414 Nicollet Mall
Minneapolis, Minnesota 55401

PUBLIC DOCUMENT
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October 30, 2015

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: SUPPLEMENTAL FILING
CHANGES IN CONTRACT DEMAND ENTITLEMENTS
DOCKET NO. G002/M-15-727

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits this Supplemental Filing in response to the September 11, 2015 Comments of the Minnesota Department of Commerce, Division of Energy Resources.

The Department recommended that the Commission:

- approve Xcel [Energy's] proposed level of demand entitlement, subject to possible adjustment in the Company's November 1, 2015 supplemental filing;
- allow Xcel [Energy] to recover associated demand costs, subject to possible adjustment in the Company's November 1, 2015 supplemental filing, through the monthly Purchased Gas Adjustment effective November 1, 2015;
- approve changes in the jurisdictional allocation for demand costs; and
- the Company provide in its November 1, 2015 supplemental filing, an update on any hedging transactions that are entered into for the 2015-2016 heating season.

We include the following revised attachments:

Attachment 1, Schedule 2, Pages 1 and 2
Attachment 1, Schedule 5
Attachment 2, Page 2

Attachment 2, Schedule 1, Pages 1 and 2
Attachment 2, Schedule 2, Pages 1-4
Attachment 3, Schedule 1

Changes to Demand Entitlement Levels

There are a few updates to the entitlement levels provided in the Petition filed August 3, 2015 in Docket No. G002/M-15-727. These changes are summarized below and presented in the revised **Attachment 1, Schedule 2, Pages 1 and 2**, **Attachment 1, Schedule 5**, and **Attachment 2, Schedule 1, Pages 1 and 2**. There are no changes to transportation costs identified in the Petition.

1. Our original design for Design Day resources in the Petition, called for 46,000 Dth/day of peak shaving capacity from Sibley Propane Plant. We recently determined that the plant will have a limited reliable operating output above 19,200 Dth/day this heating season due to some malfunctioning air compressor equipment. As a peak shaving facility used mainly for reserve, this lowers our current heating season reserve margin to 2.9% from the expected 6.2% margin filed in the Petition.

   We explored the acquisition of additional transportation capacity to replace this reduction of reserve capacity; however Northern Natural Gas has no additional capacity available to serve the system where the Sibley Plant is located.

   While this event lowers our reserve margin, we do have adequate resources in place to meet firm customers' Design Day Requirement for the upcoming winter. We are currently exploring alternatives for returning the facility to full service for the next heating season.

2. In the Petition, we planned to purchase 12,428 Dth/day of firm, winter-only capacity on Viking Gas Transmission (Viking) to supplement our total design day capacity. This purchase has occurred as planned and specifics of the contract are shown in **Attachment 2, Schedule 1**.

Supplier Entitlement Changes

Supplier entitlement changes are shown on **Attachment 1, Schedule 2**. We added a firm supply transaction for 9,500 Dth/day to address peak day needs at Chisago, which is a $54,000 increase over the Petition.

Update on Hedging Transactions

Updated hedging transactions are presented on the revised Attachment 3, Schedule 1. We executed five call options for the 2015-2016 heating season covering the entire supply quantity we targeted. Two hedging transactions reported in the Petition were incorrect. **Attachment 3, Schedule 1** now reflects all of the current hedging transactions. Total hedging costs for the 2015-2016 heating season are $1,559,782.50.

Miscellaneous

Portions of our filing contain trade secret information as defined under Minn. Stat. § 13.37. As such, this data is protected from public disclosure and has been marked accordingly. Xcel Energy makes extensive efforts to maintain the secrecy of this information. This information is not available outside the Company except to other parties involved in contracts and to regulatory agencies under the confidentiality provisions of state or federal law, as evidenced by the non-disclosure provisions in the contracts. Xcel Energy also provides this information to state regulatory agencies in the Annual Automatic Adjustment of Charges Reports and in the monthly purchased gas adjustment (PGA) filings in the confidential trade secret versions of these reports.

The supply information has economic value to Xcel Energy, its customers, suppliers, and competitors in at least three ways. If suppliers know the terms of Xcel Energy's supply and transportation contracts, they may be able to use this knowledge to fashion bids to Xcel Energy. Suppliers will be reluctant to offer special favorable terms to Xcel Energy if they know other competitors or customers will gain knowledge of the terms and demand similar terms in the future. Competitors of Xcel Energy such as other LDCs also purchase their services. These competitors may be able to leverage knowledge of Xcel Energy's costs to gain similar terms or may offer slightly better prices to suppliers, denying Xcel Energy's access to this gas or other services.

