Minnesota Public Utilities Commission
Staff Briefing Papers

Meeting Date: **January 15, 2015 .... *Agenda Item #2**

Company: Minnesota Energy Resources Corporation (MERC)

Docket Nos.

G-007/M-10-1166
In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC-NMU) for Approval of Changes in Contract Demand Entitlements for the 2010-2011 Heating Season Supply Plan effective November 1, 2010.

G-011/M-10-1167
In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC-PNG GLGT) for Approval of Changes in Contract Demand Entitlements for the 2010-2011 Heating Season Supply Plan effective November 1, 2010.

G-011/M-10-1168
In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC-PNG NNG) for Approval of Changes in Contract Demand Entitlements for the 2010-2011 Heating Season Supply Plan effective November 1, 2010.

G-011/M-10-1169
In the Matter of a Petition by Minnesota Energy Resources Corporation (MERC-PNG Viking) for Approval of Changes in Contract Demand Entitlements for the 2010-2011 Heating Season Supply Plan effective November 1, 2010.

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, 2010?

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

Relevant Documents

G-007/M-10-1166 (MERC-NMU)

MERC Initial Petition ....November 1, 2010
MERC Revised Initial Petition ....November 4, 2010
Department of Commerce (Department) Comments...February 18, 2011
MERC Reply Comments and Attachments ....May 5, 2011
Department Reply Comments...November 15, 2011
MERC Supplemental Reply Comments ....November 29, 2011

G-011/M-10-1167 (MERC-PNG GLGT)

MERC Initial Petition ....November 1, 2010
Department of Commerce (Department) Comments..March 16, 2011
MERC Reply Comments ....May 2, 2011
Department Reply Comments...November 15, 2011
MERC Supplemental Reply Comments ....November 29, 2011

G-011/M-10-1168 (MERC-PNG NNG)

MERC Initial Petition ....November 1, 2010
Department of Commerce (Department) Comments..January 3, 2011
MERC Reply Comments and Attachments ....May 2, 2011
Department Reply Comments...November 15, 2011
MERC Supplemental Reply Comments ....November 29, 2011

G-011/M-10-1169 (MERC-PNG VGT)

MERC Initial Petition ....November 1, 2010
Department of Commerce (Department) Comments...April 22, 2011
MERC Reply Comments ....May 2, 2011

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, 2010?

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 seek 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.

PUC staff reviewed MERC's Demand Entitlement Petitions and the several rounds of *Comments* filed by MERC and the Department. The Department and MERC have worked together and resolved all of issues raised by the Department. PUC staff generally agrees with the Department's April 22, 2011 (in docket #10-1169) and November 15, 2011 (in docket #s10-1166, 10-1167 and 10-1168) recommendations with minor qualifications.

For its briefing papers, PUC staff is consolidating all of MERC's 4 PGA areas[3] into one discussion, but will discuss issues related to a particular PGA area separately.

Minnesota Rules

Minnesota Rule, part 7825.2910, subpart 2[4] 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.

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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] MERC has four separate PGA areas, MERC-NMU (10-1166), MERC-PNG Viking (10-1169), MERC-PNG GLGT (10-1167), and MERC-PNG NNG (10-1168).

[4] 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.

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, 2010?

MERC

MERC's Design Day (DD) Requirements

MERC calculated its 2010-2011 Design Day (DD) requirements at 268,992 Mcf/day.

Table 1 - Design Day (DD) requirements[5] by PGA areas (reflected in Mcf/day):

Total MERC	MERC-NMU	MERC-PNG Viking	MERC-PNG GLGT	MERC-PNG NNG
268,992	57,662	7,292	9,440	194,598

Table 2 - DD requirements by interstate pipeline (reflected in Mcf/day):

Pipeline	Total	MERC-NMU	MERC-PNG Viking	MERC-PNG GLGT	MERC-PNG NNG
NNG	218,213	23,615			194,598
Viking	18,127	10,835	7,292		
GLGT	24,404	14,964		9,440	
Centra	8,248	8,248			
Total	268,992	57,662	7,292	9,440	194,598

MERC's Demand Entitlement Contract Levels

To transport its DD requirements, MERC used a series of interstate pipeline contracts to meet its annual total system transportation and storage requirements for each PGA area, i.e. demand entitlements. The 2010-2011 transportation demand entitlement contract levels were modified from the previous 2009-2010 levels, which resulted in 324,571 Mcf/day of available interstate pipeline transportation capacity.

Table 3 – Transportation Demand Entitlements[6] by PGA area (reflected in Mcf/day):

Total MERC	MERC-NMU	MERC-PNG Viking	MERC-PNG GLGT	MERC-PNG NNG
324,571	71,819	7,625	11,500	233,627

[PUC staff note: The transportation demand entitlements reflected in Table 3 does not include the 50,000 Dth/d Bison and NBPL interstate pipeline contracts.]

[5] Includes Transportation only, does not include Storage Entitlements.
[6] Ibid.

MERC's Reserve Margin

The Reserve Margin is the difference between MERC's DD requirements and its transportation demand entitlements. 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 conditions, and the need to protect against the potential firm gas supply loss; maintain system reliability.

