85 7th Place East, Suite 500
St. Paul, MN 55101-2198
main: 651.296.4026
tty: 651.296.2860
fax: 651.297.7891
www.energy.mn.gov

April 2, 2010

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

RE: **Comments of the Minnesota Office of Energy Security**
Docket No. G011/M-09-1284

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 Company) for approval of changes in demand entitlements on its Northern Natural Gas (Northern) pipeline system.

The *Petition* was filed on November 2, 2009 by:

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

The OES withholds recommendation in this proceeding until the Company provides additional information in its *Reply Comments*. Specifically, the OES recommends that MERC-PNG provide the following in its *Reply Comments*:

- a full discussion explaining why MERC-PNG uses a different wind chill calculation and what, if any, impact using the official wind chill calculation would have on MERC-PNG's design-day forecast;
- an updated design day analysis, and all supporting regression models and data, that corrects the data error referenced by the Company in its discussions with the OES;

- a full discussion detailing how MERC-PNG intends to install telemetry equipment for its transportation customers and an estimate of how long it will be before the Company has adequate daily data to estimate its firm design day more accurately;
- a discussion clarifying whether the TFX contract included in MERC-PNG's November 2009 PGA filings should be a seven-month or twelve-month contract; and
- a full discussion justifying the large reserve margin on MERC-PNG's Northern PGA system.

The OES also recommends that, on a going-forward basis, MERC-PNG conduct its design-day analysis using weather data from the following weather stations: Cloquet, MN; Minneapolis-Saint Paul, MN; Rochester, MN; and Worthington, MN.

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

Sincerely,

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

AJH/ja
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA OFFICE OF ENERGY SECURITY

DOCKET NO. G011/M-09-1284

I. SUMMARY OF MERC-PNG'S PROPOSAL

Pursuant to Minnesota Rules 7825.2910, subpart 2 (Filing Upon Change in Demand), on November 2, 2009, Minnesota Energy Resources Corporation-PNG (MERC-PNG or Company), submitted a demand entitlement filing (*Petition*) for its Northern Natural Gas (Northern) pipeline system.[1] In its *Petition*, MERC-PNG requests the Minnesota Public Utilities Commission's (Commission) approval to "change demand levels by type" on the Northern system for service to its Minnesota firm customers. Specifically, MERC-PNG requests to change its level of overall demand entitlement (capacity). In addition, MERC-PNG requests approval to recover the associated demand costs in the monthly Purchase Gas Adjustment (PGA) effective November 1, 2009. The OES provides comments regarding MERC-PNG's proposal below.

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

The Minnesota Office of Energy Security (OES) reviewed MERC-PNG's proposed design-day requirement, proposed demand entitlement, and resulting reserve margins. Additionally, the

[1] MERC-PNG also serves Minnesota customers off the Viking Gas Transmission (Viking) pipeline system and the Great Lakes Transmission (Great Lakes) pipeline system. On November 2, 2009, MERC-PNG submitted the following requests with respect to these two systems:

- A request to change the Company's demand entitlements on the Viking system for the 2009-2010 heating season in Docket No. G011/M-09-1285; and
- A request to change the Company's demand entitlements on the Great Lakes system for the 2009-2010 heating season in Docket No. G011/M-09-1283.

In addition, on November 2, 2009, MERC-NMU (NMU), a division of Integrys Energy, submitted a request to change demand entitlements in Docket No. G007/M-09-1282. The OES separately addresses the requests in each of these dockets.

OES compared this year's amounts with previous years' amounts. The OES's analysis of the Company's request includes three parts:

- MERC-PNG's proposed Design-Day Requirement, Demand Entitlement Level, and Reserve Margin for the Northern PGA system;
- MERC-PNG's proposed demand entitlement changes for the Northern PGA system; and
- MERC-PNG's Cost Recovery Proposal for the Northern PGA System.

A. *MERC-PNG'S PROPOSED DESIGN-DAY REQUIREMENT, PROPOSED DEMAND ENTITLEMENT LEVEL, AND RESULTING RESERVE MARGIN FOR THE NORTHERN PGA SYSTEM*

1. *Design-Day Requirement*

a. *Peak-Day Calculation*

In its *Petition* and in response to OES discovery, MERC-PNG explained the peak-day model it uses to determine its design-day requirement and provided the model results and input data in its response to OES Information Request No. 2 (OES Attachment 1). Based on its review, the OES concludes that MERC-PNG conducted its design-day study using a statistically valid model. However, the OES requests that MERC-PNG provide further information to help ensure that the Company's design-day analysis will provide sufficient volumes on a peak day as defined by Commission practice.[2]

Before discussing its concerns with MERC-PNG's design-day calculations, the OES provides a brief description of the Company's design-day analysis.

MERC-PNG conducts its design-day and peak-day analyses using statistical techniques, specifically ordinary least squares (OLS) regression. The Company's regression analysis is based on daily system throughput, wind-adjusted heating degree days (AHDDs) from three weather stations (Rochester, Minneapolis-St. Paul, and Cloquet),[3] and other significant independent variables (*e.g.,* month, day of the week) for the months of December through February over the past three heating seasons (*i.e.,* 2006-2007, 2007-2008, 2008-2009). The OES notes that MERC-

[2] Minnesota Rules 7825.2400, subp. 13d, defines a design-day as: "a 24-hour-day period of the greatest possible gas requirement to meet firm customer needs." The Commission later clarified this definition to mean a 24-hour period with an average temperature of -25°F (90 heating degree days (HDD)). The 90 HDD event corresponds to the coldest day in the last twenty years.

[3] Commission Staff has indicated concerns, in another utility's demand entitlement filing, about using AHDD when conducting a design-day analysis. MERC-PNG notes in its response to OES Information Request No. 3 (OES Attachment 2) that AHDDs produce more robust regression results than using non-wind-adjusted HDDs.

PNG's adjusted HDD calculation is different than the official calculation used by the National Weather Service (NWS). Given this difference, the OES recommends that MERC-PNG provide, in its *Reply Comments*, a full discussion explaining why it uses a different calculation and what, if any, impact using the official wind chill calculation has on MERC-PNG's design-day forecast.

This regression analysis allows MERC-PNG to estimate weather's (AHDDs) impact on system throughput and then compare this impact to the Company's all-time system peak day. This comparison then allows MERC-PNG to estimate total system throughput, based on current customer counts and system characteristics, if a day similar to the system's all-time peak sendout were to occur during the heating season. Finally, the Company includes a volume risk adjustment, removes interruptible and transportation customer usage, use by taconites and other large industrial users, and applies a customer growth figure to its estimate of total system throughput.

As stated above, MERC-PNG calculates its design-day study using weather data from three weather stations. In Information Request No. 6 (OES Attachment 3), the OES noted that the test-year sales numbers approved by the Commission for MERC-PNG's Northern PGA system were calculated using data from four weather stations (Rochester, Minneapolis-St. Paul, Cloquet, and Sioux Falls, South Dakota). In an effort to synthesize analyses and account for the Company's customer base in Southwestern Minnesota, the OES requested that MERC-PNG conduct its design-day day analysis with weather data from the same weather stations that were used in the Company's last rate case. In its response to OES Information Request No. 6 (OES Attachment 3), MERC-PNG conducted its design-day analysis including weather data from Worthington, MN in place of Sioux Falls, South Dakota.[4] The Company states that the regression results associated with the updated design-day analysis are more robust than those associated with MERC-PNG's originally filed design-day analysis. The OES recommends that, on a going-forward basis, MERC-PNG conduct its design-day analysis using weather data from the following weather stations: Cloquet, MN; Minneapolis-Saint Paul, MN; Rochester, MN; and Worthington, MN.

As noted above, the OES believes that MERC-PNG conducts its design-day analysis using a statistically valid technique; however, the OES is still concerned that this analysis may not be able to fully ensure system reliability on an all-time peak day. The OES's primary concern relates to estimating firm throughput on a peak day. To estimate daily use by firm customers, MERC-PNG must subtract estimated use by interruptible and transportation customers from total throughput As mentioned in MERC-PNG's *Initial Petition*, page 9, the Company states that it only has monthly billing cycle data, rather than daily data, for the majority of its interruptible and transportation customers. Thus, the Company must estimate daily use by interruptible and

[4] MERC-PNG conducted its updated sales forecast in the Docket No. G007,011/GR-08-835 using weather data from Sioux Falls, South Dakota. The Company used weather data from Worthington in place of Sioux Falls since Worthington is located in the middle of its Southwestern Minnesota customer base and, thus, is more representative of the weather conditions that these ratepayers experienced.

transportation customers before estimating firm sales. However, since natural gas use by these non-firm customers is less sensitive to weather than firm customers, it is not unreasonable to assume, as MERC-PNG does, that these customers will consume roughly the same amount of gas each day. While reviewing MERC-PNG's calculation of average daily interruptible and transportation use, the OES observed that the Company bases its calculation on 20 days in the month, which indicates that MERC-PNG believes that these customers operate approximately five days a week. The OES would prefer a more precise estimate, but notes that MERC-PNG is in the process of obtaining data for a more precise estimate of peak-day use, as discussed below.

