division of energy resources
Minnesota Department of Commerce

85 7th Place East, Suite 500, St. Paul, MN 55101-2198
Main: 651.539.1500
Fax: 651.539.1549

mn.gov/commerce/energy

January 13, 2014

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Response Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G011/M-13-670

Dear Dr. Haar:

On August 1, 2013, Minnesota Energy Resources Corporation - (MERC or the Company) filed a change in demand entitlement petition (petition) for its customers served off of the Northern Natural Gas Co. (NNG or Northern) Purchased Gas Adjustment (PGA) system (MERC-NNG) but agreed to provide updated information on November 1, 2013. On October 3, 2013, the Minnesota Department of Commerce, Division of Energy Resources (Department) filed its Comments recommending that the Commission:

- allow MERC to recover storage gas costs through the commodity portion of the PGA, rather than the demand portion;
- accept MERC-NNG's peak-day analysis with the caveat that the Department cannot fully verify the results of MERC's analysis as mentioned herein;
- accept MERC-NNG's proposed level of demand entitlement; and
- allow the proposed recovery of associated demand costs effective November 1, 2013.

Additionally, the Department requested that MERC confirm in Reply Comments, the change in TFX5 Max and Discount demand levels. The Department also requested that MERC explain in Reply Comments the differences in Firm Deferred Delivery (FDD) storage contract reservation and capacity amounts shown in DOC Attachment 1.

On October 31, 2013, MERC filed a response to the Department's two requests. Regarding the change in TFX5 demand levels, MERC stated that its petition was incorrect due to a problem with a formula. According to the Company, MERC had contracted with Northern for 1,800 MMBtu of discounted TFX5 (1,601 MMBtu for MERC-PNG NNG's PGA and 199 MMBtu for MERC-NMU's PGA). However, the discounted TFX5 was overstated in MERC-PNG NNG's PGA by 199 MMBtu. Although not mentioned by MERC in its response, TFX5 at the maximum rate was correspondingly understated by 199 MMBtu. The Department notes that the Company corrected these errors in its November 2013 MERC-NNG PGA. Since the errors caused an under-recovery rather than an over-recovery by the Company, the Department concludes that the under-recovery should be accounted for in the 2014 true up.

Regarding the Department's second request, MERC explained the differences in FDD storage contract reservation and capacity amounts shown in the Department's October 3, 2013 Attachment 1.

On November 1, 2013 MERC filed a Revised Petition updating information and explaining the reason for a new capacity addition purchased since MERC's August 1 petition:

> In addition, NNG held an open season in October 2013 for capacity on their constrained line [*sic*] Tomah line segment, in which MERC submitted a proposal for 7,500 dth/day capacity during the winter period. Based on the results of the open season, MERC was awarded 2,900 Mcf/day[1] capacity during the winter (November through March). The Tomah line segment supplies gas to the Rochester area, where MERC is expecting significant growth.

This increase in entitlement increases the reserve margin from 3.09 to 4.27 percent and appears reasonable considering MERC expects significant growth in Rochester.

Also, in a January 8, 2014 telephone conversation with Company personnel, the Department requested an update on Northern's reallocation of MERC's TF-12 Base (B) and Variable (V) service.[2] Northern increased TF-12 B by 2,109 MMBtu and decreased TF-12V by the same amount. Thus, there is no change in the total level of entitlement. This change will be implemented in MERC's February 2014 PGA.[3]

Based on MERC's Reply Comments and Revised Petition, the Department updated DOC Attachments 1 and 2 and added DOC Attachment 3. Below, the Department updates its Tables 1 through 4 as filed on October 3, 2013.

---

[1] The Department notes that the pipeline sells capacity on a dekatherm (dth) or MMBtu basis rather than Mcf.

[2] NNG annually reallocates TF-12 B and V entitlements (B/V split) on or about November 1 based on the utility's previous May through September usage.

[3] According to the Company, it did not receive the reallocation in time for implementation in the January 2014 PGA.

