$ 3,908	$ 2,004	$ 878	$ 15,453
62															
63	Deferred Cost Amortization (Under)/Over		$ 965	$ 1,092	$ 993	$ 885	$ 898	$ 1,081	$ 1,202	$ 1,030	$ 976	$ 894	$ 1,212	$ 1,234	$ 12,461
64	Monthly Deferred Cost		$ 11,319	$ 269	$ 127	$ (29)	$ (3)	$ 279	$ 819	$ 139	$ (64)	$ (388)	$ 1,665	$ 2,858	$ 16,990
65	Cumulative Deferred Cost		$ 11,319	$ 11,588	$ 11,715	$ 11,686	$ 11,682	$ 11,961	$ 12,781	$ 12,920	$ 12,856	$ 12,468	$ 14,132	$ 16,990	
66															
67	Variable Rate-Base Deferred														
68	Beginning Balance		$ **15,574**	$ 3,290	$ 1,929	$ 810	$ (47)	$ (941)	$ (2,301)	$ (4,323)	$ (5,492)	$ (6,404)	$ (6,910)	$ (9,786)	
69	Monthly Deferred Cost		$ (12,284)	$ (1,361)	$ (1,120)	$ (856)	$ (895)	$ (1,360)	$ (2,021)	$ (1,169)	$ (913)	$ (506)	$ (2,876)	$ (4,092)	
70	Ending Balance Under/(Over)		$ 3,290	$ 1,929	$ 810	$ (47)	$ (941)	$ (2,301)	$ (4,323)	$ (5,492)	$ (6,404)	$ (6,910)	$ (9,786)	$ (13,878)	
71															

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Spion Kop Asset Component**														
2			**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Total**
3			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
4	**Spion Kop Fixed Cost Revenue Requirement -- Per Order 7159l**														
5	Spion Kop Plant In Service														
6	Electric Generation Plant		$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 83,900,949
7	Accumulated Depreciation		$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (417,011)	$ (5,004,126)
8	Total Net Plant		$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 6,574,735	$ 78,896,823
9															
10	Accelerated Tax Depreciation		$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 1,510,502	$ 18,126,024
11	NOL Deferred Tax Asset		$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (1,745,968)	$ (20,951,616)
12	Total Customer Contributed Capital		$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (235,466)	$ (2,825,592)
13															
14	Total Year End Rate Base		$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 6,810,201	$ 81,722,415
15															
16	Fixed Return (Avg RB * Cost of Capital)	7.00%	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 476,714	$ 5,720,569
17															
18	Fixed Cost of Service														
19	Operation & Maintenance Turbine Expense		$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 1,742,500
20	Landowner Maintenance Expense		$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 12,000
21	Landowner Right of Way Expense		$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 12,280
22	Royalty Fee		$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 186,521
23	Administrative and General Expense		$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 237,000
24	Depreciation		$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 3,336,078
25	Wind Generation Facility Impact Fee		$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 157,314
26	Property & Other Taxes		$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 439,798
27	MPSC & MCC Revenue Tax	0.53%	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 3,849	$ 46,188
28	Deferred Income Taxes		$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (11,626)	$ (139,511)
29	Current Income Taxes		$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (3,036,000)
30	Fixed Cost of Service		$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 249,514	$ 2,994,168
31															
32	Total Spion Kop Fixed Cost Revenue Requirement		$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 726,228	$ 8,714,737
33															

	A/B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
34	**Spion Kop Asset Component**														
35			**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jan-00**
36			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
37	**Spion Kop Variable Cost**														
38	Total Forecast Sales														
39	2011/12 Tracker Sales MWh		516,208	541,697	492,397	468,897	489,975	535,138	566,841	530,208	500,071	476,340	456,744	465,627	6,040,143
40	Spion Kop Cost		$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	$ 0.0185	
41	Prior Year Deferred Expense		$ (0.0023)	$ (0.0023)	$ (0.0023)	$ (0.0023)	$ (0.0023)	$ (0.0023)	$ (0.0023)	$ (0.0023)	$ (0.0023)	$ (0.0023)	$ (0.0023)	$ (0.0023)	
42															
43	Spion Kop Variable Cost Revenues														
44	NWE Spion Kop Revenues		$ 9,526	$ 9,997	$ 9,087	$ 8,653	$ 9,042	$ 9,876	$ 10,461	$ 9,785	$ 9,229	$ 8,791	$ 8,429	$ 8,593	$ 111,468
45															
46	Subtotal		$ 9,526	$ 9,997	$ 9,087	$ 8,653	$ 9,042	$ 9,876	$ 10,461	$ 9,785	$ 9,229	$ 8,791	$ 8,429	$ 8,593	$ 111,468
47	Prior Year(s) Deferred Expense		$ (1,186)	$ (1,245)	$ (1,131)	$ (1,077)	$ (1,126)	$ (1,230)	$ (1,302)	$ (1,218)	$ (1,149)	$ (1,094)	$ (1,049)	$ (1,070)	$ (13,878)
48	Total Revenue		$ 8,340	$ 8,752	$ 7,956	$ 7,576	$ 7,917	$ 8,646	$ 9,158	$ 8,567	$ 8,080	$ 7,696	$ 7,380	$ 7,523	$ 97,591
49															
50	Incremental Property Tax Adjustment		$ (9,688)	$ (9,688)	$ (9,688)	$ (9,688)	$ (9,688)	$ (9,688)	$ (9,688)	$ (9,688)	$ (9,688)	$ (9,688)	$ (9,688)	$ (9,688)	$ (116,251)
51															
52	Lost Revenue		$ 19,024	$ 19,024	$ 19,024	$ 19,024	$ 19,024	$ 19,024	$ 19,024	$ 19,024	$ 19,024	$ 19,024	$ 19,024	$ 19,024	$ 228,290
53	Lost Revenue Adjustment			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54															
55	Subtotal Spion Kop Variable Cost		$ 9,337	$ 9,337	$ 9,337	$ 9,337	$ 9,337	$ 9,337	$ 9,337	$ 9,337	$ 9,337	$ 9,337	$ 9,337	$ 9,337	$ 112,039
56															
57	**Carrying Cost Expense**														
58	Carrying Costs	7.92%	$ (86)	$ (82)	$ (74)	$ (62)	$ (53)	$ (49)	$ (48)	$ (44)	$ (35)	$ (25)	$ (12)	$ 0	$ (570)
59															
60	Total Variable Costs		$ 9,251	$ 9,254	$ 9,263	$ 9,274	$ 9,283	$ 9,287	$ 9,288	$ 9,293	$ 9,301	$ 9,312	$ 9,325	$ 9,337	$ 111,469
61															
62	Deferred Cost Amortization (Under)/Over		$ (1,186)	$ (1,245)	$ (1,131)	$ (1,077)	$ (1,126)	$ (1,230)	$ (1,302)	$ (1,218)	$ (1,149)	$ (1,094)	$ (1,049)	$ (1,070)	$ (13,878)
63	Monthly Deferred Cost		$ 275	$ 742	$ (176)	$ (621)	$ (241)	$ 588	$ 1,173	$ 492	$ (73)	$ (521)	$ (896)	$ (744)	$ (0)
64	Cumulative Deferred Cost		$ 275	$ 1,018	$ 842	$ 221	$ (20)	$ 568	$ 1,741	$ 2,233	$ 2,160	$ 1,639	$ 743	$ (0)	
65															
66	Variable Rate-Base Deferred														
67	Beginning Balance		$ (13,878)	$ (12,967)	$ (12,465)	$ (11,158)	$ (9,459)	$ (8,093)	$ (7,452)	$ (7,322)	$ (6,595)	$ (5,374)	$ (3,758)	$ (1,813)	
68	Monthly Deferred Cost		$ 911	$ 502	$ 1,307	$ 1,698	$ 1,367	$ 641	$ 130	$ 727	$ 1,222	$ 1,616	$ 1,945	$ 1,813	
69	Ending Balance Under/(Over)		$ (12,967)	$ (12,465)	$ (11,158)	$ (9,459)	$ (8,093)	$ (7,452)	$ (7,322)	$ (6,595)	$ (5,374)	$ (3,758)	$ (1,813)	$ 0	
70															