Table 4 - Reserve Margins[7] by PGA areas

	MERC-NMU	MERC-PNG Viking	MERC-PNG GLGT	MERC-PNG NNG
Quantities in Mcf[8]	14,157	333	2,060	39,029
As a Percentage[9]	24.55%	4.57%	21.82%	20.06%

Table 5 - Reserve Margin – MERC total system

All Dockets-Total MERC	Quantities in Mcf
Total MERC Reserve Margin	55,579
Total MERC DD requirements	268,992
Reserve Margin as a percentage	**20.66%**

MERC's Demand Entitlement Contract Costs

The Commission approved MERC's 2009-2010 demand entitlement contract costs of $21,521,801. In these dockets, MERC proposed to recover 2010-2011 demand entitlement costs of $34,069,682, an increase of $12,817,881.

MERC's justification for entering into the Bison and NBPL contracts was that MERC believes the contracts on Bison Pipeline LLC[10] and Northern Border Pipeline Company (NBPL) for 50,000 Dth/day of capacity would diversify MERC's gas supply. The additional gas supply diversity provides benefits to MERC's system by allowing the supply to come onto MERC's system using the Bison capacity which enters NBPL at the Bison interconnection on NBPL, which then feeds into NNG for ultimate delivery into MERC for its customers. MERC allocated the Bison and NBPL contracts to PNG-NNG at 44,589 Dth/day and to NMU at 5,411 Dth/day.

MERC stated that this capacity does not add any incremental capacity to its demand entitlements, but allows it to use Rockies' supply for PNG-NNG and NMU-NNG customers at Northern Border Pipeline (NBPL) interconnection with NNG. The Bison and NBPL contracts[11] added $12,847,800 to MERC's demand entitlement contract costs. Tables 6a reflects the

[7] See Appendix A for calculation

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

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

[10] First brought to the Commission in Docket No. 08-698, Bison Pipeline LLC, is a wholly-owned subsidiary of Northern Border Pipeline Company.

[11] Reflected a projected in-service date of December 15, 2010, the actual in-service date was January 15, 2011

Bison/NBPL contract cost as part of MERC's demand entitlement costs, while Table 6b does not reflect the contracts as part of MERC's demand entitlement costs.

Table 6a - Transportation Demand Entitlement Costs, with Bison and NBPL:

PGA area	2009-2010 Demand Cost of Gas	2010-2011 Demand Cost of Gas	Difference
MERC-NMU	$4,271,840	$5,145,359	$873,519
MERC-PNG Viking	$391,418	$285,943	($105,475)
MERC-PNG GLGT	$440,895	$440,895	0
MERC-PNG NNG	$16,147,648	$28,197,485	$12,049,837
Total	**$21,251,801**	**$34,069,682**	**$12,817,881**

Table 6b - Transportation Demand Entitlement Costs, without Bison and NBPL:

PGA area	2009-2010 Demand Cost of Gas	2010-2011 Demand Cost of Gas	Difference
MERC-NMU	$4,271,840	$3,754,970	($516,870)
MERC-PNG Viking	$391,418	$285,943	($105,475)
MERC-PNG GLGT	$440,895	$440,895	0
MERC-PNG NNG	$16,147,648	$16,740,074	$592,426
Total	**$21,251,801**	**$21,221,882**	**($29,919)**

Other Demand Entitlements Contract Costs

MERC further indicated that in its petitions, it shifted 7,000 Dth/day of demand entitlements that historically were allocated to the NMU and PNG-VGT to PNG-NNG and NMU-NNG. MERC stated that this capacity was rarely used by PNG-VGT, and its decision was made to allocate the demand cost to the customer base that benefits from the capacity which is PNG-NNG and NMU-NNG customers. Further, MERC also changed its allocation calculation for its LS Power arrangement to allocate capacity between PNG-NNG and NMU-NNG customers based upon its forecasted Design Day.[12]

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

[12] See MERC's 2010-2011 demand entitlement petitions, Attachment 5. The change in allocation process was made to address the Department's concern of NMU-NNG customers having a negative reserve margin in its 2009-2010 petitions

Department

The Department reviewed MERC's proposed Design Day (DD) requirements, demand entitlements, resulting reserve margins, and the additional Bison/NBPL contracts for 50,000 Dth/day.

The Department summarized MERC's proposed DD requirements by PGA area, and identified a total decrease of 15,952 Mcf/day from 2009-2010 to 2010-2011, see Table 7:

Table 7 – MERC's DD requirements

PGA area	2009-2010	2010-2011	Difference	% increase/(decrease)
MERC-NMU	60,918	57,662	(3,256)	(5.35%)
MERC-PNG Viking	6,891	7,292	401	5.82%
MERC-PNG GLGT	10,802	9,440	(1,362)	(12.61%)
MERC-PNG NNG	206,333	194,598	(11,735)	(5.69%)
Total	284,942	268,992	(15,952)	(5.60%)

MERC's proposed changes to it 2010-2011 demand entitlement and Reserve Margin levels in its 4 PGA areas are summarized in Tables 8 and 9.

