Minnesota Public Utilities Commission
Staff Briefing Papers

Meeting Date: April 21, 2016 .... *Agenda Item 5

Company: Minnesota Energy Resources Corporation (MERC)

Docket Nos. **G-011/M-15-722**
In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC-Consolidated) for Approval of Changes in Contract Demand Entitlements for the 2015-2016 Heating Season Supply Plan effective November 1, 2015.

G-011/M-15-723
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 2015-2016 Heating Season Supply Plan effective November 1, 2015.

G-011/M-15-724
In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC-Albert Lea) for Approval of Changes in Contract Demand Entitlements for the 2015-2016 Heating Season Supply Plan effective November 1, 2015.

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, 2015?

Staff: Bob Brill 651-201-2242

Relevant Documents

All Docket Petitions
MERC Initial Petition and Schedules ....July 31, 2015
MERC Revised Petition and Schedules – Compliance Filing ....November 2, 2015

G-011/M-15-722 (MERC-Consolidated)
Department of Commerce (Department) Comments ....October 15, 2015
MERC Reply Comments ....October 26, 2015
Department Reply Comments .... December 9, 2015

G-011/M-15-723 (MERC-NNG)
Department of Commerce (Department) Comments ....October 15, 2015
MERC Reply Comments ....October 26, 2015
Department Reply Comments .... February 22, 2016

G-011/M-15-724 (MERC-Albert Lea)

The attached materials are workpapers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless otherwise noted.

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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, 2015?

Introduction

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

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

In these petitions, MERC modified its previous two PGA areas to include the MERC-Albert Lea PGA area. [3] MERC's three PGA areas include:

- MERC-Consolidated PGA area - combines all of MERC's customers that receive delivered natural gas through the Viking Gas Transmission (VGT), Great Lakes Gas Transmission (GLGT), and Centra pipelines.
- MERC-NNG PGA area includes all of MERC's customers, previous to the acquisition of Interstate Power & Light (IPL) assets (the old PNG service area) that receive delivered natural gas through the Northern Natural Gas Company (NNG) pipeline.
- MERC-Albert Lea customers that receive its delivered natural gas through NNG, but includes only the old IPL customers.[4]

PUC staff reviewed MERC's 2015-2016 Demand Entitlement petitions, and the various rounds of *Comments* filed by the Department and MERC. The Department and MERC have resolved the majority of issues raised by the Department. PUC staff's analysis uncovered a MERC error when it calculated its demand entitlement cost for the November 2, 2015 update. Staff corrected

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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] Pursuant to the Commission's Order in Docket No.14-107 dated December 8, 2014, MERC's acquisition of IPL's natural gas assets and customer base. MERC was required to maintain a separate PGA area for IPL customers until MERC filed its next general rate case. In Docket No. 15-736, MERC's subsequent general rate case, MERC requested that the Commission allow it to consolidate its two NNG PGA areas.

[4] Ibid.

this error, which amounted to an approximate additional $1.1 million in demand entitlement costs.

PUC staff generally agrees with the Department's recommendations, but provides additional decision alternatives for the Commission to consider.

Pursuant to the Commission's 2007 demand entitlements Order, MERC assigned all storage costs to its PGA commodity factors, effective November 1, 2014.[5]

For these briefing papers, PUC staff combined MERC's three PGA areas into one discussion, but discusses issues related to a particular PGA area separately.[6]

Minnesota Rules

Minnesota Rule, part 7825.2910, subpart 2 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. [7]

MERC – Initial Filings

MERC's Design Day (DD) Requirements

MERC's calculation of its DD was similar to the process that it had used in prior demand entitlement filings. MERC performed its regression analysis by pipeline and weather station. As a result of its telemetry program, MERC was able to perform its regression analysis with daily metered interruptible customer data.[8] MERC calculated its 2015-2016 Design Day (DD) requirements at 312,151 Mcf/day (for difference from MERC's 2014-2015 demand entitlement petition, see the below Department discussion, Table 6).

Table 1 – Design Day (DD) requirements by PGA area and interstate pipeline: [9]

(Reflected in Mcf/day)

Pipeline	Total	MERC-Consolidated	MERC-NNG	MERC-Albert Lea
GLGT	28,543	28,543		
Viking	15,858	15,858		
Centra	8,674	8,674		
NNG	259,076		245,263	13,813
Total	312,151	53,075	245,263	13,813

[5] See Docket Nos. 07-1402, 07-1403, 07-1404, and 07-1405, and includes storage reservation, capacity, and injection/withdrawal costs.

[6] MERC has three separate PGA areas, MERC-Consolidated (15-722), MERC-NNG (15-723), and MERC-Albert Lea (15-724). MERC purchased IPL's assets pursuant to Docket No. 14-107.

[7] 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.

[8] Approved by the Commission in Docket No. 08-835, MERC's 2008 general rate case, see the Commission's June 29, 2009 Order

[9] Includes Transportation entitlements only, does not include Storage entitlements.

[Staff note: MERC did not own the IPL assets when its 2014-2015 demand entitlement petitions were filed. MERC's purchase of the IPL assets was approved by the Commission in its December 8, 2014 Order in Docket No. 14-107].

MERC's Demand Entitlement Contract Levels

To transport its DD requirements, MERC proposed to use a series of interstate pipeline contracts (for both transportation and storage services) for each of its PGA areas, i.e. demand entitlements. The 2015-2016 transportation demand entitlement contract levels were modified from the previous year's levels (for 2014-2015), which resulted in 321,766 Mcf/day (see Table 2) of available interstate pipeline transportation capacity, a decrease of 10,297 Mcf/day (see the below Department discussion, Table 7).

