Minnesota Energy Resources Corporation
Suite 200
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Eagan, MN 55122
www.minnesotaenergyresources.com

November 1, 2017

VIA ELECTRONIC FILING

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101

Re: In the Matter Minnesota Energy Resources Corporation's Petition for Approval of a Change in Demand Entitlement for its NNG System – November 1 Update

Docket No. G011/M-17-588

Dear Mr. Wolf:

On August 1, 2017, Minnesota Energy Resources Corporation ("MERC" or the "Company") filed its Petition for Change in Demand Entitlement for the MERC-NNG purchased gas adjustment ("PGA") area. MERC submits this update to its August 1, 2017 Demand Entitlement filing. Additionally, MERC provides information as requested by the Department of Commerce, Division of Energy Resources (the "Department") in its October 23, 2017 Comments in Docket No. G011/GR-17-564.

In its April 28, 2016 Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724, the Minnesota Public Utilities Commission ("Commission") required that MERC explain changes made in its compliance petitions that are different from its original petitions, and provide a redline version of both petitions identifying changes. In accordance with the Commission's Order, MERC provides redlined changes in the attached Petition and has highlighted the affected schedules.

As of the date of this filing, MERC has completed its purchases of future contracts and call options for the 2017-2018 winter period. These final financial hedge volumes and costs are shown in Attachments 5 and 11 (pages 1 and 3). The call option premium costs additionally flow through the spreadsheet in Attachment 4, pages 1 and 2 and in Attachment 8.

In its October 23, 2017, Comments submitted in Docket No. G011/GR-17-564 on MERC's petition for approval of a base cost of gas to coincide with the implementation of interim rates, the Department requested that MERC provide, in its November 1, 2017 update in this docket, a reconciliation and explanation of changes proposed in Docket No. G011/M-17-588 (MERC-NNG's 2017-2018 Demand Entitlement) to the information included in MERC's October 1, 2017 Purchased Gas Adjustment ("PGA") filing in Docket No. G011/AA-17-703.

MERC responds that with respect to the requested reconciliation between the October 1 PGA and November 1 Demand Entitlement, the this docket are proposed effective November 1, 2017. Therefore, the changes would not be reflected in the October PGA. Additionally, however, MERC's August 1, 2017 Demand Entitlement filing schedules comparing the 2016-2017 demand costs to the proposed 2017-2018 demand costs only included the NNG costs for 2016-2017; whereas both the MERC-NNG and MERC-Albert Lea (now the consolidated MERC-NNG PGA) costs were included in the 2017-2018 demand costs. The following updated comparison includes the total demand costs for the consolidated NNG PGA between 2016-2017 and 2017-2018.

The former MERC-Albert Lea PGA was combined into the MERC-NNG PGA effective July 1, 2017. In order to provide an accurate comparison between the 2016 and 2017 Demand Entitlement filings, Attachment 8.1 was added to this filing to reconcile the differences between the combined PGA. This reconciliation is shown in the table below.

2016/17 Total Annual Cost	2016/17 Albert Lea Cost	2017/18 Total Annual Cost	Net Annual Cost Change
$2,037,100	$161,481	$2,517,552	$318,971
$1,584,318	$373,663	$1,957,981	$0
$3,304,978	$432,342	$3,304,978	($432,342)
$2,445,543	$302,833	$2,748,375	$0
$467,694		$467,694	$0
$1,250,434		$1,250,434	$0
$11,366		$11,366	$0
$11,366		$11,366	$0
$6,204,244	$60,612	$6,264,856	$0
$90,288		$90,288	$0
$74,886		$74,886	$0
$543,107		$543,107	$0
$1,087,553		$1,087,553	$0
$9,217		$9,217	$0
$66,895		$66,895	$0
$1,679,619		$1,679,619	$0
$0		$0	$0
$103,560		$103,560	$0
$20,972,169	$1,330,930	$22,189,728	($113,370)

In review of this update, MERC also discovered an error in the storage cost calculation in the 2016-2017 Demand Entitlement. This error has been corrected in Attachment 8 and the new Attachment 8.1 to accurately reflect the change from 2016-2017 to 2017-2018.

Finally, in its April 28, 2016 Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724, the Commission directed MERC to work with the Department to develop an appropriate Design Day regression analysis methodology for its subsequent demand entitlement petitions until MERC has three years of daily interruptible data available for all interruptible for the consolidated (MERC-NNG and MERC-Albert Lea), NNG PGA area. MERC has worked with the Department to ensure its design day regression analysis for the NNG-PGA is reasonable. In particular, MERC has utilized daily telemetry data in its regression analysis for all of the MERC-NNG customers with adequate data available. MERC has completed installation of telemetry for its former MERC-Albert Lea customers and anticipates having sufficient data for these customers in approximately two years to utilize in MERC's Design Day analysis. Until that time, MERC intends to utilize the same methodology it had utilized prior to having telemetry equipment for its other interruptible customers.

Please contact me at (651) 322-8965 if you have any questions regarding the information in this filing. Thank you for your attention to this matter.

Sincerely yours,

/s/ Amber S. Lee

Amber S. Lee
Regulatory and Legislative Affairs Manager
Minnesota Energy Resources Corporation

Enclosure
cc: Service List

ATTACHMENT A

~~August~~ November 1, 2017

To: Service List

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

Notice of Availability

Please take notice that Minnesota Energy Resources Corporation has filed a petition with the Minnesota Public Utilities Commission for approval of a change in demand entitlement for its NNG Purchased Gas Adjustment system.

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

Amber Lee
Minnesota Energy Resources Corporation
1995 Rahncliff Court, Suite 200
Eagan, MN 55122
(651) 322-8965

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~~the docket number 17-588.

ATTACHMENT B

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	**Chair**
Dan Lipschultz	**Commissioner**
Matt Schuerger	**Commissioner**
Katie Sieben	**Commissioner**
John Tuma	**Commissioner**

In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Change in Demand Entitlement for its NNG System	Docket No. G011/M-17-588

SUMMARY OF FILING

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation – NNG (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC customers served off of the Northern Natural Gas (NNG) system. MERC requests the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) beginning November 1, 2017.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	**Chair**
Dan Lipschultz	**Commissioner**
Matt Schuerger	**Commissioner**
Katie Sieben	**Commissioner**
John Tuma	**Commissioner**

In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Change in Demand Entitlement for its NNG System

Docket No. G011/M-17-588

FILING UPON CHANGE IN DEMAND

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - NNG (MERC or the Company), a subsidiary of WEC Energy Group, hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-NNG customers served off the Northern Natural Gas interstate pipeline system.[1] MERC requests the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) beginning November 1, 2017.

This filing includes the following attachments:

Attachment A:	Notice of Availability.
Attachment B:	One paragraph summary of the filing in accordance with Minn. R. 7829.1300, subp. 1.
Attachment C:	Petition for Change in Demand with Attachments.
Attachment D:	Certificate of Service and Service List.

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

[1] MERC also serves certain of its Minnesota customers off of the Viking, Great Lakes and Centra pipeline systems. MERC requests approval of a demand entitlement change for the 2017-2018 heating season for its MERC-CONSOLIDATED PGA in a separate docket.

I. Summary of Filing

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

II. Service

Pursuant to Minn. R. 7829.1300, subp. 2, MERC has served a copy of this filing on the Department of Commerce, Division of Energy Resources and the Office of the Attorney General — Residential Utilities and Antitrust Division. The summary of 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.

III. General Filing Information

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

Minnesota Energy Resources Corporation
1995 Rahncliff Court, Suite 200
Eagan, MN 55122
(651) 322-8901

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

Kristin M. Stastny
Briggs and Morgan, P.A.
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
KStastny@briggs.com
(612) 977-8656

C. Date of the Filing and Proposed Effective Date

Date of filing: ~~August~~ November 1, 2017
Proposed Effective Date: November 1, 2017

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. Signature, Electronic Address, and Title of Utility Employee Responsible for the Filing

Amber S. Lee
Regulatory and Legislative Affairs Manager
ASLee@minnesotaenergyresources.com
1995 Rahncliff Court, Suite 200
Eagan, MN 55122
(651) 322-8965

If additional information is required, please contact Amber S. Lee at (651) 322-8965.

DATED: ~~August~~ November 1, 2017

Respectfully submitted,
MINNESOTA ENERGY RESOURCES CORPORATION

By: /s/ Amber S. Lee
Amber S. Lee
1995 Rahncliff Court, Suite 200
Eagan, MN 55122
Telephone: (651) 322-8965

ATTACHMENT C

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	**Chair**
Dan Lipschultz	**Commissioner**
Matt Schuerger	**Commissioner**
Katie Sieben	**Commissioner**
John Tuma	**Commissioner**

In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Change in Demand Entitlement for its NNG System	Docket No. G011/M-17-588

PETITION OF MINNESOTA ENERGY RESOURCES CORPORATION-NNG FOR CHANGE IN DEMAND

I. Introduction

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - NNG (MERC or the Company), a subsidiary of WEC Energy Group, hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-NNG customers served off the Northern Natural Gas interstate pipeline system. MERC requests the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) beginning November 1, 2017. Included with this filing are the following Attachments:

Attachment 1: Design-Day Demand Summary

Attachment 2: Sales Forecast

Attachment 3: Current and Proposed Entitlement Levels

Attachment 4: Rate Impact of the Proposed Demand Change

Attachment 5: Financial Option Summary

Attachment 6: Winter Plan

Attachment 7: Entitlement History

Attachment 8: Change in Entitlement Levels and Related Demand Costs

Attachment 8.1: Change in Entitlement Levels and Related Demand Costs (Including MERC-NNG and MERC-Albert Lea)[2]

Attachment 9: Actual Throughput and Design Day Forecast Estimated Throughput

Attachment 10: Customer Counts

Attachment 11: Hedging Summary

Attachment 12: Forecast Methodology

II. Discussion

A. MERC's NNG Design-Day Requirements

Minn. R. 7825.2910, subp. 2 (b) requires that a filing upon change in demand include the utility's Design-Day demand by customer class and the change in Design-Day demand, if any, necessitating the demand revision. The NNG Design-Day requirement has increased by 18,029 dekatherms (dth) from the November 1, 2016, filing. The larger than usual increase in Design-Day requirement is attributable to combining the MERC-Albert Lea PGA into the MERC-NNG PGA and new town growth load. The addition of MERC-Albert Lea alone accounts for 14,819 dth of the increase over the last heating season.

