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November 1, 2011

VIA ELECTRONIC FILING

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

Re: In the Matter of the Petition of Minnesota Energy Resources Corporation–NMU for Approval of a Change in Demand Entitlement
Docket No. ___________________

Dear Dr. Haar:

In accordance with Minnesota Rule 7825.2910, subpart 2, please find the public and nonpublic versions of Minnesota Energy Resources Corporation's (MERC) request to change demand entitlement.

Please note that Attachments 5 and 9 contain financial information with independent economic value that is not generally known to, and not readily ascertainable by, competitors of MERC, who could obtain economic value from its disclosure. MERC maintains this information as secret. Accordingly this data qualifies as trade secret data as defined in Minn. Stat. § 13.37, subd. 1(b), and MERC requests that the data be treated as trade secret information.

In accordance with 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 feel free to contact me at (612) 340-2881 if you have any questions regarding this matter.

Sincerely yours,

/s/ Michael J. Ahern

Michael J. Ahern

cc: Service List

November 1, 2011

To: Service List

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

Notice of Availability

Please take notice that Minnesota Energy Resources Corporation-NMU has filed a 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.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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

In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation – NMU	)	
for Approval of a Change in Demand	)	Docket No. _______________
Entitlement	)	

SUMMARY OF FILING

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation-NMU (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-NMU's customers. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2011.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
J. Dennis O'Brien	Commissioner
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In the Matter of the Petition of Minnesota Energy Resources Corporation – NMU for Approval of a Change in Demand Entitlement	))))	Docket No. ______________

FILING UPON CHANGE IN DEMAND

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation-NMU (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-NMU's customers. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2011.

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 – Residential 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, 2011
Proposed Effective Date: November 1, 2011

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, 2011

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

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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

In the Matter of the Petition of	)	
Minnesota Energy Resources	)	
Corporation – NMU for Approval of a	)	Docket No. G007/M-10-1166
Change in 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 - NMU (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-NMU's customers. MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) effective on November 1, 2011.

II. DISCUSSION

A. MERC's NMU Design Day Requirements

MERC's 2011-2012 NMU design day requirements increased 327 Mcf (or approximately 0.567 percent) from 57,662 Mcf to 57,989 Mcf.

Table 1: MERC's Proposed Reserve Margins
For the 2010-2011 Heating Season
NMU (NNG, GLGT, VGT & Centra)

	Reserve Margin 2011-2012 Heating Season	Reserve Margin 2010-2011 Heating Season	Change
NNG Zone E-F	7.09%	18.31%	11.22%

As shown in Table 1 and Attachment 3, MERC's proposed system wide reserve margin for NMU for the 2011-2012 heating season is positive.

For the Demand Entitlement filing effective November 1, 2011, the total Design Day requirement for Northern Natural Gas (NNG), which includes PNG and NMU is 234,960 Dth as calculated in Attachment 5 and Attachment 7 under the NNG-PNG Entitlement Allocation.

For the Demand Entitlement filing effective November 1, 2011, the total Design Day capacity on Northern Natural Gas (NNG), which includes PNG and NMU is 245,985 Dth as calculated in Attachment 5 and Attachment 7 under the NNG-PNG Entitlement Allocation.

The difference between the total Design Day requirement and total Design Day capacity results in a 4.81% positive reserve margin.

On NNG, Demand Entitlement decreased primarily due to the elimination of the LSP Peaking Service (3,149 Dth). NNG, Bison and NBPL capacity is allocated between PNG and NMU based on a prorated share based on design day numbers. PNG prorated percentage of NNG capacity is approximately 89.88% and NMU's prorated percentage is approximately 10.12%. Due to the proration, there was a decrease of 1,615 Dth in PNG-NNG winter capacity, 351 Dth decrease in PNG-NNG Bison and NBPL capacity.

For the Demand Entitlement filing effective November 1, 2011, the total Design Day requirement for NMU-Centra is 8,295 Mcf as calculated in Attachment 1, page 2 of 3.

For the Demand Entitlement filing effective November 1, 2011, the total Design Day capacity for NMU-Centra is 9,858 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 18.84% positive reserve margin.

For the Demand Entitlement filing effective November 1, 2011, the total Design Day requirement for NMU-GLGT is 14,870 Dth as calculated in Attachment 1, page 2 of 3.

For the Demand Entitlement filing effective November 1, 2011, the total Design Day capacity for NMU-GLGT is 16,219 Mcf as calculated in Attachment 4, age 2 of 6.[1] The capacity is allocated between PNG and NMU on a prorated share based on design day numbers.

The difference between the total Design Day requirement and total Design Day capacity results in a 9.07% positive reserve margin.

For the Demand Entitlement filing effective November 1, 2011, the total Design Day requirement for NMU-VGT is 11,046 Dth as calculated in Attachment 1, page 2 of 3.

[1] MERC initially filed its Demand Entitlement filing on November 1, 2010 but subsequently discovered an error in the total filed Design Day capacity for NMU-GLGT. The original filing indicated there was 20,046 Mcf allocated to NMU-GLGT but the correct number is 16,446 Mcf as calculated in the revised Attachment 4, page 2 of 6.

For the Demand Entitlement filing effective November 1, 2010, the total Design Day capacity for NMU-VGT is 11,475 Mcf as calculated in Attachment 4, page 2 of 6. The capacity is allocated between PNG and NMU on a prorated share based on design day numbers.

The difference between the total Design Day requirement and total Design Day capacity results in a 3.88% positive reserve margin.

B. Forecast Methodology for MERC Demand Entitlement Nov. 1, 2010

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 (company – approximately 170,000 customers)
2. NMU - Northern Minn Utility (company – approximately 40,000 customers)

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)

Four Petitions for Change in Demand are filed (one for each PGA):

A. PNG customers served off of VGT = PNG-VGT

B. PNG customers served off of GLGT = PNG-GLGT

C. PNG customers served off of NNG = PNG-NNG

D. All NMU customers - served off NNG, GLGT, VGT & Centra = NMU

Weather data is obtained from the following weather stations:

1. International Falls
2. Bemidji
3. Cloquet
4. Fargo
5. Minneapolis
6. Rochester
7. Worthington
8. 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 as shown in Attachment 13

2. Obtain daily total throughput volumes by pipeline

3. Perform total throughput peak day regressions

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 MERC 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 (AHDD65) 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	2/2/1996	-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 an 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, resulting 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

[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.

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. Summarize the Baseload and Use/AHDD65 from each regression.
6. 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).

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, resulting 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

[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.

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:

The MERC-PNG and MERC-NMU tariff General Rules, Regulations, Terms, and Conditions Section 1.N "Maximum Daily Quantity (MDQ)" on 1st Revised 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 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 the 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.

Demand Area / (Service Area / Pipeline) Regression Notes

A. Interruptible, Transportation and Joint Interruptible

NMU-GLGT = Paper Mills

NMU-VGT = Lamb Weston

PNG-NNG = Taconites / Direct Connects

PNG-NNG = OSEU (End Users)

B. Daily Firm Capacity

PNG-VGT

PNG-GLGT

PNG-NNG

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, pages 1 through 4. 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 6,414 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 6,414 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 NMU 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 NMU 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

As shown in Attachment 3, MERC-NMU proposes to decrease its approved NNG total heating season entitlement by 3,499 Mcf/day (or approximately 12.48 percent). To obtain the proposed entitlement level, the Company proposes changes to its portfolio of capacity services identified below in Table 4.

Demand Entitlement decreased primarily due to the elimination of the LSP Peaking Service (3,149 Dth). NNG, Bison and NBPL capacity is allocated between PNG and NMU based on a prorated share based on design day numbers. PNG prorated percentage of NNG capacity is approximately 89.88% and NMU's prorated percentage is approximately 10.12%. Due to the proration, there was an decrease of 1,615 Dth in NMU-NNG winter capacity and a 351 Dth decrease in NMU Bison and NBPL capacity. As stated previously, MERC terminated the LSP Peaking Service provision with LS Power. In lieu of the call option, MERC replaced that peaking capability with a physical delivered Gas Daily Daily call option (1,265 Dth).

MERC reduced the amount of capacity on GLGT due to the timing of contract expiration. Capacity on GLGT was allocated between NMU and PNG-GLGT based on prorated share calculated by design day numbers. Due to the reduction in capacity and allocation factor, GLGT capacity on NMU was decreased by 227 volumes.

MERC purchased firm winter only (November 2011 through March 2012) from VGT, which replaced the Wadena Call Option from the previous year. Capacity on VGT was allocated between NMU and PNG-VGT based on prorated share calculated by design day numbers. Due to the acquiring firm capacity and allocation factor change, VGT capacity on NMU was decreased by 2,393 volumes.

There was no change in Centra firm entitlement.

Table 4

Capacity Entitlement	Propose Change Increase / (Decrease)	
NNG TF12B & TF12V	(529)	Mcf/Day
NNG TF5	(226)	Mcf/Day
NNG TFX12	(227)	Mcf/Day
NNG TFX5	(633)	Mcf/Day
LS Power	(3,149)	Mcf/Day
Bison *	(351)	Mcf/Day
NBPL *	(351)	Mcf/Day
NNG Zone GDD Call Option	1,265	Mcf/Day
NNG Subtotal	(3,499)	Mcf/Day
GLGT FT0016	(3,899)	Mcf/Day
GLGT FT0155 (12)	1,036	Mcf/Day
GLGT FT0155 (5)	100	Mcf/Day
GLGT FT8466	(3,000)	Mcf/Day
GLGT FT15782	5,536	Mcf/Day
VGT AF0012	(255)	Mcf/Day
VGT AF0014	678	Mcf/Day
VGT AF0102	1,234	Mcf/Day
VGT AF0183	1,852	Mcf/Day
Wadena Delivered Option	(5,902)	Mcf/Day
Centra FT	0	Mcf/Day
Total Overall Change	(6,119)	Mcf/Day

* Numbers are not part of peak day deliverability

2. Other Demand Entitlement Changes

As shown in Attachment 6, MERC-NMU proposes a decrease in TFX Apr and TFX Oct and an increase of Firm Deferred Delivery (storage) in other pipeline entitlements that are not included in peak day deliverability. MERC has AECO Storage, to deliver the supply from storage to MERC-NMU's markets, MERC entered in 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 PNG-GLGT, PNG-VGT and NMU (GLGT, VGT and Centra) customers. The swap substituted the need to contract for firm transport on TransCanada Pipeline (TCPL) to transport the gas from AECO to Emerson/Spruce. The cost of TCPL would have been approximately $927,919 compared to the $417,042 to swap the gas.

D. <u>Financial Option Units and Premiums</u>

i. MERC entered into New York Mercantile Exchange (NYMEX) financial Call Options for the upcoming 2011/2012 winter (November through March). Please see Attachment 5.

ii. Total premium cost to enter into the financial Call Options on behalf of MERC's firm customers amounted to $375,288 for the 2011/2012 winter. Please see Attachment 5.

iii. MERC entered into 146 contracts (10,000/contract) or 1,460,000. Total premium per contract is approximately $0.2570. 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 entered into 89 futures contracts (10,000/contract) or 890,000,

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-cost-averaging 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 4.

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

The NMU 2011-2012 Winter Portfolio Plans - Minnesota Energy Resources Corporation for NNG, GLGT, VGT and Centra gas supply purchases for the Hedging Plans is in Attachment 10 pages 5 and 6. This Attachment includes the projected sales number by month for the November 2011 through March 2012 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 $4.5375. Please see Attachment 13, page 1 of 3. MERC is projecting the storage WACOG on NNG Storage and AECO Storage to be approximately $3.86. This is an estimate based upon the purchases in October but since this filing is being made before the accounting is closed for October, this estimate may change. 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 $4.6295, 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 $4.32 for 70% of normal winter volumes assuming that the NYMEX prices are above the average $4.6295 strike price plus the physical index basis spread. If the NYMEX prices are below the average $4.6295 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. PGA Cost Recovery

MERC proposes to begin recovering the costs associated with the change in demand-related costs in it monthly PGA effective November 1, 2011. 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. Impacts of Telemetry

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 PNG-NMU, there have been twenty-seven (27) customers that switched from interruptible to firm service. The switching occurred between February 16, 2011 through August 12, 2011. 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 484 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, 2011. If any further information, clarification, or substantiation is required to support this filing please advise.

DATED: November 1, 2011

Respectfully Submitted,

DORSEY & WHITNEY LLP

By /s/ Michael J. Ahern
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Attorney for Minnesota Energy Resources Corporation

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss
COUNTY OF HENNEPIN)

Amber S. Lee hereby certifies that on the 1st day of November, 2011, on behalf of Minnesota Energy Resources Corporation (MERC) she electronically filed a true and correct copy of the Petition 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/ Amber S. Lee
Amber S. Lee

Subscribed and sworn to before me
this 1st day of November, 2011.

/s/ Sara Garcia
Notary Public, State of Minnesota

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

MERC-NMU

Demand Entitlement Schedules

MINNESOTA ENERGY RESOURCES - NMU

DESIGN-DAY DEMAND SUMMARY

NOVEMBER 1, 2011

Design Day Requirement		57,989
Total Peak Day Entitlement		62,100
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 20)	43,649
Firm Annual Throughput - Minnesota		6,426,736
No. of Firm Customers		40,470
Department Load Factor Calculation		40.34%

MINNESOTA ENERGY RESOURCES - NMU

MINNESOTA DESIGN DAY REQUIREMENTS
NOVEMBER 1, 2011
HDD

Pipeline Group	2010/01 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
NNG										
Peak	17,799	103	3,244	226		26,534	2,732	23,802	-0.1%	23,778
Off Peak	17,799	55	3,244	226		15,680	2,892	12,788	-0.1%	14,151
VGT										
VGT	5,683	109	1,701	67		8,956	1,109	7,847	-0.1%	7,839
**VGT/GLGT	3,152	107	550	46	68.0%	3,745	535	3,210	-0.1%	3,207
Peak	8,835		2,251	113				11,057		11,046
VGT	5,683	57	1,701	67		5,513	401	5,112	-0.1%	5,107
VGT/GLGT	3,152	57	550	46	68.0%	2,170	249	1,921	-0.1%	1,919
Off Peak	8,835		2,251	113				7,033		7,026
GLGT										
**VGT/GLGT	3,152	107	550	46	32.0%	1,763	252	1,511	-0.1%	1,509
GLGT	8,202	105	2,061	118		14,521	1,146	13,375	-0.1%	13,361
Peak	11,354		2,611	164				14,886		14,870
VGT/GLGT	3,152	57	550	46	32.0%	1,021	117	904	-0.1%	903
GLGT	8,202	57	2,061	118		10,681	2,145	8,536	-0.1%	8,196
Off Peak	11,354		2,611	164				9,440		9,099
Centra										
Peak	5,634	107	1,704	80		10,221	1,918	8,303	-0.1%	8,295
Off Peak	5,634	57	1,704	80		6,241	880	5,361	-0.1%	5,356
Total NMU										
Peak	40,470		9,260	537		65,740	7,692	58,048	-4.0%	57,989
Off Peak	40,470		9,260	537		41,306	6,684	34,622	-4.0%	35,632

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 m inus Regression Adjustment.

