414 Nicollet Mall
Minneapolis, Minnesota 55401

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March 1, 2010

Burl W. Haar **—Via Electronic Filing—**
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: REPLY COMMENTS AND UPDATE
CHANGES IN CONTRACT DEMAND ENTITLEMENTS
DOCKET NO. G002/M-09-1287

Dear Dr. Haar:

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the Company") submits to the Minnesota Public Utilities Commission (the "Commission") our public Reply Comments in the above-referenced Docket. Our Reply is in response to the Comments of the Minnesota Office of Energy Security ("OES") dated February 10, 2010 and the Corrected Comments dated February 11, 2010. The non-public version of our Reply is being submitted separately.

Pursuant to Minn. Stat. § 216.17, subd. 3, Xcel Energy has electronically filed this document, and copies of this filing have been served on all parties on the attached service list. Please contact Scott Scheffer at (612) 330-6089 or scott.k.scheffer@xcelenergy.com or me at (612) 330-6613 or amy.a.liberkowski@xcelenergy.com if you have any questions regarding this request.

Sincerely,

/s/

AMY LIBERKOWSKI
MANAGER, PRICING & PLANNING

c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

David Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF A REQUEST BY NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR APPROVAL OF CHANGES IN CONTRACT DEMAND ENTITLEMENTS

DOCKET NO. G002/M-09-1287

REPLY COMMENTS & UPDATE

INTRODUCTION

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") submits to the Minnesota Public Utilities Commission (the "Commission") this Reply to the comments of the Minnesota Office of Energy Security ("OES") in the above-referenced matter. In our Reply, we discuss the following issues raised by the OES:

I. A discussion of the final economics of the Precedent Agreement with Viking Gas Transmission ("Viking") for the Fargo lateral project the ("Project") and an update on the Company's related entitlements;
II. How the Fargo entitlement addition and one-time Chisago realignment affect our reserve margins, for 2009-2010 and subsequent years, and why we believe our proposed reserve margin is reasonable;
III. Explain the limits of using information filed in November to analyze the cost of employing financial instruments for hedging purposes in a heating season that runs from November to March.

In addition, we believe the number of dekatherms ("Dth") shown in the third bullet point on page one of the OES February 10, 2010 Comments, and corrected in the OES Corrected Comments filed February 11, 2010, should be 6,493 Dth. We have attached a revised copy of Attachment 2, Schedule 1, Page 2 from our petition dated November 2, 2009 (the "Petition") in this docket, which shows our derivation of that number. Also, as recommended by the OES, we will continue to use both the Actual Peak Use per Customer Design Day and the Average Monthly Design Day methods to develop our design day estimate.

REPLY COMMENTS

I. Final Economics and Update Regarding Fargo Lateral Project

As stated in our Petition in this docket, we purchased an entitlement of 89,263 Dth/day under the terms of a Cost-Based Precedent Agreement ("Agreement") with Viking. In keeping with the terms of the Agreement, on February 11, 2010, Viking provided the Company with the final construction costs of the Project, which totaled $12,110,174. This figure is nearly $2.6 million less than the $14.7 million that was originally estimated.

As we described in our Petition, we negotiated a formula that was included in the Agreement to calculate the amount of firm entitlement we were required to purchase to pay for the Project. The formula was applied to the final construction costs, and the result was a requirement that the Company purchase 73,577 Dth/day of contract entitlement to pay for the cost of the Project. Since the Company had already purchased 89,263 Dth/day of contract entitlement for the period November 2009 through March 2010, Viking proposed reducing the 73,577 Dth/day to 72,213 Dth/day for the period April 1, 2010 through the end of the contract term to compensate for the overpayment.

Viking based its proposal on a net-present-value analysis using a weighted average cost of capital of 7.66 percent. Viking's proposal also conformed with the True-Up Provision of the Agreement, which provided that if the total Project cost exceeded $14,692,000, we would be required to purchase additional firm entitlement, and if the total Project cost was less than $14,692,000, we would be entitled to purchase less firm entitlement.