Any of these results would harm Xcel Energy and its natural gas customers. Because Xcel Energy competes for supplies, transportation, storage, and other services in the wholesale market, disclosure would directly harm Xcel Energy by making its delivered supply cost less competitive. To the extent that Xcel Energy supply costs rise, Xcel Energy's regulated sales customers would have to pay higher natural gas rates. This result would not serve the public interest.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service list.

Please contact Richard Derryberry at (303) 571-7104 or richard.derryberry@xcelenergy.com or me at (612) 330-6613 or amy.a.liberkowski@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

AMY A. LIBERKOWSKI
MANAGER, REGULATORY ANALYSIS

Enclosures
c: Service Lists

Northern States Power Company
DEMAND COST OF GAS IMPACT - NOVEMBER 2015
Revised from 8/3/15 filing

NGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day	Current Monthly Demand Rates	No. of Months	Total Annual Cost
NNG TFX (Nov - Mar)[1]	1,105	$ 8.6272	5	$ 47,665.28
NNG TFX (Apr - Oct)[1]	1,105	$ 4.0000	7	$ 30,940.00
NNG TFX (Jan - Dec)[1]	1,208	$ 3.8000	7	$ 32,132.80
NNG TFX (Jan - Dec)[1]	1,208	$ 3.8000	5	$ 22,952.00
NNG TFX (Nov - Mar)[1]	3,333	$ 5.3736	5	$ 89,551.04
NNG TFX (Apr - Oct)[1]	3,333	$ 4.5000	7	$ 104,989.50
NNG TFX (Nov - Mar)[1]	(5,629)	$ 15.1530	5	$ (426,481.19)
VGT FT-A (Dec - Feb)[2]	12,428	$ 4.7507	3	$ 177,125.10
VGT FT-A (Jan - Dec)[2]	(72,213)	$ 4.4954	2	$ (649,252.64)
VGT FT-A (Jan - Dec)[2]	72,213	$ 5.3593	2	$ 774,022.26
VGT FT-A (Jan - Dec)[2]	(29,002)	$ 3.3978	2	$ (197,085.99)
VGT FT-A (Jan - Dec)[2]	29,002	$ 4.3706	2	$ 253,512.28
VGT FT-A (Nov - Mar)[2]	(4,239)	$ 3.3978	2	$ (28,806.55)
VGT FT-A (Nov - Mar)[2]	4,239	$ 4.3706	2	$ 37,053.95
VGT FT-A (Jan - Dec)[2]	(10,000)	$ 3.3978	2	$ (67,956.00)
VGT FT-A (Jan - Dec)[2]	10,000	$ 4.3706	2	$ 87,412.00
VGT FT-A (Jan - Dec)[2]	(15,600)	$ 4.4954	2	$ (140,256.48)
VGT FT-A (Jan - Dec)[2]	15,600	$ 5.3593	2	$ 167,210.16
VGT FT-A (Jan - Dec)[2]	(1,903)	$ 3.3978	2	$ (12,932.03)
VGT FT-A (Jan - Dec)[2]	1,903	$ 4.3706	2	$ 16,634.50
VGT FT-A (Jan - Dec)[2]	(15,000)	$ 4.4954	2	$ (134,862.00)
VGT FT-A (Jan - Dec)[2]	15,000	$ 5.3593	2	$ 160,779.00
ANR FTS (Nov - Mar)[3]	(9,248)	$ 14.6460	5	$ (677,231.04)
ANR FTS (Nov - Mar)[3]	9,248	$ 11.4420	5	$ 529,078.08
ANR FTS (Nov - Mar)[3]	(15,310)	$ 2.0400	5	$ (156,162.00)
ANR FTS (Nov - Mar)[3]	15,310	$ 1.7820	5	$ 136,412.10
ANR FSS (Jan - Dec)[4]	34	$ 1.7820	12	$ 727.06
ANR FTS (Jan - Dec)[5]	4,829	$ 0.0900	12	$ 5,215.32
ANR FTS (Jan - Dec)[5]	4,829	$ 0.1500	12	$ 8,692.20
ANR FTS (Nov - Mar)[5]	15,171	$ 0.0900	5	$ 6,826.95
ANR FTS (Nov - Mar)[5]	15,171	$ 0.1500	5	$ 11,378.25
ANR FTS (Apr - Oct)[5]	4,935	$ 0.0900	7	$ 3,109.05
ANR FTS (Apr - Oct)[5]	4,935	$ 0.1500	7	$ 5,181.75
Total				$ 217,574.72

Supplier Entitlement Changes
Change in Supplier Reservation Fees
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Total	9,500	$190,762.00
Total MN & ND Demand Cost Adjustment		**$408,336.72**
Minnesota Allocation Factor (MN/ND Allocated Demand)		87.99%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand		**$ 359,295.48**

[1] NNG Sixth Revised Volume No. 1, Ninth Revised Sheet No. 51, Effective April 1, 2015
[2] VGT Volume No. 1, Part 5.0 Statement of Rates, Effective April 1, 2015
[3] ANR Third Revised Volume No. 1, Part 4.3 - Statement of Rates, v. 0.0.0, Effective September 30, 2010
[4] ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v. 0.0.0, Effective September 30, 2010
[5] ANR Third Revised Volume No. 1, Part 4.17 - Statement of Rates, v. 0.0.0, RP13-743 Settlement Approved by FERC Oct 15, 2015.

