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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–PNG for Approval of a Change in Demand Entitlement for its Great Lakes Gas Transmission System;
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-PNG Petition for Approval of Change in Demand Entitlement

Notice of Availability

Please take notice that Minnesota Energy Resources Corporation-PNG 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 – PNG	)	
for Approval of a Change in Demand	)	Docket No. ______________
Entitlement for its Great Lakes Gas	)	
Transmission System	)	

SUMMARY OF FILING

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

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In the Matter of the Petition of Minnesota	)	
Energy Resources Corporation – PNG	)	
for Approval of a Change in Demand	)	Docket No. _______________
Entitlement for its Great Lakes Gas	)	
Transmission System	)	

FILING UPON CHANGE IN DEMAND

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation-PNG (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-PNG's customers served off of the Great Lakes Gas Transmission (GLGT) system. 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

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 – PNG	)	
for Approval of a Change in Demand	)	Docket No. _______________
Entitlement for its Great Lakes Gas	)	
Transmission System	)	

PETITION FOR CHANGE IN DEMAND

I. INTRODUCTION

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - PNG (MERC or the Company), a division of Integrys Energy Group, Inc. (TEG), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-PNG's customers served off of the Great Lakes Gas Transmission (GLGT or Great Lakes) system. 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 PNG-GLGT Design Day Requirements

MERC's 2011-2012 PNG-GLGT design day requirements decreased 136 Mcf (or approximately 1.44 percent) from 9,440 Mcf to 9,304 Mcf.

Table 1: MERC's Proposed Reserve Margins
For the 2011-2012 Heating Season
GLGT PNG

	Reserve Margin 2011-2012 Heating Season	Reserve Margin 2010-2011 Heating Season	Change
GLGT-PNG	9.08%	21.82%	-12.74%

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

For the Demand Entitlement filing effective November 1, 2011, the total Design Day requirement for PNG-GLGT is 9,440 Dth as calculated in Attachment 1, page 2 and Attachment 3.

For the Demand Entitlement filing effective November 1, 2011, the total Design Day capacity for PNG-GLGT, is 10,149 Dth as calculated in Attachment 3.

The difference between the total Design Day requirement and total Design Day capacity results in a 9.08% positive reserve margin.

B. <u>Forecast Methodology for MERC Demand Entitlement Nov. 1, 2010</u>

<u>Peakday</u>

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[1].
    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[2]. 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[3], 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

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

[3] 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 10. 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 NNG pipeline. 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 379 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 379 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 11.

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

There are two types of demand entitlement changes. The first type is design day deliverability, which, in this case, MERC is proposing no change in the firm transportation capacity actually available to MERC-PNG-GLGT 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 6, MERC-PNG-GLGT proposes no change in design day deliverability for the upcoming heating season.

2. Other Demand Entitlement Changes

As shown in Attachment 6, MERC-PNG-GLGT terminated the Nexen PSO and replaced it with 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 MERC 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 $46,044 for the 2011-2012 winter. Please see Attachment 5.

iii. MERC entered into 18 contracts (10,000/contract) or 180,000. Total premium per contract is approximately $0.2558. 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 13 futures contracts (10,000/contract) or 130,000,

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 9, page 1 of 2.

E. Gas Supply.

The PNG-GLGT 2011-2012 Winter Portfolio Plan - Minnesota Energy Resources Corporation for GLGT gas supply purchases for the Hedging Plan is in Attachment 9, page 2. 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. Price Volatility

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 physical fixed price purchases. MERC is projecting the weighted average cost of gas (WACOG) for futures contracts of natural gas to be approximately $4.5313. Please see Attachment 12, page 1 of 3. MERC is projecting the AECO Storage for PNG-GLGT 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 12, 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 12, 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 its monthly PGA effective November 1, 2011. Rate impacts associated with this change can be found on Attachment 4, pages 1 and 2, 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 3 and 4, 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-GLGT, there have been two (2) 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 76 Mcf. Assuming the projected peak day is accurate, MERC may potentially have a negative reserve margin.

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

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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Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Richard	Haubensak	RICHARD.HAUBENSAK@CONSTELLATION.COM	Constellation New Energy Gas	Suite 200 12120 Port Grace Boulevard La Vista, NE 68128	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Jack	Kegel		MMUA	Suite 400 3025 Harbor Lane North Plymouth, MN 554475142	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Robert S	Lee	RSL@MCMLAW.COM	Mackall Crounse & Moore Law Offices	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 554022859	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Brian	Meloy	brian.meloy@leonard.com	Leonard, Street & Deinard	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List
Gregory	Walters	gjwalters@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	3460 Technology Dr. NW Rochester, MN 55901	Paper Service	No	GEN_SL_Minnesota Energy Resources Corporation_General Service List

DORSEY
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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 for Approval of a Change in Demand Entitlement

Docket No. ____________________

Dear Dr. Haar:

On September 26, 2011, the Department of Commerce, Division of Energy Resources filed Comments in Docket No. G007,011/M-10-374, recommending that the Minnesota Public Utilities Commission (Commission) accept MERC's Annual Service Quality Report pending MERC's provision of additional information. The Department requested that the Company provide, as part of its initial filing in its November 1, 2011, demand entitlement filings, a full discussion of what, if any, impacts customer migrations have had on peak day projections and a detailed accounting of how many customers have changed, or anticipate changing, classes.

In response to the Department's request, the attached spreadsheet (nonpublic and public versions) shows a detailed accounting of how many customers have changed classes and the impact customer migrations have had on peak day projections. At this time, MERC is not aware of any additional migrations, although there remains the possibility that some customers might change classes. The impacts of customer switches are also addressed in the demand entitlement report for each PGA system.

