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May 2, 2011

VIA ELECTRONIC FILING

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101

Re: In the Matter of the Petition of Minnesota Energy Resources Corporation–PNG for Approval of a Change in Demand Entitlement for its Northern Natural Gas Transmission System;
Docket No. G011/M-10-1168

Dear Dr. Haar:

Enclosed please find the Reply Comments of Minnesota Energy Resources Corporation ("MERC") in response to the January 3, 2011 Comments of the Minnesota Department of Commerce, Division of Energy Resources in the above-referenced docket.

Thank you for your attention to this matter.

Sincerely yours,

/s/ Michael J. Ahern

Michael J. Ahern

cc: Service List

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Petition of Minnesota Energy Resources Corporation-PNG for Approval of a Change in Demand Entitlement for its Northern Natural Gas Transmission System	Docket No. G011/M-10-1168

REPLY COMMENTS OF
MINNESOTA ENERGY RESOURCES CORPORATION

Minnesota Energy Resources Corporation-PNG ("MERC" or "Company") submits to the Minnesota Public Utilities Commission ("Commission") these Reply Comments in response to the January 3, 2011 Comments of the Minnesota Department of Commerce, Division of Energy Resources ("Department") in the above referenced matter.

A. <u>Bison Contract</u>

On June 11, 2008, MERC submitted to the Commission in Docket No. G007,011/M-08-698 a Petition for Approval to Contract for Capacity on the Bison Pipeline and corresponding capacity on Northern Border Pipeline to make delivery to Northern Natural Gas to serve MERC's customers. In order to diversify its gas supply portfolio and increase reliability in gas supply, MERC had submitted an offer to contract for 50,000 Dth/day capacity on Bison for a ten (10) year term at a negotiated rate of $0.55 per Dth. MERC also submitted a proposal to Northern Border to make delivery from Bison to the Northern Natural Gas (NNG) pipeline supplying MERC's customers. At that time, the Department agreed that MERC's decision to diversify its supply portfolio would likely provide its ratepayers with some level of price protection and security against supply disruptions during the term of the agreement. Based on its analysis, the Department concluded that MERC's decision to bid for capacity on the Bison Pipeline was reasonable and in the best interest of MERC's ratepayers.[1] The Commission did not take action on MERC's proposal since the Commission generally does not pre-approve cost recovery for pipeline contracts. In this docket, MERC proposes to begin recovering costs associated with the Bison Contract.

In its Comments, the Department states that it has concerns associated with the Company's Bison and Northern Border contracts. First, the Department states that it initially expressed support for MERC's proposal since the information MERC provided at that time indicated that total delivered costs would have been under $10 per Mcf. Specifically, MERC provided Exhibit 6 showing estimated "Total Bison Costs" with delivered costs on a yearly basis, through 2018 of approximately $9.00 per Dkt, including total transportation fees of just under $1.00 per Dkt. The Department notes, however, that MERC now indicates that the Company expected costs in 2008 to be roughly $25 per Dkt because Exhibit 6 to MERC's petition referred only to daily transportation fees rather than the monthly per-Dkt costs typically used for demand costs in PGAs. The Department states that when it observed that transportation fees were just under $1.00 per Dkt, the Department assumed that this amount would be comparable to how demand costs are presented in the monthly PGA. The Department states that had it been aware that total demand fees, including Northern Border costs, would have been nearly $25 per Dkt, which is approximately $10 per Dkt greater than Northern's most expensive seasonal reservation fee, the Department would not have supported MERC's proposal unless MERC was able to show that this cost was likely to be less expensive than other alternatives, including alternatives from Northern.

[1] Department Comments, Docket No. G007,011/M-08-698 (Aug. 1, 2008).

The Department states that under MERC's proposal, the current demand costs for MERC-PNG's Northern system are significantly higher than other demand costs charged by MERC in its monthly PGA. The Department notes, however, that it is possible that commodity costs secured in the Rocky Mountains may be lower than in Canada or the Mid-Continent, which means that total ratepayer costs may be comparable. The Department notes that current costs do not show whether MERC's decision to enter into the Bison Contract was reasonable or prudent and that it is necessary to examine the information available to the Company when it made its decision in the spring of 2008. The Department therefore recommends that MERC provide the following information in its Reply Comments:

- daily New York Mercantile Exchange (NYMEX) closing prices at the Henry Hub and basis spreads for the Rockies (using the CIG Rocky Mountain price or some other applicable Rocky Mountain regional hub), Ventura Hub, and Demarcation for each forward contract over the period from January 1, 2008 to August 21, 2008;
- daily volatility measures for the points detailed in the previous bullet point for each forward contract over the period from January 1, 2008 to August 21, 2008;
- a full explanation detailing whether MERC investigated procuring other sources of gas to diversify its supply portfolio;
- a detailed analysis of contract prices available for alternate demand contracts in 2008; and
- a full list and explanation, including demand and commodity prices and price differences from the Bison contract, of all alternate contracts that MERC considered as alternatives to the Bison contract.

MERC Response

1. MERC's Purpose in Entering Into the Bison and NBPL Contracts

MERC was appreciative of the Department's review and support of MERC's petition for approval to contract for capacity on the Bison Pipeline and corresponding capacity on Northern Border Pipeline (NBPL) in Docket No. G007,011/M-08-698. The Department's support of MERC's proposal was a key factor in MERC's decision to contract for the capacity on Bison and NBPL at that time.

