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November 1, 2013

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of the Petition of Minnesota Energy Resources Corporation-Consolidated for Approval of a Change in Demand Entitlement

Docket No. G011/M-13-669

Dear Dr. Haar:

In accordance with Minnesota Rule 7825.2910, subpart 2, please find enclosed Minnesota Energy Resources Corporation's (MERC) request to change demand entitlement. MERC originally filed its petition for change in demand on August 1, 2013 and agreed to provide updated information on November 1, 2013. In the August 1, 2013 petition, MERC anticipated purchasing a Wadena Delivered Call Option. Due to the lack of interest in selling this product by suppliers, MERC chose to purchase 1,500 Dth firm capacity from December 2013 through February 2014 from the pipeline. There is no change in overall VGT capacity from the August 1, 2013 petition.

MERC is also filing Excel and PDF versions of the attachments. Pursuant to Minnesota Rule 7825.2910, subpart 3, a Notice of Availability has been sent to all intervenors in the Company's previous two rate cases.

Please contact me at 612-340-2881 if you have any questions regarding the information in this filing. Thank you for your attention to this matter.

Sincerely yours,

/s/ Michael J. Ahern

Michael J. Ahern

cc: Service List

ATTACHMENT 1

November 1, 2013

To: Service List

RE: Minnesota Energy Resources Corporation-Consolidated Petition for Approval of Change in Demand Entitlement

Notice of Availability

Please take notice that Minnesota Energy Resources Corporation-Consolidated has filed a revised petition with the Minnesota Public Utilities Commission for approval of a change in demand entitlement.

To obtain copies, or if you have any questions, please contact:

Gregory J. Walters
Minnesota Energy Resources Corporation
3460 Technology Drive NW
Rochester, MN 55901
507-529-5100

Please note that this filing is also available through the eDockets system maintained by the Minnesota Department of Commerce and the Minnesota Public Utilities Commission. You can access this document by going to eDockets through the websites of the Department of Commerce or the Public Utilities Commission or going to the eDockets homepage at:

https://www.edockets.state.mn.us/EFiling/home.jsp

Once on the eDockets homepage, this document can be accessed through the Search Documents link and by entering the date of the filing.

ATTACHMENT 2

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
J. Dennis O'Brien	Commissioner
David C. Boyd	Commissioner
Betsy Wergin	Commissioner
Nancy Lange	Commissioner

In the Matter of the Petition of	)	
Minnesota Energy Resources	)	
Corporation – Consolidated for	)	
Approval of a Change in	)	Docket No. G011/M-13-669
Demand Entitlement	)	

SUMMARY OF FILING

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation-Consolidated (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-Consolidated's customers. MERC submitted its initial petition on August 1, 2013 and submits this revised petition with updated information. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2013.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
J. Dennis O'Brien	Commissioner
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In the Matter of the Petition of	)	
Minnesota Energy Resources	)	
Corporation – Consolidated for	)	
Approval of a Change in	)	Docket No. G011/M-13-669
Demand Entitlement	)	

REVISED FILING UPON CHANGE IN DEMAND

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation- Consolidated (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-Consolidated's customers. MERC submitted its initial petition on August 1, 2013 and submits this revised petition with updated information. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2013.

This filing includes the following attachments:

Attachment 1: Notice of Availability.

Attachment 2: One paragraph summary of the filing in accordance with Minn. R. 7829.1300, subp. 1.

Attachment 3: Petition for Change in Demand with Attachments.

Attachment 4: Affidavit of Service and Service List.

The following information is provided in accordance with Minn. R. 7829.1300:

1. Summary of Filing

Pursuant to Minn. R. 7829.1300, subp. 1, a one-paragraph summary of the filing is attached.

2. Service

Pursuant to Minn. R. 7829.1300, subp. 2, MERC has served a copy of this filing on the Department of Commerce and the Office of the Attorney General —Antitrust & Utilities Division. The summary of the filing has been served on all parties on the attached service list. Additionally, pursuant to Minn. R. 7825.2910, subp. 3, a Notice of Availability has been sent to all intervenors in the Company's previous two rate cases.

3. General Filing Information

A. Name, Address, and Telephone Number of the Utility

Minnesota Energy Resources Corporation
2665 145th Street West
Box 455
Rosemount, MN 55068-0455
(651) 322-8901

B. Name, Address, and Telephone Number of Attorney for the Utility

Michael J. Ahern
Dorsey & Whitney LLP
50 S. Sixth Street, Suite 1500
Minneapolis, MN 55402-1498
(612) 340-2881

C. Date of the Filing and Proposed Effective Date

Date of filing: November 1, 2013
Proposed Effective Date: November 1, 2013

D. **Statute Controlling Schedule for Processing the Filing**

Minnesota Statutes and related rules do not provide an explicit time frame for action by the Commission. Under Minn. R. 7829.1400, initial comments are due within 30 days of filing, with reply comments due 10 days thereafter.

E. **Utility Employee Responsible for the Filing**

Gregory J. Walters
3460 Technology Drive NW
Rochester, MN 55901
(507) 529-5100

If additional information is required, please contact Michael J. Ahern at: (612) 340-2881.

DATED: November 1, 2013

Respectfully Submitted,

DORSEY & WHITNEY LLP

By: /s/ Michael J. Ahern
Michael J. Ahern
Suite 1500, 50 South Sixth Street
Minneapolis, MN 55402-1498
Telephone: (612) 340-2600

Attorney for Minnesota Energy Resources Corporation

ATTACHMENT 3

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
J. Dennis O'Brien	Commissioner
David C. Boyd	Commissioner
Betsy Wergin	Commissioner
Nancy Lange	Commissioner

In the Matter of the Petition of	)	
Minnesota Energy Resources	)	
Corporation – Consolidated for	)	
Approval of a Change in	)	Docket No. G011/M-13-669
Demand Entitlement	)	

REVISED PETITION FOR CHANGE IN DEMAND

I. INTRODUCTION

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - Consolidated (MERC or the Company), a division of Integrys Energy Group, Inc. (TEG), hereby petitions the Minnesota Public Utilities Commission (Commission) approve changes in demand entitlements for MERC-Consolidated customers. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2013.

II. DISCUSSION

A. MERC's Consolidated Design Day Requirements

MERC's 2013-2014 Consolidated design day requirements decreased 2,241 Mcf (or approximately 4.29 percent) from 52,289 Mcf to 50,048 Mcf.

Table 1: MERC's Proposed Consolidated Reserve Margins
For the 2013-2014 Heating Season
Consolidated (GLGT, VGT & Centra)

	Reserve Margin 2013-2014 Heating Season	Reserve Margin 2012-2013 Heating Season	Change
NNG Zone E-F	5.82%	5.11%	0.71%

As shown in Table 1 and Attachment 3, MERC's proposed system wide reserve margin for Consolidated for the 2013-2014 heating season is positive.

For the Demand Entitlement filing effective November 1, 2013, the total Design Day requirement for Consolidated-Centra is 7,740 Mcf as calculated in Attachment 1, page 2 of 3.

For the Demand Entitlement filing effective November 1, 2013, the total Design Day capacity for Consolidated-Centra is 9,500 Mcf as calculated in Attachment 4, page 2 of 2.

The difference between the total Design Day requirement and total Design Day capacity results in a 22.74% positive reserve margin.

For the Demand Entitlement filing effective November 1, 2013, the total Design Day requirement for Consolidated-GLGT is 24,906 Dth as calculated in Attachment 1, page 2 of 3.

For the Demand Entitlement filing effective November 1, 2013, the total Design Day capacity for Consolidated-GLGT is 26,368 Mcf as calculated in Attachment 4, age 2 of 6.[1] The difference between the total Design Day requirement and total Design Day capacity results in a 5.87% positive reserve margin.

For the Demand Entitlement filing effective November 1, 2013, the total Design Day requirement for Consolidated-VGT is 17,402 Dth as calculated in Attachment 1, page 2 of 3.

For the Demand Entitlement filing effective November 1, 2013, the total Design Day capacity for Consolidated-VGT is 17,091 Mcf as calculated in Attachment 4, page 2 of 6.

The difference between the total Design Day requirement and total Design Day capacity results in a 1.79% negative reserve margin.

B. Forecast Methodology for MERC Demand Entitlement Nov. 1, 2012

Peakday

Purpose

Gather data and perform analysis used in the "Petition for Change in Demand" for Minnesota Energy Resources Corporation – PNG and Minnesota Energy Resources Corporation – NMU for "Approval of a Change in Demand Entitlement" to be sent to the Minnesota Public Utilities Commission, otherwise known as the "MERC Demand Entitlement Filings".

Background

MERC is composed of two service areas:

1. PNG - Peoples Natural Gas
2. NMU - Northern Minnesota Utility

Which are served by four pipelines:

3. VGT - Viking Gas Transmission system (serves both PNG and NMU)
4. NNG- Northern Natural Gas pipeline (serves both PNG and NMU)
5. GLGT - Great Lakes Gas Transmission pipeline (serves both PNG and NMU)
6. Centra - Centra pipeline (serves NMU)

Effective July 1, 2013, two Petitions for Change in Demand need to be filed (one for each PGA):

A. All MERC customers served off of NNG = NNG
B. All other PNG customers, served off of Centra, GLGT & VGT = MERC Consolidated

Before July 1, 2013, four Petitions for Change in Demand were filed (one for each PGA):

C. PNG customers served off of VGT = PNG - VGT
D. PNG customers served off of GLGT = PNG - GLGT
E. PNG customers served off of NNG = PNG - NNG
F. All NMU customers - served off NNG, GLGT, VGT & Centra = NMU

Weather data is obtained from eight weather stations:

International Falls, Bemidji, Cloquet, Fargo, Minneapolis, Rochester, Worthington and Ortonville.

For analytical purposes, data is subdivided, analyzed and regressed by the following demand areas:

	Demand Area (Service Area / Pipeline)	PGAC	Weather Station(s)
1	NMU-Centra	NMU	International Falls
2	NMU-GLGT *	NMU	Bemidji & Cloquet
3	NMU-NNG	NMU	Cloquet
4	NMU-VGT *	NMU	Fargo
5	NMU-GLGT&VGT*	NMU	Bemidji
6	PNG-GLGT	PNG-GLGT	Bemidji
7a	PNG-NNG – All except Ortonville	PNG-NNG	Minneapolis, Rochester, Cloquet & Worthington
7b	PNG-NNG – Ortonville Only	PNG-NNG	Ortonville
8	PNG-VGT	PNG-VGT	Fargo
* Thief River Falls is included only in NMU-GLGT&VGT			

Analytical Approach

Summary

1. Obtain daily weather data for each weather station
2. Obtain daily total throughput volumes by pipeline
3. Perform total throughput peak day regressions. In response to comments from the DOC (Minnesota Department of Commerce):
    a. Review and potentially change the regression methodology to mitigate the impact of autocorrelation.

    b. Provide a reasonable explanation whenever we choose to use a regression model that does not have an intercept.
4. Subtract interruptible, transport, and joint interruptible expected peak day load volumes based on monthly billing data
5. Add back Daily Firm Capacity (DFC) customer selections
6. Apply sales forecast growth rates

Detail
The Peak Day Forecasting Team (the Team) followed a data-driven approach for the Peak Day Forecast. Since the forecast is for a peak day, the best daily data available is required to provide the best estimate. Theoretically, the peak day regression should be performed using daily net firm load by service area, pipeline, and weather station. A review of the data available indicated that the two best daily data sources are the daily weather data by weather station and the daily throughput data by Town Border Station (TBS) and pipeline meter. (Some pipeline meters are dedicated to a TBS, and some are dedicated to individual customers.)

Most of the interruptible, transportation, and joint interruptible data available is from monthly billing record excerpts provided by ADS/Vertex, an external vendor that has been providing billing services to MERC-PNG and MERC-NMU.

The Team followed an approach generally consistent with the one used last year that would:
- Make the best use of the best available data; and
- Isolate the effects the monthly billing cycle data has on the Peak Day forecast so that the new process can be easily updated as better data is available.

The Peak Day Process consisted of:
I. Data Preparation
II. Regression Generation of Net Daily Metered Volumes
III. Volume Risk Adjustments
IV. Adjusting the Regression Results to a Firm peak day estimate

I. The **<u>Data Preparation</u>** Steps consisted of:
- Identify the coldest Adjusted Heating Degree Day (AHDD) in the last 20 years for each weather station.
- Determine the most recent three years of December through February daily total metered throughput for each of the demand areas by weather station.
- Subtract the daily pipeline meter readings for all non-firm customers with daily pipeline meter readings available for all three December through February years from the total throughput for each demand area and weather station. Use the resulting net daily metered volumes for regressions. Examples of non-firm customer meter readings subtracted from the demand area total daily throughputs are paper mills, direct-connects, taconites, and off-system end users. (see "Adjusting the Regression Results to a Firm Peak Day Estimate" below)
- Determine how to map the monthly billing data to the demand areas.

Each daily weather station data file was searched to find the coldest Adjusted Heating Degree Day (AHDD65) in the last 20 years. This 1-in-20 approach is consistent with prior years. The results are provided in the following table:

Station	Date	Avg. Temp	Avg. Wind	HDD65	AHDD65
Bemidji	2/1/1996	-34	8	99	107
Cloquet	2/2/1996	-31	7	96	103
Fargo	1/18/1996	-16	34	81	109
International Falls	2/1/1996	-34	8	99	107
Minneapolis	2/2/1996	-25	8	90	97
Rochester	2/2/1996	-27	10	92	101
Worthington	1/18/1996	-8	32	73	96
Ortonville	1/14/2009	-21	11	86	96

The daily throughput data was provided by pipeline and meter, with each meter on each pipeline mapped to one of the weather stations shown in the above chart. Each meter was also designated as either PNG or NMU. As noted above, some of the meters represented a TBS. Some meters were dedicated to a customer who is not a firm service customer of either PNG or NMU. For example, certain transportation, interruptible, direct-connect, and taconite customers have their own meter, but are not counted as firm service customers.

In a more nearly ideal world, the Team would have also had daily telemetered data from each interruptible, transportation, and joint interruptible customer mapped to each of the demand areas and related weather stations. This was the case for a handful of paper mills, direct-connects, taconites, and off-system end users. The rest of the interruptible, transportation, and joint interruptible data was available based on monthly billing cycle data that introduces billing lag, meter read lag (not all meters were read every month resulted in billing cycle estimates and reversals), and other potential errors into their volumes.

Similar to the process used the prior year, the Team generated regressions of the daily throughput data available less the known daily meter readings for non-firm customers and adjusted those regressions for the estimated peak day impact of the other non-firm customers who do not have daily readings. This approach was used because it introduced much less error into the data and regressions than trying to guess how to allocate monthly billing cycle data to daily when the load factors and relative temperature sensitivity of the non-daily-metered customers was not known. Using only the daily metered data for the regressions makes the best use of the best data available and provides insights into the total daily metered load that could be active on a peak day even if supply access at the non-firm pipeline meters were shut off.

II. The **Regression Generation of Net Daily Metered Volumes** consisted of:

- For each of the Demand Areas (Service Area / Pipeline):

1. Gather the net daily metered volumes and weather station data including AHDD65[2] .
2. If more than one weather station is represented in a given demand area, weight each weather station's AHDD65 by the total December through February metered volumes attributable to that weather station.
3. Add indicator variables for day-type and month. Day-type variables are used to isolate load that changes by day of the week, such as commercial or industrial customers who may change their consumption on weekends when they run fewer shifts. Month indicator variables are used to isolate load that changes based on winter month, such as businesses that are open extra hours in December and resume normal operating hours in January.
4. Perform ordinary least squares linear regressions for the 3-year time frame using the AHDD65 weather variable and the significant indicator variables.
5. In response to comments from the DOC (Minnesota Department of Commerce), review and potentially change the regression methodology to mitigate the impact of autocorrelation. See section below on autocorrelation.
6. In response to comments from the DOC, provide a reasonable explanation whenever we choose to use a regression model that does not have an intercept.
7. Summarize the Baseload and Use/AHDD65 from each regression.
8. Calculate a point estimate from each regression based on the baseload value plus the Use/AHDD65 coefficient times the coldest AHDD65 in 20 years (volume weighted if using more than one weather station in a single Demand Area).