Table 1

The Company's Proposed Total Entitlement Changes	
Type of Entitlement	**Proposed Changes: increase (decrease) (dth)**
TF 12 Base and Variable	763
TF5	(763)
TFX5 (Max Rate)	0
TFX5 (Discount Rate)	0
NNG Zone Gas Daily Delivery (GDD) Call Option	20,000
8-1-13 Total Entitlement Net Change	**20,000**
11-1-13 Update TFX5 (Max Rate)	2,900
1-8-14 Update TF12 B	2,109
1-8-14 Update TF12 V	(2,109)
11-1-13 Total Entitlement Net Change	**22,900**

Table 2

Filing	Previous Entitlement (Dkt)	Proposed Entitlement (Dkt)	Entitlement Changes (Dkt)	Change From Previous Year (%)
Aug. 1, 2013	233,485	253,485	20,000	8.57%
Nov. 1, 2014	233,485	256,385	22,900	9.81%

Table 3

Filing	Previous Design Day (Dkt)	Previous Design Day (Dkt)	Proposed Design Day (Dkt)	Design Day Changes (Dkt)	Change From Previous Year (%)
Aug. 1, 2013	225,883	225,883	245,878	19,995	8.85%
Nov. 1, 2014	225,883	225,883	245,878	19,995	8.85%

Table 4

Filing	Total Entitlement (Dkt)	Total Entitlement (Dkt)	Design-day Estimate (Dkt)	Difference (Dkt)	Reserve Margin %	% Change From Previous Year
Aug. 1, 2013	253,485	253,485	245,878	7,607	3.09%	-0.28%
Nov. 1, 2014	253,485	253,485	256,385	10,507	4.27%	0.91%

In DOC Attachment 3, the Department compared MERC-NNG's October 2013 PGA to a projected November 2013 PGA as a means of highlighting its changes in demand costs.[4] The Company's revised demand entitlement proposal would result in the following annual demand cost impacts:[5]

- annual bill increase of $0.0209 related to demand costs, or approximately 1.23 percent, for the average General Service customer consuming 71 Dkt annually; and
- no demand cost impacts related to MERC-NNG's interruptible rate classes.

The Department continues make the same recommendations as in its October 3, 2013 Comments stated above and is available to answer any questions that the Commission may have.

Sincerely,

/s/ MICHELLE ST. PIERRE
Financial Analyst

MS/sm
Attachment

[4] MERC also provides this comparison in its Attachment 4, page 1.
[5] The rate impacts do not include the TF12 B/V split.