The Company conducted its own analysis of Viking's proposal and found it reasonable. The reduction of 73,557 Dth/day to 72,213 Dth/day to the end of the contract term offsets the costs associated with the incremental 15,706 Dth/day that we over-purchased during the November 2009 through March 2010 timeframe.

The following attachments and schedules from our Petition have been updated to reflect the change and are provided as part of this filing:

- Attachment 1, Schedule 2, Page 1 of 1

- Attachment 2, Schedule 1, Page 1 of 2
- Attachment 2, Schedule 1, Page 2 of 2
- Attachment 2, Schedule 2, Page 1 of 2
- Attachment 2, Schedule 2, Page 2 of 2
- Attachment 4, Page 1
- Attachment 4, Page 3

In our original Petition, we stated that we would adjust our purchased gas adjustment ("PGA") effective March 1, 2010 with the revised firm entitlement level. However, Viking informed the Company that it needed to file the agreement with the Federal Energy Regulatory Commission ("FERC") for a 30-day period prior to the effective date of the contract. Therefore, the effective date for the revised contract entitlement agreement is April 1, 2010. As a result, the Company will adjust its PGA on this date.

II. Reserve Margin Impact of Fargo Lateral Addition and Chisago Realignment and Reasonableness of Reserve Margin.

Our experience with purchasing incremental capacity indicates that pipeline counterparties will rarely accommodate one to two percent capacity additions every year to keep pace with increasing customer demand. Therefore, we must purchase capacity in larger increments that may temporarily exceed customer growth for several years. This is especially true in the event of capacity additions involving construction projects.

When an expansion project adds new capacity, the project is typically over-built in the first years of operation so the Company can grow into the capacity over a period of several years. This method is desirable, as the Company avoids participating in expansion projects annually and can benefit from the economies of scale stemming from the larger projects.

The Project added 57,178 Dth of incremental deliverable capacity to the Fargo lateral. Without the addition of this capacity, the Company would have been short capacity to meet the design day requirements of its customers served by the Fargo lateral. The reserve margin did not change with the reduction of the Fargo lateral capacity described in Section I because any excess capacity over and above 57,178 Dth that is delivered to the Fargo lateral is upstream capacity and, thus, does not impact the reserve margin calculation.[1]

[1] The reserve margin is calculated as deliverable capacity in excess of design-day requirements. Deliverable capacity is pipeline capacity that delivers natural gas to the Town Border Station ("TBS") connecting the Company with an interstate pipeline. Since upstream capacity is not deliverable capacity, it is not included in this calculation.

The Chisago realignment will occur in November 2010 and realign Northern capacity presently being billed at maximum transport rates to discount rates. This realignment will not add any additional capacity, so there is no additional effect on the reserve margin as a result. Furthermore, we have not asked for Commission approval for the St. Cloud and Hugo expansions and, therefore, have not included those in our forecasted reserve margins at this time.

We anticipate that future reserve margins will decrease by approximately 1 percent per year, as the table below illustrates. We included only approved capacity purchases in this reserve margin analysis.

	Reserve Margin									
	2009-10		2010-11		2011-12		2012-13		2013-14	
	Vol.	**%**	**Vol.**	**%**	**Vol.**	**%**	**Vol.**	**%**	**Vol.**	**%**
VGT/WBI	16,541	15.9%	10.754	10.2%	9,130	8.5%	7,416	6.8%	5,790	5.2%
NNG	43,477	6.5%	36,981	5.5%	30,143	4.4%	23,500	3.4%	16,891	2.4%
Total System	**60,018**	**7.7%**	**47,736**	**6.1%**	**39,273**	**5.0%**	**30,916**	**3.9%**	**22,681**	**2.8%**

Thus, while the reserve margin is elevated initially due to the incremental deliverable capacity of the Project, the reserve margin declines over time while, as indicated in our Petition, the Project will deliver annual savings to our customers through 2017. [2]

III. Hedging Transaction Information Included in Filing

As a part of its comments, the OES invited the Company to explain the limits of using information filed in November to analyze the cost of employing financial instruments for hedging purposes. At the time we filed our petition in Docket No. G002/M-09-1287, monthly index prices, which the financial instruments are settled against, had not been published for the 2009-2010 heating season. We are able to determine the actual costs or benefits only after the index prices are finalized.