Autocorrelation Review

In regression analysis using time series data, autocorrelation of the errors is a problem. Autocorrelation of the errors, which themselves are unobserved, can generally be detected because it produces autocorrelation in the observable residuals. (Errors are also known as "error terms" in econometrics.) Autocorrelation violates the ordinary least squares (OLS) assumption that the error terms are uncorrelated. While it does not bias the OLS coefficient estimates, the standard errors tend to be underestimated (and the t-scores overestimated) when the autocorrelations of the errors at low lags are positive. The traditional test for the presence of first-order autocorrelation is the Durbin–Watson statistic or, if the explanatory variables include a lagged dependent variable, Durbin's h statistic. To correct for this used we used the MetrixND software package to employ an AR(1) regression which then showed that the Durbin –Watson statistics are all either close to 2 or above. The AR (1) is similar to that of the Cochrane-Orcutt method to correct for autocorrelation.

[2] Temperature and weather data was obtained from Weather Bank/DTN via TherMaxx then converted to HDD65 and AHDD65 in an Excel spreadsheet by MERC – Gas Supply. Temperature and wind data is 24-hour average based on the 9am to 9am gas day.

III. Volume Risk Adjustments

Volume risk adjustments were incorporated into the forecast to provide a confidence level that the daily metered load under design conditions would not exceed the daily metered regression estimate. An appropriate volume risk adjustment was determined for each regression group by multiplying the standard error of each regression analysis (sigma) by a factor needed to attain a desired confidence level. The desired confidence level chosen was 97.5%.

IV. Adjusting the Regression Results to a Firm Peak Day Estimate consisted of:

A. Subtract interruptible, transport, and joint interruptible expected peak day load volumes based on monthly billing data

In order to determine firm peak day load, volumes contained in the daily pipeline meter readings for interruptible, joint interruptible and transportation customers needed to be isolated and removed. While it would have been ideal to have daily billing data for all customers, most of the interruptible, transportation, and joint interruptible data was, in most cases, only available from monthly billing records[3]. An unfortunate, but unavoidable consequence was that this data was based on monthly billing cycles that introduce billing lag, meter read lag (not all meters were read every month resulted in billing cycle estimates and reversals), and other potential errors into their volumes.

A database of volumes billed for all customers from the prior winter was obtained. The database contained detail by customer class[4], calendar month, (service) area, city, location, zip code and responsibility center. The billing database was provided by ADS/Vertex, an outside firm that has been providing billing services to MERC. Sales and Revenue Forecasting had previously adjusted the billing data to properly fit the appropriate calendar month of consumption by apportioning billed volumes, i.e. for a bill covering February 15 to March 15, volumes were split evenly between February and March.

Volumes for the interruptible, transportation and joint interruptible customer classes (INTER, TRANS and JINTER classes) needed to be mapped to the appropriate regression demand area, and were then summed. This billing data included consumption that was billed, but not included in the daily metered volumes for several large specific customers (paper mills, direct-connects, taconites, and off-system end users), and therefore needed to be removed from the gross interruptible, transportation and joint interruptible totals. Such customers were identified, mapped to the demand areas, summed and subtracted from the interruptible, transportation and joint interruptible customer classes totals. The following peak demand estimation method based on the highest monthly total from the prior winter was then used to calculate the amount to subtract from the results of the data regressions for each demand area:

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[3] Individual daily volumes were available for a handful of paper mills, direct-connects, taconites, and off-system end users.

[4] Transportation, Interruptible, Joint Interruptible, Residential, Large Commercial & Industrial and Small Commercial & Industrial

The MERC-PNG and MERC-NMU tariff General Rules, Regulations, Terms, and Conditions Section 1.N "Maximum Daily Quantity (MDQ)" on Original Sheet No. 8.04:

N. <u>Maximum Daily Quantity (MDQ):</u>
The amount calculated by dividing the volumes consumed by a particular customer during the highest historical peak month of usage for that customer by twenty (20). Company will estimate a peak month for new customers. A Maximum Daily Quantity may also be established through direct measurement or other means (i.e. estimating the peak day requirements after installation of new processing equipment or more energy efficient heating systems) if approved by [the] Company.

B. Add back Daily Firm Capacity (DFC) customer selections

While interruptible, joint interruptible and transportation customer volumes were removed (as described above), in order to determine firm peak day load, daily firm capacity selections needed to be added back. The Sales and Revenue Forecasting department provided historical monthly DFC data for the "joint interruptible" customers from the prior winter that showed the volume that each customer has selected to receive as firm service from MERC each month. Based on the direction from MERC Gas Supply, the Small Volume Joint Firm / Interruptible customers who were relying on MERC to provide peak day firm supply were identified and their daily firm capacity volumes were summed by month for each demand area. The total volumes were then added back to the adjusted regression results.

C. Apply Sales Forecast Growth Rates

The throughput volumes used in the data regressions were from the last three winters and needed to be adjusted to properly forecast the next year. The Revenue Forecasting Department provided a growth rate for each demand area, which were then applied to the adjusted regression results.

Exhibit 1

Demand Area / (Service Area / Pipeline) Regression Notes

A. Interruptible, Transportation and Joint Interruptible

<u>NMU-GLGT</u>

Paper Mills = Blandon in Bemidji, and Sappi and USG in Cloquet

NMU-VGT

Lamb Weston.

PNG-NNG

Taconites / Direct Connects =

- CCI EMPIRE IND DEL PT 2 TILDEN
- CCI NORTHSHORE
- UNITED TACONITE (was EVELETH TACONITE)
- HIBBING TACONITE CO.
- U.S. STEEL
- NATIONAL STEEL PELLET
- COTTAGE GROVE TBS LS POWER
- INLAND STEEL
- HANNA MINING

PNG-NNG

OSEU (End Users) =

- ASSOCIATED MILK PRODUCTS, INC.
- CORRECTIONAL CTR
- KEMPS LLC
- KERRY BIO-SCIENCE
- LAKESIDE
- MILK SPECIALTIES
- LAND OF LAKES
- PRO-CORN
- SWIFT
- SENECA FOODS-ROCHERSTER
- ENGINEERED POLYMERS
- SANDSTONE FEDERAL CORRECTIONAL INSTITUTE
- Glenville #1
- Agra Resources(Exol)
- Halcon Corporation

B. Daily Firm Capacity

PNG-VGT

- DETROIT LAKES MIDDLE SCHOOL
- ROSSMAN SCHOOL

PNG-GLGT

- AMERIPRIDE
- NORTHLAND APTS
- NW TECH COLLEGE - BEMIDJI

PNG-NNG

- HENDRICKS HOSPITAL
- GLASSTITE INC

Daily Design Day Estimate to Actual Comparison

In the 2007 demand entitlement dockets, MERC agreed to include a daily estimate utilizing the design day model which is calculated in Attachment 11. The daily estimate is compared to actual consumption. The actual volumes are total through-put which includes interruptible and transportation volumes that are located behind MERC citygates. This does not include any transportation volumes that are directly connected with any interstate pipeline(s). The Design Day model only calculates firm volumes. MERC does not forecast on a daily/monthly basis utilizing the Design Day model. The Design Day model is utilized to calculate the theoretical peak day. The calculated base load natural gas usage at zero heating degree days is 6,734 Dth which includes interruptible and transportation volumes. Since daily volume consumption is not available for all interruptible and transportation customers, MERC is not able to determine an exact number to deduct from the 6,734 Dth to determine the firm base load natural gas consumption at zero (0) HDD.

Average Customer Counts

In the 2007 demand entitlement dockets, MERC agreed to include average customer counts which is provided in Attachment 12.

C. MERC's Specific Consolidated Proposed Demand-Related Changes

There are two types of demand entitlement changes. The first type is design day deliverability, which, in this case, increases the amount of firm transportation and storage capacity actually available to MERC's Consolidated customers during winter peak periods. The second type does not affect design day deliverability levels, but alters the capacity portfolio and the PGA costs recovered from customers.

1. Design Day Deliverability Changes

On GLGT there is no planned change in winter capacity.

In the August 1, 2013 petition, MERC anticipated purchasing a Wadena Delivered Call Option. Due to the lack of interest in selling this product by suppliers, MERC chose to purchase 1,500 Dth firm capacity from December 2013 through February 2014 from the pipeline. There is no change in overall VGT capacity from the August 1, 2013 petition.

On Centra there is no planned change in winter capacity.

Table 4

Capacity Entitlement	Propose Change Increase / (Decrease)
GLGT FT0016	0 Mcf/Day
GLGT FT0155 (12)	0 Mcf/Day
GLGT FT0155 (5)	0 Mcf/Day
GLGT FT15782	0 Mcf/Day
VGT AF0012	0 Mcf/Day
VGT AF0014	0 Mcf/Day
VGT AF0102	0 Mcf/Day
VGT TBD	1,500 Mcf/Day
Wadena Delivered Option	(1,500) Mcf/Day
Centra FT	0 Mcf/Day
Total Overall Change	0 Mcf/Day

* Numbers are not part of peak day deliverability

2. Other Demand Entitlement Changes

MERC has AECO Storage, to deliver the supply from storage to MERC-Consolidated markets, MERC plans to enter into an AECO/Emerson swap. MERC sells gas at the storage point (AECO) to a supplier and buys an equivalent volume at Emerson/Spruce, which MERC then transports to its Consolidated customers. The swap substituted the need to contract for firm transport on TransCanada Pipeline (TCPL) to transport the gas from AECO to Emerson/Spruce. There is no planned change in swap volume from previous year.

D. Financial Option Units and Premiums

i. MERC is entering into New York Mercantile Exchange (NYMEX) financial Call Options for the upcoming 2013/2014 winter (November through March). MERC will be making purchases through October 2013. The Call Option contracts are projected for the entire 2013/2014 winter. Please see Attachment 5.

ii. Total premium costs to date entered into the financial Call Options on behalf of MERC's Consolidated firm customers amounted to $295,511 for the 2013/2014 winter. MERC will update total premium costs in the November 1, 2013 filing. Please see Attachment 8.

iii. MERC will be entering into 117 contracts (10,000/contract) or 1,170,000. Total premium per contract to date is approximately $0.2526. Please see Attachment 5.

iv. Please see Attachment 5 for the various contract dates.

v. Please see Attachment 5 for the various contract prices.

vi. MERC will be entering into 69 futures contracts (10,000/contract) or 690,000. Please see Attachment 5.

vii. MERC believes a diversified portfolio approach towards hedging is in the best interest of MERC's firm customers. MERC implemented a 40% fixed price (storage and futures contracts), 30% financial call options and 30% market based prices, assuming normal weather. A dollar-costaveraging approach is utilized in purchasing the hedging portfolio. Although this hedging strategy will most likely not provide the lowest priced supply, it does meet MERC's stated objectives of providing reliable and reasonably priced natural gas and mitigates natural gas price volatility. Please see Attachment 10, pages 1 through 2.

E. <u>Gas Supply.</u>

The Consolidate 2013-2014 Winter Portfolio Plans - Minnesota Energy Resources Corporation for GLGT, VGT and Centra gas supply purchases for the Hedging Plans is in Attachment 10 pages 1 and 2. This Attachment includes the projected sales number by month for the November 2013 through March 2014 period as well as the planned physical fixed price, financial call options and storage and/or exchange volumes by month.

F. <u>Price Volatility</u>

MERC's hedging strategy as described in section 2.(D.)(vii.) provides the opportunity to ensure MERC customers are seventy percent (70%) hedged assuming normal winter volumes. The 70% hedged is accomplished by 40% of normal winter volumes hedged by a fixed price, which is comprised of storage and futures contracts. MERC is projecting the weighted average cost of gas (WACOG) for futures contracts of natural gas to be approximately $3.9840. Please see Attachment 13, page 1 of 3. MERC is projecting the storage WACOG on AECO Storage to be approximately $3.0943. This is an estimate based upon the purchases through June. Please see Attachment 13, page 2 of 3. The remaining 30% of the 70% is hedged by financial call options. MERC purchased call options at an average strike price of $4.0699, which means if NYMEX contract(s) settle above that price, the options are exercised and MERC customers' gas cost is capped at the average strike price. Please see Attachment 13, page 3 of 3. Since financial options are paper only MERC purchases physical index supply to back the financial call options. MERC projects the gas costs to be approximately $3.77 for 70% of normal winter volumes assuming that the NYMEX prices are above the average strike price plus the physical index basis spread. If the NYMEX prices are below the average strike price, the average natural gas cost for 70% of the normal winter volumes will be lower. The remaining 30% of normal winter volumes are purchased at index or market prices. All numbers reflected are natural gas costs only and do not include any transportation, storage, hedge premium or margin costs.

G. <u>PGA Cost Recovery</u>

MERC proposes to begin recovering the costs associated with the change in demand-related costs in its monthly PGA effective November 1, 2013. Rate impacts associated with this change can be found on Attachment 4, pages 1 through 3, and on page 1 of Attachment 7. MERC has also calculated the rate impact of moving the cost recovery of FDD Storage contracts from the demand cost recovery portion of the monthly PGA to the commodity cost recovery portion of the monthly PGA. Attachment 4, pages 4 through 6, and Attachment 7, page 2, illustrate the rate impact created by this shift in cost recovery.

H. <u>Impacts of Telemetry</u>

Based on the requirement that all interruptible and transportation customers on MERC's system must have telemetry, this has led to some customers switching from interruptible to firm. On the MERC-NMU, there have been two (2) customers that switched from interruptible to firm service. The switching occurred between December 21, 2011 through August 23, 2012. Since MERC's peak day analysis is based on December through February volumes for the three previous winters, for the most part, these volumes aren't represented in MERC's design day analysis. MERC projected the impact on firm requirements by projecting peak day volumes for the customers that switched. The projected peak day was calculated by taking actual peak day and dividing the volume by twenty (20). MERC is projecting an increase in design day of 224 Mcf. Assuming the projected peak day is accurate, MERC would still have adequate firm entitlement to meet a peak day.

II. CONCLUSION

Based upon the foregoing, MERC respectfully requests the Minnesota Public Utilities Commission grant the demand changes requested herein effective November 1, 2013. If any further information, clarification, or substantiation is required to support this filing please advise.

DATED: November 1, 2013

Respectfully Submitted,

DORSEY & WHITNEY LLP

By ____________________________

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MINNESOTA ENERGY RESOURCES - Consolidated

DESIGN-DAY DEMAND SUMMARY
NOVEMBER 1, 2013

Design Day Requirement		50,048
Total Peak Day Entitlement		52,959
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 31)	40,871
Firm Annual Throughput - Minnesota		4,509,638
No. of Firm Customers		34,007
Department Load Factor Calculation		30.23%

MINNESOTA ENERGY RESOURCES - Consolidated

MINNESOTA DESIGN DAY REQUIREMENTS
NOVEMBER 1, 2013
HDD

Pipeline Group	2011/12 Customer Count	1/20 Design DDD	Regression Factors Intercept	Regression Factors Slope	% of total load	Regression Total Footnote 1	Regression Adjustment Footnote 2	1/20 Requirements Regression Load Footnote 3	2008/09 Customer Growth	Total	
			VGT								
VGT	10,610	109	3,025	143		19,375	5,201	14,174	0.3%	14,217	
**VGT/GLGT	3,237	107	726	44	68.0%	3,980	804	3,176	0.3%	3,186	
Peak	13,847		3,751	187				17,350		17,402	(311)
VGT	10,610	57	3,025	143		12,679	3,353	9,326	0.3%	9,354	-1.79%
VGT/GLGT	3,237	57	726	44	68.0%	2,480	519	1,961	0.3%	1,967	
Off Peak	13,847		3,751	187				11,287		11,321	
			GLGT								
**VGT/GLGT	3,237	107	726	44	32.0%	1,873	378	1,495	0.3%	1,499	
GLGT	14,490	105	3,105	217		28,707	5,370	23,337	0.3%	23,407	
Peak	17,727		3,831	261				24,832		24,906	
VGT/GLGT	3,237	57	726	44	32.0%	1,167	244	923	0.3%	926	1,462
GLGT	14,490	57	3,105	217		18,292	3,388	14,904	0.3%	14,949	0.0587001
Off Peak	17,727		3,831	261				15,827		15,874	
			Centra								
Peak	5,670	107	1,874	78		10,961	3,244	7,717	0.3%	7,740	1,760
Off Peak	5,670	57	1,874	78		7,056	2,093	4,963	0.3%	4,978	0.227366
			Total Consolidated								
Peak	34,007		8,730	482		64,896	14,997	49,899	0.3%	50,048	
Off Peak	34,007		8,730	482		41,674	9,597	32,077	0.3%	32,173	

Footnote 1: Regression Total is based on total through-put data.
Footnote 2: Regression Adjustment substracts out Interruptible, Transportation and Joint Interruptible volumes and adds Firm Joint volumes.
Footnote 3: Total equals Regression Total minus Regression Adjustment.