Table 8 – MERC's Demand Entitlements requirements

PGA area	2009-2010	2010-2011	Difference	% increase/(decrease)
MERC-NMU	63,782	71,819	8,037	12.60%
MERC-PNG Viking	7,625	7,625	0	0.00%
MERC-PNG GLGT	11,500	11,500	0	0.00%
MERC-PNG NNG	231,064	233,627	2,563	1.11%
Total	313,971	324,571	10,600	3.38%

Table 9 – Reserve Margin Comparison by PGA area

Comparison in Percentage	2009-2010 Demand Entitlement Filing	2010-2011 Demand Entitlement Filing	Difference	% Difference
Docket No. 10-1166 (NMU)	4.70%	24.55%	19.85%	422.34%
Docket No. 10-1169 (Viking)	10.65%	4.57%	(6.08%)	(57.09%)
Docket No. 10-1167 (GLGT)	6.46%	21.82%	15.36%	237.77%
Docket No. 10-1168 (NNG)	11.99%	20.06%	8.07%	67.31%

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

The Department was concerned primarily about:[13]

A. MERC's design-day analysis and reserve margin and whether MERC had contracted for an appropriate amount of capacity on a peak day as defined by Commission practice.
B. The Bison and NBPL contracts' economics.
C. The procedures MERC used to evaluate the reasonableness of the Bison/NBPL contracts. In future contracts the Department suggested that MERC at minimum maintain:

   - Daily price data;
   - Cost benefit analyses if the goal is to justify diversification;
   - Other procurement options considered;
   - If there is a change in circumstance, what was done or, if nothing was done, why nothing was done; and
   - Analysis based on more than a single day.

In its November 15, 2011 comments, the Department described its initial review of the additional cost of the Bison and NBPL contracts and its initial recommendation was to disallow recovery of those costs. The Department also described its subsequent decision to reverse its position on the reasonableness of those contracts and to recommend that MERC's 2008 decision to enter into the contracts was reasonable and that the associated costs should be included in its PGA filing.

However, the Department questioned how these costs should be recovered. MERC's petitions stated that one of the benefits of these contracts was that they allowed MERC to procure a more diverse gas supply which benefits all of its customers. The Department concluded that it seemed unfair to allow cost recovery from just MERC's firm customers since the contracts provided benefits to all customers, which include interruptible sales and transportation customers, along with joint customers. The Department recommended that the cost of these contracts should be recovered in the commodity portion of MERC's PGA rates.[14] MERC has agreed to the Department cost recovery proposal.[15]

As a result, the Department recommended that for all 4 MERC PGA areas that the Commission:

- approve MERC's demand entitlement level for all PGA areas;

- approve the PGA recovery of costs associated with MERC's proposed demand entitlement level effective November 1, 2010;

- approve the PGA recovery of costs associated with MERC-NMU's proposed demand entitlement level effective November 1, 2010 with the modification that MERC recover

[13] See the Department's *Comments and Reply Comments*
[14] For the Department's discussion, see its *Comments*, pp. 2-6 and *Reply Comments*, pp. 2-5
[15] See MERC's Supplemental *Reply Comments*

costs associated with the Bison Contract through the commodity portion of the monthly PGA and not the demand portion on a going-forward basis; and

- approve the PGA recovery of costs associated with MERC-PNG's Northern PGA system proposed demand entitlement level effective November 1, 2010 with the modification that MERC recover costs associated with the Bison Contract through the commodity portion of the monthly PGA and not the demand portion on a going forward basis;

- require MERC to clarify its statements regarding system balancing and provide detailed evidence in subsequent demand entitlement filings assuring the Commission that the appropriate customer group is paying for any balancing charges or penalties;

- require MERC to provide the following when preparing future demand entitlement filings:

    a. Inclusion of determinants in its design-day models that adequately account for any, and all, impact on usage associated with economic conditions; and
    b. Detailed explanations of any, and all, causes of unexpected changes in usage that may impact the design-day calculation and what, if any, modifications the Company made to its design day numbers.

PUC Staff Comment

PUC staff has reviewed the 2010-2011 demand entitlement petitions for all of MERC's PGA areas and appreciates all the party comments. Staff believes that for the time period at issue in these dockets, all issues have been resolved by the parties. 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 22, 2011 (in docket #10-1169) and November 15, 2011 (in docket #s 10-1166, 10-1167 and 10-1168) recommendations. However, PUC staff is concerned about MERC's reserve margin calculations for its NMU, PNG-GLGT, and PNG-NNG PGA areas and the economic value provided to MERC customers through its Bison and NBPL contracts.

Reserve Margin Calculations

MERC states that its Reserve Margins are high for various reasons that include:

1. The economic benefit of using LS Power capacity arrangement.
2. Pipeline requirements for building additional capacity.