The OES conducted further peak day analysis by comparing MERC-PNG's estimate of peak day use by interruptible and transportation customers to total peak day throughput estimates calculated by the Company in its response to OES Information Request No. 2 (OES Attachment 1). Based on this analysis, it appears that MERC-PNG's design-day calculations are sufficient to ensure firm reliability on a peak day. While discussing issues in the OES's calculation of peak day throughput for MERC-PNG's Viking PGA system (Docket No. G011/M-09-1283), the Company noted that it had observed an error in the weather input data used in the Northern PGA design day analysis. The OES is unaware what impact this error may have on estimated peak day usage and, as such, its conclusion about peak day firm reliability may change based on updated data from MERC-PNG. Therefore, the OES recommends that MERC-PNG provide, in its *Reply Comments*, an updated design day analysis, and all supporting regression models and data that corrects the data error referenced by the Company in its discussion with the OES.

The OES notes the difficulty in estimating the daily amounts that interruptible and transportation customers use. The Company is further attempting to mitigate the design day risk associated with transportation customers by requiring gas meter telemetry. In its most recent general rate case, Docket No. G007,011/GR-08-835, MERC-PNG and MERC-NMU proposed a change in rate design requiring all transportation customers to install telemetry. In its June 29, 2009 *Order* in this rate case, the Commission agreed with the Administrative Law Judge's finding, and the Company's proposal, that MERC-PNG be allowed to require telemetry for transportation customers, without exception.[5]

Based on the discussion above, the OES concludes that MERC-PNG made a reasonable attempt to estimate its design-day and peak-day sendout. However, given the lack of daily data associated with MERC-PNG's interruptible and transportation customers, the OES recommends that the Commission not endorse this technique until such time that MERC-PNG has adequate daily interruptible and transportation throughput data. Further, the OES recommends that MERC-PNG provide, in its *Reply Comments*, a full discussion detailing how it intends to install telemetry equipment for its transportation customers and an estimate of how long it will be before MERC-PNG has adequate daily data to more accurately estimate its firm design day.

[5] Please note that the Commission included in its *Order* a requirement that MERC-PNG continue providing balancing service for its Small Volume Interruptible customers. As a result, it will still be necessary for MERC-PNG to estimate daily use by Small Volume Interruptible customers in its estimate of peak-day use by firm customers.

b. Volume-Risk Adjustment

In its *Initial Petition*, MERC-PNG states that it adds a volume risk adjustment to its design-day estimate. The purpose of the volume risk adjustment, as stated by the Company, is "to provide a confidence level that the daily metered load under design conditions would not exceed the daily metered regression estimate." In other words, MERC-PNG's adjustment is intended to address the concern discussed above regarding the estimate of energy used on a peak day. The confidence level MERC-PNG chose is 97.5 percent, which means that there is roughly a 2.5 percent chance that any given design day estimate will exceed the daily throughput estimate at a given point. In its response to OES Information Request No. 5 (OES Attachment 4), MERC-PNG states that a 99.9 percent confidence level could also have been chosen, which means that there would be a roughly 0.1 percent chance that a given design day estimate would exceed throughput estimates. Procuring demand contracts to meet a 99.9 percent confidence level would essentially assure full system integrity under any circumstance, but would also involve additional costs over MERC-PNG's current 97.5 percent confidence level. The OES concludes that MERC-PNG's proposed adjustment is reasonable at this time.

2. Demand Entitlement Level

In its *Petition*, MERC-PNG requests an increase in total entitlement levels between the 2008-2009 heating season and the 2009-2010 heating season of 4,279 Mcf/day. MERC-PNG's requested changes in entitlement contracts are as follows:

Table 1: MERC-PNG's Proposed Changes to Northern PGA System Demand Entitlements	
Contract Name	Level of Change (Mcf)
TF-12 Base	5,315
TF-12 Variable	(8,107)
TF-5	2,792
TFX5	(8,563)
TFX7[6]	(10,837)*
TFX12	12,790
Option Peak Service	52
Total Change	4,279

*These volumes are not included in the total entitlement calculations as the TFX7 contract is used to serve firm customers during the non-heating season months.
Note: While reviewing these changes in demand entitlement volumes, the OES notes that it appears that the information provided in MERC-PNG's original *Petition*, Attachment 3, is calculated incorrectly. The OES's revised calculation, and support for Table 1 above, is presented in OES Attachment 5.

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[6] Based on a review of MERC-PNG's October 2009 and November 2009 PGAs, and supporting documentation in the initial *Petition*, it appears that MERC-PNG incorrectly labeled a TFX12 contract in its November 2009 PGA as a TFX7 contract. The OES recommends that MERC-PNG clarify, in its *Reply Comments*, what the correct label for this contract should be.

Given relatively mild temperatures during recent heating seasons, the OES investigated historical peak-day sendout per customer information. OES Attachment 6 shows that the all-time peak-day sendout was 1.4900 Mcf/customer during the 1993-1994 heating season. The OES further notes that the all-time estimated design-day sendout was 1.5175 Mcf/customer during the 1995-1996 heating season.[7]

As indicated in OES Attachment 6, the firm peak-day sendout on MERC-PNG's Northern PGA system for the 2008-2009 heating season was 176,225 Mcf/day, a decrease of 6,584 Mcf/day (or approximately 3.70 percent) over the 2007-2008 heating season. The Company's proposed design-day requirement results in an anticipated design-day use per customer of 1.2898 Mcf/day. The total entitlement per customer of 1.4655 Mcf/day is greater than the 20-year average peak-day sendout per customer of 1.4402 Mcf/day, but less than the all-time peak day sendout per customer of 1.4900 Mcf/day. The OES further notes that the Company's total entitlement per customer is less than the all-time peak day sendout per design-day customer of 1.5175 Mcf/day. These results might suggest that the Company does not have sufficient capacity for a peak day; however, given the OES's analysis of MERC-PNG's design-day analysis, the OES concludes that the Company has sufficient capacity to ensure reliable firm service on a peak day.

It is important to ensure that the Company does not over-estimate its need unreasonably and cause PGA rates to be too high. The OES intends to continue working with the Company in refining its peak-day use per customer estimates, and looks forward to the information MERC-PNG will provide in its *Reply Comments* related to its design-day calculations.

3. Reserve Margin

As shown in OES Attachment 6, the Company's entitlement proposal results in a positive reserve margin for MERC-PNG's Northern PGA system customers of 13.62 percent, which is an increase of 13.00 percent from the 2008-2009 reserve margin of 0.62 percent. This change is a significant increase in the reserve margin over the previous heating season and results in a reserve margin that is significantly higher than the five percent threshold that the OES considers an adequate reserve margin. The OES certainly appreciates that MERC-PNG is providing reliable service to its customers. However, as noted above, it is also important to ensure that rates are reasonable, given the alternatives available to the Company in providing service. Given this large reserve margin, the OES recommends that MERC-PNG provide a full discussion, in its *Reply Comments*, justifying the large reserve margin on its Northern PGA system.

[7] Prior to a heating seasons, utilities estimate the "design-day" needs of customers by estimating the sendout and the number of customers expected to be using service on a peak day. After the heating season, it is possible to look back and determine the actual use per customer on the peak day.

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

As MERC-PNG explains in its filing, there are two types of demand entitlement changes. The first type is design-day deliverability, which, in this filing, represents changes in various firm transportation capacity available to Northern PGA customers during winter peak periods. The second type does not affect the level of design-day deliverability, but does affect the demand costs recovered from ratepayers through the PGA. Changes in the second type of demand entitlement changes are made to non-winter transportation and balancing contracts. In its filing, MERC-PNG proposes to eliminate its TFX-7 contract, which was used to serve firm customers during the non-heating months, and proposes changes to its firm storage contracts.