Since the Company files its annual Demand Entitlement petition every November, the lack of published monthly index prices will make it infeasible for us to analyze the cost of employing financial instruments at that time. We therefore believe that the Company's post-mortem review and full cost/benefit disclosure that is included in its Annual Automatic Adjustment filing each September represents the best method of determining and analyzing annual costs and benefits.

[2] As set forth in footnote 5 of our Petition, the Company's analysis shows that Xcel Energy customer savings will increase from approximately $323,000 to $616,000 beginning November 1, 2010, ratcheting up from $1.1 million to $1.4 million per year beginning November 1, 2012.

CONCLUSION

We appreciate the thorough analysis of the OES, believe that the information we have provided addresses their concerns, and respectfully request Commission approval of our 2009-2010 Contract Demand Entitlements petition. Please contact Scott Scheffer at (612) 330-6089 or me at (612) 330-6613 if you have questions or need additional information.

Dated: March 1, 2010

Northern States Power Company,
a Minnesota corporation

RESPECTFULLY SUBMITTED,

/s/

By: ______________________

AMY LIBERKOWSKI
MANAGER, PRICING AND PLANNING

Docket No. G002/M-09-1287
Attachment 1
Schedule 2

REVISED - March 2010

Northern States Power Company, a Minnesota corporation
DEMAND COST OF GAS IMPACT - NOVEMBER 2009

CHANGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day		Current Monthly Demand Rates	No. of Months		Total Annual Cost
VGT FT-A (Jan - Dec)[1]	89,263	$	4.5871	5	$	2,047,291.54
VGT FT-A (Jan - Dec)[1]	72,213	$	4.5871	7	$	2,318,737.77
VGT FT-A (Dec-Mar)[1]	(220)	$	3.4671	4	$	(3,051.05)
VGT FT-A (Dec-Mar)[1]	(600)	$	3.4671	3.5	$	(7,280.91)
VGT FT-A (Jan - Dec)[1]	(5,450)	$	3.4671	12	$	(226,748.34)
VGT FT-A (Nov - Mar)[1]	(6,550)	$	3.4671	5	$	(113,547.53)
NNG TFX (Jan - Dec)[2]	10,000	$	4.8640	12	$	583,680.00
NNG TFX (Jan - Dec)[2]	10,000	$	3.0400	12	$	364,800.00
NNG TFX (Nov - Mar)[2]	(10,084)	$	15.1530	5	$	(764,014.26)
NNG TF12 (Jan - Dec)[2]	(2,359)	$	10.2300	5	$	(120,662.85)
NNG TF12 (Jan - Dec)[2]	2,359	$	13.8660	5	$	163,549.47
NNG TF12 (Jan - Dec)[2]	(2,359)	$	5.6830	7	$	(93,843.38)
NNG TF12 (Jan - Dec)[2]	2,359	$	5.6830	7	$	93,843.38

Total for Change in Pipeline Entitlement	$ 4,242,753.84
	[TRADE SECRET BEGINS
Change in Supplier Reservation Fees	
Total MN & ND Demand Cost Adjustment	
Minnesota Allocation Factor (MN/ND Allocated Demand)	
MN only Demand Cost Adjustment due to MN/ND Allocated Demand	
	TRADE SECRET ENDS]

[1]VGT First Revised Volume No. 1, Twelfth Revised Sheet No. 5, Effective January 1, 2006

[2]NNG Fifth Revised Volume No. 1, Seventy-Eighth Revised Sheet No. 78, Effective October 1, 2008

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Docket No. G002/M-09-1287
Attachment 2
Schedule 1

REVISED - March 2010

Northern States Power Company, a Minnesota corporation
COMPANY DEMAND PROFILE
2009-2010 Heating Season

