Minnesota Public Utilities Commission
Staff Briefing Papers

Meeting Date: **June 12, 2015**.. **Agenda Item __**

Company: Minnesota Energy Resources Corporation (MERC)

Docket Nos. **G-011/M-14-660**
In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC-Northern Natural Gas (NNG)) for Approval of Changes in Contract Demand Entitlements for the 2014-2015 Heating Season Supply Plan effective November 1, 2014.

G-011/M-14-661
In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC-Consolidated) for Approval of Changes in Contract Demand Entitlements for the 2014-2015 Heating Season Supply Plan effective November 1, 2014.

Issue: Should the Commission approve MERC's proposed demand entitlement capacity (levels) and cost changes to meet its Design Day and Reserve Margin requirements as described in the listed dockets, effective November 1, 2014?

Staff: Bob Brill 651-201-2242
Bob Harding 651-201-2237

Relevant Documents

<u>G-011/M-14-660 (MERC-NNG)</u>
MERC Initial Petition and Schedules ....August 1, 2014
Department of Commerce (Department) Letter.. September 23, 2014
MERC Revised Petition and Schedules.. November 3, 2014
Department Comments ....December 8, 2014
MERC Reply Comments ....December 18, 2014
Department Reply Comments...April 3, 2015

<u>G-011/M-14-661 (MERC-Consolidated)</u>
MERC Initial Petition and Schedules ....August 1, 2014
Department of Commerce (Department) Letter.. September 23, 2014
MERC Revised Petition and Schedules.. November 3, 2014
Department Comments ....December 1, 2014
MERC Reply Comments ....December 11, 2014
Department Reply Comments...April 3, 2015
MERC Additional Reply Comments ....April 9, 2015

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Statement of the Issue

Should the Commission approve MERC's proposed demand entitlement capacity (levels) and cost changes to meet its Design Day and Reserve Margin requirements as described in the listed dockets, effective November 1, 2014?

Introduction

MERC has entered into various natural gas supply and interstate pipeline contracts to provide natural gas to its customers. MERC annually reviews and updates these contracts to ensure continued system reliability of natural gas supply deliveries to its customers.

MERC's annual demand entitlement[1] petitions request Commission approval to recover certain cost and capacity changes in these interstate pipeline transportation entitlements, supplier reservation fees, and other demand-related contract costs and to implement the rate impact of these petitions through its Purchased Gas Adjustment (PGA)[2] charges.

In these petitions, MERC continues its consolidation approach for its two PGA rate areas. The MERC-Consolidated PGA area groups all of MERC's customers that receive gas delivered through the Viking Gas Transmission (VGT), Great Lakes Gas Transmission (GLGT), and Centra pipelines. The MERC-NNG PGA area includes all customers that receive gas delivered through the Northern Natural Gas Company (NNG) pipeline.

PUC staff reviewed MERC's 2014-2015 Demand Entitlement petitions, and the various rounds of *Comments* filed by the Department and MERC. The Department and MERC have resolved all of issues raised by the Department, with the lone exception of MERC's Consolidated-VGT PGA area's negative reserve margin. PUC staff generally agrees with the Department's December 11, 2014 and December 18, 2014 recommendations for these petitions, but has a few additional comments.

Pursuant to Commission's 2007 demand entitlements Order, MERC assigned all storage costs[3] to its PGA commodity factors, effective November 1, 2014.

For these briefing papers, PUC staff consolidated MERC's two PGA areas[4] into one discussion, but will discuss issues related to a particular PGA area separately.

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[1] D*emand entitlements* can be defined as reservation charges paid by the Local Distribution Company (LDC) to an interstate natural gas pipeline to reserve pipeline capacity used to store and transport the natural gas supply for delivery to its system and contract charges associated with the LDC procuring its gas supply; these costs are recovered through the LDC's PGA.

