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March 30, 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-PNG for Approval of a Change in Demand Entitlement for its Northern Natural Gas Transmission System
Docket No. G011/M-08-1328

Dear Dr. Haar:

Enclosed please find the Reply Comments of Minnesota Energy Resources Corporation ("MERC") in the above-referenced docket.

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-PNG for Approval of a Change in Demand Entitlement for its Northern Natural Gas Transmission System

Docket No. G011/M-08-1328

REPLY COMMENTS OF
MINNESOTA ENERGY RESOURCES CORPORATION

Minnesota Energy Resources Corporation-PNG ("MERC" or "Company") submits to the Minnesota Public Utilities Commission ("Commission") these Reply Comments in response to the March 4, 2009 Comments of the Minnesota Office of Energy Security ("OES") in the above referenced matter.

A. <u>Design-Day Study</u>

1. The OES noted that using the same design-day calculation methodology, the Company proposes significant increases in its design-day requirement for its MERC-PNG Northern PGA system, MERC-PNG Great Lakes PGA system, and for its MERC-NMU PGA system, while at the same time the Company proposes a significant decrease in the design-day requirement for its MERC-PNG Viking PGA system. The OES requested that MERC provide a detailed explanation of this result in its Reply Comments.

Response

MERC believes the important point to focus on that supports the new methodology is the result when regressing total volumes. The following table indicates the total regressed results for each MERC system utilizing the 2008-2009 methodology for the 2007-2008 season compared to the 2008-2009 season:

System	2007-2008 Total Point Estimate	2008-2009 Total Point Estimate	Variance	Variance %
PNG-GLGT	11,529	12,159	630	5.46%
PNG-NNG	251,200	248,585	(2,615)	-1.04%
PNG-VGT	9,877	10,038	161	1.63%
NMU	84,763	84,632	(131)	-0.15%

As the data shows, there is not a large variance from one season to another utilizing the new methodology. MERC believes this is an important starting point to support the methodology. The major differences are based upon the methodology of deducting interruptible and transportation volumes. The new methodology requires taking the peak month consumption for interruptible and transportation customer and dividing by twenty (20) days, then dividing by ten (10) to convert to Dth. This approach calculates a Maximum Daily Quantity (MDQ) to be subtracted from the total regressed point estimate. In addition, MERC adds back the firm contracted volumes for the Joint Rate customers to calculate design day.

Unfortunately, MERC was not able to simulate the same methodology for calculating MDQ volumes to deduct for the 2007-2008 season because the data was not available in the same format as the data for 2008-2009 season. Without having an equal simulation, MERC cannot adequately address why PNG-GLGT, PNG-NNG and NMU design day increased and PNG-VGT decreased. MERC feels confident that there is adequate capacity to meet customer requirements as filed but would appreciate the opportunity to meet and discuss the new methodology with OES.

2. The OES also recommended that the Company recalculate the design day requirements in Docket No. G011/M-07-1405 for the 2007-2008 season using the approach used by the Company in the current docket. The OES stated that this information would help confirm whether the Company's revised method still ensures reliable peak day firm service.

Response

MERC completed the design day analysis for the winter of 2007-2008 utilizing the new design day methodology. The data utilized to subtract out the interruptible and transportation volumes for 2007-2008 was not available in the same format as it was in 2008-2009, so MERC was not able to simulate exactly as it did in the 2008-2009 design day. The resulting 2007-2008 design day requirements is 265,196 Dth. MERC's design day requirement for the 2008-2009 winter is 225,396 Dth. MERC believes the important point to focus on that supports the new methodology is the result when regressing total volumes. The total regressed volumes result in a point estimate of 251,200 Dth for the recalculated 2007-2008 winter compared to 248,585 Dth for the 2008-2009 winter. Please see Attachment 1 (MERC 2007&08 Peak Day Forecast Recalculation Using 2008&09 Methodology) and Attachment 2 (PNG-NNG Winter 2007&08 Peak Day Re-Run).

3. The OES noted that MERC used forecasted changes in sales volumes to estimate its growth rate but did not provide these forecasted volumes in its Petition. The OES

recommended that the Company provide these data in its Reply Comments, along with any, and all, models, data, and assumptions necessary to replicate the growth rate.