In previous demand entitlement petitions,[16] MERC has explained that it uses the LS Power capacity instead of more expensive winter only NNG capacity. The arrangement gives MERC the right to call on the LS Power capacity of 29,100 Dth/day for 20 days during December through February of every winter heating season. MERC does not need the full amount (29,100

[16] See MERC's 2007-2008 and 2008-2009 demand entitlement petitions

Dth/day) of this capacity contract to meet its needs, but this capacity is cheaper than purchasing winter-only capacity from NNG. PUC staff believes that the LS Power arrangement is still the best, least cost option.

In its 2010-2011 demand entitlement petitions, MERC stated that interstate pipelines do not construct additional facilities in one year increments to meet the Local Distribution Company's (LDC's) annual growth needs. Instead, interstate pipelines plan their construction projects around the LDC's anticipated growth needs over a multi-year time period. Interstate pipeline procedures generally require the LDC to commit to purchase in advance its projected requirements, thus, producing demand entitlement costs that may not be used and useful in the current year. Because of the interstate pipeline requirements, PUC staff believes that it may be necessary to allow the LDC to recover additional projected demand entitlement costs in the current year. (Current period capacity costs can sometimes be mitigated if there is a viable secondary market for the underutilized pipeline capacity.)

Additional Bison and NBPL contract costs
On June 11, 2008,[17] MERC submitted its petition to the Commission requesting preapproval for its bid (i.e. its offer and precedent agreement) for 50,000 Dth/day of capacity on the proposed Bison Pipeline Project for a ten (10) year term at a negotiated rate of $0.55 per Dth. MERC also submitted a proposal to Northern Border for 49,690 Dth/day[18] of capacity for a ten (10) year term at a negotiated rate of $.23 per Dth. At its August 21, 2008 meeting, the Commission voted to take no action in the 08-698 docket and no order was issued.

In these demand entitlement petitions, MERC has requested recovery for approximately $13 million in additional pipeline capacity costs. The majority of this increase is due to the cost of the Bison and NBPL contracts. MERC stated that the purpose of these contracts is to enable MERC to diversify the source of its gas supply so that it is less reliant on Canadian gas supply. MERC estimated its projected cost savings based on it being able to exploit a difference in gas cost between gas purchased for delivery at the Ventura, Iowa pipeline interconnection point (much of that gas originates in Canada), and the cost of gas purchased in the Rocky Mountains.

The Department's *Comments* and subsequent *Reply Comments* analyzed MERC's proposal and determined it to be reasonable based on the facts known to MERC in its 2008 petition.

PUC staff believes that MERC used the best information known at the time when the contracts were signed and generally agrees with the Department's recommendations in the 2010-2011 demand entitlement petitions. 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

[17] In the Matter of the Petition of Minnesota Energy Resources Corporation's for Approval to Contract for Capacity on the Bison Pipeline Project, Docket No. G-007,011/M-08-698
[18] In its 2010-2011 demand entitlement petitions, this capacity is reflected at 50,000 Dth/day

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.

PUC staff is not recommending any changes to the Department's recommendation regarding these contracts, but it is of the opinion that the Commission may wish to require MERC to address the Bison/NBPL contracts in MERC's 2015-2016 demand entitlement petitions, by requiring MERC to evaluate the available gas supply alternatives to its Bison/NBPL contracts and provide the parties with its analysis in its 2015-2016 demand entitlement petitions. (MERC's 2014-2015 demand entitlement petitions are pending in Docket Nos. G-011/M-14-660 and 661.)

Cost Recovery of the additional Bison/NBPL contracts
As mentioned above, MERC initially sought cost recovery of the Bison/NBPL contracts through the demand portion of its PGA. In its November 15, 2011 comments for the 2010-2011 demand entitlement petitions, the Department recommended that MERC apply its Bison and NBPL contract costs proposal to NMU (docket 10-1166) and PNG-NNG (docket 10-1168) PGA areas as follows:

- Approve the PGA recovery of costs associated with MERC-NMU's proposed demand entitlement level effective November 1, 2010 with the modification that MERC recover costs associated with the Bison Contract through the <u>commodity portion</u> of the monthly PGA and not the demand portion on a going-forward basis; and [Emphasis added]

- Approve the PGA recovery of costs associated with MERC-PNG's Northern PGA system proposed demand entitlement level effective November 1, 2010 with the modification that MERC recover costs associated with the Bison Contract through the <u>commodity portion</u> of the monthly PGA and not the demand portion on a going forward basis. [Emphasis added]

The Department's justification was that it believes all of MERC's sales customers benefit from these contracts (includes firm, joint and interruptible sales customers), not just the firm sales customers.

PUC staff believes it would be impractical for the Commission to accept the Department's original recommendation because MERC's annual true-up petitions and Automatic Annual Adjustment (AAA) reports for 2010, 2011, 2012, and 2013 have been ruled on by the Commission. Thus, without reopening those dockets, no mechanism appears readily available to the Commission that would allow the Commission to require MERC to adjust its monthly customer billings back to November 2010 to reflect the cost recovery change from demand to commodity.

