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February 9, 2009

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

RE: **Comments of the Minnesota Office of Energy Security**
Docket No. G011/M-08-1331

Dear Dr. Haar:

Attached are the comments of the Minnesota Office of Energy Security (OES) in the following matter:

> A request (*Petition*) submitted by Minnesota Energy Resources Corporation-PNG (MERC-PNG or the Company) for approval of a change in demand entitlements on its Viking Gas Transmission Co. (Viking) pipeline system.

The *Petition* was filed on November 3, 2008 by:

> Greg Walters
> Regulatory and Legislative Affairs Manager
> Minnesota Energy Resources Corporation
> 519 1st Avenue SW
> PO Box 6538
> Rochester, MN 55903-6538

Based on its investigation, the OES recommends that the Commission:

- **approve, subject to adequate clarification by MERC-PNG**, the Viking system demand entitlement level**,** and subject to the Commission's pending decisions regarding the Contracted Demand (CD) units in Docket Nos. G011/M-07-1403 and G007,011/GR-08-835; and

- **approve, subject to adequate clarification by MERC-PNG**, the Purchase Gas Adjustment (PGA) recovery of costs associated with the Company's proposed demand entitlement level effective November 1, 2008, and subject to the Commission's pending decisions regarding the CD units in Docket Nos. G011/M-07-1403 and G007,011/GR-08-835.

Regarding the clarification noted above, the OES recommends that the Company provide the following in its *Reply Comments*:

- the daily weather data associated with MERC-PNG's all-time Viking Peak day;

- identification, by service and interstate pipeline contract, of the amount of CD units included in the proposed design-day and peak-day entitlement levels and in the previous levels indicated in OES Attachments 1 and 2;

- information as to whether the Company had sufficient capacity available for firm customers during the recent cold spells experienced in January and February 2009;

- results of recalculating the design day requirements in the 07-1403 docket for the 2007-2008 heating season using the same approach used by the Company in the current docket;

- a detailed explanation and reconciliation between the 59 customers' Daily Firm Capacity (DFC) data used in the calculation of the firm peak-day estimate and for the 24 customers shown in Exhibit GJW-1, Schedule 12 in Docket No. G007,011/GR-08-835;

- any other pertinent information regarding other factors which affect the level of demand by customers on MERC-PNG's Viking system; and

- the reasons associated with the specific proposed changes in demand volumes for MERC-PNG's Viking system.

The OES intends to review this information and provide its final recommendations in subsequent comments. The OES is available to answer any questions that the Commission may have.

Sincerely,

/s/ SACHIN SHAH
Rates Analyst
651-296-7540

SS/sm
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA OFFICE OF ENERGY SECURITY

DOCKET NO. G011/M-08-1331

I. SUMMARY OF MERC-PNG'S PROPOSAL

Pursuant to Minnesota Rules 7825.2910, subpart 2 (Filing Upon Change in Demand), on November 3, 2008, Minnesota Energy Resource Corporation-PNG (MERC-PNG or the Company), submitted a demand entitlement filing (*Petition*) for its Viking Gas Transmission Co. (Viking) pipeline system.[1] In its *Petition*, MERC-PNG requests that the Minnesota Public Utilities Commission (Commission) approve a change in the demand entitlements level on the Viking system for service to MERC-PNG's Minnesota firm customers who are served off the Viking system. In addition, MERC-PNG requests that the Commission approve recovery of the associated demand costs in the monthly Purchase Gas Adjustment (PGA) effective November 1, 2008.

II. THE OES'S ANALYSIS OF MERC-PNG'S PROPOSAL

The Minnesota Office of Energy Security (OES) reviewed MERC-PNG's proposed design-day requirement, proposed demand entitlement, and resulting reserve margin. Additionally, the OES compared this year's amounts with previous years' amounts. Based on its investigation to date, the OES concludes that the Company has provided a reasonable basis for its proposal. However, to confirm that MERC-PNG's service to its firm customers is reliable, the OES requests additional information in MERC-PNG's *Reply Comments*. The OES also notes that this overall

[1] MERC-PNG also serves Minnesota customers off the Northern Natural Gas (NNG or Northern) pipeline system and the Great Lakes Gas Transmission (GLGT) pipeline system. On November 3, 2008, MERC-PNG submitted the following requests with respect to these two systems:

- A request to change the demand entitlements on the NNG system for the 2008-2009 heating season in Docket No. G011/M-08-1328; and
- A request to change the demand entitlements on the GLGT system in Docket No. G011/M-08-1330.

In addition, on November 3, 2008, MERC-NMU (NMU) submitted a request to change demand entitlements in Docket No. G007/M-08-1329. The OES separately addresses each of these three requests in these dockets.

conclusion is subject to the Commission's pending decisions regarding the Contracted Demand (CD) units in Docket Nos. G011/M-07-1403 (07-1403 Docket) and G007,011/GR-08-835 (08-835 Docket) as discussed below.[2] The OES's analysis of the Company's request includes three parts:

- the proposed overall demand entitlement level;
- the specific proposed changes; and
- the PGA cost recovery proposal.

A. MERC-PNG'S VIKING SYSTEM PROPOSED DESIGN-DAY REQUIREMENT, PROPOSED DEMAND ENTITLEMENT LEVEL, AND RESULTING RESERVE MARGIN

1. Background

In the Company's last demand entitlement filing in the 07-1403 Docket, despite the Company's use of a statistically valid model, the OES had some concerns related to the previous model's ability to accurately forecast use per customer during a peak-day situation.[3]

The OES's concern was that the use of linear regression analysis may bias design-day estimates (above or below) actual peak-day usage. Thus, the OES recommended that the Company provide the following additional information from the 2007-2008 heating season in its subsequent demand entitlement filing (which is the instant filing):

- daily throughput data;
- daily firm throughput data;
- estimated daily firm throughput using MERC's design-day models;
- daily firm customer counts;
- daily heating degree day values;
- peak-day throughput estimates; and
- estimates of firm baseload natural gas usage at zero heating degree days.