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Northern States Power Company
Demand Cost Changes from Prior Year
Revised from 8/3/15 filing

Docket No. G002/M-15-727
REVISED Attachment 1
Schedule 2

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2014 SUPPLEMENTAL FILED COSTS				**$30,819,929.19**	**$23,413,065.11**	**$54,232,994.30**				
2014 CHANGES FILED COMPARED TO ACTUAL COSTS										
Total					$ -	$ -				
2014 ACTUAL COSTS				**$ 30,819,929.19**	**$ 23,413,065.11**	**$ 54,232,994.30**				
CHANGES FOR 2015 FILING										
Contract Demand Entitlement Changes										
NNG TFX (Nov - Mar)	1,105	$ 8.6272	5		$ 47,665.28	$ 47,665.28	$ 47,665.28			1
NNG TFX (Apr - Oct)	1,105	$ 4.0000	7	$ 30,940.00		$ 30,940.00	$ 30,940.00			1
NNG TFX (Apr - Oct)	1,208	$ 3.8000	7	$ 32,132.80		$ 32,132.80	$ 32,132.80			2
NNG TFX (Nov - Mar)	1,208	$ 3.8000	5		$ 22,952.00	$ 22,952.00				2
NNG TFX (Nov - Mar)	3,333	$ 5.3736	5		$ 89,551.04	$ 89,551.04	$ 89,551.04			3
NNG TFX (Apr - Oct)	3,333	$ 4.5000	7	$ 104,989.50		$ 104,989.50	$ 104,989.50			3
NNG TFX (Nov - Mar)	(5,629)	$15.1530	5		$ (426,481.19)	$ (426,481.19)	$ (426,481.19)			4
VGT FT-A (Dec - Feb)	12,428	$ 4.7507	3		$ 177,125.10	$ 177,125.10		$ 177,125.10		5
VGT FT-A (Jan - Dec)	(72,213)	$ 4.4954	2	$ (649,252.64)		$ (649,252.64)	$ (571,277.40)	$ (77,975.24)		6
VGT FT-A (Jan - Dec)	72,213	$ 5.3593	2	$ 774,022.26		$ 774,022.26	$ 681,062.19	$ 92,960.07		6
VGT FT-A (Jan - Dec)	(29,002)	$ 3.3978	2	$ (197,085.99)		$ (197,085.99)	$ (173,415.96)	$ (23,670.03)		6
VGT FT-A (Jan - Dec)	29,002	$ 4.3706	2	$ 253,512.28		$ 253,512.28	$ 223,065.46	$ 30,446.83		6
VGT FT-A (Nov - Mar)	(4,239)	$ 3.3978	2		$ (28,806.55)	$ (28,806.55)	$ (25,346.88)	$ (3,459.67)		6
VGT FT-A (Nov - Mar)	4,239	$ 4.3706	2		$ 37,053.95	$ 37,053.95	$ 32,603.77	$ 4,450.18		6
VGT FT-A (Jan - Dec)	(10,000)	$ 3.3978	2	$ (67,956.00)		$ (67,956.00)	$ (59,794.48)	$ (8,161.52)		6
VGT FT-A (Jan - Dec)	10,000	$ 4.3706	2	$ 87,412.00		$ 87,412.00	$ 76,913.82	$ 10,498.18		6
VGT FT-A (Jan - Dec)	(15,600)	$ 4.4954	2	$ (140,256.48)		$ (140,256.48)	$ (123,411.68)	$ (16,844.80)		6
VGT FT-A (Jan - Dec)	15,600	$ 5.3593	2	$ 167,210.16		$ 167,210.16	$ 147,128.22	$ 20,081.94		6
VGT FT-A (Jan - Dec)	(1,903)	$ 3.3978	2	$ (12,932.03)		$ (12,932.03)	$ (11,378.89)	$ (1,553.14)		6
VGT FT-A (Jan - Dec)	1,903	$ 4.3706	2	$ 16,634.50		$ 16,634.50	$ 14,636.70	$ 1,997.80		6
VGT FT-A (Jan - Dec)	(15,000)	$ 4.4954	2	$ (134,862.00)		$ (134,862.00)	$ (31,503.76)	$ (103,358.24)		6
VGT FT-A (Jan - Dec)	15,000	$ 5.3593	2	$ 160,779.00		$ 160,779.00	$ 37,557.97	$ 123,221.03		6
GLT FT (Nov - Mar)	(9,248)	$14.6460	5		$ (677,231.04)	$ (677,231.04)			$ (677,231.04)	7
GLT FT (Nov - Mar)	9,248	$11.4420	5		$ 529,078.08	$ 529,078.08			$ 529,078.08	7
ANR FTS (Jan - Dec)	4,829	$ 0.0900	12	$ 5,215.32		$ 5,215.32			$ 5,215.32	8
ANR FTS (Jan - Dec)	4,829	$ 0.1500	12	$ 8,692.20		$ 8,692.20			$ 8,692.20	8
ANR FTS (Nov - Mar)	15,171	$ 0.0900	5		$ 6,826.95	$ 6,826.95			$ 6,826.95	8
ANR FTS (Nov - Mar)	15,171	$ 0.1500	5		$ 11,378.25	$ 11,378.25			$ 11,378.25	8
ANR FTS (Apr - Oct)	4,935	$ 0.0900	7		$ 3,109.05	$ 3,109.05			$ 3,109.05	8
ANR FTS (Apr - Oct)	4,935	$ 0.1500	7		$ 5,181.75	$ 5,181.75			$ 5,181.75	8
ANR FSS (Jan - Dec)	(15,310)	$ 2.0400	5		$ (156,162.00)	$ (156,162.00)			$ (156,162.00)	9
ANR FSS (Jan - Dec)	15,310	$ 1.7820	5		$ 136,412.10	$ 136,412.10			$ 136,412.10	9
ANR FSS (Jan - Dec)	34	$ 1.7820	12		$ 727.06	$ 727.06			$ 727.06	10
Total				$ 439,194.89	$ (221,620.17)	$ 217,574.72	$ 95,636.51	$ 225,758.50	$ (126,772.28)	
Supplier Entitlement Changes										
[TRADE SECRET BEGINS										
										11
										11
										11
										11
									TRADE SECRET ENDS]	
Total				$ -	$ 190,762.00	$ 190,762.00	$ 190,762.00	$ -	$ -	
TOTAL OF 2015 CHANGES				**$ 439,194.89**	**$ (30,858.17)**	**$ 408,336.72**	**$ 286,398.51**	**$ 225,758.50**	**$ (126,772.28)**	
2015 COSTS				**$ 31,259,124.08**	**$ 23,382,206.94**	**$ 54,641,331.02**				
2015 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							56%	44%		12