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2014.7.58
Annual Spion True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF JOSEPH S. JANHUNEN

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL SPION KOP WIND GENERATION ASSET ("SPION") TRUE-UP

TABLE OF CONTENTS

Witness Information

Q. Are you the same Joseph S. Janhunen 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 Spion True-up testimony?

A. This testimony:

1. Presents the derivation of proposed deferred Spion variable rates resulting from the over/under collection reflected in the 2013-2014 true-up period and the 2014-2015 true-up period;
2. Presents the derivation of proposed Spion variable rates for the forecasted 2015-2016 true-up period; and
3. Discusses the overall total supply rates incorporating all individual rate components.

Derivation of Proposed Deferred Spion Variable Rates

Q. What is the Spion variable cost account balance for the 12-month period ending June 2015?

A. The Spion variable cost account balance for the 12-month period ending June 2015 is an over-collection of $(13,878) as presented on page 1 of Exhibit__(JSJ-5)15-16. As discussed below, this includes the prior period

balance for the 2013-2014 true-up period and the current period balance for the 2014-2015 true-up period.

Q. Describe the status of the deferred Spion variable cost account balance associated with the 2013-2014 true-up period.

A. In the annual filing submitted on May 29, 2014, the net deferred account balance for the 2013-2014 true-up period was shown as an under-collection of $15,848. This amount becomes the starting balance in this filing. Added to this balance is the prior period true-up for the 3 months of estimated data included in the May 2014 filing. Page 1 of Exhibit__(JSJ-5)15-16 shows the true-up of the estimated months of April, May and June 2014 with the actual data for these months. The resulting actual ending balance of $15,574 is the deferred account beginning balance associated with the 2013-2014 true-up period. This balance is then combined with the current year deferred monthly activity shown on Exhibit__(JSJ-5)15-16, page 1, resulting in a net under-collection balance of $3,112 for the 2013-2014 true-up period. The months of April, May and June 2015 are estimated and will be trued-up in the next annual filing.

Q. Describe the Spion variable cost account balance associated with the 2014-2015 true-up period.

A. Page 2 of Exhibit__(JSJ-5)15-16 shows the monthly detail of the difference between the Spion variable cost revenues and expenses for the

2014-2015 true-up period, resulting in an over-collected amount of $(16,990). The months of April, May and June 2015 are estimated and will be trued-up in the next annual filing.

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

A. The total deferred Spion variable cost account adjustment proposed in this filing is an over-collection of $(13,878) shown below and on page 1, line 64 of Exhibit__(JSJ-5)15-16.

Total Deferred Spion Variable Cost Account Balance

2013-2014 Prior Period Spion Variable Account Balance	$3,112
2014-2015 Current Period Spion Variable Account Balance	$(16,990)
	$(13,878)

Derivation of the deferred Spion variable rates is shown on Exhibit__(JSJ-5)15-16, page 3 with the resulting rates and revenues shown on page 4.

Derivation of Proposed Spion Variable Rates

Q. Please describe the process NorthWestern used to derive the proposed 2015-2016 forecasted Spion variable rates in this filing.

A. The rate design methodology used in this filing to derive the proposed 2015-2016 forecasted Spion variable rates is the same as that presented in previous annual Spion true-up filings. All forecasted costs are from Exhibit__(FVB-9)15-16 of the Prefiled Direct Testimony of Frank V. Bennett and are discussed therein.

Derivation of the Spion variable rates is shown on Exhibit__(JSJ-5)15-16, page 5. The total Spion variable cost of $111,469 is the sum of incremental property taxes, Lost Revenues, and carrying costs from Exhibit__(FVB-9)15-16. This sum is the amount used to derive the Spion variable rates. The forecasted loads used in the derivation are from Exhibit__(JSJ-1)15-16, page 6. The resulting rates are the Spion variable rates proposed in this filing.

Q. Please describe the 2015-2016 Spion fixed rates included in this filing.

A. The Spion fixed cost of service rate components presented in this filing are those ordered by the Commission in Docket No. D2011.5.41. The Spion fixed rate components include rates effective January 1, 2014 reflecting the second year revenue requirement and will not change until an order is issued by the Commission in any subsequent revenue requirement filing dealing with Spion.