Thank you for your attention to this matter,

Sincerely yours,

/s/ Michael J. Ahern

Michael J. Ahern

DeleteDate	CustID	Acct	CustomerName	Address	City	Highest Monthly usage	Area	PNG/NMU	Peak Day				
	[Trade Secret Data Begins…												
16-Feb-11					INTERNATIONAL FALLS	0	Centra	NMU	0				
16-Feb-11					INTERNATIONAL FALLS	15439	Centra	NMU	772				
16-Feb-11					BAUDETTE	0	Centra	NMU	0				
16-Feb-11					INTERNATIONAL FALLS	4583	Centra	NMU	229				
16-Feb-11					DEER RIVER	5960	GLGT	NMU	298				
16-Feb-11					DEER RIVER	7728	GLGT	NMU	386				
16-Feb-11					GRAND RAPIDS	633	GLGT	NMU	32				
16-Feb-11					THIEF RIVER FALLS	5253	GLGT	NMU	263				
16-Feb-11					AITKIN	3133	NNG	NMU	157				
16-Feb-11					AITKIN	2665	NNG	NMU	133				
16-Feb-11					CLOQUET	9237	NNG	NMU	462				
16-Feb-11					CLOQUET	12828	NNG	NMU	641				
16-Feb-11					BOVEY	3153	NNG	NMU	158				
07-Mar-11					GILBERT	2587	NNG	NMU	129				
22-Mar-11					PROCTOR	2580	NNG	NMU	129				
16-Feb-11					PROCTOR	2202	NNG	NMU	110				
12-Aug-11					BOVEY	1775	NNG	NMU	89				
16-Feb-11					COLERAINE	2683	NNG	NMU	134				
07-Mar-11					PARK RAPIDS	3556	VKG	NMU	178				
17-Mar-11					PARK RAPIDS	2088	VKG	NMU	104				
16-Feb-11					WADENA	3331	VKG	NMU	167				
16-Feb-11					BERTHA	0	VKG	NMU	0				
16-Feb-11					MOTLEY	1348	VKG	NMU	67				
17-Mar-11					PARK RAPIDS	3844	VKG	NMU	192				
02-May-11					WADENA	178	VKG	NMU	9				
31-May-11					BEMIDJI	5640	GLGT	PNG	282				
17-Mar-11					BEMIDJI	9477	GLGT	PNG	474				
16-Feb-11					WEBSTER	3515	NNG	PNG	176				
16-Feb-11					CASTLE ROCK	931	NNG	PNG	47				
28-Mar-11					ELLENDALE	3266	NNG	PNG	163				
16-Feb-11					HAYFIELD	28480	NNG	PNG	1424				
16-Feb-11					HAYFIELD	3346	NNG	PNG	167				
02-Mar-11					LEWISTON	2939	NNG	PNG	147				
16-Feb-11					HOUSTON	0	NNG	PNG	0				
16-Feb-11					CHISHOLM	20	NNG	PNG	1				
16-Feb-11					SANBORN	20	NNG	PNG	1				
16-Feb-11					LAMBERTON	563	NNG	PNG	28				
16-Feb-11					CANNON FALLS	24451	NNG	PNG	1223				
25-Mar-11					EAGAN	9296	NNG	PNG	465				
16-Feb-11					CANNON FALLS	289	NNG	PNG	14				
16-Feb-11					LAKEVILLE	3629	NNG	PNG	181				
07-Mar-11					LAKEVILLE	21709	NNG	PNG	1085				
16-Feb-11					LAKEVILLE	3563	NNG	PNG	178				
16-Feb-11					LAKEFIELD	2859	NNG	PNG	143				
16-Feb-11					FAIRMONT	0	NNG	PNG	0				
16-Feb-11					JACKSON	2469	NNG	PNG	123				
01-Apr-11					FREEBORN	2025	NNG	PNG	101				
16-Feb-11					FAIRMONT	6657	NNG	PNG	333				
13-May-11					ROCHESTER	2513	NNG	PNG	126				
13-May-11					ROCHESTER	5703	NNG	PNG	285				
22-Mar-11					MANTORVILLE	2697	NNG	PNG	135				
04-Apr-11					ROCHESTER	7430	NNG	PNG	372				
16-Feb-11					PRESTON	5947	NNG	PNG	297				
03-May-11					ROCHESTER	2648	NNG	PNG	132				
16-Feb-11					BLOOMING PRAIRIE	8051	NNG	PNG	403				
28-Mar-11					RUSHFORD	4198	NNG	PNG	210				

13-May-11					ROCHESTER	4943	NNG	PNG	247				
16-Feb-11					HARMONY	13706	NNG	PNG	685				
16-Feb-11					ROCHESTER	16789	NNG	PNG	839				
04-Apr-11					ROCHESTER	21252	NNG	PNG	1063				
22-Mar-11					KENYON	4913	NNG	PNG	246				
16-Feb-11					PRESTON	1	NNG	PNG	0				
13-May-11					ROCHESTER	6337	NNG	PNG	317				
13-May-11					ROCHESTER	4427	NNG	PNG	221				
13-May-11					ROCHESTER	9514	NNG	PNG	476				
13-May-11					ROCHESTER	3398	NNG	PNG	170				
04-Apr-11					HOUSTON	8305	NNG	PNG	415				
11-May-11					ROCHESTER	1164	NNG	PNG	58				
04-Apr-11					ROCHESTER	9845	NNG	PNG	492				
03-May-11					SPRING VALLEY	7882	NNG	PNG	394				
16-Feb-11					CHATFIELD	0	NNG	PNG	0				
16-Feb-11					ROCHESTER	0	NNG	PNG	0				
16-Feb-11					FINLAYSON	3082	NNG	PNG	154				
28-Mar-11					SANDSTONE	6029	NNG	PNG	301				
31-Mar-11					MADISON	3589	NNG	PNG	179				
16-Feb-11					MADISON	0	NNG	PNG	0				
31-May-11					ORTONVILLE	2412	NNG	PNG	121				
16-Feb-11					WORTHINGTON	3384	NNG	PNG	169				
16-Feb-11					WINDOM	0	NNG	PNG	0				
15-Apr-11					TRACY	2691	NNG	PNG	135				
04-Apr-11					MADISON	0	NNG	PNG	0				
16-Feb-11					WORTHINGTON	3677	NNG	PNG	184				
16-Feb-11					PRESTON	1206291	NNG	PNG	60315				
16-Feb-11					RUSHFORD	409	NNG	PNG	20				
16-Feb-11					FAIRMONT	6133	NNG	PNG	307				
22-Mar-11					WORTHINGTON	122	NNG	PNG	6				
16-Feb-11					DOVER	1186	NNG	PNG	59				
05-Apr-11					WORTHINGTON	1765	NNG	PNG	88				
16-Feb-11					DUNNELL	15679	NNG	PNG	784				
16-Feb-11					FARMINGTON	122	NNG	PNG	6				
12-Aug-11					CHATFIELD	6775	NNG	PNG	339				
22-Mar-11					WANAMINGO	6385	NNG	PNG	319				
16-Feb-11					DETROIT LAKES	14308	VKG	PNG	715				
16-Feb-11					DETROIT LAKES	6497	VKG	PNG	325				
16-Feb-11					DETROIT LAKES	5368	VKG	PNG	268				
16-Feb-11					DETROIT LAKES	11527	VKG	PNG	576				
16-Feb-11					DETROIT LAKES	5111	VKG	PNG	256				
16-Feb-11					DETROIT LAKES	11676	VKG	PNG	584				
16-Feb-11					ADA	395	VKG	PNG	20				
16-Feb-11					DETROIT LAKES	107	VKG	PNG	5				
16-Feb-11					ADA	738	VKG	PNG	37				
16-Feb-11					DETROIT LAKES	65654	VKG	PNG	3283				
16-Feb-11					DETROIT LAKES	11309	VKG	PNG	565				
16-Feb-11					DETROIT LAKES	41960	VKG	PNG	2098				

…Trade Secret Data Ends]

PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

MERC-PNG

Demand Entitlement Schedules - GLGT

MINNESOTA ENERGY RESOURCES

DESIGN-DAY DEMAND SUMMARY

NOVEMBER 1, 2011

GLGT

Design Day Requirement		9,304
Total Entitlement on Peak Day(excl. Peak Shaving)		10,149
Firm Peak Day Actual Sendout -Non Coincidental	(Jan. 20)	7,539
Firm Annual Throughput - Minnesota		828,257
No. of Firm Customers		6,041
DPS Load Factor Calculation		30.10%

MINNESOTA ENERGY RESOURCES - PNG

MINNESOTA DESIGN DAY REQUIREMENTS
NOVEMBER 1, 2011
GLGT

Pipeline Group	Nov10-Mar 11 Avg. Customer Count	1/20 Design DDD	Regression Factors Intercept	Regression Factors Slope	Regression Total Footnote 1	Regression Adjustment Footnote 2	1/20 Requirements Regression Load Footnote 3	Nov10-Mar 11 Avg. Customer Growth	Total
PEAK									
	6,041	107	787	90	10,367	987	9,380	-0.8%	9,304
Total	6,041								9,304
OFF PEAK									
	6,041	57	787	90	5,890	298	5,592	-0.8%	5,547
Total	6,041								5,547

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

*All the requirments are adjusted by customer growth

MINNESOTA ENERGY RESOURCES

DESIGN-DAY DEMAND PER CUSTOMER

NOVEMBER 1, 2011

GLGT

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtus /Customer /Day
11/12	6,041	9,304	1.54
10/11	6,053	9,440	1.56
09/10	6,068	10,802	1.78
08/09	5,874	10,299	1.75
07/08	5,816	9,550	1.64
06/07	5,747	9,543	1.66
05/06	5,679	9,510	1.67
04/05	5,514	9,449	1.71