Table 2 – Transportation Demand Entitlements by PGA area (reflected in Mcf/day): [10]

Total MERC	MERC-Consolidated	MERC-NNG	MERC-Albert Lea
321,766	55,449	252,127	14,190

[PUC staff note: The transportation demand entitlements reflected in Table 2 do not include the 50,000 Mcf/d Bison and NBPL interstate pipeline contracts (these contracts represent upstream deliveries to NNG).]

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.

Table 3 - Reserve Margins by PGA areas: [11]

	MERC-Consolidated	MERC-NNG	MERC-Albert Lea
Transportation Demand Entitlements	55,449	252,127	14,190
Design Day Requirements	53,075	245,263	13,813
Reserve Margin:			
Quantities in Mcf[12]	2,374	6,864	377
As a Percentage[13]	4.47%	2.80%	2.73%

Table 4 - Reserve Margin – MERC total system:

All Dockets-Total MERC	Quantities in Mcf
Total MERC Reserve Margin	9,615
Total MERC DD requirements	312,151
Reserve Margin as a percentage	**3.08%**

[10] Ibid.
[11] See Appendix A for calculation
[12] Calculated by taking the Total Demand Entitlements contracts and subtracting the total DD requirements
[13] Calculated by dividing the difference between the total Demand Entitlements contracts and the total DD requirements by the total DD requirements

Pursuant to the Commission's August 6, 2014 Order in Docket Nos. 07-1402 through 07-1405, all of MERC's storage costs were assigned to the PGA commodity factor instead of its PGA demand factors, effective November 1, 2014, this includes the IPL storage contracts purchased by MERC, approved by the Commission in its December 8, 2014 Order.[14]

Department - Comments

The Department reviewed MERC's proposed Design Day (DD) requirements, demand entitlements, calculated reserve margins, and the miscellaneous changes that occurred since MERC's last demand entitlement petitions for 2014-2015.

The Department summarized MERC's proposed 2015-2016 DD requirements by PGA area, for a total decrease of 10,472 Mcf/day, see Table 5:

Table 5 – MERC's DD requirements:

PGA area	2014-2015	2015-2016	Difference	% increase/(decrease)
MERC-Consolidated	48,706	53,075	4,369	8.97%
MERC-NNG	261,002	245,263	(15,739)	(6.03%)
MERC-Albert Lea[15]	12,915	13,813	898	6.95%
Total	322,623	312,151	(10,472)	(3.25%)

The Department noted that MERC's DD analysis was similar to MERC's previously used process and because MERC's model included the use of daily metered interruptible data for the first time, MERC will no longer have to rely on estimated daily interruptible customer data. The Department appreciated MERC's efforts with its telemetry program.[16]

However, for MERC-Albert Lea the daily metered interruptible data for customers was not available. MERC used IPL's last demand entitlement filing data to adjust its DD calculation for interruptible customers.[17] The Department believes this approach is acceptable given the constraints in data availability.[18]

The Department reviewed previous Commission Orders and is satisfied that MERC is in compliance with Commission requirements, in that:

- MERC appropriately adjusted its regression models by removing autocorrelation.[19]

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[14] Includes storage reservation costs, capacity costs, and injection/withdrawal costs.
[15] The Department analysis used IPL's 2014-2015 demand entitlement levels to compare to MERC's 2015-2016 demand entitlement calculation see Docket No. 14-560.
[16] See the Department's discussion in its October 15, 2015 Comments, pp. 4-7.
[17] See MERC's Attachment 1, page 2 of 3 and Attachment 6 in its November 2, 2015 Update in Docket No. G011/M-15-724.
[18] See IPL's Supplemental Attachment A, Page 4 of 13 in its October 30, 2014 Supplemental Filing in Docket No. G001/M-14-560. At the time of IPL's asset sale to MERC, IPL had not started a telemetry program and only had one interruptible customer with the metering capability to measure daily usage data.
[19] See the Commission's February 4, 2015 Order in Docket Nos. 12-1192, 12-1193, 12-1194, and 12-1195.

- MERC's petition included a discussion of how MERC resolved its Viking Gas Transmission (VGT) negative reserve margin issue.[20]

The Department summarized MERC's proposed changes to its 2015-2016 demand entitlement requirements and Reserve Margin levels, see Tables 6, 7, and 8.

Table 6 – MERC's Demand Entitlements requirements:

PGA area	2014-2015	2015-2016	Difference	% increase/(decrease)
MERC-Consolidated	51,459	55,449	3,990	7.75%
MERC-NNG	266,385	252,127	(14,258)	(5.35%)
MERC-Albert Lea[21]	14,219	14,190	(29)	(0.20%)
Total	332,063	321,766	(10,297)	(3.10%)

Table 7 – Reserve Margin Comparison by PGA area:

PGA area	2014-2015 Demand Entitlement Filing	2015-2016 Demand Entitlement Filing	Difference	% Difference
MERC-Consolidated	5.65%	4.47%	(1.18%)	(20.88%)
MERC-NNG	2.06%	2.80%	0.74%	35.92%
MERC-Albert Lea[22]	10.10%	2.73%	(7.37%)	(72.97%)

Table 8 – MERC's DD requirements, Demand Entitlements, and Reserve Margin[23] by interstate pipeline:

PGA Area	DD Requirements	Demand Entitlements	Difference	Reserve Margin
Viking	15,858	16,591	733	4.62%
GLGT	28,543	29,758	1,215	4.26%
Centra	8,674	9,100	426	4.91%
NNG-PNG	245,263	252,127	6,864	2.80%
NNG-AL	13,813	14,190	377	2.73%
Total	312,151	321,766	9,615	3.08%

[20] See the Commission's June 22, 2015 Order in Docket Nos. 14-660 and 14-661.
[21] The Department analysis used IPL's 2014-2015 demand entitlement levels to compare to MERC's 2015-2016 demand entitlement calculation; see Docket No. 14-560.
[22] Ibid.
[23] In previous dockets, the Department has stated that a typical Reserve Margin range is between 5% - 7%.