Footnote

1. Incremental capacity added near St. Cloud, MN starting November 1, 2015.
2. Incremental capacity added at Huga Area, MN starting November 1, 2015.
3. Incremental capacity added at Lake Elmo Area, MN starting November 1, 2015.
4. Expired winter firm transport capacity, November 1, 2014 through March 31, 2015.
5. Renewed firm transport capacity serving Fargo, ND, December 1, 2015 through February 28, 2016.
6. Entries to reflect rate changes on Viking effective January 1, 2015.
7. Rate decrease due to renewal to longer term contract.
8. ANR DTCA charge per settlement agreement approved by FERC on Oct 15, 2015 (RP13-743). Reverse of credit ($0.09) and new charge ($0.15)
9. Entries to account for rate reduction on ANR Pipeline storage agreement effective April 1, 2015.
10. Volume additions on ANR transport and storage agreements. Upstream capacity serves demand in either MN or ND.
11. Expired peaking supply contract with demand charges in effect November 1, 2014 through March 31, 2015.
12. Upstream/system supply refers to costs that are incurred to serve all customers on the system across MN and ND. For purposes of this schedule, it is reasonable to split these costs between MN and ND using the overall system jurisdictional factors.

Northern States Power Company

FIRM SUPPLY ENTITLEMENTS

2015-2016 Heating Season

Revised from 8/3/15 filing

Firm Supplies (1)	Current Quantity Effective Nov-14 Dth/Day	Proposed Quantity Effective Nov-15 Dth/Day	Proposed Quantity Change Nov-15 Dth/Day
A. Upstream Supply			
	[TRADE SECRET BEGINS		
ANR Firm 3rd Party (2)			
ANRP Storage (2)			
ANR Storage Company (3)			
GLGT Firm 3rd Party (3)			
B. Minnesota Company Delivered Supply			
WBI Firm 3rd Party			
VGT Firm 3rd Party			
NNG Firm 3rd Party			
NNG FDD Storage			**TRADE SECRET ENDS]**
LP Peak Shaving	90,000	63,200	*(26,800)*
LNG Peak Shaving	156,000	156,000	-
TOTAL	856,048	839,380	(16,668)
C. Minnesota State Delivered Supply			
State of MN Allocators	88.42%	87.99%	
TOTAL	756,918	738,570	(18,347)

(1) Contracts are available for inspection upon request
(2) ANR feeds VGT.
(3) GLGT feeds NNG or VGT

PROPOSAL FOR ENTITLEMENT CHANGE
Department Format dated October 1, 1993

1 Provide a peak-day/design-day study by class for the twelve months ending one year from the proposed implementation date of the change(s):

See Attachment 1, Schedule 3.