DOC Attachment 1
MERC-NNG

	10-1168 PNG GS	10-1166 NMU GS	Total	11-1084 PNG GS	11-1088 NMU GS	Total	12-558 PNG GS	12-559 NMU GS	Total
NNG Design Day	194,598	23,615	218,213	211,182	23,778	234,960	211,182	23,778	234,960
Customer Requirements moving to Transportation	0	0	0	0	0	0	0	0	0
Adjusted NNG Design Day	194,598	23,615	218,213	211,182	23,778	234,960	211,182	23,778	234,960
Adjusted NNG Design Day Percentages	89.18%	10.82%	100.00%	89.88%	10.12%	100.00%	89.88%	10.12%	100.00%
Total NNG Design Day Capacity	233,627	23,615	257,242	221,436	23,778	245,214	221,436	23,778	245,214
Total NMU Design Day Capacity		23,615			23,778			57,989	
Less: NGPL adjusted for nonrecallable releases	0	0	0	0	0	0	0	0	0
Less: Windom	2,500	0	2,500	2,500	0	2,500	2,500	0	2,500
Less: LS Power	25,951	3,149	29,100	0	0	0	0	0	0
Less: Northwestern Energy (Ortonville)	0	0	0	910	0	910	910	0	910
Less: Chisago delivery to Viking	0	0	0	0	0	0	0	0	0
Less: TF12B	0	0	0	0	0	0	0	0	0
Less: TF5	0	0	0	0	0	0	0	0	0
Less: TFX(5)	0	0	0	0	0	0	0	0	0
Less: Contract Demand Units	0	0	0	0	0	0	0	0	0
Total Design Day Capacity (excluding direct assignme	205,176	50,379	255,555	219,846	47,556	267,402	219,846	81,767	301,613
Factors for All Winter Capacity	80.29%	19.71%	100.00%	82.22%	17.78%	100.00%	72.89%	27.11%	100.00%
Entitlements in PGA									
TF12B	34,875	4,232	39,107	42,396	4,774	47,170	42,396	4,774	47,170
TF12V	32,290	3,919	36,209	25,298	2,848	28,146	25,298	2,848	28,146
net change									
TF5	28,785	3,493	32,278	29,011	3,267	32,278	29,011	3,267	32,278
TFX12 (112486)	9,651	1,171	10,822	9,727	1,095	10,822	9,727	1,095	10,822
TFX(5) (112486)	51,163	6,208	57,371	51,383	5,806	57,189	51,383	5,806	57,189
TFX(5) (112561)	5,351	649	6,000	5,393	607	6,000	5,393	607	6,000
TFX(5) (112486)	1,605	195	1,800	1,800	182	1,982	1,800	182	1,982
TFX(5) (12-V)	0	0	0	0	0	0	0	0	0
TFX12 (111866)	1,144	139	1,283	1,153	130	1,283	1,153	130	1,283
TFX12 (111866)	7,376	895	8,271	7,434	837	8,271	7,434	837	8,271
TFX5 (111868)	22,306	2,707	25,013	22,482	2,531	25,013	22,482	2,531	25,013
Total Entitlements in PGA	194,546	23,608	218,154	196,077	22,077	218,154	196,077	22,077	218,154
Entitlements in PGA (NNG)									
	0	0	0	0	0	0	0	0	0
Windom	2,500	0	2,500	2,500	0	2,500	2,500	0	2,500
LS Power	25,951	3,149	29,100	0	0	0	0	0	0
Northwestern Energy (Ortonville)	0	0	0	910	0	910	910	0	910
NNG Zone GDD Call Option	0	0	0	11,235	1,265	12,500	11,235	1,265	12,500
	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0
TFX7 chg to TFX12 (111868)*	10,631	1,290	11,921	10,715	1,206	11,921	10,715	1,206	11,921
Total	39,082	4,439	43,521	25,360	2,471	27,831	25,360	2,471	27,831
Total Capacity before Peak Shaving	233,628	28,047	261,675	221,437	24,548	245,985	221,437	24,548	245,985
LP Peak Shaving	0	0	0	0	0	0	0	0	0
Total Design Day Capacity w/o Contract Demand	233,628	28,047	261,675	221,437	24,548	245,985	221,437	24,548	245,985
Total Transp. (with TFX Offpeak less LSP)	207,677	24,898	232,575	221,437	24,548	245,985	221,437	24,548	245,985
Total Annual Transportation	67,165	8,151	75,316	67,694	7,622	75,316	67,694	7,622	75,316
Total Seasonal Transportation	52,696	6,395	59,091	53,293	5,980	59,273	53,293	5,980	59,273
Total Percent Seasonal	22.6%	22.8%		24.1%	24.4%		24.1%	24.4%	
LS Power as % of Total DD Capacity	11.1%	11.2%		0.0%	0.0%		0.0%	0.0%	
Reserve Margin	20.06%	18.77%		4.86%	3.24%		4.86%	3.24%	
Total Design Day Capacity w/ contract demand	233,628	28,047	261,675	221,437	24,548	245,985	221,437	24,548	245,985
Factors	89.18%	10.82%	100.00%	89.88%	10.12%	100.00%	89.88%	10.12%	100.00%