The Department concluded that each of MERC's three PGA areas' modelling approach for its DD calculation, transportation demand entitlements and reserve margins calculations were reasonable. But the Department did qualify its DD recommendation for the MERC-Albert Lea PGA area by stating that its recommendation to accept MERC's NNG-Albert Lea's peak day analysis does not preclude any party from disputing the assumptions used by MERC in any other ongoing and/or future proceedings before the Commission and/or in MERC's future demand entitlement petitions.[24]

Further in Docket No. 15-724 (MERC-Albert Lea PGA area), the Department questioned MERC's choice of using the Rochester weather station data in its DD requirements calculation as opposed to using Albert Lea. The Department recommended that the Commission require MERC to fully justify its winter station selection in its next NNG-Albert Lea demand entitlement petition.[25]

PUC Staff Comment

PUC staff reviewed MERC's 2015-2016 demand entitlement petitions for its three PGA areas and appreciates the parties' comments. PUC staff believes that the majority of issues have been resolved. However, during its review, PUC staff discovered an error in MERC's demand entitlement costs reflected in its November 2, 2015 Revised Petition and Schedules – Compliance Filing, Attachments 4 and 12. See the below PUC staff discussion. Aside from this calculation error, PUC believes that the Department's analysis covered most of the relevant factors and will not repeat those comments.[26]

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

The Department recommended that the Commission approve the following:

MERC-Consolidated

1. Accept MERC-Consolidated's peak-day analysis; and
2. Approve MERC-Consolidated's proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2015.

MERC-NNG

3. Accept MERC-NNG's peak-day analysis; and
4. Approve MERC-NNG's level of demand entitlements including NNG's annual reallocation of units between TF 12-month Base and TF 12-month Variable services; and
5. Approve MERC's proposed recovery of associated demand costs effective November 1, 2015.

[24] See the Department's December 31, 2015 Comments, p. 5
[25] See the Department's December 31, 2015 Comments, pp. 3-4.
[26] See the Department's Comments dated October 15, 2015 (for Docket Nos. 15-722 and 15-723) and August 10, 2015 (for Docket No. 15-724). Further, see the Department's Reply Comments dated December 9, 2015 (for Docket No. 15-722), February 22, 2016 (for Docket No. 15-723), and January 11, 2016 (for Docket No. 15-724).

MERC-Albert Lea

6. Accept MERC NNG-Albert Lea's peak-day analysis with the caveat that the Commission require MERC to fully justify its selection of weather station in its next NNG-Albert Lea demand entitlement petition; and
7. Approve MERC NNG-Albert Lea's proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2015.
8. Require MERC to fully justify its selection of the Rochester weather station as opposed to Albert Lea in its Design Day calculation in the next NNG-Albert Lea demand entitlement petition.

The Department further recommended:

9. Require MERC to explain changes made in its compliance petitions that are different than its original petitions, and provide a red-line version of both petitions identifying changes; and
10. Require MERC to separate its summer and winter demand entitlements as reflected in Attachment 4 of its petitions, rather than combining the data as reflected on Attachment 3 of its petitions.
11. Require MERC to check the results of its regression analysis to ensure the results are consistent with the underlying theory the analysis attempts to explain.

Should the Commission approve MERC's changes to its demand entitlement levels, DD calculations and Reserve Margins?

Changes to MERC-Consolidated PGA area

For its Centra Pipeline, MERC proposed to decrease its demand entitlements capacity by 400 Dth/day and increased its DD requirement, which produced a positive reserve margin of 4.91% as opposed to the 33.28% reserve margin in its previous demand entitlement petition.

For its Great Lakes Transmission Pipeline, MERC acquired an additional 3,300 Dth/day on Great Lakes Gas Transmission to insure a reserve margin of 4.26% as opposed its last demand entitlement petition's 2.52%.

For its Viking Gas Transmission (VGT) Pipeline, MERC contracted for an additional winter capacity of 1,000 Dth/day, this provided a positive reserve margin of 4.62% as opposed to the negative 1.68% reserve margin in MERC's last demand entitlement petition.

In its June 22, 2015 Order,[27] the Commission required MERC to include in its next demand entitlement petition (2015-2016), an explanation of the different alternatives MERC reviewed to resolve MERC-Consolidated's VGT negative reserve margin.[28]

[27] Docket No. 14-661.

[28] MERC stated in its December 18, 2014 Additional Reply Comments in Docket No. 14-661, it intended to explore all available options to serve customers reliably given the negative VGT reserve margin, which included Emerson, Northern Natural Gas, Great Lakes Gas Transmission, and ANR.

As a result, MERC provided its explanation on how it resolved the VGT negative reserve margin. The option selected, resulted in MERC contracting for an additional 1,000 Dth/day of VGT winter capacity which provided a positive reserve margin.[29]

The Department believes these changes were reasonable and recommended approval to the Commission. PUC staff agrees, but notes that MERC did not explain why its MERC-Consolidated Centra pipeline's DD increased. The Commission may wish to ask MERC at the Commission's April 21, 2016 Agenda Meeting for the reason the DD requirements increased over its last 2014-2015 demand entitlements petition.