2 Provide Heating Degree Day (HDD) data for the most recent twelve month period ending March 31 or September 30. This should include HDD, use per firm customer, and the peak season and off-peak HDD used for calculating the Company's design days:

See Attachment 1, Schedule 1, and Attachment 1, Schedule 4.

3 Historical and Projected Design-Day and Peak Demand Requirements:

Minnesota State

Heating Season[1] -1	Number of Firm Customers[2] -2	Design Day Requirement (Dth) -3	Total Entitlement plus Storage plus Peak Shaving[3] (Dth) -4	Peak Day Sendout (Dth) -5	Heating Degree Days -6	Actual Peak Day
'Proposed: 2015/2016	450,630	717,478	738,570	Unknown	Unknown	Unknown
2014/2015	446,409	715,945	761,354	687,501	64	1/12/2015
2013/2014	441,573	706,935	756,918	689,990	82	1/6/2014
2012/2013	439,210	702,159	745,247	689,747	71	1/21/2013
2011/2012	439,055	702,294	745,094	659,263	65	1/19/2012
2010/2011	436,594	699,611	743,781	675,667	69	1/20/2011
2009/2010	433,698	694,487	748,267	590,931	67	12/10/2009
2008/2009	428,852	685,005	732,291	601,425	78	1/15/2009
2007/2008	431,503	683,717	721,506	585,874	72	1/29/2008
2006/2007	424,415	677,733	696,257	568,963	67	2/2/2007
2005/2006	421,570	670,846	691,689	537,660	63	12/5/2005
2004/2005	410,986	649,655	675,120	537,374	60	1/5/2005
2003/2004	401,633	603,468	643,315	561,250	80	1/29/2004
2002/2003	395,807	607,856	642,275	534,385	65	1/20/2003

1 Per Annual Financial Reports.

2 Provide data and calculations for projected number of firm customers by class and in total corresponding to the design day requirement.

See Attachment 1, Schedule 1.

3 Total entitlement for Minnesota is calculated from the Proposed November 1 Entitlement.

See Attachment 1, Schedule 5.

4 Demand Profile:

See Attachment 2, Schedule 1.

5 Rate Impact:

See Attachment 2, Schedule 2.

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Northern States Power Company
COMPANY DEMAND PROFILE
2015-2016 Heating Season
Revised from 8/3/15 filing