Table 1: MERC Proposed NNG Reserve Margins
For the 2017-2018 Heating Season

	Reserve Margin 2017-2018 Heating Season	Reserve Margin 2016-2017 Heating Season	Change
NNG Zone EF	-0.19%	1.34%	-1.53%

[2] MERC also identified an error in the storage cost calculation in its 2016-2017 Demand Entitlement. This error has been corrected in Attachment 8 and Attachment 8.1 to accurately reflect the 2016-2017 storage costs. There is no impact as a result of this correction to the proposed 2017-2018 storage costs.

For the Demand Entitlement filing effective November 1, 2017, the total Design-Day requirement for MERC NNG is 266,825 dth (Attachment 1). The difference between the total Design-Day requirement and total Design-Day capacity results in a 0.19% negative reserve margin (Attachment 3). As required by Order Point 9 of the Commission's Order in Docket No. G011/M-15-723, Attachment 3 reflects the separate summer and winter demand entitlements for MERC-NNG.

B. Gas Supply

Minn. R. 7825.2910, subp. 2, requires a description of Design-Day gas supply from all sources under the new level, allocation, or form of demand. This information is provided in Attachment 3.

C. Forecast Methodology for MERC Demand Entitlement November 1, 2017

See Attachment 12. Additionally, MERC notes that in accordance with the Commission's April 28, 2016 Order in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724, MERC has worked with the Department in developing an appropriate Design Day regression analysis methodology for this filing until MERC has three years of daily interruptible data for all of its interruptible customers for the consolidated NNG PGA area (i.e., until MERC has adequate data for the historic MERC-Albert Lea PGA).

III. Additional Filing Requirements

A. Daily Design-Day Estimate to Actual Comparison

In the 2007-2008 demand entitlement dockets,[3] MERC agreed to include a daily estimate utilizing the Design-Day model, which is calculated in Attachment 9. The daily estimate is compared to actual consumption. The actual volumes are total throughput which includes interruptible and transportation volumes that are located behind MERC citygates. The

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[3] Docket Nos. G007/M-07-1402; G007/M-07-1403; G007/M-07-1404; and G007/M-07-1405.

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.

B. Average Customer Counts

In the 2007-2008 demand entitlement dockets, MERC agreed to include average customer counts which are provided in Attachment 10.

C. Balancing

Order Point 4 of the Commission's January 21, 2015, Order in MERC's 2010-2011 demand entitlement dockets, Docket Nos. G007/M-10-1166; G007/M-10-1167; G011/M-10-1168; and G011/M-10-1169, required that in future demand entitlement filings, MERC provide a clarification of its statements regarding system balancing and detailed evidence assuring the Commission that the appropriate customer group is paying for any balancing charges or penalties. Additionally, in Docket No. G-999/AA-12-756, by Order dated November 14, 2013, the Commission ordered that "prospectively, all regulated natural gas utilities shall recover balancing service costs, and shall credit the utility's penalty revenues and the pipeline's revenue credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that can reasonably be implemented."

MERC subsequently revised its monthly PGA filings, beginning November 2013, to recover all balancing costs via the commodity portion of the PGA. MERC's 2014 AAA and true-up filings, as well as the 2014 Demand Entitlement filing, also reflected this change. The current MERC-NNG demand entitlement filing includes detailed evidence of the allocation of balancing costs to the commodity portion of the PGA in Attachment 4, page 2 of 3.

D. MERC's Proposed NNG System Demand-Related Changes

There are two types of demand entitlement changes. The first type is Design-Day Deliverability, which quantifies the amount of firm transportation and storage capacity actually available to MERC's NNG customers during winter peak periods. The second type does not affect Design-Day Deliverability levels, but alters the capacity portfolio and the PGA costs recovered from customers.

1. Design-Day Deliverability Changes

As shown in Attachment 3, MERC-NNG proposes no change in Design-Day Deliverability. The reserve margin for 2017-2018 is slightly negative. MERC will purchase city gate delivered supply to cover 0.19% of peak day throughput if necessary. This reserve margin is appropriate because incremental NNG capacity will come on line in 2018 as a result of the Rochester expansion project.

MERC contracted for capacity on the Bison Pipeline for 50,000 dth/day, which went into service on January 14, 2011. The contracted capacity with Northern Border Pipeline (NBPL) went into effect at the in-service of Bison. This capacity does not add any incremental capacity but is utilized to deliver supply to NNG customers at NBPL interconnects with NNG.

2. Other Demand Entitlement Changes

As shown in Attachment 3, MERC–NNG proposes no change in April/October Deliverability. However, MERC requests changes to increase Firm Deferred Delivery (storage) pipeline entitlements that are not included in peak day deliverability. MERC has increased the volume of capacity release NNG storage acquired from a total of 1,200,000 dth in 2016-2017 to 1,500,000 dth in 2017-2018 as discussed in the update filing for Docket No. G011/M-16-650. MERC will utilize this incremental storage to ensure supply price and reliability during the winter. MERC is targeting 30% of NNG winter forecast usage to be supplied from storage as discussed in the hedging explanation below.

E. Financial Option Units and Premiums

In accordance with the Commission's May 8, 2017, Order in Docket No. G011/M-17-85 approving MERC's variance extension request to recover the costs of financial instruments through the PGA, MERC provides the following information. MERC has completed its purchases of future contracts and call options for the 2017-2018 winter period. These final financial hedge volumes and costs are shown in Attachments 5 and 11 (pages 1 and 3). The call option premium costs additionally flow through the spreadsheet in Attachment 4, pages 1 and 2 and in Attachment 8.~~:~~

i. a list of all financial instruments purchased for the upcoming heating season (see Attachment 11);

ii. the cost premium associated with each contract (see Attachment 5);

iii. the size (in dth) of each contract (see Attachments 5 and 11);

iv. the contract date (see Attachment 5);

v. the contract price (see Attachment 11);

vi. an attachment that details the projected total system sales estimates for the upcoming heating season, including all supporting data and assumptions used when calculating the sales forecast, and the total number of volumes hedged using financial instruments for the upcoming heating season (see Attachment 2 and Attachment 6, page 1 of 2); and

vii. a detailed discussion of the anticipated benefits to ratepayers related to MERC's financial instrument contracts, discussed below.

The NNG 2017-2018 Winter Portfolio Hedging Plans - Minnesota Energy Resources Corporation for gas supply purchases is shown in Attachment 6. MERC's hedging strategy covers 60% of normal winter volumes; 30% through physical storage; and 30% through financial instruments (10% futures and 20% options). The weighted average price of currently purchased futures contracts of natural gas for the 2017/18 winter is $3.2945~~3991~~/dth. Please see Attachment 11, page 1 of 3. As shown in Attachment 11, page 2 of 3, MERC projects the NNG storage WACOG to be $2.6781/dth. MERC has purchased call options at an average strike price of $3.8311~~7985~~/dth, 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 11, page 3 of 3. The remaining 40% 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.

F. 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, 2017. Rate impacts associated with this change can be found on Attachment 4.

G. Impacts of Telemetry

Throughout the course of the year, a number of customers request to switch from interruptible to firm service. MERC evaluates these requests to determine the impact to our system and our upstream entitlement levels and our process requires us to evaluate the system capability before we allow a customer to switch to firm. As a result, the firm volumes associated with a customer switch fall within the Design-Day parameters and do not impact our demand entitlement levels.

IV. Conclusion

MERC respectfully requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) beginning November 1, 2017. ~~If any changes to the entitlements for MERC-NNG are made, MERC will submit an update to this filing by November 1, 2017.~~

DATED: ~~August~~ November 1, 2017

Respectfully submitted,

MINNESOTA ENERGY RESOURCES CORPORATION

By: /s/ Amber S. Lee
Amber S. Lee
1995 Rahncliff Court, Suite 200
Eagan, MN 55122
Telephone: (651) 322-8965

MINNESOTA ENERGY RESOURCES - NNG

DESIGN-DAY DEMAND SUMMARY
NOVEMBER 1, 2017
NNG

Design Day Requirement		266,825
Total Peak Day Entitlement		266,317
2016/17 Firm Peak Day Actual Sendout	1/5/2017	212,653
Firm Annual Throughput - Minnesota		23,618,091
No. of Firm Customers		187,194
Department Load Factor Calculation		30.43%

MINNESOTA ENERGY RESOURCES - NNG

NNG MINNESOTA DESIGN DAY REQUIREMENTS
NOVEMBER 1, 2017
NNG

Pipeline Group	2016/17 Customer Count	Zone Total Customer Count	1/20 Design DDD	Regression Factors Intercept	Regression Factors Slope	Regression Total	Regression Adjustment	1/20 Requirements Regression Load	Estimated Contract Demand Units	Total *
PEAK										
NNG	187,194	187,194	98	17,443	2,139	251,482	15,248	266,730	95	266,825
Total	187,194	187,194								266,825
OFF PEAK										
NNG	187,194	187,194	55	17,443	2,139	146,377	15,248	161,625	95	161,720
Total	187,194	187,194								161,720