MERC-PNG filed *Reply Comments* on May 27, 2008 in Docket No. *07-1403*. In its *Reply Comments*, the Company agreed to provide the above information in its next demand entitlement filing to the extent the information was available. MERC-PNG also stated the information it could or could not provide as follows:

> MERC is able to provide daily total throughput data, daily heating degree values, peak-day throughput estimates, and estimates of firm base load natural gas usage at zero heating

[2] At the time of these *Comments*, the Commission has not issued a formal *Order* in MERC-PNG's Viking system 2007-2008 heating season demand entitlement filing, Docket No. G011/M-07-1403.
[3] A peak-day situation is classified as 24-hours of -25°F temperatures.

> degree days. As noted in MERC's response to the OES' Information Request No.7 in this docket, however, daily firm throughput data is not available because firm customers are read once a month and the read date varies depending on the assigned billing cycle. No MERC firm customers are able to measure daily consumption by telemetry. Additionally, MERC is required to balance all MERC customers behind MERC city gates, whether firm, interruptible, or transportation. MERC therefore does not forecast firm requirements only. Instead, MERC forecasts system wide requirements, which include firm, interruptible, and transportation. Finally, MERC does not track daily firm customer counts. Customer counts are maintained on a monthly basis.

In this proceeding, the Company provided the comparison between daily system-wide estimates and actual throughput consumption (which includes interruptible and transportation volumes that are located behind MERC-PNG citygates) in Attachment 10 of its *Petition*. MERC-PNG also provided average customer counts in Attachment 11 of its *Petition*. However, the Company did not provide the daily weather data associated with its all-time Viking Peak day as it had agreed to do in its *07-1403 Reply Comments*. The OES requests that the Company provide the daily weather data associated with its all-time Viking Peak day in its *Reply Comments* in the instant docket.

2. Design-Day Requirement

In its *Petition* MERC-PNG explains the peak-day model it uses to estimate the design-day requirement; MERC-PNG also provided the model results via email in its response to an informal OES Information Request. Based on its review, the OES concludes that MERC-PNG conducted its design-day study using a statistically valid model. However, the OES noted a significant decrease in MERC-PNG’s estimate of its design-day requirement, which is the estimate of the needs of its firm customers during MERC-PNG’s peak day. This decrease seemed particularly unusual given that MERC-PNG forecasted an increase in the number of firm customers. Specifically, as indicated in OES Attachment 2, MERC-PNG’s proposed design-day requirement decreased 715 Mcf/day (or approximately 8.79 percent) from 8,135 Mcf/day to 7,420 Mcf/day. This change is significant, particularly given the projected growth rate in the number of customers for the 2008-2009 heating season of 1.07 percent.

In response to follow-up questions from the OES, MERC-PNG indicated that the decrease in the estimate of need for firm customers was due to more accurately estimating the natural gas used by interruptible customers during peak periods. Specifically, MERC-PNG changed its previous method of assuming that interruptible customers use the same amount of natural gas every day to a more realistic assumption that natural gas use by interruptible customers may be higher on some days. Since the estimate of design-day requirement is intended to estimate the amount of natural gas used by firm customers on the peak day, it is important to estimate as accurately as possible the amount of natural gas used by interruptible customers on the peak day, since this amount is subtracted from the total throughput. Thus, underestimating use by interruptible customers results in overestimating the amount used by firm customers on the peak day.

MERC-PNG's methodology change increased the amount of natural gas use attributed to interruptible customers, and correspondingly decreased the estimate of peak-day requirements for firm customers. The OES agrees with MERC-PNG that the previous method underestimated use by interruptible customers and thus overestimated natural gas use by firm customers. Thus it is appropriate for the estimated design-day requirement to decrease. However, the OES also agrees with MERC-PNG that it is difficult to know with certainty the amount of natural gas used by interruptible customers, so it is important to check whether this change still ensures that MERC-PNG provides reliable service to firm customers on peak days. Therefore, the OES requests that MERC-PNG provide additional information in its *Reply Comments*, as discussed further below.

Given the relatively mild temperatures over the past heating seasons, the OES investigated historical peak-day sendout per customer information. OES Attachment 2 shows that the all-time peak-day sendout per design day customer was 1.7404 Mcf/day during the 2005-2006 heating season.[4]

The OES notes that the entitlement numbers in column 7 of OES Attachment 2 may not be an apples-to-apples comparison from year to year since the 2007-2008 and presumably the 2008-2009 numbers include the contracted demand (CD) units for Joint customers whereas historical numbers, for example the Commission-approved entitlement level of 8,086 Mcf/day in Docket No. G011/M-05-1725 for the 2005-2006 season, excludes the CD units.

In its *April 29, 2008 Comments* in the 07-1403 Docket, the OES requested MERC-PNG to remove recovery of 39 Mcf/day of FT-A service related to contracted demand that it recovered from joint-rate customers and included in the monthly PGA for recovery by all demand rate customers. In the *June 12, 2008 Response Comments* of the OES in 07-1403 Docket, the OES was concerned with the Company's statement in its *Reply Comments* in the 07-1403 Docket that these contracted demand volumes were used for planning purposes and any usage deviations from these planned volumes were added or subtracted from total firm volumes. The OES was concerned that firm customers were subsidizing joint-rate customers. As a result, the OES recommended that the Commission require that MERC-PNG file testimony in its next rate case related to its joint-rate service tariffs and whether firm customers subsidize joint-rate customers. The Company filed testimony in its current rate case in the 08-835 Docket. In the *July 29, 2008 Supplemental Comments* of the OES in the 07-1403 Docket, the OES concluded that the inclusion of contracted demand volumes in the Company's PGA cost recovery was reasonable. Thus, the issue of CD units is currently pending before the Commission in the 07-1403 Docket and in the 08-835 Docket.[5] Additionally, the OES invites the Company in its *Reply Comments* to

[4] When design-day forecasts of other Minnesota regulated natural gas companies were examined, the 1995-1996 and 1993-1994 heating seasons were generally where historic peak-day throughputs occurred. However, MERC-PNG has information only from the 1997-1998 heating season going forward.
[5] See footnote 2 above.

identify separately, by service and interstate pipeline contract, the amount of CD units included in the proposed design day and peak-day entitlement levels along with the previous entitlement levels as shown in OES Attachments 1 and 2.