[2] The Purchased Gas Adjustment is a mechanism used by regulated utilities to recover its cost of energy. Minn. Rules 7825.2390 through 7825.2920 enable regulated gas and electric utilities to adjust rates on a monthly basis to reflect changes in its cost of energy delivered to customers based upon costs authorized by the Commission in the utility's most recent general rate case.

[3] Includes storage reservation, capacity, and injection/withdrawal costs.

[4] MERC has two separate PGA areas, MERC-Consolidated (13-669) and MERC-NNG (13-670).

Minnesota Rules

Minnesota Rule, part 7825.2910, subpart 2[5] require gas utilities to make a filing whenever there is a change to its demand-related entitlement services provided by a supplier or transporter of natural gas.

MERC – Initial Filings

MERC's Design Day (DD) Requirements

MERC calculated its 2014-2015 Design Day (DD) requirements at 309,708 Mcf/day.

Table 1 – Design Day (DD) requirements[6] by PGA area and interstate pipeline:
(Reflected in Mcf/day)

Pipeline	Total	MERC-Consolidated	MERC-NNG
Viking	15,858	15,858	
GLGT	25,720	25,720	
Centra	7,128	7,128	
NNG	261,002		261,002
Total	309,708	48,706	261,002

MERC's Demand Entitlement Contract Levels

To transport its DD requirements, MERC used a series of interstate pipeline contracts to meet its annual system transportation and storage requirements for each PGA area, i.e. demand entitlements. The 2014-2015 transportation demand entitlement contract levels were modified from the previous year's levels (for 2013-2014), which resulted in 317,844 Mcf/day of available interstate pipeline transportation capacity, an increase of 13,782 Dth/day.

Table 2 – Transportation Demand Entitlements[7] by PGA area (reflected in Mcf/day):

Total MERC	MERC-Consolidated	MERC-NNG
317,844	51,459	266,385

[PUC staff note: The transportation demand entitlements reflected in Table 2 <u>do not</u> include the 50,000 Dth/d Bison and NBPL interstate pipeline contracts.]

MERC's Reserve Margin

The Reserve Margin is the difference between MERC's transportation demand entitlements and DD requirements. MERC stated that its reserve margin in each PGA area is appropriate given the need to balance the uncertainty of DD conditions, customer demand during these peak conditions, and the need to protect against firm gas supply loss to maintain system reliability.

[5] Filing upon a change in demand, is included in the Automatic Adjustment of Charges rule parts 7825.2390 through 7825.2920 and requires gas utilities to file to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another.
[6] Includes Transportation only, does not include Storage Entitlements.
[7] Ibid.

Table 3 - Reserve Margins[8] by PGA areas:

	MERC-Consolidated	MERC-NNG
Transportation Demand Entitlements	51,459	266,385
Design Day Requirements	48,706	261,002
Quantities in Mcf[9]	2,753	5,383
As a Percentage[10]	5.65%	2.06%

Table 4 - Reserve Margin – MERC total system:

All Dockets-Total MERC	Quantities in Mcf
Total MERC Reserve Margin	8,136
Total MERC DD requirements	309,708
Reserve Margin as a percentage	**2.63%**

Pursuant to the Commission's August 6, 2014 Order in Docket Nos. 07-1402-05, all of MERC's storage costs[11] were assigned to the PGA commodity factor instead of its PGA demand factors, effective November 1, 2014.

MERC's Demand Entitlement Contract Costs

The Commission approved MERC's 2013-2014 demand entitlement contract costs of $36,841,976.[12] In these two dockets, MERC proposed to recover 2014-2015 demand entitlement costs of $40,226,167, an increase of $3,384,191.

Table 5 reflects the MERC's demand cost of gas with and without the Bison/NBPL contract cost as part of MERC's demand entitlement costs.