* Adjusted for customer growth

MINNESOTA ENERGY RESOURCES - NNG

DESIGN-DAY DEMAND PER CUSTOMER - GS
NOVEMBER 1, 2017

NNG

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtu /Customer /Day
17/18	187,194	266,825	1.43
16/17	184,577	248,796	1.35
15/16	181,326	245,263	1.35
14/15	178,388	261,002	1.38
13/14	178,578	245,878	1.28
12/13	176,937	225,883	1.34
11/12	175,241	235,055	1.24
10/11	176,027	218,213	1.30
09/10	175,228	228,040	1.42
08/09	173,962	247,188	1.30

MINNESOTA ENERGY RESOURCES - NNG

SUMMER/WINTER USAGE - Mcf

PROJECTED 12 MONTHS ENDING JUNE 2018

NNG

Class	Summer Apr-Oct	Winter Nov-Mar	Total
GS	6,013,697	17,589,346	23,603,043
SVI	436,673	1,255,514	1,692,187
SVJ	5,791	9,257	15,048
LVI	552,509	568,478	1,120,987
LVJ			0
SLV			0
Total	7,008,670	19,422,595	26,431,265

MINNESOTA ENERGY RESOURCES - NNG

ENTITLEMENT LEVELS
PROPOSED TO BE EFFECTIVE NOVEMBER 1, 2017

	Summer			*April/October*			*Winter*		
Capacity Type	2016/17 MMBtu	Change MMBtu	Proposed MMBtu	2016/17 MMBtu	Change MMBtu	Proposed MMBtu	2016/17 MMBtu	Change MMBtu	Proposed MMBtu
TF-12 Base & Variable	75,316	9,393	84,709	75,316	9,393	84,709	75,316	0	75,316
TF5	0	0	0	0	0	0	32,278	13,390	45,668
TFX - 12	32,297	0	32,297	32,297	0	32,297	32,297	0	32,297
TFX - 5	0	0	0	0	0	0	108,701	800	109,501
TFX- (Apr/Oct) Offpeak*	0	0	0	2,000	0	2,000	0	0	0
Bison	50,000	0	50,000	50,000	0	50,000	50,000	0	50,000
NBPL	50,000	0	50,000	50,000	0	50,000	50,000	0	50,000
Northwest Gas (Windom)	2,500	0	2,500	2,500	0	2,500	2,500	0	2,500
Northwestern Energy (Ortonville)	1,035	0	1,035	1,035	0	1,035	1,035	0	1,035
NNG Zone Delivery Call Option	0	0	0	0	0	0	0	0	0
Total	111,148	9,393	120,541	113,148	9,393	122,541	252,127	14,190	266,317
Heating Season Forecasted Design Day-Adjusted							248,796	18,029	266,825
Non-Heating Season Forecasted Design Day				152,070	9,650	161,720			
Heating Season Capacity Surplus/Shortage							3,331	(3,839)	(508)
Non-Heating Season Capacity Surplus/Shortage				(38,922)	(257)	(39,179)			
*Not included in Heating Season Total entitlement									
Reserve Margin			N3	-25.59%	1.37%	-24.23%	1.34%	-1.53%	-0.19%

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2017

All costs in $/Dth	Base Cost of Gas G011/MR15-748 Jul 1, 2017	Demand Charge Oct 1, 2016	Demand Charge Demand Filing Nov 1, 2016	Most Recent PGA Jul 1, 2017	Proposed Effective Nov 1, 2017	Result of Proposed Change: Change from Last Rate Case	Change from Nov 1, 2016 Demand Filing	Change from Last PGA %	Change from Last PGA $
1) General Service Residential: Avg. Annual Use:		**88**		**Dth**					
Commodity Cost	$3.2257	$4.3217	$4.3217	$3.2257	$3.0616	($0.1641)	($1.2601)	-5.09%	($0.1641)
Demand Cost	$0.9288	$0.9226	$0.9226	$0.9288	$0.9860	$0.0572	$0.0634	6.15%	$0.0572
Commodity Margin	$2.4116	$2.3980	$2.3980	$2.4116	$2.4116	$0.0000	$0.0136	0.00%	$0.0000
Total Cost of Gas	$6.5661	$7.6423	$7.6423	$6.5661	$6.4592	($0.1069)	($1.1831)	-1.63%	($0.1069)
Avg Annual Cost	$577.82	$672.52	$672.52	$577.82	$568.41	($9.41)	($104.12)	-1.63%	($9.41)
Effect of proposed commodity change on average annual bills:									($14.44)
Effect of proposed demand change on average annual bills:									$5.03
2) Small Vol. Interruptible: Avg. Annual Use:		**5,110**		**Dth**					
Commodity Cost	$3.2257	$4.3217	$4.3217	$3.2257	$3.0616	($0.1641)	($1.2601)	-5.09%	($0.1641)
Demand Cost									
Commodity Margin	$0.9740	$0.9336	$0.9336	$0.9740	$0.9740	$0.0000	$0.0404	0.00%	$0.0000
Total Cost of Gas	$4.1997	$5.2553	$5.2553	$4.1997	$4.0356	($0.1641)	($1.2197)	-3.91%	($0.1641)
Avg Annual Cost	$21,460.47	$26,854.58	$26,854.58	$21,460.47	$20,621.92	($838.55)	($6,232.67)	-3.91%	($838.55)
Effect of proposed commodity change on average annual bills:									($838.55)
Effect of proposed demand change on average annual bills:									$0.00
3) Large Vol. Interruptible: Avg. Annual Use:		**16,150**		**Dth**					
Commodity Cost	$3.2257	$4.3217	$4.3217	$3.2257	$3.0616	($0.1641)	($1.2601)	-5.09%	($0.1641)
Demand Cost									
Commodity Margin	$0.5329	$0.5007	$0.5007	$0.5329	$0.5329	$0.0000	$0.0322	0.00%	$0.0000
Total Cost of Gas	$3.7586	$4.8224	$4.8224	$3.7586	$3.5945	($0.1641)	($1.2279)	-4.37%	($0.1641)
Avg Annual Cost	$60,701.39	$77,881.76	$77,881.76	$60,701.39	$58,051.18	($2,650.22)	($19,830.59)	-4.37%	($2,650.22)
Effect of proposed commodity change on average annual bills:									($2,650.22)
Effect of proposed demand change on average annual bills:									$0.00
4) Small Vol. Firm: Avg. Annual Use:		**5,110**		**Dth**					
		25		**DTh**					
Commodity Cost	$3.2257	$4.3217	$4.3217	$3.2257	$3.0616	($0.1641)	($1.2601)	-5.09%	($0.1641)
Demand Cost	$27.6780	$10.1722	$10.1722	$27.6780	$10.1817	$0.0000	$0.0095	-63.21%	($17.4963)
Commodity Margin	$0.9740	$0.9336	$0.9336	$0.9740	$0.9740	$0.0000	$0.0404	0.00%	$0.0000
Demand Margin	$3.0000	$2.7493	$2.7493	$3.0000	$3.0000	$3.0000	$0.2507	0.00%	$0.0000
Total Cost of Gas	$4.1997	$5.2553	$5.2553	$4.1997	$4.0356	($0.1641)	($1.2197)	-3.91%	($0.1641)
Total Demand Cost	$30.6780	$12.9215	$12.9215	$30.6780	$13.1817	($17.4963)	$0.2602	-57.03%	($17.4963)
Avg Annual Cost	$22,227.42	$27,177.62	$27,177.62	$22,227.42	$20,951.46	($1,275.96)	($6,226.16)	-5.74%	($1,275.96)
Effect of proposed commodity change on average annual bills:									($838.55)
Effect of proposed demand change on average annual bills:									($437.41)
5) Large Vol. Firm: Avg. Annual Use:		**16,150**		**Dth**					
		75		**DTh**					
Commodity Cost	$3.2257	$4.3217	$4.3217	$3.2257	$3.0616	($0.1641)	($1.2601)	-5.09%	($0.1641)
Demand Cost	$27.6780	$10.1722	$10.1722	$27.6780	$10.1817	($17.4963)	$0.0095	-63.21%	($17.4963)
Commodity Margin	$0.5329	$0.5007	$0.5007	$0.5329	$0.5329	$0.0000	$0.0322	0.00%	$0.0000
Demand Margin	$3.0000	$2.7493	$2.7493	$3.0000	$3.0000	$0.0000	$0.2507	0.00%	$0.0000
Total Cost of Gas	$3.7586	$4.8224	$4.8224	$3.7586	$3.5945	($0.1641)	($1.2279)	-4.37%	($0.1641)
Total Demand Cost	$30.6780	$12.9215	$12.9215	$30.6780	$13.1817	$13.1817	$0.2602	-57.03%	($17.4963)
Avg Annual Cost	$63,002.24	$78,850.87	$78,850.87	$63,002.24	$59,039.80	($1,661.59)	($19,811.07)	-6.29%	($3,962.44)
Effect of proposed commodity change on average annual bills:									($2,650.22)
Effect of proposed demand change on average annual bills:									($1,312.22)

Note: Average Annual Average based on NNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-17-XXX

