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August 12, 2009

VIA ELECTRONIC FILING

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101

Re: In the Matter of the Petition of Minnesota Energy Resources Corporation-NMU for Approval of a Change in Demand Entitlement
Docket No. G011/M-08-1329; Docket No. G007,011/MR-08-836

Dear Dr. Haar:

Enclosed please find the Response Comments of Minnesota Energy Resources Corporation ("MERC" or "Company") in the above-referenced docket. MERC submitted its initial Petition to the Commission on November 3, 2008 and filed revised spreadsheets shortly thereafter on November 5, 2008. The OES issued its initial Comments on March 4, 2009 and Supplemental Comments on March 13, 2009, and MERC filed its Reply Comments on March 30, 2009. On June 17, 2009, the OES issued Response Comments that noted areas in which the OES had continuing questions or concerns regarding the Company's proposal. The Company requests that the Commission accept these Response Comments, which address the issues raised by the OES in their June 17, 2009 Response Comments.

Thank you for your attention to this matter.

Sincerely yours,

/s/ Michael J. Ahern

Michael J. Ahern

cc: Service List

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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

In the Matter of the Petition of Minnesota Energy Resources Corporation-NMU for Approval of a Change in Demand Entitlement

Docket No. G007/M-08-1329
Docket No. G007,011/MR-08-836

RESPONSE COMMENTS OF
MINNESOTA ENERGY RESOURCES CORPORATION

Minnesota Energy Resources Corporation-NMU ("MERC" or "Company") submits to the Minnesota Public Utilities Commission ("Commission") these Response Comments in response to the June 17, 2009 Response Comments of the Minnesota Office of Energy Security ("OES") in the above referenced matter.

MERC submitted its initial Petition to the Commission on November 3, 2008 and filed revised spreadsheets shortly thereafter on November 5, 2008. The OES issued its initial Comments on March 4, 2009, and MERC filed its Reply Comments on March 30, 2009. On June 17, 2009, the OES issued Response Comments that noted areas in which the OES had continuing questions or concerns regarding the Company's proposal. The Company requests that the Commission accept these Response Comments, which address the issues raised by the OES in their June 17, 2009 Response Comments.

A. Design-Day Methodology

The OES recommended that the Commission approve MERC-NMU's demand entitlement level without endorsing its design-day study analysis. The OES expressed concerns that firm system performance may be hindered on a peak-day given the large changes in design-day estimates using the old and new design-day methodologies. The OES noted, however, that:

1) MERC-NMU's method has merit in terms of providing a more realistic estimate of use by interruptible customers on peak days;
2) MERC-NMU's system appeared to perform adequately in the past year; and
3) OES agrees with MERC-NMU that it would be helpful to continue to talk about the Company's method.

Response

As the OES stated, MERC-NMU's system performed well in the past year, and MERC-NMU had sufficient firm capacity to meet its need during the 2008-2009 heating season. MERC also agrees with the OES that its new methodology provides a more realistic estimate of use by interruptible customers on peak days. In the Company's rate case in Docket No. G007,011/GR-08-835, the Commission approved MERC's proposal that all interruptible and transportation customers be required to install telemetry equipment. The use of telemetry equipment by all interruptible and transportation customers will provide the daily data to make the design day calculation more realistic. In particular, telemetry will provide MERC with daily interruptible and transportation volumes that can be deducted from the total daily throughput to ascertain actual firm consumption.

MERC agrees that it would be helpful to meet with the OES to further discuss the Company's design-day methodology.

B. Peak-Day Weather Assumptions

In its Response Comments, the OES noted that the Fargo weather station is one component used to calculate the MERC-NMU design day and that although the Fargo weather station's adjusted HDD value is greater than the Commission's prescribed peak-day weather standard, it is the only weather station that required the effects of wind to meet the Commission's standard. The OES stated that the effect of wind chill on heating load is contingent on many different factors such as building age and tightness of construction, and suggested that wind chill affected weather data may not produce the most accurate estimates of load on a Commission prescribed peak-day. The OES noted that Commission Staff discussed the use of adjusted HDDs to determine design-day estimates in the March 11, 2009 Briefing Papers in Docket No. G022/M-07-1142 for Greater Minnesota Gas. In that docket, Commission Staff expressed concern that wind chill does not necessarily affect heating load and that the use of adjusted HDDs may produce design-day throughputs that may not be sufficient to meet firm peak-day needs. The OES suggested that it would be useful to discuss MERC's design-day methodology in a meeting with MERC and that Commission Staff may wish to attend as well.