The Bison Pipeline became operational on January 14, 2011. The 50,000 Dth/day of capacity on Bison and NBPL are being fully utilized to serve MERC's customers served off of the NNG pipeline in the PNG and NMU service areas. The final cost for capacity for the ten (10) year term of the Bison contract was $.575 per Dth volumetric rate or approximately $17.49 reservation rate. The final cost for capacity for the ten (10) year term of the NBPL contract was $.23 per Dth volumetric rate or approximately $6.996 reservation rate. The reservation rates were calculated by taking the volumetric rates multiplied by 365 days divided by twelve (12) months.

MERC's main purpose in entering into the Bison and NBPL agreements was to diversify its gas supply portfolio and increase reliability in gas supply for its customers. As explained in MERC's petition filed in Docket No. G007,011/M-08-698, MERC was concerned about the supply liquidity in Canada due to production declines and increased demand for natural gas in Canada. MERC subscribes to several energy publications, such as Mackenzie's Monthly Market Update – February 2008, Mackenzie's American Gas Mid-Term Outlook and Mackenzie's Gas and Power Service – August. All of these publications refer to the continued declines in Canadian imports and/or increased demand to electric production and oil sands development.

The American Gas Association (AGA) indicated in "The 2008-09 Winter Heating Season: A View From Late September" a the year over year decline in Canadian gas imports from June 2007 to June 2008. Please see http://www.aga.org/SiteCollectionDocuments/**Presentation**s/Public Relations/0809COOPER.PPT. The Energy Information Administration's (EIA) International Energy Outlook 2007and International Energy Outlook 2008 reported projected declines in Canadian gas imports through 2030. MERC was also concerned about royalty tax changes by the Alberta Province government. Please see http://www.energy.alberta.ca/Org/pdfs/royalty_Oct25.pdf.

In its initial filing in Docket No. GG007,011/M-08-698, MERC indicated that 62.03% of its winter capacity on NNG was Canadian sourced and that MERC was concerned about relying so heavily on Canadian supply given the uncertainties surrounding Canadian supply liquidity. By entering into the Bison and NBPL contracts, MERC's reliance on Canadian capacity was reduced from 62.03% to 40.41% of winter capacity on NNG. MERC also diversified its supply portfolio by adding another supply basin in the Rockies. MERC entered into the agreements to enhance supply reliability by supply diversification and to address supply liquidity concerns in Canada. While MERC noted in its petition that the analysis at the time MERC submitted the petition showed that MERC customers might see a savings in gas cost as the result of the proposal, MERC's petition clearly stated that MERC was not relying on projected gas cost savings as the underlying reason for entering into the agreements and that MERC could not guarantee that there would be gas cost savings in the future. *See* MERC Petition at 4, 13. By entering into the Bison and NBPL contracts, MERC has achieved its purpose of diversifying its gas supply portfolio and limiting its reliance on gas supply from any one supply area, thereby increasing reliability for its customers.

2. Costs of the Bison and NBPL Contracts

MERC believes that the Department is not correctly interpreting Exhibit 6 that was filed with MERC's petition in Docket No. G007,011/M-08-698. In Exhibit 6, MERC compared the projected costs of three options to deliver supply to MERC customers served off of the NNG pipeline at NNG Ventura. Exhibit 6 projected the cost of transportation and commodity by (1) purchasing supply in the Rockies and delivering the supply via Bison and NBPL, (2) purchasing the supply in the AECO supply basin and delivering supply via Nova, Foothills and NBPL, and (3) continuing to purchase supply at NNG Ventura. What Exhibit 6 demonstrated was that Bison and NBPL provided the cheapest option of the three scenarios, resulting in a projected delivered cost of gas savings of $.6846 per Dth. Exhibit 6 did not calculate the projected total demand and commodity costs for PNG-NNG customers.

The $.55 per Dth rate presented in MERC's petition in Docket No. G007,011/M-08-698 was just that, the cost per Dth, which is how Exhibit 6 was calculated. The $.55 per Dth was not a reservation rate but rather a volumetric rate. The approximate reservation rate is $16.73 ($.55 rate * 365 days / 12 months). The $.23 per Dth rate for NBPL was a volumetric rate as well. The approximate reservation rate is $6.996 ($.23 rate* 365 days / 12 months).

MERC also believes the Department needs to consider the impacts of both the transportation and commodity costs together as the cost of delivered gas rather than considering the commodity and transportation costs separately. MERC agrees that customer demand costs will increase because of the Bison and NBPL capacity. However, since MERC is able to purchase supply based on a Colorado Interstate Gas (CIG) index price, the delivered cost of gas was the least expensive supply based on the purchase location basis at the time MERC made the commitment to the Bison capacity. In Docket No. G007,011/M-08-698, MERC was projecting a CIG basis of -$1.83, per Dth compared to -$.6948 per Dth for AECO and -$.1612 per Dth for NNG Ventura. Please see Exhibit 6 and the supporting data that was filed in Docket No. G007,011/M-08-698, which illustrate how these numbers were calculated. The numbers were based on NYMEX and basis differentials as of May 19, 2008. The demand cost would increase but the cost of commodity would decrease ($1.83 CIG basis compared to the $.1612 NNG Ventura basis).