MINNESOTA ENERGY RESOURCES

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

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	223,709	576,938	800,646
SVI	4,785	13,771	18,556
SVJ	10,952	16,658	27,611
Total	239,446	607,367	846,813

MINNESOTA ENERGY RESOURCES

ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2011

GLGT

Type of Capacity or Entitlement	Current Amount Mcf or MMBtu	Proposed Change Mcf or MMBtu	Proposed Amount Mcf or MMBtu
FT0016	4,105	(206)	3,899
FT0075	1,973	(1,973)	0
FT0155(12)	2,422	(1,036)	1,386
FT0155(5)	1,500	(100)	1,400
FT8466	1,500	(1,500)	0
FT15782	0	3,464	3,464
Heating Season Total	11,500	(1,351)	10,149
Non-Heating Season Total	10,000	(1,251)	8,749
Total Entitlement	11,500	(1,351)	10,149
Heating Season Forecasted Design Day	10,802		9,304
Non-Heating Season Forecasted Design Day	6,413		5,547
Heating Season Capacity Surplus/Shortage	698		845
Non-Heating Season Capacity Surplus/Shortage	3,587		3,202

MINNESOTA ENERGY RESOURCES - PNG

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	GLGT 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:				84	Mcf				
Commodity Cost	$5.5117	$3.6667	$3.7750	$3.7221	$4.0054	-27.33%	6.10%	7.61%	$0.2833
Demand Cost	$0.7701	$0.7964	$0.7613	$0.8421	$0.6791	-11.81%	-10.79%	-19.35%	($0.1630)
Commodity Margin	$1.7746	$1.6263	$1.7746	$1.7746	$1.7746	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$8.0564	$6.0894	$6.3109	$6.3388	$6.4591	-19.83%	2.35%	1.90%	$0.1203
Avg Annual Cost	$676.74	$511.51	$530.12	$532.46	$542.57	-19.83%	2.35%	1.90%	$10.11
Effect of proposed commodity change on average annual bills:									$23.80
Effect of proposed demand change on average annual bills:									($13.69)
2) Small Vol. Interruptible: Avg. Annual Use:				2,896	Mcf				
Commodity Cost	$5.5117	$3.6667	$3.7750	$3.7221	$4.0054	-27.33%	6.10%	7.61%	$0.2833
Demand Cost									
Commodity Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$6.6798	$4.9101	$4.9431	$4.8902	$5.1735	-22.55%	4.66%	5.79%	$0.2833
Avg Annual Cost	$19,344.70	$14,219.65	$14,315.22	$14,162.02	$14,982.52	-22.55%	4.66%	5.79%	$820.50
Effect of proposed commodity change on average annual bills:									$820.50
Effect of proposed demand change on average annual bills:									$0.00
3) Small Vol. Firm: Avg. Annual Use:				4,964	Mcf				
Avg. Annual CD units:				50					
Commodity Cost	$5.5117	$3.6667	$3.7750	$3.7221	$4.0054	-27.33%	6.10%	7.61%	$0.2833
Demand Cost	$5.2429	$3.4580	$3.4580	$3.4580	$3.4580	-34.04%	0.00%	0.00%	$0.0000
Commodity Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Demand Margin	$1.8000	$2.0724	$1.8000	$1.8000	$1.8000	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$6.6798	$4.9101	$4.9431	$4.8902	$5.1735	-22.55%	4.66%	5.79%	$0.2833
Total Demand Cost	$7.0429	$5.5304	$5.2580	$5.2580	$5.2580	-25.34%	0.00%	0.00%	$0.0000
Avg Annual Cost	$33,510.67	$24,650.26	$24,800.45	$24,537.85	$25,944.26	-22.58%	4.61%	5.73%	$1,406.41
Effect of proposed commodity change on average annual bills:									$1,406.41
Effect of proposed demand change on average annual bills:									$0.00

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 - PNG

CALCULATION OF PURCHASED GAS ADJUSTMENT (PGA) | **GLGT**
Great Lakes Current Cost of Gas

						01-Nov-11	CURRENT	
II. GREAT LAKES GAS TRANSMISSION'S RATES -- CURRENT COST OF GAS EFFECTIVE								
	Commodity From Schedule D					$0.39998	/therm	
III. ANNUAL SALES --								
	Total Annual Sales					10,762,470	therms	
	Firm Annual Sales (GS-5)					8,725,440	therms	
IV. PNG'S -- CURRENT COST OF GAS EFFECTIVE						01-Nov-11	CURRENT	
			Monthly Entitlement	**Months**	**Rate $/Dth**		**Contract Cost**	**$/therm**
A. GS-5	FT Western Zone	FT0016	3,899	12	$3.4580	=	$161,793	$0.01854
	FT Western Zone (12)	FT0155	1,386	12	$3.4580	=	$57,513	$0.00659
	FT Western Zone (5)	FT0155	1,400	5	$3.4580	=	$24,206	$0.00277
	FT Western Zone	FT15782	3,464	12	$3.4580	=	$143,742	$0.01647
	Total Demand Cost						$387,254	$0.04438
	Niska Storage (AECO)		147,196	1	$0.95483	=	$ 140,547	$0.01611
	AECO/Emerson Swap		147,197	1	$0.44000	=	$ 64,767	$0.00742
	Total Storage Demand						$ 205,314	$0.02353
	Rate Case 2008 Firm Annual Sales in therms						8,725,440	
	Current Demand Cost of Gas $/therm							**$0.06791**
	Current T-17 Commodity Cost of Gas							$0.39998
	Call Option Premium				$6,049.62	10,762,470		$0.00056
	GS-5 Total Current Commodity Cost of Gas $/therm							**$0.40054**
	Current Total Cost of Gas $/therm							$0.46845
B. SVI-5	Current Commodity Cost of Gas $/therm							$0.40054
C. SJ-5	Current Demand Cost of Gas $/therm							$0.34580
	Current Commodity Cost of Gas $/therm							$0.40054
D. LVI-5	Current Commodity Cost of Gas $/therm							$0.40054

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

MINNESOTA ENERGY RESOURCES - PNG

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	GLGT 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:				84	Mcf				
Commodity Cost	$5.5117	$3.6667	$3.7750	$3.7221	$4.2691	-22.55%	13.09%	14.69%	$0.5470
Demand Cost	$0.7701	$0.7964	$0.7613	$0.8421	$0.4438	-42.37%	-41.70%	-47.30%	($0.3983)
Commodity Margin	$1.7746	$1.6263	$1.7746	$1.7746	$1.7746	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$8.0564	$6.0894	$6.3109	$6.3388	$6.4875	-19.47%	2.80%	2.35%	$0.1487
Avg Annual Cost	$676.74	$511.51	$530.12	$532.46	$544.95	-19.47%	2.80%	2.35%	$12.49
Effect of proposed commodity change on average annual bills:									$45.94
Effect of proposed demand change on average annual bills:									($33.46)
2) Small Vol. Interruptible: Avg. Annual Use:				2,896	Mcf				
Commodity Cost	$5.5117	$3.6667	$3.7750	$3.7221	$4.2691	-22.55%	13.09%	14.69%	$0.5470
Demand Cost									
Commodity Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$6.6798	$4.9101	$4.9431	$4.8902	$5.4372	-18.60%	9.99%	11.18%	$0.5470
Avg Annual Cost	$19,344.70	$14,219.65	$14,315.22	$14,162.02	$15,745.99	-18.60%	9.99%	11.18%	$1,583.97
Effect of proposed commodity change on average annual bills:									$1,583.97
Effect of proposed demand change on average annual bills:									$0.00
3) Small Vol. Firm: Avg. Annual Use:				4,964	Mcf				
Avg. Annual CD units:				50					
Commodity Cost	$5.5117	$3.6667	$3.7750	$3.7221	$4.2691	-22.55%	13.09%	14.69%	$0.5470
Demand Cost	$5.2429	$3.4580	$3.4580	$3.4580	$3.4580	-34.04%	0.00%	0.00%	$0.0000
Commodity Margin	$1.1681	$1.2434	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Demand Margin	$1.8000	$2.0724	$1.8000	$1.8000	$1.8000	0.00%	0.00%	0.00%	$0.0000
Total Cost of Gas	$6.6798	$4.9101	$4.9431	$4.8902	$5.4372	-18.60%	9.99%	11.18%	$0.5470
Total Demand Cost	$7.0429	$5.5304	$5.2580	$5.2580	$5.2580	-25.34%	0.00%	0.00%	$0.0000
Avg Annual Cost	$33,510.67	$24,650.26	$24,800.45	$24,537.85	$27,252.92	-18.67%	9.89%	11.06%	$2,715.06
Effect of proposed commodity change on average annual bills:									$2,715.06
Effect of proposed demand change on average annual bills:									$0.00