Response

The OES noted that MERC-NMU, and its predecessor Aquila Networks-NMU, have had Commission approval to use wind adjusted HDDs since the early 1990s. . When completing regression analysis, it has been MERC's experience that there is a stronger correlation between Adjusted HDD (wind adjusted) and consumption compared to Unadjusted HDD (65 minus the average of the high/low temperature) and consumption. The stronger correlation leads MERC to believe that HDD adjusted for wind is a better indicator of customer consumption. MERC is willing to further discuss this issue in a meeting with the OES and Commission Staff to discuss MERC's design-day methodology.

C. <u>System Performance During the 2008-2009 Heating Season</u>

In its initial Comments, the OES noted that the Company's service territory has experienced two extreme cold weather events since the Petition was filed and recommended that the Company provide a discussion of its firm system performance during the cold weather events. MERC discussed this issue in the Company's Reply Comments, and the OES noted in its Response Comments that it has additional questions regarding MERC's response. The OES noted that it was unable to fully substantiate the Company's system performance discussion but that it appeared that the Company has sufficient firm demand volumes to meet the needs of its firm customers. The OES noted, however, that the Company used significantly more than anticipated on days during the past heating season that had temperatures warmer than the Commission's peak-day standard. The OES also noted its concern that the Company did not provide usage data that was specific to each of its PGA systems. Without the PGA system specific data, or at a minimum estimates, the OES stated it is unable to determine whether the Company's PGA system would have adequate firm entitlements on a Commission prescribed peak-day.

The OES also noted that in Docket No. G011/M-08-1328 (relating to the petition for a change in demand entitlement on MERC-PNG's NNG system) the Company was able to offer several options to serve firm load if needed next year. The OES stated it was not clear, however, whether such options would be available to serve MERC-NMU's firm customers and recommended that the Company be prepared to indicate to the Commission whether these tools could be used to serve MERC-NMU's customers. Finally, the OES noted that MERC-NMU's change in its method to estimate peak use by interruptible customers implies that MERC-NMU would be able to make greater use of interruptions of such customers if needed for reliability purposes.

The OES stated that although it believes that MERC-NMU's current design-day methodology has advantages over its previous estimate technique, the OES still has concerns about the design-day study's ability to estimate peak-day sendout and recommended that the Commission require the Company to provide additional evidence supporting the estimative power of its design-day study in its next demand entitlement filing.

Response

As on the MERC-PNG's NNG system, the MERC-NMU does have the capability to call transportation customers to their Maximum Daily Quantity (MDQ) as MERC deems necessary for operational integrity. MERC also has the capability to purchase a delivered service at MERC citygate(s). Contract number 111866, referenced in MERC's Reply Comments in Docket No. G011/M-08-1328, is part of the Northern Natural Gas Northern Lights project and does not provide additional capacity on MERC-NMU's system.

MERC-NMU is willing to discuss making reasonable changes to its design day forecasting process, including preparing and providing appropriate documentation related to the "estimative power of its design day study" as requested by the OES. MERC-NMU requests clarification of the specific metrics or measures that would best describe "estimative power" including the preferred method of calculation and preferred format for the results (e.g. memo, table, graph, set of graphs). To that end, MERC agrees that it would be helpful to meet with the OES to further discuss the Company's design-day methodology.

D. Treatment of FDD Storage Costs

In response to concerns raised in the OES's initial Comments, MERC filed revised Attachments 4, page 1 of 2, and 7 that shifted FDD storage costs to the commodity recovery portion of the PGA. Based on its review of MERC's revised Attachments 4 and 7, the OES stated that it was unable to replicate the Company's total demand cost recovery figure ($1.0161 per Mcf). Using the firm sales figure reported in MERC-NMU's original Attachment 4, page 2 of 2 (5,599,331 Mcf), and the same volumes for each demand contract, the OES estimated a total demand cost recovery figure of $0.99163.

Response

When MERC filed its Reply Comments on March 30, 2009, the Company provided revised Attachment 4, page 1 of 2, and Attachment 7 that showed the effects of moving the FDD storage costs to the commodity cost recovery portion of the monthly PGA in the event the Commission approves the shift of storage costs from the demand rate to the commodity rate. MERC, however, failed to provide a revised version of Attachment 4, page 2 of 2, in support of the shifting of FDD costs from demand to commodity. A complete revised Attachment 4, pages 1-2, showing the effects of moving the FDD storage costs from demand to commodity and the supporting cost details, is provided as Exhibit 1 to these Response Comments. MERC is also submitting as Exhibit 2 a spreadsheet which illustrates how the shifting of FDD costs affects commodity rates. MERC regrets any inconvenience the failure to include this information may have caused.