The proposed total entitlement level of 7,625 Mcf/day is a proposed decrease of 915 Mcf/day from the 2007-2008 level of 8,540 Mcf/day, despite the expected increase of 49 customers. As noted above, a large part of this change is due to a more accurate estimate of the amount of natural gas used by firm customers on peak days. However, this change would reduce the reserve margin from 4.98 percent to 2.76 percent, resulting in much fewer resources to respond to high demands on MERC-PNG's Viking system. Further, the Company's proposed decrease in design-day requirements results in an anticipated design-day use per customer of 1.6009 Mcf/day. The total entitlement per customer of 1.6451 Mcf/day is greater than the eight-year average peak day sendout per peak-day customer of 1.2751 Mcf/day but less than the all-time peak day sendout per design-day customer of 1.7404 Mcf/day.

Given that the total proposed entitlement per customer is less that the all-time peak day sendout per design-day customer, the OES asked if the Company had sufficient capacity and gas supply for firm customers available during the recent cold spell in December 2008. The Company's representative indicated that MERC-PNG did not experience any operational problems and that it had gas supply available for firm customers. The OES appreciates MERC-PNG's response, and the fact that MERC-PNG was able to meet its firm customers' needs. However, given that the Viking system has no peak shaving ability or available storage, the OES requests that the Company provide information in its *Reply Comments* on whether the Company had sufficient capacity available for firm customers during the recent cold spells experienced in January and February 2009.

The Company provided a summary, in its *Petition*, of the changes that it used in calculating the firm peak-day estimate compared to the approach it took in the previous year's demand entitlement filing. One of the main reasons the Company cites for the change in approach was that it wanted to introduce less error into the data and regression analysis. The three major differences that the Company states are as follows:

1. In 2007, estimates of the daily transport and interruptible volumes were removed from the total metered daily throughput to get estimated daily firm load before any regressions were performed. This method assumed that transport and interruptible loads were not weather sensitive but more process load. Thus, the estimate for the amount of natural gas used by interruptible customers was the total amount used by these customers, divided by the number of days in the month (assuming a load factor of 100 percent). This method did not recognize that interruptible customers can and often do use more natural gas on some days compared to others. In 2008, the transport and interruptible volumes were backed out after regressions were performed on measured daily throughput volumes. The estimate of the amount of natural gas

used by interruptible customers assumed a load factor for these customers of approximately 66percent,[6] which should more accurately reflect the amount of natural gas interruptible customers use during a peak day ;

2. In 2007, actual changes in customer counts were used to calculate growth rates. In 2008, forecasted changes in volumes were used (however, in both years there were increases in customer counts); and

3. In 2007, Farm Taps were handled uniquely, whereas in 2008, they were not treated differently from any other customer.

As noted above, the OES concludes that it is important to check more closely on the effects of MERC-PNG's change in methodology. Thus, the OES requests the Company to re-calculate the design day requirements in the 07-1403 Docket for the 2007-2008 season using the approach used by the Company in the current docket to see if the 2007-2008 design day requirements would have shown a decrease or an increase and to provide the results in its *Reply Comments* in the instant docket. This information would help confirm whether the Company's revised method still ensures that firm service is reliable.

The OES notes that MERC-PNG's peak demand by customers may or may not be entirely related to weather. It is important to understand the factors affecting peak demand to ensure that adequate, but not excessive amounts of resources are available to meet customers' needs. For example, although the all-time peak day sendout per design day of 1.7404 Mcf/day occurred during the 2005-2006 heating season, the OES is unaware of any weather conditions during the 2005-2006 heating season that approached the Commission's peak-day classification of 24-hours of -25°F temperatures. Given that the proposed total entitlement per customer of 1.6451 Mcf/day is roughly 5.48 percent less than the all-time peak day sendout per design day of 1.7404 Mcf/day and that the Viking system has no available storage or peak shaving ability, the OES requests the Company to provide any pertinent information regarding factors other than weather which affect the level of demand by customers on MERC-PNG's Viking system.

The OES also requests that MERC-PNG reconcile a number in this filing with a number in the Company's rate case. Specifically, when the Company calculated the "Daily Firm Capacity (DFC) customer selections" in its calculations in this proceeding, the number of joint interruptible customers used in the data was for 59 customers. However, in MERC's general rate case the Direct Testimony and Exhibits of Company Witness, Gregory J. Walters, Exhibit GJW-1, Schedule 12 shows approximately 24 joint sales customers in the test year. The OES requests the Company in its *Reply Comments* to provide a detailed explanation and reconciliation for the 59 customers DFC data used in the calculation of the firm peak-day estimate calculations and the 24 customers mentioned in the aforementioned Exhibit in Docket No. G007,011/GR-08-835. If

[6] MERC-PNG's new method divides total use by interruptible customers by 20 days rather than (approximately) 30, resulting in a load factor of 66 percent.

as a result of the reconciliation the Company's firm peak-day estimates and calculations change then the OES expects the Company will update and provide any and all such results in its *Reply Comments*.