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)	130,141	(2,359)	127,782	10 yrs - 10/31/17		15.29%	
112183	NNG TF12 VARIABLE (Max)	4,094	2,359	6,453	10 yrs - 10/31/17		0.77%	
112182	NNG TF12 VARIABLE (Disc.)	64,409	0	64,409	10 yrs - 10/31/17		7.71%	
112183	NNG TF5 (Max)	63,443	0	63,443	10 yrs - 10/31/17		7.59%	
112182	NNG TF5 (Disc.)	28,571	0	28,571	10 yrs - 10/31/17		3.42%	
111739	NNG TFX (Nov-Mar)	38,584	(10,084)	28,500	3 yrs - 3/31/12	Contract expiration	3.41%	
112185	NNG TFX (Disc. Nov-Mar)	50,846	0	50,846	10 yrs - 10/31/17		6.09%	
112185	NNG TFX (Disc. 12-month)	1,680	20,000	21,680	10 yrs - 10/31/17	Contract growth election	2.59%	
112186	NNG TFX (Max)	52,025	0	52,025	10 yrs - 10/31/17		6.23%	
112186	NNG TFX 2 (Max)	5,800	0	5,800	10 yrs - 10/31/17		Summer Only	
112186	NNG TFX 5 (Max)	29,428	0	29,428	10 yrs - 10/31/17		Summer Only	
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/17		2.99%	
		[TRADE SECRET BEGINS						
	VGT to NNG Chisago (1)							
	Upstream of Fargo (1)							
	Incremental Fargo capacity							
	VGT to NNG Pierz NNG (2)							**TRADE SECRET ENDS]**
AF0044	VGT FT-A 12 Mos.	29,002	0	29,002	5 yrs - 10/31/13		3.47%	
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/13		0.51%	
AF0036	VGT FT-A 12 Mos.	5,000	0	5,000	15 yrs - 10/31/11		0.60%	
AF0036	VGT FT-A (Nov-Mar)	16,105	0	16,105	15 yrs - 10/31/11		1.93%	
AF0103	VGT FT-A (Apr-Oct)	5,000	0	5,000	15 yrs - 10/31/14		Summer Only	
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	15 yrs - 10/31/14		1.20%	
AF0035	VGT FT-A 12 Mos.	5,450	(5,450)	0	10 yrs - 10/31/10	Contract Expired	0.00%	
AF0035	VGT FT-A (Nov-Mar)	6,550	(6,550)	0	10 yrs - 10/31/10	Contract Expired	0.00%	
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	3 yrs - 5/31/12		1.87%	
AF0116	VGT FT-A 12 Mos.	1,903	0	1,903	5 yrs - 5/31/11		0.23%	
AF0156	VGT FT-A 12 Mos.	0	72,213	72,213	8 yrs - 10/31/17		8.64%	
Capacity Acquisition	VGT FT-A 4 Mos.	220	(220)	0	4 mos - 3/31/09	Contract Expired	0.00%	
Capacity Acquisition	VGT FT-A 3.5 Mos.	600	(600)	0	3.5 mos - 3/31/09	Contract Expired	0.00%	
	WBI X-13	8,000	0	8,000	20 yrs - 10/31/12		0.96%	
	WBI FT-1	461	0	461	20 yrs - 07/01/13		0.06%	
	City Gate Deliveries	34,850	(850)	34,000	10 yrs - 10/31/17	850 contract expired	4.07%	
	LP Peak Shaving	90,000	0	90,000		Grand Forks LPG not operational	10.77%	
	LNG Peak Shaving	156,000	0	156,000			18.67%	
	Total Design Day Capacity	**819,668**		**835,492**			**100%**	
	Heating Season Total	819,668		835,492				
	Non-Heating Season Total	315,968		402,731				
	Miscellaneous Entitlements with Reservation Fees							
	Additional Pipeline Entitlements							
	ANR FT-106209 12 Mos. (1)	4,829		4,829	7 yrs - 03/31/15			
	ANR FT-106211 (Summer) (1)	4,916	15	4,931	7 yrs - 03/31/15	Capacity increase w/ fuel filing		
	ANR FT-106211 (Winter) (1)	15,171		15,171	7 yrs - 03/31/15			
	GLT FT-043 (2)	3,799		3,799	16 yrs - 03/31/10			
	GLT FT-142 (Nov-Apr) (2)	15,195		15,195	17 yr - 04/30/11			
	GLT FT-6187 (2)	960		960	7 month 10/31/09			
	NNG SMS (3)	30,650		30,650	15 yrs - 10/31/17			
	VGT OBA (3)	7,400		7,400	14 yrs - 10/31/09			
	Supply Entitlements (4)							
	[TRADE SECRET BEGINS							
						TRADE SECRET ENDS]		
	Storage Entitlements							
	ANR Pipeline Storage (.946 MMcf)	15,250	8	15,258	7 yrs - 3/31/15	**Capacity increase w/ fuel filing**		
	ANR Storage (.994 MMcf)	15,297		15,297	7 yrs - 3/31/14			
	FDD Service (8.085 MMcf)	140,230		140,230	3 yrs - 5/31/11 (6.5 MMcf expires 5/31/11)			
	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, a Minnesota corporation