The revised version of Attachment 4, page 2 of 2, displays the information and calculations substantiating MERC's revised total demand cost recovery figure of $1.0161 per Mcf. This factor is calculated by using the firm sales figure reported in MERC-NMU's resubmitted Attachment 4, page 2 of 2 (5,464,591 Mcf) included in Exhibit 3 to these Response Comments and discussed in more detail in section F, below.

E. **FT0011 Contract**

The OES recommended that the Commission require MERC to remove all costs and volumes related to the FT0011 contract from its latest update, and any future updates, to the base cost of gas dated January 27, 2009, and to submit the revised base cost of gas calculation as part of its rate case compliance filing.

Response

MERC agreed in its Reply Comments to remove all costs and volumes related to the FT0011 contract from its latest update to the base cost of gas dated January 27, 2009, and to submit the revised base cost of gas calculation as part of its rate case compliance filing.

F. **PGA Cost Recovery**

In its initial Comments, the OES had noted that the demand cost estimates included in MERC's initial Petition filed November 3, 2008 and the Company's revised spreadsheets filed November 5, 2008 were not the same. In Reply Comments, the Company noted that Attachments 4 and 7 of the initial filing included estimated demand costs that had been used as placeholders in preparation of the attachments pending calculation of the actual demand costs. Soon after filing, MERC realized that it had failed to replace the estimated costs with the actual demand costs and that Attachments 4 and 7 were not accurate. MERC therefore filed revised attachments that included the actual demand costs on November 5, 2008. Based on its review of the information provided in the Reply Comments, however, the OES stated that it could not find supporting information, or calculations, that substantiate the cost calculations provided by MERC-NMU in its November 5, 2008 filing.

Given this fact and the OES's difficulty in reconciling the Company's cost proposal discussed in C., above, the OES recommended that the Commission reject MERC-NMU's cost recovery proposal submitted on November 5, 2008, and its alternate cost recovery proposal, which moves FDD storage cost to the commodity cost recovery portion of the PGA, presented in its March 30, 2009 Reply Comments. Instead, the OES recommended that the Commission adopt the OES's cost recovery proposal and require MERC-NMU to refund to its ratepayers the difference between the OES's cost recovery proposal and MERC's cost recovery proposal submitted on November 5, 2008 and charged in rates through the PGA since November 1, 2008.

Response

As noted in MERC's Reply Comments, Attachments 4 and 7 of the Company's initial Petition included estimated demand costs that had been used as placeholders in preparation of the attachments pending calculation of the actual demand costs. MERC realized its error shortly after filing and filed revised Attachment 4, page 1 of 2, and Attachment 7 on November 5, 2009, that replaced the estimated costs with the actual demand costs. MERC recently has realized that when it submitted the revised attachments on November 5, 2008, the Company failed to submit a revised Attachment 4, page 2 of 2, that included actual (rather than estimated) costs. Attached as Exhibit 3 is a complete Attachment 4, pages 1-2, that replaces the estimated demand costs with actual demand costs in each page of the attachment.[1]

The demand entitlement and sales values contained in the resubmitted Attachment 4, page 2 of 2 in Exhibit 3 were used in the calculation of the rate factors contained in the initial

[1] The only difference between Exhibit 1 and Exhibit 3 to these Response Comments is that Exhibit 1 shows the effect of shifting the FDD storage costs from the demand portion of rates to commodity.

November 3, 2008 filing by MERC as well as the Reply Comments filed on March 30, 2009. Additionally, the demand entitlement and sales values listed on the resubmitted Attachment 4, page 2 of 2 in Exhibit 3 were used in the calculation of the November 1, 2008 monthly MERC-NMU PGA filings and have been used in subsequent monthly PGA filings. The resubmitted Attachment 4, page 2 of 2, provides supporting information and calculations that substantiate the cost recovery calculations proposed by MERC-NMU in its November 3, 2008 filing and in the calculations, requested by the OES to be filed in MERC's Reply Comments, which demonstrated shifting the recovery of FDD costs from demand to commodity (see Exhibit 1).

