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June 17, 2009

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

RE: **Response Comments of the Minnesota Office of Energy Security**
Docket Nos. G007/M-08-1329 and G007,011/MR-08-836

Dear Dr. Haar:

On March 30, 2009, Minnesota Energy Resources Corporation-NMU (MERC-NMU or Company) submitted its *Reply Comments* in response to the Minnesota Office of Energy Security's (OES) March 4, 2009 *Comments* related to MERC-NMU's demand entitlement filing. Based on its review, the OES concludes that a response to MERC-NMU's *Reply Comments* is necessary to establish a complete record in this matter. As such, the OES requests that the Minnesota Public Utilities Commission (Commission) accept these *Response Comments* to MERC-NMU's *Reply Comments*.

Based on its review of MERC-NMU's *Reply Comments*, the OES recommends that the Commission:

- **approve** MERC-NMU's demand entitlement level without endorsing its design-day study analysis subject to the Commission's decisions in the pending G007/M-07-1402 and G007,011/GR-08-835 dockets;
- **require** MERC-NMU to provide additional evidence supporting the estimative power of its design-day study in its next demand entitlement filing;
- **reject** MERC-NMU's proposed 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 Purchased Gas Adjustment, presented in its March 30, 2009 *Reply Comments*, and instead;
- **approve** the OES's alternate cost recovery proposal presented in Table R-2;
- **require** MERC-NMU to remove all costs and volumes related to the FT0011 contract from its latest update, and any other 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; and
- **require** MERC-NMU to refund to its ratepayers the difference between the OES's cost recovery proposal and MERC-NMU's cost recovery proposal submitted on November 5, 2008 and charged in rates to its customers through the PGA since November 1, 2008.

The OES is available to answer any questions that the Commission may have.

Sincerely,

/s/ ADAM JOHN HEINEN
Rates Analyst
651-296-6329

AJH/jl
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

RESPONSE COMMENTS OF THE
MINNESOTA OFFICE OF ENERGY SECURITY

DOCKET NOS. G007/M-08-1329 AND G007,011/MR-08-836

I. BACKGROUND

The following rounds of comments have been submitted to the Minnesota Public Utilities Commission (Commission) in Minnesota Energy Resources Corporation-NMU's (MERC-NMU or Company) 2008-2009 demand entitlement filing:

- November 1, 2008, MERC-NMU's initial *Petition*;
- November 5, 2008, MERC-NMU's *Supplement*;
- March 4, 2009, Minnesota Office of Energy Security's (OES) *Comments*;
- March 30, 2009, MERC-NMU's *Reply Comments*; and
- June 17, 2009, OES's *Response Comments*.

In its March 30, 2009 *Reply Comments*, MERC-NMU provided additional information and responded to concerns raised by the OES in its March 4, 2009 *Comments*. The OES requested additional information to allow the OES to assess the reasonableness of MERC-NMU's proposal. The OES discusses the Company's responses below.

II. THE OES'S RESPONSE TO MERC-NMU'S MARCH 30, 2009 REPLY COMMENTS

A. MERC'S EXPLANATION OF ITS DESIGN-DAY RESULTS FOR ITS PURCHASED GAS ADJUSTMENT (PGA) SYSTEMS AND THE COMPANY'S CALCULATION OF ITS 2007-2008 HEATING SEASON DESIGN-DAY REQUIREMENT USING ITS CURRENT DESIGN-DAY METHODOLOGY

In its March 4, 2009 *Comments*, the OES recommended that MERC provide an explanation of why its current design-day analysis showed an increase in design-day volumes for its MERC-NMU, MERC-PNG Northern, and MERC-PNG Great Lakes PGA systems and a decrease in design-day volumes for its MERC-PNG Viking PGA system. In addition, the OES also recommended that MERC-NMU re-calculate its design-day requirement for the 2007-2008 heating season using its current design-day methodology.