3. Reasonableness of Entering Into the Bison and NBPL Contracts in 2008

As the Department noted, current market conditions have changed drastically since MERC made the decision to enter into the Bison and NBPL agreements. The Shale plays have proven to be prolific in domestic production, and natural gas prices and basis spreads are considerably lower compared to 2008 numbers. Also, the discovery of Shale plays in British Columbia Province has improved Canadian production, and the recent decision by the Alberta Province government to change the Royalty Tax to match British Columbia's Royalty tax structure has also helped to increase Canadian production. As noted above, MERC's main reason for contracting on Bison and NBPL was to enhance supply reliability by addressing the Canadian supply liquidity and to diversify the supply basin, based on the information available to MERC at that time. By entering into the Bison and NBPL contracts, MERC has achieved this purpose and increased reliability for its customers. If there was a recognized gas savings, that would be a positive by-product of entering into the agreements.

The Department has requested daily NYMEX pricing, basis numbers and volatility measures from January 1, 2008 through August 21, 2008. The attached analysis indicates during the time period of January 1, 2008 through August 21, 2008, there was a projected $.2441 per Dth savings on average by contracting for the Bison and NBPL capacity. The prices ranged from an average cost increase of $.2105 per Dth (June 30, 2008) to a cost savings of $1.2478 per Dth (June 3, 2008). On average, there was a $.2441 per Dth savings during the time period. MERC utilized the pricing data from May 19, 2008 in its petition to the Minnesota Public Utilities Commission filed on June 11, 2008. At that time there was a calculated $.6742 per Dth average savings. During the January 1, 2008 through August 21, 2008 time period, there were 162 days of data. Of the 162 days, 105 days or approximately 65% of the time the analysis resulted in a projected gas savings. Please see the attached Excel file, Pricing Basis Bison to Ventura 010108 to 082110 analysis.

The Department also requested a full list and explanation, including demand and commodity prices and price differences from the Bison contract, of all alternate contracts that MERC considered as alternatives to the Bison contract. Please see Exhibit 6 and the supporting data that was filed in Docket No. G007,011/M-08-698.

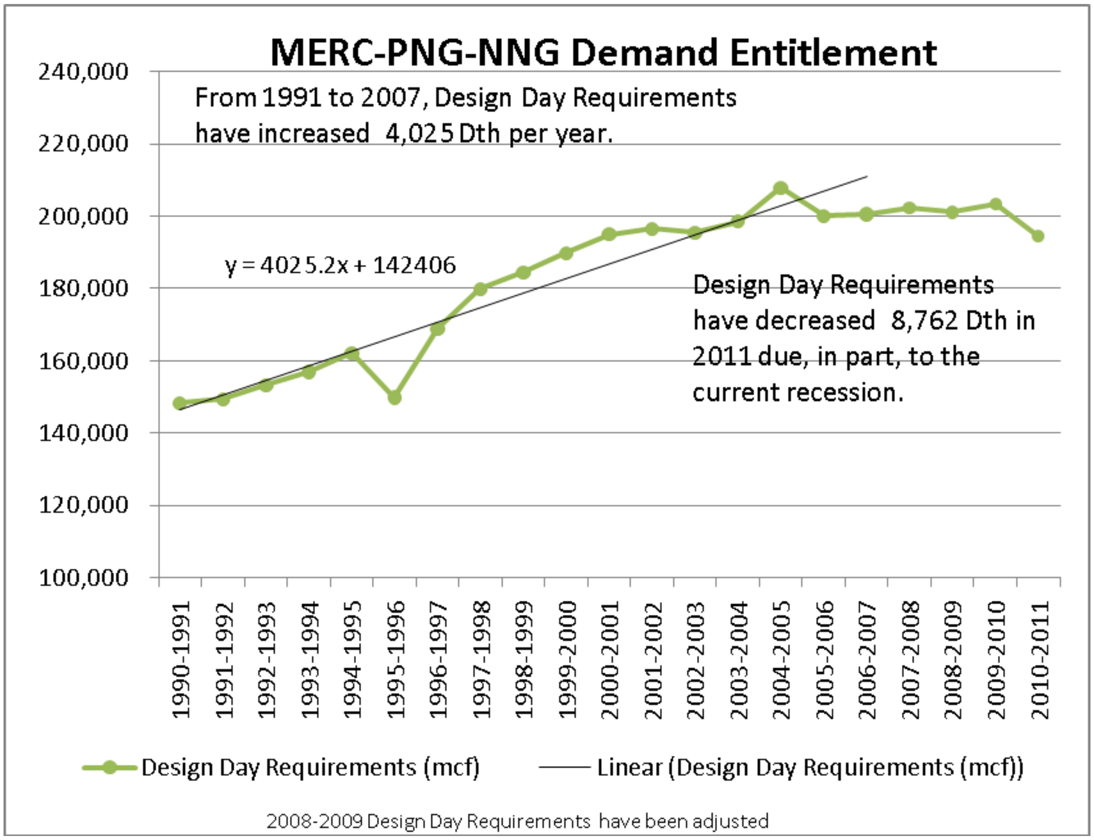
B. Design-Day Requirement

The Department concludes that MERC's design-day study and accompanying entitlements appear to ensure sufficient capacity to serve firm demand on a peak day. The Department, however, notes that MERC's reserve margin is quite high, suggesting that demand costs are too high. According to the Department, an abnormally high reserve margin raises the possibility that the Company's design-day methodology does not produce reasonable estimates. The Department therefore withholds any recommendation regarding MERC's design-day analysis until the Company provides a full explanation detailing whether its design-day approach produces reasonable estimates.