D. MERC-PNG'S COST RECOVERY PROPOSAL FOR THE NORTHERN PGA SYSTEM

The demand entitlement changes discussed above represent the demand entitlements that firm customers on MERC-PNG's Northern PGA system would pay under MERC-PNG's proposal. The Company's *Petition* uses MERC-PNG's October 2009 PGA as a means of comparison for its entitlement level cost changes since MERC-PNG proposes that the rate change take effect on November 1, 2009. MERC-PNG's changes result in the following bill impacts:

Table 2: MERC-PNG's Northern PGA System Cost Recovery Monthly Rate Impact as Calculated by MERC-PNG Compared to the October 2009 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	$1.2675	33.89%	$(0.0319)	(2.93)%	$1.2356	19.14%	$154.29
Small Vol. Interruptible	$1.2675	33.89%	$0.0000	0.00%	$1.2675	25.43%	$5,171.05
Large Vol. Interruptible	$1.2675	33.89%	$0.0000	0.00%	$1.2675	30.92%	$24,149.98
Small Vol. Firm	$1.2675	33.89%	$(1.0333)	(9.94)%	$0.2342	24.93%	$5,145.22
Large Vol. Firm	$1.2675	33.89%	$(1.0333)	(9.94)%	$0.2342	30.34%	$18,733.48

As shown in Table 2 above, and in MERC-PNG Attachment 4 in its *Initial Petition*, the Company's proposed entitlement levels would result in the following estimated annual bill impacts:

- an increase of approximately $154.29, or 19.14 percent, for an average General Service customer consuming 125 Mcf annually;
- an increase of approximately $5,171.05, or 25.43 percent, for an average Small Volume Interruptible customer consuming 4,080 Mcf annually;
- an increase of approximately $24,149.98, or 30.92 percent, for an average Large Volume Interruptible customer consuming 19,053 Mcf annually;

- an increase of approximately $5,145.22, or 24.93 percent, for an average Small Volume Firm customer consuming 4,080 Mcf annually; and
- an increase of approximately $18,733.48, or 30.43 percent, for an average Large Volume Firm customer consuming 14,841 Mcf annually.

The OES's analysis is different from that shown in MERC-PNG's *Initial Petition* for two reasons. First, 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, the OES does not include storage costs in its demand cost calculations, but rather in the commodity portion of the PGA. The OES notes that its decision to include Firm Deferred Demand (FDD) storage in the commodity portion of the PGA is the result of MERC-PNG's conclusions in its *Supplemental Comments* in Docket No. G011/M-07-1405. In that docket, the Company stated that it was appropriate to recover storage costs through the commodity portion of the PGA since all customers, not just firm customers, benefit from natural gas storage.[8] The OES's bill impacts are as follows:

Table 3: MERC-PNG's Northern PGA System Cost Recovery Monthly Rate Impact as Calculated by the OES Compared to the October 2009 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	$0.1736	4.64%	$(0.2083)	(19.14)%	$(0.0347)	(0.54)%	$(4.34)
Small Vol. Interruptible	$0.1736	4.64%	$0.0000	0.00%	$0.1736	3.48%	$708.29
Large Vol. Interruptible	$0.1736	4.64%	$0.0000	0.00%	$0.1736	4.24%	$3,307.60
Small Vol. Firm	$0.1736	4.64%	$0.2122	2.04%	$0.1736	3.48%	$713.29
Large Vol. Firm	$0.1736	4.64%	$0.2122	2.04%	$0.1558	3.78%	$2,592.31

Note: The change in commodity cost relates to the implementation of Call Option costs for the 2009-2010 heating season.

As shown in Table 3 above, and in OES Attachments 7 and 8, the OES's calculation of changes in MERC-PNG's proposed entitlement levels would result in the following estimated annual bill impacts:

- a decrease of approximately $4.34, or 0.54 percent, for an average General Service customer consuming 125 Mcf annually;
- an increase of approximately $708.29, or 3.48 percent, for an average Small Volume Interruptible customer consuming 4,080 Mcf annually;

[8] Purchased gas costs passed through the monthly PGAs to customers are classified as either demand-delivered gas costs (demand costs) or commodity-delivered gas costs (commodity costs). Generally, demand costs are recovered only from firm sales service customers and commodity costs are recovered from both firm and interruptible sales service customers. However, both firm and interruptible sales customers use storage gas and both classes receive the benefit of the possible hedge against winter price increases resulting from the use of storage gas. The Commission has not yet acted on this requested change in recovery of FDD Storage costs.

- an increase of approximately $3,307.60, or 4.24 percent, for an average Large Volume Interruptible customer consuming 19,053 Mcf annually;
- an increase of approximately $713.29, or 3.48 percent, for an average Small Volume Firm customer consuming 4,080 Mcf annually; and
- an increase of approximately $2,592.31, or 3.78 percent, for an average Large Volume Firm customer consuming 14,841 Mcf annually.

III. THE OES'S RECOMMENDATIONS

The OES withholds recommendation in this proceeding until the Company provides additional information in its *Reply Comments*. Specifically, the OES recommends that MERC-PNG provide the following in its *Reply Comments*:

- a full discussion explaining why it uses a different wind chill calculation and what, if any, impact using the official wind chill calculation has on MERC-PNG's design-day forecast;
- an updated design day analysis, and all supporting regression models and data, that corrects the data error referenced by the Company in its discussions with the OES;
- a full discussion detailing how MERC-PNG intends to install telemetry equipment for its transportation customers and an estimate of how long it will be before it has adequate daily data to more accurately estimate its firm design day;
- a discussion clarifying whether the TFX contract included in MERC-PNG's November 2009 PGA filings should be a seven-month or twelve-month contract; and
- a full discussion justifying the large reserve margin on its Northern PGA system.

The OES also recommends that, on a going-forward basis, MERC-PNG conduct its design-day analysis using weather data from the following weather stations: Cloquet, MN; Minneapolis-Saint Paul, MN; Rochester, MN; and Worthington, MN.

/ja

State of Minnesota
OFFICE OF ENERGY SECURITY

Utility Information Request

Docket Number: G011/M-09-1284 Date of Request: December 11, 2009

Requested From: Minnesota Energy Resources Corporation Response Due: December 21, 2009

Analyst Requesting Information: Adam Heinen

Type of Inquiry:

[ ]......Financial	[ ]......Rate of Return	[ ]......Rate Design
[ ]......Engineering	[ ]......Forecasting	[ ]......Conservation
[ ]......Cost of Service	[ ]......CIP	[]......Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
2	Subject: Design-Day Regression Models

Please provide the following related to MERC-PNG Northern's design-day regression:

a) a copy of any, and all, regression outputs that were used by MERC-PNG Northern to determine its design-day study;
b) any, and all, input, and raw, data used by MERC-PNG Northern in its design-day analysis; and
c) any, and all, raw weather data, and calculations, used to determine MERC-PNG Northern's weather input data.

If this information has already been provided in written testimony or in response to an earlier OES information request, please identify the specific testimony cite(s) or OES information request number(s).

Response:

a. All data used in the MERC-PNG Northern peak day regressions and the individual regression results are provided on separate tabs in the attached Excel spreadsheet "MERC09-1284-IR2a-PNG-NNGpeakdayRegressions.xls"

b. The raw input data used in the regressions appears on the "Data" tab of the Excel file attached in the response to part (a) (some of this data is "lagged" to provide prior day values on the "Values" tab of that file). The attached Excel file "MERC09-1284-IR2b-Interruptible-TransportationConsumptionReportfor2010PeakDay 091509.xls" provides support for removing the 76,449 Dths of Interruptible, Transportation, and Joint Interruptible demand. There was no Daily Firm Capacity added back into the peak day requirements. The attached Excel file "MERC09-1284-IR2b-MERCFCST2009004_June_03_09.xls" contains support for the -1.6% sales forecast change for general service customers from 2009 to 2010.

c. The attached Excel files "MERC09-1284-IR2c-Cloquet Weather Data.xls", "MERC09-1284-IR2c-Minneapolis Weather Data.xls" and "MERC09-1284-IR2c-Rochester Weather Data.xls" contain the raw weather data and calculations used to determine MERC-PNG Northern's weather input data for both the daily regression data and the design weather conditions.

State of Minnesota
OFFICE OF ENERGY SECURITY

Utility Information Request

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Analyst Requesting Information: Adam Heinen

Type of Inquiry:			
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	[ ]......Cost of Service	[ ]......CIP	[]......Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
3	Subject: Design-Day Weather Data

MERC-PNG Northern uses adjusted heating degree days (AHDDs) as an input in its design-day study models. As discussed in the OES's June 17, 2009 *Response Comments* in Docket No. G011/M-08-1328, Commission Staff raised concerns about the appropriateness of using AHDDs in calculating the design-day. Given these concerns, please provide any, and all, evidence, including by not limited to statistical analysis, that fully supports MERC-PNG's use of AHDDs in its design-day calculations.