3. Preliminary Conclusions Regarding Proposed Demand Entitlement Levels

The Company proposes to decrease its total entitlement level by 915 Mcf/day (or approximately 10.71 percent) from the previously filed level of 8,540 Mcf/day to 7,625 Mcf/day. As noted above, the OES's preliminary conclusion is that the Company's proposal appears to be reasonable. However, it is important to ensure that MERC-PNG has sufficient resources available to serve firm customers' needs, particularly since MERC-PNG does not have storage or peak shaving resources on the Viking system. Thus, the OES requests that MERC-PNG provide in its *Reply Comments* the information identified above. The OES will review the information provided by the Company and subsequently provide the OES's final recommendations regarding the proposed entitlement levels of 7,625 Mcf/day.

4. Reserve Margin

As noted above and as indicated in OES Attachment 2, the Company's proposal results in a positive reserve margin for the Viking system customers of 2.76 percent, which nearly cuts in half (a decrease of 2.22 percent) the 2007-2008 reserve margin of 4.98 percent. However, as noted above, MERC-PNG made a number of changes to its estimation methods compared to last year's demand entitlement filing, so the two years are not directly comparable. The current 2.76 percent reserve margin on the Viking system is within the OES's five percent margin threshold, and thus does not appear to overstate the amount of resources MERC-PNG needs to serve its customers. However, since the Viking system does not have peak shaving or storage, customers on this system may be more susceptible to service issues during a peak-day situation if the design-day estimates are incorrect. Peak shaving and storage facilities provide additional natural gas supplies on peak days; for those systems that lack such facilities it may be appropriate to maintain larger reserve margins. The OES will review MERC-PNG's *Reply Comments* for further information. However, at a minimum the OES recommends that the issue of reliability be monitored going forward.

B. MERC-PNG'S SPECIFIC PROPOSED DEMAND ENTITLEMENT CHANGES

In addition to the overall assessment as to whether MERC-PNG has sufficient resources, the OES assesses whether the type of resources proposed to serve firm customers is reasonable. There are two types of demand entitlement changes. The first type is design-day deliverability; in this petition, MERC proposes to decrease the amount of transportation available to MERC-PNG's Viking system customers during winter peak periods. The second type does not affect design-day deliverability level, but does affect the demand costs recovered from ratepayers through the PGA.

1. Design-Day Deliverability Changes

As indicated in OES Attachment 1, MERC-PNG's proposal would decrease the Company's pending total design-day capacity (total entitlement) by 915 Mcf/day. This total proposed decrease in total entitlement is itemized as follows:

- a decrease of 144 Mcf/day in FT-A 12 months (Viking);
- a decrease of 361 Mcf/day in TF12 months (NNG); and
- a decrease of 411 Mcf/day in TF5 months (NNG).

In its Petition, MERC-PNG states that, as shown in Attachment 6, the Company proposes a decrease in the Viking backhaul contract and the NNG Chisago contract that delivers gas into the Viking system for design-day deliverability for the heating season. Although not included in the design-day, the modifications made to the backhaul allocations appear to be reasonable.[7] However, regarding the above decreases, MERC-PNG does not provide detailed explanations in its filing to support these specific proposed changes in demand types. As a result, the OES requests that the Company provide the reasons and detailed explanations for these changes in entitlement levels in its *Reply Comments*.

2. Other Demand Entitlement Changes

Other than the above transportation changes, the Company proposes no changes in other pipeline entitlements that are not included in peak-day deliverability. However, the OES notes that MERC's hedging costs increased from $134,988 for the 2007-2008 season to $215,559 for the 2008-2009 season. It appears that the hedging strategy used by MERC-PNG during the 2008-2009 season is similar to the one used by the Company in last year's demand entitlement filing. The OES's prudency review of MERC-PNG's hedging costs from the 2007-2008 heating season will be conducted in the upcoming Review of the Annual Automatic Adjustment (AAA) Reports in Docket No. G999/AA-08-1011. The prudency review of MERC-PNG's 2008-2009 season hedging costs (this filing) will be reviewed in the subsequent AAA report.

C. MERC-PNG'S VIKING PGA COST RECOVERY PROPOSAL

The demand entitlement changes discussed above represent the demand entitlements for which MERC-PNG's firm customers on the Viking system would pay. In its *Petition*, the Company uses its November 2008 PGA as a means of comparison for its entitlement level and hedging cost changes.[8] When comparing the changes in rates due to the proposed demand entitlement changes

[7] As mentioned in the OES *Response Comments* in Docket No. G011/M-06-1538, MERC implemented a new allocation method to bring the Viking system more in line with the then industry standards and to operate more cost effectively (e.g., not maintaining volumes for a delivery point that is not serviced by a given pipeline).
[8] The Company submitted revised Attachments 4 and 7 (mistakenly identified as 11) on November 5, 2008.

with the Company's filed October 2008 PGA rates, the OES estimates that MERC-PNG's demand entitlement proposal results in the monthly rate impacts as shown in Table 1 below:

Table 1
OES Viking PGA Cost Recovery
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	$0.0000	0.00	$(0.1684)	(13.37)	$(0.1684)	(1.71)	$(23.41)
Small Vol. Interruptible Service	$0.0000	0.00	$0.0000	0.00	$0.0000	0.00	$0.00
Large Vol. Interruptible	$0.0000	0.00	$0.0000	0.00	$0.0000	0.00	$0.00
Small Vol. Firm Service	$0.0000	0.00	$0.0000	0.00	$0.0000	0.00	$0.00

The OES's analysis is somewhat different from that shown in MERC-PNG's petition. 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. As shown in Table 1 and OES Attachment 3, the OES analysis concludes that MERC-PNG's proposal would result in an annual bill decrease of ($23.41), or approximately (1.71) percent, for an average General Service customer consuming 139 Mcf.