MERC Response

1. Impact of Economy on Design-Day Requirements

The graph below provides a historical perspective of the design day requirements forecast along with the long-term best fit trend line. It is clear that the most recent few years have exhibited less positive growth than the long-term trend line would suggest. (Note that the design-day forecast for the 2008-2009 winter has been re-stated to agree with the forecast process used for 2009-2010 and 2010-2011.)



As the above graph demonstrates, from 1990 through 2007, Design Day requirements increased 4,025 Dth per year. However, the 2011 Design Day requirement decreased 8,762 Dth, which MERC believes is due to the current state of the economy since late 2008. MERC's Design Day calculation is based upon the previous three years December through February data. That means the winter data from December 2007 through February 2008, December 2008 through February 2009 and December 2009 through February 2010 data was used to calculate the Design Day requirement. These numbers are lower than previous years, especially the data from December 2008 through February 2009 because of the impacts of the recession.

Table 1 depicts total throughput on the NNG pipeline (PNG and NMU) from 2006 through 2010. The table clearly demonstrates a drastic decrease in throughput in 2009 and a large rebound in throughput in 2010. Since the data utilized for the design day calculation is based on throughput data from the previous three winter periods, a portion of the data would have been during the drastic decrease in throughput due to impacts on the economy. MERC believes the data used in the design day calculation, especially in 2009 was an anomaly resulting in much lower design day requirements.

Table 1:
NNG Annual Throughput (Bcf)

Year	Throughput	% Change
2006	62.0	
2007	61.4	-0.91%
2008	64.5	5.04%
2009	51.2	-20.61%
2010	59.9	16.98%

A large percentage of MERC's annual throughput on the NNG pipeline is due to the taconites. Table 2 indicates the approximate annual throughput from MERC's taconite customers from 2006 through 2010. The table clearly demonstrates a large reduction in throughput in 2009 and a large rebound in 2010.

Table 2:
Annual Taconite Throughput (Bcf)

Year	Throughput	% Change
2006	25.5	
2007	23.0	-9.86%
2008	22.2	-3.46%
2009	14.2	-35.82%
2010	24.3	70.65%

According to a March 27, 2011 article in the Duluth News Tribune, titled "Tac is back, Range revs up", the taconite industry hit rock bottom in 2009 but is now fully operational and looking to further expand. The article highlights a study by the University of Minnesota-Duluth that found approximately "18,000 jobs [are] directly or indirectly tied to mining industry in the region – from railroad and ports to engineers and the doctors and dentists who have miners as patients. Mining also is equipment-intensive, consuming tires, trucks, explosives and fuel." That translates into potential lower natural gas consumption by those who are directly or indirectly impacted by the reduction in taconite mining. But as the industry rebounds as it has in 2010 and runs at full capacity, natural gas consumption should potentially increase by those who are directly or indirectly impacted by the taconite industry. Please see Attachment A, the referenced article from the Duluth News Tribune.

As the economy rebounds, MERC believes there is a risk of turning back pipeline capacity based on current Design Day requirements. If MERC chooses to turn back capacity and as the economy continues to rebound and the Design Day requirements increase, as MERC believes to be the case, MERC may not be able to get capacity back on the interstate pipeline(s). The majority of pipelines MERC operates on are fully subscribed and if additional capacity is required, the pipeline(s) would require a pipeline expansion to increase capacity. The cost of a pipeline expansion can be substantially more costly than pipeline(s) maximum tariff rates. For example, MERC requested preliminary cost estimates from the NNG pipeline to increase delivery at the Worthington, MN TBS. NNG indicated that to increase the capacity by 5,000 Dth, MERC would have to agree to a ten (10) year agreement at a $1.80 per Dth. The NNG maximum tariff rate on an annual rate is approximately $.32 per Dth. The cost to expand is almost six (6) times the cost of the NNG maximum tariff rate.

Based on a potential for the economy to rebound and the potential cost of capacity if a pipeline expansion were required to contract for additional capacity after turning back current capacity, MERC believes the current levels of capacity are reasonable and prudent.

2. <u>Uncertainty in Design-Day Forecast</u>

The design-day forecast consists of three main parts:

1. Regression analysis of daily metered data and daily weather data.
2. Adjusting the regression results for non-firm customers who do not have daily meters.
3. Adding back the portion of joint firm customer demand that requires firm service even under design-day conditions.

The two most reliable parts of this forecast are part 1: the regression analysis, because it is supported by actual daily metered data, and part 3: adding back the firm portion of the joint firm customer demand, because that is based on actual signed contracts that clearly define the firm supply needs of the joint firm customers. The regression results include a confidence level of 97.5% meaning that there is only a 2.5% chance that actual load under design-day conditions will not exceed the regression-based forecast for those customers with daily meters included in the regression data.