**Dual Supplied

MINNESOTA ENERGY RESOURCES - NMU

DESIGN-DAY DEMAND PER CUSTOMER
NOVEMBER 1, 2011

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
11/12	40,470	57,989	1.43
10/11	40,400	57,662	1.43
09/10	41,135	60,918	1.48
08/09	39,112	63,726	1.63
07/08	38,258	61,008	1.59
06/07	38,483	61,060	1.59
05/06	38,208	62,107	1.63

Attachment 2

MINNESOTA ENERGY RESOURCES - NMU

SUMMER/WINTER USAGE - Mcf
PROJECTED 12 MONTHS ENDING JUNE 2012

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	1,315,856	3,977,001	5,292,857
IS	394,509	739,370	1,133,879
Total	1,710,365	4,716,371	6,426,736

MINNESOTA ENERGY RESOURCES - NMU

ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2011

Type of Capacity or Entitlement		Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
NNG TF 12 Base & Variable		8,151	(529)	7,622
NNG TF 5		3,493	(226)	3,267
NNG TFX 12		3,495	(227)	3,268
NNG TFX 5		9,759	(633)	9,126
LS Power		3,149	(3,149)	0
Bison *		5,411	(351)	5,060
NBPL *		5,411	(351)	5,060
NNG Zone GDD Call Option		0	1,265	1,265
NNG Offpeak TFX*		0	0	0
NNG Subtotal		28,047	(3,499)	24,548
FT Western Zone	FT0016	10,130	(3,899)	6,231
FT Western Zone (12)	FT0155	1,178	1,036	2,214
FT Western Zone (5)	FT0155	2,138	100	2,238
FT Western Zone (5)	FT8466	3,000	(3,000)	0
FT Western Zone	FT15782	0	5,536	5,536
FT-A ZONE 1 - 1	AF0012	7,966	(255)	7,711
FT-A ZONE 1 - 1	AF0014	0	678	678
FT-A ZONE 1 - 1	AF0102	0	1,234	1,234
FT-A ZONE 1 - 1	AF0183		1,852	1,852
Wadena Delivered Option	0	5,902	(5,902)	0
CENTRA FT-1		9,858	0	9,858
Total Entitlement		68,219	(6,119)	62,100
Forecasted Design Day-Adjusted		57,662	327	57,989
Capacity Surplus/Shortage		10,557	(6,446)	4,111
Reserve Margin		18.31%		7.09%

* Bison/NBPL does not add incremental capacity but is utilized to deliver Rockies supply

MINNESOTA ENERGY RESOURCES - NMU

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
NOVEMBER 1, 2011

All costs in $/MMBtu	Last Base Cost of Gas G007,G011/ MR10-978* Feb. 11	Demand Change G011- M-09-XXXX Oct 09	Last Demand Change G011- M-10-XXXX Oct. 10	Most Recent PGA** Oct. 2011	Current Proposal Effective Nov.1,2011	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**	**Mcf**				
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.1061	-27.23%	-41.60%	6.80%	$0.2613
Demand Cost	$1.3841	$1.0930	$1.0218	$1.2332	$1.2268	-11.36%	-14.39%	-0.52%	($0.0064)
Commodity Margin	$2.1759	$2.3126	$2.1759	$2.1759	$2.1759	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$9.2022	$7.0984	$7.0308	$7.2539	$7.5088	-18.40%	-23.86%	3.51%	$0.2549
Avg Annual Cost	$828.20	$638.86	$632.77	$652.85	$675.80	-18.40%	-23.86%	3.51%	$22.95
Effect of proposed commodity change on average annual bills:									$23.52
Effect of proposed demand change on average annual bills:									($0.57)
2) Large General Service: Avg. Annual Use:				**4,932**	**Mcf**				
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.1061	-27.23%	11.19%	6.80%	$0.2613
Demand Cost	$1.3841	$1.0930	$1.0218	$1.2332	$1.2268	-11.36%	12.25%	-0.52%	($0.0064)
Commodity Margin	$1.9660	$2.3126	$0.1966	$1.9660	$1.9660	0.00%	-14.99%	0.00%	$0.0000
Total Cost of Gas	$8.9923	$7.0984	$5.0515	$7.0440	$7.2989	-18.83%	2.83%	3.62%	$0.2549
Avg Annual Cost	$44,350.02	$35,009.31	$24,914.00	$34,741.01	$35,998.40	-18.83%	2.83%	3.62%	$1,257.39
Effect of proposed commodity change on average annual bills:									$1,288.73
Effect of proposed demand change on average annual bills:									($31.34)
3) SV Interruptible Service: Avg. Annual Use:				**6,068**	**Mcf**				
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.1061	-27.23%	11.19%	6.80%	$0.2613
Commodity Margin	$0.9560	$1.0127	$0.9560	$0.9560	$0.9560	0.00%	-5.60%	0.00%	$0.0000
Total Cost of Gas	$6.5982	$4.7055	$4.7891	$4.8008	$5.0621	-23.28%	7.58%	5.44%	$0.2613
Avg Annual Cost	$40,037.88	$28,552.97	$29,060.26	$29,131.25	$30,716.82	-23.28%	7.58%	5.44%	$1,585.57
Effect of proposed commodity change on average annual bills:									$1,585.57
4) LV Interruptible Service: Avg. Annual Use:				**40,821**	**Mcf**				
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.1061	-27.23%	11.19%	6.80%	$0.2613
Commodity Margin	$0.2846	$0.3395	$0.2846	$0.2846	$0.2846	0.00%	-16.17%	0.00%	$0.0000
Total Cost of Gas	$5.9268	$4.0323	$4.1177	$4.1294	$4.3907	-25.92%	8.89%	6.33%	$0.2613
Avg Annual Cost	$241,937.90	$164,602.52	$168,088.63	$168,566.24	$179,232.76	-25.92%	8.89%	6.33%	$10,666.53
Effect of proposed commodity change on average annual bills:									$10,666.53

Note: Average Annual Average based on PNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-11-793
*As submitted in Docket No. G007,011/MR-10-978; to coincide with implementation of interim rates in Docket No. G007,011/MR-10-977
**$/Mcf rates do not include refunds/charges issued via October 2011 PGA per Docket Nos. G-007,011/M-11-154 & FERC Docket RP11-1781

MINNESOTA ENERGY RESOURCES - NMU

DEMAND									Cost/Ccf
Contract Type			Monthly Entitlement		Rate		Contract	Rate Case Sales	
Northern Natural Gas (NNG)		Season	(Dth)	Months	($/Dth)		Costs	(therms)	
TF12B (Max Rate)	112495	Annual	4,774	12	$7.5776	$	434,106	54,901,770	$0.00791
TF12V (Max Rate)	112495	Annual	2,848	12	$9.0926	$	310,749	54,901,770	$0.00566
TF5 (Max Rate)	112495	Winter	3,267	5	$15.1530	$	247,524	54,901,770	$0.00451
TF12B (Discount-Winter)	112495	Annual	0	12	$6.4816	$	-	54,901,770	$0.00000
TFX5 (Discount)	112561	Winter	607	5	$4.5600	$	13,840	54,901,770	$0.00025
TFX12 (Max Rate)	112486	Annual	1,095	12	$9.6288	$	126,522	54,901,770	$0.00230
TFX Apr (Max Rate)	112486	Summer	202	1	$5.6830	$	1,148	54,901,770	$0.00002
TFX Oct (Max Rate)	112486	Summer	202	1	$5.6830	$	1,148	54,901,770	$0.00002
TFX5 (Max Rate)	112486	Winter	5,806	5	$15.1530	$	439,892	54,901,770	$0.00801
TFX5 (Discount)	112486	Winter	182	5	$7.6000	$	6,916	54,901,770	$0.00013
TFX12 (Discount)	111866	Annual	130	12	$4.8640	$	7,588	54,901,770	$0.00014
TFX12 (Discount)	111866	Annual	837	12	$5.4720	$	54,961	54,901,770	$0.00100
TFX12 (Discount)	111866	Annual	1,206	12	$2.2192	$	32,116	54,901,770	$0.00058
TFX5 (Discount)	111866	Winter	38	5	$4.8640	$	924	54,901,770	$0.00002
TFX5 (Discount)	111866	Winter	247	5	$5.4720	$	6,758	54,901,770	$0.00012
TFX5 (Discount)	111866	Winter	2,246	5	$15.1392	$	170,013	54,901,770	$0.00310
Bison	FT0003	Annual	5,060	12.0	$17.4800	$	1,061,386	54,901,770	$0.01933
NBPL	T8673F	Annual	5,060	12.0	$6.9920	$	424,554	54,901,770	$0.00773
LS Power		Winter	0	0	$4.3463	$	-	54,901,770	$0.00000
Windom		Annual	0	12	$0.0000	$	-	54,901,770	$0.00000
Ortonville		Annual	0	12	$8.0000	$	-	54,901,770	$0.00000
NNG Zone GDD Call Option		Winter	1,265	3	$0.9100	$	3,453	54,901,770	$0.00006
SMS	112521	Annual	2,295	12	$2.1800	$	60,037	54,901,770	$0.00109
FDD - Reservation	118657	Annual	7,634	12	$1.7140	$	157,016	54,901,770	$0.00286
FDD - Storage Cycle	118657	Annual	88,030	5	$0.3567	$	157,002	54,901,770	$0.00286
FDD - Reservation	118657	Annual	562	12	$3.3157	$	22,361	54,901,770	$0.00041
FDD - Storage Cycle	118657	Annual	6,477	5	$0.6901	$	22,349	54,901,770	$0.00041
FDD - Reservation	122800	Annual	702	12	$1.7140	$	14,439	54,901,770	$0.00026
FDD - Storage Cycle	122800	Annual	8,096	5	$0.3567	$	14,439	54,901,770	$0.00026
NNG Demand						$	3,791,241	54,901,770	$0.06905
Viking (VGT)									
FT-A ZONE 1 - 1	AF0012	Annual	7,711	12	$3.4671	$	320,818	54,901,770	$0.00584
FT-A ZONE 1 - 1	AF0014	Winter	678	3	$3.4671	$	7,052	54,901,770	$0.00013
FT-A ZONE 1 - 1	AF0102	Annual	1,234	12	$3.4671	$	51,341	54,901,770	$0.00094
FT-A ZONE 1 - 1	AF0183	Winter	1,852	5	$3.7671	$	34,883	54,901,770	$0.00064
Wadena Delivered Option		Winter	0	0	$0.0000	$	-	54,901,770	$0.00000
Balancing Agreement	ML0021	Annual	4,607	12	$1.0000	$	55,284	54,901,770	$0.00101
VGT Demand						$	469,378	54,901,770	$0.00855
Great Lakes (GLGT)									
FT Western Zone	FT0016	Annual	6,231	12	$3.4580	$	258,562	54,901,770	$0.00471
FT Western Zone (12)	FT0155	Annual	2,214	12	$3.4580	$	91,872	54,901,770	$0.00167
FT Western Zone (5)	FT0155	Winter	2,238	5	$3.4580	$	38,695	54,901,770	$0.00070
FT Western Zone	FT15782	Annual	5,536	12	$3.4580	$	229,722	54,901,770	$0.00418
GLGT Demand						$	618,851	54,901,770	$0.01127
Centra									
CENTRA TRANSMISSION	($Cdn/103M3)				$197.7090				
Conversion ((($Cdm103M3)*279.256)/9858)		Annual	9,858	12	$5.6007	$	662,537	54,901,770	$0.01207
Union Balancing		Annual	4,500	12	$1.0000	$	54,000	54,901,770	$0.00098
CENTRA MINNESOTA PIPELINES		Annual	9,858	12	$1.7780	$	210,330	54,901,770	$0.00383
Centra Demand						$	926,867	54,901,770	$0.01689
AECO									
Niska Storage (AECO)		Annual	666,223	1	$0.9548	$	636,125	54,901,770	$0.01159
AECO/Emerson Swap		Annual	666,225	1	$0.4400	$	293,139	54,901,770	$0.00534
AECO Demand						$	929,264	54,901,770	$0.01693
NMU DEMAND - $/Ccf						$	6,735,601		$0.12269

For Joint Rate Demand — 54,901,770 Annual Firm Sales in therms

	Units Dth's	Months	Annual Dth's
Northern Natural Gas (NNG)			
TF12B (Max Rate)	4,774	12	57,288
TF12V (Max Rate)	2,848	12	34,176
TF5 (Max Rate)	3,267	5	16,335
TF12B (Discount-Winter)	0	12	-
TFX5 (Discount)	607	5	3,035
TFX12 (Max Rate)	1,095	12	13,140
TFX Apr (Max Rate)	202	1	202
TFX Oct (Max Rate)	202	1	202
TFX5 (Max Rate)	5,806	5	29,030
TFX5 (Discount)	182	5	910
TFX12 (Discount)	130	12	1,560
TFX12 (Discount)	837	12	10,044
TFX12 (Discount)	1,206	12	14,472
TFX5 (Discount)	38	5	190
TFX5 (Discount)	247	5	1,235
TFX5 (Discount)	2,246	5	11,230
Bison	5,060	12	60,720
NBPL	5,060	12	60,720
LS Power	0	0	-
Windom	0	12	-
Ortonville	0	12	-
NNG Zone GDD Call Option	1,265	3	3,795
SMS	2,295	12	27,540
Viking (VGT)			
FT-A ZONE 1 - 1	7,711	12	92,532
FT-A ZONE 1 - 1	678	3	2,034
FT-A ZONE 1 - 1	1,234	12	14,808
FT-A ZONE 1 - 1	1,852	5	9,260
Wadena Delivered Option	0	0	-
Balancing Agreement	4,607	12	55,284
Great Lakes (GLGT)			
FT Western Zone	6,231	12	74,772
FT Western Zone (12)	2,214	12	26,568
FT Western Zone (5)	2,238	5	11,190
FT Western Zone	5,536	12	66,432
Centra			
CENTRA TRANSMISSION			
Conversion ((($Cdm103M3)*279.256)/9858)	9,858	12	118,296
Union Balancing	4,500	12	54,000
CENTRA MINNESOTA PIPELINES	9,858	12	118,296

Total Demand Cost	$	6,735,601	
Total Demand Weighted Vol in Mcf		7,341,760	
Total Joint Demand Rate $/Mcf			$0.91744

MINNESOTA ENERGY RESOURCES - NMU

NOVEMBER 1, 2010

PRESENT AVERAGE COST OF GAS — EFFECTIVE: 01-Nov-11

COMMODITY

WACOG	Rate	Annual Dth	Call Option Premium	Total Annual Cost	Cost/therm
NNG					
GAS COST	$4.12410				
FUEL 1.32%	$0.05517				
COMMODITY TRANSPORTATION	$0.03630				
ACA	$0.00180				
GRI FEE	$0.00000				
NNG Commodity	$4.21737	2,512,662	$18,149	$10,614,976	$0.15836
VGT					
GAS COST	$3.97780				
FUEL 1.66%	$0.06715				
COMMODITY TRANSPORTATION	$0.01300				
GRI	$0.00000				
ACA	$0.00180				
VGT Commodity	$4.05975	1,827,195	$8,066	$7,426,022	$0.11079
GLGT					
GAS COST	$3.97780				
FUEL 0.423%	$0.01691				
COMMODITY TRANSPORTATION	$0.00326				
GRI	$0.00000				
ACA	$0.00180				
GLGT Commodity	$3.99977	966,200	$10,083	$3,874,659	$0.05781
CENTRA					
CENTRA TRANSM ($Cdn/103M3)	1.062				
Conversion x0.9306	$0.03024				
GAS COSTS	$0.03024				
FUEL 0.25%	$3.97780				
CUSTOMS FEE	$0.00029				
CENTRA Commodity	$4.00833	1,396,834	$8,066	$5,607,030	$0.08365
NMU Weighted Average gas cost - $/Dth		6,702,891	$44,364	$27,522,687	$0.41061
Total Annual Sales in therms		67,028,910			