Contract No.	Type of Capacity or Entitlement	Current Amount Dth or MMBtu	Proposed Change Dth or MMBtu	Proposed Amount Dth or MMBtu	Contract Length and Expiration Date	Change Description	% of Peak Day Entitlement	
	Capacity Entitlements							
112183	NNG TF12 BASE (Max)	104,117	0	104,117	10 yrs - 10/31/17		12.40%	
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/17		0.00%	
112182	NNG TF12 BASE (Disc)	34,191	(7,565)	26,626	10 yrs - 10/31/17	Annual tariff req contract adj	3.17%	
112182	NNG TF12 VARIABLE (Disc.)	60,336	7,565	67,901	10 yrs - 10/31/17	Annual tariff req contract adj	8.09%	
112183	NNG TF5 (Max)	62,415	0	62,415	10 yrs - 10/31/17		7.44%	
112182	NNG TF5 (Disc.)	29,599	0	29,599	10 yrs - 10/31/17		3.53%	
111739	NNG TFX (Nov-Mar)	28,500	0	28,500	8 yrs - 10/31/17		3.40%	
112185	NNG TFX (Disc. Nov-Mar)	58,184	0	58,184	10 yrs - 10/31/17		6.93%	
112185	NNG TFX (Disc. 12-month)	21,680	4,541	26,221	10 yrs - 10/31/17	Growth election	3.12%	
112185	NNG TFX 5 (Disc)	6,493	0	6,493	10 yrs - 10/31/17		Summer Only	
112185	NNG TFX 2 (Disc)	2,168	0	2,168	10 yrs - 10/31/17		Summer Only	
112186	NNG TFX (Max)	49,005	0	49,005	10 yrs - 10/31/17		5.84%	
112186	NNG TFX 2 (Max)	7,950	0	7,950	10 yrs - 10/31/17		Summer Only	
112186	NNG TFX 5 (Max)	27,253	0	27,253	10 yrs - 10/31/17		Summer Only	
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/17		2.98%	
122067	NNG TFX (Disc. Nov-Mar)	6,729	1,105	7,834	10 yrs - 10/31/17	Growth election	0.93%	
122067	NNG TFX 7 (Disc)	6,729	1,105	7,834	10 yrs - 10/31/17	Growth election	Summer Only	
122068	NNG TFX (Nov-Mar)	8,875	0	8,875	10 yrs - 10/31/24		1.06%	
122068	NNG TFX 7 (Max)	8,875	0	8,875	10 yrs - 10/31/24		Summer Only	
128226	NNG TFX (Nov-Mar)	5,629	(5,629)	0	5 mos. -3/31/15	Not renewed	0.00%	
		[TRADE SECRET BEGINS						
	VGT to NNG Chisago (1)							
	VGT Pierz to NNG (2)							
	Capacity Release							**TRADE SECRET ENDS]**
AF0044	VGT FT-A 12 Mos.	29,002	0	29,002	5 yrs - 10/31/18		3.46%	
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/18		0.51%	
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	5 yrs - 10/31/19		1.19%	
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	8.5 yrs - 10/31/17		1.86%	
AF0116	VGT FT-A 12 Mos.	1,903	0	1,903	5 yrs - 5/31/16		0.23%	
AF0217	VGT FT-A 12 Mos.	72,213	0	72,213	8 yrs - 10/31/17		8.60%	
AF0218	VGT FT-A 12 Mos.	15,000	0	15,000	5 yrs - 10/31/19		1.79%	
AF0241	VGT FT-A (Dec-Feb)	0	12,428	12,428	3 mos - 2/28/2015	Capacity acquisition	1.48%	
	WBI FT-1097	8,000	0	8,000	26.5 yrs - 10/31/19		0.95%	
	WBI FT-157	461	0	461	20 yrs - 07/01/33		0.05%	
	City Gate Deliveries	24,000	0	24,000	10 yrs - 10/31/17		2.86%	
	LP Peak Shaving	90,000	(26,800)	63,200			7.53%	
	LNG Peak Shaving	156,000	0	156,000			18.59%	
	Total Design Day Capacity	**856,048**		**839,380**			**100%**	
	Heating Season Total	856,048		839,380				
	Non-Heating Season Total	431,971		437,617				
	Miscellaneous Entitlements with Reservation Fees							
	Additional Pipeline Entitlements							
	ANR FTS-106209 12 Mos. (1)	4,829	0	4,829	3 yrs - 03/31/18	Contract extension		
	ANR FTS-106211 (Summer) (1)	4,935	0	4,935	3 yrs - 03/31/18	Contract extension		
	ANR FTS-106211 (Winter) (1)	15,171	0	15,171	3 yrs - 03/31/18	Contract extension		
	ANR FTS-114492 12 Mos. (1)	66,500	0	66,500	9 yrs - 10/31/2019			
	GLT FT171836 (2)	3,509	0	3,509	3 yrs - 03/31/17			
	GLT FT171836 (2)	4,475	0	4,475	3 yrs - 03/31/17			
	GLT Backhaul FT18130 (2)	895	0	895	2 yrs. - 03/31/17			
	GLT Backhaul FT18129 (2)	9,248	0	9,248	2 yrs. - 03/31/17			
	NNG SMS (3)	30,650		30,650	15 yrs - 10/31/17			
	VGT OBA (3)	7,400		7,400	14 yrs - 10/31/16			
	Supply Entitlements (4)							
	[TRADE SECRET BEGINS							
						TRADE SECRET ENDS]		
	Storage Entitlements							
	ANR Pipeline Storage (.951 MMcf)	15,310	34	15,344	3 yrs - 3/31/18	Contract extension		
	ANR Storage (1.165 MMcf)	9,248	0	9,248	2 yrs - 3/31/17	Contract extension		
	FDD Service (8.085 MMcf)	140,230		140,230	4 yrs - 5/31/18			
	FDD Service (4.5 MMcf)	78,050		78,050	15 yrs - 5/31/27			

(1) Not included in total peak deliverability -- feeds VGT (capacity not additive)
(2) Not included in total peak deliverability -- feeds NNG (capacity not additive).
(3) Not included in total peak deliverability -- entitlement delivered by or associated with TF or FT-A service.
(4) Supply contracts containing reservation fees.