MERC requests that OES re-evaluate MERC's proposed cost recovery proposal submitted on November 3, 2008 and the cost recovery calculations provided in MERC's March 30, 2009 Reply Comments using the resubmitted version of Attachment 4 included in Exhibit 3 and the revised version of Attachment 4 included in Exhibit 1, respectively.

At this point in time the Commission has not approved the shifting of FDD costs from the demand recovery to the commodity recovery portion of the PGA. If the Commission does approve that shift, MERC believes it would be appropriate to work with the OES and Commission Staff to develop a process which will credit GS customers for the collection of FDD costs recovered via the demand portion of the PGA and recover those same FDD costs from all customer groups via the commodity portion of the PGA.

DATED this 12th day of August, 2009.

Respectfully submitted,

DORSEY & WHITNEY LLP

/s/ Michael J. Ahern _
Michael J. Ahern
50 South Sixth Street
Minneapolis, MN 55402
(612) 340-2600

Attorney for MERC

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MINNESOTA ENERGY RESOURCES - NMU

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
NOVEMBER 1, 2008

All costs in $/MMBtu	Last Rate Case G007 MR03-1372	Last Demand Change G006 M-06-XXXX Nov. 06	Last Demand Change G007 M-07-XXXX Nov. 07	Most Recent PGA Oct. 08	Current Proposal Effective Nov.1,2008	Result of Proposed Change: Change from Last Rate Case	Change from Last Demand Change	Change from Last PGA	Change from Last PGA $
1) General Service: Avg. Annual Use:				**143**	**Mcf**				
Commodity Cost	$2.3640	$7.3411	$6.9558	$6.5778	$7.5206	218.13%	70.24%	14.33%	$0.9428
Demand Cost	$1.3009	$1.2448	$1.0999	$1.1201	$1.0161	-21.89%	-22.88%	-9.28%	($0.1040)
Commodity Margin	$1.9411	$1.9411	$1.9411	$2.3126	$2.3126	19.14%	19.14%	0.00%	$0.0000
Total Cost of Gas	$5.6060	$10.5270	$9.9968	$10.0105	$10.8493	93.53%	49.81%	8.38%	$0.8388
Avg Annual Cost	$801.66	$1,505.36	$1,429.54	$1,431.50	$1,551.45	93.53%	49.81%	8.38%	$119.95
Effect of proposed commodity change on average annual bills:									$134.82
Effect of proposed demand change on average annual bills:									($14.87)
2) Large General Service: Avg. Annual Use:				**6,838**	**Mcf**				
Commodity Cost	$2.3640	$7.3411	$6.9558	$6.5778	$7.5206	218.13%	2.45%	14.33%	$0.9428
Demand Cost	$1.3009	$1.2448	$1.0999	$1.1201	$1.0161	-21.89%	-18.37%	-9.28%	($0.1040)
Commodity Margin	$1.9411	$1.9411	$1.9411	$2.3126	$2.3126	19.14%	19.14%	0.00%	$0.0000
Total Cost of Gas	$5.6060	$10.5270	$9.9968	$10.0105	$10.8493	93.53%	3.06%	8.38%	$0.8388
Avg Annual Cost	$38,333.83	$71,983.63	$68,358.12	$68,451.80	$74,187.51	93.53%	3.06%	8.38%	$5,735.71
Effect of proposed commodity change on average annual bills:									$6,446.87
Effect of proposed demand change on average annual bills:									($711.15)
3) SV Interruptible Service: Avg. Annual Use:				**7,982**	**Mcf**				
Commodity Cost	$2.3640	$7.3411	$6.9558	$6.5778	$7.5206	218.13%	2.45%	14.33%	$0.9428
Commodity Margin	$0.8500	$0.8500	$0.8500	$1.0127	$1.0127	19.14%	19.14%	0.00%	$0.0000
Total Cost of Gas	$3.2140	$8.1911	$7.8058	$7.5905	$8.5333	165.50%	4.18%	12.42%	$0.9428
Avg Annual Cost	$25,654.15	$65,381.36	$62,305.90	$60,587.37	$68,112.80	165.50%	4.18%	12.42%	$7,525.43
Effect of proposed commodity change on average annual bills:									$7,525.43
4) LV Interruptible Service: Avg. Annual Use:				**38,443**	**Mcf**				
Commodity Cost	$2.3640	$7.3411	$6.9558	$6.5778	$7.5206	218.13%	2.45%	14.33%	$0.9428
Commodity Margin	$0.2850	$0.2850	$0.2850	$0.3395	$0.3395	19.12%	19.12%	0.00%	$0.0000
Total Cost of Gas	$2.6490	$7.6261	$7.2408	$6.9173	$7.8601	196.72%	3.07%	13.63%	$0.9428
Avg Annual Cost	$101,835.51	$293,170.16	$278,358.07	$265,921.76	$302,165.82	196.72%	3.07%	13.63%	$36,244.06
Effect of proposed commodity change on average annual bills:									$36,244.06