Page 6 of Exhibit__(JSJ-5)15-16 reflects the Spion fixed and variable rates and revenues in summarized format.

Proposed Total Deferred Supply and Total Supply Rates

Q. Please describe the process NorthWestern used to derive the total 2015-2016 deferred supply rates proposed in this filing.

A. The total deferred supply rate includes four separate rate components – a deferred electricity supply rate, a deferred Colstrip Unit 4 ("CU4") variable rate, a deferred Dave Gates Generating Station ("DGGS") variable rate, and a deferred Spion variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(JSJ-8)15-16, page 1.

Q. Please describe the process NorthWestern used to derive the total 2015-2016 supply rates proposed in this filing.

A. 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 variable rate, a Spion fixed cost of service rate, a Spion variable rate, a Hydro Generation Asset ("Hydro") fixed cost of service rate, a Hydro variable rate, and a Revenue Credits rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(JSJ-8)15-16, page 3.

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

A. Yes, it does.

NorthWestern Energy
Electric Utility
Deferred Spion Variable Cost Account Balance
July 2014 - June 2015

Line	Month	Monthly Collection	Collection to-date	Balance Remaining
12				
13	**Jul13-Jun14 under collected balance as filed in D2014.5.46**			**$ 15,848**
14				
15	**Prior Period Tracker Year True-up - Deferred:**			
16	Apr14: Estimated as filed in D2014.5.46		$ -	
17	Apr14: Actual		$ -	$ -
18				
19	May14: Estimated as filed in D2014.5.46		$ -	
20	May14: Actual		$ -	$ -
21				
22	Jun14: Estimated as filed in D2014.5.46		$ -	
23	Jun14: Actual		$ -	$ -
24				
25	**Prior Period Tracker Year True-up - Variable:**			
26	Apr14: Est as filed in D2014.5.46 - Revenue	$ (5,695)		
27	Apr14: Est as filed in D2014.5.46 - Expense	$ (4,573)	$ 1,122	
28				
29	Apr14: Actual - Revenue	$ (5,695)		
30	Apr14: Actual - Expense	$ (4,573)	$ 1,122	$ 0
31				
32	May14: Est as filed in D2014.5.46 - Revenue	$ (5,442)		
33	May14: Est as filed in D2014.5.46 - Expense	$ (2,916)	$ 2,526	
34				
35	May14: Actual - Revenue	$ (5,387)		
36	May14: Actual - Expense	$ (2,916)	$ 2,471	$ (55)
37				
38	Jun14: Est as filed in D2014.5.46 - Revenue	$ (5,546)		
39	Jun14: Est as filed in D2014.5.46 - Expense	$ (2,898)	$ 2,648	
40				
41	Jun14: Actual - Revenue	$ (5,328)		
42	Jun14: Actual - Expense	$ (2,900)	$ 2,428	$ (220)
43				
44	**Actual Jul13-Jun4 under collected balance [1]**			**$ 15,574**
45				-
46	**Deferred Jul14-Jun15 Monthly Activity [2]:**			
47	July 2014	$ 965	$ 965	$ 14,609
48	August 2014	$ 1,092	$ 2,057	$ 13,517
49	September 2014	$ 993	$ 3,049	$ 12,524
50	October 2014	$ 885	$ 3,935	$ 11,639
51	November 2014	$ 898	$ 4,833	$ 10,741
52	December 2014	$ 1,081	$ 5,914	$ 9,660
53	January 2015	$ 1,202	$ 7,116	$ 8,458
54	February 2015	$ 1,030	$ 8,145	$ 7,428
55	March 2015	$ 976	$ 9,122	$ 6,452
56	April 2015 - Estimated	$ 894	$ 10,016	$ 5,558
57	May 2015 - Estimated	$ 1,212	$ 11,227	$ 4,346
58	June 2015 - Estimated	$ 1,234	$ 12,461	$ 3,112
59				
60	**Deferred Spion Variable Ending Balance**			**$ 3,112**
61				
62	**Current Year Spion Variable Ending Balance (see page 2)**			**$ (16,990)**
63				
64	**Total Spion Variable Cost Balance Jul14-Jun15 [3]**			**$ (13,878)**
65				-
66	[1] Exhibit__(FVB-8)14-15, page 2, line 68, col D.			
67	[2] Exhibit__(FVB-8)14-15, page 2, line 47.			
68	[3] Exhibit__(FVB-8)14-15, page 2, line 70, col O.			

NorthWestern Energy
Electric Utility
Spion Variable Cost Account Balance
July 2014 - June 2015

Month		Spion Variable Cost Revenue[1]		Spion Variable Cost Expense[2]		Spion Variable Cost Balance
July 2014	$	1,447	$	(9,872)	$	(11,319)
August 2014	$	1,638	$	1,370	$	(269)
September 2014	$	1,489	$	1,362	$	(127)
October 2014	$	1,328	$	1,357	$	29
November 2014	$	1,347	$	1,351	$	3
December 2014	$	1,621	$	1,342	$	(279)
January 2015	$	4,744	$	3,925	$	(819)
February 2015	$	4,056	$	3,917	$	(139)
March 2015	$	3,848	$	3,911	$	64
April 2015 - Estimated	$	3,520	$	3,908	$	388
May 2015 - Estimated	$	3,668	$	2,004	$	(1,665)
June 2015 - Estimated	$	3,736	$	878	$	(2,858)
Spion Cost Balance Jul14-Jun15	**$**	**32,443**	**$**	**15,453**	**$**	**(16,990)**
		-		-		-

[1]Revenue: Exhibit__(FVB-8)14-15, page 2, line 46.
[2]Expense: Exhibit__(FVB-8)14-15, page 2, line 61.