MINNESOTA ENERGY RESOURCES - NMU

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

NOVEMBER 1, 2011

All costs in $/MMBtu	Last Base Cost of Gas G007,G011/ MR10-978* Feb. 11	Demand Change G011- M-09-XXXX Oct .09	Last Demand Change G011- M-10-XXXX Oct. 10	Most Recent PGA** Oct. 2011	Current Proposal Effective Nov. 1, 2011	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**	**Mcf**				
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.2588	-24.52%	-37.46%	10.77%	$0.4140
Demand Cost	$1.3841	$1.0930	$1.0218	$1.2332	$0.9870	-28.69%	-36.33%	-19.97%	($0.2462)
Commodity Margin	$2.1759	$2.3126	$2.1759	$2.1759	$2.1759	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$9.2022	$7.0984	$7.0308	$7.2539	$7.4217	-19.35%	-25.08%	2.31%	$0.1678
Avg Annual Cost	$828.20	$638.86	$632.77	$652.85	$667.95	-19.35%	-25.08%	2.31%	$15.10
Effect of proposed commodity change on average annu al bills:									$37.26
Effect of proposed demand change on average annu al bills:									($22.16)
2) Large General Service: Avg. Annual Use:				**4,932**	**Mcf**				
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.2588	-24.52%	15.33%	10.77%	$0.4140
Demand Cost	$1.3841	$1.0930	$1.0218	$1.2332	$0.9870	-28.69%	-9.70%	-19.97%	($0.2462)
Commodity Margin	$1.9660	$2.3126	$0.1966	$1.9660	$1.9660	0.00%	-14.99%	0.00%	$0.0000
Total Cost of Gas	$8.9923	$7.0984	$5.0515	$7.0440	$7.2118	-19.80%	1.60%	2.38%	$0.1678
Avg Annual Cost	$44,350.02	$35,009.31	$24,914.00	$34,741.01	$35,568.64	-19.80%	1.60%	2.38%	$827.63
Effect of proposed commodity change on average annu al bills:									$2,041.95
Effect of proposed demand change on average annu al bills:									($1,214.32)
3) SV Interruptible Service: Avg. Annual Use:				**6,068**	**Mcf**				
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.2588	-24.52%	15.33%	10.77%	$0.4140
Commodity Margin	$0.9560	$1.0127	$0.9560	$0.9560	$0.9560	0.00%	-5.60%	0.00%	$0.0000
Total Cost of Gas	$6.5982	$4.7055	$4.7891	$4.8008	$5.2148	-20.97%	10.82%	8.62%	$0.4140
Avg Annual Cost	$40,037.88	$28,552.97	$29,060.26	$29,131.25	$31,643.54	-20.97%	10.82%	8.62%	$2,512.28
Effect of proposed commodity change on average annu al bills:									$2,512.28
4) LV Interruptible Service: Avg. Annual Use:				**40,821**	**Mcf**				
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.2588	-24.52%	15.33%	10.77%	$0.4140
Commodity Margin	$0.2846	$0.3395	$0.2846	$0.2846	$0.2846	0.00%	-16.17%	0.00%	$0.0000
Total Cost of Gas	$5.9268	$4.0323	$4.1177	$4.1294	$4.5434	-23.34%	12.68%	10.03%	$0.4140
Avg Annual Cost	$241,937.90	$164,602.52	$168,088.63	$168,566.24	$185,467.02	-23.34%	12.68%	10.03%	$16,900.78
Effect of proposed commodity change on average annu al bills:									$16,900.78

Note: Average Annual Average based on PNG Annu al Automatic Adjustment Report in Docket No. E,G999/AA-11-793

*As submitted in Docket No. G007,011/MR-10-978; to colnc ide with implementation of interim rates in Docket No. G007,011/MR-10-977

**$/Mcf rates do not include refunds/charges issued via October 2011 PGA per Docket Nos. G-007,011/M-11-154 & FERC Docket RP11-1781

MINNESOTA ENERGY RESOURCES - NMU

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

DEMAND

Contract Type		Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Rate Case Sales (therms)	Cost/Ccf
Northern Natural Gas (NNG)								
TF12B (Max Rate)	112495	Annual	4,774	12	$7.5776	$ 434,108	54,901,770	$0.00791
TF12V (Max Rate)	112495	Annual	2,848	12	$9.0926	$ 310,749	54,901,770	$0.00566
TF5 (Max Rate)	112495	Winter	3,267	5	$15.1530	$ 247,524	54,901,770	$0.00451
TF12B (Discount-Winter)	112495	Annual	0	12	$6.4818	$ -	54,901,770	$0.00000
TFX5 (Discount)	112561	Winter	607	5	$4.5600	$ 13,840	54,901,770	$0.00025
TFX12 (Max Rate)	112486	Annual	1,095	12	$9.6288	$ 126,522	54,901,770	$0.00230
TFX Apr (Max Rate)	112486	Summer	202	1	$5.6830	$ 1,148	54,901,770	$0.00002
TFX Oct (Max Rate)	112486	Summer	202	1	$5.6830	$ 1,148	54,901,770	$0.00002
TFX5 (Max Rate)	112486	Winter	5,806	5	$15.1530	$ 439,892	54,901,770	$0.00801
TFX5 (Discount)	112486	Winter	182	5	$7.6000	$ 6,916	54,901,770	$0.00013
TFX12 (Discount)	111866	Annual	130	12	$4.8640	$ 7,588	54,901,770	$0.00014
TFX12 (Discount)	111866	Annual	837	12	$5.4720	$ 54,961	54,901,770	$0.00100
TFX12 (Discount)	111866	Annual	1,206	12	$2.2192	$ 32,116	54,901,770	$0.00058
TFX5 (Discount)	111866	Winter	38	5	$4.8640	$ 924	54,901,770	$0.00002
TFX5 (Discount)	111866	Winter	247	5	$5.4720	$ 6,758	54,901,770	$0.00012
TFX5 (Discount)	111866	Winter	2,246	5	$15.1392	$ 170,013	54,901,770	$0.00310
Bison	FT0003	Annual	5,060	12.0	$17.4800	$ 1,061,386	54,901,770	$0.01933
NBPL	T6673F	Annual	5,060	12.0	$6.9920	$ 424,554	54,901,770	$0.00773
LS Power		Winter	0	0	$4.3463	$ -	54,901,770	$0.00000
Windom		Annual	0	12	$0.0000	$ -	54,901,770	$0.00000
Ortonville		Annual	0	12	$8.0000	$ -	54,901,770	$0.00000
NNG Zone GDD Call Option		Winter	1,265	3	$0.9100	$ 3,453	54,901,770	$0.00006
SMS	112521	Annual	2,295	12	$2.1800	$ 60,037	54,901,770	$0.00109
FDD - Reservation	118657	Annual	7,634	0	$1.7140	$ -	54,901,770	$0.00000
FDD - Storage Cycle	118657	Annual	88,030	0	$0.3567	$ -	54,901,770	$0.00000
FDD - Reservation	118657	Annual	662	0	$3.3157	$ -	54,901,770	$0.00000
FDD - Storage Cycle	118657	Annual	6,477	0	$0.6901	$ -	54,901,770	$0.00000
FDD - Reservation	122800	Annual	702	0	$1.7140	$ -	54,901,770	$0.00000
FDD - Storage Cycle	122800	Annual	6,096	0	$0.3567	$ -	54,901,770	$0.00000
NNG Demand						$ 3,403,635	54,901,770	$0.06199
Viking (VGT)								
FT-A ZONE 1 - 1	AF0012	Annual	7,711	12	$3.4671	$ 320,818	54,901,770	$0.00584
FT-A ZONE 1 - 1	AF0014	Winter	678	3	$3.4671	$ 7,052	54,901,770	$0.00013
FT-A ZONE 1 - 1	AF0102	Annual	1,234	12	$3.4671	$ 51,341	54,901,770	$0.00094
FT-A ZONE 1 - 1	AF0183	Annual	1,852	5	$3.7671	$ 34,883	54,901,770	$0.00064
Wadena Delivered Option		Winter	0	0	$0.0000	$ -	54,901,770	$0.00000
Balancing Agreement	ML0021	Winter	4,607	12	$1.0000	$ 55,284	54,901,770	$0.00101
VGT Demand						$ 469,378	54,901,770	$0.00855
Great Lakes (GLGT)								
FT Western Zone	FT0016	Annual	6,231	12	$3.4580	$ 258,562	54,901,770	$0.00471
FT Western Zone (12)	FT0155	Annual	2,214	12	$3.4580	$ 91,872	54,901,770	$0.00167
FT Western Zone (5)	FT0155	Winter	2,238	5	$3.4580	$ 38,695	54,901,770	$0.00070
FT Western Zone	FT15782	Annual	5,536	12	$3.4580	$ 229,722	54,901,770	$0.00418
GLGT Demand						$ 618,851	54,901,770	$0.01127
Centra								
CENTRA TRANSMISSION	($Cdn/103M3)				$197.7090			
Conversion ((($Cdm103M3)*279.256)/9858)		Annual	9,858	12	$5.6007	$ 662,537	54,901,770	$0.01207
Union Balancing		Annual	4,500	12	$1.0000	$ 54,000	54,901,770	$0.00098
CENTRA MINNESOTA PIPELINES		Annual	9,858	12	$1.7780	$ 210,330	54,901,770	$0.00383
Centra Demand						$ 926,867	54,901,770	$0.01688
AECO								
Niska Storage (AECO)		Annual	666,223	1	$0.0000	$ -	54,901,770	$0.00000
AECO/Emerson Swap		Annual	666,225	1	$0.0000	$ -	54,901,770	$0.00000
AECO Demand						$ -	54,901,770	$0.00000
NMU DEMAND - $/Ccf						$ 5,418,731		$0.09870

For Joint Rate Demand — 54,901,770 Annual Firm Sales in therms

	Units Dth's	Months	Annual Dth's
Northern Natural Gas (NNG)			
TF12B (Max Rate)	4,774	12	57,288
TF12V (Max Rate)	2,848	12	34,176
TF5 (Max Rate)	3,267	5	16,335
TF12B (Discount-Winter)	0	12	-
TFX5 (Discount)	607	5	3,035
TFX12 (Max Rate)	1,095	12	13,140
TFX Apr (Max Rate)	202	1	202
TFX Oct (Max Rate)	202	1	202
TFX5 (Max Rate)	5,806	5	29,030
TFX5 (Discount)	182	5	910
TFX12 (Discount)	130	12	1,560
TFX12 (Discount)	837	12	10,044
TFX12 (Discount)	1,206	12	14,472
TFX5 (Discount)	38	5	190
TFX5 (Discount)	247	5	1,235
TFX5 (Discount)	2,246	5	11,230
Bison	5,060	12	60,720
NBPL	5,060	12	60,720
LS Power	0	0	-
Windom	0	12	-
Ortonville	0	12	-
NNG Zone GDD Call Option	1,265	3	3,795
SMS			
Viking (VGT)			
FT-A ZONE 1 - 1	7,711	12	92,532
FT-A ZONE 1 - 1	678	3	2,034
FT-A ZONE 1 - 1	1,234	12	14,808
FT-A ZONE 1 - 1	1,852	5	9,260
Wadena Delivered Option	0	0	-
Balancing Agreement	4,607	12	55,284
Great Lakes (GLGT)			
FT Western Zone	6,231	12	74,772
FT Western Zone (12)	2,214	12	26,568
FT Western Zone (5)	2,238	5	11,190
FT Western Zone	5,536	12	66,432
Centra			
CENTRA TRANSMISSION			
Conversion ((($Cdm103M3)*279.256)/9858)	9,858	12	118,296
Union Balancing	4,500	12	54,000
CENTRA MINNESOTA PIPELINES	9,858	12	118,296

Total Demand Cost	$ 5,418,731	
Total Demand Weighted Vol in Mcf	7,341,760	
Total Joint Demand Rate $/Mcf		$0.73807

MINNESOTA ENERGY RESOURCES - NMU

November 1, 2011

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

PRESENT AVERAGE COST OF GAS — EFFECTIVE: 01-Nov-11

COMMODITY

NNG	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	NNG Annual Sales (therms)	Rate ($/therm)
FDD - Reservation	Annual	7,634	12	$1.71400	$157,016.11	67,028,910	$0.00234
FDD - Storage Cycle	Annual	88,030	5	$0.35670	$157,001.51	67,028,910	$0.00234
FDD - Reservation	Annual	562	12	$3.31570	$22,361.08	67,028,910	$0.00033
FDD - Storage Cycle	Annual	6,477	5	$0.69010	$22,348.69	67,028,910	$0.00033
FDD - Reservation	Annual	702	12	$1.71400	$14,438.74	67,028,910	$0.00022
FDD - Storage Cycle	Annual	8,096	5	$0.35670	$14,439.22	67,028,910	$0.00022
					$387,605.54	67,028,910	$0.00578

AECO	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	NNG Annual Sales (therms)	Rate ($/therm)
Niska Storage (AECO)	Annual	666,223	1	$ 0.95482	$636,125.00	67,028,910	$0.00949
					$1,023,730.54	67,028,910	$0.01527

WACOG	Rate	Annual Dth	Call Option Premium	Total Annual Cost	Cost/therm
NNG					
GAS COST	$4.12410				
FUEL 1.32%	$0.05517				
COMMODITY TRANSPORTATION	$0.03630				
ACA	$0.00180				
GRI FEE	$0.00000				
NNG Commodity	$4.21737	2,512,662	$18,149	$10,614,976	$0.15836
VGT					
GAS COST	$3.97780				
FUEL 1.66%	$0.06715				
COMMODITY TRANSPORTATION	$0.01300				
GRI	$0.00000				
ACA	$0.00180				
VGT Commodity	$4.05975	1,827,195	$8,066	$7,426,022	$0.11079
GLGT					
GAS COST	$3.97780				
FUEL 0.423%	$0.01691				
COMMODITY TRANSPORTATION	$0.00326				
GRI	$0.00000				
ACA	$0.00180				
GLGT Commodity	$3.99977	966,200	$10,083	$3,874,659	$0.05781
CENTRA					
CENTRA TRANSM ($Cdn/103M3)	1.062				
Conversion x0.9306	$0.03024				
GAS COSTS	$0.03024				
FUEL 0.250%	$3.97780				
CUSTOMS FEE	$0.00029				
CENTRA Commodity	$4.00833	1,396,834	$8,066	$5,607,030	$0.08365
NMU Weighted Average gas cost - $/Dth		6,702,891	$44,364	$27,522,687	$0.41061
Total Annual Sales in therms		67,028,910			

	Cost	Sales (therms)	Rate ($/therm)
	$27,522,687	67,028,910	$0.41061
Total Commodity Cost	$28,546,417.32	67,028,910	$0.42588

NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

Attachment 5

MINNESOTA ENERGY RESOURCES - NMU

Financial Options

Heating Season 2010-2011

[TRADE SECRET DATA BEGINS

Units - NNG Gas Daily Peaker Packages

	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												

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
1		$ -	$									

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												
2												
3												
4												
5												
6												
7												
8												
Total		6,000		4,516		7,097		4,828		6,774	29,215	890,000
		180,000		140,000		220,000		140,000		210,000		890,000

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												
2												
3												
4												
5												
6												
Total		7,333		10,000		11,935		11,034		7,742	48,045	1,460,000
		220,000		310,000		370,000		320,000		240,000		1,460,000

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												
2												
3												
4												
5												
6												
Total	$ 0.2017	$ 44,364	$ 0.2220	$ 68,827	$ 0.2638	$ 97,593	$ 0.2950	$ 91,136	$ 0.3057	$ 73,369	$ 0.2570	$ 375,288

Units - Collar Floor (put)

No Puts were purchased.