However, the part 2 data related to the non-firm customers who do not have daily meters is based on monthly billing data. Inferring daily activity from monthly totals is statistically problematic – this is often referred to as a granularity deficiency in the data. As a general rule, the forecast time granularity should not be shorter than the granularity of the data. For example, forecasting monthly or annual activity using monthly data is generally considered acceptable because the annual activity simply adds up the monthly activity. Going the other way, or making accurate daily data from monthly data, creates uncertainty.

For example, a non-firm customer without a daily meter has January consumption of 3,100 Dkt. The design-day forecast process uses the approach from MERC's tariff that estimates a customer's MDQ as monthly consumption divided by 20 in situations where the customer's actual daily consumption is not available. This customer would then show an estimated MDQ of 155 Dkt (= 3,100 Dkt / 20), which is the amount that would be subtracted from the regression estimate.

Without daily telemetry to provide the actual daily consumption, it is possible that this customer actually used nearly the same amount each day (more reflective of a constant process load than a heat load), and 31 days would have been the more accurate divisor, meaning that 100 Dkt (= 3,100 Dkt / 31) should have been used as the reduction to the regression estimate. In this case, the regression estimate should have been reduced by 100 Dkt instead of 155 Dkt, and the adjusted firm design-day forecast was 55 Dkt too low. If this nearly flat load characteristic is shared by all of PNG-NNG's non-firm customers without daily meters, then the non-firm reduction from the regression results is about 35% too high, and the PNG-NNG firm design-day forecast as filed is too low by about 22,959 Dkt[2].

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[2] Calculated on a base number for non-firm customer monthly volume of 1,294,926 Dkt and a growth rate of -0.06615%.

To be fair, without daily telemetry to provide the actual daily consumption, it is also possible that this customer actually used gas for three work weeks (more reflective of a process load for three weeks and then shutting down the other week), and 15 days would have been the more accurate divisor, meaning that 207 Dkt (= 3,100 Dkt / 15) should have been used as the reduction to the regression estimate. In this case, the regression estimate should have been reduced by 207 Dkt instead of 155 Dkt, and the adjusted firm design-day forecast was 52 Dkt too high. If this partial-month load characteristic is shared by all of MERC's non-firm customers without daily meters, then the non-firm reduction from the regression results is about 34% too low, and the firm design-day forecast as filed is too high by about 21,568 Dkt.[3]

The lack of daily data for all non-firm customers brings uncertainty regarding the proper design day adjustment for them. For reasons discussed above, this uncertainty could result in a PNG-NNG design day forecast between 173,030 Dkt (= 194,598 Dkt filed - 21,568 Dkt) and 217,557 Dkt (= 194,598 Dkt filed + 22,959 Dkt). The proposed PNG-NNG supply entitlement is 233,627 Dkt. If the non-firm customers without daily meters really consume the same amount every day in the month, resulting in the design day forecast of 217,557 Dkt, **the reserve margin would be 7.4%** (= (233,627 Dkt – 217,557 Dkt) / 217,557 Dkt).

Partly to improve the accuracy of MERC's design day requirements forecast, MERC has requested and the Commission has approved telemetry for all non-firm customers in Docket No. G007,011/GR-08-835. MERC has clarified in Docket No. G007,011/GR-10-977 that this requirement would not apply to farm tap customers who have a relatively low daily load in the winter. The availability of daily readings from telemetry for non-firm customers will reduce the uncertainty associated with the non-firm adjustment to the regression results since the

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[3]Calculated on a base number for non-firm customer monthly volume of 1,294,926 Dkt and a growth rate of -0.06615%.

adjustments for these customers will be based on daily data instead of monthly data. Gradual improvement will be seen over a three year period since the MERC design-day regressions rely on three full winters of daily metered data, so the best results will be obtained when the non-firm customers have had daily meter readings for three consecutive winters and their daily consumption can be more accurately removed from the firm load regression data before the firm load regressions are performed.

In MERC's PNG-VGT Demand Entitlement filing, Docket No. G011/M-10-1169, the Department recommended that the Commission approve MERC's proposal. The Department concluded that MERC's design-day study and accompanying entitlements, adjusted for concern over the accuracy of its design-day forecast, are reasonable to ensure sufficient capacity to serve firm customers on a peak day.[4] The same comments hold true in this docket as well. While it can be challenging to forecast entitlements in the aftermath of extreme economic conditions, and adjusting regression results for non-firm customers who do not have daily data adds to this challenge, MERC believes that its proposal ensures sufficient capacity to serve its firm customers on a peak day.