If this information has already been provided in written testimony or in response to an earlier OES information request, please identify the specific testimony cite(s) or OES information request number(s).

Response:

The Excel file attachment in the response to question 2a above shows the details of the regressions run using MERC-PNG Northern adjusted heating degree days (AHDD) on the "3yr-AHDD65" tab. The "3yr-HDD65" tab contains the regression results using standard heating degree days (HDD). The standard error, or sigma, for the AHDD regression of 10,422.2 is 6% lower than the HDD regression sigma of 11,056.2, indicating that the AHDD variable provides a better fit than HDD. The AHDD regression also has a higher R-Squared value than the HDD regression (0.893 vs. 0.880).

Note: The above analysis is focused on directly comparing AHDD verses HDD to determine which variable better matches MERC-PNG Northern customer demand. The final Design Day forecast "3yr-S+AHDD65" regression uses AHDD with additional significant indicator variables.

State of Minnesota
OFFICE OF ENERGY SECURITY

Utility Information Request

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[ ]......Financial	[ ]......Rate of Return	[ ]......Rate Design
[ ]......Engineering	[ ]......Forecasting	[ ]......Conservation
[ ]......Cost of Service	[ ]......CIP	[]......Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
6	Subject: Weather Stations

Reference: Initial Filing, Page 4

In its Direct Testimony in MERC's recent rate case (Docket No. G007,011/GR-08-835), the OES noted that MERC-PNG's Northern Purchased Gas Adjustment (PGA) system has a significant population base in Southwestern Minnesota. In response to OES discovery, MERC-PNG re-calculated its sales forecast using Sioux Falls, South Dakota data, since this National Weather Service (NWS) station is closer to MERC-PNG's Southwestern Minnesota customers. In addition, the re-calculated sales forecast was used by the Commission to set final rates. Given this, please re-calculate the MERC-PNG Northern PGA system design-day study using Sioux Falls, South Dakota weather data in the same manner as in the rate case forecast.

If this information has already been provided in written testimony or in response to an earlier OES information request, please identify the specific testimony cite(s) or OES information request number(s).

Response:

Weather station amended to Worthington, Minnesota from Sioux Falls, South Dakota with revised response due date of December 28, 2009.

Please see the attached Excel file "MERC09-1284-IR6-Worthington Regression Summary20091221.xls" for a comparison of the MERC-PNG Northern 2010 Total Peak Day Estimate calculated two ways:

1. Before – As Filed – No Worthington
2. After – Including Worthington

The "Summary" Tab shows the components of the peak day calculation that result in the "After – Including Worthington Weather" method estimate of 199,468 dth. This is a decrease of 3,892 dth or 1.91% from the "Before - As-Filed - No Worthington" 2010 Total Peak Day Estimate of 203,360 dth.

The "Regression Summary" tab shows the difference and percent difference between the individual regression coefficients, R-Squared values, sigmas, and point estimates. Note that the R-Squared values for the "After-Including Worthington Weather Station" regressions are higher than those for the "Before-As Filed" regressions, indicating that including the Worthington weather station provides a better statistical fit to the winter daily load data for MERC-PNG Northern. The Sigma values for the "After" regressions are between 10% and 15% lower than the Sigma values for the "Before-As Filed" regressions, indicating that including the Worthington weather station reduces the actual daily data point spread around the regression line. The combination of higher R-Squared and lower Sigma for each regression shows that including the Worthington weather station data provides more statistically accurate peak day regression results for MERC-PNG Northern.

The "With Worthington" tab shows the peak day design weather conditions and weightings for each of the four weather stations (4.5% Cloquet, 32.4% Minneapolis, 48.4% Rochester, and 14.7% Worthington). These weightings were based on actual daily meter readings for the Town Border Stations mapped as closest to their respective weather station for the time period used in the peak day calculation (most recent three years of December through February data). This tab also provides a short description of each regression, the regression coefficients and results.

The "As Filed" tab shows the peak day design weather conditions and weightings for each of the three weather stations (4.5% Cloquet, 35.1% Minneapolis, and 60.5% Rochester). These weightings were based on actual daily meter readings for the Town Border Stations mapped as closest to their respective weather station for the time period used in the peak day calculation (most recent three years of December through February data). This tab also provides a short description of each regression, the regression coefficients and results.

PNG-NNG Peak Day Results for Winter 2010 - Impact of Adding Worthington Weather Station
Based on December through February Data for 3 years

	Point Estimate	Sigma	97.5% Confidence Level Z-Factor	Total Risk Adjustment	(Remove) Interrupt Transport & Joint Interrupt	(Add Back) Daily Firm Capacity Jan 2008	Sub-Total 2010 Peak Day Estimate	Sales Forecast Growth Rate	2010 Total Peak Day Estimate
After - Including Worthington Weather:	262,796	8,363.10	1.96	16,391	76,449	0	202,739	-1.6%	199,468
Before - As Filed - No Worthington:	263,960	9,787.80	1.96	19,184	76,449	0	206,695	-1.6%	203,360
Difference = After - Before	(1,164)	(1,425)	0	(2,792)	0	0	(3,956)	0	(3,892)
Pct. Difference = Difference / Before	-0.44%	-14.56%		-14.56%			-1.91%		-1.91%

PNG-NNG Peak Day Regression Results for Winter 2010 - Impact of Adding Worthington Weather Station
Based on December through February Data for 3 years

Regression	Baseload	Use Per AHDD65	Use Per WCHDD65	Use Per CloudPct	Adj R Sq.	Sigma	Point Est	Total Daily Meter Risk Adjustment	Total Daily Meter Peak Day Estimate
After - Including Worthington Weather Station:									
3yr-S	15,876.52		2,325.45	9,363.94	0.938	7,956.81	279,574	15,595	295,169
3yr-S+AHDD65	**25,984.31**	**2,385.80**			**0.931**	**8,363.10**	**262,796**	**16,391**	**279,188**
3yr-AHDD65	21,997.78	2,402.04			0.919	9,075.84	260,422	17,788	278,211
3yr-WCHDD65	12,077.22		2,339.15	9,170.76	0.926	8,705.59	277,228	17,063	294,291
3yr-HDD65					0.904	9,870.35			
Before - As Filed Before Adding Worthington Weather Station:									
Last Year 3yr-S	30,317.87	2,188.99			0.908	9,386.09	248,585	18,396	266,981
Last Year 3yr-AHDD65	27,792.43	2,183.79			0.895	10,021.41	245,542	19,642	265,183
3yr-S	16,976.68		2,362.12	11,688.16	0.913	9,152.64	288,537	17,939	306,476
3yr-S+AHDD65	**30,579.97**	**2,336.94**			**0.900**	**9,787.80**	**263,960**	**19,184**	**283,144**
3yr-AHDD65	28,003.92	2,340.31			0.887	10,415.59	261,721	20,414	282,135
3yr-WCHDD65	14,138.46		2,360.57	11,261.30	0.898	9,900.96	285,333	19,406	304,738
3yr-HDD65					0.880	11,056.23			
Difference = After - Before									
3yr-S	(1,100.16)		(36.66)	(2,324.22)	0.025	(1,195.83)	(8,962)	(2,344)	(11,306)
3yr-S+AHDD65	**(4,595.66)**	**48.86**			**0.031**	**(1,424.70)**	**(1,164)**	**(2,792)**	**(3,956)**
3yr-AHDD65	(6,006.14)	61.73			0.032	(1,339.75)	(1,299)	(2,626)	(3,924)
3yr-WCHDD65	(2,061.23)		(21.42)	(2,090.54)	0.028	(1,195.38)	(8,104)	(2,343)	(10,447)
3yr-HDD65					0.024	(1,185.87)			
Pct Diff = Difference / Before									
3yr-S	-6.5%		-1.6%	-19.9%	2.8%	-13.1%	-3.1%	-13.1%	-3.7%
3yr-S+AHDD65	**-15.0%**	**2.1%**			**3.5%**	**-14.6%**	**-0.4%**	**-14.6%**	**-1.4%**
3yr-AHDD65	-21.4%	2.6%			3.7%	-12.9%	-0.5%	-12.9%	-1.4%
3yr-WCHDD65	-14.6%		-0.9%	-18.6%	3.1%	-12.1%	-2.8%	-12.1%	-3.4%
3yr-HDD65					2.8%	-10.7%			

PNG-NNG Peak Day Regression for Winter 2010 - Summary - After Adding Worthington Weather Station
Based on December through February Data for 3 years