Changes to MERC-NNG PGA area

For its NNG pipeline, MERC proposed to reduce its TFX-5 winter capacity by 14,383 Dth/day (a demand entitlement reduction), and MERC further reduced its 2015-2016 DD requirements by 15,739 Dth/day. These changes increased MERC's 2014-2015 2.06% reserve margin to 2.80%.

For its Northwestern Energy firm capacity used to service its Ortonville area, MERC proposed to increase its capacity from 910 Dth/day to 1,035 Dth/day for a 125 Dth/day increase.

The Department believes these changes were reasonable and recommended approval to the Commission.

PUC staff agrees with the Department's Ortonville recommendation, but offers the following discussion on MERC's remaining NNG PGA area.

On the basis of the information provided in this record, PUC staff cannot determine if the TFX-5 capacity reduction was a result of MERC's ability to use daily interruptible data in its DD regression analysis or if it was caused by a customer count decrease. MERC's 2014-2015 demand entitlement petition Attachment 14 reflected the annual NNG PGA area customers at June 30, 2014 at 180,150, its 2015-2016 demand entitlement petition reflected NNG PGA area customers at 180,517. This increase in customers[30] led staff to believe MERC's demand entitlement reduction was not a result of customer count loss, but believes that the reduction was a result of MERC's ability to use more accurate daily interruptible customer data in its DD regression analysis model.

In Docket No. 08-835, MERC was ordered to incorporate in its interruptible tariff, language that required all interruptible customers to upgrade their meters that would provide daily interruptible throughput data. MERC completed its telemetry program and currently has three years of historical daily interruptible data to use in its DD regression analysis for its Consolidated and NNG PGA areas.[31] PUC staff believes that the daily interruptible data availability enhanced

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[29] The capacity became available once VGT was allowed to increase its pipeline pressure back to its maximum allowable operating pressure (MAOP).

[30] From staff analysis, MERC's customer count increased by 367 (180,517 – 180,150) customers, this leads staff to believe its demand entitlements would have increased and not decreased.

[31] For the winter heating season of 2012-2013, 2013-2014, and 2014-2015.

MERC's ability to calculate its DD requirements, which led to the capacity reduction. The annual reduction provides MERC's ratepayers with approximate saving of $1.1 million.[32]

If the Commission accepts staff's conclusion that the $1.1 million of demand entitlement cost savings experienced by MERC in this docket is a result of MERC using metered daily interruptible data in its DD regression analysis, the Commission may wish to consider asking the Department to review and confirm how the other natural gas utilities' use metered daily interruptible data in each of the utilities' next demand entitlement petitions. This review would determine if similar interruptible service tariff language is already in each natural gas utilities' tariff for interruptible and transportation service and, if so, if this data is being used effectively, and, if not, should this tariff language be incorporated and this data used to possibly reduce costs.[33]

Changes to MERC-Albert Lea PGA area

MERC's DD analysis for the Albert Lea PGA area did not provide any sufficient demand entitlement changes from the previous Interstate Power & Light (IPL) demand entitlement levels.[34] MERC did increase its Albert Lea PGA areas' DD requirement by 898 Dth/day, which decreased its Reserve Margin from 10.10% to 2.73%.

The Department believed that these changes were reasonable and recommended approval to the Commission. PUC staff agrees with the Department recommendations based on MERC's limited experience in the Albert Lea service area. PUC staff believes that MERC's DD calculations will improve as it acquires additional experience. Staff further notes that MERC did not provide an explanation for why its MERC-Albert Lea DD requirements increased. The Commission may wish to inquire from MERC at the Commission's April 21, 2016 Agenda Meeting the reason the DD requirements increased over its last 2014-2015 demand entitlements petition.

As previously noted by PUC staff, MERC has the ability to calculate its DD requirements using daily interruptible customer data for its MERC-Consolidated and MERC-NNG PGA areas, but this data is not available for its MERC-Albert Lea PGA area.

In its December 8, 2014 Order in Docket No. 14-107 where it approved the IPL asset sale to MERC, the Commission ordered that the former IPL customers must comply with MERC's tariff book. Each of MERC's interruptible service tariff sheets includes the following language:

> *7. Telemetry: Customers other than farm tap customers must install telemetry equipment. Customer shall reimburse Company for all costs incurred by Company to install and maintain telemetry equipment or other related improvements. Any such equipment and improvements shall remain the property of Company.*

[32] Calculated by multiplying MERC's demand entitlement reduction of 14,383 Dth/day by 5 months by NNG's TFX-5 max rate of $15.1530 = $1,089,728.
[33] This would include CenterPoint, Xcel-Gas, Great Plains, and Greater Minnesota Gas.
[34] See Docket No. 14-560.

The purchase of the IPL assets (the Albert Lea service area) resulted in MERC acquiring 38 interruptible customers with only one customer capable of daily measurement. The Commission Order directed that the former IPL interruptible customers must comply with MERCs interruptible service tariff within 18 months from the Commission's Order date.[35] Through informal discussions between MERC and staff, MERC stated that it anticipates having the interruptible customers meter conversion completed by May or June 2016, in time for MERC's 2016-2017 demand entitlement petitions. PUC staff points out that MERC will not have three years of daily interruptible customer data available for the MERC-Albert Lea service area.

Subsequent to its 2015-2016 demand entitlement petitions, MERC filed its general rate case (15-736) and its base cost of gas petition (15-748), where MERC proposed to consolidate its MERC-NNG and MERC-Albert Lea PGA areas (both served through NNG pipeline) into one PGA area. If the Commission approves this proposal, staff believes that MERC could experience DD issues with its subsequent demand entitlement petitions. Because of Albert Lea's lack of data, PUC staff believes that the Commission should direct MERC to work with the Department in developing an appropriate DD regression analysis methodology as a substitute until MERC has three years of daily interruptible data available for all interruptible customers served through the NNG pipeline.