**Dual Supplied

MINNESOTA ENERGY RESOURCES - Consolidated

DESIGN-DAY DEMAND PER CUSTOMER
NOVEMBER 1, 2013

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
13/14	34,007	50,048	1.47
12/13	33,630	52,289	1.55
11/12	33,384	50,366	1.51
10/11	33,399	50,779	1.52
09/10	34,053	53,931	1.58
08/09	32,632	59,654	1.83
07/08	32,454	57,202	1.76

MINNESOTA ENERGY RESOURCES - Consolidated

SUMMER/WINTER USAGE - Mcf

PROJECTED 12 MONTHS ENDING JUNE 2014

Consolidated

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	1,188,777	3,296,575	4,485,352
SVI	0	0	0
SVJ	5,717	18,569	24,286
LVI	0	0	0
LVJ	0	0	0
SLV	0	0	0
IS	312,387	518,588	830,975
Total	1,506,881	3,833,732	5,340,613

MINNESOTA ENERGY RESOURCES - Consolidated

ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2013

Type of Capacity or Entitlement		Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
FT Western Zone	FT0016	10,130	0	10,130
FT Western Zone (12)	FT0155 (12)	3,600	0	3,600
FT Western Zone (5)	FT0155 (5)	3,638	0	3,638
FT Western Zone	FT15782	9,000	0	9,000
FT-A ZONE 1 - 1	AF0012	12,493	0	12,493
FT-A ZONE 1 - 1	AF0014 (3)	1,098	0	1,098
FT-A ZONE 1 - 1	AF0102	2,000	0	2,000
FA-A ZONE 1 - 1		0	1,500	1,500
Wadena Delivered GDD Call Option		3,500	(3,500)	0
CENTRA FT-1		9,500	0	9,500
Total Entitlement		54,959	(2,000)	52,959
Forecasted Design Day-Adjusted		52,289	(2,241)	50,048
Capacity Surplus/Shortage		2,670	241	2,911
Reserve Margin		5.11%		5.82%

MINNESOTA ENERGY RESOURCES - Consolidated

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2013

All costs in $/Dth	Last Base Cost of Gas G007,G011/ MR10-978*	Demand Change G011- 12-119x Nov. '12	Last Demand Change G011- 10-977 Jan. '13	Most Recent PGA** Oct. 2013	Current Proposal Effective Nov.1,2013	Result of Proposed Change			
						Change from Last Rate Case	Change from Last Demand Change	Change from Last PGA %	Change from Last PGA $
1) General Service-Residential Avg. Annual Use:				**90**	**Dth**				
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.7744	-18.93%	-26.15%	-2.39%	($0.0926)
Demand Cost	$1.0639	$1.3431	$1.4012	$0.9176	$0.8968	-15.71%	-12.44%	-2.27%	($0.0208)
Commodity Margin	$1.9754	$2.4189	$1.9754	$1.9754	$1.9754	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.6948	$7.1308	$6.7687	$6.7600	$6.6466	-13.62%	-14.70%	-1.68%	($0.1134)
Avg Annual Cost	$692.53	$641.77	$609.18	$608.40	$598.19	-13.62%	-14.70%	-1.68%	($10.21)
Effect of proposed commodity change on average annual bills:									($8.33)
Effect of proposed demand change on average annual bills:									($1.88)
2) Large General Service: Avg. Annual Use:				**4,932**	**Dth**				
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.7744	-18.93%	12.04%	-2.39%	($0.0926)
Demand Cost	$1.0639	$1.3431	$1.4012	$0.9176	$0.8968	-15.71%	-33.23%	-2.27%	($0.0208)
Commodity Margin	$1.6868	$2.1856	$1.6868	$1.6868	$1.6868	0.00%	-22.82%	0.00%	$0.0000
Total Cost of Gas	$7.4062	$6.8975	$6.4801	$6.4714	$6.3580	-14.15%	-7.82%	-1.75%	($0.1134)
Avg Annual Cost	$36,527.38	$34,018.47	$31,959.85	$31,916.94	$31,357.47	-14.15%	-7.82%	-1.75%	($559.47)
Effect of proposed commodity change on average annual bills:									($456.70)
Effect of proposed demand change on average annual bills:									($102.77)
3) SV Interruptible Service: Avg. Annual Use:				**6,068**	**Dth**				
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.7744	-18.93%	12.04%	-2.39%	($0.0926)
Commodity Margin	$1.0647	$1.0628	$1.0647	$1.0647	$1.0647	0.00%	0.18%	0.00%	$0.0000
Total Cost of Gas	$5.7202	$4.4316	$4.4568	$4.9317	$4.8391	-15.40%	9.20%	-1.88%	($0.0926)
Avg Annual Cost	$34,710.17	$26,890.95	$27,043.86	$29,925.56	$29,363.66	-15.40%	9.20%	-1.88%	($561.90)
Effect of proposed commodity change on average annual bills:									($561.90)
4) LV Interruptible Service: Avg. Annual Use:				**40,821**	**Dth**				
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.7744	-18.93%	12.04%	-2.39%	($0.0926)
Commodity Margin	$0.3568	$0.3164	$0.3568	$0.3568	$0.3568	0.00%	12.77%	0.00%	$0.0000
Total Cost of Gas	$5.0123	$3.6852	$3.7489	$4.2238	$4.1312	-17.58%	12.10%	-2.19%	($0.0926)
Avg Annual Cost	$204,607.10	$150,433.55	$153,033.85	$172,419.74	$168,639.72	-17.58%	12.10%	-2.19%	($3,780.02)
Effect of proposed commodity change on average annual bills:									($3,780.02)

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-12-756
*As approved in Docket No. G007,011/MR-10-978; with implementation consolidated PGA rates on 7/1/13 in Docket No. G007,011/MR-10-977

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

DEMAND

Contract Type			Monthly					Rate Case	
			Entitlement		Rate		Contract	Sales	
Viking (VGT)	**Contract**	**Season**	**(Dth)**	**Months**	**($/Dth)**		**Costs**	**(therms)**	**Cost/Ccf**
FT-A ZONE 1 - 1	AF0012	Annual	12,493	12	$3.4033	$	510,212	43,198,700	$0.01181
FT-A ZONE 1 - 1	AF0014 (3)	Winter	1,098	3	$3.4033	$	11,211	43,198,700	$0.00026
FT-A ZONE 1 - 1	AF0102	Annual	2,000	12	$3.4033	$	81,680	43,198,700	$0.00189
FA-A ZONE 1 - 1		Dec-Feb	1,500	3	$3.7043	$	16,669	43,198,700	$0.00039
VGT Demand			17,091			**$**	**619,772**	43,198,700	**$0.01435**
Great Lakes (GLGT)									
FT Western Zone	FT0016	Annual	10,130	12	$3.8490	$	467,886	43,198,700	$0.01083
FT Western Zone (12)	FT0155 (12)	Annual	3,600	12	$3.8490	$	166,277	43,198,700	$0.00385
FT Western Zone (5)	FT0155 (5)	Winter	3,638	5	$3.8490	$	70,013	43,198,700	$0.00162
FT Western Zone	FT15782	Annual	9,000	12	$3.8490	$	415,693	43,198,700	$0.00962
GLGT Demand			26,368			**$**	**1,119,869**	43,198,700	**$0.02592**
Centra									
CENTRA TRANSMISSION	($Cdn/103M3)				$255.8270				
Conversion (103M3 x Rate(C$ 103M3)		Annual	9,500	12	$7.2470	$	826,161	43,198,700	$0.01912
CENTRA MINNESOTA PIPELINES		Annual	9,500	12	$1.7780	$	202,692	43,198,700	$0.00469
Centra Demand			9,500			**$**	**1,028,853**	43,198,700	**$0.02382**
AECO									
Niska Storage (AECO)		Annual	947,820	1	$0.7263	$	688,362	43,198,700	$0.01593
AECO/Emerson Swap		Annual	947,823	1	$0.5200	$	417,042	43,198,700	$0.00965
AECO Demand						**$**	**1,105,404**	**43,198,700**	**$0.02559**
Consolidated DEMAND - $/Ccf			**52,959**			**$**	**3,873,898**		**$0.08968**

For Joint Rate Demand **43,198,700** Annual Firm Sales in therms

	Units Dth's	Months	Annual Dth's
Viking (VGT)			
FT-A ZONE 1 - 1	12,493	12	149,916
FT-A ZONE 1 - 1	1,098	3	3,294
FT-A ZONE 1 - 1	2,000	12	24,000
FA-A ZONE 1 - 1	1,500	3	4,500
Great Lakes (GLGT)			
FT Western Zone	10,130	12	121,560
FT Western Zone (12)	3,600	12	43,200
FT Western Zone (5)	3,638	5	18,190
FT Western Zone	9,000	12	108,000
Centra			
CENTRA TRANSMISSION			
Conversion (103M3 x Rate(C$ 103M3)	9,500	12	114,000
CENTRA MINNESOTA PIPELINES	9,500	12	114,000

Total Demand Cost	$	3,873,898	
Total Demand Weighted Vol in Mcf		5,866,600	
Total Joint Demand Rate $/Mcf			**$0.66033**

MERC-Consolidated

PRESENT AVERAGE COST OF GAS — EFFECTIVE: 01-Nov-13

COMMODITY

WACOG		Rate	Annual Dth	Call Option Premium	Balancing Service	Total Annual Cost	Cost/therm	REFERENCE	Effective
VGT									
GAS COST		$3.67010							
FUEL	0.00%	$0.00000						Sub 16th Revised Sheet No. 5B	Apr. 1, 2006
COMMODITY TRANSPORTATION		$0.01300						Sub 16th Revised Sheet No. 5B	Apr. 1, 2006
GRI		$0.00000						Sub 16th Revised Sheet No. 5B	Apr. 1, 2006
ACA		$0.00180						Sub 16th Revised Sheet No. 5B	Apr. 1, 2006
VGT Commodity		$3.68490	1,967,663	$106,283	$89,580	$7,446,506	$0.13611	**VGT Commodity**	
GLGT									
GAS COST		$3.67010							
FUEL	0.657%	$0.02427							
COMMODITY TRANSPORTATION		$0.00326						5 Revised Sheet 4	Jun 1, 1997
GRI		$0.00000						Contract	Jun. 1, 2004
ACA		$0.00180						18th Revised Sheet No. 7	Oct. 1, 2005
GLGT Commodity		$3.69943	2,480,420	$133,980	$0	$9,310,121	$0.17018	**GLGT Commodity**	
CENTRA									
CENTRA TRANSMISSION	($Cdn/103M3)	1.062						Sheet 1 (N.E.B.)	
Conversion		$0.02868							
GAS COSTS		$3.67010							
CUSTOMS FEE		$0.00039							
CENTRA Commodity		$3.69917	1,022,819	$55,248	$54,000	$3,892,827	$0.07116	**Centra Commodity**	
Consolidated Weighted Average gas cost			5,470,903	**$295,511**	**$143,580**	$20,649,455	$0.37744	**Consolidated WACOG-$/therm**	
	Total Annual Sales in therms		**54,709,030**						

Balancing Service

Pipeline	Description	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs
VGT	Balancing Agreement	Annual	7,465	12	$1.0000	$89,580
GLGT	---		0	0	$0.0000	$0
Centra	Union Balancing	Annual	4,500	12	$1.0000	$54,000

N:Group/Rates/Gas/MERC/PGAC/2013/Con1113

	2011 forecasted from base cost of gas filing data	allocator	Sales w/o Losses & Unacc			
			5,470,903			
nng	0	0	0			
glgt	2,534,363	0.45338407	2,480,420	$295,511	0.45338407	133979.8127
vgt	2,010,455	0.359659714	1,967,663	$295,511	0.359659714	106283.269
centra	1,045,063	0.186956216	1,022,819	$295,511	0.186956216	55247.54939
	5,589,881	1	5,470,903			
		$0.00540				

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

RATE IMPACT OF THE PROPOSED DEMAND CHANGE (Illustrates FDD storage contract costs shifted from Demand costs to Commodity costs)

NOVEMBER 1, 2013

All costs in $/Dth	Last Base Cost of Gas G007,G011/ MR10-978*	Demand Change G011-12-119x Nov..'12	Last Demand Change G011-10-977 Jan. '13	Most Recent PGA Oct. 2013	Current Proposal Effective Nov 1,2013	Result of Proposed Change: Change from Last Rate Case	Change from Last Demand Change	Change from Last PGA %	Change from Last PGA $
1) General Service Residential Avg. Annual Use:				**90**	**Dth**				
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.9765	-14.58%	-20.16%	2.83%	$0.1095
Demand Cost	$1.0639	$1.3431	$1.4012	$0.9176	$0.6409	-39.76%	-31.50%	-30.16%	($0.2767)
Commodity Margin	$1.9754	$2.4189	$1.9754	$1.9754	$1.9754	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.6948	$7.1308	$6.7687	$6.7600	$6.5928	-14.32%	-15.45%	-2.47%	($0.1672)
Avg Annual Cost	$692.53	$641.77	$609.18	$608.40	$593.35	-14.32%	-15.45%	-2.47%	($15.05)
Effect of proposed commodity change on average annual bills:									$9.86
Effect of proposed demand change on average annual bills:									($24.91)
2) Large General Service: Avg. Annual Use:				**4,932**	**Dth**				
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.9765	-14.58%	18.04%	2.83%	$0.1095
Demand Cost	$1.0639	$1.3431	$1.4012	$0.9176	$0.6409	-39.76%	-52.28%	-30.16%	($0.2767)
Commodity Margin	$1.6868	$2.1856	$1.6868	$1.6868	$1.6868	0.00%	-22.82%	0.00%	$0.0000
Total Cost of Gas	$7.4062	$6.8975	$6.4801	$6.4714	$6.3042	-14.88%	-8.60%	-2.58%	($0.1672)
Avg Annual Cost	$36,527.38	$34,018.47	$31,959.85	$31,916.94	$31,092.19	-14.88%	-8.60%	-2.58%	($824.76)
Effect of proposed commodity change on average annual bills:									$540.05
Effect of proposed demand change on average annual bills:									($1,364.81)
3) SV Interruptible Service: Avg. Annual Use:				**6,068**	**Dth**				
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.9765	-14.58%	18.04%	2.83%	$0.1095
Commodity Margin	$1.0647	$1.0628	$1.0647	$1.0647	$1.0647	0.00%	0.18%	0.00%	$0.0000
Total Cost of Gas	$5.7202	$4.4316	$4.4568	$4.9317	$5.0412	-11.87%	13.76%	2.22%	$0.1095
Avg Annual Cost	$34,710.17	$26,890.95	$27,043.86	$29,925.56	$30,590.00	-11.87%	13.76%	2.22%	$664.45
Effect of proposed commodity change on average annual bills:									$664.45
4) LV Interruptible Service: Avg. Annual Use:				**40,821**	**Dth**				
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.9765	-14.58%	18.04%	2.83%	$0.1095
Commodity Margin	$0.3568	$0.3164	$0.3568	$0.3568	$0.3568	0.00%	12.77%	0.00%	$0.0000
Total Cost of Gas	$5.0123	$3.6852	$3.7489	$4.2238	$4.3333	-13.55%	17.59%	2.59%	$0.1095
Avg Annual Cost	$204,607.10	$150,433.55	$153,033.85	$172,419.74	$176,889.64	-13.55%	17.59%	2.59%	$4,469.90
Effect of proposed commodity change on average annual bills:									$4,469.90

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-12-756

*As approved in Docket No. G007,011/MR-10-978; with implementation consolidated PGA rates on 7/1/13 in Docket No. G007,011/MR-10-977

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

(Illustrates FDD storage contract costs shifted from Demand costs to Commodity costs)

DEMAND									Cost/Ccf
Contract Type		**Season**	**Monthly Entitlement (Dth)**	**Months**	**Rate ($/Dth)**		**Contract Costs**	**Rate Case Sales (therms)**	
Viking (VGT)									
FT-A ZONE 1 - 1	AF0012	Annual	12,493	12	$3.4033	$	510,212	43,198,700	$0.01181
FT-A ZONE 1 - 1	AF0014 (3)	Winter	1,098	3	$3.4033	$	11,211	43,198,700	$0.00026
FT-A ZONE 1 - 1	AF0102	Annual	2,000	12	$3.4033	$	81,680	43,198,700	$0.00189
FA-A ZONE 1 - 1		Dec-Feb	1,500	3	$3.7043	$	16,669	43,198,700	$0.00039
VGT Demand						**$**	**619,772**	43,198,700	**$0.01435**
Great Lakes (GLGT)									
FT Western Zone	FT0016	Annual	10,130	12	$3.8490	$	467,886	43,198,700	$0.01083
FT Western Zone (12)	FT0155 (12)	Annual	3,600	12	$3.8490	$	166,277	43,198,700	$0.00385
FT Western Zone (5)	FT0155 (5)	Winter	3,638	5	$3.8490	$	70,013	43,198,700	$0.00162
FT Western Zone	FT15782	Annual	9,000	12	$3.8490	$	415,693	43,198,700	$0.00962
GLGT Demand						**$**	**1,119,869**	43,198,700	**$0.02592**
Centra									
CENTRA TRANSMISSION	($Cdn/103M3)				$255.8270				
Conversion (103M3 x Rate(C$ 103M3)		Annual	9,500	12	$7.2470	$	826,161	43,198,700	$0.01912
CENTRA MINNESOTA PIPELINES		Annual	9,500	12	$1.7780	$	202,692	43,198,700	$0.00469
Centra Demand						**$**	**1,028,853**	43,198,700	**$0.02382**
AECO									
Niska Storage (AECO)		Annual	947,820	1	$0.7263	$	-	43,198,700	$0.00000
AECO/Emerson Swap		Annual	947,823	1	$0.5200	$	-	43,198,700	$0.00000
AECO Demand						**$**	**-**	**43,198,700**	**$0.00000**
NMU DEMAND - $/Ccf						**$**	**2,768,494**		**$0.06409**