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in
Docket No. E,G999/AA-05-1403

Illustration of the Effect of Moving FDD Storage Contracts From Demand Costs to Commodity Costs

MERC-NMU

PRESENT AVERAGE COST OF GAS **EFFECTIVE: 1-Nov-08** 03/26/09

N:Group/Rates/Gas/MERC/PGAC/2008/NMU1108 12:00 AM

DEMAND

Contract Type Northern Natural Gas (NNG)	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Rate Case Sales (therms)	Rate ($/therm)
TF12-B (Max Rate)	Annual	2,653	12	$7.57760	$241,240.47	54,645,910	$0.00441
TF12-V (Max Rate)	Annual	6,643	12	$9.09260	$724,825.70	54,645,910	$0.01326
TF5 (Max Rate)	Winter	5,451	5	$15.15300	$412,995.02	54,645,910	$0.00756
TFX5 (Max Rate)	Winter	6,139	5	$15.15300	$465,121.34	54,645,910	$0.00851
SMS	Annual	2,143	12	$2.18000	$56,060.88	54,645,910	$0.00103
LS Power	Winter	2,777	3	$4.34625	$36,208.61	54,645,910	$0.00066
Exchange	Annual	0	1	$2.00350	$0.00	54,645,910	$0.00000
NNG Demand					**$1,936,452**	54,645,910	**$0.03544**
Viking (VGT)							
FT	Annual	7,966	12	$3.46710	$331,427.02	54,645,910	$0.00606
FT	Winter	5,902	5	$3.76710	$111,167.12	54,645,910	$0.00203
TF-12	Summer	926	12	$7.57760	$84,181.45	54,645,910	$0.00154
TF-5	Winter	2,089	5	$15.15300	$158,296.42	54,645,910	$0.00290
TFX-12	Summer	2,324	12	$9.62880	$268,493.51	54,645,910	$0.00491
TFX-5	Winter	563	5	$15.15300	$42,672.32	54,645,910	$0.00078
VGT Demand					**$996,238**	54,645,910	**$0.01823**
Great Lakes (GLGT)							
FT	Annual	10,130	12	$3.45800	$420,354.48	54,645,910	$0.00769
FT	Annual	1,178	12	$3.45800	$48,882.29	54,645,910	$0.00089
FT	Winter	2,138	5	$3.45800	$36,966.02	54,645,910	$0.00068
T	Summer	0	7	$10.27800	$0.00	54,645,910	$0.00000
FT	Annual	4,000	12	$3.45800	$165,984.00	54,645,910	$0.00304
GLGT Demand					**$672,187**	54,645,910	**$0.01230**
Centra							
FT	Annual	9,858	12	$1.23110	$145,634.21	54,645,910	$0.00267
FT	Annual	9,858	12	$4.53280	$536,212.11	54,645,910	$0.00981
Balancing	Annual	9,858	12	$4,500.00	$54,000.00	54,645,910	$0.00099
Centra Demand					**$735,846**	54,645,910	**$0.01347**
Nexen	Annual	684,604	1	$1.77	$1,211,749.08	54,645,910	$0.02217
Nexen Demand					**$1,211,749**		
NMU DEMAND - $/Ccf					**$5,552,472**		**$0.10161**

For Joint Rate Demand				**54,645,910**	**Annual Firm Sales in therms**
Northern Natural Gas (NNG)					
TF12-B (Max Rate)	Annual	2,653	12		
TF12-V (Max Rate)	Annual	6,643	12		
TF5 (Max Rate)	Winter	5,451	5		
TFX5 (Max Rate)	Winter	6,139	5		
			169,502		
Viking (VGT)					
FT	Annual	7,966	12		
TF-12	Summer	926	12		
TF-5	Winter	2,089	5		
TFX-12	Summer	2,324	12		
TFX-5	Winter	563	5		
			147,848		
Great Lakes (GLGT)					
FT	Annual	10,130	12		
FT	Annual	1,178	12		
FT	Winter	2,138	5		
			146,386		
Centra					
FT	Annual	9,858	12		
			118,296		
Total Demand Cost			**$5,552,472**		
Total Demand Weighted Vol in therms			**5,820,323**		
Total Joint Demand Rate $/therm				**$0.95398**	**/therm**