Response

Please see Attachment 3 (MERC 2009 Design Day Growth Factors) for the growth rate data.

4. The OES discussed a smaller adjustment MERC undertook with respect to its farm tap customers. The OES recommended that MERC provide a full discussion of the changes to the design-day related to these customers and whether it classifies farm taps as firm or non-firm customers.

Response

MERC has both firm and interruptible farm tap customers. The volumes from farm tap customers were included in the total throughput numbers which were regressed to establish a point estimate. Volumes for interruptible farm tap customers would have been reflected in the MDQ calculation explained in the response to paragraph 1 which was subtracted from the total regressed point estimate. There were no farm tap customers on a Joint Rate. If there had been any farm tap customers that were on a Joint Rate, the firm portion would be added to the total regressed point estimate.

5. The OES noted that the Company's service territory has experienced two extreme cold weather events since the Petition was filed, one in December 2008 and one in January 2009. Considering the recent cold weather and the changes in design-day calculations, the OES recommended that MERC provide the following in its Reply Comments:

a) a full discussion of MERC-PNG's firm system performance during the two recent cold weather events during the current heating season;
b) a full discussion of MERC-PNG's interruptible customer tariffs and whether interruptions during the recent cold weather events occurred according to the Company's tariffs;
c) the dates that peak usage occurred during each month in the 2008-2009 heating season;
d) daily Heating Degree Days and Adjusted Heating Degree Days for each day during the 2008-2009 heating season;
e) total daily system throughput for each day during the 2008-2009 heating season; and
f) total Daily Firm Capacity (DFC) throughput volumes for each day during the 2008-2009 heating season.

Response

a) MERC experienced a sustained cold spell from January 12-16, January 23-26, and February 2-3, 2009. The table below shows the unadjusted/adjusted HDD, MERC contracted firm capacity, MERC nominations, third party nominations and total consumption for all customers (sales and transportation) on NNG. MERC does not nominate for PNG-NNG and NMU-NNG customers separately but nominates for MERC customers system-wide on the NNG pipeline.

Date	Unadj. HDD	Adj. HDD	Contracted Firm Capacity	MERC Nominated Capacity	Third Party Nomination	Total Noms	Actual Usage
1/12/2009	66	76	250,448	196,078	102,097	298,175	277,854
1/13/2009	76	82	250,448	208,842	123,493	332,335	314,231
1/14/2009	78	89	250,448	215,736	133,816	349,552	334,761
1/15/2009	80	87	250,448	210,842	148,739	359,581	344,185
1/16/2009	66	75	250,448	209,103	108,288	317,391	295,381
1/23/2009	63	73	250,448	197,702	90,361	288,063	269,200
1/24/2009	71	78	250,448	197,721	95,059	292,780	277,332
1/25/2009	64	69	250,448	189,721	115,638	305,359	289,579
1/26/2009	65	69	250,448	197,649	127,605	325,254	307,815
2/2/2009	63	73	250,448	184,795	119,244	304,039	294,812
2/3/2009	65	71	250,448	185,427	127,906	313,333	304,952

As the table indicates, during the coldest weather experienced during 2009, MERC had adequate nominated capacity to meet total system requirements. MERC did not fully utilize all of its firm capacity on any of the days. In addition, MERC has to make sure the total system is balanced on a daily basis, which is why MERC has to factor in third party nominations and compare to total system usage, not just firm usage.

b) MERC offers three levels of interruptible service: small volume, large volume and super large volume. The following describes the qualifying criteria for each level:

Super Large Volume: Customers must have capacity to take 4,000 dekatherm (Dth) or more per day and annual consumption of 1,200,000 Dth. *See* MERC Tariff, Sheet No. 5.50.

Large Volume: Customers must have taken 200 Dth or more per day at least once in a calendar year. *See* MERC Tariff, Sheet No. 8.02.

Small Volume: Customer's consumption should not exceed 199 Dth in any given day. *See* MERC Tariff, Sheet No. 8.02.