C. <u>Reserve Margin</u>

The Department notes that MERC's reserve margin of more than 20 percent is much higher than the 5 percent level the Department generally considers to be reasonable. In its June 7, 2010 Response Comments in Docket No. G011/M-09-1284, the Department concluded that a 13.62 reserve margin was acceptable for MERC's Northern PGA system based on cost savings associated with the LS Power contract over more expensive Northern entitlements. Using this 13.62 reserve margin, MERC would need to decrease its total entitlements by 12,525 Dkt/day to

[4] Department Comments, Docket No. G011/M-10-1169 (Apr. 22, 2011).

a total amount of 221,102 Dkt/day. The Department states that unless MERC can support a higher amount, the Department recommends that the Commission not allow MERC to recover the costs of these demand volumes, resulting in a disallowance of approximately $896,367. The Department recommends that MERC fully explain in its Reply Comments the reasonableness of its proposed reserve margin and procured entitlement level.[5]

MERC Response

In the Department's Comments in the VGT demand entitlement docket, the Department noted that although MERC's reserve margin was quite high, MERC had fully mitigated concerns about charging customers too much and that the Company's reserve margin was reasonable in these circumstances. In particular, the Department noted:

> The Company has valid concerns that its forecast is too low. Furthermore, MERC has acquired the additional protection for an extreme cold-weather event that the large reserve margin provides, for much less than it was paying for a smaller volume of gas. The Company also explained that its need to honor the terms of certain of its contracts leaves it less flexibility than it would like as it builds its design-day capacity. Consequently, MERC has had to acquire the rights to firm transportation in blocks that are larger than it would prefer. Thus, although the Department does not endorse a reserve margin of nearly 20 percent, the Department concludes that MERC has fully mitigated concerns about charging customers too much and the Company's reserve margin is reasonable in these circumstances.[6]

The same circumstances are true in this docket as well.

As discussed above, MERC has concerns that the design day requirement may be low due to the data from late 2008 through 2009. In addition, the lack of daily metered data for MERC's non-firm customers makes it difficult to determine the proper design day adjustment for

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[5] The Department notes that the appropriateness of re-allocating demand costs from its Viking PGA to its Northern and NMU PGAs is discussed in greater detail in the Department's demand entitlement filing in Docket No. G011/M-10-1169. In that docket, the Department recommended that the Commission approve MERC's proposal.

[6] Department Comments at 5, Docket No. G011/M-10-1169 (Apr. 22, 2011).

them. Consequently, MERC's reserve margin could be much lower than the 20 percent cited by the Department. Additionally, even though MERC does not contract for firm capacity to meet interruptible and transportation load, MERC still has the responsibility to balance the entire system with each respective pipeline. That means MERC not only has to deliver enough supply to meet General System firm volumes but also enough supply to meet General System interruptible volumes and any third party transportation volumes in excess of third party delivered supply.

MERC does not typically curtail interruptible load unless there are operational reason(s) or MERC is experiencing a peak day. For example, at the Worthington Town Border Station (TBS), MERC curtails due to pressure drops on the NNG pipeline because there is more demand on colder days than the NNG pipeline can physically deliver. With that said, MERC will typically purchase and deliver supply for interruptible customers, unless there are operational reason(s) to curtail.

When capacity is contracted with a pipeline, it is typically for a long term, typically three to five years. MERC doesn't have any firm capacity on NNG expiring until October 31, 2013, so that would be the earliest MERC could turn back capacity. MERC can terminate the LS Power contract but must provide four (4) months notice and can't be during the winter period (November through March). MERC releases excess capacity to offset capacity costs. MERC is willing to terminate the LS Power contract for the 2011/2012 winter to address the Department's concerns. MERC is also concerned with turning capacity back, because the capacity could be subscribed by another party. In the event MERC needs future capacity, the pipeline may not have any to purchase. The pipeline could provide additional capacity by a pipeline expansion, but the cost would be greater than the pipeline maximum tariff rates, as explained above.

Although MERC believes its design-day forecast and accompanying entitlements are reasonable and sufficient to meet peak day need, the Department has indicated that a 13.62% reserve margin is acceptable. To reduce its reserve margin to that level, MERC would need to decrease capacity by 12,525 Dth. The Department calculated the $896,367 disallowance on the cost of NNG capacity. Although MERC does not agree that a reduction in capacity is warranted, if MERC were to reduce its capacity by 12,525, MERC contends any disallowance should be based on the cost of the LS Power contract and not on capacity with NNG. As stated previously, once capacity is turned back to a pipeline, the potential exists that capacity won't be available if MERC had the need to subscribe for that capacity in the future. With that said, if any capacity were to be turned back, MERC would turn back some or all of LS Power. The contract MERC has with LS Power gives MERC the right to call on 29,100 Dth of capacity and supply from LS Power for twenty (20) days during the months of December through February. The annual cost of the LS Power contract is $379,428. If MERC were to reduce the LS Power contract by 12,525 Dth, the total reduction would be $163,311 ($379,428 divided by 29,100 multiplied by 12,525) not $896,367.

As stated previously, MERC believes the design day requirement in the current docket is not an accurate reflection as the economy rebounds. MERC's Attachment 1, Page 3 or 3, reflects the design day requirements. MERC believes the design day numbers from the heating seasons 2005/2006 through 2007/2008 are a more representative requirement in the future as the economy rebounds. The design day requirement for 2005/2006 was 200,421 Dth, 2006/2007 was 200,484 Dth and 2007/2008 was 202,263 Dth. The average during that three heating seasons is 201,056 Dth. As stated previously, the design day requirement is calculated based off of previous three years winter data. During these years, the economy was doing well and the design day requirements were consistent. Assuming the average 201,056 Dth design day requirement is a more accurate representative requirement in the future and assuming a five (5) percent reserve margin, MERC would need 211,109 Dth. If MERC didn't have the LS Power contract, MERC would need to contract with NNG for an additional 5,933 Dth (211,109 Dth less 205,176 Dth) capacity. The cost for an additional 5,933 Dth of NNG capacity would be $449,514 (5,933 Dth multiplied by five months multiplied by NNG maximum TF5 tariff rate of $15.153. The LS Power agreement annual cost is $379,428. The LS Power contract therefore provides greater level of protection at a lower cost.