From these 2010-2011 petitions to the current 2014-2015 demand entitlement petitions, MERC has continued to include the Bison and NBPL contract costs in its demand PGA factors. Because it has taken time to bring MERC's 2010-2011 demand entitlement petitions to the Commission for a decision; PUC staff believes that any change in cost recovery should be made on a prospective basis.

PUC staff suggests to the Commission that this demand to commodity cost recovery shift be made effective as of November 1, 2014. Since November 1, 2014 has already passed and MERC has billed its customers for this time period using demand cost recovery in its calculation, the period of time from November 1, 2014 until the effective date of the Commission Order should be trued-up in MERC's 2014-2015 annual true-up filing and AAA report, which will be filed on September 1, 2015. PUC staff is recommending to the Commission that it modify the Department's recommendation to clarify the effective date of the cost recovery shift from demand to commodity in its PGA.

Should the Commission approve MERC's proposed allocation method for assigning storage demand charges to firm and interruptible customers?

Background

In Docket No. 06-1208 (the 2005-2006 annual automatic adjustment (AAA) reports docket), the Commission requested MERC to submit its proposal on storage classification and allocation. On March 7, 2008 (in a subsequent demand entitlement petition), MERC submitted its proposal to allocate all storage demand charges to both firm and interruptible sales customers through its commodity charges.

In its June 7, 2010 comments for the 2009-2010 demand entitlement petitions, the Department recommended that MERC apply its storage proposal to PNG-NNG (docket 09-1284) PGA area as follows:

- approve the PGA recovery of costs associated with MERC-PNG's Northern PGA systems demand entitlement level, <u>based on FDD storage costs being included in the commodity cost of gas, as presented in the Company's initial petition, Attachment 11, and OES Attachment 7 in its April 2, 2010 Comments</u> effective November 1, 2009;

In these dockets involving MERC's petitions for approval of its 2010-2011 demand entitlements, MERC and the Department continued their discussion of assigning storage demand costs to MERC's commodity costs. MERC's initial petitions, in these dockets, do not reflect the assignment of demand storage costs to the commodity factors, with the exception of Attachment 11, page 2[19] provided by MERC that shows the effect of re-classifying storage cost recovery in its commodity factors. The Department continued to endorse its recommendation to the

[19] For further details, see Petition, Attachment 4, pp. 4 -6, and Attachment 11, p. 2

Commission that MERC be required to reflect the storage demand costs in its commodity factors.[20]

However, staff notes that in its August 6, 2014 Order on MERC's 2007-2008 demand entitlements, the Commission approved MERC's storage classification and allocation proposal, effective November 1, 2014.[21]

PUC Staff Comment

PUC staff agrees the Department's recommendation that the Commission approve the PGA cost recovery associated with MERC's PNG-NNG PGA systems (in docket #10-1168), but considers the FDD storage costs allocation issue to be resolved on a going forward basis for all outstanding MERC demand entitlement petitions. As mentioned above, the Commission approved MERC's March 7, 2008 storage classification and allocation proposal,[22] effective November 1, 2014, in its August 6, 2014 Order in MERC's 2007-2008 demand entitlement petitions.

PUC staff believes the Commission does not need to address the Department's recommendation in this docket because the Commission has made its decision on storage cost recovery. Staff did not include this issue in the decision alternatives at the end of these briefing papers because it believes this issue has been addressed and resolved. If the Commission issues informal letter orders adopting the Department's recommendations in these dockets, it may want to make clear in its order that it is not adopting that part of the Department's recommendation.

(Staff is working on bringing the filings from 2011-2012, 2012-2013, 2013-2014, and 2014-2015 to the Commission now that this issue is resolved.)

Decision Alternatives

1. MERC Change in Demand Entitlements for 2010-2011

MERC is seeking Commission Approval for Change in Demand Entitlement petitions, effective November 1, 2010, for its 4 PGA areas; MERC-NMU, MERC-PNG Viking, MERC-PNG GLGT, and MERC-PNG NNG, in the following dockets:

Docket Nos. G-007/M-10-1166 (MERC NMU)
Docket Nos. G-011/M-10-1167 (MERC-PNG GLGT)
Docket Nos. G-011/M-10-1168 (MERC-PNG NNG)
Docket Nos. G-011/M-10-1169 (MERC-PNG Viking)

MERC and the Department do not have any issues remaining on the following resolved issues:

[20] See the Department comments in MERC's 2008-2009 and 2009-2010 demand entitlement petitions
[21] For further detail, see the July 15, 2014 PUC staff briefing papers for Docket Nos. 07-1402, 07-1403, 07-1404, and 07-1405
[22] Ibid.