On a separate issue, MERC-PNG has been consistent regarding the volumes identified in its October PGA monthly report and the volumes identified in its initial Base Cost of Gas filing (BCOG filing) in Docket No. G007,011/MR-08-836. The Commission issued its *Order Setting New Base Cost of Gas* on September 25, 2008 in Docket No. G007,011/MR-08-836. However, the OES notes that MERC-PNG has been using the 2000 rate case volumes in its monthly PGA reports from at least September 2008 and prior periods.[9] The OES expects MERC-PNG, after the end of the general rate case in the 08-835 Docket, to comply with Minnesota Rules including Minnesota Rule 7825.2700, subpart 5, and Minnesota Rule 7825.2400, subpart 3 in the Company's future PGA and demand entitlement filings. Specifically, Minnesota Rule 7825.2700, subpart 5 states in part that the demand adjustment must be computed using test year demand volumes for three years after the end of the utility's most recent general rate case test year. After this time period, the demand adjustment must be computed on the basis of the annual demand volume. Minnesota Rule 7825.2400, subpart 3 defines the annual demand volume as follows:

[9] On May 11, 2001, the Commission issued its *Order Modifying And Accepting Settlement* (May 11, 2001 Order) in Aquila Networks-NMU's and Aquila Networks-PNG's general rate case in Docket No. G007,011/GR-00-951. In its June 1, 2006 Order Approving Sale Subject to Conditions, (Docket No. G007,011/PA-05-1676) the Commission approved Aquila Inc.'s (Aquila) sale of its two divisions operating in Minnesota, Aquila Networks-PNG and Aquila Networks-NMU to Minnesota Energy Resources Corporation (MERC), a subsidiary of WPS Resources Corporation. MERC has two divisions: MERC-PNG and MERC-NMU.

> "Annual demand volume" is the annual sales volume adjusted by an average percentage change in sales computed over the preceding three-year period, normalized for weather. Annual demand volume includes interruptible sales to the extent that demand cost is incurred to service interruptible customers.

Thus, MERC-PNG would use the Commission-approved test year demand volumes for three years after the end of its general rate case test year (which was calendar year 2008 in the 08-835 Docket) and the definition cited above in the Company's future PGA and demand entitlement filings.

III. THE OES'S RECOMMENDATIONS

Based on its investigation to date, the OES recommends that the Commission:

- **approve, subject to adequate clarification by MERC-PNG**, the Viking system demand entitlement level**,** and subject to the Commission's pending decisions regarding the Contracted Demand (CD) units in Docket Nos. G011/M-07-1403 and G007,011/GR-08-835; and

- **approve, subject to adequate clarification by MERC-PNG**, the Purchase Gas Adjustment (PGA) recovery of costs associated with the Company's proposed demand entitlement level effective November 1, 2008, and subject to the Commission's pending decisions regarding the CD units in Docket Nos. G011/M-07-1403 and G007,011/GR-08-835.

The OES also recommends that the Company provide the following in its *Reply Comments*:

- the daily weather data associated with MERC-PNG's all-time Viking Peak day;

- identification, by service and interstate pipeline contract, of the amount of CD units included in the proposed design-day and peak-day entitlement levels and in the previous levels indicated in OES Attachments 1 and 2;

- information, and detailed explanations as to whether the Company had sufficient capacity available for firm customers during the recent cold spells experienced in January and February 2009;

- results of recalculating the design day requirements in the 07-1403 docket for the 2007-2008 heating season using the same approach used by the Company in the current docket;

- a detailed explanation and reconciliation between the 59 customers Daily Firm Capacity (DFC) data used in the calculation of the firm peak-day estimate and for the 24 customers shown in Exhibit GJW-1, Schedule 12 in Docket No. G007,011/GR-08-835;

- any other pertinent information regarding other factors which affect the level of demand by customers on MERC-PNG's Viking system; and

- the reasons associated with the proposed specific changes in MERC-PNG's Viking system demand volumes.

The OES intends to review this information and provide its final recommendations in subsequent comments.

/sm

OES Attachment 1

Details of MERC-PNG's Viking Area Demand Entitlements Historical and Current Proposal

2004-05 G011/M-04-1767	Quantity (Mcf)		2005-06 G011/M-05-1725	Quantity (Mcf)		2006-07 G011/M-06-1538	Quantity (Mcf)		Change in Quantity		2007-2008 G011/M-07-1403	Quantity (Mcf)		Change in Quantity
FT-A 12 months	4,120	2/	FT-A 12 months	4,088	2/	FT-A 12 months	3,488	2/	(600)	2/	FT-A 12 months	3,488	2/	0
FT-A 12 months	1,098		FT-A 12 months	1,098		FT-A 12 months	935		(163)		FT-A 12 months	316		(619)
FT-A (5 month backhaul)	600	1/	FT-A (5 month backhaul)	600	1/	FT-A (5 month backhaul)	1,277	1/	677	1/	FT-A (5 month backhaul)	1,277	1/	0
NNG TF 12 mos. (backhaul)	1,098	1/	NNG TF 12 mos. (backhaul)	1,098	1/	NNG TF 12 mos. (backhaul)	1,098	1/	0	1/	NNG TF 12 mos. (backhaul)	1,098	1/	0
TF12 (NNG)	286		TF12 (NNG)	286		TF12 (NNG)	373		87		TF12 (NNG)	713		340
TF5 (NNG)	314		TF5 (NNG)	614		TF5 (NNG)	1,068		454		TF5 (NNG)	985		(83)
FT-D 12 months	2,000		FT-D 12 months	2,000		FT-D 12 months	2,000		0		FT-D 12 months	3,000		1,000
						FT-A 12 months	1,000		1,000					
Total Demand Entitlement	7,818		Total Demand Entitlement	8,086		Total Demand Entitlement	8,864		778		Total Demand Entitlement	8,502		(362)
Total Viking Transportation	7,818		Total Viking Transportation	8,086		Total Viking Transportation	7,864		(222)		Total Viking Transportation	8,502		638
Total Annual Transportation	7,504		Total Annual Transportation	7,472		Total Annual Transportation	6,796		(676)		Total Annual Transportation	7,517		721
Total Seasonal Transport	314		Total Seasonal Transport	614		Total Seasonal Transport	1,068		454		Total Seasonal Transport	985		(83)
Percent Seasonal on Viking	4.0%		Percent Seasonal on Viking	7.6%		Percent Seasonal on Viking	13.6%		6.0%		Percent Seasonal on Viking	11.6%		-2.0%

1/ The amount is excluded from the design day capacity since it is a backhaul to transport gas to Viking.
2/ Excludes CD units.