D. <u>FDD Storage Costs</u>

The Department notes that MERC includes the cost for its FDD contracts in the demand portion of the PGA. It is the Department's position that these costs should be included in the commodity portion of the PGA.

<u>MERC Response</u>

MERC agrees with the Department that it is appropriate to recover storage costs through the commodity rather than the demand portion of rates. On March 7, 2008, MERC made a Supplemental Filing in Docket No. G011/M-07-1405 in which the Company proposed to include storage costs in the commodity rate rather than the demand rate. The Commission has not yet issued a decision in Docket No. G011/M-07-1405 and has not yet approved MERC's proposal to shift storage costs from the demand portion of rates to the commodity portion of rates. As noted in MERC's Reply Comments dated March 30, 2009 in Docket No. G011/M-08-1328, MERC has not implemented its proposal in the monthly PGA because the Company is awaiting Commission approval of this change. MERC, however, has included attachments with its initial filing in this docket that calculates costs based on inclusion of these costs in the commodity portion of rates.[7]

DATED this 2nd day of May, 2011.

Respectfully submitted,

DORSEY & WHITNEY LLP

/s/ Michael J. Ahern
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[7] *See* Petition, Attachment 4, pages 4-6 and Attachment 11, page 2.

Attachment A

Tac is back, Range revs up - Minnesota's iron ore industry has bounced back to full speed this spring, less than two years after hitting rock-bottom — one of the fastest turnarounds in a century of mining.

Duluth News Tribune (MN) - Sunday, March 27, 2011

Author: *John Myers, Duluth News Tribune*

Minnesota's iron ore industry has bounced back to full speed this spring, less than two years after hitting rock-bottom — one of the fastest turnarounds in a century of mining.

As the first lakers of the 2011 season leave ore docks in Duluth, Two Harbors, Silver Bay and Superior with full loads of taconite bound for steel mills on the lower lakes, Iron Range taconite experts and workers say they are poised to hit full capacity in taconite production even as they plan to expand.

"Everyone is going at full capacity-plus right now and we've got new projects down the line," said Craig Pagel, executive director of the Iron Mining Association of Minnesota. "It's having a ripple effect on our whole region's economy."

Suddenly, an industry tied since the 1800s to national and global economic slumps and upturns seems to have shortened the period between bust and boom.

That's good news for Northeastern Minnesota's economy, which is tied to hard-rock mining more than most people know.

"Everyone's back to work now. You can have all the overtime you want. … And they're trying to hire new people," said Jack Thronson, an electrician at Keetac in Keewatin and president of Steelworkers Local 2660. "It was pretty bad in 2009; we were down for most of a year. But things have changed so fast. The steel demand is supposed to be good for a while now."

Record bounce-back

It's been a whirlwind four years. In 2008, the industry was eating high on the hog, producing 39 million tons of taconite iron ore — one of the best years of the decade.

But the global economic meltdown that started in late 2008 caused one of the fastest downturns ever. Production in 2009 dropped by more than half to the lowest level since 1963, just 17 million tons.

For a few weeks in 2009, all six of the state's taconite plants were completely shut down, and nearly all their workers were laid off. It was suddenly slim pickings, rivaling the early 1980s when the industry lost half its workers, half its production and some 20,000 residents moved out of St. Louis County to find new homes and jobs elsewhere.

Fast-forward to 2010 and the recession quickly became old news. Taconite production rocketed back to 37.5 million tons and employment returned to 3,600 workers. Global steel demand turned healthy again and demand for Minnesota ore was heavy.

Experts say one key to the breakneck bounce-back was taconite plant owners quickly reacting to dwindling demand by squeezing off production. In years past, the industry responded at a snail's pace, often leading to huge stockpiles of unwanted ore followed by long periods of slowdown and shutdown.

"They shut down faster this time, with some very harsh consequences for the workers," said Drew Digby, regional analyst for the Minnesota Department of Employment and Economic Development. "But it's allowed them to bounce back faster as well."

The rebound has also meant more trains hauling taconite from the Range to Lake Superior and more freighters hauling it across the Great Lakes and beyond.

“It’s always good news when our Minnesota operations are at or near capacity, and that’s where we are,” said Sandy Karnowski, Cliffs Minnesota regional manager of public affairs.

For 2011, industry experts say production will hit at least 40 million tons, a mark not seen since LTV Steel permanently shuttered in 2000. Production could go higher if plants continue to push the efficiency envelope, Pagel said. “All indications are that world steel demand should remain high.”

Good news compounded

Compounding the economic good news are new products and new markets.

Mesabi Nugget is making an iron nugget that can be used in electric mini-mills, a new market for Minnesota ore.