Table 5 - Transportation Demand Entitlement Costs, with and without Bison and NBPL

PGA area	2014-2015 Demand Cost of Gas, with Bison and NBPL	2014-2015 Demand Cost of Gas, without Bison and NBPL
MERC-Consolidated	$3,675,805	$3,675,805
MERC-NNG	$36,550,362	$21,859,112
Total	**$40,226,167**	**$25,534,917**

(PUC staff has summarized MERC's transportation DD requirements and demand entitlements in ***Appendix A***, and its demand entitlement costs in ***Appendix B***.)

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[8] See Appendix A for calculation

[9] Calculated by taking the Total Demand Entitlements contracts and subtracting the total DD requirements

[10] Calculated by dividing the difference between the total Demand Entitlements contracts and the total DD requirements by the total DD requirements

[11] Includes storage reservation costs, capacity costs, and injection/withdrawal costs.

[12] See Docket Nos. 13-669 and 13-670, MERC's 2013-2014 demand entitlement petitions were approved at the February 26, 2015 Commission Agenda meeting

MERC - Reply Comments

In its December 11, 2014 (Consolidated) and December 18, 2014 (NNG) *Reply Comments*, MERC provided its response to the Department's request for additional information.

NNG/Consolidated PGA areas

- Whether all of the Contracted Demand Volumes on the NNG and Consolidated Pipelines are used to serve the Firm Customers Who are Charged for These Costs.

MERC stated that it contracts for ***firm*** interstate pipeline capacity to serve its ***firm*** customers based upon its DD requirements plus a reasonable reserve margin and interruptible customers are not factored into the calculations.

- Additional Details and Clarification Regarding the Pipeline Rates for both PGA areas

MERC provided various data and clarifying statements regarding its PGA cost proposals that the Department requested in its *Comments*.[13]

NNG PGA area

- An Explanation for Why the Changes in Contracts 112561 and 112486 and Associated Entitlement Amounts and Associated Increases in Costs Are Reasonable.

MERC stated that Contract 112561 was a 6,000 Dth/day discount contract that could only be used when the average temperature was -3 or below, and had a termination date of April 1, 2014. NNG was no longer willing to sell this capacity to MERC at a discount under the temperature restriction and only would sell the capacity to MERC at maximum tariff rates.

This capacity's delivery point is in the Rochester, MN area where MERC needs the winter period capacity to meet its system DD requirements; MERC only alternative was to sign the NNG maximum rate contract.[14] Because this capacity was priced at maximum NNG tariff rates, MERC requested NNG to consolidate the 6,000 Dth/day contract into MERC's contract 112486 to minimize the number of contracts it administers.

Consolidated PGA area

- MERC's perspective on the bi-directional Viking (VGT) system

MERC stated that VGT bi-directional receipt points will be beneficial once it lifts the Maximum Allowable Operating Pressure (MAOP) restrictions. However, MERC's Consolidated-VGT supply source has previously been purchased at Emerson, MN; supplied by TransCanada.

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[13] See MERC's December 11, 2014 (Consolidated) and December 18, 2014 (NNG) *Reply Comments* for detailed explanation as required by the Department.
[14] This contract is for the winter period (November – November) through March 2017.

- MERC's perspective on whether the Viking pipeline situation and related PHMSA[15] action contributed to its decision to do the regression analysis by pipeline

MERC stated that the capacity situation on VGT did not influence its decision to do regression analysis by pipeline to estimate its design day requirements. Before MERC received Commission approval to consolidate GLGT, Centra, and VGT into a single PGA area, MERC perform six different regression analyses.[16]

With Commission consolidation approval, MERC no longer needed to prepare regression analysis between PNG and NMU that alleviated two regressions on GLGT and VGT. In addition, effective November 1, 2014, Thief River Falls is no longer dual supplied, but is supplied entirely by GLGT. MERC no longer needed to prepare a separate regression for Thief River Falls. MERC currently performs three regressions analysis for its Consolidation PGA area: 1) Centra; 2) GLGT; and 3) VGT.