Attachment 4
Page 2 of 3

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2017

NNG

IV. NORTHERN NATURAL GAS COMPANY'S RATES -- CURRENT COST OF GAS EFFECTIVE 01-Nov-17

		Tariff-Summer(7 mths)	Tariff-Winter(5 mths)	Wt. Annual	GRI	Total
TF-12B	112495	$ 5.6830	$ 10.2300	$7.5776	$0.0000	$7.5776
TF-12B Discount	112495	$ 5.6830	$ 10.0320	$7.4951	$0.0000	$7.4951
TF-12V	112495	$ 5.6830	$ 13.8660	$9.0926	$0.0000	$9.0926
TF-5	112495	$ -	$ 15.1530	$15.1530	$0.0000	$15.1530
TFX	112486	$ 5.6830	$ 15.1530	$9.6288	$0.0000	$9.6288
TFX-5	112486	$ -	$ 15.1530	$15.1530	$0.0000	$15.1530
TFX-5 Discount	112486	$ -	$ 10.0320	$10.0320	$0.0000	$10.0320
TFX - Discount	111866	$ 2.2192	$ 15.1392	$7.6025	$0.0000	$7.6025
TFX - Discount	111866	$ 4.8640	$ 4.8640	$4.8640	$0.0000	$4.8640
TFX - Discount	111866	$ 5.4720	$ 5.4720	$5.4720	$0.0000	$5.4720
TFX-5	127852	$ -	$ 15.1530	$15.1530	$0.0000	$15.1530
Gas Cost						$2.2444 /Dth

V. ANNUAL SALES -- As approved in Docket No. G011/MR-15-748 253,351,745

VI. MERC-NNG'S CURRENT COST OF GAS EFFECTIVE: 01-Nov-17

		Contract #(s)	Monthly Entitlements (Dth)	Months	Rate $/Dth		Contract Costs	Rate/Therm
A. GS-NNG	TF12B (Max Rate) Winter	112495	49,219	5	$ 10.2300	=	$2,517,552	$ 0.01119
	TF12B (Max Rate) Summer	112495	49,219	7	$ 5.6830	=	$1,957,981	$ 0.00870
	TF12V (Max Rate)	112495	30,290	12	$ 9.0926	=	$3,304,978	$ 0.01469
	TF5 (Max Rate)	112495	36,275	5	$ 15.1530	=	$2,748,375	$ 0.01221
	TF12B (Discount-Winter)	112495	5,200	12	$ 7.4951	=	$467,694	$ 0.00208
	TFX12 (Max Rate)	112486	10,822	12	$ 9.6288	=	$1,250,434	$ 0.00556
	TFX Apr (Max Rate)	112486	2,000	1	$ 5.6830	=	$11,366	$ 0.00005
	TFX Oct (Max Rate)	112486	2,000	1	$ 5.6830	=	$11,366	$ 0.00005
	TFX5 (Max Rate)	112486	82,688	5	$ 15.1530	=	$6,264,856	$ 0.02784
	TFX5 (Discount)	112486	1,800	5	$ 10.0320	=	$90,288	$ 0.00040
	TFX12 (Discount)	111866	1,283	12	$ 4.8640	=	$74,886	$ 0.00033
	TFX12 (Discount)	111866	8,271	12	$ 5.4720	=	$543,107	$ 0.00241
	TFX12 (Discount)	111866	11,921	12	$ 7.6025	=	$1,087,553	$ 0.00483
	TFX5 (Discount)	111866	379	5	$ 4.8640	=	$9,217	$ 0.00004
	TFX5 (Discount)	111866	2,445	5	$ 5.4720	=	$66,895	$ 0.00030
	TFX5 (Discount)	111866	22,189	5	$ 15.1392	=	$1,679,619	$ 0.00746
	Windom	118657	2,500	12	$ -	=	$0	$ -
	Northwestern Energy		1,035	12	$ 8.3382	=	$103,560	$ 0.00046
	Total Demand Cost						$22,189,727	**$ 0.09860**
	As approved in Docket No. G011/MR-15-748						225,057,235	
	GS-1 Demand Current Cost of Gas/therm							**$ 0.09860**
	GS-1 Commodity Current Cost of Gas/therm							**$ 0.30616**
	Total GS-1 Current Cost of Gas/therm							**$ 0.40476**

B. GS-NNG, SVI-NNG, LVI-NNG, SJ-NNG, LJ-NNG, SLV-Commodity

		Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Contract Costs	Rate ($/therm)
FDD - Reservation	118657	87,058	12	$ 1.7140	=	$1,790,633	$ 0.00707
FDD - Storage Cycle	118657	1,003,864	5	$ 0.3567	=	$1,790,392	$ 0.00707
FDD - Reservation	132024	17,345	12	$ 1.7140	=	$356,748	$ 0.00141
FDD - Storage Cycle	132024	200,000	5	$ 0.3567	=	$356,700	$ 0.00141
FDD - Reservation	132112	8,672	12	$ 1.7140	=	$178,374	$ 0.00070
FDD - Storage Cycle	132112	100,000	5	$ 0.3567	=	$178,350	$ 0.00070
Firm Deferred Delivery Storage Contracts						$4,651,197	$ 0.01836

Per Docket No. G-007/M-07-1402-05 dated August 6, 2014, storage demand charges will be allocated through the commodity charge effective 11/1/2014.

		Monthly Entitlement (Dth)	Months	Rate ($/Dth)	Contract Costs	Contract Costs	Rate ($/therm)
Bison	FT0003	50,000	12	$ 17.4896	=	$10,493,750	$ 0.04142
NBPL	T8673F	50,000	12	$ 6.9958	=	$4,197,500	$ 0.01657
						$14,691,250	$ 0.05799

Per Doct No. G-007/M-10-1166 and G-011/M-10-1168 dated January 26, 2015, recover the costs associated with Bison contract through commodity effective

	Annual Sales (Dth)		Rate ($/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate ($/therm)
CD-1 Commodity	25,335,175	x	$2.2444	$56,862,266	253,351,745	$ 0.22444
SMS-Bal Service	272,160	x	$2.1800	$593,309	253,351,745	$ 0.00234
Physical Forward Start Premium				$53,820	253,351,745	$ 0.00021
Call Option Premium				$713,379	253,351,745	$ 0.00282
GS-NNG, SVI-NNG, LVI-NNG, SJ-NNG, LJ-NNG, SLV Commodity Current Cost of Gas/therm				$62,873,970	253,351,745	$ 0.30616

MINNESOTA ENERGY RESOURCES - NNG

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

NOVEMBER 1, 2017

NNG

COSTS ASSIGNED IN JOINT RATE:

	Units	Contract #	Month	$/Dth		Cost	$/therm
TF12B (Max Rate) Winter	49,219	112495	5	$10.2300	=	$2,517,552	$0.11552
TF12B (Max Rate) Summer	49,219	112495	7	$5.6830	=	$1,957,981	$0.08984
TF12V (Max Rate)	30,290	112495	12	$9.0926	=	$3,304,978	$0.15165
TF5 (Max Rate)	36,275	112495	5	$15.1530	=	$2,748,375	$0.12611
TF12B (Discount-Winter)	5,200	112495	12	$7.4951	=	$467,694	$0.02146
TFX12 (Max Rate)	10,822	112486	12	$9.6288	=	$1,250,434	$0.05738
TFX Apr (Max Rate)	2,000	112486	1	$5.6830	=	$11,366	$0.00052
TFX Oct (Max Rate)	2,000	112486	1	$5.6830	=	$11,366	$0.00052
TFX5 (Max Rate)	82,688	112486	5	$15.1530	=	$6,264,856	$0.28746
TFX5 (Discount)	1,800	112486	5	$10.0320	=	$90,288	$0.00414
TFX12 (Discount)	1,283	111866	12	$4.8640	=	$74,886	$0.00344
TFX12 (Discount)	8,271	111866	12	$5.4720	=	$543,107	$0.02492
TFX12 (Discount)	11,921	111866	12	$7.6025	=	$1,087,553	$0.04990
TFX5 (Discount)	379	111866	5	$4.8640	=	$9,217	$0.00042
TFX5 (Discount)	2,445	111866	5	$5.4720	=	$66,895	$0.00307
TFX5 (Discount)	22,189	111866	5	$15.1392	=	$1,679,619	$0.07707
Windom	2,500	118657	12	$0.0000	=	$0	$0.00000
Northwestern Energy	1,035		12	$8.3382	=	$103,560	$0.00475
				TOTAL		$22,189,728	
				Annualized Entitlement		21,793,720	
				Demand Component		$1.01817	$1.01817

Attachment 5

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

Financial Options

Heating Season 2017-2018

Units - Gas Daily Peaker Packages (Physical)

November		December		January		February		March			
Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Daily Total	Term Total
N/A		N/A		N/A		N/A		N/A			

Premium - Gas Daily Peaker (Monthly Cost)

November		December		January		February		March		Total	
Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost
N/A		N/A		N/A		N/A		N/A			

Units - Futures (Dth)

	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	Term Total
1	05/15/17	1,896	05/25/17	2,688	05/22/17	2,926	05/17/17	2,941	05/19/17	2,395	387,513
2	06/07/17	1,354	06/21/17	2,688	06/19/17	2,926	06/08/17	2,941	06/14/17	1,863	354,763
3	07/11/17	1,354	07/21/17	1,882	07/18/17	2,660	07/12/17	2,647	07/17/17	798	280,282
4	08/01/17	1,354	08/24/17	1,882	08/21/17	2,394	08/07/17	2,353	07/17/17	798	263,801
5	09/05/17	1,354	09/19/17	1,882	09/14/17	2,128	09/07/17	2,059	08/10/17	1,597	272,070
6	10/03/17	1,354	10/17/17	1,882	10/18/17	2,128	10/05/17	2,059	09/12/17	1,597	272,070
7									10/12/17	1,597	49,500
8											
Total		8,667		12,903		15,161		15,000		10,645	1,880,000

Units - Call Options (Dth)