Illustration of the Effect of Moving FDD Storage Contracts From Demand Costs to Commodity Costs

MERC-NMU

PRESENT AVERAGE COST OF GAS **EFFECTIVE: 01-Nov-08** 03/26/09

N:Group/Rates/Gas/MERC/PGAC/2008/NMU1108 **COMMODITY** 12:00 AM

NNG

	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Rate Case Sales (therms)	Rate ($/therm)
FDD - Reservation	Annual	7,128	12	$1.71400	$146,599.40	2,503,071	$0.05857
FDD - Storage Cycle	Annual	82,188	5	$0.35670	$146,581.89	2,503,071	$0.05856
FDD - Reservation	Annual	524	12	$3.31570	$20,864.37	2,503,071	$0.00834
FDD - Storage Cycle	Annual	6,047	5	$0.69010	$20,864.97	2,503,071	$0.00834
FDD - Reservation	Annual	328	12	$1.71400	$6,741.43	2,503,071	$0.00269
FDD - Storage Cycle	Annual	3,779	5	$0.35670	$6,740.45	2,503,071	$0.00269
Firm Deferred Delivery Storage Contracts					$348,392.51	2,503,071	$0.13919

	WACOG Rate	Annual Dth	Call Option Premium	Total Annual Cost	Cost/therm	REFERENCE	Effective
GAS COST	$5.84270						
FUEL 1.91%	$0.11377					Sub 21 Revised Sheet No. 64	Apr 1, 2006
COMMODITY TRANSPORTATION	$0.03600					3 Rev 72 Revised Sheet No. 50	Oct 1, 2006
ACA	$0.00170					4 Rev 72 Revised Sheet No. 50	Oct 1, 2007
GRI FEE	$0.00000					3 Rev 72 Revised Sheet No. 50	Oct 1, 2006
NNG Commodity	$5.99417	2,503,071	$141,092	$15,493,318	$0.23203	**NNG Commodity**	
VGT							
GAS COST	$8.24920						
FUEL 1.95%	$0.16406					Sub 16th Revised Sheet No. 5B	Apr. 1, 2006
COMMODITY TRANSPORTATION	$0.01300					Sub 16th Revised Sheet No. 5B	Apr. 1, 2006
GRI	$0.00000					Sub 16th Revised Sheet No. 5B	Apr. 1, 2006
ACA	$0.00170					Sub 16th Revised Sheet No. 5B	Apr. 1, 2006
VGT Commodity	$8.42796	1,820,220	$46,997	$15,387,742	$0.23045	**VGT Commodity**	
GLGT							
GAS COST	$8.05540						
FUEL 1.053%	$0.08571						
COMMODITY TRANSPORTATION	$0.00326					5 Revised Sheet 4	Jun 1, 1997
GRI	$0.00000					Contract	Jun. 1, 2004
ACA	$0.00170					18th Revised Sheet No. 7	Oct. 1, 2005
GLGT Commodity	$8.14607	962,512	$46,997	$7,887,683	$0.11813	**GLGT Commodity**	
CENTRA							
CENTRA TRANSMI: ($Cdn/103M3)	1.062					Sheet 1 (N.E.B.)	
Conversion x0.9306	$0.02486						
GAS COSTS	$8.17520						
CUSTOMS FEE	$0.00029						
CENTRA Commodity	$8.20035	1,391,502	$37,638	$11,448,433	$0.17145	**Centra Commodity**	
NMU Weighted Average gas cost - $/Dth		**6,677,305**	**$272,724**	**$50,217,177**	**$0.75206**	**NMU WACOG-$/therm**	
Total Annual Sales in therms		**66,773,050**					