For Joint Rate Demand | **43,198,700** | Annual Firm Sales in therms

	Units Dth's	**Months**	**Annual Dth's**		
Viking (VGT)					
FT-A ZONE 1 - 1	12,493	12	149,916		
FT-A ZONE 1 - 1	1,098	3	3,294		
FT-A ZONE 1 - 1	2,000	12	24,000		
Wadena Delivered GDD Option	3,500	3	10,500		
Balancing Agreement	7,465	12	89,580		
Great Lakes (GLGT)					
FT Western Zone	10,130	12	121,560		
FT Western Zone (12)	3,600	12	43,200		
FT Western Zone (5)	3,638	5	18,190		
FT Western Zone	9,000	12	108,000		
Centra					
CENTRA TRANSMISSION					
Conversion (103M3 x Rate(C$ 103M3)	9,500	12	114,000		
Union Balancing	4,500	12	54,000		
CENTRA MINNESOTA PIPELINES	9,500	12	114,000		
Total Demand Cost				$ 2,768,494	
Total Demand Weighted Vol in Mcf				5,926,600	
Total Joint Demand Rate $/Mcf					**$0.46713**

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

November 1, 2013

(Illustrates FDD storage contract costs shifted from Demand costs to Commodity costs)

PRESENT AVERAGE COST OF GAS COMMODITY

EFFECTIVE: 01-Aug-13

	Season	Monthly Entitlement (Dth)	Months		Rate ($/Dth)	Contract Costs	Annual Sales (therms)	Rate ($/therm)
Niska Storage (AECO)	Annual	947,820	1	$	0.72626	$688,361.79	54,709,030	$0.01258
AECO/Emerson Swap	Annual	947,823	1	$	0.52000	$417,042.00	54,709,030	$0.00762
						$1,105,403.79	54,709,030	$0.02021

WACOG		Rate	Annual Dth	Call Option Premium	Balancing Service	Total Annual Cost	Cost/therm	REFERENCE	Effective
VGT									
GAS COST		$3.67010							
FUEL	0.00%	$0.00000						Sub 16th Revised Sheet No. 5B	Apr. 1, 2006
COMMODITY TRANSPORTATION		$0.01300						Sub 16th Revised Sheet No. 5B	Apr. 1, 2006
GRI		$0.00000						Sub 16th Revised Sheet No. 5B	Apr. 1, 2006
ACA		$0.00180						Sub 16th Revised Sheet No. 5B	Apr. 1, 2006
VGT Commodity		$3.68490	1,967,663	$106,283	$89,580	$7,446,506	$0.13611	**VGT Commodity**	
GLGT									
GAS COST		$3.67010							
FUEL	0.657%	$0.02427							
COMMODITY TRANSPORTATION		$0.00326						5 Revised Sheet 4	Jun 1, 1997
GRI		$0.00000						Contract	Jun. 1, 2004
ACA		$0.00180						18th Revised Sheet No. 7	Oct. 1, 2005
GLGT Commodity		$3.69943	2,480,420	$133,980	$0	$9,310,121	$0.17018	**GLGT Commodity**	
CENTRA									
CENTRA TRANSMISSION	($Cdn/103M3)	1.062						Sheet 1 (N.E.B.)	
Conversion		$0.02868							
GAS COSTS		$3.67010							
CUSTOMS FEE		$0.00039							
CENTRA Commodity		$3.69917	1,022,819	$55,248	$54,000	$3,892,827	$0.07116	**Centra Commodity**	
Consolidated Weighted Average gas cost			**5,470,903**	**$295,511**	**$143,580**	**$20,649,455**	**$0.37744**	**Consolidated WACOG-$/therm**	
		Total Annual Sales in therms	**54,709,030**						

Balancing Service						
Pipeline	**Description**	**Season**	**Monthly Entitlement (Dth)**	**Months**	**Rate ($/Dth)**	**Contract Costs**
VGT	Balancing Agreement	Annual	7,465	12	$1.0000	$89,580
GLGT	---		0	0	$0.0000	$0
Centra	Union Balancing	Annual	4,500	12	$1.0000	$54,000

N:Group/Rates/Gas/MERC/PGAC/2013/Con1113

Total Commodity Cost: $0.39765

Attachment 5

MINNESOTA ENERGY RESOURCES - PNG-NNG

Financial Options

Heating Season 2012-2013

Units - Gas Daily Peaker Packages (Physical)

	November		December		January		February		March			
	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Daily Total	Term Total
No GDD Peakers											-	-

Premium - Gas Daily Peaker (Monthly Cost)

	November		December		January		February		March		Total	
	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost
No GDD Peakers											$ -	$ -

Units - Futures (Daily Volume)

	November		December		January		February		March			
	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Daily Total	Term Total
1	05/17/13	778	05/03/13	323	05/23/13	860	05/07/13	153	05/29/13	924	3,037	92,922
2	06/19/13	778	05/03/13	323	06/24/13	108	05/07/13	459	06/27/13	924	2,591	78,160
3	07/19/13	778	06/04/13	645	06/24/13	753	06/11/13	306	07/30/13	990	3,471	105,920
4	08/20/13	194	07/02/13	645	07/24/13	860	06/11/13	306	08/29/13	990	2,996	91,753
5	08/20/13	292	08/06/13	645	08/26/13	753	07/09/13	765	09/27/13	990	3,445	104,194
6	08/20/13	292	09/17/13	323	09/25/13	753	08/13/13	765	10/25/13	990	3,122	94,194
7	09/23/13	778	10/08/13	323	10/21/13	753	09/19/13	765			2,618	78,095
8	10/16/13	778					10/11/13	459			1,237	36,190
9							10/11/13	306			306	8,571
10											-	-
Total		4,667		3,226		4,839		4,286		5,806	22,823	690,000
		140,000		100,000		150,000		120,000		180,000		690,000

Units - Call Options (Daily Volume)

	November		December		January		February		March			
	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Daily Total	Term Total
1	05/09/13	888	05/30/13	1,301	05/14/13	1,519	05/21/13	1,467	05/02/13	1,079	6,253	188,550
2	06/13/13	956	06/26/13	1,301	06/18/13	1,579	06/20/13	1,467	06/06/13	1,079	6,382	192,481
3	07/11/13	956	07/26/13	1,301	07/16/13	1,579	07/22/13	1,467	07/03/13	1,079	6,382	192,481
4	08/08/13	956	08/28/13	1,366	08/15/13	1,579	08/22/13	702	08/02/13	1,139	5,742	174,927
5	09/18/13	956	09/26/13	1,366	09/20/13	1,579	08/22/13	765	09/16/13	1,199	5,865	178,571
6	10/10/13	956	10/23/13	1,431	10/14/13	1,519	09/24/13	1,467	10/03/13	1,199	6,571	198,347
7							10/18/13	1,594				44,643
Total		5,667		8,065		9,355		8,929		6,774	37,194	1,170,000
		170,000		250,000		290,000		250,000		210,000		1,170,000

Premium - Call Option (Monthly Cost)

	November		December		January		February		March		Total	
	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost
1	$ 0.3100	$ 8,254	$ 0.2500	$10,081	$ 0.3520	$16,571	$ 0.3850	$15,812	$ 0.4000	$ 13,381	$ 0.3400	$ 64,099
2	$ 0.2450	$ 7,025	$ 0.2830	$11,411	$ 0.3230	$15,814	$ 0.3520	$14,457	$ 0.3230	$ 10,805	$ 0.3092	$ 59,513
3	$ 0.2150	$ 6,165	$ 0.1870	$7,540	$ 0.2960	$14,492	$ 0.3280	$13,471	$ 0.3500	$ 11,708	$ 0.2773	$ 53,377
4	$ 0.1660	$ 4,760	$ 0.1570	$6,647	$ 0.1970	$9,645	$ 0.2800	$5,500	$ 0.3090	$ 10,911	$ 0.2142	$ 37,463
5	$ 0.0670	$ 1,921	$ 0.1680	$7,113	$ 0.1500	$7,344	$ 0.2840	$6,086	$ 0.2900	$ 10,779	$ 0.1862	$ 33,243
6	$ 0.0960	$ 2,753	$ 0.1320	$5,855	$ 0.2590	$12,193	$ 0.2050	$8,420	$ 0.1880	$ 6,988	$ 0.1825	$ 36,208
7							$ 0.2600	$11,607				$ 11,607
Total	**$ 0.1816**	**$ 30,879**	**$ 0.1946**	**$ 48,647**	**$ 0.2623**	**$ 76,061**	**$ 0.3014**	**$ 75,354**	**$ 0.3075**	**$ 64,570**	**$ 0.2526**	**$ 295,511**
		$ 150,760		**$ 241,290**		**$ 403,910**		**$ 421,980**		**$ 347,450**		**$ 1,565,390**

Units - Collar Floor (put)

No Puts were purchased.

Attachment 6

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

	M-10-Consolidated GS	M-11-Consolidated GS	**M-12-Consolidated GS**	**M-13-Consolidated GS**	Proposed Change
Viking Gas Transmission (VGT)					
AF0012	12,493	12,493	**12,493**	**12,493**	0
AF0014 (3)	1,098	1,098	**1,098**	**1,098**	0
AF0102	2,000	2,000	**2,000**	**2,000**	0
TBD	0	0	**0**	**1,500**	1,500
Wadena Delivered GDD Option	0	0	**3500**	**0**	-3,500
Great Lakes Gas Transmission (GLGT)					
FT0016	10,130	10,130	**10,130**	**10,130**	0
FT0155 (12)	3,600	3,600	**3,600**	**3,600**	0
FT0155 (5)	3,638	3,638	**3,638**	**3,638**	0
FT8466	4,500	0	**0**	**0**	0
FT15782	0	9,000	**9,000**	**9,000**	0
Centra Transmission Holding/Centra Minnesota Pipelines (CTHI/CPMI)					
Centra FT-1	9,858	9,858	**9,500**	**9,500**	0
Total VGT Transportation	15,591	15,591	**19,091**	**17,091**	-2,000
Total GLGT Transportation	21,868	26,368	**26,368**	**26,368**	0
Total CTHI/CPMI Transportation	9,858	9,858	**9,500**	**9,500**	0
Total Transportation	47,317	51,817	**54,959**	**52,959**	-2,000
Total Seasonal Transportation	11,236	6,736	**6,736**	**6,736**	0
Total Seasonal Transportation %	23.75%	13.00%	**12.26%**	**12.72%**	0.46%
Other Entitlements not included in Peak Day Deliverability					
AECO Storage	947,819	947,820	**947,820**	**947,820**	0
AECO/Emerson Swap	947,780	947,823	**947,823**	**947,823**	0

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

Rate Impacts
Consolidated

General Service-Residential	Base Cost of Gas Change MR10-978*	Demand Change Nov. '12	Last Demand Change Jan. '13	Most Recent PGA Oct. 2013	Nov.1,2013 w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.7744	-18.93%	11.27%	-2.39%	($0.0926)
Demand Cost	$1.0639	$1.3431	$1.4012	$0.9176	$0.8968	-15.71%	-36.00%	-2.27%	($0.0208)
Margin	$1.9754	$2.4189	$1.9754	$1.9754	$1.9754	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.6948	$7.1308	$6.7687	$6.7600	$6.6466	-13.62%	-1.80%	-1.68%	($0.1134)
Average Annual Use	90	90	90	90	90				
Average Annual Cost of Gas	$692.53	$641.77	$609.18	$608.40	$598.19	-13.62%	-1.80%	-1.68%	($10.21)

Large General Service	Base Cost of Gas Change MR10-978*	Demand Change Nov. '12	Last Demand Change Jan. '13	Most Recent PGA Oct. 2013	Nov.1,2013 w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.7744	-18.93%	11.27%	-2.39%	($0.0926)
Demand Cost	$1.0639	$1.3431	$1.4012	$0.9176	$0.8968	-15.71%	-36.00%	-2.27%	($0.0208)
Margin	$1.6868	$2.1856	$1.6868	$1.6868	$1.6868	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.4062	$6.8975	$6.4801	$6.4714	$6.3580	-14.15%	-1.88%	-1.75%	($0.1134)
Average Annual Use	4,932	4,932	4,932	4,932	4,932				
Average Annual Cost of Gas	$36,527.38	$34,018.47	$31,959.85	$31,916.94	$31,357.47	-14.15%	-1.88%	-1.75%	($559.47)

SV Interruptible Service	Base Cost of Gas Change MR10-978*	Demand Change Nov. '12	Last Demand Change Jan. '13	Most Recent PGA Oct. 2013	Nov.1,2013 w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.7744	-18.93%	11.27%	-2.39%	($0.0926)
Commodity Margin	$1.0647	$1.0628	$1.0647	$1.0647	$1.0647	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.7202	$4.4316	$4.4568	$4.9317	$4.8391	-15.40%	8.58%	-1.88%	($0.0926)
Average Annual Use	6,068	6,068	6,068	6,068	6,068				
Average Annual Cost of Gas	$34,710.17	$26,890.95	$27,043.86	$29,925.56	$29,363.66	-15.40%	8.58%	-1.88%	($561.90)

LV Interruptible Service	Base Cost of Gas Change MR10-978*	Demand Change Nov. '12	Last Demand Change Jan. '13	Most Recent PGA Oct. 2013	Nov.1,2013 w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.7744	-18.93%	11.27%	-2.39%	($0.0926)
Commodity Margin	$0.3568	$0.3164	$0.3568	$0.3568	$0.3568	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.0123	$3.6852	$3.7489	$4.2238	$4.1312	-17.58%	10.20%	-2.19%	($0.0926)
Average Annual Use	40,821	40,821	40,821	40,821	40,821				
Average Annual Cost of Gas	$204,607.10	$150,433.55	$153,033.85	$172,419.74	$168,639.72	-17.58%	10.20%	-2.19%	($3,780.02)

November Change Summary	Commodity Change $/Mcf	Commodity Change %	Demand Change $/Mcf	Demand Change $/Mcf	Demand Change %	Total Change $/Mcf	Total Change %	Average Annual Change
General Service	($0.0926)	-9.26%	($0.0227)	($0.0208)	-2.27%	($0.1134)	-1.68%	($10.21)
Large General Service	($0.0926)	-9.26%	($0.0227)	($0.0208)	-2.27%	($0.1134)	-1.75%	($559.47)
SV Interruptible Service	($0.0926)	($0.0926)	$0.0000	$0.0000	0.00%	($0.0926)	-1.88%	($561.90)
LV Interruptible Service	($0.0926)	($0.0926)	$0.0000	$0.0000	0.00%	($0.0926)	-2.19%	($3,780.02)

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

MINNESOTA ENERGY RESOURCES - Consolidated

Rate Impacts (Illustrates FDD storage contract costs shifted from Demand costs to Commodity costs)

Consolidated

General Service-Residential	Base Cost of Gas Change MR10-978*	Demand Change Nov. '12	Last Demand Change Jan. '13	Most Recent PGA Aug. 2013	Nov.1,2013 w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.9765	-14.58%	17.23%	2.83%	$0.1095
Demand Cost	$1.0639	$1.3431	$1.4012	$0.9176	$0.6409	-39.76%	-54.26%	-30.16%	($0.2767)
Margin	$1.9754	$2.4189	$1.9754	$1.9754	$1.9754	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.6948	$7.1308	$6.7687	$6.7600	$6.5928	-14.32%	-2.60%	-2.47%	($0.1672)
Average Annual Use	90	90	90	90	90				
Average Annual Cost of Gas*	$692.53	$641.77	$609.18	$608.40	$593.35	-14.32%	-2.60%	-2.47%	($15.05)