In its *Reply Comments*, MERC-NMU states that when examining its new design-day methodology it is important to look at the total number of volumes estimated by its regression analysis and not just its firm throughput estimates. In support of this statement, the Company used its current design-day methodology to estimate total system throughput for the 2007-2008 heating season. When using its current methodology for the 2007-2008 heating season, MERC-NMU was able to produce total throughput estimates that are comparable to the same estimates for the 2008-2009 heating season.[1] MERC-NMU then explains that the difference between its old design-day methodology and its current methodology is the Company's treatment of transport and interruptible sales volumes.

However, in an effort to respond to the OES's original questions, MERC-NMU states that the necessary data to estimate previous design-days with its current design-day analysis is unavailable and, as such, the Company is unable to address why there were significant differences in the design-day changes between PGA systems and fully compare the design-day estimates for both heating seasons. MERC-NMU produces a design-day estimate for the 2007-2008 heating season using its current design-day methodology; however, given the data issues expressed by the Company, there is not complete support in this docket for the Company's analysis. Ideally, MERC-NMU should initiate a new design-day methodology when the Company has the ability to test the new approach against previous results and weather conditions. Given the large changes in design-day estimates, the OES is concerned that firm system performance may be hindered on a peak-day. However, the OES notes, as discusses both in our original *Comments* in this docket, and below, 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, as discussed further below.

B. MERC-NMU PEAK-DAY WEATHER ASSUMPTIONS

In its original *Comments*, the OES expressed concern that the weather data for the Fargo weather station, which MERC-NMU uses in the calculation of its design-day weather data, did not meet the Commission's prescribed peak-day weather standard of -25°F for 24 hours and recommended that the Company provide a discussion of whether its peak-day weather assumptions are sufficient to meet the Commission's peak-day standard. In its *Reply Comments*, MERC-NMU

[1] These results are presented in the table at the top of page 2 in MERC-NMU's March 30, 2009 *Reply Comments*.

states that Fargo was not the sole weather station that it used to determine its design-day weather coefficients. The Company further states that it uses wind adjusted heating degree days (HDDs), which produce weather results that are greater than the Commission's prescribed peak-day standard.

Although it is true that the Fargo weather station data is not the only data used to calculate the MERC-NMU design-day, the OES notes that it is still a component used in the calculation of the weather coefficient for the entire PGA system. MERC-NMU states in its *Reply Comments* that it used adjusted HDDs when determining its design-day weather coefficients; however, the OES's concern with the Fargo weather data is not related to adjusted HDDs. In the table found on page 6 of MERC-NMU's November 1, 2008 *Petition*, the OES notes that although Fargo's weather station 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.[2] The effect of wind chill on heating load is contingent on many different factors (*e.g.,* building age, tightness of construction) and, as such, wind chill affected weather data may not produce the most accurate estimates of load on a Commission prescribed peak-day.

The OES notes the 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.[3] 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. MERC-NMU has offered to meet with the OES regarding several aspects of MERC-NMU's method. The OES agrees that such a meeting would likely be helpful. The OES notes that Commission Staff may wish to attend as well.

C. OES'S REQUEST FOR INFORMATION RELATED TO MERC-NMU'S SALES GROWTH RATE

In its initial *Petition*, MERC-NMU stated that it estimated sales growth in its current demand entitlement filing using a different technique than it had in previous demand entitlement filings. The Company did not provide the data necessary to replicate these growth rates and, as such, the OES recommended that MERC-NMU provide these growth rate data in its *Reply Comments*. In its *Reply Comments*, MERC-NMU provided this growth rate information, and the assumptions necessary to replicate its growth rates, and, after reviewing these data, the OES believes that MERC-NMU's growth rate estimates are reasonable.

[2] Without the wind adjustment, the HDDs at the Fargo weather station would be 81 or 9 degrees less than the Commission design-day standard.
[3] MERC-NMU, and its predecessor Aquila Networks-NMU, have had Commission approval to use wind adjusted HDDs since the early 1990s; as a result, facts may be different for MERC-NMU than Greater Minnesota Gas.