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

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

MINNESOTA ENERGY RESOURCES - PNG

CALCULATION OF PURCHASED GAS ADJUSTMENT (PGA) GLGT

Great Lakes Current Cost of Gas

II. GREAT LAKES GAS TRANSMISSION'S RATES -- CURRENT COST OF GAS EFFECTIVE					01-Nov-11	CURRENT	
Commodity From Schedule D					$0.39998	/therm	
III. ANNUAL SALES --							
Total Annual Sales					10,762,470	therms	
Firm Annual Sales (GS-5)					8,725,440	therms	
IV. PNG'S -- CURRENT COST OF GAS EFFECTIVE					01-Nov-11	CURRENT	
		Monthly Entitlement	**Months**	**Rate $/Dth**		**Contract Cost**	**$/therm**
A. GS-5 FT Western Zone	FT0016	3,899	12	$3.4580	=	$161,793	$0.01854
FT Western Zone (12)	FT0155	1,386	12	$3.4580	=	$57,513	$0.00659
FT Western Zone (5)	FT0155	1,400	5	$3.4580	=	$24,206	$0.00277
FT Western Zone	FT15782	3,464	12	$3.4580	=	$143,742	$0.01647
					=	$0	$0.00000
Total Demand Cost						$387,254	$0.04438
Niska Storage (AECO)		147,196	0	$0.00000	=	$ -	$0.00000
AECO/Emerson Swap		147,197	0	$0.00000	=	$0	$0.00000
Total Storage Demand						$ -	$0.00000
Rate Case 2008 GS-5 sales in therms						8,725,440	
Current Demand Cost of Gas $/therm							**$0.04438**
Current T-17 Commodity Cost of Gas							$0.39998
Call Option Premium				$9,433.28	10,762,470		$0.00088
Niska Storage (AECO)		147,196	1	$0.95483	10,762,470	$210,432	$0.01955
AECO/Emerson Swap		147,197	1	$0.44000	10,762,470	$69,915	$0.00650
GS-5 Total Current Commodity Cost of Gas $/therm							**$0.42691**
Current Total Cost of Gas $/therm							$0.47129
B. SVI-5 Current Commodity Cost of Gas $/therm							$0.42691
C. SJ-5 Current Demand Cost of Gas $/therm							$0.34580
Current Commodity Cost of Gas $/therm							$0.42691
D. LVI-5 Current Commodity Cost of Gas $/therm							$0.42691

NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

Attachment 5

MINNESOTA ENERGY RESOURCES - PNG-GLGT

Financial Options

Heating Season 2011-2012

[TRADE SECRET DATA BEGINS

Units - Gas Daily Packages

No Gas Daily Peakers were purchased

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		1,000		645		968		690		968	4,270	130,000
		30,000		20,000		30,000		20,000		30,000		130,000

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		1,000		1,290		1,290		1,379		968	5,928	180,000
		30,000		40,000		40,000		40,000		30,000		180,000

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	$ 6,050	$ 0.2220	$ 8,881	$ 0.2638	$ 10,551	$ 0.2950	$ 11,392	$ 0.3057	$ 9,171	$ 0.2558	$ 46,044

Units - Collar Floor (put)

No Puts were purchased.

TRADE SECRET DATA ENDS]

NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

Attachment 6

Peoples' Great Lakes Area Demand Entitlements Historical and Current Proposal

MINNESOTA ENERGY RESOURCES - PNG

2008-09 G011/M-08-1330	Quantity (Mcf)	2009-10 G011/M-09-	Quantity (Mcf)	
FT0017	4,105	FT0017	4,105	
FT0075	1,973	FT0075	1,973	
FT0155	2,422	FT0155	2,422	
FT0155	1,500	FT0155	1,500	
FT0011	0	FT0011	0	
FT8466	500	FT8466	1,500	
Total Design Day Capacity	10,500	Total Design Day Capacity	11,500	
Total GL Transportation	10,500	Total GL Transportation	11,500	
Total Transportation	10,500	Total Transportation	11,500	
Total Seasonal Transport	1,500	Total Seasonal Transport	1,500	
Percent Seasonal on GL	14.3%	Percent Seasonal on GL	13.0%	

2010-11 G011/M-10-	Quantity (Mcf)	2011-12 G011/M-11-	Quantity (Mcf)	Change in Quantity
FT0016	4,105	FT0016	3,899	(206)

MINNESOTA ENERGY RESOURCES - PNG

General Service-Residential	Base Cost of Gas Change G011/MR10-978	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 of Gas (WACOG)	$5.5117	$3.7750	$3.7221	$4.0054	-27.33%	6.10%	7.61%	$0.2833
Demand Cost of Gas	$0.7701	$0.7613	$0.8421	$0.6791	-11.81%	-10.79%	-19.35%	($0.1630)
Commodity Margin	$1.7746	$1.7746	$1.7746	$1.7746	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$8.0564	$6.3109	$6.3388	$6.4591	-19.83%	2.35%	1.90%	$0.1203
Average Annual Usage (Mcf)	84	84	84	84				
Average Annual Bill^	$676.74	$530.12	$532.46	$542.57	-19.83%	2.35%	1.90%	$10.11

Small Volume Interruptible	Base Cost of Gas Change G011/MR10-978	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 of Gas (WACOG)	$5.5117	$3.7750	$3.7221	$4.0054	-27.33%	6.10%	7.61%	$0.2833
Demand Cost of Gas					0.00%	0.00%	0.00%	$0.0000
Commodity Margin	$1.1681	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$6.6798	$4.9431	$4.8902	$5.1735	-22.55%	4.66%	5.79%	$0.2833
Average Annual Usage (Mcf)	2,896	2,896	2,896	2,896				
Average Annual Bill^	$19,344.70	$14,315.22	$14,162.02	$14,982.52	-22.55%	4.66%	5.79%	$820.50

Small Volume Firm	Base Cost of Gas Change G011/MR10-978	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 of Gas (WACOG)	$5.5117	$3.7750	$3.7221	$4.0054	-27.33%	6.10%	7.61%	$0.2833
Demand Cost of Gas	$5.2429	$3.4580	$3.4580	$3.4580	-34.04%	0.00%	0.00%	$0.0000
Commodity Margin	$1.1681	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Demand Margin	$1.8000	$1.8000	$1.8000	$1.8000	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$6.6798	$4.9431	$4.8902	$5.1735	-22.55%	4.66%	5.79%	$0.2833
Total Demand Cost	$7.0429	$5.2580	$5.2580	$5.2580	-25.34%	0.00%	0.00%	$0.0000
Total Recovery	$27.4454	$20.4022	$20.2964	$20.8630	-23.98%	2.26%	2.79%	$0.5666
Average Annual Usage (Mcf)	4,964	4,964	4,964	4,964				
Average Annual CD units (Mcf)	50	50	50	50				
Average Annual Commodity Bill^	$33,510.67	$24,800.45	$24,537.85	$25,944.26	-22.58%	4.61%	5.73%	$1,406.41