TRADE SECRET DATA ENDS]

NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

Attachment 6

MINNESOTA ENERGY RESOURCES - NMU

	M-07-1402 NMU GS	M-08-1329 NMU GS	M-09- NMU GS	M-10- NMU GS	M-11- NMU GS	Proposed Change
NNG Design Day	21,491	21,791	24,680	23,615	23,778	163
Customer Requirements moving to Transportation						
Adjusted Design Day						
Adjusted Design Day Percentages	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%
Factors for All Winter Capacity	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%
NNG Allocated Entitlements in PGA						
TF12B	2,954	2,653	7,513	4,232	4,774	542
TF12V	9,802	6,643	5,243	3,919	2,848	-1,071
TF(5)	1,991	5,451	1,991	3,493	3,267	-226
TFX(12)	0	0	0	3,495	3,268	-227
TFX(5)	6,139	6,139	6,139	9,759	9,126	-633
LS Power	2,725	2,777	2,725	3,149	0	-3,149
TFX(5)	0	0	0	0	0	0
Peak Capacity 3 mo.	0	0	0	0	0	0
Total NNG Allocated Entitlements in PGA	23,611	23,663	23,611	28,047	23,283	-4,764
Other Pipelines Entitlements In PGA						
Viking FT-A	7,966	7,966	7,966	7,966	8,945	979
Viking FT-(5)	0	0	0	0	2,530	2,530
Viking FT-A Backhaul	5,902	5,902	5,902	0	0	0
Viking/NNG Chisago TF12 Base	782	926	1,368	0	0	0
Viking/NNG Chisago TF12 Variable	0	0	955	0	0	0
Viking/NNG Chisago TF5	1,765	2,089	563	0	0	0
Viking/NNG Chisago TFX 12	1,963	2,324	2,089	0	0	0
Viking/NNG Chisago TFX 5	476	563	926	0	0	0
Great Lakes FT-A (12)	14,308	15,308	14,308	14,308	13,981	-327
Great Lakes FT-A (5)	2,138	2,138	2,138	2,138	2,238	100
Centra FT-1	9,858	9,858	9,858	9,858	9,858	0
Total Capacity	62,867	64,835	63,783	62,317	60,835	-1,482
Total NNG Transportation	23,611	23,663	23,611	28,047	23,283	-4,764
Total Transportation	62,867	64,835	63,783	62,317	60,835	-1,482
Total Seasonal Transportation	10,855	14,367	10,855	19,896	17,161	-2,735
Percent Seasonal on NNG	46.0%	60.7%	46.0%	70.9%	73.7%	2.77%
Other Entitlements not included in Peak Day Deliverability						
TFX Offpeak Old (Apr/Oct) one mo.	0	0	0	216	202	-14
TFX (Apr/Oct) one mo.	0	0	0	216	202	-14
TFX Apr.-Oct. 7 mos.	0	0	0	0	0	0
TFX May-Sept 5 mos.	0	0	0	0	0	0
FDD Storage reservation per mo.	7,619	7,980	7,830	9,516	8,898	-618
FDD Storage capacity per mo.	428,702	460,070	451,428	548,602	513,016	-35,586
ANR Capacity per mo.	0	0	0	0	0	0
Nexen PSO	684,604	684,604	684,604	0	0	0
Tenaska PSO	17,763	17,763	0	0	0	0
AECO Storage	0	0	0	665,043	666,223	1,180
NGPL per mo.	0	0	0	0	0	0
SMS per mo.	2,172	2,143	2,103	2,454	2,295	-159
SBA	0	0	0	0	0	0
Upstream Demand per mo.	0	0	0	0	0	0

MINNESOTA ENERGY RESOURCES - NMU

Rate Impacts
NMU

General Service-Residential	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.1061	-27.23%	7.12%	6.80%	$0.2613
Demand Cost	$1.3841	$1.0930	$1.0218	$1.2332	$1.2268	-11.36%	20.07%	-0.52%	($0.0064)
Margin	$2.1759	$2.3126	$2.1759	$2.1759	$2.1759	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$9.2022	$7.0984	$7.0308	$7.2539	$7.5088	-18.40%	6.80%	3.51%	$0.2549
Average Annual Use	90	90	90	90	90				
Average Annual Cost of Gas	$828.20	$638.86	$632.77	$652.85	$675.80	-18.40%	6.80%	3.51%	$22.95

Large General Service	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.1061	-27.23%	7.12%	6.80%	$0.2613
Demand Cost	$1.3841	$1.0930	$1.0218	$1.2332	$1.2268	-11.36%	20.07%	-0.52%	($0.0064)
Margin	$1.9660	$2.3126	$0.1966	$1.9660	$1.9660	0.00%	900.00%	0.00%	$0.0000
Total Cost of Gas	$8.9923	$7.0984	$5.0515	$7.0440	$7.2989	-18.83%	44.49%	3.62%	$0.2549
Average Annual Use	4,932	4,932	4,932	4,932	4,932				
Average Annual Cost of Gas	$44,350.02	$35,009.31	$24,914.00	$34,741.01	$35,998.40	-18.83%	44.49%	3.62%	$1,257.39

SV Interruptible Service	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.1061	-27.23%	7.12%	6.80%	$0.2613
Commodity Margin	$0.9560	$1.0127	$0.9560	$0.9560	$0.9560	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$6.5982	$4.7055	$4.7891	$4.8008	$5.0621	-23.28%	5.70%	5.44%	$0.2613
Average Annual Use	6,068	6,068	6,068	6,068	6,068				
Average Annual Cost of Gas	$40,037.88	$28,552.97	$29,060.26	$29,131.25	$30,716.82	-23.28%	5.70%	5.44%	$1,585.57

LV Interruptible Service	Base Cost of Gas Change G011/MR10-978	Demand Change M-10-XXXX	Last Demand Change Oct 1/11	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.1061	-27.23%	7.12%	6.80%	$0.2613
Commodity Margin	$0.2846	$0.3395	$0.2846	$0.2846	$0.2846	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.9268	$4.0323	$4.1177	$4.1294	$4.3907	-25.92%	6.63%	6.33%	$0.2613
Average Annual Use	40,821	40,821	40,821	40,821	40,821				
Average Annual Cost of Gas	$241,937.90	$164,602.52	$168,088.63	$168,566.24	$179,232.76	-25.92%	6.63%	6.33%	$10,666.53

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	$0.2613	26.13%	($0.0052)	($0.0064)	-0.52%	$0.2549	3.51%	$22.95
Large General Service	$0.2613	26.13%	($0.0052)	($0.0064)	-0.52%	$0.2549	3.62%	$1,257.39
SV Interruptible Service	$0.2613	$0.2613	$0.0000	$0.0000	0.00%	$0.2613	5.44%	$1,585.57
LV Interruptible Service	$0.2613	$0.2613	$0.0000	$0.0000	0.00%	$0.2613	6.33%	$10,666.53

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

MINNESOTA ENERGY RESOURCES - NMU

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

NMU

General Service-Residential	Base Cost of Gas Change G011/MR08-836^	Demand Change M-09-XXXX	Last Demand Change M-10-XXXX	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.2588	-24.52%	11.11%	10.77%	$0.4140
Demand Cost	$1.3841	$1.0930	$1.0218	$1.2332	$0.9870	-28.69%	-3.41%	-19.97%	($0.2462)
Margin	$2.1759	$2.3126	$2.1759	$2.1759	$2.1759	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$9.2022	$7.0984	$7.0308	$7.2539	$7.4217	-19.35%	5.56%	2.31%	$0.1678
Average Annual Use	90	90	90	90	90				
Average Annual Cost of Gas*	$828.20	$638.86	$632.77	$652.85	$667.95	-19.35%	5.56%	2.31%	$15.10

Large General Service	Base Cost of Gas Change G011/MR08-836^	Demand Change M-09-XXXX	Last Demand Change M-10-XXXX	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.2588	-24.52%	11.11%	10.77%	$0.4140
Demand Cost	$1.3841	$1.0930	$1.0218	$1.2332	$0.9870	-28.69%	-3.41%	-19.97%	($0.2462)
Margin	$1.9660	$2.3126	$0.1966	$1.9660	$1.9660	0.00%	900.00%	0.00%	$0.0000
Total Cost of Gas	$8.9923	$7.0984	$5.0515	$7.0440	$7.2118	-19.80%	42.77%	2.38%	$0.1678
Average Annual Use	4,932	4,932	4,932	4,932	4,932				
Average Annual Cost of Gas*	$44,350.02	$35,009.31	$24,914.00	$34,741.01	$35,568.64	-19.80%	42.77%	2.38%	$827.63

SV Interruptible Service	Base Cost of Gas Change G011/MR08-836^	Demand Change M-09-XXXX	Last Demand Change M-10-XXXX	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.2588	-24.52%	11.11%	10.77%	$0.4140
Commodity Margin	$0.9560	$1.0127	$0.9560	$0.9560	$0.9560	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$6.5982	$4.7055	$4.7891	$4.8008	$5.2148	-20.97%	8.89%	8.62%	$0.4140
Average Annual Use	6,068	6,068	6,068	6,068	6,068				
Average Annual Cost of Gas*	$40,037.88	$28,552.97	$29,060.26	$29,131.25	$31,643.54	-20.97%	8.89%	8.62%	$2,512.28

LV Interruptible Service	Base Cost of Gas Change G011/MR08-836^	Demand Change M-09-XXXX	Last Demand Change M-10-XXXX	Most Recent PGA Oct 1/11	Nov 1/11 PGA w/ Proposed Demand Changes**	% Change From Last Rate Case^^	% Change From Last Demand Filing	% Change From Last PGA	$ Change From Last PGA
Commodity Cost	$5.6422	$3.6928	$3.8331	$3.8448	$4.2588	-24.52%	11.11%	10.77%	$0.4140
Commodity Margin	$0.2846	$0.3395	$0.2846	$0.2846	$0.2846	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$5.9268	$4.0323	$4.1177	$4.1294	$4.5434	-23.34%	10.34%	10.03%	$0.4140
Average Annual Use	40,821	40,821	40,821	40,821	40,821				
Average Annual Cost of Gas*	$241,937.90	$164,602.52	$168,088.63	$168,566.24	$185,467.02	-23.34%	10.34%	10.03%	$16,900.78

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	$0.4140	41.40%	($0.1997)	($0.2462)	-19.97%	$0.1678	2.31%	$15.10
Large General Service	$0.4140	41.40%	($0.1997)	($0.2462)	-19.97%	$0.1678	2.38%	$827.63
SV Interruptible Service	$0.4140	$0.4140	$0.0000	$0.0000	0.00%	$0.4140	8.62%	$2,512.28
LV Interruptible Service	$0.4140	$0.4140	$0.0000	$0.0000	0.00%	$0.4140	10.03%	$16,900.78

* Average Annual Bill amount does not include customer charges.

** Commodity includes Upstream costs.

^ Implemented with Interim rates

^^ Interim rates implented on 10/1/08

MINNESOTA ENERGY RESOURCES - NMU

Change in Costs due to November 1, 2011 Change in Entitlement Levels and Related Demand Costs

NMU

	Oct. 2011 Entitlements	Nov. 2011 Entitlements	Entitlement Change	Oct. 2011 Rate	Months	Oct. 2011 Total Annual Cost	Nov. 2011 Total Annual Cost	Total Annual Cost Change
NNG Pipeline								
TF12B (Max Rate)	4,232	4,774	542	$ 7.5776	12	$384,821	$434,106	$49,285
TF12V (Max Rate)	3,919	2,848	-1,071	$ 9.0926	12	$427,607	$310,749	-$116,858
TF5 (Max Rate)	3,493	3,267	-226	$ 15.1530	5	$264,647	$247,524	-$17,123
TF12B (Discount-Winter)	0	0	0	$ 6.4818	12	$0	$0	$0
TFX5 (Discount)	649	607	-42	$ 4.5600	5	$14,797	$13,840	-$957
TFX12 (Max Rate)	1,171	1,095	-76	$ 9.6288	12	$135,304	$126,522	-$8,782
TFX Apr (Max Rate)	216	202	-14	$ 5.6830	1	$1,228	$1,148	-$80
TFX Oct (Max Rate)	216	202	-14	$ 5.6830	1	$1,228	$1,148	-$80
TFX5 (Max Rate)	6,208	5,806	-402	$ 15.1530	5	$470,349	$439,892	-$30,457
TFX5 (Discount)	195	182	-13	$ 7.6000	5	$7,415	$6,916	-$499
TFX12 (Discount)	139	130	-9	$ 4.8640	12	$8,113	$7,588	-$525
TFX12 (Discount)	895	837	-58	$ 5.4720	12	$58,769	$54,961	-$3,808
TFX12 (Discount)	1,290	1,206	-84	$ 2.2192	12	$34,353	$32,116	-$2,237
TFX5 (Discount)	41	38	-3	$ 4.8640	5	$997	$924	-$73
TFX5 (Discount)	265	247	-18	$ 5.4720	5	$7,250	$6,758	-$492
TFX5 (Discount)	2,401	2,246	-155	$ 15.1392	5	$181,746	$170,013	-$11,733
Bison	5,411	5,060	-351	$ 17.4800	12	$993,135	$1,061,386	$68,251
NBPL	5,411	5,060	-351	$ 6.9920	12	$397,254	$424,554	$27,300
LS Power	2,725	0	-2,725	$ 4.3463	0	$41,059	$0	-$41,059
Windom	0	0	0	$ -	12	$0	$0	$0
NNG Zone GDD Call Option	0	1,265	1,265	$ 0.9100	3	$0	$3,453	$3,453
NNG 3-Party demand								
Producer Demand	$0	$0	$0			$0	$0	$0
Call Options Premium	$592,119	$375,288	-$216,831			$592,119	$375,288	-$216,831
Upstream Demand Costs								
SMS	2,454	2,295	-159	$ 2.1800	12	$64,197	$60,037	-$4,160
FDD - Reservation	8,164	7,634	-530	$ 1.7140	12	$167,917	$157,016	-$10,901
FDD - Storage Cycle	94,137	88,030	-6,107	$ 0.3567	5	$167,893	$157,002	-$10,891
FDD - Reservation	601	562	-39	$ 3.3157	12	$23,913	$22,361	-$1,552
FDD - Storage Cycle	6,926	6,477	-449	$ 0.6901	5	$23,898	$22,349	-$1,549
FDD - Reservation	751	702	-49	$ 1.7140	12	$15,447	$14,439	-$1,008
FDD - Storage Cycle	8,658	8,096	-562	$ 0.3567	5	$15,442	$14,439	-$1,003
Viking Pipeline								
Viking FT-A	7,966	8,945	979	$ 3.4671	12	$331,427	$372,159	$40,732
Viking FT-(5)	0	678	678	$ 3.4671	3	$0	$7,052	$7,052
Viking FT-(5)	0	1,852	1,852	$ 3.7671	5	$0	$34,883	$34,883
Wadena Delivered Option	5,902	0	-5,902	$ 0.9000	0	$15,935	$0	-$15,935
Balancing Agreement	0	4,607	4,607	$ 1.0000	12	$15,936	$55,284	$39,348
GLGTPipeline								
FT Western Zone	10,130	6,231	-3,899	$ 3.4580	12	$420,354	$258,562	-$161,792
FT Western Zone (12)	1,178	2,214	1,036	$ 3.4580	12	$48,882	$91,872	$42,990
FT Western Zone (5)	2,138	2,238	100	$ 3.4580	5	$36,966	$38,695	$1,729
FT Western Zone	3,000	5,536	2,536	$ 3.4580	12	$124,488	$229,722	$105,234
CENTRA Pipeline								
CENTRA Transmission ($cdn/103M3)				197.70900				
Centra Transmission	9,858	9,858	0	$ 5.6007	12	$540,057	$662,537	$122,480
Union Balancing	4,500	4,500	0	$ 1.0000	12	$54,000	$54,000	$0
Centra MN Pipelines	9,858	9,858	0	$ 1.7780	12	$145,634	$210,330	$64,696
NISKA STORAGE (AECO)								
Niska Storage (AECO)	665,043	666,223	1,180	$ 0.9548	1	$950,744	$636,125	-$314,619
AECO/Emerson Swap	665,015	666,225	1,210	$ 0.4400	1	$315,882	$293,139	-$22,743
TOTAL DEMAND						$7,501,203	$7,110,889	-$390,314

NMU's DE Attachment 4 page 2

$6,735,601	
-$375,288	Call Option Premiums

MINNESOTA ENERGY RESOURCES - NMU

NNG-NMU

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	103	3,244	226	-0.10%	23,802	23,778
Off Peak	55	3,244	226	-0.10%	12,788	14,151

GLGT-NMU

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	105	2,237	133	-0.10%	14,886	14,870
Off Peak	57	2,237	133	-0.10%	9,440	9,099

VGT-NMU

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	109	2,075	98	-0.10%	11,057	11,046
Off Peak	57	2,075	98	-0.10%	7,033	7,026

Centra-NMU

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	107	1,704	80	-0.10%	8,303	8,295
Off Peak	57	1,704	80	-0.10%	5,361	5,356

Total-NMU

	1/20 Design Day HDD	Regression Intercept	HDD Slope	Customer Growth	1/20 Regression Load	Total
Peak	0	9,260	537	-4.00%	58,048	57,989
Off Peak	0	9,260	537	-4.00%	34,622	35,632