	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	Term Total
1	05/15/17	3,313	05/19/17	4,533	05/18/17	5,596	05/25/17	5,305	05/22/17	3,943	684,129
2	06/07/17	3,313	06/14/17	4,533	06/08/17	5,330	06/21/17	5,305	06/19/17	3,943	675,869
3	07/11/17	3,036	07/17/17	4,533	07/12/17	5,063	07/21/17	5,305	07/18/17	3,943	659,326
4	08/01/17	2,760	08/10/17	4,533	08/07/17	5,063	08/24/17	5,010	08/21/17	3,154	618,348
5	09/05/17	2,760	09/12/17	4,266	09/07/17	4,797	09/19/17	4,716	09/14/17	3,154	593,570
6	10/03/17	2,484	10/12/17	3,733	10/05/17	4,797	10/17/17	4,716	10/18/17	3,154	568,758
7											
8											
Total		17,667		26,129		30,645		30,357		21,290	3,800,000

Premium - Call Option (Monthly Cost)

	November		December		January		February		March		Total	
	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost
1	$ 0.3060	$ 30,409	$ 0.2760	$ 38,781	$ 0.2790	$ 48,400	$ 0.2670	$ 39,661	$ 0.2820	$ 34,467	$ 0.2802	$ 191,718
2	$ 0.2260	$ 22,459	$ 0.2610	$ 36,673	$ 0.2560	$ 42,296	$ 0.2710	$ 40,255	$ 0.2720	$ 33,244	$ 0.2588	$ 174,927
3	$ 0.1790	$ 16,306	$ 0.2740	$ 38,500	$ 0.2720	$ 42,692	$ 0.2590	$ 38,473	$ 0.3150	$ 38,500	$ 0.2646	$ 174,471
4	$ 0.1000	$ 8,281	$ 0.1000	$ 14,051	$ 0.0950	$ 14,911	$ 0.0970	$ 13,608	$ 0.1000	$ 9,778	$ 0.0981	$ 60,629
5	$ 0.0850	$ 7,039	$ 0.0980	$ 12,960	$ 0.0970	$ 14,423	$ 0.1000	$ 13,204	$ 0.0980	$ 9,582	$ 0.0964	$ 57,209
6	$ 0.0970	$ 7,230	$ 0.0910	$ 10,530	$ 0.0940	$ 13,977	$ 0.1000	$ 13,204	$ 0.0970	$ 9,484	$ 0.0957	$ 54,425
7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Total	$ 0.1731	$ 91,723	$ 0.1870	$ 151,495	$ 0.1860	$ 176,700	$ 0.1864	$ 158,405	$ 0.2046	$ 135,056	$ 0.1877	$ 713,379

Units - Collar Floor (put)

No Puts were purchased.

Attachment 6
Page 1 of 2

17/18 Winter Portfolio Plan - NNG MERC Hedging Plan

10,000 Contract Size

		Contracts		Contracts		Contracts		Contracts		Contracts		Total		Percent
System	Purchase Month	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	Number Contracts	Contract Volume	of Requirements
MN Requirements			2,666,421		4,073,091		4,832,256		4,255,202		3,347,470		19,174,439	19,174,439
NNG -MERC			88,881		131,390		155,879		151,971		107,983		126,942	
10%	Futures		266,642		407,309		483,226		425,520		334,747		1,917,444	
20%	Call		533,284		814,618		966,451		851,040		669,494		3,834,888	
30%	Storage		799,926		1,221,927		1,449,677		1,276,561		1,004,241		5,752,332	
40%	Index		1,066,568		1,629,236		1,932,902		1,702,081		1,338,988		7,669,776	
Futures														
Contracts	May-17	6	60,000	8	80,000	9	90,000	8	80,000	7	70,000	38	380,000	
	Jun-17	4	40,000	8	80,000	9	90,000	8	80,000	6	60,000	35	350,000	
	Jul-17	4	40,000	6	60,000	8	80,000	7	70,000	5	50,000	30	300,000	
	Aug-17	4	40,000	6	60,000	7	70,000	7	70,000	5	50,000	29	290,000	
	Sep-17	4	40,000	6	60,000	7	70,000	6	60,000	5	50,000	28	280,000	
	Oct-17	4	40,000	6	60,000	7	70,000	6	60,000	5	50,000	28	280,000	
	Total	26	260,000	40	400,000	47	470,000	42	420,000	33	330,000	188	1,880,000	**9.80%**
Call Options	May-17	10	100,000	14	140,000	17	170,000	15	150,000	12	120,000	68	680,000	
	Jun-17	10	100,000	14	140,000	16	160,000	15	150,000	12	120,000	67	670,000	
	Jul-17	9	90,000	14	140,000	16	160,000	15	150,000	12	120,000	66	660,000	
	Aug-17	8	80,000	14	140,000	16	160,000	14	140,000	10	100,000	62	620,000	
	Sep-17	8	80,000	13	130,000	15	150,000	13	130,000	10	100,000	59	590,000	
	Oct-17	8	80,000	12	120,000	15	150,000	13	130,000	10	100,000	58	580,000	
	Total	53	530,000	81	810,000	95	950,000	85	850,000	66	660,000	380	3,800,000	**19.82%**
Collars	May-17													
	Jun-17													
	Jul-17													
	Aug-17													
	Sep-17													
	Oct-17													
	Total													**0.00%**
Index (back financial)														
	Total		790,000		1,210,000		1,420,000		1,270,000		990,000		5,680,000	**29.62%**
Physical Hedges														
Storage			586,884		1,474,734		1,474,734		1,474,734		586,884		5,597,969	**29.19%**
Prepaid Obl														**0.00%**
Term Index														**0.00%**
Total NNG MN														
Futures													1,880,000	**9.80%**
Call Options													3,800,000	**19.82%**
Costing Collar														**0.00%**
Storage													5,597,969	**29.19%**
Prepaid Obl														**0.00%**
Term Index														**0.00%**
Month/Daily													7,896,471	**41.18%**
Total													19,174,439	**100.00%**

NOTE:

MINNESOTA ENERGY RESOURCES

NNG WINTER PLAN
NOVEMBER, 2015 THROUGH MARCH, 2016

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

INDEX	Contract Number	Date	Receipt Point	Nov	Dec	Jan	Feb	Mar	Total
	48980	4/28/2017	NBPL Port of Morgan		10,000	10,000	10,000		900,000
	48982	4/28/2017	NBPL Port of Morgan	20,000	20,000	20,000	20,000	20,000	3,020,000
	49012	4/28/2017	NBPL Port of Morgan		10,000	10,000	10,000		900,000
	49014	4/28/2017	NBPL Port of Morgan		10,000	10,000	10,000		900,000
	48981	4/28/2017	NNG Ventura	10,846	10,846	10,846	10,846	10,846	1,637,746
	49013	4/28/2017	NNG Demarc		5,000	5,000	5,000		450,000
	49017	4/28/2017	NNG/GLGT Carlton	8,000	8,000	8,000	8,000	8,000	1,208,000
	49018	4/28/2017	NNG/GLGT Grand Rapids	6,064	6,064	6,064	6,064	6,064	915,664
	49019	4/28/2017	NNG/GLGT Carlton		5,000	5,000	5,000		450,000
	Total Actual Seasonal Index			44,910	84,910	84,910	84,910	44,910	4,661,410
GAS DAILY PACKAGES									
Physical Call Option	49015	4/28/2017	NNG Ventura	-	10,000	10,000	10,000	-	
Physical Call Option	49016	4/28/2017	NNG Ventura	-	20,000	20,000	20,000	-	

STORAGE

Injection Month	K#118657 Volume Injected	K#132024 Volume Injected	K#132112 Volume Injected	Total Volume Injected
May - balance forward	0	0	0	0
June	984,181	98,039	196,078	1,278,298
July	1,016,987	101,307	202,614	1,320,908
August	1,016,987	101,307	202,614	1,320,908
Sept	984,181	98,039	196,078	1,278,298
Oct (est)	1,016,987	101,307	202,614	1,320,908
Total	**5,019,321**	**500,000**	**1,000,000**	**6,519,321**

Attachment 7
NNG

MINNESOTA ENERGY RESOURCES - NNG

	2013 NNG GS	2014 NNG GS	2015 NNG GS	2016 NNG GS	2017 NNG GS	Proposed Change
Design Day	245,878	261,002	245,263	248,796	**266,825**	18,029
Customer Requirements moving to Transportation 2005-6						
Adjusted Design Day						
Design Day Percentages	28.43%	28.07%	32.40%	29.71%	**30.43%**	0.71%
Total Design Day Capacity (includes non-recallable capacity)	256,385	266,385	252,127	252,127	**266,317**	14,190
Less: Windom	2,500	2,500	2,500	2,500	**2,500**	0
Less: Northwestern Energy	910	910	1,035	1,035	**1,035**	0
Total Design Day Capacity	252,975	262,975	248,592	248,592	**262,782**	14,190
Factors for All Winter Capacity	100.00%	100.00%	100.00%	100.00%	**100.00%**	
<u>Direct Assigned Entitlements in PGA</u>						
TF12B	49153	55019	45,026	45,026	**54,419**	**9,393**
TF12V	26926	21060	30,290	30,290	**30,290**	**0**
TF5	31515	31515	32,278	32,278	**36,275**	**3,997**
TFX12	32297	32297	32,297	32,297	**32,297**	**0**
TFX(5)	93084	123084	108,701	108,701	**109,501**	**800**
TFX(5) (12-V)						**0**
TFX (April Only)	2000	2000	2,000	2,000	**2,000**	**0**
TFX (October Only)	2000	2000	2,000	2,000	**2,000**	**0**
Windom	2,500	2,500	2,500	2,500	**2,500**	**0**
Northwestern Energy	910	910	1,035	1,035	**1,035**	**0**
NNG Zone Delivery Call Option	20,000	0	0	0	**0**	**0**
Bison *	50,000	50,000	50,000	50,000	**50,000**	**0**
NBPL *	50,000	50,000	50,000	50,000	**50,000**	**0**
Total Direct Assignments	256,385	266,385	252,127	252,127	**266,317**	**14,190**
LP Peak Shaving	0					**0**
Total Design Day Capacity	256,385	266,385	252,127	252,127	**266,317**	**14,190**
Total Annual Transportation	111,786	111,786	111,148	111,148	**120,541**	**9,393**
Total Seasonal Transportation	144,599	154,599	140,979	140,979	**145,776**	**4,797**
Total Percent Seasonal	56.4%	58.0%	55.9%	55.9%	**54.7%**	**-1.2%**
Reserve Margin	4.27%	2.06%	2.80%	1.34%	**-0.19%**	**-1.5%**
Total Design Day Capacity w/ contract demand	256,385	266,385	252,127	252,127	**266,317**	14,190
Factors	28.43%	28.07%	32.40%	29.71%	**30.43%**	0.71%
<u>Other Entitlements not included in Peak Day Deliverability</u>						
TFX Oct	2,000	2,000	2,000	2,000	**2,000**	0
TFX Apr	2,000	2,000	2,000	2,000	**2,000**	0
FDD Storage Reservation	97,463	94,863	94,863	101,800	**113,075**	11,275
FDD Storage Capacity	1,123,864	1,093,864	1,093,864	1,093,864	**1,303,864**	130,000
FDD Maximum Storage Quantity	5,619,321	5,469,321	5,469,321	5,869,321	**6,519,321**	650,000
SMS	22,680	22,680	22,680	272,160	**272,160**	0