102.7	Coldest Cloquet AHDD65 in 20 years (Feb 2, 1996)	4.5%
97.2	Coldest Minneapolis AHDD65 in 20 years (Feb 2, 1996)	32.4%
101.2	Coldest Rochester AHDD65 in 20 years (Feb 2, 1996)	48.4%
96.4	Coldest Worthington AHDD65 in 20 years (January 18, 1996)	14.7%
99.3	Weighted Average AHDD65 based on 3 years of volumes	

115.4	Coldest Cloquet WCHDD65 in 20 years (Feb 2, 1996)
109.6	Coldest Minneapolis WCHDD65 in 20 years (Feb 2, 1996)
114.4	Coldest Rochester WCHDD65 in 20 years (Feb 2, 1996)
107.0	Coldest Worthington WCHDD65 in 20 years (Feb 2, 1996)
111.8	Weighted Average WCHDD65 based on 3 years of volumes

82%	Cloud Pct on Coldest Cloquet WCHDD65 in 20 years (Feb 2, 1996)
43%	Cloud Pct on Coldest Minneapolis WCHDD65 in 20 years (Feb 2, 1996)
43%	Cloud Pct on Coldest Rochester WCHDD65 in 20 years (Feb 2, 1996)
11%	Cloud Pct on Coldest Worthington WCHDD65 in 20 years (Feb 2, 1996)
40%	Weighted Average Cloud Pct based on 3 years of volumes

2.5%	Risk Tolerance for Actual Load Exceeding Estimate

Regression	Baseload	Use Per AHDD65	Use Per WCHDD65	Use Per CloudPct	Adj R Sq.	Sigma	Point Est	Total Daily Meter Risk Adjustment	Total Daily Meter Peak Day Estimate	Notes:
Last Year 3yr-S	30,317.87	2,188.99			0.908	9,386.09	248,585	18,396	266,981	Dec 2005 to Feb 2008, only statistically significant independent variables
Last Year 3yr-AHDD65	27,792.43	2,183.79			0.895	10,021.41	245,542	19,642	265,183	Dec 2005 to Feb 2008, only AHDD65
3yr-S	15,876.52		2,325.45	9,363.94	0.938	7,956.81	279,574	15,595	295,169	Dec 2006 to Feb 2009, SAS best statistically significant independent variables
3yr-S+AHDD65	25,984.31	2,385.80			0.931	8,363.10	262,796	16,391	279,188	Dec 2006 to Feb 2009, AHDD65 plus Significant non-weather variables
3yr-AHDD65	21,997.78	2,402.04			0.919	9,075.84	260,422	17,788	278,211	Dec 2006 to Feb 2009, only AHDD65
3yr-WCHDD65	12,077.22		2,339.15	9,170.76	0.926	8,705.59	277,228	17,063	294,291	Dec 2006 to Feb 2009, only WCHDD65 (New Significant Weather Variables)

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Attachment 3
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PNG-NNG Peak Day Regression for Winter 2010 - Summary - As Filed - Before Adding Worthington Weather Station
Based on December through February Data for 3 years

102.7	Coldest Cloquet AHDD65 in 20 years (Feb 2, 1996)	4.5%
97.2	Coldest Minneapolis AHDD65 in 20 years (Feb 2, 1996)	35.1%
101.2	Coldest Rochester AHDD65 in 20 years (Feb 2, 1996)	60.5%
99.9	Weighted Average AHDD65 based on 3 years of volumes	

115.4	Coldest Cloquet WCHDD65 in 20 years (Feb 2, 1996)
109.6	Coldest Minneapolis WCHDD65 in 20 years (Feb 2, 1996)
114.4	Coldest Rochester WCHDD65 in 20 years (Feb 2, 1996)
112.8	Weighted Average WCHDD65 based on 3 years of volumes

82%	Cloud Pct on Coldest Cloquet WCHDD65 in 20 years (Feb 2, 1996)
43%	Cloud Pct on Coldest Minneapolis WCHDD65 in 20 years (Feb 2, 1996)
43%	Cloud Pct on Coldest Rochester WCHDD65 in 20 years (Feb 2, 1996)
45%	Weighted Average Cloud Pct based on 3 years of volumes

2.5%	Risk Tolerance for Actual Load Exceeding Estimate

Regression	Baseload	Use Per AHDD65	Use Per WCHDD65	Use Per CloudPct	Adj R Sq.	Sigma	Point Est	Total Daily Meter Risk Adjustment	Total Daily Meter Peak Day Estimate	Notes:
Last Year 3yr-S	30,317.87	2,188.99			0.908	9,386.09	248,585	18,396	266,981	Dec 2005 to Feb 2008, only statistically significant independent variables
Last Year 3yr-AHDD65	27,792.43	2,183.79			0.895	10,021.41	245,542	19,642	265,183	Dec 2005 to Feb 2008, only AHDD65
3yr-S	16,976.68		2,362.12	11,688.16	0.913	9,152.64	288,537	17,939	306,476	Dec 2006 to Feb 2009, SAS best statistically significant independent variables
3yr-S+AHDD65	30,579.97	2,336.94			0.900	9,787.80	263,960	19,184	283,144	Dec 2006 to Feb 2009, AHDD65 plus Significant non-weather variables
3yr-AHDD65	28,003.92	2,340.31			0.887	10,415.59	261,721	20,414	282,135	Dec 2006 to Feb 2009, only AHDD65
3yr-WCHDD65	14,138.46		2,360.57	11,261.30	0.898	9,900.96	285,333	19,406	304,738	Dec 2006 to Feb 2009, only WCHDD65 (New Significant Weather Variables)
3yr-HDD65					0.880	11,056.23				

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Attachment 3
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State of Minnesota
OFFICE OF ENERGY SECURITY

Utility Information Request

Docket Number: G011/M-09-1284 Date of Request: December 11, 2009

Requested From: Minnesota Energy Resources Corporation Response Due: December 21, 2009

Analyst Requesting Information: Adam Heinen

Type of Inquiry:			
	[ ].....Financial	[ ].....Rate of Return	[ ].....Rate Design
	[ ].....Engineering	[ ].....Forecasting	[ ].....Conservation
	[ ].....Cost of Service	[ ].....CIP	[].......Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
5	Subject: Volume Risk Adjustments

Reference: MERC-PNG Northern Initial Filing, Page 9

A. Please provide a full explanation of how MERC-PNG arrived at its desired confidence level of 97.5 percent, which is mentioned in the above reference.

B. Please provide a full explanation, including calculations where applicable, of how MERC-PNG's volume risk adjustment influences load under design-day conditions.

If this information has already been provided in written testimony or in response to an earlier OES information request, please identify the specific testimony cite(s) or OES information request number(s).

Response:

A. MERC-PNG used management judgment and traditional statistical techniques to select the 97.5% confidence level that actual firm customer demand under design peak day conditions would not exceed the estimate. MERC-PNG selected 97.5% because the resulting confidence level covers actual observations up to 1.96 standard deviations (sigmas) above the regression line and represents a reasonable balance between the volume risk inherent in covering only 1 sigma and the incremental supply required to cover 3 sigmas.

Covering only 1 sigma leaves about a 16% chance that actual firm customer demand under design-day conditions would exceed the forecast, which seemed too risky. Covering 3 sigmas reduces the risk that actual firm customer demand under design-day conditions would exceed the forecast to about 0.1%. It takes the same incremental peak day volumes to move from covering 1 sigma to covering 2 sigmas as it does to move from covering 2 sigmas to covering 3 sigmas. Covering 2 sigmas instead of 1 reduces the volume risk from 16% to about 2.5%. Covering 3 sigmas instead of 2 reduces the volume risk from about 2.5% to about 0.1%. MERC-PNG management did not feel that the incremental risk reduction associated with moving from 2 to 3 sigmas justified the incremental peak day volumes required and increasing their associated costs to ratepayers. MERC-PNG management decided that 2.5% was a reasonable volume risk and fine tuned the number of sigmas to 1.96 based on the traditional statistical one-tailed test.

There is no single correct answer as to the proper method for selecting the peak day design volume risk conditions. Any method will result in different risks and costs for MERC-PNG's customers, as MERC-PNG needs to balance 1) the probability that firm customer requirements under design-day weather conditions could exceed the peak day requirements forecast and 2) the costs associated with actual firm supply exceeding firm requirements.

B. MERC-PNG's volume risk adjustment does not influence the actual load under design-day conditions. The volume risk adjustment quantifies the risk that actual load under design-day conditions could exceed the peak day forecast.