NorthWestern Energy
Electric Utility Derivation of Rates
Deferred Spion Variable
Tracker Period July 2015 to June 2016

Customer Rate Class	**Loss Factor**	**Jul15 to Jun16 Supply Retail kWh Sales**	**Sales Adjusted for Employee Discount**	**Sales Weighted by Losses**	**Deferred Spion Variable Rate After Losses**	**Deferred Spion Variable Revenue Check**
Residential	8.5100%	2,394,862,903	2,394,862,903	2,598,665,736	$ (0.000002)	$ (4,790)
Residential Employee	8.5100%	3,379,973	2,027,984	2,200,565	$ (0.000001)	$ (3)
GS 1 Secondary NonDemand	8.5100%	278,748,374	278,748,374	302,469,861	$ (0.000002)	$ (557)
GS 1 Secondary Demand	8.5100%	2,476,869,018	2,476,869,018	2,687,650,572	$ (0.000002)	$ (4,954)
GS 1 Primary NonDemand	5.5400%	473,438	473,438	499,666	$ (0.000002)	$ (1)
GS 1 Primary Demand	5.5400%	341,297,734	341,297,734	360,205,628	$ (0.000002)	$ (683)
General Service Substation	4.6300%	251,830,078	251,830,078	263,489,810	$ (0.000002)	$ (504)
General Service Transmission	4.0000%	134,636,802	134,636,802	140,022,274	$ (0.000002)	$ (269)
Irrigation	8.5100%	96,759,889	96,759,889	104,994,156	$ (0.000002)	$ (194)
Lighting	8.5100%	61,285,015	61,285,015	66,500,369	$ (0.000002)	$ (123)
		6,040,143,224	6,038,791,235	6,526,698,638	$ (0.000002)	$ (12,077)
YNP Contract		20,691,140			Rounding Adjustment	$ (1,801)
Total Supply Load		6,060,834,364				$ (13,878)
		-				

2014-15 Deferred Spion Variable Cost Over-Collection	**$**	**(13,878)**
Total Deferred Spion Variable Rate Before Losses	$	(0.000002)
Total Deferred Spion Variable Rate After Losses	$	(0.000002)

NorthWestern Energy
Electric Utility
Deferred Spion Variable Revenue ($000) Summary
Tracker Period July 2015 to June 2016

	Jul15 to Jun16 Supply Retail MWh Sales	Current Deferred Spion Rates[1]	Current Deferred Spion Revenue	Proposed Deferred Spion Rates 7/1/2015	Proposed Deferred Spion Revenue	Revenue Diff Proposed vs Current
Residential						
Residential	2,394,863	$ 0.000002	$ 5	$ (0.000002)	$ (5)	$ (10)
Residential Employee	3,380	$ 0.000001	$ 0	$ (0.000001)	$ (0)	$ (0)
Total Residential			$ 5		$ (5)	$ (10)
General Service 1						
GS-1 Sec Non Demand	278,748	$ 0.000002	$ 1	$ (0.000002)	$ (1)	$ (1)
GS-1 Sec Demand	2,476,869	$ 0.000002	$ 5	$ (0.000002)	$ (5)	$ (10)
GS-1 Pri Non Demand	473	$ 0.000002	$ 0	$ (0.000002)	$ (0)	$ (0)
GS-1 Pri Demand	341,298	$ 0.000002	$ 1	$ (0.000002)	$ (1)	$ (1)
Total GS-1			$ 6		$ (6)	$ (12)
General Service 2						
GS-2 Substation	251,830	$ 0.000002	$ 1	$ (0.000002)	$ (1)	$ (1)
GS-2 Transmission	134,637	$ 0.000002	$ 0	$ (0.000002)	$ (0)	$ (1)
Total GS-2			$ 1		$ (1)	$ (2)
Irrigation						
Irrigation	96,760	$ 0.000002	$ 0	$ (0.000002)	$ (0)	$ (0)
Total Irrigation			$ 0		$ (0)	$ (0)
Lighting						
Lighting	61,285	$ 0.000002	$ 0	$ (0.000002)	$ (0)	$ (0)
Total Lighting			$ 0		$ (0)	$ (0)
Total Rate Schedule	**6,040,143**		**$ 12**		**$ (12)**	$\boxed{\textbf{\$ (24.154)}}$
	-				-	

[1]Docket No. D2014.5.46, Interim Order No. 7283a, effective 7/1/2014.

NorthWestern Energy
Electric Utility Derivation of Rates
Spion Variable Cost of Service
Tracker Period July 2015 to June 2016

Customer Rate Class	Loss Factor	Jul15 to Jun16 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Spion Variable After Losses kWh Charges	Spion Variable Revenue/Cost Check
Residential	8.5100%	2,394,862,903	2,394,862,903	2,598,665,736	$ 0.000018	$ 43,108
Residential Employee	8.5100%	3,379,973	2,027,984	2,200,565	$ 0.000011	$ 37
GS 1 Secondary NonDemand	8.5100%	278,748,374	278,748,374	302,469,861	$ 0.000018	$ 5,017
GS 1 Secondary Demand	8.5100%	2,476,869,018	2,476,869,018	2,687,650,572	$ 0.000018	$ 44,584
GS 1 Primary NonDemand	5.5400%	473,438	473,438	499,666	$ 0.000018	$ 9
GS 1 Primary Demand	5.5400%	341,297,734	341,297,734	360,205,628	$ 0.000018	$ 6,143
General Service Substation	4.6300%	251,830,078	251,830,078	263,489,810	$ 0.000018	$ 4,533
General Service Transmission	4.0000%	134,636,802	134,636,802	140,022,274	$ 0.000018	$ 2,423
Irrigation	8.5100%	96,759,889	96,759,889	104,994,156	$ 0.000018	$ 1,742
Lighting	8.5100%	61,285,015	61,285,015	66,500,369	$ 0.000018	$ 1,103
		6,040,143,224	6,038,791,235	6,526,698,638	$ 0.000018	$ 108,699
YNP Contract		20,691,140			Rounding Adjustment	$ 2,770
Total Supply Load		6,060,834,364				$ 111,469
		-				

2015-16 Spion Variable Cost of Service $ 111,469

Total Spion Variable COS Rate Before Losses $ 0.000017
Total Spion Variable COS Rate After Losses $ 0.000018

NorthWestern Energy
Electric Utility
Total Spion Revenue ($000) Summary
Tracker Period July 2015 to June 2016