MINNESOTA ENERGY RESOURCES - NMU

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
NOVEMBER 1, 2008

All costs in $/MMBtu	Last Rate Case G007 MR03-1372	Last Demand Change G006 M-06-XXXX Nov. 06	Last Demand Change G007 M-07-XXXX Nov. 07	Most Recent PGA Oct. 08	Current Proposal Effective Nov.1,2008	Result of Proposed Change: Change from Last Rate Case	Change from Last Demand Change	Change from Last PGA	Change from Last PGA $
1) General Service: Avg. Annual Use:				**143**	**Mcf**				
Commodity Cost	$2.3640	$7.3411	$6.9558	$6.5778	$7.4684	215.92%	69.53%	13.54%	$0.8906
Demand Cost	$1.3009	$1.2448	$1.0999	$1.1201	$1.0798	-17.00%	-17.76%	-3.60%	($0.0403)
Commodity Margin	$1.9411	$1.9411	$1.9411	$2.3126	$2.3126	19.14%	19.14%	0.00%	$0.0000
Total Cost of Gas	$5.6060	$10.5270	$9.9968	$10.0105	$10.8608	93.74%	49.92%	8.49%	$0.8503
Avg Annual Cost	$801.66	$1,505.36	$1,429.54	$1,431.50	$1,553.09	93.74%	49.92%	8.49%	$121.59
Effect of proposed commodity change on average annual bills:									$127.36
Effect of proposed demand change on average annual bills:									($5.76)
2) Large General Service: Avg. Annual Use:				**6,838**	**Mcf**				
Commodity Cost	$2.3640	$7.3411	$6.9558	$6.5778	$7.4684	215.92%	1.73%	13.54%	$0.8906
Demand Cost	$1.3009	$1.2448	$1.0999	$1.1201	$1.0798	-17.00%	-13.26%	-3.60%	($0.0403)
Commodity Margin	$1.9411	$1.9411	$1.9411	$2.3126	$2.3126	19.14%	19.14%	0.00%	$0.0000
Total Cost of Gas	$5.6060	$10.5270	$9.9968	$10.0105	$10.8608	93.74%	3.17%	8.49%	$0.8503
Avg Annual Cost	$38,333.83	$71,983.63	$68,358.12	$68,451.80	$74,266.15	93.74%	3.17%	8.49%	$5,814.35
Effect of proposed commodity change on average annual bills:									$6,089.92
Effect of proposed demand change on average annual bills:									($275.57)
3) SV Interruptible Service: Avg. Annual Use:				**7,982**	**Mcf**				
Commodity Cost	$2.3640	$7.3411	$6.9558	$6.5778	$7.4684	215.92%	1.73%	13.54%	$0.8906
Commodity Margin	$0.8500	$0.8500	$0.8500	$1.0127	$1.0127	19.14%	19.14%	0.00%	$0.0000
Total Cost of Gas	$3.2140	$8.1911	$7.8058	$7.5905	$8.4811	163.88%	3.54%	11.73%	$0.8906
Avg Annual Cost	$25,654.15	$65,381.36	$62,305.90	$60,587.37	$67,696.14	163.88%	3.54%	11.73%	$7,108.77
Effect of proposed commodity change on average annual bills:									$7,108.77
4) LV Interruptible Service: Avg. Annual Use:				**38,443**	**Mcf**				
Commodity Cost	$2.3640	$7.3411	$6.9558	$6.5778	$7.4684	215.92%	1.73%	13.54%	$0.8906
Commodity Margin	$0.2850	$0.2850	$0.2850	$0.3395	$0.3395	19.12%	19.12%	0.00%	$0.0000
Total Cost of Gas	$2.6490	$7.6261	$7.2408	$6.9173	$7.8079	194.75%	2.38%	12.87%	$0.8906
Avg Annual Cost	$101,835.51	$293,170.16	$278,358.07	$265,921.76	$300,159.10	194.75%	2.38%	12.87%	$34,237.34
Effect of proposed commodity change on average annual bills:									$34,237.34

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in
Docket No. E,G999/AA-05-1403