Should the Commission approve MERC's demand entitlement costs, effective November 1, 2015?

In Docket Nos. 14-660 and 14-661, the Commission approved MERC's 2014-2015 demand entitlement costs of $41,557,098.[36] Based on the information in this record, MERC proposed to recover 2015-2016 demand entitlement costs of $39,554,445, a decrease of $2,002,653, see Table 9.[37] The majority of the reduction is attributed to the MERC-NNG PGA zone, $2,074,365 (Table 9).

Table 9 - Transportation Demand Entitlement Costs

PGA area	2014-2015 Demand Entitlement Costs, with Bison and NBPL	2015-2016 Demand Entitlement Costs, with Bison and NBPL	Difference
MERC-Consolidated	$3,675,805	$3,747,517	$71,712
MERC-NNG	$36,550,362	$34,475,997	($2,074,365)
MERC-Albert Lea	$1,330,931	$1,330,931	$0
Total	**$41,557,098**	**$39,554,445**	**($2,002,653)**

[35] To be in compliance with MERC's existing tariff book as ordered by the Commission.
[36] See Docket Nos. 14-660 and 14-661, MERC's 2014-2015 demand entitlement petitions were approved at the June 22, 2015 Commission Agenda meeting, the Commission approved a demand entitlement cost of $40,226,167. To calculate the total demand entitlement costs including MERC-Albert Lea, staff added $1,330,931(from Docket No. 14-560), for the total 2014-2015 demand entitlement cost of 41,557,098.
[37] See MERC's November 2, 2015 compliance filing, Attachment 4, page 2 and Attachment 12.

As part of its analysis, staff divided this amount by MERC-NNG PGA zone's demand entitlement reduction of 14,383 Dth/day (represents the NNG demand entitlement changes[38]), the resulting transportation rate is $28.845.[39] The current NNG TFX-5 winter transportation rate is $15.1530; staff's calculated transportation rate is approximately double that.

Because of its calculated rate, staff analyzed MERC's demand entitlement costs reflected in its updated November 2, 2015 compliance petition's Attachments 4, page 2 and 12. PUC staff concluded that when MERC updated its July 1, 2015 initial petition to its November 2, 2015 compliance filing, MERC incorrectly stated contract 112486 – NNG's TFX-5 at 66,271 Dth/day as opposed to the correct amount of 81,888 Dth/day.

As part of its annual contract review, MERC revised contract 112486 from 66,271 Dth/day to 81,888 Dth/day (MERC's initial petition reflected the correct amount). The capacity increase of 15,617 Dth/day[40] was offset by MERC not renewing contract 127852 for 30,000 Dth/day. The result of MERC's contract restructuring was a 14,383 Dth/day capacity reduction.[41]

PUC staff corrected MERC's demand entitlement cost using the correct contract 112486 amount of 81,888 Dth/day. This correction resulted in an increase to the demand entitlement costs of $1,183,211, see Table 10. PUC staff believes the corrected amount is justified and recommends that the Commission approve the adjusted $40,737,656[42] demand entitlement costs instead of the MERC calculated $39,554,445, effective at November 1, 2015.

Table 10 - Transportation Demand Entitlement Costs, as adjusted by PUC staff

PGA area	MERC's Calculation	PUC staff Calculation	Difference
MERC-Consolidated	$3,747,517	$3,747,517	$0
MERC-NNG	$34,475,997	$35,659,208	$1,183,211
MERC-Albert Lea	$1,330,931	$1,330,931	$0
Total	**$39,554,445**	**$40,737,656**	**$1,183,211**

[Staff note: Both MERC's and staff's calculated amounts included Bison demand entitlement cost at $10,493,760 and NBPL demand entitlement costs at $4,197,480.]

In the alternative, the Commission could approve MERC's $39,554,445 demand entitlement cost level and require MERC's shareholders to absorb the $1,183,211 of increased demand entitlement costs.

[38] See the above staff discussion – NNG's demand entitlements changed by (14,258) Dth/day – caused by a 14,383 Dth/day reduction to a NNG TFX-5 contract and a 125 Dth/day increase in Ortonville capacity. For this calculation, staff excluded the Ortonville increase.
[39] Represents the following calculation demand entitlement cost reduction of $2,074,365 is divided by 71,290 Dth = $28.845, (14,383 Dth/day times 5) = 71,915 Dth for the winter period).
[40] (81,888 Dth/day minus 66,271 Dth/day = 15,617 Dth/day capacity increase) and was necessary to satisfy MERC's firm commitments.
[41] (15,617 Dth/day increase minus 30,000 Dth/day reduction = 14,383 Dth/day reduction)
[42] See PUC staff Appendix C.

Bison/NBPL Contract

In its January 21, 2015 Order,[43] the Commission required MERC to provide an evaluation and analysis of available gas supply alternatives to its Bison/NBPL contracts, in its next demand entitlement filing.

PUC Staff's December 31, 2014 Briefing Papers stated that:[44]

> *But as PUC staff first mentioned in its Docket No. 08-698 briefing papers, the gas supply market continues to change because of the increased supply generated from fracking and other drilling operations throughout the United States. This increase in the supply of gas has generated interest from interstate pipelines and producers/marketers to construct new pipelines to connect these new gas supplies to areas that were not previously served from those sources of gas. The new facilities and the new gas supply have created a gas market that provides new alternative sources of supply, is extremely competitive and has resulted in lower gas supply prices.*
>
> *Further, because of the availability of new and possibly lower priced gas supply options, PUC staff believes that the Bison/NBPL contract option may not currently be the best or least cost gas option to supply MERC's customers. While PUC staff firmly believes that a LDC should have a diversified gas supply, the cost of the diversification should not over-burden MERC's rate payers.*

In its November 2, 2015 Revised Petition and Schedules – Compliance Filing, MERC stated its Bison contract term was 10 years, scheduled to terminate January 2021. MERC stated that the Bison/NBPL pipelines do not have a released capacity market. MERC believes that no feasible and financial alternatives are available to allow it to escape its contractual commitments and that it would not be reasonable or beneficial for MERC to acquire alternative capacity or supply.