Attachment 8

MINNESOTA ENERGY RESOURCES - NNG

Change in Costs due to November 1, 2017 Change in Entitlement Levels and Related Demand Costs

Costs Assigned In Demand	Contract	2016/17 Entitlements	2017/18 Entitlements	Entitlement Change	Months	2017/18 Rate	2016/17 Total Annual Cost	2017/18 Total Annual Cost	Total Annual Cost Change
TF12B (Max Rate) Winter	112495	39,826	49,219	9,393	5	$10.2300	$2,037,100	$2,517,552	$480,452
TF12B (Max Rate) Summer	112495	39,826	49,219	9,393	7	$5.6830	$1,584,318	$1,957,981	$373,663
TF12V (Max Rate)	112495	30,290	30,290	0	12	$9.0926	$3,304,978	$3,304,978	$0
TF5 (Max Rate)	112495	32,278	36,275	3,997	5	$15.1530	$2,445,543	$2,748,375	$302,833
TF12B (Discount-Winter)	112495	5,200	5,200	0	12	$7.4951	$467,694	$467,694	$0
TFX12 (Max Rate)	112486	10,822	10,822	0	12	$9.6288	$1,250,434	$1,250,434	$0
TFX Apr (Max Rate)	112486	2,000	2,000	0	1	$5.6830	$11,366	$11,366	$0
TFX Oct (Max Rate)	112486	2,000	2,000	0	1	$5.6830	$11,366	$11,366	$0
TFX5 (Max Rate)	112486	81,888	82,688	800	5	$15.1530	$6,204,244	$6,264,856	$60,612
TFX5 (Discount)	112486	1,800	1,800	0	5	$10.0320	$90,288	$90,288	$0
TFX12 (Discount)	111866	1,283	1,283	0	12	$4.8640	$74,886	$74,886	$0
TFX12 (Discount)	111866	8,271	8,271	0	12	$5.4720	$543,107	$543,107	$0
TFX12 (Discount)	111866	11,921	11,921	0	12	$7.6025	$1,087,553	$1,087,553	$0
TFX5 (Discount)	111866	379	379	0	5	$4.8640	$9,217	$9,217	$0
TFX5 (Discount)	111866	2,445	2,445	0	5	$5.4720	$66,895	$66,895	$0
TFX5 (Discount)	111866	22,189	22,189	0	5	$15.1392	$1,679,619	$1,679,619	$0
Windom	118657	2,500	2,500	0	12	$0.0000	$0	$0	$0
Northwestern Energy		1,035	1,035	0	12	$8.3382	$103,560	$103,560	$0
Total Demand Cost							$20,972,169	$22,189,728	$1,217,560

Costs Assigned In Commodity	Contract	2016/17 Entitlements	2017/18 Entitlement	Entitlement Change	Months	2017/18 Rate/Dth	2016/17 Total Annual Cost	Entitlement Total Cost	Entitlement Change
Upstream Surcharges:									
Storage (FDD)									
FDD - Reservation	118657	80,989	87,058	6,069	12	$ 1.7140	$1,665,782	$1,790,633	$124,851
FDD - Storage Cycle	118657	933,864	1,003,864	70,000	5	$ 0.3567	$1,665,547	$1,790,392	$124,845
FDD - Reservation	132024	2,602	17,345	14,743	12	$ 1.7140	$249,716	$356,748	$107,032
FDD - Storage Cycle	132024	30,000	200,000	170,000	5	$ 0.3567	$249,690	$356,700	$107,010
FDD - Reservation	132112	11,274	8,672	(2,602)	12	$ 1.7140	$178,366	$178,374	$8
FDD - Storage Cycle	132112	130,000	100,000	(30,000)	5	$ 0.3567	$178,350	$178,350	$0
Pipeline									
Bison	FT0003	50,000	50,000	0	12	$17.4896	$10,493,750	$10,493,750	$0
NBPL	T8673F	50,000	50,000	0	12	$6.9958	$4,197,500	$4,197,500	$0
SMS-Bal Service		272,160	272,160	0	1	$2.1800	$593,309	$593,309	$0
Physical Forward Start Premium							$175,451	$53,820	($121,631)
Producer Demand Payments/Option Premium							$1,352,456	$713,379	($639,077)
Total Commodity Costs							$20,999,916	$20,702,954	($296,962)

Attachment 8.1

MINNESOTA ENERGY RESOURCES - NNG

Change in Costs due to November 1, 2017 Change in Entitlement Levels and Related Demand Costs

Costs Assigned In Demand	Contract	2016/17 NNG Entitlements	2016/17 Albert Lea Entitlements	2017/18 Entitlements	Net Entitlement Change	Months	2017/18 Rate	2016/17 Total Annual Cost	2016/17 Albert Lea Cost	2017/18 Total Annual Cost	Net Annual Cost Change
TF12B (Max Rate) Winter	112495	39,826	3,157	49,219	6,236	5	$10.2300	$2,037,100	$161,481	$2,517,552	$318,971
TF12B (Max Rate) Summer	112495	39,826	9,393	49,219	0	7	$5.6830	$1,584,318	$373,663	$1,957,981	$0
TF12V (Max Rate)	112495	30,290	6,236	30,290	(6,236)	12	$9.0926	$3,304,978	$432,342	$3,304,978	($432,342)
TF5 (Max Rate)	112495	32,278	3,997	36,275	0	5	$15.1530	$2,445,543	$302,833	$2,748,375	$0
TF12B (Discount-Winter)	112495	5,200		5,200	0	12	$7.4951	$467,694		$467,694	$0
TFX12 (Max Rate)	112486	10,822		10,822	0	12	$9.6288	$1,250,434		$1,250,434	$0
TFX Apr (Max Rate)	112486	2,000		2,000	0	1	$5.6830	$11,366		$11,366	$0
TFX Oct (Max Rate)	112486	2,000		2,000	0	1	$5.6830	$11,366		$11,366	$0
TFX5 (Max Rate)	112486	81,888	800	82,688	0	5	$15.1530	$6,204,244	$60,612	$6,264,856	$0
TFX5 (Discount)	112486	1,800		1,800	0	5	$10.0320	$90,288		$90,288	$0
TFX12 (Discount)	111866	1,283		1,283	0	12	$4.8640	$74,886		$74,886	$0
TFX12 (Discount)	111866	8,271		8,271	0	12	$5.4720	$543,107		$543,107	$0
TFX12 (Discount)	111866	11,921		11,921	0	12	$7.6025	$1,087,553		$1,087,553	$0
TFX5 (Discount)	111866	379		379	0	5	$4.8640	$9,217		$9,217	$0
TFX5 (Discount)	111866	2,445		2,445	0	5	$5.4720	$66,895		$66,895	$0
TFX5 (Discount)	111866	22,189		22,189	0	5	$15.1392	$1,679,619		$1,679,619	$0
Windom	118657	2,500		2,500	0	12	$0.0000	$0		$0	$0
Northwestern Energy		1,035		1,035	0	12	$8.3382	$103,560		$103,560	$0
Total Demand Cost								$20,972,169	$1,330,930	$22,189,728	($113,370)

Costs Assigned In Commodity		2016/17 Entitlements	2016/17 Albert Lea Entitlements	2017/18 Entitlement	Net Entitlement Change	Months	2017/18 Rate/Dth	2016/17 Total Annual Cost	2016/17 Albert Lea Cost	Entitlement Total Cost	Entitlement Change
Upstream Surcharges:											
Storage (FDD)											
FDD - Reservation	118657	80,989	6,071	87,058	(2)	12	$ 1.7140	$1,665,782	$124,868	$1,790,633	($17)
FDD - Storage Cycle	118657	933,864	70,000	1,003,864	0	5	$ 0.3567	$1,665,547	$124,845	$1,790,392	($0)
FDD - Reservation	132024	2,602		17,345	14,743	12	$ 1.7140	$249,716		$356,748	$107,032
FDD - Storage Cycle	132024	30,000		200,000	170,000	5	$ 0.3567	$249,690		$356,700	$107,010
FDD - Reservation	132112	11,274		8,672	(2,602)	12	$ 1.7140	$178,366		$178,374	$8
FDD - Storage Cycle	132112	130,000		100,000	(30,000)	5	$ 0.3567	$178,350		$178,350	$0
Pipeline											
Bison	FT0003	50,000		50,000	0	12	$17.4896	$10,493,750		$10,493,750	$0
NBPL	T8673F	50,000		50,000	0	12	$6.9958	$4,197,500		$4,197,500	$0
SMS-Bal Service		272,160	1,700	272,160	(1,700)	1	$2.1800	$593,309	$44,472	$593,309	($44,472)
Physical Forward Start Premium								$175,451		$53,820	($174,285)
Producer Demand Payments/Option Premium								$1,352,456	$52,654	$713,379	($639,077)
Total Commodity Costs								$20,999,916		$20,702,954	($643,801)