Summary	Commodity Change ($/Mcf)	Commodity Change (%)	Demand Change ($/Mcf)	Demand Change (%)	Total Change ($/Mcf)	Total Change (%)
General Service	$0.2833	7.61%	($0.1630)	-19.35%	$0.1203	1.90%
Small Volume Interruptible	$0.2833	7.61%	$0.0000	0.00%	$0.2833	5.79%
Small/Large Volume Firm	$0.2833	0.00%	$0.0000	0.00%	$0.5666	2.79%

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

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

MINNESOTA ENERGY RESOURCES - PNG

General Service	Base Cost of Gas Change G011/MR10-978^	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 of Gas (WACOG)	$5.5117	$3.7750	$3.7221	$4.2691	-22.55%	13.09%	14.69%	$0.5470
Demand Cost of Gas	$0.7701	$0.7613	$0.8421	$0.4438	-42.37%	-41.70%	-47.30%	($0.3983)
Commodity Margin	$1.7746	$1.7746	$1.7746	$1.7746	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$8.0564	$6.3109	$6.3388	$6.4875	-19.47%	2.80%	2.35%	$0.1487
Average Annual Usage (Mcf)	84	84	84	84				
Average Annual Bill^	$676.74	$530.12	$532.46	$544.95	-19.47%	2.80%	2.35%	$12.49

Small Volume Interruptible	Base Cost of Gas Change G011/MR10-978^	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 of Gas (WACOG)	$5.5117	$3.7750	$3.7221	$4.2691	-22.55%	13.09%	14.69%	$0.5470
Demand Cost of Gas					0.00%	0.00%	0.00%	$0.0000
Commodity Margin	$1.1681	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Total Recovery	$6.6798	$4.9431	$4.8902	$5.4372	-18.60%	9.99%	11.18%	$0.5470
Average Annual Usage (Mcf)	2,896	2,896	2,896	2,896				
Average Annual Bill^	$19,344.70	$14,315.22	$14,162.02	$15,745.99	-18.60%	9.99%	11.18%	$1,583.97

Small Volume Firm	Base Cost of Gas Change G011/MR10-978^	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 of Gas (WACOG)	$5.5117	$3.7750	$3.7221	$4.2691	-22.55%	13.09%	14.69%	$0.5470
Demand Cost of Gas	$5.2429	$3.4580	$3.4580	$3.4580	-34.04%	0.00%	0.00%	$0.0000
Commodity Margin	$1.1681	$1.1681	$1.1681	$1.1681	0.00%	0.00%	0.00%	$0.0000
Demand Margin	$1.8000	$1.8000	$1.8000	$1.8000	0.00%	0.00%	0.00%	$0.0000
Total Commodity Cost	$6.6798	$4.9431	$4.8902	$5.4372	-18.60%	9.99%	11.18%	$0.5470
Total Demand Cost	$7.0429	$5.2580	$5.2580	$5.2580	-25.34%	0.00%	0.00%	$0.0000
Total Recovery	$27.4454	$20.4022	$20.2964	$21.3903	-22.06%	4.84%	5.39%	$1.0939
Average Annual Usage (Mcf)	4,964	4,964	4,964	4,964				
Average Annual CD units (Mcf)	50	50	50	50				
Average Annual Commodity Bill^	$33,510.67	$24,800.45	$24,537.85	$27,252.92	-18.67%	9.89%	11.06%	$2,715.06

Summary	Commodity Change ($/Mcf)	Commodity Change (%)	Demand Change ($/Mcf)	Demand Change (%)	Total Change ($/Mcf)	Total Change (%)
General Service	$0.5470	14.69%	($0.3983)	-47.30%	$0.1487	2.35%
Small Volume Interruptible	$0.5470	14.69%	$0.0000	0.00%	$0.5470	11.18%
Small/Large Volume Firm	$0.5470	0.00%	$0.0000	0.00%	$1.0939	5.39%

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

MINNESOTA ENERGY RESOURCES - PNG

GLGT

Peoples Great Lakes – Current Cost of Gas Effective

	Oct. 2011 Entitlements	Nov. 2011 Entitlements	Entitlement Change	Months	Oct. 2011 Rate	Oct. 2011 Total Annual Cost	Nov. 2011 Total Annual Cost	Total Annual Cost Change
T-17 Demand	4,105	3,899	-206	12	$3.4580	$170,341	$161,793	($8,548)
FT-075- Res Fee	1,973	0	-1,973	12	$3.4580	$81,872	$0	($81,872)
FT-155 (12)	2,422	1,386	-1,036	12	$3.4580	$100,503	$57,513	($42,990)
FT-155 (5)	1,500	1,400	-100	5	$3.4580	$25,935	$24,206	($1,729)
FT-8466	1,500	0	-1,500	12	$3.4580	$62,244	$0	($62,244)
FT-15782	0	3,464	3,464	12	$3.4580	$0	$143,742	$143,742
Niska Storage (AECO)	154,307	147,196	-7,111	1	$ 0.9548	$147,336	$ 140,547	($6,789)
AECO/Emerson Swap	154,301	147,197	-7,104	1	$ 0.4400	$73,293	$ 64,767	($8,526)
						$661,524	$592,569	($68,956)

MERC

File name: Copy of MERC 11 12 Demand-Filing Schedules Non-Public Filed 103111.xlsx
Worksheet Name: G8

MINNESOTA ENERGY RESOURCES - PNG

10/11 Winter Portfolio Plan - MERC GLGT-PNG Hedging Plan

[TRADE SECRET DATA BEGINS

10,000 Contract Size

REVISED:

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														
GLGT -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													607,367	**100.00%**

NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

MINNESOTA ENERGY RESOURCES

GLGT WINTER PLAN (PNG)
NOVEMBER, 2010 THROUGH MARCH, 2011

[TRADE SECRET DATA BEGINS

PHYSICAL FIXED PRICE HEDGES - GLGT	Deal #	Trigger Locked	Trigger Exercised	Receipt Point	Nov	Dec	Daily Volumes Jan	Feb	Mar	Monthly Total
	Total Actual Fixed/Option Physical				-	-	-	-	-	-

INDEX - GLGT	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
	Total Actual Seasonal Index			2,000	1,936	2,258	2,069	1,936	310,050