D. MERC-NMU'S TREATMENT OF FARM TAP CUSTOMERS IN ITS DESIGN-DAY CALCULATIONS

MERC-NMU stated in its original *Petition* that it modified its treatment of farm tap customers in its current demand entitlement filing. The Company did not elaborate on this statement; therefore, the OES recommended in its *Comments* that MERC-NMU provide a detailed discussion of how farm tap customers effect design-day calculations in its *Reply Comments*. In response, MERC-NMU explained in greater detail how farm tap customers are accounted for and how these volumes are treated in the design-day calculation. Based on this response, the OES does not have any further concerns related to MERC-NMU's treatment of farm tap customers in its design-day calculations at this time.

E. MERC-NMU SYSTEM PERFORMANCE DURING THE 2008-2009 HEATING SEASON

In its March 4, 2009 *Comments*, the OES noted that MERC-NMU service territory had experienced relatively cold weather conditions during the 2008-2009 heating season. Given these weather events, the OES recommended that the Company provide information related to the performance of its natural gas system during the 2008-2009 heating season. In response, MERC-NMU provided the requested information and included a discussion of its system performance during the most recent heating season. In its *Reply Comments*, the Company states that it does not make nominations based on NMU or PNG customers but rather on a full system level for each pipeline on its distribution system. Further, MERC-NMU states that during the most recent heating season it nominated adequate capacity to meet system requirements and that at no point during the heating season did the Company have to fully utilize its firm entitlement capacity.

Based on its review of the Company's Attachments 8 and 9 filed on March 30, 2009, the OES cannot fully substantiate MERC-NMU's system performance discussion. While examining the peak-day data provided in Attachment 8, the OES notes that on several occasions during the 2008-2009 heating season, the Company's total system nominations were not sufficient to meet total system usage. Because these data contains both firm and interruptible customer information, it is not possible to determine whether there were any difficulties serving firm customers. However, the OES notes that MERC-NMU states on page 6 of its *Reply Comments* that "MERC did not fully utilize all of its firm capacity on any of the days." Further, third-party nominated volumes make up a significant amount of total nominated volumes, which suggests that interruptible load was available on the system at levels which, had there been a need for interruptions for reliability reasons, would have prevented any need to interrupt firm customers. Thus, it appears that the Company has sufficient firm demand volumes to meet the needs of its firm customers. The OES notes, 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 is also concerned that the Company did not provide usage data that was specific to each of its PGA systems. Without these PGA system specific data, or at the minimum estimates, the OES is unable to determine whether the Company's PGA system would have adequate firm entitlements on a Commission prescribed peak-day.

In MERC-NMU's companion docket, G011/M-08-1328, the Company was able to offer several options to serve firm load if needed next year. However, it is not clear whether such options would be available to serve MERC-NMU's firm customers. The OES recommends 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 notes 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.

Based on the information in Attachments 8 and 9, and MERC-NMU's inability to fully compare its design-day estimates against previous heating seasons as discussed in Section II, Subsection A, the OES now recommends that the Commission approve MERC-NMU's demand entitlement level without endorsing its design-day study analysis. Although the OES 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 it recommends 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.

F. MERC-NMU'S TREATMENT OF FDD STORAGE IN ITS COST RECOVERY PROPOSAL

In its March 4, 2009 *Comments*, the OES noted that there were some inconsistencies in the values presented for these contracts in MERC-NMU's initial *Petition* and that the Company had not moved the cost recovery of its FDD Storage contracts to the commodity cost recovery portion of the monthly PGA, rather than the demand cost recovery portion, as it had proposed in its March 7, 2008 *Supplemental Comments* in Docket No. G007/M-07-1402. In response to the OES's concerns, MERC-NMU identified which FDD Storage values were appropriate to use in the OES's cost recovery analysis and provided a discussion of why it included FDD Storage costs in the demand cost recovery portion of the PGA. In this discussion, MERC-NMU states that it did not include FDD Storage costs in the commodity cost recovery portion of the PGA, as it had proposed in the previous demand entitlement filing, since the Commission has not issued an *Order* in Docket No. G007/M-07-1402. However, MERC-NMU did file on March 30, 2009 with the Commission revised Attachments 4 and 7 from its original *Petition* that shift these FDD Storage costs to the commodity recovery portion of the PGA.[4]

[4] Please note that MERC-NMU only filed a revised Attachment 4, page 1 of 2. The Company did not include page 2 of this Attachment 4 in its filing.