Large General Service	Base Cost of Gas Change MR10-978*	Demand Change Nov. '12	Last Demand Change Jan. '13	Most Recent PGA Aug. 2013	Nov.1,2013 w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.9765	-14.58%	17.23%	2.83%	$0.1095
Demand Cost	$1.0639	$1.3431	$1.4012	$0.9176	$0.6409	-39.76%	-54.26%	-30.16%	($0.2767)
Margin	$1.6868	$2.1856	$1.6868	$1.6868	$1.6868	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.4062	$6.8975	$6.4801	$6.4714	$6.3042	-14.88%	-2.71%	-2.58%	($0.1672)
Average Annual Use	4,932	4,932	4,932	4,932	4,932				
Average Annual Cost of Gas*	$36,527.38	$34,018.47	$31,959.85	$31,916.94	$31,092.19	-14.88%	-2.71%	-2.58%	($824.76)

SV Interruptible Service	Base Cost of Gas Change MR10-978*	Demand Change Nov. '12	Last Demand Change Jan. '13	Most Recent PGA Aug. 2013	Nov.1,2013 w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.9765	-14.58%	17.23%	2.83%	$0.1095
Commodity Margin	$1.0647	$1.0628	$1.0647	$1.0647	$1.0647	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.7202	$4.4316	$4.4568	$4.9317	$5.0412	-11.87%	13.11%	2.22%	$0.1095
Average Annual Use	6,068	6,068	6,068	6,068	6,068				
Average Annual Cost of Gas*	$34,710.17	$26,890.95	$27,043.86	$29,925.56	$30,590.00	-11.87%	13.11%	2.22%	$664.45

LV Interruptible Service	Base Cost of Gas Change MR10-978*	Demand Change Nov. '12	Last Demand Change Jan. '13	Most Recent PGA Aug. 2013	Nov.1,2013 w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$4.6555	$3.3688	$3.3921	$3.8670	$3.9765	-14.58%	17.23%	2.83%	$0.1095
Commodity Margin	$0.3568	$0.3164	$0.3568	$0.3568	$0.3568	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.0123	$3.6852	$3.7489	$4.2238	$4.3333	-13.55%	15.59%	2.59%	$0.1095
Average Annual Use	40,821	40,821	40,821	40,821	40,821				
Average Annual Cost of Gas*	$204,607.10	$150,433.55	$153,033.85	$172,419.74	$176,889.64	-13.55%	15.59%	2.59%	$4,469.90

October Change Summary	Commodity Change $/Mcf	Commodity Change %	Demand Change $/Mcf	Demand Change $/Mcf	Demand Change %	Total Change $/Mcf	Total Change %	Average Annual Change
General Service	$0.1095	10.95%	($0.3016)	($0.2767)	-30.16%	($0.1672)	-2.47%	($15.05)
Large General Service	$0.1095	10.95%	($0.3016)	($0.2767)	-30.16%	($0.1672)	-2.58%	($824.76)
SV Interruptible Service	$0.1095	$0.1095	$0.0000	$0.0000	0.00%	$0.1095	2.22%	$664.45
LV Interruptible Service	$0.1095	$0.1095	$0.0000	$0.0000	0.00%	$0.1095	2.59%	$4,469.90

***** Average Annual Bill amount does not include customer charges.

****** Commodity includes Upstream costs.

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

Change in Costs due to November,1 2013 Change in Entitlement Levels and Related Demand Costs

Consolidated

	Aug. 2013 Entitlements	Nov. 2013 Entitlements	Entitlement Change	Aug. 2013 Rate	Months	Aug. 2013 Total Annual Cost	Nov. 2013 Total Annual Cost	Total Annual Cost Change
Call Options Premium	$470,146	$295,511	-$174,635			$470,146	$295,511	-$174,635
Viking Pipeline								
AF0012	12,493	12,493	0	$ 3.4033	12	$510,212	$510,212	$0
AF0014 (3)	1,098	1,098	0	$ 3.4033	3	$11,211	$11,211	$0
AF0102	2,000	2,000	0	$ 3.4033	12	$81,680	$81,680	$0
TBD	0	1,500	1,500	$ 3.7043	3	$0	$16,669	$0
Wadena Delivered GDD Option	3,500	0	-3,500	$ -	3	$0	$0	$0
GLGTPipeline								
FT Western Zone	10,130	10,130	0	$ 3.8490	12	$420,355	$467,886	$47,531
FT Western Zone (12)	1,178	3,600	2,422	$ 3.8490	12	$149,385	$166,277	$16,892
FT Western Zone (5)	2,138	3,638	1,500	$ 3.8490	5	$62,901	$70,013	$7,112
FT Western Zone	3,000	9,000	6,000	$ 3.8490	12	$373,464	$415,693	$42,229
CENTRA Pipeline								
CENTRA Transmission ($cdn/103M3)				255.82700				
Centra Transmission	9,858	9,500	-358	$ 7.2470	12	$662,537	$826,161	$163,624
Centra MN Pipelines	9,858	9,500	-358	$ 1.7780	12	$202,692	$202,692	$0
NISKA STORAGE (AECO)								
Niska Storage (AECO)	665,043	947,820	282,777	$ 0.7263	1	$905,000	$688,362	-$216,638
AECO/Emerson Swap	665,015	947,823	282,808	$ 0.5200	1	$417,042	$417,042	$0
TOTAL DEMAND						$4,266,625	$4,169,408	-$113,886
NMU's DE Attachment 4 page 2							$3,873,898	
VGT Balancing Agreement	7,465	7,465	0	$ 1.0000	12	$89,580	$89,580	$0
Union Balancing	4,500	4,500	0	$ 1.0000	12	$54,000	$54,000	$0
							-$295,511	Call Option Premiums

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

GLGT

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	105	3,337	231	0.30%	24,832	24,906
Off Peak	57	3,337	231	0.30%	15,827	15,874

VGT

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	109	3,519	173	0.30%	17,350	17,402
Off Peak	57	3,519	173	0.30%	11,287	11,321

Centra

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	107	1,874	78	0.30%	7,717	7,740
Off Peak	57	1,874	78	0.30%	4,963	4,978

Consolidated

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak		8,730	482	0.30%	49,899	50,048
Off Peak		8,730	482	0.30%	32,077	32,173

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

13/14 Winter Portfolio Plan - MERC Consolidated Hedging Plan

10,000 Contract Size

REVISED:

System	Purchase Month	Nov-13 Number Contracts	Nov-13 Contract Volume	Dec-13 Number Contracts	Dec-13 Contract Volume	Jan-14 Number Contracts	Jan-14 Contract Volume	Feb-14 Number Contracts	Feb-14 Contract Volume	Mar-14 Number Contracts	Mar-14 Contract Volume	Total Number Contracts	Total Contract Volume	Percent of Requirements
MN Requirements			554,243		823,568		949,791		823,773		687,744		3,839,118	3,839,118
GLGT -MN			18,475		26,567		30,638		28,406		22,185		25,425	
70%			387,970		576,497		664,853		576,641		481,420		2,687,383	
40%			221,697		329,427		379,916		329,509		275,097		1,535,647	
			85,304		231,769		231,769		209,339		96,374		854,555	
			136,393		97,658		148,147		120,170		178,723		681,092	
30%			166,273		247,070		284,937		247,132		206,323		1,151,735	
Contracts	Feb-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Mar-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Apr-13	0	0	0	0	0	0	0	0	0	0	0	0	
	May-13	3	30,000	2	20,000	3	30,000	2	20,000	3	30,000	13	130,000	
	Jun-13	3	30,000	2	20,000	3	30,000	2	20,000	3	30,000	13	130,000	
	Jul-13	2	20,000	2	20,000	3	30,000	2	20,000	3	30,000	12	120,000	
	Aug-13	2	20,000	2	20,000	2	20,000	2	20,000	3	30,000	11	110,000	
	Sep-13	2	20,000	1	10,000	2	20,000	2	20,000	3	30,000	10	100,000	
	Oct-13	2	20,000	1	10,000	2	20,000	2	20,000	3	30,000	10	100,000	
	Total	**14**	**140,000**	**10**	**100,000**	**15**	**150,000**	**12**	**120,000**	**18**	**180,000**	**69**	**690,000**	**17.97%**
Call Options	Feb-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Mar-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Apr-13	0	0	0	0	0	0	0	0	0	0	0	0	
	May-13	2	20,000	4	40,000	5	50,000	4	40,000	3	30,000	18	180,000	
	Jun-13	3	30,000	4	40,000	5	50,000	4	40,000	3	30,000	19	190,000	
	Jul-13	3	30,000	4	40,000	5	50,000	4	40,000	3	30,000	19	190,000	
	Aug-13	3	30,000	4	40,000	5	50,000	4	40,000	4	40,000	20	200,000	
	Sep-13	3	30,000	4	40,000	5	50,000	4	40,000	4	40,000	20	200,000	
	Oct-13	3	30,000	5	50,000	4	40,000	5	50,000	4	40,000	21	210,000	
	Total	**17**	**170,000**	**25**	**250,000**	**29**	**290,000**	**25**	**250,000**	**21**	**210,000**	**117**	**1,170,000**	**30.48%**
Collars	Feb-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Mar-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Apr-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Aug-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Sep-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Oct-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.00%**
Index (back financial)	May-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Jun-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Jul-13	0	0	0	0	0	0	0	0	0	0	0	0	
	Aug-13	3,446	103,380	3,767	116,777	4,732	146,692	4,405	123,340	4,193	129,983	20,543	620,172	
	Sep-13	3,444	103,320	3,762	116,622	4,731	146,661	4,405	123,340	4,194	130,014	20,536	619,957	
	Oct-13	3,444	103,320	3,762	116,622	4,731	146,661	4,405	123,340	4,194	130,014	20,536	619,957	
	Total		**310,020**		**350,021**		**440,014**		**370,020**		**390,011**		**1,860,086**	**48.45%**
Physical Hedges			**0**		**0**		**0**		**0**		**0**		**0**	
Storage			85,304		231,769		231,769		209,339		96,374		854,555	**22.26%**
Prepaid Obl			0		0		0		0		0		0	**0.00%**
			71.33%		70.64%		70.73%		70.33%		70.72%		70.71%	
Term Index	Aug-13	0	0	0	0	0	0	0	0	0	0		0	**0.00%**
	Sep-13	0	0	0	0	0	0	0	0	0	0		0	**0.00%**
	Oct-13	0	0	0	0	0	0	0	0	0	0		0	**0.00%**
Total NNG MN														
Contracts													690,000	**17.97%**
Call Options													1,170,000	**30.48%**
Costing Collar													0	**0.00%**
Storage													854,555	**22.26%**
Prepaid Obl													0	**0.00%**
Term Index													0	**0.00%**
Month/Daily													1,124,563	**29.29%**
Total													3,839,118	**100.00%**

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

WINTER PLAN - CONSOLIDATED
NOVEMBER, 2013 THROUGH MARCH, 2014

PHYSICAL FIXED PRICE HEDGES	Deal #	Trigger Locked	Trigger Exercised	Receipt Point	Nov	Dec	Daily Volumes Jan	Feb	Mar	Monthly Total
										-
No Physical Fixed Price Hedges										-
										-
	Total Actual Fixed/Option Physical				-	-	-	-	-	-

INDEX	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
Index - Back Financial Options	6976	9/26/2013	Emerson	5,167	5,646	7,097	6,608	6,291	930,088
Index - Back Financial Options	7233	10/10/2013	Emerson	5,167	5,645	7,097	6,607	6,290	929,998
	Total Actual Seasonal Index			**10,334**	**11,291**	**14,194**	**13,215**	**12,581**	**1,860,086**

GAS DAILY PACKAGES

No GDD Options

STORAGE

Injection Month	Contract # AECO Volume Injected	Total Volume Injected
May - balance forward	191,103	191,103
June	184,938	184,938
July	191,102	191,102
August	191,103	191,103
Sept	93,237	93,237
Oct (est)	96,337	96,337
Total	**947,820**	**947,820**

MINNESOTA ENERGY RESOURCES - Consolidated

Daily Total Throughput Data - July 1, 2012 through June 30, 2013

Base	6,734
Variable	495

Date	21.70% Bemidji Adjusted HDD	49.07% Cloquet Adjusted HDD	13.77% Fargo Adjusted HDD	15.47% Intl. Falls Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put **
7/1/12	0	0	0	0	0	3,691	6,734
7/2/12	0	0	0	0	0	4,103	6,734
7/3/12	0	0	0	0	0	3,421	6,734
7/4/12	0	0	0	0	0	3,007	6,734
7/5/12	2	1	0	2	1	4,924	7,375
7/6/12	0	0	0	0	0	5,018	6,734
7/7/12	0	0	0	0	0	4,701	6,734
7/8/12	0	0	0	0	0	5,074	6,734
7/9/12	0	0	0	0	0	5,598	6,734
7/10/12	0	0	0	0	0	5,033	6,734
7/11/12	0	0	0	0	0	5,205	6,734
7/12/12	0	0	0	0	0	5,164	6,734
7/13/12	0	0	0	0	0	4,468	6,734
7/14/12	0	0	0	0	0	4,340	6,734
7/15/12	0	0	0	0	0	4,544	6,734
7/16/12	0	0	0	0	0	4,393	6,734
7/17/12	0	0	0	0	0	4,856	6,734
7/18/12	0	0	0	0	0	5,510	6,734
7/19/12	0	0	0	0	0	5,421	6,734
7/20/12	0	0	0	0	0	4,537	6,734
7/21/12	0	0	0	0	0	3,641	6,734
7/22/12	0	0	0	0	0	4,133	6,734
7/23/12	0	0	0	0	0	5,878	6,734
7/24/12	0	0	0	0	0	5,831	6,734
7/25/12	1	0	0	0	0	5,974	6,850
7/26/12	0	1	0	2	1	5,950	7,141
7/27/12	0	0	0	1	0	4,946	6,813
7/28/12	0	0	0	0	0	-389	6,734
7/29/12	0	0	0	0	0	419	6,734
7/30/12	0	0	0	0	0	5,518	6,734
7/31/12	0	0	0	0	0	5,822	6,734
8/1/12	0	0	0	0	0	5,663	6,734
8/2/12	0	0	0	0	0	5,374	6,734
8/3/12	4	0	0	4	2	4,779	7,545
8/4/12	7	2	2	4	3	4,036	8,444
8/5/12	0	0	0	0	0	3,946	6,734
8/6/12	4	0	0	5	2	5,022	7,579
8/7/12	0	4	0	0	2	5,433	7,715
8/8/12	4	4	0	7	4	5,296	8,815
8/9/12	6	5	1	8	5	5,604	9,369
8/10/12	8	4	0	5	5	4,621	8,995
8/11/12	2	0	0	3	1	3,350	7,194
8/12/12	5	1	0	5	2	3,889	7,967
8/13/12	7	2	1	6	4	5,173	8,550
8/14/12	0	0	0	4	1	5,359	7,062
8/15/12	12	9	5	12	9	4,975	11,410
8/16/12	11	8	4	11	9	5,486	11,003
8/17/12	4	3	0	7	4	4,866	8,519
8/18/12	9	7	2	11	8	3,691	10,524
8/19/12	10	8	4	6	8	4,317	10,610
8/20/12	3	4	0	3	3	5,643	8,349
8/21/12	0	0	0	0	0	5,649	6,734
8/22/12	0	0	0	0	0	5,427	6,734
8/23/12	0	0	0	0	0	5,342	6,734
8/24/12	1	0	0	4	1	4,770	7,176
8/25/12	0	0	0	2	0	4,047	6,898
8/26/12	2	0	0	5	1	4,651	7,352
8/27/12	0	0	0	0	0	5,772	6,734
8/28/12	0	0	0	0	0	5,902	6,734
8/29/12	3	0	0	3	1	5,232	7,317
8/30/12	3	0	0	4	1	5,941	7,381
8/31/12	0	1	0	5	1	4,626	7,391
9/1/12	0	0	0	0	0	3,405	6,734
9/2/12	0	0	0	0	0	3,200	6,734
9/3/12	0	0	0	0	0	4,959	6,734
9/4/12	2	0	0	6	1	5,673	7,460
9/5/12	13	1	6	11	6	6,193	9,652
9/6/12	14	10	7	14	11	6,024	12,124
9/7/12	15	14	7	16	14	6,478	13,448
9/8/12	11	8	10	13	10	6,583	11,659
9/9/12	0	3	0	3	2	5,921	7,767
9/10/12	0	0	0	0	0	5,665	6,734
9/11/12	8	6	6	9	7	6,085	10,202
9/12/12	15	10	12	18	12	7,275	12,867
9/13/12	17	13	8	19	14	7,832	13,873