MERC – Additional Reply Comments

In its April 9, 2015 *Additional Reply Comments,* MERC stated that it did not have any reliability issue during the 2014-2015 winter heating season and that it intends to explore all available options to serves its customers reliably given the negative VGT reserve margin; that includes Emerson, Northern Natural Gas, Great Lakes Gas Transmission, and ANR in its 2015-2016 demand entitlement filing.

In addition, MERC stated that it is planning to modify its current DD methodology now that daily interruptible data is available, which will eliminate the current need to estimate the interruptible load in calculating its firm DD requirements.

Department - Comments

The Department reviewed MERC's proposed Design Day (DD) requirements, demand entitlements, resulting reserve margins, and the miscellaneous changes that occurred since MERC's last demand entitlement petitions for 2013-2014.

The Department summarized MERC's proposed 2014-2015 DD requirements by PGA area, for a total increase of 13,782 Mcf/day, see Table 6:

Table 6 – MERC's DD requirements:

PGA area	2013-2014	2014-2015	Difference	% increase/(decrease)
MERC-Consolidated	50,048	48,706	(1,342)	(2.68%)
MERC-NNG	245,878	261,002	15,124	6.15%
Total	295,926	309,708	13,782	4.66%

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[15] PHMSA is the federal Department of Transportation's Pipeline and Hazardous Materials Safety Administration.
[16] 1) Centra-NMU; 2) GLGT-PNG; 3) GLGT-NMU; 4) VGT-PNG; 5) VGT-NMU; and 6) Thief Rivers Falls (GLGT/VGT) (this point was dual supplied between GLGT (approximately 33%) and VGT (approximately 67%)).

MERC's proposed changes to its 2014-2015 demand entitlement requirements and Reserve Margin levels in its two PGA areas are summarized in Tables 7 and 8.

Table 7 – MERC's Demand Entitlements requirements:

PGA area	2013-2014	2014-2015	Difference	% increase/(decrease)
MERC-Consolidated	52,959	51,459	(1,500)	(2.83%)
MERC-NNG	256,385	266,385	10,000	3.90%
Total	309,344	317,844	8,500	2.75%

Table 8 – Reserve Margin Comparison by PGA area:

PGA area	2013-2014 Demand Entitlement Filing	2014-2015 Demand Entitlement Filing	Difference	% Difference
MERC-Consolidated	5.82%	5.65%	(0.17%)	(2.92%)
MERC-NNG	4.27%	2.06%	(2.21%)	(51.76)

Table 9 – MERC's DD requirements, Demand Entitlements, and Reserve Margin by interstate pipeline:

PGA Area	DD Requirements	Demand Entitlements	Difference	Reserve Margin
Viking	15,858	15,591	(267)	(1.68%)
GLGT	25,720	26,368	648	2.52%
Centra	7,128	9,500	2,372	33.28%
NNG	261,002	266,385	5,383	2.06%
Total	309,708	317,844	8,136	2.63%

The Department stated in previous dockets that a typical Reserve Margin range is between 5% - 7%.

Department Concerns

MERC's Design Day Calculations

The Department stated that MERC's 2014-2015 DD requirement calculations included additional weather variables in certain DD regression models which were used by MERC in its final DD analysis. This is similar to how these additional variables were treated in MERC's 2013-2014 demand entitlement petitions.

The Department does not oppose MERC's use of other weather determinants in its effort to produce robust DD estimates, but noted that some of this additional data was taken from proprietary sources. The Department stated that when a utility uses proprietary data in its analysis, the Department cannot fully or independently verify the results of the analysis. The Department previously recommended in MERC's 2013-2014 demand entitlement petitions that the Commission accept MERC's peak-day analysis with the caveat that the Department cannot fully verify the results.

MERC's Ortonville Regression Analysis

The Department noted that in MERC's DD regression analysis for Ortonville it used a regression model with a negative intercept term without providing a reasonable explanation for why it would be appropriate to do so. The Department stated that a negative intercept term in a regression model would tend to imply that MERC would not need any pipeline entitlements (capacity) for base-load usage; rather its customers are supplying the base-load natural gas to MERC, which seems implausible.