- Design Day Requirements Estimates
- Demand Entitlement Estimates without endorsing its design-day study analysis
- Bison and NBPL pipeline contracts, a new gas supply source
- Reserve Margin Calculation
- Peak day send-out use per customer
- Storage Contract changes and cost recovery
- PGA Cost Recovery

A. Approve MERC's request for interstate pipeline and other capacity changes to meet its Design Day and Reserve Margin requirements as described in the listed dockets, and

B. Approve MERC's request to recover the associated cost changes in its pipeline demand entitlement contracts and supplier reservation fees as requested by MERC, and

C. Require MERC to address the Bison/NBPL contracts in it 2015-2016 demand entitlement petitions, by requiring MERC to evaluate available gas supply alternatives to its Bison/NBPL contracts and provide parties with its analysis in its petitions in the 2015-2016 dockets; and

D. Require MERC to clarify its statements regarding system balancing and provide detailed evidence in subsequent demand entitlement filings assuring the Commission that the appropriate customer group is paying for any balancing charges or penalties; and

E. Require MERC to provide the following when preparing future demand entitlement filings:

  i. Inclusion of determinants in its design-day models that adequately account for any, and all, impact on usage associated with economic conditions; and
  ii. Detailed explanations of any, and all, causes of unexpected changes in usage that may impact the design-day calculation and what, if any, modifications the Company made to its design day numbers.

2. Should the Commission approve the Department's recommendation to allocate the Bison/NBPL contract costs to all of MERC's customers, i.e. firm, interruptible, joint sales customers?

A. Approve the PGA recovery of costs associated with MERC-NMU's proposed demand entitlement level effective November 1, 2010 with the modification that MERC recover costs associated with the Bison Contract through the commodity portion of the monthly PGA and not the demand portion on a going-forward basis. (The Commission may also want to clarify the effective date of the cost recovery treatment from demand to commodity in MERC's PGA, for example, November 1, 2014.)[23] [Emphasis added] and

[23] The change in PGA demand and commodity rate factors should be implemented to be effective on customer bills February 1, 2015. The November 1, 2014 through January 31, 2015 portion would need to be made effective through an adjustment to MERC's true-up factors in MERC's September 1, 2015 annual true-up filing.

B. Approve the PGA recovery of costs associated with MERC-PNG's Northern PGA system proposed demand entitlement level effective November 1, 2010 with the modification that MERC recover costs associated with the Bison Contract through the <u>commodity portion</u> of the monthly PGA and not the demand portion on a going forward basis. (The Commission may also want to clarify the effective date of the cost recovery treatment from demand to commodity in MERC's PGA, for example, November 1, 2014.)[24] [Emphasis added]

<u>OR</u>

C. Require MERC to continue treating the Bison/NBPL contract costs as demand costs in the demand portion of MERC's PGA chargeable to firm sales customers only.

[24] Ibid.

Transportation Demand Entitlements Changes

MERC-NMU		06-1535	07-1402	08-1329	09-1282	10-1166	Difference
		(1)	(2)	(3)	(4)	(5)	(6)
		Mcf	Mcf	Mcf	Mcf	Mcf	Mcf
							(5) - (4)
NNG TF 12 B&V		13,270	12,756	9,296	12,756	8,151	(4,605)
NNG TF 5		2,102	1,991	5,451	1,991	3,493	1,502
NNG TFX 12		0	0	0	0	3,495	3,495
NNG TFX 5		5,514	6,139	6,139	6,139	9,759	3,620
LS Power		0	2,777	2,777	2,725	3,149	424
Bison	*	0	0	0	0	5,411	5,411
NBPL	*	0	0	0	0	5,411	5,411
GLGT FT		10,130	10,130	10,130	10,130	10,130	0
GLGT FT (12)		1,178	1,178	1,178	1,178	1,178	0
GLGT FT (5)		2,138	2,138	2,138	2,138	5,738	3,600
GLGT FT		0	4,500	4,000	3,000	3,000	0
VGT FT-A		7,966	7,966	7,966	7,966	7,966	0
VGT FT-A (4)	*	0	0	5,902	5,902	0	(5,902)
NNG-TF 12 Chisago Base		2,546	782	926	1,368	0	(1,368)
NNG-TF 12 Chisago Var.		0	0	0	955	0	(955)
NNG-TF 5 Chisago		2,079	1,765	2,089	563	0	(563)
NNG-TFX12 Chisago		0	1,963	2,324	2,089	0	(2,089)
NNG-TFX 5 Chisago		0	476	563	926	0	(926)
Wadena Delivered Option		0	0	0	0	5,902	5,902
Centra FT-1		9,858	9,858	9,858	9,858	9,858	0
NEXEN/VGT CR		6,000	0	0	0	0	0
Total Demand Entitlements		62,781	64,419	64,835	63,782	71,819	8,037
Total DD Requirements		61,060	61,008	63,726	60,918	57,662	(3,256)
Surplus/Deficient		1,721	3,411	1,109	2,864	14,157	11,293
Reserve Margin		**2.82%**	**5.59%**	**1.74%**	**4.70%**	**24.55%**	19.85%

[* PUC staff note: The VGT FT-A (4)/Bison/NBPL volumes are not included in the Total Demand Entitlement volume, the VGT FT-A (4) was a backhaul arrangement, the Bison and NBPL are used to deliver Rockies supply into NNG - does not add incremental capacity for MERC's design day demand entitlements.]