Interruptible service is offered to commercial/industrial customers. Interruptible customers agree to have their gas service interrupted, curtailed or discontinued at any time at the option of the Company. According to MERC's tariff, the largest customers are the first to be curtailed. There are penalties associated with unauthorized use of natural gas during a curtailment period, with penalty costs based on tariff language. *See* MERC Tariff, Sheet Nos. 8.41 – 8.42.

The follow curtailments occurred in December 2008:

- MERC-PNG NNG - 2 curtailments at North Branch and Webster, in accordance with the Company's tariff.

The following curtailments occurred in January 2009:

- MERC-NMU - 1 curtailment at Moose Lake, in accordance with the Company's tariff.
- MERC-PNG NNG - 7 curtailments at Eagan, Fairmont, Webster and Worthington, in accordance with the Company's tariff.

In all instances, large volume customers were curtailed before any small volume customers were required to curtail. No customers incurred any curtailment penalties.

c) The following table contains the total throughput peak day usage. The data is for all of NNG for PNG and NMU customers which include sales, interruptible and transportation volumes. Data is not yet available for March 2009.

Month/ Year	Peak Day	Peak Volume
Nov-08	11/20/08	268,017
Dec-08	12/15/08	351,996
Jan-09	01/15/09	344,185
Feb-09	02/03/09	304,952

d) MERC utilizes three weather station for forecasting purposes on the NNG pipeline, which are Cloquet, Minneapolis and Rochester, Minnesota. Please see Attachment 4 (MERC Winter 2008-09 NNG HDD Data).

e) Please see Attachment 4 (MERC Winter 2008-09 NNG HDD Data).

f) MERC is unable to provide firm volumes on a daily basis because many customers (e.g., residential, small volume) do not have daily telemetry. Information is only available on a daily basis for total throughput as shown on Attachment 4 (MERC Winter 2008-09 NNG HDD Data).

B. Peak-Day Sendout

The OES noted that the estimated total entitlement per forecasted design-day customer of 1.4447 Mcf/day is smaller than the all-time peak day sendout of 1.5175 Mcf/day, which indicates that the Company's proposal may not ensure system reliability on a peak day. The OES recommended that MERC provide in its Reply Comments a full discussion of why its total entitlement per customer estimate is sufficient to ensure system reliability on a Commission prescribed peak day of -25ºF for 24 hours.

Response

Assuming the 1.5175 Mcf/day and the customer count in the filing (156,973) this would mean a capacity need of 238,207 Dth, which is 11,422 Dth less than the currently contracted capacity of 226,785 Dth. MERC has seen the continued decline in use per customer, so it is doubtful the all-time peak would be 1.5175 Mcf/day. MERC has many options available to address this issue:

- MERC has contracted for an additional 4,227 Dth of capacity during the winter (November through March) starting November 1, 2009 on contract number 111866. This contract has a provision where MERC can acquire additional capacity every two years due to growth in the Twin Cities area. This is part of the Northern Natural Gas Northern Lights project.
- MERC's tariff allows calling transportation customers to their Maximum Daily Quantity (MDQ) as MERC deems necessary for operational integrity. The MDQ

is established by taking a customer's peak month, dividing by twenty (20) days, and then dividing by ten (10) to convert to a Dth. By requiring customers to be at MDQ this would increase the amount of supply purchased by third party(s).

- MERC has the capability to purchase a delivered service at MERC citygate(s).

Although MERC believes there is adequate capacity to meet peak day needs, MERC would appreciate the opportunity to meet with the OES to further discuss this matter and the level of firm entitlement that the OES believes to be prudent.

C. Demand Entitlement Changes

1. Based on an examination of MERC's attachments and PGA cost recovery proposal and information presented in the Company's last demand entitlement filing, the OES concluded that there was a discrepancy in MERC's proposed changes to its design-day capacity portfolio. In particular, the OES believes that MERC incorrectly stated that 10,837 Mcf/day relates to its TFX12 and TFX5 contracts, whereas the OES's review shows that these volumes relate to MERC's TFX7 contact. The OES noted that in the Company's previous demand entitlement filing and its current cost proposal, MERC lists the TFX7 contract as having a total volume amount of 10,837 Mcf/day. Based on this discrepancy, the OES withheld any recommendation on MERC's total peak day entitlement level proposal and recommended that MERC provide a full explanation in its Reply Comments of all discrepancies in its Petition, including, but not limited to, an explanation of why these discrepancies occurred and which volumes are appropriate to include in the demand entitlement analysis.