2007-2008* G011/M-07-1403	Quantity (Mcf)		Change in Quantity		2008-2009 G011/M-08-1331	Quantity (Mcf)		Change in Quantity
FT-A 12 months	3,527		39		FT-A 12 months	3,527		0
FT-A 12 months	316		(619)		FT-A 12 months	172		(144)
FT-A (5 month backhaul)	915	1/	(362)	1/	FT-A (5 month backhaul)	0	1/	(915)
NNG TF 12 mos. (backhaul)	1,098	1/	0	1/	NNG TF 12 mos. (backhaul)	1,098	1/	0
TF12 (NNG)	793		420		TF12 (NNG)	432		(361)
TF5 (NNG)	905		(163)		TF5 (NNG)	494		(411)
FT-A 12 months	2,000		0		FT-A 12 months	2,000		0
FT-A 12 months	1,000		0		FT-A 12 months	1,000		0
Total Demand Entitlement	8,541		(323)		Total Demand Entitlement	7,625		(916)
Total Viking Transportation	8,541		677		Total Viking Transportation	7,625		(916)
Total Annual Transportation	7,636		840		Total Annual Transportation	7,131		(505)
Total Seasonal Transport	905		(163)		Total Seasonal Transport	494		(411)
Percent Seasonal on Viking	10.6%		-3.0%		Percent Seasonal on Viking	6.5%		-4.1%

* **Reflects the OES recommendation to include the 39 units of FT-A service for joint customers and the correction to the OES' inadvertent error in calculating the TF12 (NNG) and TF5 (NNG) amounts.**
In Docket No. G011/M-06-1538, the FT-D 12 month service in the amount of 2,000 Mcf/day should have been changed to FT-A 12 month service. The FT-D service was cancelled as shown in Viking Gas Transmission Company's FERC Gas Tariff First Revised Volume No. 1, fourth Revised Sheet No. 15K superseding Sheet Nos. 15K through 15P, effective January 1, 2006. As a result, there should be no impact to the demand costs for firm customers since both the FT-A and FT-D interstate pipeline rates were equivalent.

In the Company's *07-1403 Petition*, Attachment 3 shows that the Company proposed the NNG-TFX 12 service going from the then current amount of 373 Mcf/day to 793 Mcf/day.
The OES mistakenly input the NNG-TFX 5 proposed amount of 713 Mcf/day. As a result the computations for the NNG-TFX 5 amounts were incorrect.
Instead of showing a proposed level of 985 Mcf/day for the TF5 (NNG) amount in the 07-1403 Docket, OES believes the correct amount should have been going from the then current amount of 1,068 Mcf/day to 905 Mcf/day for the TF5 (NNG) service.

OES Attachment 2
MERC-PNG's Viking Area Demand Entitlement Analysis

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Peak Shaving	+ Peak Shaving		Reserve Margin
Heating Season *	(1) Number of 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)
2008-2009	4,635	49	1.07%	7,420	-715	-8.79%	7,625	(915)	-10.71%	2.76%
2007-2008	4,586	63	1.39%	8,135	23	0.28%	8,540	(324)	-3.66%	4.98%
2006-2007	4,523	62	1.39%	8,112	198	2.50%	8,864	778	9.62%	9.27%
2005-2006	4,461	(63)	-1.39%	7,914	316	4.16%	8,086	268	3.43%	2.17%
2004-2005	4,524	211	4.89%	7,598	175	2.36%	7,818	300	3.99%	2.90%
2003-2004	4,313	89	2.11%	7,423	340	4.80%	7,518	293	4.06%	1.28%
2002-2003	4,224	9	0.21%	7,083	286	4.21%	7,225	400	5.86%	2.00%
2001-2002	4,215	23	0.55%	6,797	93	1.39%	6,825	0	0.00%	0.41%
2000-2001	4,192	188	4.70%	6,704	193	2.96%	6,825	600	9.64%	1.80%
1999-2000	4,004	101	2.59%	6,511	269	4.31%	6,225	2,000	47.34%	-4.39%
1998-1999	3,903	128	3.39%	6,242	205	3.40%	4,225	0	0.00%	-32.31%
1997-1998	3,775			6,037			4,225			-30.01%
Average Change Per Year:			1.90%			1.96%			6.32%	-3.26%

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 per Customer [(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)	(19) Peak Day Sendout per DD Customer (12)/(1)
2008-2009	unknown	unknown			0.0442	1.6009	1.6451	unknown	unknown
2007-2008	unknown	7,058	143	2.07%	0.0883	1.7739	1.8622	unknown	1.5390
2006-2007	unknown	6,915	(849)	-10.94%	0.1663	1.7935	1.9598	unknown	1.5289
2005-2006	unknown	7,764	2,191	39.31%	0.0386	1.7740	1.8126	unknown	1.7404
2004-2005	4,474	5,573	(428)	-7.13%	0.0486	1.6795	1.7281	1.2456	1.2319
2003-2004	4,383	6,001	85	1.44%	0.0220	1.7211	1.7431	1.3692	1.3914
2002-2003	4,313	5,916	1,816	44.29%	0.0336	1.6768	1.7105	1.3717	1.4006
2001-2002	4,228	4,100	(439)	-9.67%	0.0066	1.6126	1.6192	0.9697	0.9727
2000-2001	4,217	4,539	(1,421)	-23.84%	0.0289	1.5992	1.6281	1.0764	1.0828
1999-2000	4,152	5,960	(367)	-5.80%	-0.0714	1.6261	1.5547	1.4355	1.4885
1998-1999	4,071	6,327	1,529	31.87%	-0.5168	1.5993	1.0825	1.5542	1.6211
1997-1998	4,040	4,798			-0.4800	1.5992	1.1192	1.1786	1.2710
Average Change Per Year:				6.16%	-0.0578	1.6778	1.6200	1.2751	1.3880

*Per Peoples, information prior to 1995 is not available.