Transportation Demand Entitlements Changes

MERC-PNG GLGT	06-1535	07-1402	08-1329	09-1282	10-1166	Difference
	(1)	(2)	(3)	(4)	(5)	(6)
	Mcf	Mcf	Mcf	Mcf	Mcf	Mcf
						(5) - (4)
FT0017	4,105	4,105	4,105	4,105	4,105	0
FT0075	1,973	1,973	1,973	1,973	1,973	0
FT0155 (12)	2,422	2,422	2,422	2,422	2,422	0
FT0155 (5)	1,500	1,500	1,500	1,500	1,500	0
FT8466	0	0	500	1,500	1,500	0
Total Demand Entitlements	10,000	10,000	10,500	11,500	11,500	0
Total DD Requirements	9,543	9,550	10,299	10,802	9,440	(1,362)
Surplus/Deficient	457	450	201	698	2,060	1,362
Reserve Margin	**4.79%**	**4.71%**	**1.95%**	**6.46%**	**21.82%**	**15.36%**

Transportation Demand Entitlements Changes

MERC-PNG NNG		06-1535	07-1402	08-1329	09-1282	10-1166	Difference
		(1)	(2)	(3)	(4)	(5)	(6)
		Mcf	Mcf	Mcf	Mcf	Mcf	Mcf
							(5) - (4)
TF-12 Base and Variable		76,240	59,804	62,596	59,804	67,165	7,361
TF5		36,772	29,619	26,827	29,619	28,785	(834)
TFX-12		9,724	18,409	29,246	31,199	28,802	(2,397)
TFX-5		73,190	90,130	79,293	81,567	80,424	(1,143)
Bison	*	0	0	0	0	44,589	44,589
NBPL	*	0	0	0	0	44,589	44,589
Windom		2,500	2,500	2,500	2,500	2,500	0
LSP Peaking Service		29,100	26,323	26,323	26,375	25,951	(424)
Total Demand Entitlement		227,526	226,785	226,785	231,064	233,627	91,741
Total DD Requirements		200,484	202,263	**225,397**	**206,333**	**194,598**	(11,735)
Surplus/Deficient		27,042	24,522	1,388	24,731	39,029	103,476
Reserve Margin		**13.49%**	**12.12%**	**0.62%**	**11.99%**	**20.06%**	8.07%

[* 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-PNG Viking	06-1535	07-1402	08-1329	09-1282	10-1166	Difference
	(1)	(2)	(3)	(4)	(5)	(6)
	Mcf	Mcf	Mcf	Mcf	Mcf	Mcf
						(5) - (4)
AF0012	3,527	3,527	3,527	3,527	3,527	0
AF0016	1,000	1,000	1,000	1,000	1,000	0
AF0102	2,000	2,000	2,000	2,000	2,000	0
Wadena Delivered Option	0	0	0	0	1,098	1,098
NNG-TF 12 Chisago 112495 B	935	316	172	255	0	(255)
NNG-TF 12 Chisago 112495 V			0	178	0	(178)
NNG-TF 5 Chisago 112495	227	713	389	105	0	(105)
NNG-TFX 12 Chisago 112486	373	793	432	389	0	(389)
NNG-TFX 5 Chisago 112486	841	192	105	172	0	(172)
Total Demand Entitlement	8,903	8,541	7,625	7,626	7,625	(1)
Forecasted DD Requirement	8,112	8,135	**7,420**	**6,891**	**7,292**	401
Surplus/Deficient	791	406	205	735	333	(402)
Reserve Margin	**9.75%**	**4.99%**	**2.76%**	**10.67%**	**4.57%**	**-6.10%**

Transportation Demand Entitlements PGA Costs, as adjusted

MERC-NMU	06-1535	07-1402	08-1329	09-1282	10-1166	Difference
	(1)	(2)	(3)	(4)	(5)	(6)
	$	$	$	$	Mcf	Mcf
						(5) - (4)
NNG TF 12 B&V 112495	1,299,191	1,338,116	966,064	1,255,236	812,428	(442,808)
NNG TF 5 112495	157,398	150,848	412,995	150,848	264,647	113,799
NNG TFX 5 112486	412,888	465,121	465,121	465,121	682,554	217,433
NNG TFX 12 112486	0	0	0	0	236,539	236,539
LS Power	0	36,211	36,211	35,531	41,059	5,528
Bison	0	0	0	0	993,135	993,135
NBPL	0	0	0	0	397,254	397,254
GLGT FT FT0016	420,354	420,354	420,354	420,354	420,354	0
GLGT FT (12) FT0155	48,882	48,882	48,882	48,882	48,882	0
GLGT FT (5) FT0155	36,966	36,966	36,966	36,966	36,966	0
GLGT FT FT8466	0	186,732	165,984	124,488	124,488	0
VGT FT-A AF0012	331,427	331,427	331,427	331,427	331,427	0
Wadeena Delivery Option	0	0	0	0	15,935	15,935
VGT FT-A	0	0	111,167	88,934	0	(88,934)
VGT – Cap. Release RF0361	80,177	68,222	0	0	0	0
NNG-TF 12 B Chisago 112495	163,654	71,130	84,181	124,431	0	(124,431)
NNG-TF 12 V Chisago	0	0	0	104,232	0	(104,232)
NNG-TF 5 Chisago 112495	33,049	133,755	158,296	42,672	0	(42,672)
NNG-TFX12Chisago 112486	82,847	226,869	268,494	241,411	0	(241,411)
NNG-TFX 5 Chisago 112486	122,597	36,057	42,672	70,141	0	(70,141)
Centra FT-1	489,742	536,214	536,214	531,532	540,057	8,525
Union Balancing	54,000	54,000	54,000	54,000	54,000	0
Centra MN Pipelines	145,634	145,634	145,634	145,634	145,634	0
Total Demand Entitlement	**3,878,806**	**4,286,538**	**4,284,662**	**4,271,840**	**5,145,359**	**873,519**