Northern States Power Company

CHANGES TO CONTRACT ENTITLEMENTS AS OF NOVEMBER 1, 2015

Revised from 8/3/15 filing

	Current Amount Dth	Proposed Change Dth	Proposed Amount Dth
Total MN Company Available Capacity:			
Heating Season	856,048	(16,668)	839,380
Non-Heating Season	431,971	5,646	437,617
Heating Season Forecasted Design Day	809,671	5,781	815,452
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	46,377	(22,449)	23,928
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	5.7%	-2.8%	2.9%
Total MN State Available Capacity:			
State of MN Allocation Factor	88.42%	-0.43%	87.99%
State of MN Heating Season Capacity	756,918	(18,347)	738,570
State of MN Design Day Demand	715,945	1,533	717,478
State of MN Heating Season Capacity Reserve/(Shortage)	40,973	(19,880)	21,093
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	5.7%	-2.8%	2.9%

(1) Entitlement changes for November are included in Available Capacity.
Please reference Attachment 1 Schedule 5 for the detail on supply entitlement changes.

MINNESOTA STATE RATE IMPACT

Revised from 8/3/15 filing

Date to implement proposed changes: November 1, 2015

$/Dth

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-14-654)	Last Month PGA: October 2015	Estimated Nov. 2015 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Residential								
Commodity Cost of Gas (WACOG)	$5.5042	$4.4493	$2.7897	$2.8402	-48.40%	-36.17%	1.81%	$0.0505
Demand Cost of Gas (1)	$0.9008	$0.8349	$0.8365	$0.8220	-8.75%	-1.55%	-1.73%	($0.0145)
Distribution Margin	$1.8591	$1.8591	$1.8591	$1.8591	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$7.1433	$5.4853	$5.5213	-33.19%	-22.71%	0.66%	$0.0360
Average Annual Usage (Dth)	87	87	87	87				
Average Annual Total Cost	$718.60	$621.14	$476.97	$480.10	-33.19%	-22.71%	0.66%	$3.13
Average Annual Total Demand Cost of Gas	$78.33	$72.60	$72.74	$71.48				**($1.26)**
Small Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$4.4493	$2.7897	$2.8402	-48.24%	-36.17%	1.81%	$0.0505
Demand Cost of Gas (1)	$0.8984	$0.8381	$0.8400	$0.8254	-8.13%	-1.52%	-1.74%	($0.0146)
Distribution Margin	$1.2331	$1.2331	$1.2331	$1.2331	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$6.5205	$4.8628	$4.8987	-35.70%	-24.87%	0.74%	$0.0359
Average Annual Usage (Dth)	284	284	284	284				
Average Annual Total Cost	$2,163.87	$1,851.99	$1,381.16	$1,391.35	-35.70%	-24.87%	0.74%	$10.20
Average Annual Total Demand Cost of Gas	$255.17	$238.04	$238.58	$234.43				**($4.15)**
Large Commercial								
Commodity Cost of Gas (WACOG)	$5.4871	$4.4493	$2.7897	$2.8402	-48.24%	-36.17%	1.81%	$0.0505
Demand Cost of Gas (1)	$0.8917	$0.8200	$0.8243	$0.8099	-9.17%	-1.23%	-1.75%	($0.0144)
Distribution Margin	$1.2315	$1.2315	$1.2315	$1.2315	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$6.5008	$4.8455	$4.8816	-35.86%	-24.91%	0.75%	$0.0361
Average Annual Usage (Dth)	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$9,508.34	$7,087.23	$7,140.04	-35.86%	-24.91%	0.75%	$52.80
Average Annual Total Demand Cost of Gas	$1,304.24	$1,199.36	$1,205.65	$1,184.59				**($21.06)**

(1) Includes demand smoothing

MINNESOTA STATE RATE IMPACT

Revised from 8/3/15 filing

	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-14-654)	Last Month PGA: October 2015	Estimated Nov. 2015 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Small Interruptible								
Commodity Cost of Gas (WACOG)	$5.4926	$4.4493	$2.7897	$2.8402	-48.29%	-36.17%	1.81%	$0.0505
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.9635	$0.9635	$0.9635	$0.9635	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$6.4561	$5.4128	$3.7532	$3.8037	-41.08%	-29.73%	1.35%	$0.0505
Average Annual Usage (Dth)	7,936	7,936	7,936	7,936				
Average Annual Total Cost	$51,236.58	$42,956.85	$29,786.09	$30,186.87	-41.08%	-29.73%	1.35%	$400.77
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible								
Commodity Cost of Gas (WACOG)	$5.4696	$4.4493	$2.7897	$2.8402	-48.07%	-36.17%	1.81%	$0.0505
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4751	$0.4751	$0.4751	$0.4751	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$5.9447	$4.9244	$3.2648	$3.3153	-44.23%	-32.68%	1.55%	$0.0505
Average Annual Usage (Dth)	64,709	64,709	64,709	64,709				
Average Annual Total Cost	$384,678.21	$318,655.39	$211,263.97	$214,531.78	-44.23%	-32.68%	1.55%	$3,267.82
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible								
Commodity Cost of Gas (WACOG)	$5.5006	$4.4493	$2.7897	$2.8402	-48.37%	-36.17%	1.81%	$0.0505
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$0.4346	$0.4346	$0.4346	$0.4346	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$5.9352	$4.8839	$3.2243	$3.2748	-44.82%	-32.95%	1.57%	$0.0505
Average Annual Usage (Dth)	745,979	745,979	745,979	745,979				
Average Annual Total Cost	$4,427,543.89	$3,643,295.84	$2,405,268.56	$2,442,940.52	-44.82%	-32.95%	1.57%	$37,671.96
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**