		Spion Fixed		Spion Variable				
	Jul15 to Jun16 Supply Retail MWh Sales	Current Rates[1]	Current Rate Revenue	Current Rates[2]	Current Rate Revenue	Proposed Rates 7/1/2015	Proposed Rate Revenue	Revenue Diff Proposed vs Current
Residential								
Residential	2,394,863	0.001458	$ 3,492	0.000008	$ 19	0.000018	$ 43	$ 24
Residential Employee	3,380	0.000875	$ 3	0.000005	$ 0	0.000011	$ 0	$ 0
Total Residential			$ 3,495		$ 19		$ 43	$ 24
General Service 1								
GS-1 Sec Non Demand	278,748	0.001459	$ 407	0.000008	$ 2	0.000018	$ 5	$ 3
GS-1 Sec Demand	2,476,869	0.001459	$ 3,614	0.000008	$ 20	0.000018	$ 45	$ 25
GS-1 Pri Non Demand	473	0.001420	$ 1	0.000007	$ 0	0.000018	$ 0	$ 0
GS-1 Pri Demand	341,298	0.001420	$ 485	0.000007	$ 2	0.000018	$ 6	$ 4
Total GS-1			$ 4,506		$ 24		$ 56	$ 31
General Service 2								
GS-2 Substation	251,830	0.001407	$ 354	0.000007	$ 2	0.000018	$ 5	$ 3
GS-2 Transmission	134,637	0.001399	$ 188	0.000007	$ 1	0.000018	$ 2	$ 1
Total GS-2			$ 543		$ 3		$ 7	$ 4
Irrigation								
Irrigation	96,760	0.001459	$ 141	0.000008	$ 1	0.000018	$ 2	$ 1
Total Irrigation			$ 141		$ 1		$ 2	$ 1
Lighting								
Lighting	61,285	0.001459	$ 89	0.000008	$ 0	0.000018	$ 1	$ 1
Total Lighting			$ 89		$ 0		$ 1	$ 1
Total Rate Schedule	**6,040,143**		**$ 8,774**		**$ 48**		**$ 109**	**$ 61.116**
	-							

[1]Spion Kop Rates (based on 2nd yr rev req) approved in Docket No. D2011.5.41 Order No.7159i, effective 1/1/2014.
[2]Spion Variable Rates updated for property taxes in January 2015 Electric Supply monthly filing, effective 1/1/2015.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2014.7.58
Annual Hydro True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF FRANK V. BENNETT

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL HYDRO ASSETS ("HYDRO") TRUE-UP

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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 this portion of your testimony.

A. In this testimony, I present the following information:

- The forecast Hydro costs for the 12-month ended June 2016 true-up period.

Forecast of Hydro in the 2015/2016 True-up Period

Q. Please summarize the 12-month Hydro true-up period ending June 2016.

A. The Hydro fixed cost of service and associated fixed cost rates presented in this filing are the same as approved in Docket No. D2013.12.85, Order No. 7323k. The fixed costs will remain unchanged until such time that an order is issued in a subsequent revenue requirement filing. July 2015 through June 2016 information is based on forecast numbers. Please see Exhibit__(FVB-10)15-16 for supply volume and cost details of the 12-month forecast true-up period.

Q. Describe the changes within the Hydro variable Revenue and Cost categories for the 12-month ended June 2016 forecast true-up period.

A. The Hydro variable cost revenue and expense details are reflected on page 2 of Exhibit__(FVB-10)15-16 under two main sections: Total Revenue and Total Variable Cost Allocation. Total Revenue is estimated to be $1,794,473. The 12-month forecast true-up period estimates a Total Hydro Variable Cost of $1,794,473.

Q. Please provide a summary table of the 12-month ended June 2016 Hydro true-up period.

A. The Hydro true-up period is summarized in the following table (rounded from true-up values):

Beginning Deferred Hydro		**Balance ($)**
Even-Collection		$0

Variable Costs Hydro		**Cost ($)**
Incremental Property Tax Adjustment		0
MPSC/MCC Tax Adjustment		0
Lost Revenue		1,400,936
Lost Revenue Adjustment		380,619
Subtotal Variable Hydro Cost of Service:		1,781,555

Carrying Cost		12,918
Total Hydro Variable Cost Allocation		$1,794,473

Variable Revenues Hydro		**Revenue ($)**
Revenues		1,794,473
Prior Deferred Expense		$0
Total Revenues:		$1,794,473