Transportation Demand Entitlements PGA Costs

MERC-PNG GLGT	06-1535	07-1402	08-1329	09-1282	10-1166	Difference
	(1)	(2)	(3)	(4)	(5)	(6)
	$	$	$	$	Mcf	Mcf
						(5) - (4)
FT-A FT0017	170,341	170,341	170,341	170,341	170,341	0
FT-A FT0075	81,872	81,872	81,872	81,872	81,872	0
FT-A FT0155	100,503	100,503	100,503	100,503	100,503	0
FT-A FT0155	25,935	25,935	25,935	25,935	25,935	0
FT-A FT8466	0	0	25,935	62,244	62,244	0
Total Demand Entitlement	**378,651**	**378,651**	**404,586**	**440,895**	**440,895**	**0**

Transportation Demand Entitlements PGA Costs

MERC-PNG NNG	06-1535	07-1402	08-1329	09-1282	10-1166	Difference
	(1)	(2)	(3)	(4)	(5)	(6)
	$	$	$	$	Mcf	Mcf
						(5) - (4)
TF-12 Base and Variable	7,357,729	5,452,825	6,227,986	5,816,707	6,626,048	809,341
TF5	2,753,487	2,244,084	2,003,752	2,244,084	2,180,896	(63,188)
TFX-12	1,110,471	1,689,365	1,689,365	1,746,271	1,949,350	203,079
TFX-5	5,074,869	6,303,269	6,303,269	5,656,324	5,625,135	(31,189)
Bison	0	0	0	0	8,183,865	8,183,865
NBPL	0	0	0	0	3,273,546	3,273,546
TFX 112486	0	11,366	11,366	11,366	10,138	(1,228)
TFX 112486	4,867	11,366	11,366	11,366	10,138	(1,228)
TFX7 111866	0	168,437	168,437	317,633	0	(317,633)
Windom	0	0	0	0	0	0
LSP Peaking Service	349,444	343,217	343,217	343,897	338,369	(5,528)
Total Demand Entitlement	**16,650,867**	**16,223,929**	**16,758,758**	**16,147,648**	**28,197,485**	**12,049,837**

Transportation Demand Entitlements PGA Costs

MERC-PNG Viking	06-1535	07-1402	08-1329	09-1282	10-1166	Difference
	(1)	(2)	(3)	(4)	(5)	(6)
	$	$	$	$	Mcf	Mcf
						(5) - (4)
FT-A AF0012	146,742	146,742	146,742	146,742	146,742	0
FT-A AF0014	45,683	11,421	11,421	11,421	11,421	0
FT-A AF0016	41,605	41,605	41,605	41,605	41,605	0
FT-A AF0102	83,210	83,210	83,210	83,210	83,210	0
Wadena Delivery Option	0	0	0	0	2,965	2,965
NNG-TF 12 Chisago B 112495	35,016	28,712	15,661	23,149	0	(23,149)
NNG-TF 12 Chisago V 112495	0	0	0	19,391	0	(19,391)
NNG-TF 5 Chisago 112495	40,730	53,990	29,449	7,939	0	(7,939)
NNG-TFX12Chisago 112486	17,726	91,576	49,950	44,912	0	(44,912)
NNG-TFX 5 Chisago 112486	151,093	14,554	7,939	13,049	0	(13,049)
Capacity Release RF03061	53,130	12,517	0	0	0	0
Total Demand Entitlement	**614,935**	**484,327**	**385,977**	**391,418**	**285,943**	**(105,475)**

Summary of demand entitlement costs for all PGA areas

PGA Area	06-1535	07-1402	08-1329	09-1282	10-1166	Difference
	(1)	(2)	(3)	(4)	(5)	(6)
	$	$	$	$	Mcf	Mcf
						(5) - (4)
MERC-NMU	3,878,806	4,286,538	4,284,662	4,271,840	5,145,359	873,519
MERC-PNG Viking	614,935	484,327	385,977	391,418	285,943	(105,475)
MERC-PNG GLGT	378,651	378,651	404,586	440,895	440,895	0
MERC-PNG NNG	16,650,867	16,223,929	16,758,758	16,147,648	28,197,485	12,049,837
Total Demand Entitlement	**21,523,259**	**21,373,445**	**21,833,983**	**21,251,801**	**34,069,682**	**12,817,881**