(1) Includes demand smoothing

Summary - Change from most recent PGA

Customer Class	Commodity Change ($/Dth)	Commodity Change (Percent)	Demand Change ($/Dth)	Demand Change (Percent)	Demand Annual Change ($/Dth)	Total Annual Change ($/Dth)	Total Annual Change (Percent)
Residential	$0.0505	1.81%	($0.0145)	-1.73%	($1.26)	$3.13	0.66%
Small Commercial	$0.0505	1.81%	($0.0146)	-1.74%	($4.15)	$10.20	0.74%
Large Commercial	$0.0505	1.81%	($0.0144)	-1.75%	($21.06)	$52.80	0.75%
Small Interruptible	$0.0505	1.81%	$0.0000	NA	$0.00	$400.77	1.35%
Medium Interruptible	$0.0505	1.81%	$0.0000	NA	$0.00	$3,267.82	1.55%
Large Interruptible	$0.0505	1.81%	$0.0000	NA	$0.00	$37,671.96	1.57%

DERIVATION OF CURRENT PGA COSTS

Nov. 2015 - Projected Costs (Actual prices will be determined Nov.1, 2015)*

Revised from 8/3/15 filing

		Annual Cost	Winter Cost	Total
Demand Cost (Res, Sm & Lg Commercial Firm)				
1.	MN & ND Total Demand	$31,259,124	$23,382,207	
2.	x Minnesota Design Day Ratio (2015 Demand Entitlement Filing)	87.99%	87.99%	
3.	Annual System Demand Allocation to MN	$27,504,903	$20,574,004	
4.	MN State Design Day (2015 Demand Entitlement Filing)	717,478	717,478	
5.	- Small & Large Demand Billed Dth (2015 Demand Entitlement Filing)	22,295	22,295	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	695,183	695,183	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$26,650,212	$19,934,685	
8.	Demand Billed Cost Allocation (3 - 7)	$854,691	$639,319	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	568,148,146	422,545,695	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.04691	$0.04718	$0.09409
11.	Demand Cost True-up - Residential, Oct-May			$0.00000
12.	Demand Cost True-up - Commercial, Oct-May			$0.00000
13.	Total Demand Rate - Residential (10 +11)			$0.09409
14.	Total Demand Rate -Commercial (10 + 12)			$0.09409
Demand Cost (Demand Billed)				
15.	Cost Allocated to Demand Billed (8)	$854,691	$639,319	$1,494,010
16.	/ Annual Contract Billing Demand (2015 Demand Entitlement Filing)			2,675,400
17.	Monthly Commercial Demand Billed Demand Rate			$0.55842

		Monthly Cost
Commodity Costs		
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$25,152,004
19.	x MN Portion of Monthly Retail Sales	86.45%
20.	MN Portion of Monthly Commodity Costs	$21,743,907
21.	MN Budgeted Calendar Month Retail Therm Sales	76,558,967
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.28402
Total Gas Cost per Therm		
23.	Residential (13 + 22)	**$0.37811**
24.	Small & Large Commercial (14 +22)	**$0.37811**
25.	Small & Large Demand Billed - Demand (17)	**$0.55842**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.28402**

*Commodity costs are projected and for illustrative purposed only.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Northern States Power Company
SUMMARY OF COMPANY HEDGE TRANSACTIONS
2015-2016 Heating Season
Revised from 8/3/15 filing

Docket No. G002/M-15-727
REVISED Attachment 3
Schedule 1

								Monthly Volumes (Dth)					
Transaction Date	**Hedge Instrument**	**Counterparty**	**Premium ($/Dth)**	**Call Strike Price**	**Put Strike Price**	**Daily Vol (Dth)**	**Basis Point**	**November**	**December**	**January**	**February**	**March**	**Total Volume (Dth)**	**Total Dollars**

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

CERTIFICATE OF SERVICE

I, SaGonna Thompson, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. G002/M-15-727

Dated this 30th day of October 2015

/s/

____

SaGonna Thompson
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Sandra	Hofstetter	N/A	MN Chamber of Commerce	7261 County Road H Fremont, WI 54940-9317	Paper Service	No	OFF_SL_15-727_M-15-727

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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SaGonna	Thompson	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_15-727_M-15-727
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