MERC-Consolidated Reserve Margins

The Department reviewed each pipeline's proposed DD requirements and demand entitlements for each pipeline, VGT, GLGT, Centra (Consolidated), and NNG, with results reflecting that MERC-Consolidated VGT has a negative reserve margin and MERC-Consolidated Centra has a high reserve margin, see Table 9.

Because of these concerns, the Department requested that MERC provide additional information in its *Reply Comments*.

MERC-NNG

- indicate whether all of the contracted demand volumes on the NNG pipeline are used to serve the firm customers who are charged for these costs;

- provide additional details confirming and clarifying its petition for the following items:
    1. additional details and clarification regarding the pipeline rates for NNG; and
    2. explanation for the changes in contracts 112561 and 112486, and why the associated entitlement amounts and associated increase in costs are reasonable.

MERC-Consolidated

- additional details confirming and clarifying the reserve margin on the Viking pipeline and the proposed levels of capacity and costs;

- indicate whether all of the contracted demand volumes on these three pipelines (Viking, GLGT, and Centra) are used to serve the firm customers who are charged for these costs;

- The Department stated that it believes the Consolidated area's reserve margin is reasonable in total, but the MERC-Consolidated Viking pipeline reserve margin is negative. The Department requested additional details confirming and clarifying the following:

    1. How MERC expects to serve its firm customers reliably given the negative Viking pipeline reserve margin and the Viking pipeline situation based on the pressure restrictions and PHMSA action;
    2. MERC's perspective on the bi-directional Viking system; and

3. MERC's perspective on whether the Viking pipeline situation and related PHMSA action contributed to its decision to do the regression analysis by pipeline.

- that MERC provide additional details and clarification regarding the pipeline rates for Viking, Centra and the AECO/Emerson Swap entitlement amounts and rates; and

- that MERC supplement its November PGA filing in Docket No. G-011/AA-14-939 with the relevant FERC pipeline tariff sheets and associated details/clarifications for Viking, Centra and the AECO/Emerson Swap entitlement amounts and rates.

Department - Reply Comments

In its April 3, 2015 *Reply Comments*, the Department noted that MERC's responses to its request for additional information appear to be reasonable, with the exception of MERC's explanation for its Consolidated-VGT negative reserve margin. Please see PUC staff discussion below on this point.

Department Recommendations

The Department recommended to the Commission that it:

MERC-NNG

1. accept MERC-NNG's peak-day analysis with the caveat that the Department cannot fully verify the results of MERC's analysis; and

2. approve MERC-NNG's proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2014.

MERC-Consolidated

3. accept MERC-Consolidated's peak-day analysis with the caveat that the Department cannot fully verify the results of MERC's analysis; and
4. approve MERC's proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2014.

The Department's above recommendations are the same for both of MERC's PGA areas. For these staff briefing papers, PUC staff is consolidating the Department's recommendations into a single set of recommendations that would apply to both PGA areas.

PUC Staff Comment

PUC staff reviewed MERC's 2014-2015 demand entitlement petitions for its two PGA areas and appreciates the parties' comments. PUC staff believes that for these dockets, all issues have been resolved by the parties through the rounds of comments. PUC staff believes that the Department's analysis covers most of the relevant factors and will not repeat those comments.

PUC staff generally agrees with the Department's April 3, 2015 recommendations for MERC's NNG and Consolidated PGA areas, but offers additional discussion.

Assigning storage demand charges to firm and interruptible customers

Pursuant to the Commission's August 6, 2014 Order, MERC implemented its March 7, 2008 storage classification and allocation proposal assigning all storage costs to its PGA commodity factors starting on November 1, 2014. [17]

PUC staff believes that this issue is settled and no further discussion is needed.