9/14/12	5	9	0	12	8	6,846	10,559
9/15/12	10	2	9	13	6	4,445	9,901
9/16/12	22	19	18	24	20	5,848	16,754
9/17/12	24	23	20	27	23	10,672	18,260
9/18/12	15	11	12	14	13	10,654	12,931
9/19/12	17	15	12	20	16	10,228	14,597
9/20/12	22	21	15	24	21	10,475	16,970
9/21/12	26	26	24	29	26	11,767	19,614
9/22/12	26	24	22	27	24	11,040	18,806
9/23/12	13	10	4	20	11	9,961	12,399
9/24/12	24	21	21	27	22	10,448	17,759
9/25/12	24	22	18	22	22	11,812	17,443
9/26/12	18	19	7	19	17	11,835	15,227
9/27/12	5	12	0	12	9	9,361	11,183
9/28/12	6	13	0	12	9	6,950	11,404
9/29/12	2	10	0	4	6	4,935	9,812
9/30/12	15	9	8	19	12	5,160	12,444
10/1/12	15	17	6	18	15	8,075	14,183
10/2/12	19	8	18	17	13	7,590	13,340
10/3/12	31	22	33	26	26	8,930	19,642
10/4/12	37	32	34	33	33	17,164	23,313
10/5/12	32	30	30	31	31	17,870	22,017
10/6/12	26	28	21	29	27	15,325	19,967
10/7/12	25	26	21	28	25	13,289	19,260
10/8/12	33	29	33	34	31	16,061	22,121
10/9/12	32	28	28	33	30	19,204	21,441
10/10/12	36	31	32	37	33	18,148	23,232
10/11/12	34	33	28	37	33	20,463	23,007
10/12/12	18	23	14	25	21	16,043	17,050
10/13/12	23	19	23	26	21	10,883	17,361
10/14/12	24	21	16	26	22	12,734	17,512
10/15/12	5	11	5	9	9	12,163	11,156
10/16/12	18	17	14	18	17	8,765	15,120
10/17/12	21	18	24	15	19	11,833	16,262
10/18/12	24	24	26	22	24	13,117	18,635
10/19/12	22	24	21	25	24	13,709	18,436
10/20/12	18	20	17	20	19	11,915	16,070
10/21/12	22	20	20	22	21	11,374	17,001
10/22/12	20	21	14	20	20	14,767	16,465
10/23/12	24	16	26	21	20	13,592	16,563
10/24/12	35	30	32	32	32	16,452	22,329
10/25/12	38	34	32	37	35	22,430	24,119
10/26/12	39	34	36	39	36	23,056	24,537
10/27/12	39	34	38	42	37	20,929	24,884
10/28/12	31	28	26	37	30	21,124	21,375
10/29/12	30	28	23	32	29	20,707	20,856
10/30/12	35	36	26	39	35	20,540	23,946
10/31/12	28	25	27	30	27	18,771	19,963
11/1/12	39	39	38	39	39	23,428	25,993
11/2/12	35	33	32	39	34	21,124	23,767
11/3/12	37	38	30	39	37	19,365	24,960
11/4/12	31	35	29	41	34	19,103	23,633
11/5/12	33	30	28	33	31	20,200	21,896
11/6/12	33	30	32	32	31	19,939	22,135
11/7/12	27	28	27	30	28	17,941	20,525
11/8/12	32	25	33	32	29	19,328	20,868
11/9/12	36	33	31	40	35	20,771	23,915
11/10/12	35	26	39	34	31	18,542	22,070
11/11/12	51	41	54	44	45	26,910	29,117
11/12/12	54	48	52	47	50	31,611	31,443
11/13/12	40	39	40	44	40	26,388	26,708
11/14/12	32	27	33	35	30	22,532	21,751
11/15/12	46	39	40	47	42	27,385	27,280
11/16/12	37	34	36	39	36	23,063	24,508
11/17/12	27	20	24	25	23	16,150	18,109
11/18/12	22	17	25	24	20	14,642	16,680
11/19/12	30	26	32	26	28	20,395	20,537
11/20/12	32	29	29	32	30	20,989	21,471
11/21/12	24	23	21	26	23	16,584	18,271
11/22/12	50	36	50	44	42	27,499	27,666
11/23/12	59	60	58	63	60	33,068	36,435
11/24/12	54	51	47	55	52	28,755	32,432
11/25/12	62	57	56	59	58	33,376	35,532
11/26/12	58	58	54	58	58	33,883	35,264
11/27/12	50	45	42	57	48	31,379	30,279
11/28/12	47	46	44	54	47	29,879	30,064
11/29/12	53	44	46	55	48	31,680	30,636
11/30/12	41	36	37	42	38	25,757	25,776
12/1/12	33	31	31	32	31	20,157	22,256
12/2/12	30	28	29	28	28	20,264	20,799
12/3/12	43	36	37	41	38	26,241	25,739
12/4/12	56	52	50	54	53	33,449	33,052
12/5/12	44	41	39	43	42	28,138	27,466
12/6/12	51	41	46	44	44	29,071	28,668
12/7/12	54	45	47	57	49	31,473	30,950
12/8/12	48	43	53	56	48	27,222	30,261

12/9/12	69	53	74	71	62	37,403	37,451
12/10/12	67	58	67	65	62	38,893	37,487
12/11/12	69	61	57	67	63	39,892	38,107
12/12/12	49	48	50	55	50	33,003	31,278
12/13/12	54	54	42	50	52	33,365	32,303
12/14/12	48	42	45	45	44	27,595	28,492
12/15/12	45	33	50	40	39	24,942	26,165
12/16/12	49	46	48	48	47	29,423	30,224
12/17/12	49	46	46	50	47	31,883	30,111
12/18/12	43	43	46	47	44	29,026	28,641
12/19/12	51	42	52	45	46	29,661	29,412
12/20/12	63	61	64	64	63	36,641	37,747
12/21/12	58	57	63	64	59	36,136	36,030
12/22/12	61	56	64	66	60	34,371	36,195
12/23/12	66	60	75	71	65	36,179	38,942
12/24/12	77	71	77	76	74	42,004	43,356
12/25/12	72	67	72	77	70	39,796	41,547
12/26/12	66	58	63	70	62	40,881	37,585
12/27/12	56	54	56	65	56	36,476	34,647
12/28/12	54	52	63	55	54	31,945	33,474
12/29/12	67	59	64	62	62	33,854	37,522
12/30/12	65	60	65	66	63	32,701	37,796
12/31/12	73	68	69	76	70	40,225	41,581
1/1/13	63	63	53	65	62	34,088	37,233
1/2/13	59	51	59	55	55	34,585	33,776
1/3/13	61	56	56	59	57	40,884	35,020
1/4/13	53	45	54	55	49	33,043	31,171
1/5/13	55	48	60	62	53	32,833	32,999
1/6/13	58	51	55	61	55	34,064	33,953
1/7/13	49	42	46	46	45	27,892	28,886
1/8/13	50	45	42	47	46	34,048	29,472
1/9/13	42	42	43	45	43	33,169	27,800
1/10/13	29	29	31	27	29	22,111	21,120
1/11/13	49	35	56	46	43	28,013	27,945
1/12/13	72	61	73	72	67	41,120	39,669
1/13/13	71	64	66	72	67	39,629	39,980
1/14/13	63	63	64	67	64	40,094	38,169
1/15/13	53	54	49	56	53	35,109	33,103
1/16/13	67	57	66	73	63	41,463	37,929
1/17/13	65	66	55	78	66	43,323	39,355
1/18/13	49	51	39	59	50	32,644	31,546
1/19/13	71	63	61	74	66	44,451	39,538
1/20/13	87	81	82	86	83	49,326	47,830
1/21/13	88	87	80	91	87	55,528	49,786
1/22/13	80	78	72	84	78	48,730	45,540
1/23/13	85	79	81	93	83	52,115	47,790
1/24/13	75	73	71	82	75	49,459	43,779
1/25/13	76	67	73	77	71	43,632	42,067
1/26/13	63	63	60	66	63	39,941	38,020
1/27/13	48	42	43	51	45	28,337	28,899
1/28/13	38	37	42	37	38	30,589	25,556
1/29/13	57	48	55	53	51	31,002	32,202
1/30/13	75	67	74	69	70	42,822	41,416
1/31/13	91	84	87	88	87	52,529	49,633
2/1/13	82	78	77	88	80	59,691	46,444
2/2/13	77	69	69	83	73	42,011	42,774
2/3/13	74	73	64	80	73	42,222	42,960
2/4/13	63	64	56	62	63	40,517	37,706
2/5/13	62	58	58	67	60	37,808	36,618
2/6/13	54	51	50	59	53	36,552	32,744
2/7/13	60	48	54	62	53	37,224	33,168
2/8/13	59	49	51	49	52	33,240	32,377
2/9/13	43	44	38	43	43	28,457	27,883
2/10/13	49	44	49	48	46	31,267	29,601
2/11/13	57	52	53	56	54	35,506	33,298
2/12/13	48	45	46	45	46	30,751	29,429
2/13/13	48	37	46	48	42	30,022	27,626
2/14/13	67	59	64	65	62	37,307	37,574
2/15/13	66	63	64	74	65	38,139	39,026
2/16/13	58	61	61	69	62	33,101	37,212
2/17/13	46	50	52	48	49	29,232	31,095
2/18/13	66	63	83	66	66	41,611	39,630
2/19/13	80	76	84	78	78	46,661	45,451
2/20/13	70	62	71	72	66	42,404	39,590
2/21/13	61	54	59	61	58	36,724	35,247
2/22/13	50	44	53	54	48	31,547	30,662
2/23/13	50	47	56	53	50	29,748	31,429
2/24/13	47	42	55	46	45	28,756	29,221
2/25/13	46	47	50	48	48	30,933	30,264
2/26/13	44	41	51	41	43	29,655	27,990
2/27/13	42	39	52	47	42	29,151	27,763
2/28/13	48	46	52	51	48	31,134	30,635
3/1/13	55	62	53	64	59	30,650	36,155
3/2/13	52	47	52	54	50	31,061	31,537
3/3/13	44	46	45	48	46	27,558	29,400
3/4/13	47	45	44	47	46	33,130	29,319

3/5/13	48	52	49	60	52	30,203	32,568
3/6/13	56	58	51	60	57	32,355	34,776
3/7/13	50	47	48	46	48	28,751	30,348
3/8/13	39	39	39	40	39	25,905	26,070
3/9/13	42	35	47	39	39	26,247	25,867
3/10/13	55	42	59	51	49	29,774	30,803
3/11/13	51	46	49	50	48	29,728	30,563
3/12/13	58	57	60	62	58	31,323	35,593
3/13/13	41	44	46	53	45	28,102	28,912
3/14/13	40	35	43	46	39	26,974	26,001
3/15/13	59	52	64	63	57	33,090	34,882
3/16/13	76	67	71	79	71	34,185	41,949
3/17/13	50	47	53	52	49	31,676	31,021
3/18/13	63	56	68	54	59	35,079	35,809
3/19/13	70	62	66	66	65	39,284	38,758
3/20/13	67	60	65	67	63	41,038	38,148
3/21/13	57	50	62	56	54	30,927	33,632
3/22/13	43	43	55	50	46	22,173	29,361
3/23/13	39	34	49	47	39	23,595	26,149
3/24/13	44	46	46	46	45	25,760	29,244
3/25/13	48	35	54	41	41	28,722	27,215
3/26/13	45	32	53	35	38	25,419	25,691
3/27/13	38	37	40	42	38	22,561	25,784
3/28/13	32	33	41	36	34	19,994	23,743
3/29/13	25	23	33	31	26	15,633	19,663
3/30/13	35	26	36	32	31	20,969	21,881
3/31/13	54	49	49	55	51	30,290	31,959
4/1/13	49	47	45	48	47	27,871	30,176
4/2/13	44	41	39	47	42	22,826	27,747
4/3/13	37	29	33	33	32	20,926	22,524
4/4/13	45	39	43	46	42	23,896	27,344
4/5/13	36	36	32	35	36	23,346	24,311
4/6/13	32	32	31	31	32	20,409	22,497
4/7/13	40	31	45	35	36	20,178	24,364
4/8/13	47	34	51	42	40	26,216	26,687
4/9/13	38	38	42	36	38	24,857	25,772
4/10/13	42	44	37	41	42	24,538	27,584
4/11/13	40	41	38	41	41	28,843	26,818
4/12/13	41	40	37	42	40	25,593	26,495
4/13/13	43	48	40	46	45	22,583	29,129
4/14/13	34	35	36	34	35	24,880	23,821
4/15/13	34	31	36	34	33	22,650	23,100
4/16/13	33	37	35	34	35	21,666	24,259
4/17/13	37	37	38	37	37	23,845	25,148
4/18/13	45	47	42	45	46	25,926	29,325
4/19/13	42	43	40	44	43	24,840	27,823
4/20/13	37	36	34	37	36	22,618	24,526
4/21/13	40	33	38	35	35	21,749	24,288
4/22/13	43	35	35	38	37	24,926	25,053
4/23/13	36	36	31	37	36	22,660	24,411
4/24/13	32	31	31	32	31	21,396	22,322
4/25/13	21	17	17	17	18	18,040	15,452
4/26/13	13	17	10	13	14	11,259	13,878
4/27/13	17	13	16	16	15	8,780	14,052
4/28/13	21	14	18	20	17	11,773	15,081
4/29/13	24	13	20	20	18	10,793	15,451
4/30/13	37	28	32	35	31	15,943	22,234
5/1/13	40	32	35	34	34	22,591	23,699
5/2/13	35	36	29	34	35	22,327	23,870
5/3/13	32	33	21	31	31	18,499	22,032
5/4/13	26	23	21	25	24	17,953	18,466
5/5/13	16	14	7	16	14	14,516	13,721
5/6/13	11	10	3	10	9	9,786	11,358
5/7/13	5	11	3	10	9	8,100	10,978
5/8/13	15	25	12	19	20	10,076	16,588
5/9/13	19	26	13	23	22	12,671	17,676
5/10/13	33	29	27	32	30	12,213	21,639
5/11/13	29	28	22	32	28	14,128	20,508
5/12/13	9	19	0	23	15	11,767	14,066
5/13/13	1	10	0	8	6	9,827	9,819
5/14/13	5	1	0	6	3	7,739	8,008
5/15/13	10	9	2	17	9	7,292	11,293
5/16/13	5	18	0	5	11	8,656	12,028
5/17/13	13	21	0	11	15	6,238	14,079
5/18/13	7	17	0	12	12	5,994	12,428
5/19/13	16	22	7	19	18	6,784	15,619
5/20/13	21	21	15	22	20	11,721	16,848
5/21/13	9	18	6	10	13	12,667	13,219
5/22/13	15	21	8	19	18	9,844	15,491
5/23/13	17	18	8	17	16	8,769	14,712
5/24/13	7	18	2	8	12	7,538	12,725
5/25/13	8	15	8	6	11	6,970	12,327
5/26/13	8	16	2	10	11	6,660	12,390
5/27/13	5	12	0	6	8	6,820	10,628
5/28/13	2	6	0	0	4	7,115	8,496
5/29/13	0	5	0	0	3	6,674	8,033

5/30/13	4	2	3	3	3	6,385	8,190
5/31/13	21	15	14	18	17	6,481	14,979
6/1/13	17	14	13	19	15	7,622	14,276
6/2/13	19	16	11	19	16	6,723	14,689
6/3/13	8	13	9	12	11	8,460	12,193
6/4/13	19	18	7	15	16	10,778	14,784
6/5/13	17	16	4	17	15	10,558	13,944
6/6/13	15	10	2	15	11	9,081	12,048
6/7/13	9	8	1	11	8	6,783	10,611
6/8/13	12	15	7	10	13	4,716	12,925
6/9/13	1	8	3	4	5	6,792	9,365
6/10/13	0	0	0	3	0	6,343	6,973
6/11/13	5	1	0	7	3	6,374	8,134
6/12/13	4	2	0	1	2	6,312	7,776
6/13/13	1	7	0	4	5	6,160	8,979
6/14/13	0	3	0	0	2	4,988	7,492
6/15/13	0	0	0	2	0	3,657	6,898
6/16/13	4	19	0	12	12	4,196	12,756
6/17/13	4	14	0	9	9	8,308	11,180
6/18/13	0	2	0	0	1	13,207	7,239
6/19/13	0	6	0	0	3	-3,846	8,293
6/20/13	0	4	0	0	2	5,677	7,774
6/21/13	0	11	0	0	5	5,203	9,333
6/22/13	0	0	0	0	0	4,865	6,734
6/23/13	0	0	0	0	0	5,141	6,734
6/24/13	0	0	0	0	0	5,454	6,734
6/25/13	0	0	0	0	0	5,395	6,734
6/26/13	0	0	0	0	0	5,226	6,734
6/27/13	0	0	0	0	0	5,405	6,734
6/28/13	0	3	0	1	2	4,897	7,579
6/29/13	0	0	0	1	0	3,453	6,813
6/30/13	8	6	2	8	6	4,281	9,896
Totals	10,997	10,282	10,258	11,354	10,599	6,976,263	7,704,594

* Volumes include interruptible and transportation volumes except for transportation volumes that are not located behind MERC citygates.