	12-1193 PNG GS	12-1195 NMU GS	Total	13-670 NNG Total *	August Change	13-670 NNG Total	November Change
NNG Design Day	200,785	25,003	225,883 ***	245,878	19,995	245,878	0
Customer Requirements moving to Transportation	0	0	0	0	0	0	0
Adjusted NNG Design Day	200,785	25,003	225,883 ***	245,878	19,995	245,878	0
Adjusted NNG Design Day Percentages	88.89%	11.07%	99.96%	100.00%	0	100.00%	0
Total NNG Design Day Capacity	208,007	25,003	233,010	253,485	20,475	256,385	2,900
Total NMU Design Day Capacity		25,003					
Less: NGPL adjusted for nonrecallable releases	0	0	0	N/A	N/A	N/A	N/A
Less: Windom	2,500	0	2,500	N/A	N/A	N/A	N/A
Less: LS Power	0	0	0	N/A	N/A	N/A	N/A
Less: Northwestern Energy (Ortonville)	910	0	910	N/A	N/A	N/A	N/A
Less: Chisago delivery to Viking	0	0	0	N/A	N/A	N/A	N/A
Less: TF12B	0	0	0	N/A	N/A	N/A	N/A
Less: TF5	0	0	0	N/A	N/A	N/A	N/A
Less: TFX(5)	0	0	0	N/A	N/A	N/A	N/A
Less: Contract Demand Units	0	0	0	N/A	N/A	N/A	N/A
Total Design Day Capacity (excluding direct assignme	206,417	50,006	256,423	N/A	N/A	N/A	N/A
Factors for All Winter Capacity	80.50%	19.50%	100.00%	N/A	N/A	N/A	N/A
Entitlements in PGA							
TF12B	41,156	6,014	47,170	47,044	(126)	47,044	0
TF12V	25,820	2,326	28,146	29,035	889	29,035	0
net change					763		0
TF5	28,704	3,574	32,278	31,515	(763)	31,515	0
TFX12 (112486)	9,624	1,198	10,822	10,822	0	10,822	0
TFX(5) (112486)	50,819	6,370	57,189 **	57,371	182	60,271	2,900
TFX(5) (112561)	5,336	664	6,000	6,000	0	6,000	0
TFX(5) (112486)	1,800	182	1,982 **	1,800	(182)	1,800	0
TFX(5) (12-V)	0	0	0	0	0	0	0
TFX12 (111866)	1,141	142	1,283	1,283	0	1,283	0
TFX12 (111866)	7,355	916	8,271	8,271	0	8,271	0
TFX5 (111868)	22,243	2,770	25,013	25,013	0	25,013	0
Total Entitlements in PGA	193,998	24,158	218,154	218,154	0	221,054	2,900
Entitlements in PGA (NNG)							
	0	0	0	0	0	0	0
Windom	2,500	0	2,500	2,500	0	2,500	0
LS Power	0	0	0	0	0	0	0
Northwestern Energy (Ortonville)	910	0	910	910	0	910	0
NNG Zone GDD Call Option	0	0	0	20,000	20,000	20,000	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
TFX7 chg to TFX12 (111868)*	10,601	1,320	11,921	11,921	0	11,921	0
Total	14,011	1,320	15,331	35,331	20,000	35,331	0
Total Capacity before Peak Shaving	208,009	25,476	233,485	253,485	20,000	256,385	2,900
LP Peak Shaving	0	0	0	0	0	0	0
Total Design Day Capacity w/o Contract Demand	208,009	25,476	233,485	253,485	20,000	256,385	2,900
Total Transp. (with TFX Offpeak less LSP)	208,009	25,476	233,485	253,485	20,000	256,385	2,900
Total Annual Transportation	66,976	8,340	75,316	111,786	36,470	111,786	0
Total Seasonal Transportation	52,747	6,526	59,273	141,699	82,426	144,599	2,900
Total Percent Seasonal	25.4%	25.6%		55.9%	1	56.4%	0.50%
LS Power as % of Total DD Capacity	0.0%	0.0%		0.0%	0	0.0%	0.00%
Reserve Margin	3.60%	1.89%		3.09%	0	4.27%	1.18%
					0		
Total Design Day Capacity w/ contract demand	208,009	25,476	233,485	253,485	20,000	253,485	0
Factors	88.89%	11.07%	99.96%	100.00%	0	100.00%	0.00%

* Source: MERC's Aug. 1, 2013 filing, Atths. 10 and 12.
**The DOC notes that these figures are different by 17 units from the PGA.
*** Added 95 for joint customers demand level.