Changes in interstate pipeline transportation and storage contracts

MERC stated its demand entitlement changes were primarily caused by:

MERC-NNG changes

- In previous years, MERC has been able to acquire a winter contract for 20,000 Dth NNG Zone Delivery Call Option with another company on NNG's system. MERC attempted to purchase the same product for this demand entitlement period in the amount of 30,000 Dth but was unable to secure a contract from NNG's other customers. MERC's only alternative was to contract with NNG for 30,000 Dth/day of TFX firm winter capacity[18].

  The net change in Demand Entitlement from the previous demand entitlement filing is 10,000 Dth. The firm capacity increase was necessary for MERC to meet its 2014-2015 theoretical DD. In its NNG PGA area, MERC had twelve (12) customers that switched from interruptible to firm service.[19] This adjustment was reflected in MERC firm DD requirements at November 1, 2014.

- MERC's Firm Storage capacity decreased from 5,619,321 Dth to 5,469,321 Dth.[20] The decrease was caused by LS Power reducing the amount of Firm Deferred Delivery storage capacity released to MERC.

MERC-Consolidated

MERC stated its demand entitlement costs increased primarily due to changes in interstate pipeline rates.

The Department recommended to the Commission that it approve MERC's demand entitlement levels for both of MERC's PGA areas effective November 1, 2014.

[17] For further detail, see the July 15, 2014 PUC staff briefing papers for Docket Nos. 07-1402, 07-1403, 07-1404, and 07-1405.
[18] November 1, 2014 through March 31, 2015 until 2017.
[19] The switching occurred between November 1, 2013 and July 1, 2014.
[20] This is a decrease of 150,000 Dth or approximately 2.67% from the previous level.

PUC staff agrees. PUC staff believes that the interruptible customers that converted to firm service and the decrease in firm storage released from LS Power were a direct result of the 2013-2014 winter heating season, which produced some of the coldest weather experienced in MN when compared to historical averages from previous years. Further, that the increased rates on MERC's Consolidated PGA areas were a result of various customer settlements involving the Federal Regulatory Energy Commission (FERC).

MERC's negative Consolidated-VGT reserve margin

As previously stated, MERC's Consolidated-VGT demand entitlement petition reflects a negative reserve margin of 1.67% or a shortfall of 267 Dth/day in its DD requirement calculation.[21]

The Department requested MERC to respond in *Reply Comments* to the concerns about the Consolidated-VGT reserve margin shortfall. MERC responded by stating:

> *"In the event of the theoretical design day, because Great Lakes Gas Transmission (GLGT) and Viking Gas Transmission (VGT) interconnect each other at St. Vincent, MERC could utilize the positive reserve margin and deliver supply into GLGT on an interruptible basis. Northern Natural Gas (NNG) and VGT also interconnect at Chisago, so MERC could utilize the positive reserve margin on NNG pipeline as well to deliver supply at Chisago into NNG on an interruptible basis. In the event interruptible supply doesn't flow on VGT or NNG, MERC would curtail all interruptible volumes on VGT to ensure serving MERC's firm requirements. Based on the Design Day, MERC is short 267 Dth or a negative 1.68 reserve margin for Viking."*

The Department stated that MERC's explanation was not satisfactory. The Department stated that in the event of a DD, MERC would presumably curtail all interruptible customers on its system, and given the fact that MERC plans its DD around serving firm customer requirements, it is not entirely clear how a negative reserve margin would ensure reliable service for MERC's Consolidated-VGT firm customers.

PUC staff agrees. PUC staff realizes that the 2014-2015 winter heating season is over and that MERC did not incur any reliability issues during the season. But, MERC's Consolidated-VGT DD calculation caused staff concern by not providing enough interstate pipeline capacity that would permit MERC to have its DD requirements delivered. MERC stated that it could use its St. Vincent interconnection (where VGT and GLGT interconnect) or its Chisago interconnection (where VGT and NNG interconnect) to bring gas supply to its VGT customers on an interruptible basis.