Ending Deferred Hydro		**Balance ($)**
Even-Collection		$0

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

A. Yes, it does.

	A / B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Hydro Asset Purchase**														
2			**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Total**
3			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
4	**Hydro Asset Revenue Requirement -- Per Final Order 7323k**														
5	Hydro Assets Plant In Service														
6	Electric Generation Plants		$ 43,589,852	$ 43,589,852	$ 43,589,852	$ 43,589,852	$ 43,589,852	$ 43,589,852	$ 43,589,852	$ 43,589,852	$ 43,589,852	$ 43,589,852	$ 43,589,852	$ 43,589,852	$523,078,225
7	Acqusition Adjustment		$ 28,910,148	$ 28,910,148	$ 28,910,148	$ 28,910,148	$ 28,910,148	$ 28,910,148	$ 28,910,148	$ 28,910,148	$ 28,910,148	$ 28,910,148	$ 28,910,148	$ 28,910,148	$346,921,775
8	Total Electric Plant		$ 72,500,000	$ 72,500,000	$ 72,500,000	$ 72,500,000	$ 72,500,000	$ 72,500,000	$ 72,500,000	$ 72,500,000	$ 72,500,000	$ 72,500,000	$ 72,500,000	$ 72,500,000	$870,000,000
9															
10	Less:														
11	Accumulated Depreciation (Book Life 50 Yrs)		$ (721,612)	$ (721,612)	$ (721,612)	$ (721,612)	$ (721,612)	$ (721,612)	$ (721,612)	$ (721,612)	$ (721,612)	$ (721,612)	$ (721,612)	$ (721,612)	$ (8,659,349)
12	Total Net Plant		$ 71,778,388	$ 71,778,388	$ 71,778,388	$ 71,778,388	$ 71,778,388	$ 71,778,388	$ 71,778,388	$ 71,778,388	$ 71,778,388	$ 71,778,388	$ 71,778,388	$ 71,778,388	$861,340,651
13															
14	Less:														
15	Deferred Income Taxes														
16	Accelerated Tax Depreciation Deferred Liability		$ 220,674	$ 220,674	$ 220,674	$ 220,674	$ 220,674	$ 220,674	$ 220,674	$ 220,674	$ 220,674	$ 220,674	$ 220,674	$ 220,674	$ 2,648,088
17	NOL Deferred Tax Liability		$ 781,374	$ 781,374	$ 781,374	$ 781,374	$ 781,374	$ 781,374	$ 781,374	$ 781,374	$ 781,374	$ 781,374	$ 781,374	$ 781,374	$ 9,376,483
18	Total Customer Contrubuted Capital		$ 1,002,048	$ 1,002,048	$ 1,002,048	$ 1,002,048	$ 1,002,048	$ 1,002,048	$ 1,002,048	$ 1,002,048	$ 1,002,048	$ 1,002,048	$ 1,002,048	$ 1,002,048	$ 12,024,571
19															
20	Plus: Working Capital														
21	Gross Cash Requirements		$ (824,541)	$ (824,541)	$ (824,541)	$ (824,541)	$ (824,541)	$ (824,541)	$ (824,541)	$ (824,541)	$ (824,541)	$ (824,541)	$ (824,541)	$ (824,541)	$ (9,894,487)
22															
23	Total Annual Rate-Base		$ 69,951,799	$ 69,951,799	$ 69,951,799	$ 69,951,799	$ 69,951,799	$ 69,951,799	$ 69,951,799	$ 69,951,799	$ 69,951,799	$ 69,951,799	$ 69,951,799	$ 69,951,799	$839,421,593
24															
25	Fixed Return (Avg Rate-Base * Rate of Return)	6.91%	$ 4,833,669	$ 4,833,669	$ 4,833,669	$ 4,833,669	$ 4,833,669	$ 4,833,669	$ 4,833,669	$ 4,833,669	$ 4,833,669	$ 4,833,669	$ 4,833,669	$ 4,833,669	$ 58,004,032
26															
27	Fixed Cost of Service														
28	Operation & Maintenance Expense		$ 3,484,701	$ 3,484,701	$ 3,484,701	$ 3,484,701	$ 3,484,701	$ 3,484,701	$ 3,484,701	$ 3,484,701	$ 3,484,701	$ 3,484,701	$ 3,484,701	$ 3,484,701	$ 41,816,411
29	Administrative and General Expenses		$ 483,998	$ 483,998	$ 483,998	$ 483,998	$ 483,998	$ 483,998	$ 483,998	$ 483,998	$ 483,998	$ 483,998	$ 483,998	$ 483,998	$ 5,807,975
30	Depreciation		$ 1,443,225	$ 1,443,225	$ 1,443,225	$ 1,443,225	$ 1,443,225	$ 1,443,225	$ 1,443,225	$ 1,443,225	$ 1,443,225	$ 1,443,225	$ 1,443,225	$ 1,443,225	$ 17,318,699
31	Property & Other Taxes		$ 1,109,965	$ 1,109,965	$ 1,109,965	$ 1,109,965	$ 1,109,965	$ 1,109,965	$ 1,109,965	$ 1,109,965	$ 1,109,965	$ 1,109,965	$ 1,109,965	$ 1,109,965	$ 13,319,585
32	MCC/MPSC Revenue Taxes	0.53%	$ 51,616	$ 51,616	$ 51,616	$ 51,616	$ 51,616	$ 51,616	$ 51,616	$ 51,616	$ 51,616	$ 51,616	$ 51,616	$ 51,616	$ 619,386
33	Deferred Income Taxes		$ 2,004,095	$ 2,004,095	$ 2,004,095	$ 2,004,095	$ 2,004,095	$ 2,004,095	$ 2,004,095	$ 2,004,095	$ 2,004,095	$ 2,004,095	$ 2,004,095	$ 2,004,095	$ 24,049,141
34	Current Income Taxes		$ (63,213)	$ (63,213)	$ (63,213)	$ (63,213)	$ (63,213)	$ (63,213)	$ (63,213)	$ (63,213)	$ (63,213)	$ (63,213)	$ (63,213)	$ (63,213)	$ (758,561)
35	Fixed Cost of Service		$ 8,514,386	$ 8,514,386	$ 8,514,386	$ 8,514,386	$ 8,514,386	$ 8,514,386	$ 8,514,386	$ 8,514,386	$ 8,514,386	$ 8,514,386	$ 8,514,386	$ 8,514,386	$102,172,636
36															
37	Total Hydro Asset Fixed Cost Revenue Requirement		$ 13,348,056	$ 13,348,056	$ 13,348,056	$ 13,348,056	$ 13,348,056	$ 13,348,056	$ 13,348,056	$ 13,348,056	$ 13,348,056	$ 13,348,056	$ 13,348,056	$ 13,348,056	$160,176,668
38															
39															