CHANGES TO CONTRACT ENTITLEMENTS AS OF NOVEMBER 1, 2009

REVISED - March 2010

	Current Amount Dth	Proposed Change Dth	Proposed Amount Dth
Total MN Company Available Capacity:			
Heating Season	819,668	15,824	835,492
Non-Heating Season	315,968	86,763	402,731
Heating Season Forecasted Design Day	766,782	8,693	775,474
Non-Heating Season Forecasted Design Day	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage)	52,886	7,131	60,018
Non-Heating Season Capacity Reserve/(Shortage)	N/A	N/A	N/A
Heating Season Capacity Reserve/(Shortage) Margin %	6.9%	0.8%	7.7%
Total MN State Available Capacity:			
State of MN Allocation Factor	89.34%	0.22%	89.56%
State of MN Heating Season Capacity	732,291	15,975	748,267
State of MN Design Day Demand	685,005	9,482	694,487
State of MN Heating Season Capacity Reserve/(Shortage)	47,286	6,493	53,779
State of MN Heating Season Capacity Reserve/(Shortage) Margin %	6.9%	0.8%	7.7%

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

Northern States Power Company, a Minnesota corporation
MINNESOTA STATE RATE IMPACT

Docket No. G002/M-09-1287
Attachment 2
Schedule 2

REVISED - March-2010

Please use the following table to illustrate the financial effects of the poposed change, based on the most recent Purchased Gas Adjustment (PGA), the first PGA which implemented the most recently approved demand change and the last rate case for residential customers and all firm customers. If interruptible customers are affected, please identify the rate impact in the same format as specified bleow.

Date to implement proposed change: April 1, 2010
Docket No. of most recently approve demand change: G002/M-06-1454
Date of last rate case: November 9, 2006, 2007 Test Year
Docket No. of last rate case: G002/GR-06-1429

RESIDENTIAL FIRM

All Cost $/Dth	2007 Rate Case Base Cost of Gas (7)	Last Approved Demand Adjustment: November 2006	PGA before Nov-09 filing: October 2009 (8)	Current PGA without Adjustment: April 2010 (8)	Current PGA with Adjustment: April 2010 (8)	Change From Last Rate Case Base Cost	Change From Last Approved Demand Adjustment	Change From Last Month PGA	Change From Current PGA
Commodity Cost of Gas (WACOG) (1)	$7.2073	$7.0824	$3.9971	$4.2795	$4.2795	-40.6%	-39.6%	7.1%	0.0%
Demand Cost of Gas -Summer (4)	$0.6030	$0.6608	$0.3586	$0.4418	$0.4426	-26.6%	-33.0%	23.4%	0.2%
Demand Cost of Gas - Winter (4, 5)	$1.1856	$1.2166	$0.9486	$1.0250	$1.0269	-13.4%	-15.6%	8.3%	0.2%
Total Cost of Gas - Summer (2)	$7.8103	$7.7432	$4.3557	$4.7213	$4.7221	-39.5%	-39.0%	8.4%	0.0%
Total Cost of Gas - Winter (2)	$8.3929	$8.2990	$4.9457	$5.3045	$5.3064	-36.8%	-36.1%	7.3%	0.0%
Average Annual Total Usage (6)	35,410,972	36,533,488	35,410,972	35,410,972	35,410,972	0.0%	-3.1%	0.0%	0.0%
Average Annual Total Cost of Gas (2)	$292,314,298	$298,381,973	$170,183,530	$182,946,021	$183,004,075	-37.4%	-38.7%	7.5%	0.0%