In Column 12, the value for the 2005-2006 season has been changed to 7,764 from 5,573.
As shown in Docket No. E,G999/AA-05-1403, Aquila Networks-PNG's response to Dept of Commerce Information Request No. 2 in Docket No.E,G999/AA-05-1403, and in Docket No. G011/M-05-1725, the firm peak day sendout occurred on January 14, 2005 which would be indicative of the 2004-2005 season.
In Docket No. E,G999/AA-06-1208, the firm peak day sendout of 7,764 Mcf occurred on 2/17/06 as identified in Table G10, during the 2005-2006 heating season.

The Company has not provided the number of peak-day customers beginning from the 2005-2006 heating season.

There appears to be a minor rounding error between the entitlement amounts shown in OES attachments 1 and 2.
OES Attachment 1 shows a decrease of 916 Mcf/day in the entitlement levels compared to the 915 Mcf/day decrease shown in OES Attachment 2.

OES Attachment 3
Effect of Proposed Demand Entitlement Changes on MERC-PNG's Viking area PGAs

General Service	Last Rate Case GR-03-1372	Last Demand Change M-07-1403	Most Recent PGA as Filed-October 2008	October 2008 PGA with Current Demand Entitlement Change	Change From Last Rate Case	Change From Last Demand Change	Change From Most Recent PGA	Change From Most Recent PGA
Commodity Cost of Gas (WACOG)	$2.7770	$6.1350	$6.9633	$6.9633	150.75%	13.50%	0.00%	$0.0000
Demand Cost of Gas	$0.6947	$1.1747	$1.2592	$1.0908	57.02%	-7.14%	-13.37%	($0.1684)
Commodity Margin	$1.2628	$1.1771	$1.6263	$1.6263	28.79%	38.16%	0.00%	$0.0000
Total Cost of Gas	$4.7345	$8.4868	$9.8488	$9.6804	104.47%	14.06%	-1.71%	($0.1684)
Average Annual Usage (Mcf)	139	139	139	139				
Average Annual Total Cost of Gas	$658.10	$1,179.67	$1,368.98	$1,345.58	104.47%	14.06%	-1.71%	($23.41)

Small Volume Interruptible	Last Rate Case GR-03-1372	Last Demand Change M-07-1403	Most Recent PGA	Current Proposal	Change From Last Rate Case	Change From Last Demand Change	Change From Most Recent PGA	Change From Most Recent PGA
Commodity Cost of Gas (WACOG)	$2.7770	$6.1350	$6.9633	$6.9633	150.75%	13.50%	0.00%	$0.0000
Demand Cost of Gas	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Commodity Margin	$0.9000	$0.9000	$1.2434	$1.2434	38.16%	38.16%	0.00%	$0.0000
Total Cost of Gas	$3.6770	$7.0350	$8.2067	$8.2067	123.19%	16.66%	0.00%	$0.0000
Average Annual Usage (Mcf)	3,744	3,744	3,744	3,744				
Average Annual Total Cost of Gas	$13,766.69	$26,339.04	$30,725.88	$30,725.88	123.19%	16.66%	0.00%	$0.00

Large Volume Interruptible	Last Rate Case GR-03-1372	Last Demand Change M-07-1403	Most Recent PGA	Current Proposal	Change From Last Rate Case	Change From Last Demand Change	Change From Most Recent PGA	Change From Most Recent PGA
Commodity Cost of Gas (WACOG)	$2.7770	$6.1350	$6.9633	$6.9633	150.75%	13.50%	0.00%	$0.0000
Demand Cost of Gas	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Commodity Margin	$0.2600	$0.2600	$0.3592	$0.3592	38.15%	38.15%	0.00%	$0.0000
Total Cost of Gas	$3.0370	$6.3950	$7.3225	$7.3225	141.11%	14.50%	0.00%	$0.0000
Average Annual Usage (Mcf)	106,427	106,427	106,427	106,427				
Average Annual Total Cost of Gas	$323,218.80	$680,600.67	$779,311.71	$779,311.71	141.11%	14.50%	0.00%	$0.00

Small Volume Firm	Last Rate Case GR-03-1372	Last Demand Change M-07-1403	Most Recent PGA	Current Proposal	Change From Last Rate Case	Change From Last Demand Change	Change From Most Recent PGA	$ Change From Most Recent PGA
Commodity Cost of Gas (WACOG)	$2.7770	$6.1350	$6.9633	$6.9633	150.75%	13.50%	0.00%	$0.0000
Demand Cost of Gas	$2.7846	$3.4671	$3.4671	$3.4671	24.51%	0.00%	0.00%	$0.0000
Commodity Margin	$0.9000	$0.9000	$1.2434	$1.2434	38.16%	38.16%	0.00%	$0.0000
Demand Margin	$1.5000	$1.5000	$2.0724	$2.0724	38.16%	38.16%	0.00%	$0.0000
Total Commodity Cost	$3.6770	$7.0350	$8.2067	$8.2067	123.19%	16.66%	0.00%	$0.0000
Total Demand Cost	$4.2846	$4.9671	$5.5395	$5.5395	29.29%	11.52%	0.00%	$0.0000
Total Recovery	$15.9232	$24.0042	$27.4924	$27.4924	72.66%	14.53%	0.00%	$0.0000
Average Annual Usage (Mcf)*	3,893	3,893	3,893	3,893				
Average Annual Commodity Bill^	$14,314.56	$27,387.26	$31,948.68	$31,948.68	123.19%	16.66%	0.00%	$0.0000