DOC Attachment 1
MERC-NNG

	10-1166 PNG GS	10-1166 NMU GS	Total	11-1084 PNG GS	11-1066 NMU GS	Total	12-558 PNG GS	12-559 NMU GS	Total	12-1193 PNG GS	12-1195 NMU GS	Total	13-670 NNG Total *	August Change	13-670 NNG Total	November Change
														0		0
Other: Storage levels not included in Peak Day Deliverability														0		0
TFX Oct	1,764	216	2,000	1,798	202	2,000	1,798	202	2,000	1,779	221	2,000	2,000	0	2,000	0
TFX Apr	1,764	216	2,000	1,798	202	2,000	1,798	202	2,000	1,779	221	2,000	2,000	0	2,000	0
FDD Storage reservation (112490)	67,273	8,164	75,437	67,803	7,634	75,437	67,803	7,634	75,437	67,083	8,354	75,437	75,437	0	75,437	0
FDD Storage capacity MSQ 1/	3,878,642	470,684	4,349,326	3,909,172	440,149	4,349,321	3,909,172	440,149	4,349,321	3,867,690	481,630	4,349,320	4,349,320	0	4,349,320	0
FDD Storage reservation (113704)	0	0	0	0	0	0	3,118	351	3,469	4,935	615	5,550	5,550	0	5,550	0
FDD Storage capacity MSQ 2/	0	0	0	0	0	0	179,755	20,245	200,000	177,855	22,145	200,000	200,000	0	200,000	0
FDD Storage reservation (116215)	6,187	751	6,938	6,236	702	6,938	11,692	1,317	13,009	11,568	1,441	13,009	13,008	(1)	13,008	0
FDD Storage capacity MSQ 3/	356,700	43,301	400,002	359,510	40,491	400,001	674,081	75,920	750,001	674,100	75,900	750,000	750,000	0	750,000	0
FDD Storage reservation (118657)	4,949	601	5,550	4,988	562	5,550	4,988	562	5,550	3,085	384	3,469	3,468	(1)	3,468	0
FDD Storage capacity MSQ 4/	285,370	34,630	320,000	287,615	32,385	320,000	287,615	32,385	320,000	284,565	35,435	320,000	320,000	0	320,000	0
FDD Storage reservation total										86,671	10,794	97,465	97,463	(2)	97,463	0
FDD Storage capacity total										5,004,210	615,110	5,619,320	5,619,320	0	5,619,320	0
SMS	20,226	2,454	22,680	20,385	2,295	22,680	20,385	2,295	22,680	20,168	2,512	22,680	22,680	0	22,680	0
Bison/NBPL (FT0003 & T8673F)	44,589	5,411	50,000	44,940	5,060	50,000	44,940	5,060	50,000	44,463	5,537	50,000	50,000	0	50,000	0
AECO Storage	0	665,043	665,043	0	666,223	666,223	0	666,223	666,223	0	648,265	648,265	648,265	0	648,265	0
FDD																
1/ Cycled Volumes =	775,728	94,137	869,865	781,834	88,030	869,864	781,834	88,030	869,864	773,538	96,326	869,864	869,864	0	869,864	0
2/ Cycled Volumes =	0	0	0	0	0	0	35,952	4,048	40,000	35,571	4,429	40,000	40,000	0	40,000	0
3/ Cycled Volumes =	71,342	8,658	80,000	71,904	8,096	80,000	134,820	15,180	150,000	134,820	15,180	150,000	150,000	0	150,000	0
4/ Cycled Volumes =	57,074	6,926	64,000	57,523	6,477	64,000	57,523	6,477	64,000	56,913	7,087	64,000	64,000	0	64,000	0