Relying on the regression line forecast alone provides an average "point estimate" of load under design-day conditions with a 50% chance that actual load under those design-day conditions would be higher than the forecast. MERC-PNG management interprets this as a 50% chance of facing more demand than the regression line shows on the day that our customers need service most.

Statistical confidence levels based on the 1-tail test are employed to convert the management risk preference of a 2.5% chance that actual load under design-day conditions could exceed the forecast to a volume risk adjustment required to provide that level of statistical confidence. Traditional statistical practice indicates that adding 1.96 sigmas to the regression line value provides an estimate that covers all but the highest 2.5% of expected occurrences. This approach does nothing to change the actual load under design-day conditions, it just recognizes that the actual load under design-day conditions is unknown and quantifies the chance that the peak day forecast could be exceeded when design-day conditions occur.

OES Attachment 5
OES's Modified Total Entitlement Change Calculations

OES's Modified Total Entitlement Change Calculations

	October 2009 Volumes	November 2009 Volumes	Difference
TF12B (MR)	25,469	30,021	4,552
TF12V (MR)	32,690	24,583	(8,107)
TF5 (MR)	26,064	29,619	3,555
TF12B (Dis)	4,437	5,200	763
TF5 (Dis)	763	0	(763)
TFX 5 (Dis)	6,000	6,000	0
TFX12 (MR)	9,724	9,724	0
TFX Apr	2,000	2,000	0
TFX Oct	2,000	2,000	0
TFX5 (MR)	46,558	48,754	2,196
TFX5 (Dis)	2,196	0	(2,196)
TFX5 (Dis)	1,800	1,800	0
TFX12 (Dis)	414	414	0
TFX12 (Dis)	8,271	9,140	869
TFX7 (Dis)	10,837	0	(10,837)
TFX12	0	11,921	11,921
TFX5 (Dis)	122	122	0
TFX5 (Dis)	2,445	2,702	257
TFX5 (Dis)	31,009	22,189	(8,820)
SMS	20,537	20,577	40
Option	26,323	26,375	52

	October 2009 Volumes	November 2009 Volumes	Difference
TF12	62,596	59,804	(2,792)
TF5	26,827	29,619	2,792
TFX5	90,130	81,567	(8,563)
TFX7	10,837	0	(10,837)
TFX12	18,409	31,199	12,790
TFX Apr	2,000	2,000	0
TFX Oct	2,000	2,000	0
Option	26,323	26,375	52
Total Entitlements	228,285	232,564	4,279

OES Attachment 6
Demand Entitlement Analysis
MERC-PNG's Northern Customers
As Proposed by MERC-PNG

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Peak Shaving			Reserve Margin
Heating Season	(1) No. of Design Day Customers	(2) Change from Previous Year	(3) % Change From Previous Year	(4) Design Day (Mcf)	(5) Change from Previous Year	(6) % Change From Previous Year	(7) Total Entitlement (Mcf)***	(8) Change from Previous Year	(9) % Change From Previous Year	(10) % of Reserve Margin [(7)-(4)]/(4)
2009-2010	157,670	697	0.44%	203,360	(22,037)	-9.78%	231,064	4,279	1.89%	13.62%
2008-2009	156,973	1,063	0.68%	225,397	23,134	11.44%	226,785	0	0.00%	0.62%
2007-2008	155,910	6,861	4.60%	202,263	1,779	0.89%	226,785	(741)	-0.33%	12.12%
2006-2007	149,049	741	0.50%	200,484	463	0.23%	227,526	17,399	8.28%	13.49%
2005-2006	148,308	4,412	3.07%	200,021	(7,813)	-3.76%	210,127	(9,857)	-4.48%	5.05%
2004-2005	143,896	3,191	2.27%	207,834	9,313	4.69%	219,984	13,844	6.72%	5.85%
2003-2004	140,705	3,957	2.89%	198,521	3,042	1.56%	206,140	(5,537)	-2.62%	3.84%
2002-2003	136,748	4,156	3.13%	195,479	(1,007)	-0.51%	211,677	13,282	6.69%	8.29%
2001-2002	132,592	2,844	2.19%	196,486	1,522	0.78%	198,395	0	0.00%	0.97%
2000-2001	129,748	3,446	2.73%	194,964	5,146	2.71%	198,395	7,195	3.76%	1.76%
1999-2000	126,302	3,619	2.95%	189,818	5,336	2.89%	191,200	3,425	1.82%	0.73%
1998-1999	122,683	3,102	2.59%	184,482	4,634	2.58%	187,775	6,709	3.71%	1.78%
1997-1998	119,581	700	0.59%	179,848	10,952	6.48%	181,066	27,179	17.66%	0.68%
1996-1997	118,881	2,942	2.54%	168,896	19,064	12.72%	153,887	12,792	9.07%	-8.89%
1995-1996	115,939	2,061	1.81%	149,832	(12,357)	-7.62%	141,095	0	0.00%	-5.83%
1994-1995	113,878	3,886	3.53%	162,189	5,252	3.35%	141,095	0	0.00%	-13.01%
1993-1994	109,992	2,588	2.41%	156,937	3,693	2.41%	141,095	(3,685)	-2.55%	-10.09%
1992-1993	107,404	2,705	2.58%	153,244	3,859	2.58%	144,780	0	0.00%	-5.52%
1991-1992	104,699	731	0.70%	149,385	1,043	0.70%	144,780	907	0.63%	-3.08%
1990-1991	103,968			148,342			143,873			
Average:			2.22%			1.81%			2.65%	1.18%

Prepared by the Minnesota Office of Energy Security

OES Attachment 6
Demand Entitlement Analysis
MERC-PNG's Northern Customers
As Proposed by MERC-PNG

Firm Peak Day Sendout

Heating Season	(11) Number of Peak Day Customers	(12) Firm Peak Day Sendout (Mcf)	(13) Change from Previous Year	(14) % Change From Previous Year	(15) Excess/Def. per Cust. [(7) - (4)]/(1)	(16) Design Day per Customer** (4)/(1)	(17) Entitlement per Customer (7)/(1)	(18) Peak Day Sendout per PD Customer (12)/(11)****	(19) Peak Day Sendout per DD Customer (12)/(1)
2009-2010	unknown	unknown			0.1757	1.2898	1.4655	unknown	unknown
2008-2009	157,951	176,225	(6,584)	-3.60%	0.0088	1.4359	1.4447	1.1157	1.0062
2007-2008	156,973	182,809	21,626	13.42%	0.1573	1.2973	1.4546	1.1646	1.0068
2006-2007	155,910	161,183	(22,248)	-12.13%	0.1814	1.3451	1.5265	1.0338	1.0814
2005-2006	148,308	183,431	24,083	15.11%	0.0681	1.3487	1.4168	1.2368	1.2368
2004-2005	148,242	159,348	(7,019)	-4.22%	0.0844	1.4443	1.5288	1.0749	1.1074
2003-2004	143,830	166,367	7,044	4.42%	0.0541	1.4109	1.4651	1.1567	1.1824
2002-2003	140,705	159,323	17,247	12.14%	0.1185	1.4295	1.5479	1.1323	1.1651
2001-2002	137,259	142,076	(22,028)	-13.42%	0.0144	1.4819	1.4963	1.0351	1.0715
2000-2001	132,247	164,104	21,769	15.29%	0.0264	1.5026	1.5291	1.2409	1.2648
1999-2000	131,538	142,335	(13,628)	-8.74%	0.0109	1.5029	1.5138	1.0821	1.1269
1998-1999	127,014	155,963	7,292	4.90%	0.0268	1.5037	1.5306	1.2279	1.2713
1997-1998 *	122,683	148,671	(13,962)	-8.58%	0.0102	1.5040	1.5142	1.2118	1.2433
1996-1997	119,581	162,633	(13,299)	-7.56%	-0.1263	1.4207	1.2945	1.3600	1.3680
1995-1996 **	118,881	175,932	39,122	28.60%	-0.0754	1.2923	1.2170	1.4799	**1.5175**
1994-1995	116,296	136,810	(27,074)	-16.52%	-0.1852	1.4242	1.2390	1.1764	1.2014
1993-1994	unknown	163,884	35,896	28.05%	-0.1440	1.4268	1.2828	**1.4900**	1.4900
1992-1993	unknown	127,988	7,396	6.13%	-0.0788	1.4268	1.3480	1.1917	1.1917
1991-1992	unknown	120,592	(12,451)	-9.36%	-0.0440	1.4268	1.3828	1.1518	1.1518
1990-1991	unknown	133,043			-0.0430		1.3838	1.2797	1.2797
Average:				2.44%	0.0120	1.4234	1.4402	1.2022	1.2086

* The Firm Peak Day Sendout and all related amounts in columns 13, 14, and 18 for all years prior to 1997-98 have been corrected.
** The calculated historic average of "Design-Day per Customer" excludes the 1995-96 design-day per customer projection of 1.2923 Mcf/day which, as discussed in Docket No. G011/M-95-1145, was incorrectly calculated.
*** The total entitlement for 2002-2003 includes the 7,410 Mcf/day of entitlement permanently released to Cornerstone.
**** The number of design day customers are used when the number of firm peak day customers is unknown.