MERC-NMU

PRESENT AVERAGE COST OF GAS **EFFECTIVE: 1-Nov-08**

10/30/08
12:00 AM

N:Group/Rates/Gas/MERC/PGAC/2008/NMU1108

DEMAND

Contract Type / Northern Natural Gas (NNG)	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Rate Case Sales (therms)	Rate ($/therm)
TF12-B (Max Rate)	Annual	2,653	12	$7.57760	$241,240.47	54,645,910	$0.00441
TF12-V (Max Rate)	Annual	6,643	12	$9.09260	$724,825.70	54,645,910	$0.01326
TF5 (Max Rate)	Winter	5,451	5	$15.15300	$412,995.02	54,645,910	$0.00756
TFX5 (Max Rate)	Winter	6,139	5	$15.15300	$465,121.34	54,645,910	$0.00851
SMS	Annual	2,143	12	$2.18000	$56,060.88	54,645,910	$0.00103
FDD - Reservation	Annual	7,128	12	$1.71400	$146,608.70	54,645,910	$0.00268
FDD - Storage Cycle	Annual	82,188	5	$0.35670	$146,582.30	54,645,910	$0.00268
FDD - Reservation	Annual	524	12	$3.31570	$20,849.12	54,645,910	$0.00038
FDD - Storage Cycle	Annual	6,047	5	$0.69010	$20,865.17	54,645,910	$0.00038
FDD - Reservation	Annual	328	12	$1.71400	$6,746.30	54,645,910	$0.00012
FDD - Storage Cycle	Annual	3,779	5	$0.35670	$6,739.85	54,645,910	$0.00012
LS Power	Winter	2,777	3	$4.34625	$36,208.61	54,645,910	$0.00066
Exchange	Annual	0	1	$2.00350	$0.00	54,645,910	$0.00000
NNG Demand					**$2,284,843**	54,645,910	**$0.04181**
Viking (VGT)							
FT	Annual	7,966	12	$3.46710	$331,427.02	54,645,910	$0.00606
FT	Winter	5,902	5	$3.76710	$111,167.12	54,645,910	$0.00203
TF-12	Summer	926	12	$7.57760	$84,181.45	54,645,910	$0.00154
TF-5	Winter	2,089	5	$15.15300	$158,296.42	54,645,910	$0.00290
TFX-12	Summer	2,324	12	$9.62880	$268,493.51	54,645,910	$0.00491
TFX-5	Winter	563	5	$15.15300	$42,672.32	54,645,910	$0.00078
VGT Demand					**$996,238**	54,645,910	**$0.01823**
Great Lakes (GLGT)							
FT	Annual	10,130	12	$3.45800	$420,354.48	54,645,910	$0.00769
FT	Annual	1,178	12	$3.45800	$48,882.29	54,645,910	$0.00089
FT	Winter	2,138	5	$3.45800	$36,966.02	54,645,910	$0.00068
T	Summer	0	7	$10.27800	$0.00	54,645,910	$0.00000
FT	Annual	4,000	12	$3.45800	$165,984.00	54,645,910	$0.00304
GLGT Demand					**$672,187**	54,645,910	**$0.01230**
Centra							
FT	Annual	9,858	12	$1.23110	$145,634.21	54,645,910	$0.00267
FT	Annual	9,858	12	$4.53280	$536,212.11	54,645,910	$0.00981
Balancing	Annual	9,858	12	$4,500.00	$54,000.00	54,645,910	$0.00099
Centra Demand					**$735,846**	54,645,910	**$0.01347**
Nexen	Annual	684,604	1	$1.77	$1,211,749.08	54,645,910	$0.02217
Nexen Demand					**$1,211,749**	0	**$0.02217**
NMU DEMAND - $/Ccf					**$5,900,863**		**$0.10798**

For Joint Rate Demand				
Northern Natural Gas (NNG)				**54,645,910** **Annual Firm Sales in therms**
TF12-B (Max Rate)	Annual	2,653	12	
TF12-V (Max Rate)	Annual	6,643	12	
TF5 (Max Rate)	Winter	5,451	5	
TFX5 (Max Rate)	Winter	6,139	5	
			169,502	
Viking (VGT)				
FT	Annual	7,966	12	
TF-12	Summer	926	12	
TF-5	Winter	2,089	5	
TFX-12	Summer	2,324	12	
TFX-5	Winter	563	5	
			147,848	
Great Lakes (GLGT)				
FT	Annual	10,130	12	
FT	Annual	1,178	12	
FT	Winter	2,138	5	
			146,386	
Centra				
FT	Annual	9,858	12	
			118,296	
Total Demand Cost			**$5,900,863**	
Total Demand Weighted Vol in therms			**5,820,323**	
Total Joint Demand Rate $/therm				**$1.01384 /therm**

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Sarah J. Kerbeshian, being first duly sworn on oath, deposes and states that on the 12th day of August, 2009, the Response Comments of Minnesota Energy Resources Corporation were electronically filed with the Minnesota Public Utilities Commission and the Minnesota Department of Commerce. A copy of the filing was delivered by first class mail to the remaining individuals on the attached service list.

/s/ Sarah J. Kerbeshian

Subscribed and sworn to before me
this 12th day of August, 2009.

/s/ Paula R. Bjorkman
Notary Public, State of Minnesota

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