DOC Attachment 2
MERC-NNG

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Peak Shaving			Reserve Margin
Heating Season	(1) No. of Design Day Customers	(2) Change from Previous Year	(3) % Change From Previous Year	(4) Design Day (Mcf)	(5) Change from Previous Year	(6) % Change From Previous Year	(7) Total Entitlement (Mcf)*	(8) Change from Previous Year	(9) % Change From Previous Year	(10) % of Reserve Margin [(7)-(4)]/(4)
2013-2014	178,578	1,641	0.93%	245,878	19,995	8.85%	256,385	22,900	9.81%	4.27%
2012-2013	176,937	1,696	0.97%	225,883	(9,172)	-3.90%	233,485	-12,500	-5.08%	3.37%
2011-2012	175,241	-786	-0.45%	235,055	16,842	7.72%	245,985	-15,690	-6.00%	4.65%
2010-2011	176,027	799	0.46%	218,213	(9,827)	-4.31%	261,675	7,000	2.75%	19.92%
2009-2010	175,228	1,266	0.73%	228,040	(19,148)	-7.75%	254,675	4,227	1.69%	11.68%
2008-2009	173,962	1,846	1.07%	247,188	23,434	10.47%	250,448	0	0.00%	1.32%
2007-2008	172,116	7,063	4.28%	223,754	1,635	0.74%	250,448	2036	0.82%	11.93%
2006-2007	165,053			222,119			248,412			11.84%
Average:			1.14%			1.69%			0.57%	8.62%

Columns (1) and (4) were provided by MERC in Attachment 1, page 3.

	Firm Peak Day Sendout							
Heating Season	(11) Number of Peak Day Customers	(12) Firm Peak Day Sendout (Mcf)	(13) Change from Previous Year	(14) % Change From Previous Year	**(15) Excess/Def. per Cust. [(7) - (4)]/(1)**	**(16) Design Day per Customer (4)/(1)**	**(17) Entitlement per Customer (7)/(1)**	**(18) Peak Day Sendout per PD Customer (12)/(11)****
2013-2014	unknown	unknown	unknown	unknown	0.06	1.38	1.44	unknown
2012-2013	176937	unknown	#VALUE!	#VALUE!	0.04	1.28	1.32	#VALUE!
2011-2012	175,241	unknown	#VALUE!	#VALUE!	0.06	1.34	1.40	#VALUE!
2010-2011	176,027	unknown	#VALUE!	#VALUE!	0.25	1.24	1.49	#VALUE!
2009-2010	175,228	unknown	#VALUE!	#VALUE!	0.15	1.30	1.45	#VALUE!
2008-2009	173,962	unknown	#VALUE!	#VALUE!	0.02	1.42	1.44	#VALUE!
2007-2008	172,116	unknown	#VALUE!	#VALUE!	0.16	1.30	1.46	#VALUE!
2006-2007	165,053	unknown	#VALUE!	#VALUE!	0.16	1.35	1.51	#VALUE!
Average:				#VALUE!	0.11	1.33	1.44	#VALUE!

*** MERC-PNG NNG added to MERC-NMU NNG areas from DOC's prior Attachment 2 for each company.**
**** The number of design day customers are used when the number of firm peak day customers is unknown (18=19).**

OES Attachment 3
Rate Impact of MERC-Northern PGA System Proposed Demand Entitlement Changes