ALL FIRM CUSTOMERS (3)

All Cost $/Dth	2007 Rate Case Base Cost of Gas (7)	Last Approved Demand Adjustment: November 2006	PGA before Nov-09 filing: October 2009 (8)	Current PGA without Adjustment: April 2010 (8)	Current PGA with Adjustment: April 2010 (8)	Change From Last Rate Case Base Cost	Change From Last Approved Demand Adjustment	Change From Last Month PGA	Change From Current PGA
Commodity Cost of Gas (WACOG) (1)	$7.1744	$7.0824	$3.9971	$4.2795	$4.2795	-40.4%	-39.6%	7.1%	0.0%
Demand Cost of Gas -Summer (4)	$0.6030	$0.6608	$0.3586	$0.4418	$0.4426	-26.6%	-33.0%	23.4%	0.2%
Demand Cost of Gas - Winter (4, 5)	$1.1856	$1.2166	$0.9486	$1.0250	$1.0269	-13.4%	-15.6%	8.3%	0.2%
Total Cost of Gas - Summer (2)	$7.7774	$7.7432	$4.3557	$4.7213	$4.7221	-39.3%	-39.0%	8.4%	0.0%
Total Cost of Gas - Winter (2)	$8.3600	$8.2990	$4.9457	$5.3045	$5.3064	-36.5%	-36.1%	7.3%	0.0%
Average Annual Total Usage	53,437,474	55,131,424	53,437,474	53,437,474	53,437,474	0.0%	-3.1%	0.0%	0.0%
Average Annual Total Cost of Gas (2)	$439,038,540	$449,958,270	$256,489,185	$275,752,409	$275,839,404	-37.2%	-38.7%	7.5%	0.0%

(1) Commodity costs include Peakshaving.
(2) Total cost of gas excludes distribution margin
(3) Excludes Demand Billed Customers firm sales.
(4) Rate for Rate Case is a weighted average firm rate since each class has a unique cost of gas.
(5) Not applicable during the summer months
(6) Residential Total Usage for October and November colums were imputed by taking the Residental % of usage in the 2004 Rate Case usage multiplied by the annual usage filed in the PGA for specific months.
(7) As in the compliance filing
(8) Does not include the monthly demand true-up surcharge(credit)

DERIVATION OF CURRENT PGA COSTS

April 2010 - Projected Costs*

(Commodity Costs based on 2010 Test Year Base Cost of Gas filing, Docket No. G002/MR-09-1324)

REVISED - March-2010

	Demand Cost (Res, Sm & Lg Commercial Firm)	Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$27,164,301	$26,978,699	
2.	x Minnesota Design Day Ratio (2009 Demand Entitlement Filing)	89.56%	89.56%	
3.	Annual System Demand Allocation to MN	$24,328,348	$24,162,123	
4.	Grand Forks Total Demand	$275,226	$369,376	
5.	x Minnesota Allocator (2009 Demand Entitlement Filing)	14.67%	14.67%	
6.	Annual Grand Forks Demand Allocation to MN	$40,376	$54,187	
7.	Minnesota Total Demand (3 + 6)	$24,368,724	$24,216,310	
8.	MN State Design Day (2009 Demand Entitlement Filing)	694,487	694,487	
9.	- Small & Large Demand Billed Dth (2009 Demand Entitlement Filing)	20,439	20,439	
10.	Non-Demand Billed Design Day Dkt (8 - 9)	674,048	674,048	
11.	Non-Demand Billed Allocation (7 x 10 / 8)	$23,651,534	$23,503,606	
12.	Demand Billed Cost Allocation (7 - 11)	$717,190	$712,704	
13.	MN Annual / Seasonal Firm Therm Sales (2007 Rate Case)	534,374,742	402,230,147	
14.	Demand Unit Cost $/Therm (11 / 13)	$0.04426	$0.05843	$0.10269
15.	Demand Cost True-up - Residential, Oct-May			$0.00000
16.	Demand Cost True-up - Commercial, Oct-May			$0.00000
17.	Total Demand Rate - Residential (14 + 15)			$0.04426
18.	Total Demand Rate -Commercial (14 + 16)			$0.04426
	Demand Cost (Demand Billed)			
19.	Cost Allocated to Demand Billed (12)	$717,190	$712,704	$1,429,894
20.	/ Annual Contract Billing Demand (2009 Demand Entitlement Filing)			2,452,715
21.	Monthly Commercial Demand Billed Demand Rate			$0.58298
	Commodity Costs			Monthly Cost
22.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv *			$28,480,635
23.	x MN Portion of Monthly Retail Sales			89.94%
24.	MN Portion of Monthly Commodity Costs			$25,615,851
25.	MN Budgeted Calendar Month Retail Therm Sales			59,857,606
26.	Commodity Unit Cost $/Therm (24 / 25)			$0.42795
	Total Gas Cost per Therm			
27.	Residential (17 + 26)			**$0.47221**
28.	Small & Large Commercial (18 +26)			**$0.47221**
29.	Small & Large Demand Billed - Demand (21)			**$0.58298**
30.	Small & Large Demand Billed - Commodity; All Interruptible (26)			**$0.42795**