Response

The OES is correct that the 10,837 Mcf/day relates to the TFX12 and TFX5 for contract 111866, there is 8,635 Mcf/day TFX12 capacity at Eagan #1 and 2,202 TFX12 capacity at Rosemount #1A and not TFX7 as indicated in the filing. For purposes of transparency in the filing, MERC wanted to indicate how many months the discount rate of $2.2204 rate applies to those volumes. That rate is a discount MERC receives on the 10,837 Mcf/day during the summer months (April through October) from NNG, which is why MERC designated the volumes as TFX7.

2. After reviewing MERC's cost recovery proposal, the OES noted its belief that the Company is treating the cost recovery of its Firm Deferred Delivery (FDD) storage contracts incorrectly. In particular, FDD contracts are storage contracts that allow a utility to withdraw, or inject, natural gas into storage without any prior notice to the pipeline or storage company.[1] The OES noted that MERC agreed in its Supplemental Comments in Docket No. G011/M-07-1405 that it was appropriate to recover storage costs through the commodity rather than the demand portion of rates. Additionally, in its Reply Comments in that same docket, MERC requested a date of July 1, 2008 to shift these storage demand costs to the commodity portion of the PGA, but MERC has continued to recover FDD storage costs in the demand portion of the PGA. The OES recommended that MERC provide the following in its Reply Comments:

- a full discussion of why it continues to recover FDD storage costs through the demand cost recovery portion of the PGA rather than the commodity cost portion; and

[1] MERC notes that the FDD storage contracts do require MERC to provide notice to the pipeline before withdrawing or injecting natural gas into storage.

- updated exhibits and attachments that show the effects of moving the FDD storage costs to the commodity cost recovery portion of the monthly PGA.

Response

In an Order dated February 6, 2008 in Docket No. E,G-999/AA-06-1208, the Commission required all gas utilities to make a supplementary filing addressing the cost allocation of producer demand and storage costs in their demand entitlement dockets. The OES correctly noted that on March 7, 2008, MERC made a Supplemental Filing in Docket No. G011/M-07-1405 in which the Company proposed to include storage costs in the commodity rate rather than the demand rate. The OES agreed with MERC's proposal in its Comments dated June 12, 2008. In Reply Comments dated July 8, 2008, MERC requested that the Commission approve the proposed shift of storage costs from demand to commodity effective July 1, 2008. In Response Comments dated July 29, 2008, the OES recommended that the Commission approve the change effective April 1, 2008.

The Commission has not issued a decision in Docket No. G011/M-07-1405 and has not yet approved MERC's proposal to shift storage costs from the demand portion of rates to the commodity portion of rates. MERC therefore has not implemented its proposal in the monthly PGA because the Company is awaiting Commission approval of this change.

MERC, however, has provided with these Reply Comments updated Attachment 4, page 1 of 3, and Attachment 11 that show 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.

D. PGA Cost Recovery

Based on an examination of MERC's cost recovery proposal submitted in its initial filing and the revised spreadsheets filed on November 5, 2008, the OES noted that the estimated demand cost are not the same. The OES concluded that MERC did not provide support for the change in demand costs with its revised spreadsheets and was not able to complete its analysis. The OES withheld any recommendation on MERC's cost recovery proposal until MERC provides sufficient evidence supporting its demand cost changes and cost recovery proposal.

Response

When MERC made its initial filing on November 3, 2008, Attachment 4, page 1 of 2, and Attachment 7 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.

DATED this 30th day of March, 2009.

Respectfully submitted,

DORSEY & WHITNEY LLP

/s/ Michael J. Ahern_

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Attorney for MERC

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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 30th day of March, 2009, the Reply 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 30th day of March, 2009.

/s/ Alice A. Jaworski
Notary Public, State of Minnesota

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