Recovery	Last Base Cost of Gas G011/MR-10 978	Last Demand Change Jan. '13 M-12-1193	Most Recent PGA 10/1/13	PGA with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
1) General Service - Residential: Avg. Annual Use:			**71 Mcf**					
Recovery	Last Base Cost of Gas G011/MR-10 978	Last Demand Change Jan. '13 M-12-1193	Most Recent PGA 10/1/13	Nov-13 PGA with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate***	$4.7461	$3.4651	$3.7392	$4.0475	-14.72%	16.81%	8.25%	$0.3083
Demand Rate	$1.6894	$1.8818	$1.6968	$1.7177	1.68%	-8.72%	1.23%	$0.0209
Margin	$1.9754	$1.9417	$1.9754	$1.9754	0.00%	1.74%	0.00%	$0.0000
Total Recovery	$8.4109	$7.2886	$7.4114	$7.7406	-7.97%	6.20%	4.44%	$0.3292
Avg. Annual Bill*	$597.17	$517.49	$526.21	$549.58	-7.97%	6.20%	4.44%	$23.3732
Effect of proposed commodity change on average annual bills:								$21.89
Effect of proposed demand change on average annual bills:								$1.48
2) Small Volume Interruptible: Avg. Annual Use:			**4,034 Mcf**					$23.3732
Recovery	Last Base Cost of Gas G011/MR-10 978	Last Demand Change Jan. '13 M-12-1193	Most Recent PGA 10/1/13	Aug-13 PGA with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate***	$4.7461	$3.4651	$3.7392	$4.0475	-14.72%	16.81%	8.25%	$0.3083
Demand Rate	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Margin	$1.0647	$1.2781	$1.0647	$1.0647	0.00%	-16.70%	0.00%	$0.0000
Total Recovery	$5.8108	$4.7432	$4.8039	$5.1122	-12.02%	7.78%	6.42%	$0.3083
Avg. Annual Bill*	$23,440.77	$19,134.07	$19,378.93	$20,622.61	-12.02%	7.78%	6.42%	$1,243.68
Effect of proposed commodity change on average annual bills:								$1,243.68
Effect of proposed demand change on average annual bills:								$0.0000
3) Large Volume Interruptible: Avg. Annual Use:			**20,096 Mcf**					
Recovery	Last Base Cost of Gas G011/MR-10 978	Last Demand Change Jan. '13 M-12-1193	Most Recent PGA 10/1/13	Aug-13 PGA with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate***	$4.7461	$3.4651	$3.7392	$4.0475	-14.72%	16.81%	8.25%	$0.3083
Demand Rate	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Margin	$0.3568	$0.3554	$0.3248	$0.3248	-8.97%	-8.61%	0.00%	$0.0000
Total Recovery	$5.1029	$3.8205	$4.0640	$4.3723	-14.32%	14.44%	7.59%	$0.3083
Avg. Annual Bill*	$102,547.88	$76,776.77	$81,670.14	$87,865.74	-14.32%	14.44%	7.59%	$6,195.60
Effect of proposed commodity change on average annual bills:								$6,195.60
Effect of proposed demand change on average annual bills:								$0.00
4) Small Volume Firm: Avg. Annual Use:			**4,800 Mcf**					
Avg. Annual CD Volumes:			**25 Mcf**					
Recovery	Last Base Cost of Gas G011/MR-10 978	Last Demand Change Jan. '13 M-12-1193	Most Recent PGA 10/1/13	Aug-13 PGA with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate***	$4.7461	$3.4651	$3.7392	$4.0475	-14.72%	16.81%	8.25%	$0.3083
Demand Rate	$19.5620	$19.3628	$19.4140	$18.8796	-3.49%	-2.50%	-2.75%	($0.5344)
Comm. Margin	$1.0647	$1.2781	$1.0647	$1.0647	0.00%	-16.70%	0.00%	$0.0000
SV Dem. Margin	$2.3000	$1.9695	$2.3000	$2.3000	0.00%	16.78%	0.00%	$0.0000
Total Commodity Cost	$5.8108	$4.7432	$4.8039	$5.1122	-12.02%	7.78%	6.42%	$0.3083
Total Demand Cost	$21.8620	$21.3323	$21.7140	$21.1796	-3.12%	-0.72%	-2.46%	($0.5344)
Avg. Annual Bill*	$28,438.39	$23,300.67	$23,601.57	$25,068.05	-11.85%	7.59%	6.21%	$1,466.4800
Effect of proposed commodity change on average annual bills:								$1,479.84
Effect of proposed demand change on average annual bills:								($13.36)
5) Large Volume Firm: Avg. Annual Use:			**14,841 Mcf**					
Avg. Annual CD Units:			**75 Mcf**					
Recovery	Last Base Cost of Gas G011/MR-10 978	Last Demand Change Jan. '13 M-12-1193	Most Recent PGA 10/1/13	Aug-13 PGA with Demand Changes	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate***	$4.7461	$3.4651	$3.7392	$4.0475	-14.72%	16.81%	8.25%	$0.3083
Demand Rate	$19.5620	$19.3628	$19.4140	$18.8796	-3.49%	-2.50%	-2.75%	($0.5344)
Comm. Margin	$0.3568	$0.3554	$0.3568	$0.3568	0.00%	0.39%	0.00%	$0.0000
LV Dem. Margin	$2.3000	$1.5319	$2.3000	$2.3000	0.00%	50.14%	0.00%	$0.0000
Total Commodity Cost	$5.1029	$3.8205	$4.0960	$4.4043	-13.69%	15.28%	7.53%	$0.3083
Total Demand Cost	$21.8620	$20.8947	$21.7140	$21.1796	-3.12%	1.36%	-2.46%	($0.5344)
Avg. Annual Bill*	$77,371.79	$58,267.14	$62,417.29	$66,952.69	-13.47%	14.91%	7.27%	$4,535.4003
Effect of proposed commodity change on average annual bills:								$4,575.48
Effect of proposed demand change on average annual bills:								($40.08)

Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Demand Change ($/Mcf)	Demand Change (Percent)	Total Change ($/Mcf)		Total Change (Percent)
All Firm	$0.3083	8.25%	$0.0209	1.23%	0.3292		4.44%
Sm Vol Inter. Service	$0.3083	8.25%	$0.0000	0.00%	0.3083		6.42%
Lrg Vol Inter. Service	$0.3083	8.25%	$0.0000	0.00%	0.3083		7.59%
Sm Vol Joint Service	$0.3083	8.25%	($0.5344)	-2.75%	0.3083	**	6.42%
Lrg Vol Joint Service	$0.3083	8.25%	($0.5344)	-2.75%	0.3083	**	7.53%

*** The average annual bill shown does not include customer charges.**
**** The total change for Joint customers includes only commodity change since not all joint customers purchase CD units.**

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Response Comments

Docket No. G011/M-13-670

Dated this **13th** day of **January 2014**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	50 S 6th St Ste 1500 Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_13-670_M-13-670
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_13-670_M-13-670
Michael	Bradley	mike.bradley@lawmoss.com	Moss & Barnett	Suite 4800 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_13-670_M-13-670
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_13-670_M-13-670
Daryll	Fuentes	N/A	USG	550 W. Adams Street Chicago, IL 60661	Paper Service	No	OFF_SL_13-670_M-13-670
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_13-670_M-13-670
Richard	Haubensak	RICHARD.HAUBENSAK@CONSTELLATION.COM	Constellation New Energy Gas	Suite 200 12120 Port Grace Boulevard La Vista, NE 68128	Electronic Service	No	OFF_SL_13-670_M-13-670
Amber	Lee	alee@briggs.com	Briggs and Morgan	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-670_M-13-670
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_13-670_M-13-670
Brian	Meloy	brian.meloy@leonard.com	Leonard, Street & Deinard	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-670_M-13-670

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-670_M-13-670
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_13-670_M-13-670
Gregory	Walters	gjwalters@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	3460 Technology Dr. NW Rochester, MN 55901	Electronic Service	No	OFF_SL_13-670_M-13-670