MINNESOTA ENERGY RESOURCES - NMU

11/12 Winter Portfolio Plan - MERC NMU-NNG Hedging Plan

[TRADE SECRET DATA BEGINS

10,000 Contract Size

REVISED: 09/13/11

		Nov-11		Dec-11		Jan-12		Feb-12		Mar-12		Total		Percent of Requirements
System	Purchase Month	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	
MN Requirements														
NNG -MN														
70%														
40%														
30%														
Contracts														
Call Options														
Collars														
Index (back financial)														
Physical Hedges														
Storage														
Prepaid Obl														
Term Index														
Total NNG MN														
Contracts														
Call Options														
Costing Collar														
Storage														
Prepaid Obl														
Term Index														
Month/Daily														
Total														

TRADE SECRET DATA ENDS]

MINNESOTA ENERGY RESOURCES - NMU

1/12 Winter Portfolio Plan - MERC GLGT-NMU Hedging Plan

[TRADE SECRET DATA BEGINS

REVISED: 09/13/11

10,000 Contract Size

System	Purchase Month	Nov-11		Dec-11		Jan-12		Feb-12		Mar-12		Total		Percent of Requirements
		Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	
MN Requirements														
VGT -MN														
70%														
40%														
30%														
Contracts														
Call Options														
Collars														
Index (back financial)														
Physical Hedges														
Storage														
Prepaid Obl														
Term Index														
Total NNG MN														
Contracts														
Call Options														
Costing Collar														
Storage														
Prepaid Obl														
Term Index														%
Month/Daily														%
Total														

MINNESOTA ENERGY RESOURCES - NMU

10/11 Winter Portfolio Plan - MERC VGT-NMU Hedging Plan

[TRADE SECRET DATA BEGINS

REVISED: 09/13/11

10,000 Contract Size

		Nov-11		Dec-11		Jan-12		Feb-12		Mar-12		Total		Percent of Requirements
System	Purchase Month	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	
MN Requirements														
VGT -MN														
70%														
40%														
30%														
Contracts														
Call Options														
Collars														
Index (back financial)														
Physical Hedges														
Storage														
Prepaid Obl														
Term Index														
Total NNG MN														
Contracts														
Call Options														
Costing Collar														
Storage														
Prepaid Obl														
Term Index														
Month/Daily														100.00%
Total														

MINNESOTA ENERGY RESOURCES - NMU

10/11 Winter Portfolio Plan - MERC Centra-NMU Hedging Plan

[TRADE SECRET DATA BEGINS

REVISED: 09/13/11

10,000 Contract Size		Nov-11		Dec-11		Jan-12		Feb-12		Mar-12		Total		Percent of Requirements
System	Purchase Month	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	
MN Requirements														
VGT -MN														
70%														
40%														
30%														
Contracts														
Call Options														
Collars														
Index (back financial)														
Physical Hedges														
Storage														
Prepaid Obl														
Term Index														
Total NNG MN														
Contracts														
Call Options														
Costing Collar														
Storage														
Prepaid Obl														
Term Index														
Month/Daily														
Total														

NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

MINNESOTA ENERGY RESOURCES

NNG WINTER PLAN (NMU)

NOVEMBER, 2011 THROUGH MARCH, 2012

[TRADE SECRET DATA BEGINS

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			NNG Ventura						
Index - Back Financial Options			NNG Welcome						
Index - Back Financial Options			Bison Pipeline						
Index - Back Financial Options		10/25/2011	NNG Ventura						
Index - Back Financial Options									
Index - Back Financial Options									
Index - Back Financial Options									
	Total Actual Seasonal Index								

GAS DAILY PACKAGES

NO Gas Daily Peakers

STORAGE

Injection Month	Contract # 118657 Volume Injected	Contract # 122800 Volume Injected	Total Volume Injected
May - balance forward			
June			
July			
August			
Sept			
Oct (est)			
Total			

MINNESOTA ENERGY RESOURCES

GLGT/VGT/Centra WINTER PLAN (NMU)
NOVEMBER, 2011 THROUGH MARCH, 2012

[TRADE SECRET DATA BEGINS

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					-	-	-	-	-	-

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 - Emerson	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
Index - Back Financial Options									
Index - Back Financial Options									
Index - Back Financial Options									
Index - Back Financial Options									

INDEX - Spruce

Index - Back Financial Options
Index - Back Financial Options
Index - Back Financial Options
Index - Back Financial Options

GAS DAILY PACKAGES

NO Gas Daily Peakers

MINNESOTA ENERGY RESOURCES - NMU

Daily Total Throughput Data - July 1, 2010 through June 30, 2011

Base	6,414
Variable	580

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 **
7/1/10	0	0	0	0	0	4,303	6,414
7/2/10	0	0	0	0	0	3,590	6,414
7/3/10	0	0	0	0	0	2,724	6,414
7/4/10	0	0	0	0	0	2,772	6,414
7/5/10	0	0	0	0	0	3,559	6,414
7/6/10	0	0	0	0	0	4,228	6,414
7/7/10	0	0	0	2	0	4,171	6,601
7/8/10	0	0	0	3	0	4,379	6,702
7/9/10	0	0	0	0	0	4,874	6,414
7/10/10	0	0	0	0	0	4,454	6,414
7/11/10	4	4	0	7	4	4,749	8,825
7/12/10	0	1	0	4	1	5,272	7,080
7/13/10	0	0	0	0	0	5,133	6,414
7/14/10	0	0	0	0	0	5,054	6,414
7/15/10	0	0	0	0	0	5,161	6,414
7/16/10	0	0	0	2	0	5,029	6,610
7/17/10	0	0	0	0	0	4,288	6,414
7/18/10	0	0	0	1	0	4,676	6,507
7/19/10	0	0	0	1	0	4,974	6,508
7/20/10	0	0	0	0	0	4,959	6,414
7/21/10	0	0	0	0	0	5,620	6,414
7/22/10	0	0	0	0	0	5,616	6,414
7/23/10	0	0	0	0	0	4,508	6,414
7/24/10	0	0	0	0	0	3,976	6,414
7/25/10	0	0	0	0	0	4,248	6,414
7/26/10	0	0	0	0	0	4,583	6,414
7/27/10	0	0	0	0	0	5,082	6,414
7/28/10	0	0	0	4	1	5,533	6,794
7/29/10	0	0	0	0	0	5,043	6,414
7/30/10	0	0	0	1	0	4,779	6,506
7/31/10	0	0	0	0	0	3,649	6,414
8/1/10	0	0	0	0	0	4,501	6,414
8/2/10	0	0	0	0	0	4,986	6,414
8/3/10	0	0	0	0	0	4,914	6,414
8/4/10	0	0	0	0	0	5,140	6,414
8/5/10	1	1	0	10	2	5,100	7,724
8/6/10	1	0	0	7	1	4,571	7,196
8/7/10	0	0	0	0	0	3,405	6,414
8/8/10	0	0	0	0	0	3,665	6,414
8/9/10	0	0	0	0	0	3,872	6,414
8/10/10	0	0	0	0	0	3,948	6,414
8/11/10	0	0	0	0	0	3,890	6,414
8/12/10	0	0	0	0	0	3,902	6,414
8/13/10	0	0	0	0	0	3,272	6,414
8/14/10	1	0	0	0	0	3,137	6,559
8/15/10	9	6	2	11	7	4,276	10,364
8/16/10	12	9	5	13	10	4,979	12,101
8/17/10	1	0	0	9	2	5,014	7,391
8/18/10	10	6	4	12	8	5,024	10,906
8/19/10	0	2	0	3	2	4,159	7,308
8/20/10	0	3	0	1	2	3,854	7,405
8/21/10	0	0	0	0	0	3,428	6,414
8/22/10	0	0	0	0	0	3,841	6,414
8/23/10	0	0	0	0	0	5,438	6,414
8/24/10	10	3	3	9	6	5,772	9,707
8/25/10	6	7	1	11	7	5,793	10,362
8/26/10	0	1	0	1	1	5,945	6,804
8/27/10	0	0	0	0	0	4,483	6,414
8/28/10	0	0	0	0	0	3,962	6,414
8/29/10	0	0	0	0	0	4,303	6,414
8/30/10	0	0	0	0	0	5,073	6,414
8/31/10	6	0	2	5	2	5,228	7,771
9/1/10	0	1	0	0	1	5,435	6,713
9/2/10	9	8	6	5	7	6,042	10,735
9/3/10	16	15	11	19	15	6,727	15,155
9/4/10	16	16	5	20	15	6,215	15,154
9/5/10	11	9	4	14	10	5,790	12,092
9/6/10	10	11	8	9	10	6,986	12,328
9/7/10	18	16	16	16	17	8,784	16,042
9/8/10	14	18	6	22	16	8,293	15,573
9/9/10	13	14	7	11	12	8,503	13,526
9/10/10	11	8	10	8	9	7,378	11,478
9/11/10	11	9	7	13	10	6,755	12,010
9/12/10	13	7	7	13	9	6,898	11,713
9/13/10	11	12	6	18	12	7,494	13,281
9/14/10	13	14	9	20	14	7,831	14,342
9/15/10	22	18	19	23	20	10,929	18,057
9/16/10	9	15	9	12	12	9,259	13,506
9/17/10	20	15	19	23	18	9,508	16,837
9/18/10	19	20	15	22	19	9,348	17,611
9/19/10	11	13	10	[illegible]	[illegible]	[illegible]	[illegible]
9/20/10	11	9	9	12	10	9,656	12,083
9/21/10	19	16	17	22	18	10,220	16,746
9/22/10	14	12	10	15	13	9,185	13,760
9/23/10	17	17	15	18	17	9,946	16,231

9/24/10	14	22	9	26	19	10,258	17,470
9/25/10	14	21	11	20	18	8,664	16,709
9/26/10	4	13	2	9	9	7,953	11,509
9/27/10	6	7	4	10	7	8,134	10,548
9/28/10	3	15	4	13	10	8,564	12,494
9/29/10	8	9	8	11	9	8,263	11,481
9/30/10	9	12	5	15	11	8,765	12,592
10/1/10	22	20	19	23	21	11,229	18,473
10/2/10	19	25	18	26	23	10,811	19,615
10/3/10	12	19	13	17	16	10,422	15,870
10/4/10	8	16	7	12	12	10,197	13,477
10/5/10	1	6	2	3	4	8,190	8,877
10/6/10	10	10	11	14	11	8,744	12,577
10/7/10	2	2	3	8	3	7,519	8,277
10/8/10	0	0	0	1	0	6,221	6,509
10/9/10	0	15	0	5	8	4,832	11,144
10/10/10	2	5	0	7	4	5,122	8,790
10/11/10	0	14	0	6	8	7,718	10,822
10/12/10	16	15	17	19	16	10,021	15,770
10/13/10	12	13	13	18	14	10,062	14,311
10/14/10	18	18	19	23	19	10,868	17,312
10/15/10	12	17	12	14	15	9,990	14,839
10/16/10	22	19	22	24	21	9,773	18,463
10/17/10	23	25	20	30	25	12,021	20,880
10/18/10	21	21	23	28	22	14,746	19,167
10/19/10	13	15	13	19	15	12,835	15,275
10/20/10	23	21	25	28	23	15,181	19,760
10/21/10	24	28	19	28	26	16,649	21,350
10/22/10	12	16	13	16	15	12,169	14,980
10/23/10	21	22	15	25	21	13,546	18,708
10/24/10	19	20	18	21	20	12,643	17,753
10/25/10	15	14	15	17	15	12,466	15,027
10/26/10	21	23	33	19	24	17,056	20,145
10/27/10	37	34	38	31	35	22,914	26,459
10/28/10	37	38	37	41	38	28,595	28,511
10/29/10	28	33	29	32	31	24,637	24,488
10/30/10	30	32	32	28	31	19,037	24,293
10/31/10	28	31	26	35	30	17,725	23,970
11/1/10	19	27	23	24	24	20,757	20,538
11/2/10	20	22	21	23	22	17,802	18,992
11/3/10	25	24	24	27	25	18,398	20,691
11/4/10	36	38	33	40	37	24,233	27,961
11/5/10	31	33	30	34	32	21,179	25,063
11/6/10	23	27	22	27	26	17,480	21,220
11/7/10	20	24	19	23	22	14,159	19,352
11/8/10	18	20	16	17	19	14,816	17,300
11/9/10	14	19	16	16	17	12,226	16,481
11/10/10	19	19	28	13	19	13,624	17,480
11/11/10	32	26	33	35	30	21,808	23,605
11/12/10	31	26	31	35	29	21,134	23,284
11/13/10	34	36	32	36	35	22,701	26,596
11/14/10	37	36	35	36	36	23,977	27,385
11/15/10	38	40	36	38	39	26,066	28,958
11/16/10	35	40	34	39	38	25,744	28,379
11/17/10	47	41	44	44	43	29,368	31,337
11/18/10	46	41	43	46	43	29,991	31,632
11/19/10	54	47	56	50	50	33,093	35,390
11/20/10	51	50	51	53	51	32,930	35,766
11/21/10	49	46	55	49	48	30,624	34,292
11/22/10	61	54	68	55	57	37,982	39,699
11/23/10	56	51	62	61	55	37,220	38,544
11/24/10	59	51	62	48	54	33,055	37,695
11/25/10	68	60	70	63	64	39,322	43,436
11/26/10	61	54	59	54	56	37,769	39,008
11/27/10	54	49	52	55	52	32,841	36,300
11/28/10	33	37	42	43	38	26,186	28,463
11/29/10	41	34	54	36	39	27,957	28,921
11/30/10	61	47	64	50	53	36,490	37,011
12/1/10	61	61	55	55	59	38,562	40,688
12/2/10	64	64	60	60	63	42,417	43,027
12/3/10	58	58	54	54	57	38,422	39,193
12/4/10	56	56	60	60	57	36,272	39,613
12/5/10	52	52	56	56	53	36,555	37,255
12/6/10	62	62	68	68	64	41,467	43,613
12/7/10	60	60	68	68	62	41,291	42,437
12/8/10	56	56	63	63	58	40,594	39,855
12/9/10	50	50	56	56	52	36,945	36,511
12/10/10	62	62	67	67	63	40,548	43,209
12/11/10	78	78	82	82	80	47,917	52,595
12/12/10	78	78	84	84	80	50,281	52,589
12/13/10	77	77	80	80	78	51,043	51,403
12/14/10	59	59	67	67	62	46,536	42,189
12/15/10	57	57	70	70	61	42,462	41,562
12/16/10	59	59	63	63	60	49,323	41,415
12/17/10	57	57	57	57	57	39,502	39,469
12/18/10	57	57	55	55	57	38,366	39,247
12/19/10	61	61	64	64	62	43,234	42,290
12/20/10	52	52	55	55	53	36,401	36,875
12/21/10	42	42	41	41	41	39,241	30,436
12/22/10	44	44	48	48	45	45,891	32,782
12/23/10	48	48	51	51	49	44,928	34,886
12/24/10	54	54	54	54	54	41,858	37,473
12/25/10	58	58	59	59	58	45,712	40,043
12/26/10	56	56	56	56	56	47,922	38,876
12/27/10	47	47	51	51	48	50,454	34,408
12/28/10	40	40	41	41	40	44,197	29,774