** Design Model numbers are used to calculate firm volumes only

Attachment 12

MINNESOTA ENERGY RESOURCES - Consolidated

Customer Counts by PGAC Class - July 1, 2012 through June 30, 2013

Rate Class	Tariff Rate Designation	Jul-12 Average Customers	Aug-12 Average Customers	Sep-12 Average Customers	Oct-12 Average Customers	Nov-12 Average Customers	Dec-12 Average Customers	Jan-13 Average Customers	Feb-13 Average Customers	Mar-13 Average Customers	Apr-13 Average Customers	May-13 Average Customers	Jun-13 Average Customers
Residential w/ Heat	2H004	3,863	3,884	3,906	3,936	3,949	3,958	3,949	3,955	3,944	3,939	3,875	3,887
Residential w/o Heat	2R003	71	71	71	71	71	72	71	70	70	70	69	70
Commercial-SV	2C051 / 2I051 2C072	376	380	377	388	390	392	392	392	391	393	392	391
Commercial-LV	2C061 / 2I061 2C073	333	333	331	333	333	333	334	334	334	334	334	335
Industrial-LV	2I758	1	1	1	1	1	1	1	1	1	1	1	1
Interruptible-SV	2D126 / 2J126 2D705	22	21	20	20	20	20	19	19	19	19	19	19
Interruptible-LV	2J723	1	1	1	1	1	1	1	1	1	1	1	1
Transport-SVI	2C779 / 2D779 / 2J779 2D70A	9	9	9	9	9	9	9	9	9	8	8	8
Transport-LJ	2I795	1	1	1	1	1	1	1	1	1	1	1	1
Transport-LVJ	2J796	2	2	2	2	2	2	2	2	2	2	2	2
Residential w/ Heat	2H006	4,958	4,993	5,028	5,090	5,124	5,130	5,128	5,126	5,121	5,089	4,990	4,997
Residential w/o Heat	2R005	34	32	33	35	35	35	35	35	35	33	32	31
Commercial-SV	2C052 2C074	507	506	506	513	513	510	510	510	509	508	501	506
Commercial-LV	2C062 / 2I062 2C075 / 2I075	479	479	479	479	480	479	479	479	479	479	472	474
SV-Joint	2D706	3	3	3	3	3	3	3	3	3	3	3	3
SV-Interruptible	2D127	5	5	5	5	5	5	5	5	5	5	5	5
LJ-TP	2D708	1	1	1	1	1	1	1	1	1	1	1	1
Transport	2D709 2D83L	4	4	4	4	4	4	4	4	4	4	4	4
Residential w/ Heat	3H001	35,154	35,354	35,511	35,749	35,908	35,980	35,995	35,977	35,951	35,769	35,369	35,424
Residential w/o Heat	3R002	22	22	23	23	23	23	23	23	22	22	21	21
Commercial-SV	3C050 / 3I050 3C070	2,610	2,604	2,603	2,615	2,626	2,632	2,637	2,633	2,629	2,620	2,613	2,605
Commercial-LV	3C052 / 3I052 3C071	2,748	2,752	2,756	2,768	2,780	2,787	2,785	2,787	2,787	2,782	2,771	2,772
Industrial-LV	3C150 / 3I150	13	13	13	13	13	13	13	13	13	13	13	13
Interruptible-SV	3D125 / 3J125	99	99	99	99	98	98	99	100	101	101	101	100
Interruptible-LV	3D200 / 3J200 3D203	13	13	13	12	11	11	11	11	11	10	10	10
Transport-SV	3C700 / 3J700 3D701	18	18	18	18	18	18	18	18	18	18	18	18
Transport-LV	3I703 / 3J703 3D704 / 3J704	15	15	15	15	15	15	15	15	15	15	15	15
Transport (CIP)	3J713	9	9	9	9	9	9	9	9	9	9	9	9
Total		51,371	51,625	51,838	52,213	52,443	52,542	52,549	52,533	52,485	52,249	51,650	51,723

Note: Customer counts include NMU-NNG. MERC was not able to separate out customer counts by pipeline for NMU.

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

Projected Fixed Cost - November 2013 through March 2014

Futures Contracts WACOG

NMU
Futures

Nov-13 (30)

Purchase Date	Financial Volume	Purchase Price	Total Cost	Emerson Index	Emerson Index Cost	Over/(Under) Market
05/17/13	23,333	$ 4.1999	$ 97,998	$ 3.8970	$ 90,930	$ 7,068
06/19/13	23,333	$ 4.0540	$ 94,593	$ 3.8970	$ 90,930	$ 3,663
07/19/13	23,333	$ 3.8580	$ 90,020	$ 3.8970	$ 90,930	$ (910)
08/20/13	5,833	$ 3.5960	$ 20,977	$ 3.8970	$ 22,732	$ (1,756)
08/20/13	8,750	$ 3.5970	$ 31,474	$ 3.8970	$ 34,099	$ (2,625)
08/20/13	8,750	$ 3.5980	$ 31,483	$ 3.8970	$ 34,099	$ (2,616)
09/23/13	23,333	$ 3.6910	$ 86,123	$ 3.8970	$ 90,930	$ (4,807)
10/16/13	23,333	$ 3.7990	$ 88,643	$ 3.8970	$ 90,930	$ (2,287)
Total	140,000		$ 541,311		$ 545,580	$ (4,269)
WACOG			$ 3.8665		$ 3.8970	$ (0.0305)

Dec-13 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	Emerson Index	Emerson Index Cost	Over/(Under) Market
05/03/13	10,000	$ 4.3820	$ 43,820	$ 4.0020	$ 40,020	$ 3,800
05/03/13	10,000	$ 4.3830	$ 43,830	$ 4.0020	$ 40,020	$ 3,810
06/04/13	20,000	$ 4.2420	$ 84,840	$ 4.0020	$ 80,040	$ 4,800
07/02/13	20,000	$ 3.8980	$ 77,960	$ 4.0020	$ 80,040	$ (2,080)
08/06/13	20,000	$ 3.6470	$ 72,940	$ 4.0020	$ 80,040	$ (7,100)
09/17/13	10,000	$ 3.9760	$ 39,760	$ 4.0020	$ 40,020	$ (260)
10/08/13	10,000	$ 3.8630	$ 38,630	$ 4.0020	$ 40,020	$ (1,390)
	100,000		$ 401,780		$ 400,200	$ 1,580
			$ 4.0178		$ 4.0020	$ 0.0158

Jan-14 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	Emerson Index	Emerson Index Cost	Over/(Under) Market
05/23/13	26,667	$ 4.6130	$ 123,013	$ 3.9935	$ 106,493	$ 16,520
06/24/13	3,333	$ 4.0980	$ 13,660	$ 3.9935	$ 13,312	$ 348
06/24/13	23,333	$ 4.0990	$ 95,643	$ 3.9935	$ 93,182	$ 2,462
07/24/13	26,667	$ 4.0210	$ 107,227	$ 3.9935	$ 106,493	$ 733
08/26/13	23,333	$ 3.9190	$ 91,443	$ 3.9935	$ 93,182	$ (1,738)
09/25/13	23,333	$ 3.8440	$ 89,693	$ 3.9935	$ 93,182	$ (3,488)
10/21/13	23,333	$ 3.9200	$ 91,467	$ 3.9935	$ 93,182	$ (1,715)
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
	150,000		$ 612,147		$ 599,025	$ 13,122
			$ 4.0810		$ 3.9935	$ 0.0875

Feb-12 (28)

Purchase Date	Physical Volume	Purchase Price	Total Cost	Emerson Index	Emerson Index Cost	Over/(Under) Market
05/07/13	4,286	$ 4.3480	$ 18,634	$ 4.0060	$ 17,169	$ 1,466
05/07/13	12,857	$ 4.3490	$ 55,916	$ 4.0060	$ 51,506	$ 4,410
06/11/13	8,571	$ 4.0940	$ 35,091	$ 4.0060	$ 34,337	$ 754
06/11/13	8,571	$ 4.0950	$ 35,100	$ 4.0060	$ 34,337	$ 763
07/09/13	21,429	$ 3.9830	$ 85,350	$ 4.0060	$ 85,843	$ (493)
08/13/13	21,429	$ 3.7100	$ 79,500	$ 4.0060	$ 85,843	$ (6,343)
09/19/13	21,429	$ 4.0400	$ 86,571	$ 4.0060	$ 85,843	$ 729
10/11/13	12,857	$ 4.0240	$ 51,737	$ 4.0060	$ 51,506	$ 231
10/11/13	8,571	$ 4.0250	$ 34,500	$ 4.0060	$ 34,337	$ 163
Total	120,000		$ 482,400		$ 480,720	$ 1,680
WACOG			$ 4.0200		$ 4.0060	$ 0.0140

Mar-12 (31)

Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/29/13	28,636	$ 4.4130	$ 126,372	$ 3.9815	$ 114,016	$ 12,357
06/27/13	28,636	$ 3.8820	$ 111,166	$ 3.9815	$ 114,016	$ (2,849)
07/30/13	30,682	$ 3.7950	$ 116,438	$ 3.9815	$ 122,160	$ (5,722)
08/29/13	30,682	$ 3.9190	$ 120,242	$ 3.9815	$ 122,160	$ (1,918)
09/27/13	30,682	$ 3.8530	$ 118,217	$ 3.9815	$ 122,160	$ (3,943)
10/25/13	30,682	$ 3.8740	$ 118,861	$ 3.9815	$ 122,160	$ (3,298)
	180,000		$ 711,297		$ 716,670	$ (5,373)
			$ 3.9516		$ 3.9815	$ (0.0299)

Total

	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
	92,922	$ 4.4106	$ 409,838	$ 3.9671	$ 368,628	$ 41,210
	78,160	$ 4.0835	$ 319,165	$ 3.9634	$ 309,783	$ 9,382
	105,920	$ 3.9844	$ 422,032	$ 3.9714	$ 420,648	$ 1,384
	91,753	$ 3.9400	$ 361,505	$ 3.9864	$ 365,763	$ (4,257)
	104,194	$ 3.8335	$ 399,424	$ 3.9861	$ 415,323	$ (15,899)
	94,194	$ 3.8144	$ 359,297	$ 3.9844	$ 375,303	$ (16,006)
	78,095	$ 3.8772	$ 302,791	$ 3.9692	$ 309,975	$ (7,183)
	36,190	$ 3.8789	$ 140,380	$ 3.9357	$ 142,436	$ (2,055)
	681,429		$ 2,714,434		$ 2,707,858	$ 6,576
			$ 3.9834		$ 3.9738	$ 0.0097

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

Projected Storage Cost - November 2013 through March 2014

Month/ Year	K#118657 NNG Storage	Storage K#125344 LS Power	Storage K#125345 LS Power	Total NNG Storage	Projected Storage NNG WACOG	K#118657 NNG Storage Cost	K#125344 NNG Storage Cost	K#125345 NNG Storage Cost	Total NNG Storage Cost	AECO Storage GLGT/VGT Centra Emerson	AECO Storage GLGT/VGT Centra Emerson WACOG	AECO Storage GLGT/VGT Centra Emerson Cost
Nov-13	455,259	73,125	19,500	547,884	$ 3.7882	$ 1,724,612	$ 277,012	$ 73,870	$ 2,075,494	85,304	$ 3.0943	$ 263,956
Dec-13	1,143,984	183,750	49,000	1,376,734	$ 3.7882	$ 4,333,640	$ 696,082	$ 185,622	$ 5,215,344	231,769	$ 3.0943	$ 717,163
Jan-14	1,143,984	183,750	49,000	1,376,734	$ 3.7882	$ 4,333,640	$ 696,082	$ 185,622	$ 5,215,344	231,769	$ 3.0943	$ 717,163
Feb-14	1,143,984	183,750	49,000	1,376,734	$ 3.7882	$ 4,333,640	$ 696,082	$ 185,622	$ 5,215,344	209,339	$ 3.0943	$ 647,758
Mar-14	455,259	73,125	19,500	547,884	$ 3.7882	$ 1,724,612	$ 277,012	$ 73,870	$ 2,075,494	96,374	$ 3.0943	$ 298,210
Total	4,342,470	697,500	186,000	5,225,970	$ 3.7882	$16,450,145	$ 2,642,270	$ 704,605	$19,797,020	854,555	$ 3.0943	$ 2,644,250

Month/ Year	NNG Storage Volume	NNG Indexes Price	NNG Indexes Cost	AECO Storage Volume	Emerson LDS + Basis	Emerson LDS + Cost
Nov-13	547,884	$ 3.8520	$ 2,110,449	85,304	$ 3.8970	$ 332,430
Dec-13	1,376,734	$ 3.9470	$ 5,433,969	231,769	$ 4.0020	$ 927,540
Jan-14	1,376,734	$ 3.9935	$ 5,497,987	231,769	$ 4.0110	$ 929,625
Feb-14	1,376,734	$ 4.0035	$ 5,511,755	209,339	$ 4.0060	$ 838,612
Mar-14	547,884	$ 3.8940	$ 2,133,460	96,374	$ 3.9815	$ 383,713
Total	5,225,970	$ 3.9586	$20,687,620	854,555	$ 3.9926	$ 3,411,920

Max NNG Storage (Storage plan withdrawals through Apr 14)	5,225,970	5,669,321	10/31/13 Storage Balance - NNG - Est.	5,669,321	100.00%	5,225,970
Max AECO Storage	854,555	947,820	10/31/13 Storage Balance - AECO - Est.	947,820	100.00%	854,555
						100.00%

Month/ Year	K#118657 NNG Storage	Storage K#125344 LS Power	Storage K#125345 LS Power	Total NNG Storage	Projected K#118657 NNG WACOG	Projected K#125344 NNG WACOG	K#118657 K#125345 NNG WACOG	WACOG NNG PNG Cost	Projected NNG Indexes Price	Projected NNG Index Cost	Additional Storage (Savings)/ Cost
Nov-13	455,259	73,125	19,500	547,884	$ 3.7882	$ 3.7882	$ 3.7882	$ 2,075,494	$ 3.8520	$ 2,110,449	$ (34,955)
Dec-13	1,143,984	183,750	49,000	1,376,734	$ 3.7882	$ 3.7882	$ 3.7882	$ 5,215,344	$ 3.9470	$ 5,433,969	$ (218,625)
Jan-14	1,143,984	183,750	49,000	1,376,734	$ 3.7882	$ 3.7882	$ 3.7882	$ 5,215,344	$ 3.9935	$ 5,497,987	$ (282,643)
Feb-14	1,143,984	183,750	49,000	1,376,734	$ 3.7882	$ 3.7882	$ 3.7882	$ 5,215,344	$ 4.0035	$ 5,511,755	$ (296,411)
Mar-14	455,259	73,125	19,500	547,884	$ 3.7882	$ 3.7882	$ 3.7882	$ 2,075,494	$ 3.8940	$ 2,133,460	$ (57,966)
Total	4,342,470	697,500	186,000	5,225,970	$ 3.7882	$ 3.7882	$ 3.7882	$ 19,797,020	$ 3.9586	$ 20,687,620	$ (890,601)
								$ 3.6991	$ (0.2690)	$ (1,405,835)	

Month/ Year	AECO Storage	AECO Storage Other WACOG	Total AECO Cost	Projected Emerson Index Price	Projected Emerson Index Cost	Additional Storage (Savings)/ Cost
Nov-13	85,304	$ 3.0943	$ 263,956	$ 3.8970	$ 332,430	$ (68,474)
Dec-13	231,769	$ 3.0943	$ 717,163	$ 4.0020	$ 927,540	$ (210,377)
Jan-14	231,769	$ 3.0943	$ 717,163	$ 4.0110	$ 929,625	$ (212,463)
Feb-14	209,339	$ 3.0943	$ 647,758	$ 4.0060	$ 838,612	$ (190,854)
Mar-14	96,374	$ 3.0943	$ 298,210	$ 3.9815	$ 383,713	$ (85,503)
Total	854,555	$ 3.0943	$ 2,644,250	$ 3.9926	$3,411,920	$ (767,670)
			$ 3.2341	$ (0.8488)	$ (725,378)	