This statement alone causes staff to have concerns over MERC's process.

First, staff believes that a natural gas utility should develop its DD requirements and ultimately its demand entitlement contracts with interstate pipelines to serve its firm service customers. Using interruptible transportation contracts that are subject to interruption could put MERC's

[21] See Table 9.

firm customers at risk of not receiving natural gas, which is not the intent of designing demand entitlements through these petitions.

Second, MERC stated that its Chisago interconnection could be used to bring gas supply to its VGT firm customers. The Chisago interconnection would use MERC's demand entitlements on NNG, which are purchased to serve its NNG firm customers. This leads staff to be concern that Consolidated-VGT firm customers will be subsidized by NNG firm customers. MERC previously stated one of the conditions imposed by the Commission in MERC's PGA consolidation was that MERC could not allow one PGA area to subsidize another PGA area; that each PGA area's demand entitlements would be calculated on the basis of that area's DD requirements.

PUC staff believes that the Commission may wish to require MERC to provide a compliance filing 30 days after the Commission's Order in these dockets detailing the different alternatives being reviewed and a discussion on each option that is being considered by MERC to resolve Consolidated-VGT's negative reserve margin. Alternatively, the Commission may want to require MERC to provide this information in its next demand entitlements filings for 2015-2016.

Decision Alternatives

The following Decision Alternatives apply to the two MERC dockets addressed in these briefing papers. Those dockets are:

Docket No. G-011/M-14-660 (MERC-NNG)
Docket No. G-011/M-14-661 (MERC-Consolidated)

1. Accept MERC's peak-day analysis with the caveat that the Department cannot fully verify the results of MERC's analysis (as described above and in the Department's comments) for all of its PGA areas; <u>and</u>

2. Approve MERC's demand entitlement petitions for 2014-2015, effective November 1, 2014, for its two PGA areas – MERC-Consolidated and MERC-NNG.

Consolidated-VGT's Negative Reserve Margin

3. Require MERC to submit a compliance filing in these dockets, within 30 days after the Commission's Order, stating the different alternatives being reviewed and a discussion on each option that is being considered by MERC to resolve Consolidated-VGT's negative reserve margin. <u>or</u>

4. Require MERC to include in its next petition for a change in demand entitlements for the MERC-Consolidated (VGT) area a description and explanation of the different alternatives MERC reviewed and a discussion on each option that was considered by MERC to resolve Consolidated-VGT negative reserve margin.

Transportation Demand Entitlements Changes

MERC-Consolidated	12-1192&1194&1195	13-669	14-661	Difference
	(1)	(2)	(3)	(4)
	Mcf	Mcf	Mcf	Mcf
				(3) - (2)
GLGT FT FT0016	10,130	10,130	10,130	0
GLGT FT (12) FT0155	3,600	3,600	0	(3,600)
GLGT FT (5) FT0155	3,638	3,638	0	(3,638)
GLGT FT FT15782	9,000	9,000	9,000	0
GLGT FT (12) FT17891	0	0	3,600	3,600
GLGT FT (5) FT17891	0	0	3,638	3,638
VGT FT-A AF0012	12,493	12,493	12,493	0
VGT FT-A AF0014	1,098	1,098	1,098	0
VGT FT-A AF0102	2,000	2,000	2,000	0
VGT FA-A	0	1,500	0	(1,500)
Wadena Delivered Option	3,500	0	0	0
Centra FT-1	9,500	9,500	9,500	0
Total Demand Entitlements	54,959	52,959	51,459	(1,500)
Total DD Requirements	52,289	50,048	48,706	(1,342)
Surplus/Deficient	2,670	2,911	2,753	(158)
Reserve Margin	**5.11%**	**5.82%**	**5.65%**	