12/29/10	40	40	40	40	40	40,671	29,429
12/30/10	59	59	60	60	59	45,963	40,671
12/31/10	65	65	65	65	65	50,710	44,091
1/1/11	79	70	76	74	73	53,237	48,947
1/2/11	73	71	72	80	73	54,258	48,630
1/3/11	72	66	76	80	71	61,722	47,342
1/4/11	59	64	66	66	63	43,920	43,229
1/5/11	64	62	64	68	64	41,922	43,438
1/6/11	69	66	59	66	66	43,079	44,666
1/7/11	72	72	71	74	72	44,622	48,196
1/8/11	70	67	73	76	70	45,686	47,091
1/9/11	69	60	70	69	65	42,366	43,995
1/10/11	53	52	55	59	54	38,150	37,457
1/11/11	58	48	67	53	53	36,930	37,387
1/12/11	57	52	63	50	54	38,059	37,911
1/13/11	58	53	60	59	56	37,119	38,836
1/14/11	62	59	66	62	61	39,042	41,825
1/15/11	71	70	77	84	73	44,966	48,960
1/16/11	69	66	66	76	68	41,892	46,042
1/17/11	65	61	77	75	66	42,582	44,812
1/18/11	71	66	81	76	70	47,041	47,268
1/19/11	67	65	74	72	68	45,514	45,611
1/20/11	92	86	89	98	89	54,964	58,321
1/21/11	83	83	83	86	83	53,395	54,738
1/22/11	79	82	84	87	82	49,952	54,078
1/23/11	64	75	61	66	69	44,904	46,524
1/24/11	56	54	61	60	56	39,690	39,037
1/25/11	51	51	52	53	51	37,072	36,189
1/26/11	51	46	52	47	48	34,389	34,392
1/27/11	49	45	41	50	46	32,878	33,173
1/28/11	48	48	50	58	50	34,206	35,238
1/29/11	62	54	74	60	59	36,590	40,735
1/30/11	64	59	75	72	64	41,106	43,734
1/31/11	75	68	84	80	73	53,845	48,970
2/1/11	73	73	83	78	75	46,158	50,005
2/2/11	69	70	80	76	72	45,209	48,259
2/3/11	47	53	48	51	51	35,970	35,800
2/4/11	40	45	42	36	42	28,947	30,893
2/5/11	37	40	44	43	40	28,288	29,878
2/6/11	58	57	71	61	60	36,476	40,944
2/7/11	78	76	80	80	78	49,006	51,496
2/8/11	75	68	78	74	72	47,547	48,164
2/9/11	81	77	76	86	79	49,825	52,316
2/10/11	69	68	71	74	70	47,077	46,781
2/11/11	48	57	44	62	54	38,144	37,680
2/12/11	35	46	39	51	43	29,660	31,496
2/13/11	30	31	33	33	31	25,446	24,611
2/14/11	31	34	36	40	35	27,344	26,429
2/15/11	30	34	34	33	33	25,133	25,632
2/16/11	21	24	31	27	24	20,722	20,595
2/17/11	49	42	56	51	47	31,220	33,485
2/18/11	68	62	63	77	66	42,198	44,608
2/19/11	58	58	62	64	59	38,664	40,897
2/20/11	58	55	66	63	58	40,798	40,301
2/21/11	49	57	58	61	56	37,929	38,834
2/22/11	48	49	54	49	50	33,724	35,127
2/23/11	56	48	61	56	53	34,058	36,997
2/24/11	71	64	77	77	69	42,528	46,473
2/25/11	78	72	78	83	76	48,209	50,597
2/26/11	70	70	78	72	71	46,050	47,789
2/27/11	62	56	62	65	60	40,691	40,948
2/28/11	49	52	61	54	53	34,888	37,166
3/1/11	69	62	73	73	67	44,990	45,191
3/2/11	67	63	64	70	65	43,845	44,262
3/3/11	47	48	52	51	49	35,370	34,725
3/4/11	60	51	65	63	57	36,459	39,412
3/5/11	55	48	59	55	52	33,962	36,765
3/6/11	50	48	60	58	52	35,074	36,386
3/7/11	60	49	67	62	56	36,295	38,855
3/8/11	50	41	50	50	46	30,280	32,879
3/9/11	41	40	47	40	41	29,318	30,206
3/10/11	40	38	47	39	40	27,875	29,392
3/11/11	44	34	53	38	39	27,202	29,298
3/12/11	61	50	63	53	55	35,587	38,097
3/13/11	47	44	58	45	47	31,291	33,548
3/14/11	34	40	45	34	38	26,036	28,577
3/15/11	30	36	35	29	33	24,656	25,692
3/16/11	27	29	30	31	29	21,802	23,356
3/17/11	36	31	40	32	33	24,728	25,791
3/18/11	42	39	44	49	42	28,217	30,673
3/19/11	36	31	32	39	34	22,509	25,851
3/20/11	31	31	31	32	31	23,816	24,484
3/21/11	29	32	32	34	32	24,559	24,905
3/22/11	46	49	43	51	48	34,693	34,185
3/23/11	48	55	56	54	53	34,453	37,337
3/24/11	43	45	52	49	46	31,434	33,339
3/25/11	42	53	48	49	49	30,541	34,972
3/26/11	45	53	51	52	51	30,768	35,866
3/27/11	44	47	48	48	47	29,483	33,444
3/28/11	40	42	46	44	42	28,254	30,998
3/29/11	35	36	41	38	37	25,313	27,671
3/30/11	32	34	38	33	34	29,033	26,147
3/31/11	30	29	36	34	31	23,487	24,308
4/1/11	31	32	35	32	32	22,765	24,918
4/2/11	25	25	31	24	26	17,575	21,367
4/3/11	34	33	34	36	34	24,305	26,061

4/4/11	36	36	34	39	36	25,172	27,367
4/5/11	27	29	31	32	30	20,737	23,554
4/6/11	26	29	24	27	28	21,942	22,402
4/7/11	19	20	16	25	20	22,392	17,876
4/8/11	11	17	18	19	16	13,739	15,705
4/9/11	14	18	17	17	17	12,156	16,181
4/10/11	27	24	29	28	26	15,734	21,566
4/11/11	17	22	14	21	20	14,630	17,807
4/12/11	16	11	17	16	13	12,033	14,236
4/13/11	37	27	37	40	33	20,769	25,358
4/14/11	31	41	29	34	36	25,588	27,484
4/15/11	32	38	36	32	35	25,652	26,922
4/16/11	40	38	36	41	38	24,628	28,728
4/17/11	35	36	33	41	36	22,768	27,421
4/18/11	36	35	32	35	35	24,189	26,546
4/19/11	28	32	29	29	30	21,996	23,812
4/20/11	31	30	29	32	31	21,267	24,116
4/21/11	24	24	27	21	24	18,516	20,476
4/22/11	27	28	27	24	27	19,488	22,206
4/23/11	21	25	20	25	24	16,189	20,150
4/24/11	14	17	15	19	16	12,286	15,750
4/25/11	10	12	8	14	11	11,259	12,998
4/26/11	20	29	17	21	24	18,021	20,420
4/27/11	21	33	19	25	27	20,731	22,288
4/28/11	19	24	11	17	20	16,223	17,998
4/29/11	8	12	9	10	10	10,713	12,404
4/30/11	30	29	31	28	29	16,952	23,445
5/1/11	41	39	39	42	40	27,124	29,458
5/2/11	28	31	26	29	29	26,639	23,287
5/3/11	15	23	15	22	20	18,864	17,863
5/4/11	12	14	16	10	13	17,450	14,008
5/5/11	17	24	9	23	20	20,116	18,138
5/6/11	9	14	3	15	12	12,509	13,167
5/7/11	9	19	2	12	14	9,532	14,262
5/8/11	9	14	9	9	11	9,631	13,023
5/9/11	11	18	6	12	14	16,226	14,381
5/10/11	3	18	2	6	11	15,444	12,556
5/11/11	11	3	16	10	8	14,243	10,938
5/12/11	20	15	25	21	18	17,642	16,920
5/13/11	23	20	24	24	22	16,161	19,041
5/14/11	13	20	18	14	17	11,378	16,355
5/15/11	17	25	14	20	21	10,427	18,539
5/16/11	12	15	10	11	13	13,793	13,951
5/17/11	11	15	7	14	13	14,261	13,876
5/18/11	2	12	3	2	7	12,500	10,477
5/19/11	0	7	0	2	4	12,480	8,738
5/20/11	0	7	0	0	3	9,863	8,275
5/21/11	8	17	1	8	11	7,133	13,014
5/22/11	2	9	2	2	5	6,854	9,490
5/23/11	10	9	12	14	10	12,363	12,370
5/24/11	19	19	16	23	19	16,554	17,610
5/25/11	18	17	18	21	18	15,670	16,861
5/26/11	12	24	9	18	18	11,838	17,018
5/27/11	15	19	13	13	17	10,269	16,070
5/28/11	12	8	11	17	10	6,576	12,454
5/29/11	8	10	9	7	9	5,482	11,535
5/30/11	3	16	0	7	10	7,688	12,102
5/31/11	12	4	13	9	8	10,293	10,859
6/1/11	9	10	3	19	10	9,874	12,316
6/2/11	1	14	0	4	8	9,859	11,033
6/3/11	0	0	0	0	0	7,511	6,414
6/4/11	10	5	3	15	8	6,767	10,765
6/5/11	0	4	0	0	2	4,530	7,598
6/6/11	0	0	0	2	0	2,087	6,602
6/7/11	0	7	0	6	4	2,534	8,773
6/8/11	15	11	11	24	14	4,878	14,556
6/9/11	9	17	5	11	13	5,223	13,720
6/10/11	14	16	11	18	15	8,097	15,167
6/11/11	8	12	1	11	10	8,888	12,026
6/12/11	4	7	1	6	6	8,946	9,677
6/13/11	0	4	0	0	2	8,428	7,609
6/14/11	0	1	0	0	1	3,664	6,716
6/15/11	6	14	1	9	10	5,200	11,972
6/16/11	2	9	0	5	6	4,368	9,802
6/17/11	0	4	0	0	2	3,800	7,655
6/18/11	0	14	0	8	8	4,192	11,131
6/19/11	1	16	0	6	9	4,928	11,742
6/20/11	2	9	0	6	6	7,992	9,799
6/21/11	7	12	5	5	9	7,079	11,366
6/22/11	10	15	8	11	12	10,178	13,658
6/23/11	6	10	0	9	8	10,191	10,803
6/24/11	0	0	0	1	0	7,855	6,506
6/25/11	0	0	0	0	0	6,875	6,414
6/26/11	1	2	0	0	1	7,384	7,148
6/27/11	6	6	4	9	6	8,775	9,912
6/28/11	4	4	0	4	4	8,554	8,490
6/29/11	0	2	0	0	1	7,008	7,023
6/30/11	0	2	0	0	1	6,305	7,017
Totals	10,055	10,248	10,296	10,885	10,311	7,574,478	8,321,658

* 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

MINNESOTA ENERGY RESOURCES - NMU

Customer Counts by PGAC Class - July 1, 2010 through June 30, 2011

Rate Class	Tariff Rate Designation	Jul-10 Average Customers	Aug-10 Average Customers	Sep-10 Average Customers	Oct-10 Average Customers	Nov-10 Average Customers	Dec-10 Average Customers	Jan-11 Average Customers	Feb-11 Average Customers	Mar-11 Average Customers	Apr-11 Average Customers	May-11 Average Customers	Jun-11 Average Customers
Residential w/ Heat	NM001	34,406	34,186	34,146	34,260	35,025	35,360						
Residential w/o Heat	NM002	18	18	20	21	22	23						
Commercial-SV	NM050/070	2,327	2,318	2,301	2,487	2,328	2,326						
Commercial-LV	NM052/071	3,013	3,001	2,993	2,998	3,036	3,043						
Industrial-LV	NM150	12	10	13	12	14	13						
SV-Joint	NM100/101	0	0	0	0	0	0						
SV-Interruptible	NM125	123	118	124	124	124	125						
LV-Interruptible	NM200/201/210/211	13	11	14	14	13	13						
Transport	NM500/512/501/502/522/70A/71A	12	8	17	18	18	18						
Transport	NM503/511/504/506/508/74L/80A	12	9	13	13	13	12						
Transport	NM516	0	0	0	0	0	0						
Transport	NM507/513/514	8	8	0	0	3	10						
Transport	NM72A/73A	0	0	0	0	0	0						
Transport	NM510	0	0	0	0	0	0						
Transport	NM515	0	0	0	0	0	0						
Total		39,944	39,687	39,641	39,947	40,596	40,943	0	0	0	0	0	0

MINNESOTA ENERGY RESOURCES - NMU

Projected Fixed Cost - November 2011 through March 2012

Futures Contracts WACOG

NMU
Futures

Nov-11 (30)

Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/31/11	38,734	$ 4.8940	$ 189,565	$ 3.6310	$ 140,644	$ 48,921
06/16/11	36,456	$ 4.6510	$ 169,555	$ 3.6310	$ 132,371	$ 37,185
07/25/11	31,899	$ 4.4700	$ 142,587	$ 3.6310	$ 115,824	$ 26,763
08/02/11	27,342	$ 4.2550	$ 116,339	$ 3.6310	$ 99,278	$ 17,061
09/21/11	22,785	$ 3.8260	$ 87,175	$ 3.6310	$ 82,732	$ 4,443
10/03/11	22,785	$ 3.6160	$ 82,390	$ 3.6310	$ 82,732	$ (342)
Total	180,000		$ 787,612		$ 653,580	$ 134,032
WACOG			$ 4.3756		$ 3.6310	$ 0.7446

Dec-11 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/31/11	34,222	$ 5.0870	$ 174,088	$ 4.0440	$ 138,395	$ 35,694
06/16/11	24,889	$ 4.8410	$ 120,487	$ 4.0440	$ 100,651	$ 19,836
06/16/11	9,333	$ 4.8420	$ 45,192	$ 4.0440	$ 37,744	$ 7,448
07/07/11	24,889	$ 4.5500	$ 113,244	$ 4.0440	$ 100,651	$ 12,594
08/04/11	15,556	$ 4.2840	$ 66,640	$ 4.0440	$ 62,907	$ 3,733
09/19/11	15,556	$ 4.1800	$ 65,022	$ 4.0440	$ 62,907	$ 2,116
10/05/11	15,556	$ 3.9080	$ 60,791	$ 4.0440	$ 62,907	$ (2,116)
Total	140,000		$ 645,465		$ 566,160	$ 79,305
WACOG			$ 4.6105		$ 4.0440	$ 0.5665

Jan-12 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/26/11	44,638	$ 4.9410	$ 220,555	$ 4.1910	$ 187,077	$ 33,478
06/22/11	44,638	$ 4.8580	$ 216,850	$ 4.1910	$ 187,077	$ 29,773
07/21/11	41,449	$ 4.7690	$ 197,672	$ 4.1910	$ 173,714	$ 23,958
08/16/11	19,130	$ 4.4320	$ 84,786	$ 4.1910	$ 80,176	$ 4,610
08/16/11	15,942	$ 4.4330	$ 70,671	$ 4.1910	$ 66,813	$ 3,858
09/15/11	28,696	$ 4.3300	$ 124,252	$ 4.1910	$ 120,263	$ 3,989
10/20/11	25,507	$ 3.9670	$ 101,187	$ 4.1910	$ 106,901	$ (5,714)
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
Total	220,000		$ 1,015,973		$ 922,020	$ 93,953
WACOG			$ 4.6181		$ 4.1910	$ 0.4271

Feb-12 (29)

Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/26/11	38,889	$ 4.9000	$ 190,556	$ 4.2190	$ 164,072	$ 26,483
06/30/11	31,111	$ 4.8300	$ 150,267	$ 4.2190	$ 131,258	$ 19,009
07/07/11	11,667	$ 4.6580	$ 54,343	$ 4.2190	$ 49,222	$ 5,122
07/07/11	15,556	$ 4.6620	$ 72,520	$ 4.2190	$ 65,629	$ 6,891
08/25/11	15,556	$ 4.3340	$ 67,418	$ 4.2190	$ 65,629	$ 1,789
09/16/11	15,556	$ 4.3140	$ 67,107	$ 4.2190	$ 65,629	$ 1,478
10/06/11	11,667	$ 4.1000	$ 47,833	$ 4.2190	$ 49,222	$ (1,388)
Total	140,000		$ 650,043		$ 590,660	$ 59,383
WACOG			$ 4.6432		$ 4.2190	$ 0.4242

Mar-12 (31)

Purchase Date	Physical Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
05/19/11	41,538	$ 4.7660	$ 197,972	$ 4.1105	$ 170,744	$ 27,228
06/23/11	13,846	$ 4.6590	$ 64,509	$ 4.1105	$ 56,915	$ 7,595
06/23/11	27,692	$ 4.6600	$ 129,046	$ 4.1105	$ 113,829	$ 15,217
07/27/11	41,538	$ 4.6700	$ 193,985	$ 4.1105	$ 170,744	$ 23,241
08/29/11	32,308	$ 4.2840	$ 138,406	$ 4.1105	$ 132,801	$ 5,605
09/22/11	27,692	$ 4.1800	$ 115,754	$ 4.1105	$ 113,829	$ 1,925
10/21/11	25,385	$ 3.9250	$ 99,635	$ 4.1105	$ 104,343	$ (4,709)
Total	210,000		$ 939,307		$ 863,205	$ 76,102
WACOG			$ 4.4729		$ 4.1105	$ 0.3624