MERC stated its plans use its Bison/NBPL capacity on the basis of which receipt point(s) provide the lowest price gas option taking into account supply reliability: [45]

a. Buffalo – Cheyenne HUB index
b. Port of Morgan – Ventura minus index
c. Stateline or alternate Bakken receipt point – Ventura minus index
d. NNG Ventura or alternate NBPL/NNG interconnects – Ventura flat/plus index

MERC believes that each receipt point has different pricing aspects and depending on gas costs plus the variable transportation costs (fuel, volumetric transportation commodity charges, compressor usage surcharge, and ACA), MERC will choose the lowest cost option.

[43] See Docket Nos. G007/M-10-1166, G011/M-10-1167, G011/M-10-1168, and G011/M-10-1169.
[44] Ibid.
[45] The gas supply can be purchased daily, monthly or on a term basis (greater than one month).

The Department concluded that MERC complied with the Commission's January 21, 2015 Order requirements by providing its evaluation and analysis of available gas supply alternatives to its Bison/NBPL contracts.

PUC staff is not recommending any changes to the Department's recommendations regarding these contracts. With no available Bison/NBPL capacity release market, MERC is committed to honoring the contract terms until expiration. It would be foolish for MERC to acquire other pipeline capacity or attempt to negotiate a Bison/NBPL contract buy-out. MERC's customers would not receive any benefit and could end up paying for the same capacity twice.

PUC staff believes that this issue has been resolved until January 2021 when MERC will be able to shed the Bison/NBPL contract if cheaper alternatives are available.

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.[46]

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

Decision Alternatives

Docket No. G-011/M-15-722 (MERC- Consolidated)

1. Accept MERC-Consolidated's peak-day analysis (Department and MERC); <u>and</u>
2. Approve MERC-Consolidated's proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2015. (Department and MERC)

Docket No. G-011/M-15-723 (MERC- NNG (PNG))

3. Accept MERC-NNG's peak-day analysis (Department and MERC); <u>and</u>
4. Approve MERC-NNG's level of demand entitlements including NNG's annual reallocation of units between TF 12-month Base and TF 12-month Variable services (Department and MERC); <u>and</u>
5. Approve MERC's proposed recovery of associated demand costs effective November 1, 2015 (Department and MERC); <u>or</u>
6. Instead of Decision Alternative #5, approve PUC staff's adjusted demand entitlement costs of $40,737,656[47] as opposed to MERC's calculated $39,554,445 demand entitlement costs, effective at November 1, 2015; <u>or</u>
7. Approve MERC's proposed recovery of associated demand costs of $39,554,445 (Decision Alternative #5) and do not allow MERC to recover the $1,183,211 difference ($40,737,656 - $39,554,445) from its ratepayers.

[46] For further detail, see the July 15, 2014 PUC staff briefing papers for Docket Nos. 07-1402, 07-1403, 07-1404, and 07-1405.
[47] See PUC staff Appendix C.

Docket No. G-011/M-15-724 (MERC- NNG (Albert Lea))

8. Accept MERC NNG-Albert Lea's peak-day analysis with the Department's caveats:
    a. Require MERC to fully justify its selection of the Rochester weather station as opposed to Albert Lea in its Design Day calculation in its next NNG-Albert Lea demand entitlement petition (Department and MERC); and
9. Approve MERC NNG-Albert Lea's proposed level of demand entitlement and proposed recovery of associated demand costs effective November 1, 2015 (Department and MERC); and

Other Department recommendations for all dockets listed:

10. Require MERC to explain changes made in its compliance petitions that are different than its original petitions, and provide a red-line version of both petitions identifying changes (Department); and
11. Require MERC to separate its summer and winter demand entitlements as reflected in Attachment 4 of its petitions, rather than combining the data as reflected on Attachment 3 of its petitions (Department); and
12. Require MERC to check the results of its regression analysis to ensure the results are consistent with the underlying theory the analysis attempts to explain (Department).

Additional PUC staff recommendations

13. If the Commission approves MERC's general rate case proposal to consolidate its MERC-NNG and MERC-Albert Lea PGA areas into one PGA area, direct MERC to work with the Department in developing an appropriate DD regression analysis methodology for its subsequent demand entitlement petitions until MERC has three years daily interruptible data available for all its interruptible customers for the consolidated NNG PGA area. and
14. Inquire from MERC, at the Commission's April 21 Agenda Meeting, the reason that DD requirements increased over its last 2014-2015 demand entitlements petition for its MERC-Consolidated (Centra Pipeline) and MERC-Albert Lea PGA areas. and
15. Request the Department to review and confirm how the other natural gas utilities' use metered daily interruptible data in each of the utilities' next demand entitlement petitions. This review should determine if similar interruptible service tariff language requiring telemetering is already in each natural gas utilities' tariff for interruptible and transportation service and, if so, whether data from telemetering is being used effectively, and, if not, should a telemetering requirement be incorporated into their tariffs, and this data be used to possibly reduce costs.