* Excludes 7 CD Units

Summary	Commodity Change ($/Mcf)	Commodity Change (%)	Demand Change ($/Mcf)	Demand Change (%)	Total Change ($/Mcf)	Total Change (%)	Effect on Annual Bill
General Service	$0.0000	0.00%	($0.1684)	-13.37%	($0.1684)	-1.71%	($23.41)
Small Volume Interruptible	$0.0000	0.00%	$0.0000	0.00%	$0.0000	0.00%	$0.00
Large Volume Interruptible	$0.0000	0.00%	$0.0000	0.00%	$0.0000	0.00%	$0.00
Small Volume Firm	$0.0000	0.00%	$0.0000	0.00%	$0.0000	0.00%	$0.00

OES Attachment 4

Comparion of MERC-PNG' Viking Area October PGA and October PGA with Updated Demand Entitlement Levels

October PGA							
IV. Peoples Natural Gas Company's -- Current Cost of Gas Effective					**1-Oct-08**		
		MCF	x Months	x Tariff Rate		Equals	Rate/CCF
A. GS-4	FT-A	3,527	12	$3.4671		$146,742	$0.02438
	FT-A	1,098	3	$3.4671		$11,421	$0.00190
	FT-A	1,000	12	$3.4671		$41,605	$0.00691
	FT-A	2,000	12	$3.4671		$83,210	$0.01382
	TF-12 (NNG)	316	12	$7.5776		$28,734	$0.00477
	TFX-12	793	12	$9.6288		$91,628	$0.01522
	TF-5 (NNG)	713	5	$15.1530		$54,020	$0.00897
	TFX-5	192	5	$15.1530		$14,547	$0.00242
	Chisago Back	915	5	$2.7360		$12,517	$0.00208
	Nexen Exchange	154,541	1	$1.7700		$273,538	$0.04544
	FT-D	0	12	$3.4671		$0	$0.00000
						$0	$0.00000
						$0	$0.00000
	Subtotal					$757,962	$0.12592
							$0.00000
							$0.00000
							$0.00000
	Total Demand Cost					$757,962	
	Rate Case 2008 General Sales Service Volumes-CCF				6,019,300		
	Current Demand Cost of Gas / CCF						**0.12592**
	Rate Case 2008 All Classes Volumes-CCF				8,641,860		
	All Classes Commodity					$6,017,586	
	Current Commodity Cost of Gas/CCF						**0.69633**
	Total Cost of Gas/CCF						**0.82225**
B. SVI- 4	Current Commodity Cost of Gas / CCF						**0.69633**
C. SVJ - 4	Current Demand Cost of Gas / CCF						**0.34671**
	Current Commodity Cost of Gas /CCF						**0.69633**
D. LVI-4	Current Commodity Cost of Gas /CCF						**0.69633**

October PGA with updated entitlement values							
IV. Peoples Natural Gas Company's -- Current Cost of Gas Effective					**1-Oct-08**		
		MCF	x Months	x Tariff Rate		Equals	Rate/CCF
A. GS-4	FT-A	3,527	12	$3.4671		$146,742	$0.02438
	FT-A	1,098	3	$3.4671		$11,421	$0.00190
	FT-A	1,000	12	$3.4671		$41,605	$0.00691
	FT-A	2,000	12	$3.4671		$83,210	$0.01382
	TF-12 (NNG)	172	12	$7.5776		$15,640	$0.00260
	TFX-12	432	12	$9.6288		$49,916	$0.00829
	TF-5 (NNG)	389	5	$15.1530		$29,473	$0.00490
	TFX-5	105	5	$15.1530		$7,955	$0.00132
	Chisago Back	0	5	$2.7360		$0	$0.00000
	Nexen Exchange	152,888	1	$1.7700		$270,612	$0.04496
	FT-D	0	12	$3.4671		$0	$0.00000
	Subtotal					$656,573	$0.10908
	Total Demand Cost					$656,573	
	Rate Case 2008 General Sales Service Volumes-CCF				6,019,300		
	Current Demand Cost of Gas / CCF						**$ 0.10908**
	Rate Case 2008 All Classes Volumes-CCF				8,641,860		
	All Classes Commodity					$6,017,586	
	Current Commodity Cost of Gas/CCF						**$0.69633**
	Call Option Premium					$0	$0.00000
	Total Commodity Cost of Gas/CCF						**$0.69633**
	Total Cost of Gas/CCF						**$0.80541**
B. SVI- 4	Current Commodity Cost of Gas / CCF						**$0.69633**
C. SVJ - 4	Current Demand Cost of Gas / CCF						**$0.34671**
	Current Commodity Cost of Gas /CCF						**$0.69633**
D. LVI-4	Current Commodity Cost of Gas /CCF						**$0.69633**

STATE OF MINNESOTA)
) ss
COUNTY OF RAMSEY)

AFFIDAVIT OF SERVICE

I, **Sharon Ferguson**, being first duly sworn, deposes and says: that on the **9th** of **February, 2009**, served the **Minnesota Office of Energy Security Comments**

MNPUC DOCKET NUMBER: G011/M-08-1331

XX by depositing in the United States Mail at the City of St. Paul, a true and correct copy thereof, properly enveloped with postage prepaid

XX electronic filing

/s/Sharon Ferguson

Subscribed and sworn to before me

this 9th of February , 2009

/s/ Lisa Maria DeTomaso

Lisa Maria DeTomaso
Notary Public-Minnesota
Commission Expires Jan 31, 2011

G011/M-08-1331

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