Based on its review of MERC-NMU's revised Attachments 4 and 7, the OES is unable to replicate MERC-NMU's total demand cost recovery figure ($1.0161 per Mcf). Using the annual 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 estimates a total demand cost recovery figure of $0.99163 (OES Attachment S-2). The OES discusses this difference and its overall cost recovery proposal in Section III below.

G. MERC-NMU'S TREATMENT OF ITS FT0011 CONTRACT IN DOCKET NO. G007,011/MR-08-836 (BASE COST OF GAS FILING)

In its March 4, 2009 *Comments*, the OES noted that MERC-NMU had terminated its FT0011 contract and refunded any related costs to its ratepayers; however, based on an examination of the total volumes in the base cost of gas calculation, the OES observed that volumes related to this contract were included in the cost calculation. Given this observation, the OES recommended that the Commission require MERC, in its final compliance in Docket No. G007,011/MR-08-836, to remove all costs and volumes related to the FT0011 contract from its final base cost of gas calculations.

In its *Reply Comments*, MERC-NMU explains that at the time it filed its initial base cost of gas filing, the OES and Company were in dispute over whether the volumes associated with the FT0011 contract were appropriate for recovery or not. However, after this initial filing was made, the Company agreed to discontinue recovery and refund these charges. MERC-NMU explains that it made additional filings in this docket and it acknowledges that these base cost of gas calculations include costs and volumes associated with the FT0011 contract.[5] Further, the Company states that the annual costs in the base cost of gas filing associated with the FT0011 account for approximately $62,000 of total annual gas costs on this PGA system. When this amount is compared to MERC-NMU's annual sales projection of 69,321,120 therms, it translates into per therm cost of $0.00089.

Given the above discussion, the OES recommends that the Commission require MERC-NMU, as proposed by the Company, 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.

[5] MERC-NMU filed updated base cost of gas values on September 19, 2008; October 29, 2008; December 22, 2008; and January 27, 2009 in Docket No. G007,011/MR-08-836.

H. MERC-NMU'S PGA COST RECOVERY

Through its analysis of MERC-NMU's initial *Petition*, the OES noted that the revised spreadsheets filed by MERC-NMU on November 5, 2008 did not include evidence substantiating the demand cost figures reported by the Company. Based on the change in demand costs included in the revised spreadsheets and the Company's cost recovery proposal for its storage-related contracts, the OES withheld recommendation on MERC-NMU's cost recovery proposal until the Company could provide sufficient evidence supporting its cost recovery proposal.

In response to this concern, the Company states in its *Reply Comments* that the demand costs reported in its original Attachment 4 and Attachment 7 were placeholders and did not represent calculated demand costs, and the cost estimates provided in its November 5, 2008 are in fact the calculated demand costs. However, based on its review of the information provided in its *Reply Comments*, the OES still cannot 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 Section II, Subsection F above, the OES recommends that the Commission reject MERC-NMU's proposed 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* since MERC-NMU has been unable to substantiate its cost calculations. Instead, the OES proposes a cost recovery proposal, based on the Company's filed entitlement numbers, in Section III below.