Ore concentrate pulled from what used to be waste by upstart producer Magnetation in Nashwauk is heading to Mexico.

And the growing new market of China is hungry for taconite pellets. Cliffs Natural Resources has said it will ship 1 million tons of Michigan and Minnesota taconite pellets there this year.

“The price per ton on that (taconite going to China) is something close to $200, and it’s never been that high before,” Pagel said.

For the first time in any major way, the price that foreign steel mills are willing to pay for the ore will more than cover the huge cost of shipping taconite from Minnesota overseas. Minnesota-processed taconite is now competing with raw iron ore from Brazil and Australia.

Magnetation’s Matt Lehtinen noted that his company’s iron ore concentrate is being shipped to a Mexican mill by train, taking the place of raw ore from Brazil.

“It now matters more for Minnesota taconite whether India’s growth rate is 8 percent or 12 percent than what sales are for the U.S. auto industry,” Digby said.

Just how good is it now for the taconite companies?

Peter Kakela, Michigan State University professor and an expert on the global iron ore industry, said companies are selling taconite at four times what it cost to produce, a return on investment unheard of in the past when profits of a few dollars per ton were common.

“For years — decades, even — the price hovered in that $30 to $35-per-ton range. … And now someone is paying $200. They’ve never seen anything like this before,” Kakela said. “There’s your incentive for all the expansions people are talking about. That’s why everything is running at full capacity.”

Huge economic impact

Not only have mines recalled all the 3,600 Steelworkers who were laid off in 2009, but about 100 jobs have been added. With the increasing pace of retirements by aging Steelworkers, 1,000 of today’s workers are new employees never before in the taconite business. The industry continues to recruit local students onto “wrench-smart” training and engineering career tracks at local colleges and universities.

Digby said there is no doubting taconite’s impact on the region, even as the service economy becomes larger. In 2009, when checks from the mines stopped, the region’s entire payroll numbers crashed and sent shock waves through the regional economy.

Taconite has “been especially important in Northeastern Minnesota as the wood-products jobs continue to dwindle,” Digby said.

Mining amounts to about 2 percent of total regional employment and 8 percent of regional sales. Health care, by comparison, accounts for 14 percent of employment and 8 percent of sales. But a 2009 UMD study showed the direct and related economic contribution of mining amounts to 30 percent of the regional domestic product.

That UMD study found some 18,000 jobs directly or indirectly tied to the mining industry in the region — from railroad and ports to engineers and the doctors and dentists who have miners as patients. Mining also is equipment-intensive, consuming tires, trucks, explosives and fuel.

Still, direct employment in the taconite industry has dropped from more than 15,000 at its peak, to 5,600 in 2001 to about 3,700 now. Digby said that, while mining is still big and now growing, its role as an employer is shrinking as health care, education and other service industries grow at a faster pace.

“On one hand they have become far more able to adapt to the global economy and become more efficient with technology and innovation. And that’s great for the industry and for stability,” Digby said. “The downside of that is it has usually meant fewer people employed, and that limits (taconite’s) impact on the regional economy going forward, at least as far as direct employment is concerned.”

Prepare now for downturn

Tony Sertich, commissioner of the Iron Range Resources and Rehabilitation Board, said the current good times are spurring mining companies to invest in new and improved operations worldwide. That’s most noticeable now with the India-owned Essar Steel plant near Nashwauk, expected to be the first major steel mill on the Iron Range by 2015.

“That’s been the goal since Day One, to not just be at the front end of the mining industry but to get that added value and the added jobs and benefits right here,” Sertich said.

Sertich said economic analysis he’s seen points to another four-year period of high demand for steel and ore. But the good times won’t last forever.

“We know there are going to be boom and bust cycles and we need to leverage these good times for the inevitable downturn,” Sertich said. “We have to help the companies invest now to stabilize for the future. These multinational companies are eager to make investments in the early stages of a good forecast, so we can’t miss this opportunity.”

The industry could add another 1,000 direct jobs in coming years, Pagel said, and that doesn’t count the potential for copper-nickel mining operations such as PolyMet and Twin Metals.

Kakela said the good times appear to be here for a while, thanks to unrelenting demand for steel in Asia and to new efforts on Minnesota’s Iron Range.

“I don’t see any downturn in global demand right now anywhere on the horizon,” he said. “And northern Minnesota is poised to supply that demand because it’s really become the cradle of innovation for iron ore worldwide.”

Caption: Workers load limestone at the DM&IR ore docks in West Duluth in front of a mountain of taconite pellets waiting to be shipped down the Great Lakes. (Bob King / rking@duluthnews.com)

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AFFIDAVIT OF SERVICE

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COUNTY OF HENNEPIN)

Sarah J. Sorenson, being first duly sworn on oath, deposes and states that on the 2nd day of May, 2011, the Reply Comments of Minnesota Energy Resources Corporation were electronically filed with the Minnesota Public Utilities Commission and the Minnesota Department of Commerce. A copy of the filing was delivered by electronic service or first class mail to the remaining individuals on the attached service list.

/s/ Sarah J. Sorenson

Subscribed and sworn to before me
this 2nd day of May, 2011.

/s/ Sara Garcia
Notary Public, State of Minnesota

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