Prepared by the Minnesota Office of Energy Security

OES Attachment 7
Rate Impact of MERC-PNG's Northern PGA System Proposed Demand Entitlement Changes as Modified by the OES

1) General Service: Avg. Annual Use: 125 Mcf

Recovery	Last Base Cost of Gas G011/MR-08 836	Last Demand Change M-08-1328	Most Recent PGA Oct 1/09	Oct 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9135	-55.02%	-34.55%	4.64%	$0.1736
Demand Rate	$1.1197	$1.0903	$1.0883	$0.8800	-21.41%	-19.29%	-19.14%	($0.2083)
Margin	$1.6263	$1.6263	$1.6263	$1.6263	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$11.4474	$8.6958	$6.4545	$6.4198	-43.92%	-26.17%	-0.54%	($0.0347)
Avg. Annual Bill*	$1,430.93	$1,086.98	$806.81	$802.48	-43.92%	-26.17%	-0.54%	($4.3375)
Effect of proposed commodity change on average annual bills:								$21.7000
Effect of proposed demand change on average annual bills:								($26.0375)

2) Small Volume Interruptible: Avg. Annual Use: 4,080 Mcf

Recovery	Last Base Cost of Gas G011/MR-08 836	Last Demand Change M-08-1328	Most Recent PGA Oct 1/09	Oct 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9135	-55.02%	-34.55%	4.64%	$0.1736
Demand Rate	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Margin	$1.2434	$0.9000	$1.2434	$1.2434	0.00%	38.16%	0.00%	$0.0000
Total Recovery	$9.9448	$6.8792	$4.9833	$5.1569	-48.14%	-25.04%	3.48%	$0.1736
Avg. Annual Bill*	$40,574.78	$28,067.14	$20,331.86	$21,040.15	-48.14%	-25.04%	3.48%	$708.2880
Effect of proposed commodity change on average annual bills:								$708.2880
Effect of proposed demand change on average annual bills:								$0.0000

3) Large Volume Interruptible: Avg. Annual Use: 19,053 Mcf

Recovery	Last Base Cost of Gas G011/MR-08 836	Last Demand Change M-08-1328	Most Recent PGA Oct 1/09	Oct 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9135	-55.02%	-34.55%	4.64%	$0.1736
Demand Rate	$0.0000	$0.0000	$0.0000	$0.0000	0.00%	0.00%	0.00%	$0.0000
Margin	$0.3592	$0.3592	$0.3592	$0.3592	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$9.0606	$6.3384	$4.0991	$4.2727	-52.84%	-32.59%	4.24%	$0.1736
Avg. Annual Bill*	$172,631.61	$120,765.54	$78,100.15	$81,407.75	-52.84%	-32.59%	4.24%	$3,307.6008
Effect of proposed commodity change on average annual bills:								$3,307.6008
Effect of proposed demand change on average annual bills:								$0.0000

4) Small Volume Firm: Avg. Annual Use: 4,080 Mcf (MERC-PNG currently has no customers in this class.)
Avg. Annual CD Volumes: 25 Mcf

Recovery	Last Base Cost of Gas G011/MR-08 836	Last Demand Change M-08-1328	Most Recent PGA Oct 1/09	Oct 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$8.7014	$5.9792	$3.7399	$3.9135	-55.02%	-34.55%	4.64%	$0.1736
Demand Rate	$13.4177	$12.0195	$10.3925	$10.6047	-20.96%	-11.77%	2.04%	$0.2122
Comm. Margin	$1.2434	$1.2434	$1.2434	$1.2434	0.00%	0.00%	0.00%	$0.0000
SV Dem. Margin	$2.0724	$2.0724	$2.0724	$2.0724	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$9.9448	$7.2226	$4.9833	$5.1569	-48.14%	-28.60%	3.48%	$0.1736
Total Demand Cost	$15.4901	$14.0919	$12.4649	$12.6771	-18.16%	-10.04%	1.70%	$0.2122
Avg. Annual Bill*	$40,962.04	$29,820.51	$20,643.49	$21,357.08	-47.86%	-28.38%	3.46%	$713.5930
Effect of proposed commodity change on average annual bills:								$708.2880
Effect of proposed demand change on average annual bills:								$5.3050

5) Large Volume Firm: Avg. Annual Use: 14,841 Mcf (MERC-PNG currently has no customers in this class.)
Avg. Annual CD Units: 75 Mcf

Recovery	Last Base Cost of Ga G011/MR-08 836	Last Demand Change M-08-1328	Most Recent PGA Oct 1/09	Oct 1/09 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Rate	$1.6138	$5.9792	$3.7399	$3.9135	142.50%	-34.55%	4.64%	$0.1736
Demand Rate	$13.4177	$12.0195	$10.3925	$10.6047	-20.96%	-11.77%	2.04%	$0.2122
Comm. Margin	$0.3770	$0.2600	$0.3770	$0.3592	-4.72%	38.15%	-4.72%	($0.0178)
LV Dem. Margin	$1.5000	$1.2000	$1.5000	$1.6579	10.53%	38.16%	10.53%	$0.1579
Total Commodity Cost	$1.9908	$6.2392	$4.1169	$4.2727	114.62%	-31.52%	3.78%	$0.1558
Total Demand Cost	$14.9177	$13.2195	$11.8925	$12.2626	-17.80%	-7.24%	3.11%	$0.3701
Avg. Annual Bill*	$30,664.29	$93,587.43	$61,990.85	$64,330.84	109.79%	-31.26%	3.77%	$2,339.9853
Effect of proposed commodity change on average annual bills:								$2,576.3976
Effect of proposed demand change on average annual bills:								$15.9150

* Average Annual Bill amount does not include customer charges.
** Commodity includes Upstream costs.

Customer Class	Commodity Change ($/Mcf)	Commodity Change (Percent)	Demand Change ($/Mcf)	Demand Change (Percent)	Total Change ($/Mcf)		Total Change (Percent)
All Firm	$0.1736	4.64%	($0.2083)	-19.14%	(0.0347)		-0.54%
Sm Vol Inter. Service	$0.1736	4.64%	$0.0000	0.00%	0.1736		3.48%
Lrg Vol Inter. Service	$0.1736	4.64%	$0.0000	0.00%	0.1736		4.24%
Sm Vol Joint Service	$0.1736	4.64%	$0.2122	2.04%	0.1736	***	3.48%
Lrg Vol Joint Service	$0.1736	4.64%	$0.2122	2.04%	0.1558	***	3.78%

***** Joint total change includes only commodity change since not all joint customers purchase CD units.**
Note: The commodity figure with updated demand entitlement levels of $3.9135 includes $0.1736 in costs related to storage and call option premiums.

MERC-PNG's Northern PGA System October 2009 PGA with updated entitlements as modified by the OES

I. Minnesota Energy Resources Corporation's Cost of Gas Effective **Oct-01-09**

	Summer	Winter	Weighted Annual
TF-12B	7.5776	15.1530	10.7340
TF-12V	9.0926	6.4838	8.0056
TF-5	0.0000	7.6050	7.6050
FTX	4.5600	9.6288	6.6720
Field TF	0.0000	0.0000	0.0000
Commodity			3.7399