Transportation Demand Entitlements Changes

MERC-NNG	12-1193&1195	13-670	14-660	Difference
	(1)	(2)	(3)	(4)
	Mcf	Mcf	Mcf	Mcf
				(3) - (2)
TF-12 Base and Variable	75,316	76,079	76,079	0
TF5	32,278	31,515	31,515	0
TFX-12	32,297	32,297	32,297	0
TFX-5	90,183	93,084	123,084	30,000
Bison	50,000	50,000	50,000	0
NBPL	50,000	50,000	50,000	0
Northwest Gas (Windom)	2,500	2,500	2,500	0
NW Energy (Ortonville)	910	910	910	0
NNG Zone Delivery Call Opt	0	20,000	0	(20,000)
Total Demand Entitlement	233,484	256,385	266,385	10,000
Total DD Requirements	**225,788**	**245,878**	261,002	15,124
Surplus/Deficient	7,696	10,507	5,383	(5,124)
Reserve Margin	**3.41%**	**4.27%**	**2.06%**	

[PUC staff note: The Bison and NBPL are used to deliver Rockies supply into NNG - does not add incremental capacity deliveries for MERC's design day demand entitlements.]

Transportation Demand Entitlements PGA Costs, as adjusted

MERC-Consolidated	12-1192&1194&1195	13-669	14-661	Difference
	(1)	(2)	(3)	(4)
	$	$	$	$
VGT FT-A AF0012	519,774	510,212	630,921	120,709
VGT FT-A AF0014	11,420	11,211	13,863	2,652
VGT FT-A AF0102	83,210	81,680	101,003	19,323
VGT FA-A	0	16,669	0	(16,669)
Wadena Delivery Option	12,597	0	0	0
GLGT FT FT0016	420,355	467,886	467,886	0
GLGT FT (12) FT0155	149,385	166,277	0	(166,277)
GLGT FT (5) FT0155	62,901	70,013	0	(70,013)
GLGT FT FT15782	373,464	415,693	415,693	0
GLGT FT (12) FT17891	0	0	166,277	166,277
GLGT FT (5) FT17891	0	0	70,013	70,013
Balancing Service	55,656	0	0	0
Centra FT-1	662,537	826,161	1,439,535	613,374
Union Balancing	54,000	0	0	0
Centra MN Pipelines	202,692	202,692	370,614	167,922
Total Demand Entitlement	**2,607,991**	**2,768,494**	**3,675,805**	**907,311**

Transportation Demand Entitlements PGA Costs

MERC-NNG	12-1193&1195	13-670	14-660	Difference
	(1)	(2)	(3)	(4)
	$	$	$	$
				(3) - (2)
TF-12 Base and Variable	7,318,086	7,347,063	7,265,315	(81,748)
TF5	2,416,728	2,387,734	2,387,734	0
TFX-12	2,185,889	2,955,980	2,955,980	0
TFX-5	6,300,130	6,527,363	9,139,991	2,612,628
Bison	10,488,000	10,493,750	10,493,750	0
NBPL	4,195,200	4,197,500	4,197,500	0
TFX 112486	11,366	11,366	11,366	0
TFX 112486	11,366	11,366	11,366	0
TFX7 111866	0	0	0	0
Windom	0	0	0	0
Ortonville	87,360	87,360	87,360	0
NNG Zone GDD Call Option	0	54,000	0	(54,000)
LSP Peaking Service	0	0	0	0
Total Demand Entitlement	**33,014,125**	**34,073,482**	**36,550,362**	**2,476,880**

Summary of demand entitlement costs for all PGA areas

PGA Area	12 Total Costs	13 Total Costs	143 Total Costs	Difference
	(1)	(2)	(3)	(4)
	$	$	$	$
				(3) - (2)
MERC-NMU	2,607,991	2,768,494	3,675,805	907,311
MERC-PNG NNG	33,014,125	34,073,482	36,550,362	2,476,880
Total Demand Entitlement	**35,622,116**	**36,841,976**	**40,226,167**	**3,384,191**