GAS DAILY PACKAGES

STORAGE

Contract #

Total

MINNESOTA ENERGY RESOURCES - PNG

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

Base	379
Variable	95

Date	100.00% Bemidji Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Through-Put
7/1/10	0	0	619	379
7/2/10	0	0	581	379
7/3/10	0	0	540	379
7/4/10	0	0	550	379
7/5/10	0	0	605	379
7/6/10	0	0	654	379
7/7/10	0	0	680	379
7/8/10	0	0	687	379
7/9/10	0	0	624	379
7/10/10	0	0	544	379
7/11/10	4	4	636	786
7/12/10	0	0	668	379
7/13/10	0	0	634	379
7/14/10	0	0	647	379
7/15/10	0	0	643	379
7/16/10	0	0	621	379
7/17/10	0	0	580	379
7/18/10	0	0	587	379
7/19/10	0	0	645	379
7/20/10	0	0	655	379
7/21/10	0	0	640	379
7/22/10	0	0	640	379
7/23/10	0	0	619	379
7/24/10	0	0	587	379
7/25/10	0	0	575	379
7/26/10	0	0	596	379
7/27/10	0	0	656	379
7/28/10	0	0	662	379
7/29/10	0	0	647	379
7/30/10	0	0	626	379
7/31/10	0	0	547	379
8/1/10	0	0	570	379
8/2/10	0	0	601	379
8/3/10	0	0	617	379
8/4/10	0	0	658	379
8/5/10	1	1	658	482
8/6/10	1	1	645	476
8/7/10	0	0	554	379
8/8/10	0	0	553	379
8/9/10	0	0	581	379
8/10/10	0	0	607	379
8/11/10	0	0	601	379
8/12/10	0	0	644	379
8/13/10	0	0	603	379
8/14/10	1	1	604	488
8/15/10	9	9	711	1,238
8/16/10	12	12	776	1,529
8/17/10	1	1	688	483
8/18/10	10	10	756	1,358
8/19/10	0	0	671	379
8/20/10	0	0	614	379
8/21/10	0	0	563	379
8/22/10	0	0	569	379
8/23/10	0	0	641	379
8/24/10	10	10	752	1,345
8/25/10	6	6	719	983
8/26/10	0	0	687	379
8/27/10	0	0	604	379
8/28/10	0	0	551	379
8/29/10	0	0	562	379
8/30/10	0	0	582	379
8/31/10	6	6	683	902
9/1/10	0	0	703	379
9/2/10	9	9	796	1,268
9/3/10	16	16	1,004	1,869
9/4/10	16	16	848	1,861
9/5/10	11	11	758	1,396
9/6/10	10	10	864	1,345
9/7/10	18	18	1,208	2,051
9/8/10	14	14	1,096	1,676
9/9/10	13	13	1,073	1,570
9/10/10	11	11	976	1,443
9/11/10	11	11	885	1,443
9/12/10	13	13	907	1,633
9/13/10	11	11	1,005	1,396
9/14/10	13	13	1,064	1,587
9/15/10	22	22	1,469	2,474
9/16/10	9	9	1,099	1,207
9/17/10	20	20	1,364	2,277
9/18/10	19	19	1,323	2,175
9/19/10	11	11	1,087	1,386
9/20/10	11	11	1,237	1,453
9/21/10	19	19	1,380	2,209
9/22/10	14	14	1,297	1,738
9/23/10	17	17	1,424	1,975

MERC

9/24/10	14	14	1,458	1,700
9/25/10	14	14	1,262	1,749
9/26/10	4	4	1,025	797
9/27/10	6	6	936	995
9/28/10	3	3	959	684
9/29/10	8	8	1,034	1,117
9/30/10	9	9	1,076	1,192
10/1/10	22	22	1,485	2,431
10/2/10	19	19	1,554	2,220
10/3/10	12	12	1,405	1,529
10/4/10	8	8	1,123	1,111
10/5/10	1	1	905	485
10/6/10	10	10	1,074	1,302
10/7/10	2	2	878	577
10/8/10	0	0	780	379
10/9/10	0	0	714	379
10/10/10	2	2	765	573
10/11/10	0	0	853	379
10/12/10	16	16	1,263	1,855
10/13/10	12	12	1,371	1,529
10/14/10	18	18	1,433	2,123
10/15/10	12	12	1,379	1,529
10/16/10	22	22	1,542	2,507
10/17/10	23	23	1,865	2,594
10/18/10	21	21	2,130	2,346
10/19/10	13	13	1,722	1,633
10/20/10	23	23	2,016	2,545
10/21/10	24	24	2,365	2,695
10/22/10	12	12	1,632	1,487
10/23/10	21	21	2,021	2,346
10/24/10	19	19	1,902	2,209
10/25/10	15	15	1,685	1,762
10/26/10	21	21	2,302	2,397
10/27/10	37	37	3,313	3,885
10/28/10	37	37	3,712	3,900
10/29/10	28	28	3,096	3,047
10/30/10	30	30	2,973	3,272
10/31/10	28	28	2,985	3,047
11/1/10	19	19	2,608	2,192
11/2/10	20	20	2,478	2,260
11/3/10	25	25	2,633	2,783
11/4/10	36	36	3,484	3,796
11/5/10	31	31	2,989	3,299
11/6/10	23	23	2,719	2,553
11/7/10	20	20	2,220	2,310
11/8/10	18	18	2,185	2,123
11/9/10	14	14	1,773	1,750
11/10/10	19	19	2,144	2,156
11/11/10	32	32	3,576	3,410
11/12/10	31	31	3,614	3,286
11/13/10	34	34	3,354	3,601
11/14/10	37	37	3,786	3,936
11/15/10	38	38	4,133	3,989
11/16/10	35	35	4,082	3,738
11/17/10	47	47	4,712	4,873
11/18/10	46	46	4,565	4,780
11/19/10	54	54	5,428	5,514
11/20/10	51	51	5,246	5,186
11/21/10	49	49	5,089	5,055
11/22/10	61	61	6,064	6,127
11/23/10	56	56	5,679	5,714
11/24/10	59	59	5,427	6,018
11/25/10	68	68	6,241	6,820
11/26/10	61	61	6,140	6,178
11/27/10	54	54	5,039	5,515
11/28/10	33	33	3,775	3,560
11/29/10	41	41	4,297	4,316
11/30/10	61	61	5,915	6,145
12/1/10	61	61	6,247	6,173
12/2/10	64	64	6,688	6,505
12/3/10	58	58	6,101	5,865
12/4/10	56	56	5,860	5,714
12/5/10	52	52	5,621	5,313
12/6/10	62	62	6,035	6,307
12/7/10	60	60	6,037	6,054
12/8/10	56	56	6,150	5,665
12/9/10	50	50	5,400	5,167
12/10/10	62	62	6,272	6,275
12/11/10	78	78	7,657	7,835
12/12/10	78	78	8,013	7,761
12/13/10	77	77	7,665	7,661
12/14/10	59	59	6,743	6,022
12/15/10	57	57	6,199	5,766
12/16/10	59	59	6,063	6,022
12/17/10	57	57	6,095	5,805
12/18/10	57	57	5,944	5,817
12/19/10	61	61	6,316	6,152
12/20/10	52	52	5,786	5,291
12/21/10	42	42	4,543	4,343
12/22/10	44	44	4,957	4,587
12/23/10	48	48	5,224	4,968
12/24/10	54	54	5,387	5,466
12/25/10	58	58	5,743	5,859
12/26/10	56	56	5,797	5,709
12/27/10	47	47	5,624	4,873
12/28/10	40	40	4,407	4,175