Transportation Demand Entitlements Changes

MERC-Consolidated	12-1192&1194&1195	13-669	14-661	15-722	Difference
	(1)	(2)	(3)	(4)	(5)
	Mcf	Mcf	Mcf	Mcf	Mcf
					(5) - (4)
GLGT FT FT0016	10,130	10,130	10,130	10,130	0
GLGT FT (12) FT0155	3,600	3,600	0	0	0
GLGT FT (5) FT0155	3,638	3,638	0	0	0
GLGT FT FT15782	9,000	9,000	9,000	9,000	0
GLGT FT (12) FT17891	0	0	3,600	3,600	0
GLGT FT (5) FT17891	0	0	3,638	3,728	90
GLGT FT (5) FT18283	0	0	0	3,300	3,300
VGT FT-A AF0012	12,493	12,493	12,493	12,493	0
VGT FT-A AF0014	1,098	1,098	1,098	1,098	0
VGT FT-A AF0102	2,000	2,000	2,000	2,000	0
VGT FT-A AF0229	0	0	0	1,000	1,000
VGT FA-A	0	1,500	0	0	0
Wadena Delivered Option	3,500	0	0	0	0
Centra FT-1	9,500	9,500	9,500	9,100	(400)
Total Demand Entitlements	54,959	52,959	51,459	55,449	3,990
Total DD Requirements	52,289	50,048	48,706	53,075	4,369
Surplus/Deficient	2,670	2,911	2,753	2,374	(379)
Reserve Margin	**5.11%**	**5.82%**	**5.65%**	**4.47%**	

Transportation Demand Entitlements Changes

MERC-NNG	12-1193&1195	13-670	14-660	15-723	Difference
	(1)	(2)	(3)	(4)	(5)
	Mcf	Mcf	Mcf	Mcf	Mcf
					(5) - (4)
TF-12 Base and Variable	75,316	76,079	76,079	75,316	(763)
TF5	32,278	31,515	31,515	32,278	763
TFX-12	32,297	32,297	32,297	32,297	0
TFX-5	90,183	93,084	123,084	108,701	(14,383)
Bison	50,000	50,000	50,000	50,000	0
NBPL	50,000	50,000	50,000	50,000	0
Northwest Gas (Windom)	2,500	2,500	2,500	2,500	0
NW Energy (Ortonville)	910	910	910	1,035	125
NNG Zone Delivery Call Opt	0	20,000	0	0	0
Total Demand Entitlement	233,484	256,385	266,385	252,127	(14,258)
Total DD Requirements	**225,788**	**245,878**	261,002	245,263	(15,739)
Surplus/Deficient	7,696	10,507	5,383	6,864	1,481
Reserve Margin	**3.41%**	**4.27%**	**2.06%**	**2.80%**	

[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 Changes

MERC-Albert Lea	12-1193&1195	13-670	14-660	15-723	Difference
	(1)	(2)	(3)	(4)	(5)
	Mcf	Mcf	Mcf	Mcf	Mcf
					(5) - (4)
TF-12 Base and Variable				9,393	9,393
TF5				3,997	3,997
TFX-12				800	800
Total Demand Entitlement				14,190	14,190
Total DD Requirements				**13,813**	**13,813**
Surplus/Deficient				377	377
Reserve Margin				**2.73%**	

<u>Transportation Demand Entitlements PGA Costs, as adjusted</u>

MERC-Consolidated	12-1192&1194&1195	13-669	14-661	15-722	Difference
	(1)	(2)	(3)	(4)	(5)
	$	$	$	$	$
					(5) - (4)
VGT FT-A AF0012	519,774	510,212	630,921	655,223	24,302
VGT FT-A AF0014	11,420	11,211	13,863	14,397	534
VGT FT-A AF0102	83,210	81,680	101,003	109,457	8,454
VGT FT-A AF0229	0	0	0	23,754	23,754
VGT FA-A	0	16,669	0	0	0
Wadena Delivery Option	12,597	0	0	0	0
GLGT FT FT0016	420,355	467,886	467,886	467,886	0
GLGT FT (12) FT0155	149,385	166,277	0	0	0
GLGT FT (5) FT0155	62,901	70,013	0	0	0
GLGT FT FT15782	373,464	415,693	415,693	415,693	0
GLGT FT (12) FT17891	0	0	166,277	166,277	0
GLGT FT (5) FT17891	0	0	70,013	71,746	1,733
GLGT FT (5) FT18283	0	0	0	63,509	63,509
Balancing Service	55,656	0	0	0	0
Centra FT-1	662,537	826,161	1,439,535	1,350,566	(88,969)
Union Balancing	54,000	0	0	54,000	54,000
Centra MN Pipelines	202,692	202,692	370,614	355,009	(15,605)
Total Demand Entitlement	**2,607,991**	**2,768,494**	**3,675,805**	**3,747,517**	**71,712**

Transportation Demand Entitlements PGA Costs

MERC-NNG	12-1193&1195	13-670	14-660	15-723	Difference
	(1)	(2)	(3)	(4)	(5)
	$	$	$	$	$
					(5) - (4)
TF-12 Base and Variable	7,318,086	7,347,063	7,265,315	7,394,090	128,775
TF5	2,416,728	2,387,734	2,387,734	2,445,543	57,809
TFX-12	2,185,889	2,955,980	2,955,980	2,955,980	0
TFX-5	6,300,130	6,527,363	9,139,991	8,050,263	(1,089,728)
Bison	10,488,000	10,493,750	10,493,750	10,493,760	10
NBPL	4,195,200	4,197,500	4,197,500	4,197,480	(20)
TFX 112486	11,366	11,366	11,366	11,366	0
TFX 112486	11,366	11,366	11,366	11,366	0
TFX7 111866	0	0	0	0	0
Windom	0	0	0	0	0
Ortonville	87,360	87,360	87,360	99,360	12,000
NNG Zone GDD Call Option	0	54,000	0	0	0
LSP Peaking Service	0	0	0	0	0
Total Demand Entitlement	**33,014,125**	**34,073,482**	**36,550,362**	**35,659,208**	**(891,154)**