MINNESOTA ENERGY RESOURCES - NNG

Daily Total Throughput Data - July 1, 2016 through June 30, 2017

NNG

Minnesota Energy Resources Corporation
2017-2018 Demand Entilement
MERC-NNG
Attachment 9

Design Day:

Base	17,443
Variable	2,139

Date	13.98% Cloquet Adjusted HDD	29.22% Minneapolis Adjusted HDD	45.15% Rochester Adjusted HDD	11.65% Worthington Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Firm Through-Put **
7/1/16	5	0	3	1	2	138,989	**21,634**
7/2/16	3	0	2	1	1	119,267	**20,040**
7/3/16	0	0	0	0	0	118,351	**17,443**
7/4/16	0	0	0	0	0	124,073	**17,443**
7/5/16	0	0	0	0	0	155,167	**17,443**
7/6/16	0	0	0	0	0	150,273	**17,443**
7/7/16	1	0	0	0	0	151,894	**17,593**
7/8/16	2	0	0	0	0	145,046	**17,921**
7/9/16	0	0	0	0	0	125,662	**17,443**
7/10/16	2	0	0	0	0	114,313	**17,921**
7/11/16	0	0	0	0	0	121,087	**17,443**
7/12/16	0	0	0	0	0	133,973	**17,443**
7/13/16	0	0	0	0	0	120,877	**17,443**
7/14/16	5	0	0	2	1	117,143	**19,272**
7/15/16	4	0	1	0	1	137,475	**19,002**
7/16/16	0	0	0	0	0	115,536	**17,443**
7/17/16	0	0	0	0	0	120,474	**17,443**
7/18/16	0	0	0	0	0	164,474	**17,443**
7/19/16	0	0	0	0	0	149,523	**17,443**
7/20/16	0	0	0	0	0	159,411	**17,443**
7/21/16	0	0	0	0	0	169,741	**17,443**
7/22/16	0	0	0	0	0	159,383	**17,443**
7/23/16	0	0	0	0	0	137,119	**17,443**
7/24/16	0	0	0	0	0	128,533	**17,443**
7/25/16	0	0	0	0	0	159,618	**17,443**
7/26/16	0	0	0	0	0	157,013	**17,443**
7/27/16	5	0	0	0	1	152,327	**18,848**
7/28/16	6	0	0	0	1	147,173	**19,327**
7/29/16	6	0	0	2	1	144,825	**19,546**
7/30/16	0	0	0	0	0	133,540	**17,443**
7/31/16	0	0	0	0	0	124,401	**17,443**
8/1/16	0	0	0	0	0	152,800	**17,443**
8/2/16	0	0	0	0	0	165,672	**17,443**
8/3/16	0	0	0	0	0	152,176	**17,443**
8/4/16	0	0	0	0	0	138,146	**17,443**
8/5/16	1	0	0	0	0	122,449	**17,772**
8/6/16	2	0	0	0	0	118,320	**17,921**
8/7/16	3	0	0	0	0	107,876	**18,191**
8/8/16	0	0	0	0	0	128,201	**17,443**
8/9/16	0	0	0	0	0	136,909	**17,443**
8/10/16	2	0	0	0	0	136,607	**17,921**
8/11/16	0	0	0	0	0	137,271	**17,443**
8/12/16	0	0	0	0	0	119,752	**17,443**
8/13/16	0	0	0	0	0	109,044	**17,443**
8/14/16	0	0	0	0	0	96,958	**17,443**
8/15/16	0	0	0	0	0	115,444	**17,443**
8/16/16	0	0	0	0	0	121,417	**17,443**
8/17/16	0	0	0	0	0	116,285	**17,443**
8/18/16	0	0	0	0	0	108,754	**17,443**
8/19/16	0	0	0	0	0	103,462	**17,443**
8/20/16	8	3	6	7	5	90,642	**28,829**
8/21/16	4	0	3	0	2	102,420	**21,789**
8/22/16	0	0	0	0	0	114,711	**17,443**
8/23/16	0	0	0	0	0	124,458	**17,443**
8/24/16	0	0	0	0	0	134,269	**17,443**
8/25/16	7	0	0	5	1	137,157	**20,558**
8/26/16	2	0	1	2	1	118,876	**18,898**
8/27/16	5	0	1	0	1	104,042	**19,301**
8/28/16	0	0	0	0	0	124,833	**17,443**
8/29/16	0	0	0	0	0	158,567	**17,443**
8/30/16	4	0	0	0	1	147,238	**18,549**
8/31/16	3	0	0	0	0	135,047	**18,220**
9/1/16	6	0	3	1	2	120,978	**22,059**
9/2/16	3	0	3	0	2	113,860	**20,978**
9/3/16	1	0	0	0	0	107,434	**17,593**
9/4/16	0	0	0	0	0	97,344	**17,443**
9/5/16	0	0	0	0	0	101,559	**17,443**
9/6/16	0	0	0	0	0	138,653	**17,443**
9/7/16	2	0	0	0	0	127,110	**17,921**
9/8/16	2	0	0	0	0	125,226	**18,071**
9/9/16	4	0	3	5	3	101,279	**23,165**
9/10/16	8	1	6	3	4	97,358	**26,132**
9/11/16	0	0	0	0	0	94,085	**17,443**
9/12/16	5	0	0	6	1	112,136	**20,453**
9/13/16	17	9	8	17	10	112,697	**39,578**
9/14/16	11	4	3	6	5	111,904	**27,978**

MERC

9/15/16	3	0	0	3	1	95,472	**19,167**
9/16/16	4	0	0	2	1	95,632	**18,943**
9/17/16	12	2	5	1	5	94,526	**27,371**
9/18/16	2	0	0	0	0	90,576	**17,921**
9/19/16	7	0	0	0	1	119,108	**19,387**
9/20/16	5	0	0	0	1	113,338	**18,848**
9/21/16	4	0	0	0	1	109,618	**18,759**
9/22/16	9	0	0	0	1	113,478	**20,134**
9/23/16	7	0	1	0	1	108,287	**20,479**
9/24/16	6	0	0	0	1	94,908	**19,357**
9/25/16	9	8	8	13	9	96,494	**35,894**
9/26/16	15	9	10	13	11	123,792	**40,304**
9/27/16	19	11	10	10	12	127,224	**42,467**
9/28/16	11	12	10	16	11	123,921	**41,860**
9/29/16	10	6	7	12	8	128,198	**34,206**
9/30/16	12	4	3	5	5	121,543	**27,400**
10/1/16	11	3	6	6	6	129,385	**29,474**
10/2/16	9	1	4	1	3	129,498	**24,687**
10/3/16	10	0	1	0	2	131,294	**21,376**
10/4/16	2	0	0	10	1	125,955	**20,314**
10/5/16	17	10	9	13	11	151,183	**40,010**
10/6/16	20	15	15	24	17	145,758	**53,002**
10/7/16	28	25	25	26	26	157,338	**72,251**
10/8/16	29	22	20	24	22	154,969	**64,674**
10/9/16	21	17	15	14	16	143,895	**52,046**
10/10/16	2	1	4	7	3	140,791	**23,714**
10/11/16	17	8	6	19	10	145,564	**37,946**
10/12/16	29	24	30	31	28	175,486	**77,755**
10/13/16	23	21	23	21	22	174,460	**65,008**
10/14/16	13	11	14	9	13	149,216	**44,350**
10/15/16	16	8	7	11	9	140,215	**36,976**
10/16/16	15	6	3	4	6	134,911	**29,806**
10/17/16	16	4	5	10	7	167,367	**31,687**
10/18/16	13	9	10	13	10	178,397	**39,681**
10/19/16	30	19	17	26	21	203,088	**61,524**
10/20/16	26	21	26	26	25	210,708	**70,286**
10/21/16	27	20	23	18	22	175,613	**64,631**
10/22/16	17	12	12	10	12	153,898	**43,842**
10/23/16	28	21	21	23	22	160,729	**64,789**
10/24/16	24	19	20	22	20	175,000	**60,966**
10/25/16	26	20	24	18	22	179,338	**64,991**
10/26/16	28	22	24	22	24	192,371	**68,224**
10/27/16	23	20	25	14	22	185,294	**64,220**
10/28/16	16	4	8	5	8	149,938	**33,489**
10/29/16	23	17	17	23	18	160,032	**56,716**
10/30/16	27	22	24	25	24	173,131	**68,966**
10/31/16	21	13	14	18	15	169,962	**50,281**
11/1/16	24	14	11	16	14	183,410	**47,300**
11/2/16	21	13	15	16	16	190,222	**50,870**
11/3/16	20	12	16	11	15	198,342	**48,489**
11/4/16	16	10	12	8	12	168,867	**42,107**
11/5/16	13	6	10	6	9	151,412	**36,569**
11/6/16	7	7	13	9	10	147,862	**38,986**
11/7/16	17	12	17	19	16	166,101	**50,845**
11/8/16	24	19	23	24	22	180,011	**63,821**
11/9/16	16	15	18	17	17	176,530	**53,084**
11/10/16	21	13	17	16	16	171,771	**52,096**
11/11/16	30	25	29	29	28	196,137	**77,117**
11/12/16	22	20	24	24	22	182,285	**65,317**
11/13/16	14	15	17	19	16	164,931	**51,955**
11/14/16	23	24	27	23	25	183,955	**70,772**
11/15/16	25	21	22	20	22	174,735	**64,237**
11/16/16	24	15	18	15	18	164,123	**55,257**
11/17/16	26	15	12	30	17	167,660	**53,652**
11/18/16	43	34	29	51	35	219,713	**91,638**
11/19/16	50	42	46	50	46	239,663	**115,052**
11/20/16	43	41	42	42	42	251,845	**107,157**
11/21/16	42	35	37	38	37	232,672	**97,134**
11/22/16	37	34	35	35	35	234,728	**92,742**
11/23/16	35	33	34	35	34	218,519	**89,826**
11/24/16	33	32	32	37	32	217,703	**86,838**
11/25/16	34	35	35	28	34	225,346	**89,999**
11/26/16	32	29	31	30	30	208,686	**82,302**
11/27/16	33	27	29	29	29	200,666	**79,357**
11/28/16	27	23	28	35	27	203,478	**75,846**
11/29/16	31	31	34	38	33	219,158	**88,566**
11/30/16	34	31	34	39	34	218,927	**89,260**
12/1/16	39	34	36	37	36	233,555	**93,706**
12/2/16	40	37	39	40	38	242,710	**99,700**
12/3/16	39	37	38	38	38	226,037	**98,073**
12/4/16	36	34	39	32	37	227,289	**95,636**
12/5/16	37	39	42	45	40	229,031	**103,978**
12/6/16	53	53	59	64	57	274,909	**138,639**
12/7/16	53	55	60	66	58	288,743	**141,655**
12/8/16	54	52	59	64	57	310,657	**139,263**
12/9/16	63	58	61	60	60	335,218	**146,032**
12/10/16	62	57	59	58	59	301,660	**143,080**
12/11/16	59	59	58	65	59	301,565	**143,855**
12/12/16	70	71	74	66	71	336,250	**170,059**