III. THE OES'S COST RECOVERY PROPOSAL

For comparative purposes, the OES includes in Table R-1 below the Company's cost recovery proposal submitted in its November 5, 2008 *Supplement*. When analyzing the effects associated with its demand entitlement changes, MERC-NMU calculates the following changes effective November 1, 2008 and proposes to begin recovering the costs associated with the requested demand entitlement changes in the monthly PGA effective November 1, 2008. These changes result in the following bill impacts:

Table R-1 MERC-NMU's November 5, 2008 PGA Cost Recovery Proposal Monthly Rate Impact Compared to October 2008 PGA							
Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Demand Change ($/Mcf)	Demand Change (Percent)	Total Change ($/Mcf)	Total Change (Percent)	Effect on Annual Bill
General Service	$0.8906	13.54	$(0.0403)	(3.60)	$0.8503	8.49	$121.60
Large General Service	$0.8906	13.54	$(0.0403)	(3.60)	$0.8503	8.49	$5,814.35
Small Vol. Interruptible	$0.8906	13.54	$0.0000	0.00	$0.8906	11.73	$7,108.77
Large Vol. Interruptible	$0.8906	13.54	$0.0000	0.00	$0.8906	12.87	$34,237.34

As shown above, and in MERC-NMU's Attachment 7 filed on November 5, 2008, the Company's proposed entitlement levels result in the following estimated annual bill impacts:

- an increase of approximately $121.60 per year, or 8.49 percent, for an average General Service customer who consumes 143 Mcf annually;
- an increase of approximately $5,814.35 per year, or 8.49 percent, for an average Large General Service customer who consumes 6,838 Mcf annually;
- an increase of approximately $7,108.77 per year, or 11.73 percent, for an average Small Volume Interruptible customer who consumes 7,982 Mcf annually; and
- an increase of approximately $34,237.34 per year, or 12.87 percent, for an average Large Volume Interruptible customer who consumes 38,443 Mcf annually.

Based on the concerns that the OES discusses in Section II, Subsections F and H above, the OES proposes a cost recovery proposal using the same demand entitlement levels, and changes, proposed by MERC-NMU in its November 1, 2008 *Petition* and discussed in the OES's March 4, 2009 *Comments*. The OES's cost recovery proposal is different from that presented in MERC-NMU's November 5, 2008 filing because of the OES's treatment of FDD storage costs and how the OES determines bill impacts. First, unlike the Company, the OES holds the weighted average cost of gas constant, so as to isolate the increases in total gas costs associated solely with the demand cost of gas. Second, while the OES understands why MERC-NMU calculated FDD Storage costs in the manner used in the November 5, 2008 filing, the OES expects that FDD Storage costs are likely to be recovered from all customers. As a result, the OES includes FDD Storage related costs in the commodity cost recovery portion of the PGA, as proposed by MERC-NMU in its March 7, 2008 *Supplemental Comments* in Docket No. G007/M-07-1402. The OES's bill impacts are presented in Table R-2 below:

Table R-2 OES's Modified PGA Cost Recovery Proposal Monthly Rate Impact Compared to October 2008 PGA							
Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Demand Change ($/Mcf)	Demand Change (Percent)	Total Change ($/Mcf)	Total Change (Percent)	Effect on Annual Bill
General Service	$(0.0435)	(0.65)	$0.0057	0.58	$(0.0378)	(0.39)	$(5.41)
Large General Service	$(0.0435)	(0.65)	$0.0057	0.58	$(0.0378)	(0.39)	$(258.68)
Small Vol. Interruptible	$(0.0435)	(0.65)	$0.0000	0.00	$(0.0435)	(0.58)	$(347.62)
Large Vol. Interruptible	$(0.0435)	(0.65)	$0.0000	0.00	$(0.0435)	(0.58)	$(1,674.19)

Note: The changes in commodity costs presented in Table R-2 are the result of a decrease in MERC-NMU's FDD Storage levels and cost contracts.

As shown above, and in OES Attachment R-1, the OES's demand entitlement analysis results in the following estimated annual bill impacts:

- a decrease of approximately $5.41 per year, or 0.39 percent, for an average General Service customer who consumes 143 Mcf annually;
- a decrease of approximately $258.68 per year, or 0.39 percent, for an average Large General Service customer who consumes 6,838 Mcf annually;
- a decrease of approximately $347.62 per year, or 0.58 percent, for an average Small Volume Interruptible customer who consumes 7,982 Mcf annually; and
- a decrease of approximately $1,674.19 per year, or 0.58 percent, for an average Large Volume Interruptible customer who consumes 38,443 Mcf annually.