Transportation Demand Entitlements PGA Costs

MERC-Albert Lea	12-1193&1195	13-670	14-660	15-723	Difference
	(1)	(2)	(3)	(4)	(5)
	$	$	$	$	$
					(5) - (4)
TF-12 Base and Variable	0	0	967,486	967,486	0
TF5	0	0	302,833	302,833	0
TFX-12	0	0	60,612	60,612	0
Total Demand Entitlement	**0**	**0**	**1,330,931**	**1,330,931**	**0**

Summary of demand entitlement costs for all PGA areas

PGA Area	12 Total Costs	13 Total Costs	14 Total Costs	15 Total Costs	Difference
	(1)	(2)	(3)	(4)	(5)
	$	$	$		$
					(5) - (4)
MERC-Consolidated (NMU)	2,607,991	2,768,494	3,675,805	3,747,517	71,712
MERC-NNG (PNG)	33,014,125	34,073,482	36,550,362	35,659,208	(891,154)
MERC-NNG (Albert Lea)	0	0	1,330,931	1,330,931	0
Total Demand Entitlement	**35,622,116**	**36,841,976**	**41,557,098**	**40,737,656**	**(819,442)**

Appendix C

MERC

PUC staff Adjusted Demand Entitlement Cost

Contract Type	Contract Number	Monthly Entitlement	Months	Rate	Contract Costs
	(1)	(3)	(4)	(5)	(6)
		Dth		$	$
MERC-Consolidated					
Viking (VGT)					
FT-A Zone 1 - 1	AF0012	12,493	12	4.3706	$ 655,223
FT-A Zone 1 - 1	AF0209	1,098	3	4.3706	$ 14,397
FT-A Zone 1 - 1	AF0102	2,000	12	4.5607	$ 109,457
FA-A Zone 1 - 1	AF0229	1,000	5	4.7507	$ 23,754
Total VGT Demand					$ 802,831
Great Lakes (GLGT)					
FT Western Zone	FT0016	10,130	12	$3.8490	$ 467,886
FT Western Zone	FT15782	9,000	12	$3.8490	$ 415,693
FT Western Zone (12)	FT17891 (12)	3,600	12	$3.8490	$ 166,277
FT Western Zone (5)	FT17891 (5)	3,728	5	$3.8490	$ 71,746
FT Western Zone (5)	FT18283 (5)	3,300	5	$3.8490	$ 63,509
Total GLGT Demand					$ 1,185,111
Centra					
Conversion (103M3 x Rate(C$ 103M3)		9,100	12	$12.3678	$ 1,350,566
CENTRA MINNESOTA PIPELINES		9,100	12	$3.2510	$ 355,009
Union Balancing					$ 54,000
Total Centra Demand					$ 1,759,575
Total MERC-Consolidated					$ 3,747,517
MERC-NNG					
TF12B (Max Rate) Winter	112495	39,826	5	$ 10.2300	$2,037,100
TF12B (Max Rate) Summer	112495	39,826	7	$ 5.6830	$1,584,318
TF12V (Max Rate)	112495	30,290	12	$ 9.0926	$3,304,978
TF5 (Max Rate)	112495	32,278	5	$ 15.1530	$2,445,543
TF12B (Discount-Winter)	112495	5,200	12	$ 7.4951	$467,694
TFX5 (Discount)	112561	0	5	$ -	$0
TFX12 (Max Rate)	112486	10,822	12	$ 9.6288	$1,250,434
TFX Apr (Max Rate)	112486	2,000	1	$ 5.6830	$11,366
TFX Oct (Max Rate)	112486	2,000	1	$ 5.6830	$11,366
TFX5 (Max Rate)	112486	81,888 1/	5	$ 15.1530	$6,204,244
TFX5 (Discount)	112486	1,800	5	$ 10.0320	$90,288
TFX12 (Discount)	111866	1,283	12	$ 4.8640	$74,886
TFX12 (Discount)	111866	8,271	12	$ 5.4720	$543,107
TFX12 (Discount)	111866	11,921	12	$ 7.6025	$1,087,553
TFX5 (Discount)	111866	379	5	$ 4.8640	$9,217
TFX5 (Discount)	111866	2,445	5	$ 5.4720	$66,895
TFX5 (Discount)	111866	22,189	5	$ 15.1392	$1,679,619
Bison	FT0003	50,000	12	$ 17.4896	$10,493,760
NBPL	T8673F	50,000	12	$ 6.9958	$4,197,480
Total NNG					$35,559,848
Northwestern Energy		1,035	12	$ 8.0000	$99,360
Total MERC-NNG					$35,659,208
MERC-Albert Lea					
TF-12B (Max Rate) - Winter	129170	3,157	5	$ 10.2300	$161,481
TF-12B (Max Rate) - Summer	129170	9,393	7	$ 5.6830	$373,663
TF-12V (Max Rate)	129170	6,236	5	$ 13.8660	$432,342
TF-5 (Max Rate)	129170	3,997	5	$ 15.1530	$302,833
TFX-5 (Max Rate)	106082	800	5	$ 15.1530	$60,612
Total MERC-Albert Lea					$1,330,931
Total Demand Entitlement Costs					$ 40,737,656

1/ MERC erroneously stated this contract at 66,271 Dth/day