II. Annual Firm Sales -- Rate Case 2008 General Service (CCF) 209,429,630

III. Minnesota Energy Resources Corporation's Cost of Gas Effective **Oct 01, 2009**

A. GS, SVI, LVI	MCF	Months	Rate/MCF	Total	Rate/CCF
TF-12-B	*30,021*	*12*	*7.5776*	*$2,729,846*	*$0.01440*
TF-12-V	*24,583*	*12*	*9.0926*	*$2,682,281*	*$0.01415*
TF-5	*29,619*	*5*	*15.1530*	*$2,244,084*	*$0.01184*
TF-12B (Discount Winter)	*5,200*	*12*	*6.4838*	*$404,589*	*$0.00213*
TF5 (Discount-Winter)	*0*	*5*	*7.6050*	*$0*	*$0.00000*
TFX-12	9,724	12	9.6288	$1,123,565	$0.00593
TFX-5	6,000	5	4.5600	$136,800	$0.00072
TFX Apr	2,000	1	5.6830	$11,366	$0.00006
TFX Oct	2,000	1	5.6830	$11,366	$0.00006
TFX-5 (Max)	*48,754*	*5*	*15.1530*	*$3,693,847*	*$0.01948*
TFX-5 (Discount)	*0*	*5*	*13.8736*	*$0*	*$0.00000*
TFX-5 (Discount)	1,800	5	7.6050	$68,445	$0.00036
TFX-12 (Discount)	414	12	4.8667	$24,178	$0.00013
TFX-12 (Discount)	*9,140*	*12*	*5.4570*	*$598,524*	*$0.00316*
TFX-12	*11,921*	*12*	*2.2204*	*$317,633*	*$0.00168*
TFX-5 (Discount)	122	5	4.8667	$2,969	$0.00002
TFX-5 (Discount)	*2,702*	*5*	*5.4570*	*$73,724*	*$0.00039*
TFX-5 (Discount)	*22,189*	*5*	*15.1475*	*$1,680,539*	*$0.00886*
SMS Charge	*20,577*	*12*	*2.1800*	*$538,294*	*$0.00284*
Option	*26,375*	*3*	*4.3463*	*$343,901*	*$0.00181*
Windom	0	12	0	$0	$0.00000
Exchange	0		2.0035	$0	$0.00000
Total Demand Cost				$16,685,950	$0.08800
FDD: Res Fee	*66,871*	*12*	*1.7140*	*$1,375,403*	*$0.00725*
FDD: Capacity	*771,074*	*5*	*0.3567*	*$1,375,210*	*$0.00725*
FDD-Reservation	*4,722*	*12*	*1.714*	*$97,122*	*$0.00051*
FDD-Storage Cycle	*54,437*	*5*	*0.3567*	*$97,088*	*$0.00051*
FDD-Reservation	*5,035*	*12*	*3.3157*	*$200,335*	*$0.00106*
FDD-Storage Cycle	*58,067*	*5*	*0.6901*	*$200,360*	*$0.00106*
Total Storage				$3,345,518	$0.01597
GS Rate Case 2008 Volume in CCF				189,613,000	
GS-1 Demand Base Cost of Gas/Ccf					**$0.08800**
	Total Annual Volumes				
GS-1 Commodity Base Cost of Gas/Ccf		209,429,630	$0.37399	$78,324,587	$0.37399
FDD Storage Costs				$3,345,518	$0.01597
Call Option Premium				$0	$0.00000
Commodity Assigned 636 Costs From Schedule C				$290,828	$0.00139
All Classes Commodity				$81,960,934	$0.39135
All Classes Rate Case 2000 Volume in Ccf				209,429,630	
Commodity Cost of Gas/CCF					**$0.39135**
Other Adjustments		0		$0	**$0.00000**
Total Cost of Gas/CCF					**$0.47935**

B. GS-1, SVI, SJ-1, LJ-1, SLV-Commodity

Total Base Commodity Cost of Gas/CCF	$0.39135
Firm Transportation Base Cost of Gas/CCF	$1.07340

C. Joint Rate Demand Calculation (See MERC's Sch. C) $10.6047 /MCF $1.06047

Costs Assigned In Commodity:

Canadian Contracts	Units	Cost/Unit	Day/Mo.	Cost	$/MCF
Upstream					
NBPL (West Coast)	0	$0.000	12	$0	$0.00000
FT0011 (GLGT-Nexen)	0	$10.278	7	$0	$0.00000
Great Lakes	0	$3.458	12	$0	$0.00000
					$0.00000
Storage					
FDD Withdrawal	0	$0.0149		$0	$0.00000
FDD Injection	0	$0.0149		$0	$0.00000
FDD Withdrawal	0	$0.0149		$0	$0.00000
FDD Injection	0	$0.0149		$0	$0.00000
					$0.00000
Producer Demand Payments				$0	$0.00000
Total Commodity Costs				$0	$0.00000

Costs Assigned In Joint Rate

	Units	Months	Rate	Total	Rate/Mcf
TF-12-B	30,021	12	$7.5776	$2,729,846	$1.77145
TF-12-V	24,583	12	$9.0926	$2,682,281	$1.74059
TF5-(12V)	29,619	5	$15.1530	$2,244,084	$1.45623
TF-12B	5,200	12	$6.4838	$404,589	$0.26255
TF5 (Discount)	0	5	$7.6050	$0	$0.00000
TFX5	6,000	5	$4.5600	$136,800	$0.08877
TFX12	9,724	12	$9.6288	$1,123,565	$0.72910
TFX Oct	2,000	1	$5.6830	$11,366	$0.00738
TFX5	2,000	1	$5.6830	$11,366	$0.00738
TFX5	48,754	5	$15.1530	$3,693,847	$2.39701
TFX5 (Discount)	0	5	$13.8736	$0	$0.00000
TFX5 (Discount)	1,800	5	$7.6050	$68,445	$0.04442
TFX12 (Discount)	414	12	$4.8667	$24,178	$0.01569
TFX12 (Discount)	9,140	12	$5.4570	$598,524	$0.38839
TFX12 (Discount)	11,921	12	$2.2204	$317,633	$0.20612
TFX5 (Discount)	122	5	$4.8667	$2,969	$0.00193
TFX5 (Discount)	2,702	5	$5.4570	$73,724	$0.04784
TFX5 (Discount)	22,189	5	$15.1475	$1,680,539	$1.09054
SMS Charge	20,577	12	$2.1800	$538,294	$0.34931
LS Power	0	3	$4.3463	$0	$0.00000
Windom	0	12	$0.0000	$0	$0.00000
Exchange	0	1	$2.0035	$0	$0.00000
FDD-Reservation	4,722	12	$1.7140	$97,122	$0.06302
FDD-Storage Cycle	54,437	5	$0.3567	$97,088	$0.06300
FDD-Reservation	5,035	12	$3.3157	$200,335	$0.13000
FDD-Storage Cycle	58,067	5	$0.6901	$200,360	$0.13002
FDD-Reservation	66,871	12	$1.7140	$1,375,403	$0.89253
FDD-Storage Cycle	771,074	5	$0.3567	$1,375,210	$0.89240
Total Demand Cost	Total			$16,342,049	
	Annualized Entitlement Mcf			1,541,021	
	Demand Component			$10.6047	**$10.6047**

Note: Italicized lines indicate contracts that have changed since the October 2009 PGA.

CERTIFICATE OF SERVICE

I, Jan Mottaz, 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 Comments

Docket No. G011/M-09-1284

Dated this **2nd** day of **April 2010**

/s/Jan Mottaz

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Paper Service	No	OFF_SL_9-1284_09-1284
Julia	Anderson	Julia.Anderson@state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	OFF_SL_9-1284_09-1284
Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Paper Service	No	OFF_SL_9-1284_09-1284
Marie	Doyle	marie.doyle@centerpointenergy.com	CenterPoint Energy	800 LaSalle Avenue P O Box 59038 Minneapolis, MN 554590038	Paper Service	No	OFF_SL_9-1284_09-1284
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_9-1284_09-1284
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	No	OFF_SL_9-1284_09-1284
Jack	Kegel		MMUA	Suite 400 3025 Harbor Lane North Plymouth, MN 554475142	Paper Service	No	OFF_SL_9-1284_09-1284
James D.	Larson		Avant Energy Services	200 S 6th St Ste 300 Minneapolis, MN 55402	Paper Service	No	OFF_SL_9-1284_09-1284
Robert S	Lee	RSL@MCMLAW.COM	Mackall Crounse & Moore Law Offices	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 554022859	Paper Service	No	OFF_SL_9-1284_09-1284
John	Lindell	agorud.ecf@state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	OFF_SL_9-1284_09-1284
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Paper Service	No	OFF_SL_9-1284_09-1284

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Brian	Meloy	brian.meloy@leonard.com	Leonard, Street & Deinard	150 S 5th St Ste 2300 Minneapolis, MN 55402	Paper Service	No	OFF_SL_9-1284_09-1284
Ann	Seha	seha.ann@dorsey.com	Dorsey & Whitney	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Paper Service	No	OFF_SL_9-1284_09-1284
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Paper Service	No	OFF_SL_9-1284_09-1284
James R.	Talcott		Northern Natural Gas Company	1111 South 103rd Street Omaha, NE 68124	Paper Service	No	OFF_SL_9-1284_09-1284
Gregory	Walters	gjwalters@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	3460 Technology Dr. NW Rochester, MN 55901	Paper Service	No	OFF_SL_9-1284_09-1284