Call/Put Options WACOG

Contract = 10,000

Call/Put Options

Deal Number	Purchase Date	%	Nov-13 Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/09/13		13	130,000	$ 4.2500	$ 552,500	$ 3.7070	$ 481,910	$ 3.7070	$ 481,910	$ -	$ 0.3100	$ 40,300	$ 522,210
2	06/13/13		14	140,000	$ 4.0000	$ 560,000	$ 3.7070	$ 518,980	$ 3.7070	$ 518,980	$ -	$ 0.2450	$ 34,300	$ 553,280
3	07/11/13		14	140,000	$ 3.7500	$ 525,000	$ 3.7070	$ 518,980	$ 3.7070	$ 518,980	$ -	$ 0.2150	$ 30,100	$ 549,080
4	08/08/13		14	140,000	$ 3.5000	$ 490,000	$ 3.5000	$ 490,000	$ 3.7070	$ 518,980	$ (28,980)	$ 0.1660	$ 23,240	$ 513,240
5	09/18/13		14	140,000	$ 4.0000	$ 560,000	$ 3.7070	$ 518,980	$ 3.7070	$ 518,980	$ -	$ 0.0670	$ 9,380	$ 528,360
6	10/10/13		14	140,000	$ 3.7500	$ 525,000	$ 3.7070	$ 518,980	$ 3.7070	$ 518,980	$ -	$ 0.0960	$ 13,440	$ 532,420
7				-		$ -	$ -	$ -	$ 3.7070	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.7070	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.7070	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.7070	$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -	$ 3.7070	$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -	$ 3.7070	$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -	$ 3.7070	$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -	$ 3.7070	$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -	$ 3.7070	$ -	$ -		$ -	$ -
Total			83	830,000		$ 3,212,500		$ 3,047,830		$ 3,076,810	$ (28,980)		$ 150,760	$ 3,198,590
						$ 3.8705		$ 3.6721		$ 3.7070	$ (0.0349)		$ 0.0469	$ 3.8537
NNG-Cons	66	79.52%	66	660,000	$ 3.8705	$ 2,554,518	$ 3.6721	$ 2,423,576	$ 3.6613	$ 2,446,620	$ (23,044)	$ 0.1816	$ 119,881	$ 2,543,457
Other-Cons	17	20.48%	17	170,000	$ 3.8705	$ 657,982	$ 3.6721	$ 624,254	$ 3.8902	$ 630,190	$ (5,936)	$ 0.1816	$ 30,879	$ 655,133
Total	83	100.0%	83	830,000	$ 3.8705	$ 3,212,500	$ 3.6721	$ 3,047,830	$ 3.7060	$ 3,076,810	$ (28,980)	$ 0.1816	$ 150,760	$ 3,198,590

Deal Number	Purchase Date	%	Feb-14 Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/21/13		23	230,000	$ 4.7500	$ 1,092,500	$ 3.8910	$ 894,930	$ 3.8910	$ 894,930	$ -	$ 0.3850	$ 88,550	$ 983,480
2	06/20/13		23	230,000	$ 4.2500	$ 977,500	$ 3.8910	$ 894,930	$ 3.8910	$ 894,930	$ -	$ 0.3520	$ 80,960	$ 975,890
3	07/22/13		23	230,000	$ 4.0000	$ 920,000	$ 3.8910	$ 894,930	$ 3.8910	$ 894,930	$ -	$ 0.3280	$ 75,440	$ 970,370
4	08/22/13		11	110,000	$ 4.0000	$ 440,000	$ 3.8910	$ 428,010	$ 3.8910	$ 428,010	$ -	$ 0.2800	$ 30,800	$ 458,810
5	08/22/13		12	120,000	$ 4.0000	$ 480,000	$ 3.8910	$ 466,920	$ 3.8910	$ 466,920	$ -	$ 0.2840	$ 34,080	$ 501,000
6	09/24/13		23	230,000	$ 4.0000	$ 920,000	$ 3.8910	$ 894,930	$ 3.8910	$ 894,930	$ -	$ 0.2050	$ 47,150	$ 942,080
7	10/18/13		25	250,000	$ 4.0000	$ 1,000,000	$ 3.8910	$ 972,750	$ 3.8910	$ 972,750	$ -	$ 0.2600	$ 65,000	$ 1,037,750
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total			140	1,400,000		$ 5,830,000		$ 5,447,400		$ 5,447,400	$ -		$ 421,980	$ 5,869,380
						$ 4.1643		$ 3.8910		$ 3.8910	$ -		$ 0.0724	$ 4.1924
NNG-Cons	115	82.14%	115	1,150,000	$ 4.1643	$ 4,788,929	$ 3.8910	$ 4,474,650	$ 3.6613	$ 4,474,650	$ -	$ 0.3014	$ 346,626	$ 4,821,276
Other-Cons	25	17.86%	25	250,000	$ 4.1643	$ 1,041,071	$ 3.8910	$ 972,750	$ 3.8902	$ 972,750	$ -	$ 0.3014	$ 75,354	$ 1,048,104
Total	140	100.0%	140	1,400,000	$ 4.1643	$ 5,830,000	$ 3.8910	$ 5,447,400	$ 3.7060	$ 5,447,400	$ -	$ 0.3014	$ 421,980	$ 5,869,380

MINNESOTA ENERGY RESOURCES - NNG

Projected Call Option Costs - November 2013 through March 2014

Dec-13														
Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/30/13		20	200,000	$ 4.5000	$ 900,000	$ 3.8120	$ 762,400	$ 3.8120	$ 762,400	$ -	$ 0.2500	$ 50,000	$ 812,400
2	06/26/13		20	200,000	$ 4.0000	$ 800,000	$ 3.8120	$ 762,400	$ 3.8120	$ 762,400	$ -	$ 0.2830	$ 56,600	$ 819,000
3	07/26/13		20	200,000	$ 4.0000	$ 800,000	$ 3.8120	$ 762,400	$ 3.8120	$ 762,400	$ -	$ 0.1870	$ 37,400	$ 799,800
4	08/28/13		21	210,000	$ 4.0000	$ 840,000	$ 3.8120	$ 800,520	$ 3.8120	$ 800,520	$ -	$ 0.1570	$ 32,970	$ 833,490
5	09/26/13		21	210,000	$ 3.7500	$ 787,500	$ 3.7500	$ 787,500	$ 3.8120	$ 800,520	$ (13,020)	$ 0.1680	$ 35,280	$ 822,780
6	10/23/13		22	220,000	$ 3.7500	$ 825,000	$ 3.7500	$ 825,000	$ 3.8120	$ 838,640	$ (13,640)	$ 0.1320	$ 29,040	$ 854,040
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total			124	1,240,000		$ 4,952,500		$ 4,700,220		$ 4,726,880	$ (26,660)		$ 241,290	$ 4,941,510
						$ 3.9940		$ 3.7905		$ 3.8120	$ (0.0215)		$ 0.0487	$ 3.9851
NNG-Cons	99	79.84%	99	990,000	$ 3.9940	$ 3,954,012	$ 3.7905	$ 3,752,595	$ 3.8120	$ 3,773,880	$ (21,285)	$ 0.1946	$ 192,643	$ 3,945,238
Other-Cons	25	20.16%	25	250,000	$ 3.9940	$ 998,488	$ 3.7905	$ 947,625	$ 3.8120	$ 953,000	$ (5,375)	$ 0.1946	$ 48,647	$ 996,272
Total	124	100.0%	124	1,240,000	$ 3.9940	$ 4,952,500	$ 3.7905	$ 4,700,220	$ 3.7060	$ 4,726,880	$ (26,660)	$ 0.1946	$ 241,290	$ 4,941,510

Mar-14														
Deal Number	Purchase Date	%	Number Contracts	Financial Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/02/13		18	180,000	$ 4.5000	$ 810,000	$ 3.8690	$ 696,420	$ 3.8690	$ 696,420	$ -	$ 0.4000	$ 72,000	$ 768,420
2	06/06/13		18	180,000	$ 4.2500	$ 765,000	$ 3.8690	$ 696,420	$ 3.8690	$ 696,420	$ -	$ 0.3230	$ 58,140	$ 754,560
3	07/0313		18	180,000	$ 4.0000	$ 720,000	$ 3.8690	$ 696,420	$ 3.8690	$ 696,420	$ -	$ 0.3500	$ 63,000	$ 759,420
4	08/02/13		19	190,000	$ 3.7500	$ 712,500	$ 3.7500	$ 712,500	$ 3.8690	$ 735,110	$ (22,610)	$ 0.3090	$ 58,710	$ 771,210
5	09/16/13		20	200,000	$ 4.0000	$ 800,000	$ 3.8690	$ 773,800	$ 3.8690	$ 773,800	$ -	$ 0.2900	$ 58,000	$ 831,800
6	10/03/13		20	200,000	$ 4.0000	$ 800,000	$ 3.8690	$ 773,800	$ 3.8690	$ 773,800	$ -	$ 0.1880	$ 37,600	$ 811,400
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total			113	1,130,000		$ 4,607,500		$ 4,349,360		$ 4,371,970	$ (22,610)		$ 347,450	$ 4,696,810
						$ 4.0774		$ 3.8490		$ 3.8690	$ (0.0200)		$ 0.0754	$ 4.1565
NNG-Cons	92	81.42%	92	920,000	$ 4.0774	$ 3,751,239	$ 3.8490	$ 3,541,072	$ 3.6613	$ 3,559,480	$ (18,408)	$ 0.3075	$ 282,880	$ 3,823,952
Other-Cons	21	18.58%	21	210,000	$ 4.0774	$ 856,261	$ 3.8490	$ 808,288	$ 3.8902	$ 812,490	$ (4,202)	$ 0.3075	$ 64,570	$ 872,858
Total	113	100.0%	113	1,130,000	$ 4.0774	$ 4,607,500	$ 3.8490	$ 4,349,360	$ 3.7060	$ 4,371,970	$ (22,610)	$ 0.3075	$ 347,450	$ 4,696,810

Jan-14														
Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/14/13		25	250,000	$ 4.5000	$ 1,125,000	$ 3.8860	$ 971,500	$ 3.8860	$ 971,500	$ -	$ 0.3520	$ 88,000	$ 1,059,500
2	06/18/13		26	260,000	$ 4.2500	$ 1,105,000	$ 3.8860	$ 1,010,360	$ 3.8860	$ 1,010,360	$ -	$ 0.3230	$ 83,980	$ 1,094,340
3	07/16/13		26	260,000	$ 4.0000	$ 1,040,000	$ 3.8860	$ 1,010,360	$ 3.8860	$ 1,010,360	$ -	$ 0.2960	$ 76,960	$ 1,087,320
4	08/15/13		26	260,000	$ 4.0000	$ 1,040,000	$ 3.8860	$ 1,010,360	$ 3.8860	$ 1,010,360	$ -	$ 0.1970	$ 51,220	$ 1,061,580
5	09/20/13		26	260,000	$ 4.2500	$ 1,105,000	$ 3.8860	$ 1,010,360	$ 3.8860	$ 1,010,360	$ -	$ 0.1500	$ 39,000	$ 1,049,360
6	10/14/13		25	250,000	$ 4.0000	$ 1,000,000	$ 3.8860	$ 971,500	$ 3.8860	$ 971,500	$ -	$ 0.2590	$ 64,750	$ 1,036,250
7				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
11				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
12				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
13				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
14				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
15				-		$ -	$ -	$ -		$ -	$ -		$ -	$ -
Total	Total		154	1,540,000		$ 6,415,000		$ 5,984,440		$ 5,984,440	$ -		$ 403,910	$ 6,388,350
						$ 4.1656		$ 3.8860		$ 3.8860	$ -		$ 0.0630	$ 4.1483
NNG-Cons	125	81.17%	125	1,250,000	$ 4.1656	$ 5,206,981	$ 3.8860	$ 4,857,500	$ 3.8860	$ 4,857,500	$ -	$ 0.2623	$ 327,849	$ 5,185,349
Other-Cons	29	18.83%	29	290,000	$ 4.1656	$ 1,208,019	$ 3.8860	$ 1,126,940	$ 3.8860	$ 1,126,940	$ -	$ 0.2623	$ 76,061	$ 1,203,001
Total	154	100.0%	154	1,540,000	$ 4.1656	$ 6,415,000	$ 3.8860	$ 5,984,440	$ 3.7060	$ 5,984,440	$ -	$ 0.2623	$ 403,910	$ 6,388,350

Total														
Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1			99	990,000	$ 4.5253	$ 4,480,000	$ 3.8456	$ 3,807,160	19.165	$ 3,807,160	$ -	$ 0.3423	$ 338,850	$ 4,146,010
2			101	1,010,000	$ 4.1658	$ 4,207,500	$ 3.8446	$ 3,883,090	19.165	$ 3,883,090	$ -	$ 0.3109	$ 313,980	$ 4,197,070
3			101	1,010,000	$ 3.9653	$ 4,005,000	$ 3.8446	$ 3,883,090	19.165	$ 3,883,090	$ -	$ 0.2801	$ 282,900	$ 4,165,990
4			91	910,000	$ 3.8709	$ 3,522,500	$ 3.7817	$ 3,441,390	19.165	$ 3,492,980	$ (51,590)	$ 0.2164	$ 196,940	$ 3,638,330
5			93	930,000	$ 4.0134	$ 3,732,500	$ 3.8253	$ 3,557,560	19.165	$ 3,570,580	$ (13,020)	$ 0.1890	$ 175,740	$ 3,733,300
6			104	1,040,000	$ 3.9135	$ 4,070,000	$ 3.8310	$ 3,984,210	19.165	$ 3,997,850	$ (13,640)	$ 0.1846	$ 191,980	$ 4,176,190
7			25	250,000	$ 4.0000	$ 1,000,000	$ 3.8910	$ 972,750	7.598	$ 972,750	$ -	$ 0.2600	$ 65,000	$ 1,037,750
8														
9														
10														
11														
12														
13														
14														
15														
Total			614	6,140,000		$ 25,017,500		$ 23,529,250		$ 23,607,500	$ (78,250)		$ 1,565,390	$ 25,094,640
						$ 4.0745		$ 3.8321		$ 3.8449	$ (0.0127)		$ 0.0626	$ 4.0871
NNG-Cons	497	80.94%	497	4,970,000	$ 4.0756	$ 20,255,678	$ 3.8329	$ 19,049,393	18.6820482	$ 19,112,130	$ (62,737)	$ 0.2555	$ 1,269,879	$ 20,319,272
Other-Cons	117	19.06%	117	1,170,000	$ 4.0699	$ 4,761,822	$ 3.8289	$ 4,479,857	19.3685512	$ 4,495,370	$ (15,513)	$ 0.2526	$ 295,511	$ 4,775,368
Total	614	100.0%	614	6,140,000	$ 4.0745	$ 25,017,500	$ 3.8321	$ 23,529,250	$ 3.7060	$ 23,607,500	$ (78,250)	$ 0.2549	$ 1,565,390	$ 25,094,640

ATTACHMENT 4

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss
COUNTY OF HENNEPIN)

Kristin M. Stastny hereby certifies that on the 1st day of November, 2013, on behalf of Minnesota Energy Resources Corporation (MERC) she electronically filed a true and correct copy of MERC's Petition for Approval of a Change in Demand Entitlement on www.edockets.state.mn.us. Said documents were also served via U.S. mail and electronic service as designated on the attached service list.

/s/ Kristin M. Stastny
Kristin M. Stastny

Subscribed and sworn to before me
This 1st day of November, 2013.

/s/ Alice Jaworski
Notary Public, State of Minnesota

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	50 S 6th St Ste 1500 Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_13-669_M-13-669
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_13-669_M-13-669
Michael	Bradley	mike.bradley@lawmoss.com	Moss & Barnett	Suite 4800 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_13-669_M-13-669
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_13-669_M-13-669
Daryll	Fuentes	N/A	USG	550 W. Adams Street Chicago, IL 60661	Paper Service	No	OFF_SL_13-669_M-13-669
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Richard	Haubensak	RICHARD.HAUBENSAK@CONSTELLATION.COM	Constellation New Energy Gas	Suite 200 12120 Port Grace Boulevard La Vista, NE 68128	Electronic Service	No	OFF_SL_13-669_M-13-669
Amber	Lee	alee@briggs.com	Briggs and Morgan	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_13-669_M-13-669
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_13-669_M-13-669
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Gregory	Walters	gjwalters@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	3460 Technology Dr. NW Rochester, MN 55901	Electronic Service	No	OFF_SL_13-669_M-13-669