	A / B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
40	**Hydro Asset Purchase**														
41			**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Total**
42			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
43	**Hydro Asset Purchase**														
44	Total Forecast Sales														
45	2011/12 Tracker Sales MWh		516,208	541,697	492,397	468,897	489,975	535,138	566,841	530,208	500,071	476,340	456,744	465,627	6,040,143
46	Hydro Cost		$ 0.2971	$ 0.2971	$ 0.2971	$ 0.2971	$ 0.2971	$ 0.2971	$ 0.2971	$ 0.2971	$ 0.2971	$ 0.2971	$ 0.2971	$ 0.2971	
47	Prior Year Deferred Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
48															
49	Hydro Asset Variable Cost Revenues														
50	Hydro Asset Revenues		$ 153,361	$ 160,933	$ 146,287	$ 139,305	$ 145,567	$ 158,985	$ 168,403	$ 157,520	$ 148,567	$ 141,516	$ 135,695	$ 138,334	$ 1,794,473
51															
52	Subtotal		$ 153,361	$ 160,933	$ 146,287	$ 139,305	$ 145,567	$ 158,985	$ 168,403	$ 157,520	$ 148,567	$ 141,516	$ 135,695	$ 138,334	$ 1,794,473
53	Prior Year(s) Deferred Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	Total Revenue		$ 153,361	$ 160,933	$ 146,287	$ 139,305	$ 145,567	$ 158,985	$ 168,403	$ 157,520	$ 148,567	$ 141,516	$ 135,695	$ 138,334	$ 1,794,473
55															
56															
57	Incremental Property Tax Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	MPSC/MCC Tax Adjustment														
59															
60	Lost Revenue		$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 1,400,936
61	Lost Revenue Adjustment		$ 380,619	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 380,619
62															
63	Subtotal Hydro Asset Variable Cost		$ 497,364	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 116,745	$ 1,781,555
64															
65															
66	**Carrying Cost Expense**														
67	Carrying Costs	7.92%	$ 2,286	$ 2,007	$ 1,824	$ 1,686	$ 1,506	$ 1,235	$ 900	$ 636	$ 428	$ 267	$ 142	$ 0	$ 12,918
68															
69	Total Hydro Asset Variable Cost		$ 499,649	$ 118,752	$ 118,569	$ 118,431	$ 118,251	$ 117,980	$ 117,645	$ 117,380	$ 117,173	$ 117,011	$ 116,887	$ 116,745	$ 1,794,473
70															
71	Deferred Cost Amortization (Under)/Over		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	Monthly Deferred Cost		$ (346,288)	$ 42,182	$ 27,718	$ 20,874	$ 27,316	$ 41,005	$ 50,758	$ 40,140	$ 31,394	$ 24,505	$ 18,807	$ 21,589	$ (0)
73	Cumulative Deferred Cost		$ (346,288)	$ (304,107)	$ (276,389)	$ (255,515)	$ (228,198)	$ (187,194)	$ (136,435)	$ (96,295)	$ (64,902)	$ (40,397)	$ (21,589)	$ (0)	
74															
75	Variable Rate-Base Deferred														
76	Beginning Balance		$ -	$ 346,288	$ 304,107	$ 276,389	$ 255,515	$ 228,198	$ 187,194	$ 136,435	$ 96,295	$ 64,902	$ 40,397	$ 21,589	
77	Monthly Deferred Cost		$ 346,288	$ (42,182)	$ (27,718)	$ (20,874)	$ (27,316)	$ (41,005)	$ (50,758)	$ (40,140)	$ (31,394)	$ (24,505)	$ (18,807)	$ (21,589)	
78	Ending Balance Under/(Over)		$ 346,288	$ 304,107	$ 276,389	$ 255,515	$ 228,198	$ 187,194	$ 136,435	$ 96,295	$ 64,902	$ 40,397	$ 21,589	$ 0	
79															

PREFILED DIRECT TESTIMONY

OF JOSEPH S. JANHUNEN

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL HYDRO GENERATION ASSET ("HYDRO") TRUE-UP

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Witness Information

Q. Are you the same Joseph S. Janhunen 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 Hydro True-up testimony?

A. This testimony:

1. Presents the derivation of proposed Hydro variable rates for the forecasted 2015-2016 true-up period; and
2. Discusses the overall total supply rates incorporating all individual rate components.

Derivation of Proposed Hydro Variable Rates

Q. Please describe the process NorthWestern used to derive the proposed 2015-2016 forecasted Hydro variable rates in this filing.

A. The rate design methodology used in this filing to derive the proposed 2015-2016 forecasted Hydro variable rates is the same as that presented in other sections of this filing, such as the Colstrip Unit 4 ("CU4") section. All forecasted costs are from Exhibit__(FVB-10)15-16 of the Prefiled Direct Testimony of Frank V. Bennett and are discussed therein.

Derivation of the Hydro variable rates is shown on Exhibit__(JSJ-6)15-16, page 1. The total Hydro variable cost of $1,794,473 is the sum of Lost Revenues and carrying costs from Exhibit__(FVB-10)15-16. This sum is the amount used to derive the Hydro variable rates. The forecasted loads used in the derivation are from Exhibit__(JSJ-1)14-15, page 6. The resulting rates are the Hydro variable rates proposed in this filing.

Q. Please describe the 2015-2016 Hydro fixed rates included in this filing.

A. The Hydro fixed cost of service rate components presented in this filing are those ordered by the Commission in Docket No. D2013.12.85. The Hydro fixed rate components include rates effective November 18, 2014 and will not change until the compliance filing to be made later this year as required by Order No. 7323k.

Page 2 of Exhibit__(JSJ-6)15-16 reflects the Hydro fixed and variable rates and revenues in summarized format.

Proposed Total Deferred Supply and Total Supply Rates

Q. Please describe the process NorthWestern used to derive the total 2015-2016 deferred supply rates proposed in this filing.

A. The total deferred supply rate includes four separate rate components – a deferred electricity supply rate, a deferred CU4 variable rate, a deferred

Dave Gates Generating Station ("DGGS") variable rate, and a deferred Spion Kop Wind Generation Asset ("Spion") variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(JSJ-8)15-16, page 1.

Q. Please describe the process NorthWestern used to derive the total 2015-2016 supply rates proposed in this filing.

A. 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 variable rate, a Spion fixed cost of service rate, a Spion variable rate, a Hydro fixed cost of service rate, a Hydro variable rate, and a Revenue Credits rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(JSJ-8)15-16, page 3.

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

A. Yes, it does.

NorthWestern Energy
Electric Utility Derivation of Rates
Hydro Variable Cost of Service
Tracker Period July 2015 to June 2016

Customer Rate Class	**Loss Factor**	**Jul15 to Jun16 Supply Retail kWh Sales**	**Sales Adjusted for Employee Discount**	**Sales Weighted by Losses**	**Hydro Variable After Losses kWh Charges**	**Hydro Variable Revenue/Cost Check**
Residential	8.5100%	2,394,862,903	2,394,862,903	2,598,665,736	$ 0.000298	$ 713,669
Residential Employee	8.5100%	3,379,973	2,027,984	2,200,565	$ 0.000179	$ 605
GS 1 Secondary NonDemand	8.5100%	278,748,374	278,748,374	302,469,861	$ 0.000298	$ 83,067
GS 1 Secondary Demand	8.5100%	2,476,869,018	2,476,869,018	2,687,650,572	$ 0.000298	$ 738,107
GS 1 Primary NonDemand	5.5400%	473,438	473,438	499,666	$ 0.000290	$ 137
GS 1 Primary Demand	5.5400%	341,297,734	341,297,734	360,205,628	$ 0.000290	$ 98,976
General Service Substation	4.6300%	251,830,078	251,830,078	263,489,810	$ 0.000288	$ 72,527
General Service Transmission	4.0000%	134,636,802	134,636,802	140,022,274	$ 0.000286	$ 38,506
Irrigation	8.5100%	96,759,889	96,759,889	104,994,156	$ 0.000298	$ 28,834
Lighting	8.5100%	61,285,015	61,285,015	66,500,369	$ 0.000298	$ 18,263
		6,040,143,224	6,038,791,235	6,526,698,638	$ 0.000297	$ 1,792,692
YNP Contract		20,691,140			Rounding Adjustment	$ 1,781
Total Supply Load		6,060,834,364				$ 1,794,473
		-				