MERC

12/29/10	40	40	4,121	4,140
12/30/10	59	59	6,026	5,961
12/31/10	65	65	6,471	6,550
1/1/11	79	79	6,980	7,894
1/2/11	73	73	7,436	7,287
1/3/11	72	72	7,618	7,196
1/4/11	59	59	6,479	5,965
1/5/11	64	64	6,536	6,505
1/6/11	69	69	6,646	6,900
1/7/11	72	72	6,988	7,189
1/8/11	70	70	7,113	7,065
1/9/11	69	69	6,882	6,968
1/10/11	53	53	6,198	5,418
1/11/11	58	58	5,926	5,918
1/12/11	57	57	6,049	5,761
1/13/11	58	58	6,030	5,865
1/14/11	62	62	6,280	6,264
1/15/11	71	71	7,017	7,097
1/16/11	69	69	6,609	6,963
1/17/11	65	65	6,739	6,535
1/18/11	71	71	7,392	7,131
1/19/11	67	67	7,162	6,740
1/20/11	92	92	8,919	9,121
1/21/11	83	83	8,609	8,234
1/22/11	79	79	8,137	7,888
1/23/11	64	64	6,925	6,444
1/24/11	56	56	6,164	5,660
1/25/11	51	51	5,533	5,201
1/26/11	51	51	5,235	5,220
1/27/11	49	49	5,025	5,023
1/28/11	48	48	5,011	4,954
1/29/11	62	62	6,085	6,227
1/30/11	64	64	6,615	6,421
1/31/11	75	75	7,560	7,495
2/1/11	73	73	7,729	7,356
2/2/11	69	69	6,852	6,976
2/3/11	47	47	5,302	4,832
2/4/11	40	40	4,396	4,206
2/5/11	37	37	4,427	3,870
2/6/11	58	58	5,921	5,867
2/7/11	78	78	8,018	7,766
2/8/11	75	75	7,699	7,527
2/9/11	81	81	7,942	8,104
2/10/11	69	69	7,257	6,968
2/11/11	48	48	5,421	4,977
2/12/11	35	35	3,883	3,733
2/13/11	30	30	3,762	3,244
2/14/11	31	31	3,873	3,305
2/15/11	30	30	3,582	3,252
2/16/11	21	21	2,917	2,328
2/17/11	49	49	4,940	5,014
2/18/11	68	68	6,842	6,811
2/19/11	58	58	6,299	5,919
2/20/11	58	58	6,408	5,902
2/21/11	49	49	5,704	5,011
2/22/11	48	48	5,338	4,913
2/23/11	56	56	5,539	5,714
2/24/11	71	71	7,120	7,088
2/25/11	78	78	8,069	7,789
2/26/11	70	70	7,196	6,986
2/27/11	62	62	6,489	6,281
2/28/11	49	49	5,376	5,039
3/1/11	69	69	7,678	6,927
3/2/11	67	67	6,944	6,723
3/3/11	47	47	5,248	4,868
3/4/11	60	60	6,066	6,125
3/5/11	55	55	5,339	5,615
3/6/11	50	50	5,376	5,167
3/7/11	60	60	5,898	6,109
3/8/11	50	50	4,489	5,121
3/9/11	41	41	4,201	4,306
3/10/11	40	40	3,917	4,140
3/11/11	44	44	4,154	4,562
3/12/11	61	61	6,174	6,176
3/13/11	47	47	4,594	4,868
3/14/11	34	34	3,616	3,589
3/15/11	30	30	3,267	3,199
3/16/11	27	27	3,157	2,944
3/17/11	36	36	3,852	3,766
3/18/11	42	42	4,349	4,407
3/19/11	36	36	3,716	3,753
3/20/11	31	31	3,609	3,332
3/21/11	29	29	3,503	3,145
3/22/11	46	46	4,908	4,747
3/23/11	48	48	4,749	4,893
3/24/11	43	43	4,494	4,489
3/25/11	42	42	4,262	4,407
3/26/11	45	45	4,349	4,627
3/27/11	44	44	4,282	4,546
3/28/11	40	40	4,072	4,158
3/29/11	35	35	3,661	3,674
3/30/11	32	32	3,302	3,400
3/31/11	30	30	3,527	3,199
4/1/11	31	31	3,396	3,305
4/2/11	25	25	2,629	2,761
4/3/11	34	34	3,646	3,648

MERC

4/4/11	36	36	3,676	3,753
4/5/11	27	27	3,118	2,948
4/6/11	26	26	2,741	2,849
4/7/11	19	19	2,534	2,175
4/8/11	11	11	1,571	1,386
4/9/11	14	14	1,702	1,676
4/10/11	27	27	2,702	2,955
4/11/11	17	17	2,046	2,036
4/12/11	16	16	1,785	1,855
4/13/11	37	37	3,263	3,890
4/14/11	31	31	3,460	3,354
4/15/11	32	32	3,736	3,437
4/16/11	40	40	3,745	4,136
4/17/11	35	35	3,307	3,702
4/18/11	36	36	3,487	3,833
4/19/11	28	28	3,128	2,997
4/20/11	31	31	3,208	3,343
4/21/11	24	24	2,916	2,699
4/22/11	27	27	3,068	2,968
4/23/11	21	21	2,537	2,412
4/24/11	14	14	1,878	1,738
4/25/11	10	10	1,492	1,367
4/26/11	20	20	2,159	2,277
4/27/11	21	21	2,642	2,401
4/28/11	19	19	1,953	2,157
4/29/11	8	8	1,438	1,157
4/30/11	30	30	2,584	3,220
5/1/11	41	41	4,188	4,269
5/2/11	28	28	2,964	2,997
5/3/11	15	15	1,922	1,789
5/4/11	12	12	1,720	1,529
5/5/11	17	17	1,765	2,005
5/6/11	9	9	1,116	1,277
5/7/11	9	9	1,085	1,200
5/8/11	9	9	1,240	1,230
5/9/11	11	11	1,331	1,424
5/10/11	3	3	1,029	693
5/11/11	11	11	1,047	1,443
5/12/11	20	20	1,645	2,260
5/13/11	23	23	1,906	2,574
5/14/11	13	13	1,469	1,644
5/15/11	17	17	1,153	1,990
5/16/11	12	12	989	1,565
5/17/11	11	11	912	1,396
5/18/11	2	2	853	580
5/19/11	0	0	794	379
5/20/11	0	0	731	379
5/21/11	8	8	843	1,104
5/22/11	2	2	734	584
5/23/11	10	10	922	1,311
5/24/11	19	19	1,254	2,175
5/25/11	18	18	1,176	2,051
5/26/11	12	12	1,109	1,508
5/27/11	15	15	1,317	1,842
5/28/11	12	12	1,058	1,497
5/29/11	8	8	812	1,177
5/30/11	3	3	864	701
5/31/11	12	12	1,274	1,519
6/1/11	9	9	1,050	1,223
6/2/11	1	1	876	490
6/3/11	0	0	756	379
6/4/11	10	10	715	1,294
6/5/11	0	0	630	379
6/6/11	0	0	645	379
6/7/11	0	0	664	379
6/8/11	15	15	942	1,829
6/9/11	9	9	861	1,192
6/10/11	14	14	836	1,676
6/11/11	8	8	681	1,162
6/12/11	4	4	719	801
6/13/11	0	0	719	379
6/14/11	0	0	687	379
6/15/11	6	6	790	978
6/16/11	2	2	723	577
6/17/11	0	0	694	379
6/18/11	0	0	626	379
6/19/11	1	1	649	482
6/20/11	2	2	744	588
6/21/11	7	7	880	1,017
6/22/11	10	10	940	1,320
6/23/11	6	6	804	983
6/24/11	0	0	627	379
6/25/11	0	0	579	379
6/26/11	1	1	636	482
6/27/11	6	6	793	995
6/28/11	4	4	693	770
6/29/11	0	0	633	379
6/30/11	0	0	595	379
Totals	10,055	10,055	1,090,175	1,093,528

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

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

MINNESOTA ENERGY RESOURCES - PNG

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	MN006	4,906	4,931	4,877	4,933	5,036	5,094						
Residential w/o Heat	MN005	36	34	35	35	36	35						
Commercial-SV	MN052/074	439	438	434	433	440	444						
Commercial-LV	MN062/075	497	505	507	502	507	509						
SV-Joint	MN106	6	5	6	6	6	6						
SV-Interruptible	MN127	6	5	6	6	6	6						
Transport	MN509/83L	4	2	4	4	3	3						
Total		5,894	5,920	5,869	5,919	6,034	6,097	0	0	0	0	0	0