*Commodity costs are projected and for illustrative purposed only.

Fargo Lateral Pipeline Project
Project Cost Estimate and Payment Options

Rev ised - March 2010

CIAC Option

Estimated Project Cost	$ 12,110,175

Capacity Option

			Forecast Cost	
Service	**Rate (Cat. 3)**	**Capacity Factor**	**Volume**	**Ann. Cost**
Zone 1-2 Backhaul (8 yr)	$4.59	0.0060756	73,577	$4,050,061
Zone 1 Backhaul (10 yr)	$3.47	0.0067464	81,700	$3,399,148
Zone 2 Backhaul (10 yr)	$1.84	0.0127121	153,946	$3,399,122

Negotiated Rate Option

		Forecast Cost	
Service	**Rate (Cat. 3)**	**Volume**	**Ann. Cost**
Zone 1-2 Backhaul (8 yr)	$5.90	57,178	4,050,061
Zone 1 Backhaul (10 yr)	$4.95	57,178	3,399,148
Zone 2 Backhaul (10 yr)	$4.95	57,178	3,399,122

Northern States Power Company, a Minnesota corporation

Docket No. G002/M-09-1287
Attachment 4
Page 3 of 3
REVISED - March 2010

Combined Fargo Project Costs and Northern Discount Savings

Fargo Project Costs	**2009-10**	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**
Zone 1-2 Backhaul (8 yr)	$2,047,292	$2,047,292	$2,047,292	$2,047,292	$2,047,292	$2,047,292	$2,047,292	$2,047,292

Northern Discount Savings

Assumptions
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Volume Requirements	**2009-10**	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**
ANR Capacity		50,000	57,500	66,500	66,500	66,500	66,500	66,500
Viking Capacity - excess Fargo summer	15,035	15,035	15,035	15,035	15,035	15,035	15,035	15,035
Viking Capacity - incremental backhaul		20,059	27,559	36,559	36,559	36,559	36,559	36,559
NNG Capacity (Hugo Summer)		34,443	34,443	34,443	34,443	34,443	34,443	34,443
NNG Capacity (Hugo Winter)		36,316	36,316	36,316	36,316	36,316	36,316	36,316
NNG Capacity (Hugo Expansion)		3,884	7,962	12,245	12,245	12,245	12,245	12,245
NNG Capacity (St Cloud Expansion)		2,401	4,921	6,067	6,067	6,067	6,067	6,067

The costs associated with this Viking capacity are shown above in the Fargo Project Costs line item. Costs for incremental backhaul capacity are included below.

Project Economics **Daily Rate**
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Annual Cost Savings	**$ -**	**$ 460,559**	**$ 1,024,207**	**$ 1,271,691**	**$ 1,271,691**	**$ 1,271,691**	**$ 1,271,691**	**$ 1,271,691**

CERTIFICATE OF SERVICE

I, Aimee Lemen, 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-09-1287

Dated this 1st day of March 2010

/s/

Aimee Lemen
Administrative Assistant

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