Given the concerns expressed by the OES as they relate to MERC-NMU's cost recovery proposal, the OES recommends that the Commission approve its alternate cost recovery proposal presented in Table R-2. Once the Commission decides the issues in Docket Nos. G007/M-07-1402 and G007,011/GR-08-835, the OES recommends that the Commission require MERC-NMU to refund to its ratepayers the difference between the OES's cost recovery proposal and MERC-NMU's cost recovery proposal submitted on November 5, 2008 and charged in rates to its customers through the PGA since November 1, 2008.

IV. OES RECOMMENDATIONS AND CONCLUSIONS

Based on its review of MERC-NMU's *Reply Comments*, the OES recommends that the Commission:

- **approve** MERC-NMU's demand entitlement level without endorsing its design-day study analysis subject to the Commission's decisions in the pending G007/M-07-1402 and G007/011/GR-08-835 dockets;
- **require** MERC-NMU to provide additional evidence supporting the estimative power of its design-day study in its next demand entitlement filing;
- **reject** MERC-NMU's proposed 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 Purchased Gas Adjustment, presented in its March 30, 2009 *Reply Comments*, and instead;
- **approve** the OES's alternate cost recovery proposal presented in Table R-2;
- **require** MERC-NMU to remove all costs and volumes related to the FT0011 contract from its latest update, and any other 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; and
- **require** MERC-NMU to refund to its ratepayers the difference between the OES's cost recovery proposal and MERC-NMU's cost recovery proposal submitted on November 5, 2008 and charged in rates to its customers through the PGA since November 1, 2008.

/jl

OES Attachment R-1
Effect of MERC-NMU's Proposed Demand Entitlement Changes as Modified by the OES

General Service	Last Rate Case GR-03-1372	Last Demand Filing M-07-1402	October PGA 2008	October PGA with Proposed Demand Changes	% Change from Last Rate Case	% Change from Last Demand Filing	% Change from Oct. PGA	$ Change from Oct. PGA
Commodity Cost	$2.3640	$6.9558	$6.6836	$6.6400	180.88%	-4.54%	-0.65%	($0.0435)
Demand Cost	$1.3009	$0.9923	$0.9859	$0.9916	-23.77%	-0.06%	0.58%	$0.0057
Margin	$1.9411	$1.9411	$1.9411	$1.9411	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.6060	$9.8892	$9.6106	$9.5728	70.76%	-3.20%	-0.39%	($0.0378)
Average Annual Use	**143**	**143**	**143**	**143**				
Average Annual Cost of Gas	$801.66	$1,414.15	$1,374.31	$1,368.90	70.76%	-3.20%	-0.39%	($5.41)

Large General Service	Last Rate Case GR-03-1372	Last Demand Filing M-07-1402	October PGA 2008	October PGA with Proposed Demand Changes	% Change from Last Rate Case	% Change from Last Demand Filing	% Change from Oct. PGA	$ Change from Oct. PGA
Commodity Cost	$2.3640	$6.9558	$6.6836	$6.6400	180.88%	-4.54%	-0.65%	($0.0435)
Demand Cost	$1.3009	$0.9923	$0.9859	$0.9916	-23.77%	-0.06%	0.58%	$0.0057
Margin	$1.9411	$1.9411	$1.9411	$1.9411	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.6060	$9.8892	$9.6106	$9.5728	70.76%	-3.20%	-0.39%	($0.0378)
Average Annual Use	**6,838**	**6,838**	**6,838**	**6,838**				
Average Annual Cost of Gas	$38,333.83	$67,622.08	$65,717.15	$65,458.46	70.76%	-3.20%	-0.39%	($258.68)