Total

	Financial Volume	Purchase Price	Total Cost	NNG Indexes	NNG Indexes Cost	Over/(Under) Market
	198,021	$ 4.9123	$ 972,736	$ 4.0447	$ 800,931	$ 171,805
	150,940	$ 4.7812	$ 721,668	$ 4.0299	$ 608,270	$ 113,398
	122,040	$ 4.6611	$ 568,840	$ 4.0178	$ 490,333	$ 78,507
	128,455	$ 4.5220	$ 580,874	$ 4.0207	$ 516,477	$ 64,397
	102,146	$ 4.2127	$ 430,310	$ 4.0225	$ 410,881	$ 19,429
	110,284	$ 4.1214	$ 454,525	$ 4.0383	$ 445,360	$ 9,165
	78,114	$ 3.9615	$ 309,446	$ 4.1397	$ 323,373	$ (13,926)
	890,000		$ 4,038,400		$ 3,595,625	$ 442,775
			$ 4.5375		$ 4.0400	$ 0.4975

MINNESOTA ENERGY RESOURCES - NMU

Projected Storage Cost - November 2011 through March 2012

Month/ Year	K#118657 NNG Storage	Storage K#122800 LS Power	Total NNG Storage	WACOG Projected K#118657 NNG WACOG	Projected K#122800 NNG WACOG	K#118657 NNG Storage Cost	K#122800 NNG Storage Cost	Total NNG Storage Cost	GLGT/VGT Centra AECO Storage	GLGT/VGT Centra AECO Storage WACOG	GLGT/VGT Centra AECO Storage Cost
Nov-11	455,259	39,000	494,259	$ 4.1398	$ 4.1398	$ 1,884,666	$ 161,451	$ 2,046,116	85,304	$ 3.8600	$ 329,277
Dec-11	1,143,984	98,000	1,241,984	$ 4.1398	$ 4.1398	$ 4,735,825	$ 405,697	$ 5,141,523	229,242	$ 3.8600	$ 884,885
Jan-12	1,143,984	98,000	1,241,984	$ 4.1398	$ 4.1398	$ 4,735,825	$ 405,697	$ 5,141,523	229,242	$ 3.8600	$ 884,885
Feb-12	1,143,984	98,000	1,241,984	$ 4.1398	$ 4.1398	$ 4,735,825	$ 405,697	$ 5,141,523	214,452	$ 3.8600	$ 827,795
Mar-12	455,259	39,000	494,259	$ 4.1398	$ 4.1398	$ 1,884,666	$ 161,451	$ 2,046,116	96,345	$ 3.8600	$ 371,896
Total	4,342,470	372,000	4,714,470	$ 4.1398	$ 4.1398	$17,976,807	$1,539,993	$ 19,516,800	854,585	$ 3.8600	$ 3,298,737
								$ 4.1398			$ 3.8600

Month/ Year	NNG Storage Volume	NNG Indexes Price	NNG Indexes Cost	AECO Storage Volume	Emerson Indexes Price	Emerson Indexes Cost
Nov-11	494,259	$ 3.6310	$ 1,794,654	85,304	$ 3.4860	$ 297,370
Dec-11	1,241,984	$ 4.0440	$ 5,022,583	229,242	$ 3.9515	$ 905,850
Jan-12	1,241,984	$ 4.1910	$ 5,205,155	229,242	$ 4.0160	$ 920,636
Feb-12	1,241,984	$ 4.2190	$ 5,239,930	214,452	$ 4.0365	$ 865,635
Mar-12	494,259	$ 4.1105	$ 2,031,652	96,345	$ 3.9580	$ 381,334
Total	4,714,470	$ 4.0925	$19,293,975	854,585	$ 3.9444	$ 3,370,824

Total AECO Storage Volumes	Total AECO Storage WACOG	Total AECO Storage Cost	Total Emerson WACOG	Total Emerson Cost
85,304	$ 3.8600	$ 329,277	$ 3.4860	$ 297,370
229,242	$ 3.8600	$ 884,885	$ 3.9515	$ 905,850
229,242	$ 3.8600	$ 884,885	$ 4.0160	$ 920,636
214,452	$ 3.8600	$ 827,795	$ 4.0365	$ 865,635
96,345	$ 3.8600	$ 371,896	$ 3.9580	$ 381,334
854,585	$ 3.8600	$ 3,298,737	$ 3.9444	$ 3,370,824

Max NNG Storage (Storage plan withdrawals through Apr 12) 4,714,470 5,069,321
Max AECO Storage 854,585

10/31/11 Storage Balance - NNG (estimate) 5,069,321 100.00% 4,714,470
10/31/11 Storage Balance - AECO (estimate) 947,820

Month/ Year	K#118657 NNG Storage	Storage K#122800 LS Power	Total NNG Storage	NNG PNG Volumes	NNG NMU Volumes	NNG Total Volumes	Projected K#118657 NNG WACOG	Projected K#122800 NNG WACOG	WACOG NNG PNG Cost	WACOG NNG NMU Cost	WACOG NNG Total Cost	NNG Indexes Price	NNG Index NNG PNG Cost	NNG Index NNG NMU Cost	NNG Index NNG Total Cost
Nov-11	455,259	39,000	494,259	444,240	50,019	494,259	$ 4.1398	$ 4.1398	$ 1,839,049	$ 207,067	$ 2,046,116	$ 3.6890	$ 1,638,801	$ 184,521	$ 1,823,321
Dec-11	1,143,984	98,000	1,241,984	1,116,295	125,689	1,241,984	$ 4.1398	$ 4.1398	$ 4,621,199	$ 520,323	$ 5,141,523	$ 4.0684	$ 4,541,502	$ 511,350	$ 5,052,852
Jan-12	1,143,984	98,000	1,241,984	1,116,295	125,689	1,241,984	$ 4.1398	$ 4.1398	$ 4,621,199	$ 520,323	$ 5,141,523	$ 4.3351	$ 4,839,301	$ 544,880	$ 5,384,181
Feb-12	1,143,984	98,000	1,241,984	1,116,295	125,689	1,241,984	$ 4.1398	$ 4.1398	$ 4,621,199	$ 520,323	$ 5,141,523	$ 4.3571	$ 4,863,811	$ 547,640	$ 5,411,451
Mar-12	455,259	39,000	494,259	444,240	50,019	494,259	$ 4.1398	$ 4.1398	$ 1,839,049	$ 207,067	$ 2,046,116	$ 4.2157	$ 1,872,779	$ 210,865	$ 2,083,645
Total	4,342,470	372,000	4,714,470	4,237,365	477,105	4,714,470	$ 4.1398	$ 4.1398	$17,541,696	$ 1,975,104	$ 19,516,800	$ 4.1904	$17,756,194	$ 1,999,256	$19,755,450
									$ 4.1398	$ 4.1398	$ 4.1398		$ 4.1904	$ 4.1904	$ 4.1904

Month/ Year	AECO Storage	GLGT PNG Volumes	GLGT NMU Volumes	VGT PNG Volumes	VGT NMU Volumes	Centra NMU Volumes	Total Nexen Volumes	GLGT/VGT Centra AECO Storage WACOG	GLGT PNG Cost	GLGT NMU Cost	VGT PNG Cost	VGT NMU Cost	Centra NMU Cost	Total AECO Storage Cost
Nov-11	85,304	13,244	22,538	12,100	21,191	16,230	85,304	$ 3.8600	$ 51,123	$ 86,999	$ 46,708	$ 81,798	$ 62,649	$ 329,277
Dec-11	229,242	35,591	60,569	32,518	56,948	43,616	229,242	$ 3.8600	$ 137,384	$ 233,797	$ 125,521	$ 219,821	$ 168,361	$ 884,885
Jan-12	229,242	35,591	60,569	32,518	56,948	43,616	229,242	$ 3.8600	$ 137,384	$ 233,797	$ 125,521	$ 219,821	$ 168,361	$ 884,885
Feb-12	214,452	33,295	56,661	30,420	53,274	40,802	214,452	$ 3.8600	$ 128,521	$ 218,713	$ 117,422	$ 205,639	$ 157,499	$ 827,795
Mar-12	96,345	14,958	25,456	13,667	23,934	18,331	96,345	$ 3.8600	$ 57,739	$ 98,259	$ 52,753	$ 92,386	$ 70,758	$ 371,896
Total	854,585	132,680	225,792	121,223	212,294	162,596	854,585	$ 3.8600	$ 512,152	$ 871,566	$ 467,925	$ 819,464	$ 627,629	$ 3,298,737
		15.53%	26.42%	14.18%	24.84%	19.03%	100.00%		$ 3.8600	$ 3.8600	$ 3.8600	$ 3.8600	$ 3.8600	$ 3.8600

Month/ Year	AECO Storage	GLGT PNG Volumes	GLGT NMU Volumes	VGT PNG Volumes	VGT NMU Volumes	Centra NMU Volumes	Total AECO Storage Volumes	Projected Emerson Index Price	GLGT PNG Cost	GLGT NMU Cost	VGT PNG Cost	VGT NMU Cost	Centra NMU Cost	Total AECO Cost
Nov-11	85,304	13,244	22,538	12,100	21,191	16,230	85,304	$ 3.4860	$ 46,169	$ 78,569	$ 42,182	$ 73,872	$ 56,579	$ 297,370
Dec-11	229,242	35,591	60,569	32,518	56,948	43,616	229,242	$ 3.9515	$ 140,639	$ 239,337	$ 128,495	$ 225,029	$ 172,350	$ 905,850
Jan-12	229,242	35,591	60,569	32,518	56,948	43,616	229,242	$ 4.0160	$ 142,935	$ 243,243	$ 130,592	$ 228,702	$ 175,163	$ 920,636
Feb-12	214,452	33,295	56,661	30,420	53,274	40,802	214,452	$ 4.0365	$ 134,396	$ 228,711	$ 122,790	$ 215,039	$ 164,699	$ 865,635
Mar-12	96,345	14,958	25,456	13,667	23,934	18,331	96,345	$ 3.9580	$ 59,205	$ 100,753	$ 54,092	$ 94,730	$ 72,554	$ 381,334
Total	854,585	132,680	225,792	121,223	212,294	162,596	854,585	$ 3.9444	523,344	890,613	478,151	837,372	641,345	3,370,824
		15.53%	26.42%	14.18%	24.84%	19.03%	100.00%		$ 3.9444	$ 3.9444	$ 3.9444	$ 3.9444	$ 3.9444	$ 3.9444

Call/Put Options WACOG

Contract = 10,000

Call/Put Options

Nov-11

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	05/31/11		14	140,000	$ 5.0000	$ 700,000	$ 3.5310	$ 494,340	$ 3.5310	$ 494,340	$ -	$ 0.3750	$ 52,500	$ 546,840
2	06/23/11		15	150,000	$ 4.5000	$ 675,000	$ 3.5310	$ 529,650	$ 3.5310	$ 529,650	$ -	$ 0.3350	$ 50,250	$ 579,900
3	07/21/11		16	160,000	$ 4.5000	$ 720,000	$ 3.5310	$ 564,960	$ 3.5310	$ 564,960	$ -	$ 0.3000	$ 48,000	$ 612,960
4	08/31/11		20	200,000	$ 4.5000	$ 900,000	$ 3.5310	$ 706,200	$ 3.5310	$ 706,200	$ -	$ 0.1030	$ 20,600	$ 726,800
5	09/15/11		20	200,000	$ 4.0000	$ 800,000	$ 3.5310	$ 706,200	$ 3.5310	$ 706,200	$ -	$ 0.1700	$ 34,000	$ 740,200
6	10/04/11		19	190,000	$ 4.0000	$ 760,000	$ 3.5310	$ 670,890	$ 3.5310	$ 670,890	$ -	$ 0.0230	$ 4,370	$ 675,260
7				-		$ -	$ -	$ -	$ 3.5310	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.5310	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.5310	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.5310	$ -	$ -		$ -	$ -
Total			104	1,040,000		$ 4,555,000		$ 3,672,240		$ 3,672,240	$ -		$ 209,720	$ 3,881,960
						$ 4.3798		$ 3.5310		$ 3.5310	$ -		$ 0.2017	$ 3.7327
NNG-PNG	76	73.08%	76	760,000	$ 4.3798	$ 3,328,654	$ 3.5310	$ 2,683,560	$ 3.5310	$ 2,683,560	$ -	$ 0.2017	$ 153,257	$ 2,836,817
NNG-NMU	9	8.65%	9	90,000	$ 4.3798	$ 394,183	$ 3.5310	$ 317,790	$ 3.5310	$ 317,790	$ -	$ 0.2017	$ 18,149	$ 335,939
GLGT-PNG	3	2.88%	3	30,000	$ 4.3798	$ 131,394	$ 3.5310	$ 105,930	$ 3.5310	$ 105,930	$ -	$ 0.2017	$ 6,050	$ 111,980
GLGT-NMU	5	4.81%	5	50,000	$ 4.3798	$ 218,990	$ 3.5310	$ 176,550	$ 3.5310	$ 176,550	$ -	$ 0.2017	$ 10,083	$ 186,633
VGT-PNG	3	2.88%	3	30,000	$ 4.3798	$ 131,394	$ 3.5310	$ 105,930	$ 3.5310	$ 105,930	$ -	$ 0.2017	$ 6,050	$ 111,980
VGT-NMU	4	3.85%	4	40,000	$ 4.3798	$ 175,192	$ 3.5310	$ 141,240	$ 3.5310	$ 141,240	$ -	$ 0.2017	$ 8,066	$ 149,306
Centra	4	3.85%	4	40,000	$ 4.3798	$ 175,192	$ 3.5310	$ 141,240	$ 3.5310	$ 141,240	$ -	$ 0.2017	$ 8,066	$ 149,306
Total	104	100.0%	104	1,040,000	$ 4.3798	$ 4,555,000	$ 3.5310	$ 3,672,240	$ 3.5310	$ 3,672,240	$ -	$ 0.2017	$ 209,720	$ 3,881,960
														$ 3.7327

Dec-11

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	05/31/11		22	220,000	$ 5.5000	$ 1,210,000	$ 3.8140	$ 839,080	$ 3.8140	$ 839,080	$ -	$ 0.2880	$ 63,360	$ 902,440
2	06/30/11		22	220,000	$ 5.0000	$ 1,100,000	$ 3.8140	$ 839,080	$ 3.8140	$ 839,080	$ -	$ 0.2750	$ 60,500	$ 899,580
3	07/25/11		21	210,000	$ 5.0000	$ 1,050,000	$ 3.8140	$ 800,940	$ 3.8140	$ 800,940	$ -	$ 0.1980	$ 41,580	$ 842,520
4	08/03/11		25	250,000	$ 4.5000	$ 1,125,000	$ 3.8140	$ 953,500	$ 3.8140	$ 953,500	$ -	$ 0.2670	$ 66,750	$ 1,020,250
5	09/23/11		25	250,000	$ 4.0000	$ 1,000,000	$ 3.8140	$ 953,500	$ 3.8140	$ 953,500	$ -	$ 0.2180	$ 54,500	$ 1,008,000
6	10/07/11		28	280,000	$ 4.0000	$ 1,120,000	$ 3.8140	$ 1,067,920	$ 3.8140	$ 1,067,920	$ -	$ 0.1100	$ 30,800	$ 1,098,720
7				-		$ -	$ -	$ -	$ 3.8140	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.8140	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.8140	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.8140	$ -	$ -		$ -	$ -
Total			143	1,430,000		$ 6,605,000		$ 5,454,020		$ 5,454,020	$ -		$ 317,490	$ 5,771,510
						$ 4.6189		$ 3.8140		$ 3.8140	$ -		$ 0.2220	$ 4.0360
NNG-PNG	105	73.43%	105	1,050,000	$ 4.6189	$ 4,849,825	$ 3.8140	$ 4,004,700	$ 3.8140	$ 4,004,700	$ -	$ 0.2220	$ 233,122	$ 4,237,822
NNG-NMU	13	9.09%	13	130,000	$ 4.6189	$ 600,455	$ 3.8140	$ 495,820	$ 3.8140	$ 495,820	$ -	$ 0.2220	$ 28,863	$ 524,683
GLGT-PNG	4	2.80%	4	40,000	$ 4.6189	$ 184,755	$ 3.8140	$ 152,560	$ 3.8140	$ 152,560	$ -	$ 0.2220	$ 8,881	$ 161,441
GLGT-NMU	7	4.90%	7	70,000	$ 4.6189	$ 323,322	$ 3.8140	$ 266,980	$ 3.8140	$ 266,980	$ -	$ 0.2220	$ 15,541	$ 282,521
VGT-PNG	3	2.10%	3	30,000	$ 4.6189	$ 138,566	$ 3.8140	$ 114,420	$ 3.8140	$ 114,420	$ -	$ 0.2220	$ 6,661	$ 121,081
VGT-NMU	6	4.20%	6	60,000	$ 4.6189	$ 277,133	$ 3.8140	$ 228,840	$ 3.8140	$ 228,840	$ -	$ 0.2220	$ 13,321	$ 242,161
Centra	5	3.50%	5	50,000	$ 4.6189	$ 230,944	$ 3.8140	$ 190,700	$ 3.8140	$ 190,700	$ -	$ 0.2220	$ 11,101	$ 201,801
Total	143	100.0%	143	1,430,000	$ 4.6189	$ 6,605,000	$ 3.8140	$ 5,454,020	$ 3.8140	$ 5,454,020	$ -	$ 0.2220	$ 317,490	$ 5,771,510
														$ 4.0360