2015-16 Hydro Variable Cost of Service	**$**	**1,794,473**
Total Hydro Variable COS Rate Before Losses	$	0.000275
Total Hydro Variable COS Rate After Losses	$	0.000297

NorthWestern Energy
Electric Utility
Total Hydro Revenue ($000) Summary
Tracker Period July 2015 to June 2016

		Hydro Fixed		Hydro Variable				
	Jul15 to Jun16 Supply Retail MWh Sales	Current Rates[1]	Current Rate Revenue	Current Rates	Current Rate Revenue	Proposed Rates 7/1/2015	Proposed Rate Revenue	Revenue Diff Proposed vs Current
Residential								
Residential	2,394,863	0.026817	$ 64,223	-	$ -	0.000298	$ 714	$ 714
Residential Employee	3,380	0.016090	$ 54	-	$ -	0.000179	$ 1	$ 1
Total Residential			$ 64,277		$ -		$ 714	$ 714
General Service 1								
GS-1 Sec Non Demand	278,748	0.026817	$ 7,475	-	$ -	0.000298	$ 83	$ 83
GS-1 Sec Demand	2,476,869	0.026817	$ 66,422	-	$ -	0.000298	$ 738	$ 738
GS-1 Pri Non Demand	473	0.026083	$ 12	-	$ -	0.000290	$ 0	$ 0
GS-1 Pri Demand	341,298	0.026083	$ 8,902	-	$ -	0.000290	$ 99	$ 99
Total GS-1			$ 82,812		$ -		$ 920	$ 920
General Service 2								
GS-2 Substation	251,830	0.025858	$ 6,512	-	$ -	0.000288	$ 73	$ 73
GS-2 Transmission	134,637	0.025703	$ 3,461	-	$ -	0.000286	$ 39	$ 39
Total GS-2			$ 9,972		$ -		$ 111	$ 111
Irrigation								
Irrigation	96,760	0.026817	$ 2,595	-	$ -	0.000298	$ 29	$ 29
Total Irrigation			$ 2,595		$ -		$ 29	$ 29
Lighting								
Lighting	61,285	0.026817	$ 1,643	-	$ -	0.000298	$ 18	$ 18
Total Lighting			$ 1,643		$ -		$ 18	$ 18
Total Rate Schedule	**6,040,143**		**$ 161,300**		**$ -**		**$ 1,793**	**$ 1,792.692**
	-							

[1]Hydro Rates approved in Docket No. D2013.12.85 Order No.7323k, effective 11/18/2014.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2014.7.58
Annual Revenue Credits True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF JOSEPH S. JANHUNEN

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL REVENUE CREDITS ("REV CREDITS") TRUE-UP

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Witness Information

Q. Are you the same Joseph S. Janhunen 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 Rev Credits True-up testimony?

A. This testimony:

1. Presents the current Rev Credits rates and revenues for the forecasted 2015-2016 true-up period; and
2. Discusses the overall total supply rates incorporating all individual rate components.

Current Rates

Q. Please describe the current Rev Credits rates in this filing.

A. The current Rev Credits rates are the rates approved in Docket No. D2013.12.85. The Rev Credits rates are shown on Exhibit__(JSJ-7)15-16, page 1.

Proposed Total Deferred Supply and Total Supply Rates

Q. Please describe the process NorthWestern used to derive the total 2015-2016 deferred supply rates proposed in this filing.

A. The total deferred supply rate includes four separate rate components – a deferred electricity supply rate, a deferred Colstrip Unit 4 (“CU4”) variable rate, a deferred Dave Gates Generating Station (“DGGS”) variable rate, and a deferred Spion Kop Wind Generation Asset (“Spion”) variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(JSJ-8)15-16, page 1.

Q. Please describe the process NorthWestern used to derive the total 2015-2016 supply rates proposed in this filing.

A. 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 variable rate, a Spion fixed cost of service rate, a Spion variable rate, a Hydro Generation Asset (“Hydro”) fixed cost of service rate, a Hydro variable rate, and a Rev Credits rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(JSJ-8)15-16, page 3.

Q. Does this conclude your Rev Credits True-up testimony?

A. Yes, it does.

NorthWestern Energy
Electric Utility
Total Rev Credits Revenue ($000) Summary
Tracker Period July 2015 to June 2016

	Jul15 to Jun16 Supply Retail MWh Sales	Rev Credits Current Rates[1]	Rev Credits Current Rate Revenue
Residential			
Residential	2,394,863	(0.007252)	$ (17,368)
Residential Employee	3,380	(0.004351)	$ (15)
Total Residential			$ (17,382)
General Service 1			
GS-1 Sec Non Demand	278,748	(0.007252)	$ (2,021)
GS-1 Sec Demand	2,476,869	(0.007252)	$ (17,962)
GS-1 Pri Non Demand	473	(0.007053)	$ (3)
GS-1 Pri Demand	341,298	(0.007053)	$ (2,407)
Total GS-1			$ (22,394)
General Service 2			
GS-2 Substation	251,830	(0.006992)	$ (1,761)
GS-2 Transmission	134,637	(0.006950)	$ (936)
Total GS-2			$ (2,697)
Irrigation			
Irrigation	96,760	(0.007252)	$ (702)
Total Irrigation			$ (702)
Lighting			
Lighting	61,285	(0.007252)	$ (444)
Total Lighting			$ (444)
Total Rate Schedule	**6,040,143**		**$ (43,619)**
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[1]Rev Credits Rates approved in Docket No. D2013.12.85 Order No.7323k, effective 11/18/2014.