MINNESOTA ENERGY RESOURCES - PNG

Projected Fixed Cost - November 2011 through March 2012

Futures Contracts WACOG

GLGT

Nov-10 (30)

Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/31/11	6,456	$ 4.8940	$ 31,594	$ 3.4860	$ 22,505	$ 9,090
06/16/11	6,076	$ 4.6510	$ 28,259	$ 3.4860	$ 21,181	$ 7,078
07/25/11	5,316	$ 4.4700	$ 23,765	$ 3.4860	$ 18,533	$ 5,231
08/02/11	4,557	$ 4.2550	$ 19,390	$ 3.4860	$ 15,886	$ 3,504
09/21/11	3,797	$ 3.8260	$ 14,529	$ 3.4860	$ 13,238	$ 1,291
10/03/11	3,797	$ 3.6160	$ 13,732	$ 3.4860	$ 13,238	$ 494
Total	30,000		$ 131,269		$ 104,580	$ 26,689
WACOG			$ 4.3756		$ 3.4860	$ 0.8896

Dec-10 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/31/11	4,889	$ 5.0870	$ 24,870	$ 3.9515	$ 19,318	$ 5,551
06/16/11	3,556	$ 4.8410	$ 17,212	$ 3.9515	$ 14,050	$ 3,163
06/16/11	1,333	$ 4.8420	$ 6,456	$ 3.9515	$ 5,269	$ 1,187
07/07/11	3,556	$ 4.5500	$ 16,178	$ 3.9515	$ 14,050	$ 2,128
08/04/11	2,222	$ 4.2840	$ 9,520	$ 3.9515	$ 8,781	$ 739
09/19/11	2,222	$ 4.1800	$ 9,289	$ 3.9515	$ 8,781	$ 508
10/05/11	2,222	$ 3.9080	$ 8,684	$ 3.9515	$ 8,781	$ (97)
Total	20,000		$ 92,209		$ 79,030	$ 13,179
WACOG			$ 4.6105		$ 3.9515	$ 0.6590

Jan-11 (31)

Purchase Date	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/26/11	6,087	$ 4.9410	$ 30,076	$ 4.0160	$ 24,445	$ 5,630
06/22/11	6,087	$ 4.8580	$ 29,570	$ 4.0160	$ 24,445	$ 5,125
07/21/11	5,652	$ 4.7690	$ 26,955	$ 4.0160	$ 22,699	$ 4,256
08/16/11	2,609	$ 4.4320	$ 11,562	$ 4.0160	$ 10,477	$ 1,085
08/16/11	2,174	$ 4.4330	$ 9,637	$ 4.0160	$ 8,730	$ 907
09/15/11	3,913	$ 4.3300	$ 16,943	$ 4.0160	$ 15,715	$ 1,229
10/20/11	3,478	$ 3.9670	$ 13,798	$ 4.0160	$ 13,969	$ (170)
Total	30,000		$ 138,542		$ 120,480	$ 18,062
WACOG			$ 4.6181		$ 4.0160	$ 0.6021

Feb-10 (29)

Purchase Date	Physical Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/26/11	5,556	$ 4.9000	$ 27,222	$ 4.0365	$ 22,425	$ 4,797
06/30/11	4,444	$ 4.8300	$ 21,467	$ 4.0365	$ 17,940	$ 3,527
07/07/11	1,667	$ 4.6580	$ 7,763	$ 4.0365	$ 6,728	$ 1,036
07/07/11	2,222	$ 4.6620	$ 10,360	$ 4.0365	$ 8,970	$ 1,390
08/25/11	2,222	$ 4.3340	$ 9,631	$ 4.0365	$ 8,970	$ 661
09/16/11	2,222	$ 4.3140	$ 9,587	$ 4.0365	$ 8,970	$ 617
10/06/11	1,667	$ 4.1000	$ 6,833	$ 4.0365	$ 6,728	$ 106
Total	20,000		$ 92,863		$ 80,730	$ 12,133
WACOG			$ 4.6432		$ 4.0365	$ 0.6067

Mar-11 (31)

Purchase Date	Physical Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
05/19/11	5,934	$ 4.7660	$ 28,282	$ 3.9580	$ 23,487	$ 4,795
06/23/11	1,978	$ 4.6590	$ 9,216	$ 3.9580	$ 7,829	$ 1,387
06/23/11	3,956	$ 4.6600	$ 18,435	$ 3.9580	$ 15,658	$ 2,777
07/27/11	5,934	$ 4.6700	$ 27,712	$ 3.9580	$ 23,487	$ 4,225
08/29/11	4,615	$ 4.2840	$ 19,772	$ 3.9580	$ 18,268	$ 1,505
09/22/11	3,956	$ 4.1800	$ 16,536	$ 3.9580	$ 15,658	$ 878
10/21/11	3,626	$ 3.9250	$ 14,234	$ 3.9580	$ 14,353	$ (120)
Total	30,000		$ 134,187		$ 118,740	$ 15,447
WACOG			$ 4.4729		$ 3.9580	$ 0.5149

Total

	Financial Volume	Purchase Price	Total Cost	Indexes	Index Cost	Over/(Under) Market
	28,921	$ 4.9114	$ 142,044	$ 3.8788	$ 112,180	$ 29,863
	22,141	$ 4.7751	$ 105,724	$ 3.8591	$ 85,445	$ 20,280
	17,925	$ 4.6514	$ 83,374	$ 3.8431	$ 68,886	$ 14,488
	18,878	$ 4.5134	$ 85,201	$ 3.8601	$ 72,869	$ 12,333
	15,031	$ 4.1972	$ 63,089	$ 3.8578	$ 57,987	$ 5,102
	16,111	$ 4.1020	$ 66,087	$ 3.8708	$ 62,362	$ 3,725
	10,994	$ 3.9614	$ 43,550	$ 3.9869	$ 43,831	$ (281)
	130,000		$ 589,070		$ 503,560	$ 85,510
			$ 4.5313		$ 3.8735	$ 0.6578

MINNESOTA ENERGY RESOURCES - PNG

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	Total AECO Storage Volumes	Total AECO Storage WACOG	Total AECO Storage Cost	Total Emerson WACOG	Total Emerson Cost
Nov-11	494,259	$ 3.6310	$ 1,794,654	85,304	$ 3.4860	$ 297,370	85,304	$ 3.8600	$ 329,277	$ 3.4860	$ 297,370
Dec-11	1,241,984	$ 4.0440	$ 5,022,583	229,242	$ 3.9515	$ 905,850	229,242	$ 3.8600	$ 884,885	$ 3.9515	$ 905,850
Jan-12	1,241,984	$ 4.1910	$ 5,205,155	229,242	$ 4.0160	$ 920,636	229,242	$ 3.8600	$ 884,885	$ 4.0160	$ 920,636
Feb-12	1,241,984	$ 4.2190	$ 5,239,930	214,452	$ 4.0365	$ 865,635	214,452	$ 3.8600	$ 827,795	$ 4.0365	$ 865,635
Mar-12	494,259	$ 4.1105	$ 2,031,652	96,345	$ 3.9580	$ 381,334	96,345	$ 3.8600	$ 371,896	$ 3.9580	$ 381,334
Total	4,714,470	$ 4.0925	$19,293,975	854,585	$ 3.9444	$ 3,370,824	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	10/31/11 Storage Balance - NNG (estimate)	5,069,321	100.00%	4,714,470
Max AECO Storage	854,585		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	$ -		$ 317,430	$ 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	$ 317,430	$ 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	$ 308,606	$ 4,954,676
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	$ -	$ 0.4080	$ 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
														$ 4.2733

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	09/28/11		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	$ -	$ 0.3230	$ 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	$ 4,876,930	$ 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	$ 1,388,894	$ 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