Jan-12

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	05/27/11		21	210,000	$ 5.5000	$ 1,155,000	$ 3.9710	$ 833,910	$ 3.9710	$ 833,910	$ -	$ 0.3150	$ 66,150	$ 900,060
2	06/17/11		25	250,000	$ 5.0000	$ 1,250,000	$ 3.9710	$ 992,750	$ 3.9710	$ 992,750	$ -	$ 0.3900	$ 97,500	$ 1,090,250
3	07/26/11		27	270,000	$ 5.0000	$ 1,350,000	$ 3.9710	$ 1,072,170	$ 3.9710	$ 1,072,170	$ -	$ 0.2600	$ 70,200	$ 1,142,370
4	08/31/11		28	280,000	$ 4.5000	$ 1,260,000	$ 3.9710	$ 1,111,880	$ 3.9710	$ 1,111,880	$ -	$ 0.3150	$ 88,200	$ 1,200,080
5	09/29/11		30	300,000	$ 4.5000	$ 1,350,000	$ 3.9710	$ 1,191,300	$ 3.9710	$ 1,191,300	$ -	$ 0.1390	$ 41,700	$ 1,233,000
6	10/18/11		31	310,000	$ 4.0000	$ 1,240,000	$ 3.9710	$ 1,231,010	$ 3.9710	$ 1,231,010	$ -	$ 0.2050	$ 63,550	$ 1,294,560
7				-		$ -	$ -	$ -	$ 3.9710	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.9710	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.9710	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.9710	$ -	$ -		$ -	$ -
Total	Total		162	1,620,000		$ 7,605,000		$ 6,433,020		$ 6,433,020	$ -		$ 427,300	$ 6,860,320
						$ 4.6944		$ 3.9710		$ 3.9710	$ -		$ 0.2638	$ 4.2348
NNG-PNG	117	72.22%	117	1,170,000	$ 4.6944	$ 5,492,500	$ 3.9710	$ 4,646,070	$ 3.9710	$ 4,646,070	$ -	$ 0.2638	$ 308,506	$ 4,954,576
NNG-NMU	15	9.26%	15	150,000	$ 4.6944	$ 704,167	$ 3.9710	$ 595,650	$ 3.9710	$ 595,650	$ -	$ 0.2638	$ 39,565	$ 635,215
GLGT-PNG	4	2.47%	4	40,000	$ 4.6944	$ 187,778	$ 3.9710	$ 158,840	$ 3.9710	$ 158,840	$ -	$ 0.2638	$ 10,551	$ 169,391
GLGT-NMU	8	4.94%	8	80,000	$ 4.6944	$ 375,556	$ 3.9710	$ 317,680	$ 3.9710	$ 317,680	$ -	$ 0.2638	$ 21,101	$ 338,781
VGT-PNG	4	2.47%	4	40,000	$ 4.6944	$ 187,778	$ 3.9710	$ 158,840	$ 3.9710	$ 158,840	$ -	$ 0.2638	$ 10,551	$ 169,391
VGT-NMU	8	4.94%	8	80,000	$ 4.6944	$ 375,556	$ 3.9710	$ 317,680	$ 3.9710	$ 317,680	$ -	$ 0.2638	$ 21,101	$ 338,781
Centra	6	3.70%	6	60,000	$ 4.6944	$ 281,667	$ 3.9710	$ 238,260	$ 3.9710	$ 238,260	$ -	$ 0.2638	$ 15,826	$ 254,086
Total	162	100.0%	162	1,620,000	$ 4.6944	$ 7,605,000	$ 3.9710	$ 6,433,020	$ 3.9710	$ 6,433,020	$ -	$ 0.2638	$ 427,300	$ 6,860,320
														$ 4.2348

Feb-12

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	05/27/11		20	200,000	$ 5.5000	$ 1,100,000	$ 3.9890	$ 797,800	$ 3.9890	$ 797,800	$ -	$ 0.3250	$ 65,000	$ 862,800
2	06/17/11		21	210,000	$ 5.0000	$ 1,050,000	$ 3.9890	$ 837,690	$ 3.9890	$ 837,690	$ -	$ 0.4050	$ 85,680	$ 923,370
3	07/27/11		23	230,000	$ 5.0000	$ 1,150,000	$ 3.9890	$ 917,470	$ 3.9890	$ 917,470	$ -	$ 0.3000	$ 69,000	$ 986,470
4	08/30/11		24	240,000	$ 4.5000	$ 1,080,000	$ 3.9890	$ 957,360	$ 3.9890	$ 957,360	$ -	$ 0.2740	$ 65,760	$ 1,023,120
5	09/30/11		24	240,000	$ 4.5000	$ 1,080,000	$ 3.9890	$ 957,360	$ 3.9890	$ 957,360	$ -	$ 0.1620	$ 38,880	$ 996,240
6	10/19/11		27	270,000	$ 4.0000	$ 1,080,000	$ 3.9890	$ 1,077,030	$ 3.9890	$ 1,077,030	$ -	$ 0.2650	$ 71,550	$ 1,148,580
7				-		$ -	$ -	$ -	$ 3.9890	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.9890	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.9890	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.9890	$ -	$ -		$ -	$ -
Total			139	1,390,000		$ 6,540,000		$ 5,544,710		$ 5,544,710	$ -		$ 395,870	$ 5,940,580
						$ 4.7050		$ 3.9890		$ 3.9890	$ -		$ 0.2848	$ 4.2738
NNG-PNG	99	71.22%	99	990,000	$ 4.7050	$ 4,657,986	$ 3.9890	$ 3,949,110	$ 3.9890	$ 3,949,110	$ -	$ 0.2848	$ 281,951	$ 4,231,061
NNG-NMU	13	9.35%	13	130,000	$ 4.7050	$ 611,655	$ 3.9890	$ 518,570	$ 3.9890	$ 518,570	$ -	$ 0.2848	$ 37,024	$ 555,594
GLGT-PNG	4	2.88%	4	40,000	$ 4.7050	$ 188,201	$ 3.9890	$ 159,560	$ 3.9890	$ 159,560	$ -	$ 0.2848	$ 11,392	$ 170,952
GLGT-NMU	7	5.04%	7	70,000	$ 4.7050	$ 329,353	$ 3.9890	$ 279,230	$ 3.9890	$ 279,230	$ -	$ 0.2848	$ 19,936	$ 299,166
VGT-PNG	4	2.88%	4	40,000	$ 4.7050	$ 188,201	$ 3.9890	$ 159,560	$ 3.9890	$ 159,560	$ -	$ 0.2848	$ 11,392	$ 170,952
VGT-NMU	7	5.04%	7	70,000	$ 4.7050	$ 329,353	$ 3.9890	$ 279,230	$ 3.9890	$ 279,230	$ -	$ 0.2848	$ 19,936	$ 299,166
Centra	5	3.60%	5	50,000	$ 4.7050	$ 235,252	$ 3.9890	$ 199,450	$ 3.9890	$ 199,450	$ -	$ 0.2848	$ 14,240	$ 213,690
Total	139	100.0%	139	1,390,000	$ 4.7050	$ 6,540,000	$ 3.9890	$ 5,544,710	$ 3.9890	$ 5,544,710	$ -	$ 0.2848	$ 395,870	$ 5,940,580
														$ 4.2738

Mar-12

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	05/27/11		14	140,000	$ 5.5000	$ 770,000	$ 3.9530	$ 553,420	$ 3.9530	$ 553,420	$ -	$ 0.3450	$ 48,300	$ 601,720
2	06/30/11		17	170,000	$ 5.0000	$ 850,000	$ 3.9530	$ 672,010	$ 3.9530	$ 672,010	$ -	$ 0.3900	$ 66,300	$ 738,310
3	07/26/11		18	180,000	$ 5.0000	$ 900,000	$ 3.9530	$ 711,540	$ 3.9530	$ 711,540	$ -	$ 0.3100	$ 55,800	$ 767,340
4	08/24/11		21	210,000	$ 4.5000	$ 945,000	$ 3.9530	$ 830,130	$ 3.9530	$ 830,130	$ -	$ 0.2800	$ 58,800	$ 888,930
5	09/26/11		21	210,000	$ 4.5000	$ 945,000	$ 3.9530	$ 830,130	$ 3.9530	$ 830,130	$ -	$ 0.2100	$ 44,100	$ 874,230
6	10/17/11		21	210,000	$ 4.0000	$ 840,000	$ 3.9530	$ 830,130	$ 3.9530	$ 830,130	$ -	$ 0.3290	$ 69,090	$ 899,220
7				-		$ -	$ -	$ -	$ 3.9530	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.9530	$ -	$ -		$ -	$ -
9				-		$ -	$ -	$ -	$ 3.9530	$ -	$ -		$ -	$ -
10				-		$ -	$ -	$ -	$ 3.9530	$ -	$ -		$ -	$ -
Total			112	1,120,000		$ 5,250,000		$ 4,427,360		$ 4,427,360	$ -		$ 342,390	$ 4,769,750
						$ 4.6875		$ 3.9530		$ 3.9530	$ -		$ 0.3057	$ 4.2587
NNG-PNG	82	73.21%	82	820,000	$ 4.6875	$ 3,843,750	$ 3.9530	$ 3,241,460	$ 3.9530	$ 3,241,460	$ -	$ 0.3057	$ 250,678	$ 3,492,138
NNG-NMU	10	8.93%	10	100,000	$ 4.6875	$ 468,750	$ 3.9530	$ 395,300	$ 3.9530	$ 395,300	$ -	$ 0.3057	$ 30,571	$ 425,871
GLGT-PNG	3	2.68%	3	30,000	$ 4.6875	$ 140,625	$ 3.9530	$ 118,590	$ 3.9530	$ 118,590	$ -	$ 0.3057	$ 9,171	$ 127,761
GLGT-NMU	5	4.46%	5	50,000	$ 4.6875	$ 234,375	$ 3.9530	$ 197,650	$ 3.9530	$ 197,650	$ -	$ 0.3057	$ 15,285	$ 212,935
VGT-PNG	3	2.68%	3	30,000	$ 4.6875	$ 140,625	$ 3.9530	$ 118,590	$ 3.9530	$ 118,590	$ -	$ 0.3057	$ 9,171	$ 127,761
VGT-NMU	5	4.46%	5	50,000	$ 4.6875	$ 234,375	$ 3.9530	$ 197,650	$ 3.9530	$ 197,650	$ -	$ 0.3057	$ 15,285	$ 212,935
Centra	4	3.57%	4	40,000	$ 4.6875	$ 187,500	$ 3.9530	$ 158,120	$ 3.9530	$ 158,120	$ -	$ 0.3057	$ 12,228	$ 170,348
Total	112	100.0%	112	1,120,000	$ 4.6875	$ 5,250,000	$ 3.9530	$ 4,427,360	$ 3.9530	$ 4,427,360	$ -	$ 0.3057	$ 342,390	$ 4,769,750
														$ 4.2587

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			91	910,000	$ 5.4231	$ 4,935,000	$ 3.8665	$ 3,518,550	$ 3.8665	$ 3,518,550	$ -	$ 0.3245	$ 295,310	$ 3,813,860
2			100	1,000,000	$ 4.9250	$ 4,925,000	$ 3.8712	$ 3,871,180	$ 3.8712	$ 3,871,180	$ -	$ 0.3602	$ 360,230	$ 4,231,410
3			105	1,050,000	$ 4.9238	$ 5,170,000	$ 3.8734	$ 4,067,080	$ 3.8734	$ 4,067,080	$ -	$ 0.2710	$ 284,580	$ 4,351,660
4			118	1,180,000	$ 4.5000	$ 5,310,000	$ 3.8636	$ 4,559,070	$ 3.8636	$ 4,559,070	$ -	$ 0.2543	$ 300,110	$ 4,859,180
5			120	1,200,000	$ 4.3125	$ 5,175,000	$ 3.8654	$ 4,638,490	$ 3.8654	$ 4,638,490	$ -	$ 0.1777	$ 213,180	$ 4,851,670
6			126	1,260,000	$ 4.0000	$ 5,040,000	$ 3.8706	$ 4,876,980	$ 3.8706	$ 4,876,980	$ -	$ 0.1900	$ 239,360	$ 5,116,340
7														
8														
9														
10														
Total			660	6,600,000		$ 30,555,000		$ 25,531,350		$ 25,531,350	$ -		$ 1,692,770	$ 27,224,120
						$ 4.6295		$ 3.8684		$ 3.8684	$ -		$ 0.2565	$ 4.1249
NNG-PNG	479	72.58%	479	4,790,000	$ 4.6295	$ 22,175,523	$ 3.8684	$ 18,529,571	$ 3.8684	$ 18,529,571	$ -	$ 0.2565	$ 1,228,541	$ 19,758,111
NNG-NMU	60	9.09%	60	600,000	$ 4.6295	$ 2,777,727	$ 3.8684	$ 2,321,032	$ 3.8684	$ 2,321,032	$ -	$ 0.2565	$ 153,888	$ 2,474,920
GLGT-PNG	18	2.73%	18	180,000	$ 4.6295	$ 833,318	$ 3.8684	$ 696,310	$ 3.8684	$ 696,310	$ -	$ 0.2565	$ 46,166	$ 742,476
GLGT-NMU	32	4.85%	32	320,000	$ 4.6295	$ 1,481,455	$ 3.8684	$ 1,237,884	$ 3.8684	$ 1,237,884	$ -	$ 0.2565	$ 82,074	$ 1,319,957
VGT-PNG	17	2.58%	17	170,000	$ 4.6295	$ 787,023	$ 3.8684	$ 657,626	$ 3.8684	$ 657,626	$ -	$ 0.2565	$ 43,602	$ 701,227
VGT-NMU	30	4.55%	30	300,000	$ 4.6295	$ 1,388,864	$ 3.8684	$ 1,160,516	$ 3.8684	$ 1,160,516	$ -	$ 0.2565	$ 76,944	$ 1,237,460
Centra	24	3.64%	24	240,000	$ 4.6295	$ 1,111,091	$ 3.8684	$ 928,413	$ 3.8684	$ 928,413	$ -	$ 0.2565	$ 61,555	$ 989,968
Total	660	100.0%	660	6,600,000	$ 4.6295	$ 30,555,000	$ 3.8684	$ 25,531,350	$ 3.8684	$ 25,531,350	$ -	$ 0.2565	$ 1,692,770	$ 27,224,120
														$ 4.1249