SV Interruptible Service	Last Rate Case GR-03-1372	Last Demand Filing M-07-1402	October PGA 2008	October PGA with Proposed Demand Changes	% Change from Last Rate Case	% Change from Last Demand Filing	% Change from Oct. PGA	$ Change from Oct. PGA
Commodity Cost	$2.3640	$6.9558	$6.6836	$6.6400	180.88%	-4.54%	-0.65%	($0.0435)
Commodity Margin	$0.8500	$0.8500	$0.8500	$0.8500	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$3.2140	$7.8058	$7.5336	$7.4900	133.04%	-4.05%	-0.58%	($0.0435)
Average Annual Use	**7,982**	**7,982**	**7,982**	**7,982**				
Average Annual Cost of Gas	$25,654.15	$62,305.90	$60,132.96	$59,785.34	133.04%	-4.05%	-0.58%	($347.62)

LV Interruptible Service	Last Rate Case GR-03-1372	Last Demand Filing M-07-1402	October PGA 2008	October PGA with Proposed Demand Changes	% Change from Last Rate Case	% Change from Last Demand Filing	% Change from Oct. PGA	$ Change from Oct. PGA
Commodity Cost	$2.3640	$6.9558	$6.6836	$6.6400	180.88%	-4.54%	-0.65%	($0.0435)
Commodity Margin	$0.2850	$0.2850	$0.2850	$0.2850	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$2.6490	$7.2408	$6.9686	$6.9250	161.42%	-4.36%	-0.62%	($0.0435)
Average Annual Use	**38,443**	**38,443**	**38,443**	**38,443**				
Average Annual Cost of Gas	$101,835.51	$278,358.07	$267,892.74	$266,218.54	161.42%	-4.36%	-0.62%	($1,674.19)

October Change Summary	Commodity Change $/Mcf	Commodity Change %	Demand Change $/Mcf	Demand Change %	Total Change $/Mcf	Total Change %	Average Annual Change
General Service	($0.0435)	-0.65%	$0.0057	0.58%	($0.0378)	-0.39%	($5.41)
Large General Service	($0.0435)	-0.65%	$0.0057	0.58%	($0.0378)	-0.39%	($258.68)
SV Interruptible Service	($0.0435)	-0.65%	$0.0000	0.00%	($0.0435)	-0.58%	($347.62)
LV Interruptible Service	($0.0435)	-0.65%	$0.0000	0.00%	($0.0435)	-0.62%	($1,674.19)

Note: The October commodity cost figure of $6.6836 includes $0.10577 in costs related to storage contracts per the Company's supplemental comments filed on April 7, 2008 in Docket No. G007/M-07-1402.
Note: The November commodity cost figure of $6.6400 includes $0.06222 in costs related to storage contracts per the Company's supplemental comments filed on April 7, 2008 in Docket No. G007/M-07-1402.

OES Attachment R-2
MERC-NMU's Rate Impact Analysis as Modified by the OES

		Entitlements	Rate	Multiplied by	Total Annual Cost	Per Mcf	Tariff No./contract
NNG Pipeline							
TF 12 B		2,653	$7.5776	12	$241,240.47	$0.04308	Sheet No. 50
TF 12 V		6,643	$9.0926	12	$724,825.70	$0.12945	Sheet No. 50
TF 5		5,451	$15.1530	5	$412,995.02	$0.07376	Sheet No. 50
TFX 5		6,139	$15.1530	5	$465,121.34	$0.08307	Sheet No. 50
LS Power		2,777	$4.3463	3	$36,209.03	$0.00647	
TFX-Offpeak (Apr/Oct)		0	$2.4333	1	$0.00	$0.00000	Contract
TFX-Offpeak (Apr/Oct)		0	$5.6170	1	$0.00	$0.00000	Contract
TFX-Offpeak (Apr/Oct)		0	$5.6170	7	$0.00	$0.00000	Contract
TFX-Offpeak (May-Sept)		0	$5.6170	5	$0.00	$0.00000	Contract
Peak Capacity		0	$4.5600	5	$0.00	$0.00000	Sheet Nos. 50 &51
NNG Demand					**$1,880,391.55**	**$0.33582**	
NNG 3-Party demand							
Call Options Premium		0	$0.0000	1	$0.00	$0.00000	Contract
Upstream Demand (Storage) Costs							
Great Lakes		0	$3.4580	12	$0.00	$0.00000	Sheet 4
FDD-Storage Res		7,128	$1.7140	12	$146,608.70	$0.02618	Sheet No. 55
FDD-Storage Cycle Vol		82,188	$0.3567	5	$146,582.30	$0.02618	Sheet No. 55
FDD LS		328	$1.7140	12	$6,746.30	$0.00120	
FDD LS		3,779	$0.3567	5	$6,739.85	$0.00120	
FDD-Reservation		524	$3.3157	12	$20,849.12	$0.00372	
FDD-Storage Cycle		6,047	$0.6901	5	$20,865.17	$0.00373	
Nexen Storage Capacity		0	$0.5683	1	$0.00	$0.00000	Contract
NGPL		0	$0.4908	1	$0.00	$0.00000	Contract
NNG Storage					**$348,391.45**	**$0.06222**	
Viking Pipeline							
FTA		7,966	$3.4671	12	$331,427.02	$0.05919	Viking Sheet No. 5B
FT-A Zone 1-1 Backhaul		5,902	$3.7671	5	$111,167.12	$0.01985	Viking Sheet No. 5D
NNG TF12 Chisago (112495)		926	$7.5776	12	$84,202.29	$0.01504	Sheet No. 50
NNG TF5 Chisago (112486)		2,089	$15.1530	5	$158,273.09	$0.02827	
NNG TFX5 Chisago (112495)		563	$15.1530	5	$42,655.70	$0.00762	Sheet No. 50
NNG TFX12 Chisago (112486)		2,324	$9.6288	12	$268,527.97	$0.04796	
DDS		0	$1.0000	12	$0.00	$0.00000	Viking Sheet No. 5H
Tenaska PSO		0	$1.0500	1	$0.00	$0.00000	Contract
VGT Demand					**$996,253.19**	**$0.17792**	
GLGT Pipeline							
FT-0016		10,130	$3.4580	12	$420,354.48	$0.07507	GLGT Sheet 4
FT-0155-12		1,178	$3.4580	12	$48,882.29	$0.00873	
FT-0155-5		2,138	$3.4580	5	$36,966.02	$0.00660	GLGT Sheet 4
T		4,000	$3.4580	12	$165,984.00	$0.02964	
Tenaska PSO		0	$1.0500	1	$0.00	$0.00000	Contract
Nexen Storage		0	$0.5683	1	$0.00	$0.00000	
GLGT Demand					**$672,186.79**	**$0.12005**	
CENTRA Pipeline							
CENTRA Transmission ($cdn/103M3)			$166.3160				
Centra Transmission		9,858	$4.5328	12	$536,212.11	$0.09576	Sheet 1 (N.E.B.)
CENTRA-Boise		0	$13.5000	4	$0.00	$0.00000	Contract
Tenaska PSO		0	$0.0000	1	$0.00	$0.00000	Contract
Union Balancing		9,858	$0.4565	12	$54,002.12	$0.00964	Contract
Centra MN Pipelines		9,858	$1.2311	12	$145,634.21	$0.02601	Sheet 4
Centra Demand					**$735,848.44**	**$0.13142**	
Exchange and Balancing Agreements							
Nexen Exchange		684,604	$1.7700	1	$1,211,749.08	$0.21641	Contract
Tenaska PSO		0	$2.0035	1	$0.00	$0.00000	
SMS		2,143	$2.1800	12	$56,060.88	$0.01001	
Total Exchange and Balancing					**$1,267,809.96**	**$0.22642**	
TOTAL DEMAND					**$5,552,489.93**	**$0.99163**	
TOTAL STORAGE (Calculated as Commodity)					**$348,391.45**	**$0.06222**	

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, 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 Office of Energy Security
Response Comments

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

Dated this **17th** day of **June**, **2009**

/s/Sharon Ferguson

G007/M-08-1329

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