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12/13/16	73	70	75	70	73	334,866	**172,708**
12/14/16	80	77	80	78	79	382,958	**185,704**
12/15/16	70	69	72	69	71	373,684	**168,313**
12/16/16	64	62	61	68	63	339,779	**151,199**
12/17/16	82	80	85	89	84	360,409	**196,309**
12/18/16	78	75	88	85	82	372,217	**193,409**
12/19/16	51	48	63	57	56	292,146	**137,662**
12/20/16	41	38	41	40	40	245,841	**103,282**
12/21/16	42	39	45	45	42	242,668	**108,284**
12/22/16	40	39	44	43	42	240,206	**107,238**
12/23/16	36	32	37	42	36	224,996	**94,011**
12/24/16	45	34	38	41	38	221,052	**98,925**
12/25/16	40	41	43	49	42	224,669	**107,898**
12/26/16	57	54	56	58	56	282,403	**136,215**
12/27/16	57	46	50	45	49	274,849	**122,388**
12/28/16	45	38	43	40	41	251,797	**106,012**
12/29/16	53	44	51	47	49	267,237	**122,084**
12/30/16	54	44	47	44	46	259,010	**116,690**
12/31/16	52	45	53	50	50	262,238	**124,475**
1/1/17	49	41	45	46	45	247,788	**112,757**
1/2/17	41	43	41	53	43	247,341	**109,391**
1/3/17	67	71	72	79	71	336,838	**170,345**
1/4/17	85	75	78	78	78	361,714	**184,057**
1/5/17	82	75	80	78	79	377,996	**185,605**
1/6/17	79	71	76	66	73	372,143	**174,597**
1/7/17	76	68	74	69	72	347,734	**170,677**
1/8/17	68	61	67	60	65	312,905	**155,837**
1/9/17	53	46	47	52	48	274,677	**120,758**
1/10/17	61	54	54	63	56	288,371	**137,482**
1/11/17	72	63	64	69	66	320,488	**157,627**
1/12/17	78	68	69	67	70	333,973	**166,777**
1/13/17	76	66	65	63	67	327,130	**159,946**
1/14/17	59	54	58	48	56	288,652	**136,629**
1/15/17	52	48	56	41	51	262,697	**127,240**
1/16/17	44	43	40	41	41	251,591	**105,788**
1/17/17	39	37	41	42	40	242,487	**102,422**
1/18/17	34	32	41	34	37	224,359	**95,526**
1/19/17	27	32	37	33	34	218,820	**89,776**
1/20/17	32	31	34	33	33	211,290	**87,457**
1/21/17	31	30	34	34	32	205,484	**86,175**
1/22/17	31	30	35	36	33	209,273	**88,103**
1/23/17	33	33	36	36	35	223,841	**91,388**
1/24/17	39	37	38	43	39	227,675	**99,845**
1/25/17	43	41	43	49	43	243,285	**109,570**
1/26/17	48	46	49	56	49	277,125	**121,885**
1/27/17	47	45	52	52	49	278,216	**122,443**
1/28/17	51	43	48	44	46	260,048	**116,799**
1/29/17	58	46	58	40	52	275,720	**129,645**
1/30/17	47	37	45	37	42	260,326	**107,357**
1/31/17	52	45	45	46	46	261,934	**116,156**
2/1/17	68	60	65	61	63	313,686	**152,606**
2/2/17	70	59	64	60	63	330,316	**151,640**
2/3/17	60	53	60	58	58	305,202	**140,765**
2/4/17	51	44	46	48	46	269,236	**116,603**
2/5/17	57	46	50	48	49	279,677	**123,002**
2/6/17	51	41	41	39	42	257,489	**107,740**
2/7/17	65	59	54	65	58	302,300	**142,231**
2/8/17	71	64	67	62	66	328,498	**158,804**
2/9/17	63	56	61	57	59	300,081	**144,612**
2/10/17	38	32	40	28	36	229,113	**93,689**
2/11/17	40	31	32	34	33	217,001	**88,421**
2/12/17	40	35	42	34	38	232,926	**99,772**
2/13/17	33	28	37	32	33	226,315	**88,639**
2/14/17	48	39	42	39	42	243,849	**106,260**
2/15/17	49	40	42	37	41	251,141	**106,094**
2/16/17	37	32	36	22	33	222,754	**88,733**
2/17/17	24	18	27	22	23	184,413	**67,325**
2/18/17	27	20	24	19	23	182,839	**65,712**
2/19/17	27	17	21	16	20	171,856	**59,895**
2/20/17	27	24	27	22	25	195,159	**71,642**
2/21/17	24	19	22	16	21	184,610	**61,712**
2/22/17	33	23	23	23	24	199,557	**68,979**
2/23/17	46	39	39	49	41	248,770	**105,017**
2/24/17	57	53	56	58	55	285,199	**135,813**
2/25/17	50	44	54	49	50	264,213	**124,292**
2/26/17	55	37	49	42	45	258,707	**114,600**
2/27/17	39	29	40	31	36	234,088	**94,040**
2/28/17	42	33	37	37	36	236,467	**95,174**
3/1/17	49	43	50	43	47	270,425	**118,374**
3/2/17	66	47	53	48	53	304,960	**130,133**
3/3/17	53	46	52	45	50	272,707	**123,552**
3/4/17	39	35	41	34	38	227,605	**98,692**
3/5/17	25	15	25	14	21	191,123	**61,641**
3/6/17	33	21	22	21	23	192,953	**67,049**
3/7/17	52	38	35	35	38	235,468	**99,448**
3/8/17	58	42	41	39	43	265,340	**110,030**
3/9/17	64	54	52	58	55	296,833	**134,533**
3/10/17	66	57	57	59	58	334,351	**142,083**
3/11/17	58	54	53	55	54	295,897	**132,907**

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3/12/17	55	52	51	58	53	295,291	**130,229**
3/13/17	57	51	57	63	56	317,540	**137,169**
3/14/17	52	47	56	56	53	306,564	**130,657**
3/15/17	41	45	51	52	48	275,983	**119,700**
3/16/17	36	37	44	34	40	230,838	**102,599**
3/17/17	38	33	35	36	35	227,775	**92,331**
3/18/17	37	31	36	30	34	231,427	**90,172**
3/19/17	30	23	27	16	25	201,700	**70,727**
3/20/17	33	26	24	29	27	218,433	**74,221**
3/21/17	49	39	41	41	42	269,330	**106,770**
3/22/17	41	37	41	38	40	233,366	**102,211**
3/23/17	33	30	32	29	31	225,923	**84,206**
3/24/17	32	27	31	32	30	213,289	**81,984**
3/25/17	35	28	33	32	32	217,906	**85,580**
3/26/17	32	26	29	29	29	227,909	**78,820**
3/27/17	27	18	27	25	24	238,211	**69,283**
3/28/17	19	12	18	18	17	202,283	**53,203**
3/29/17	34	23	29	28	28	212,228	**76,322**
3/30/17	31	28	32	31	30	224,663	**82,011**
3/31/17	23	20	24	24	23	215,256	**66,471**
4/1/17	21	12	17	16	16	176,176	**51,398**
4/2/17	21	15	21	17	19	189,568	**57,473**
4/3/17	22	19	22	21	21	201,340	**62,466**
4/4/17	22	15	18	20	18	189,286	**55,722**
4/5/17	27	21	26	27	25	213,172	**70,720**
4/6/17	30	22	28	26	26	202,723	**73,601**
4/7/17	19	16	18	14	17	180,241	**54,456**
4/8/17	15	5	6	3	7	157,204	**32,017**
4/9/17	19	7	8	17	10	160,268	**39,467**
4/10/17	34	29	28	36	30	226,894	**81,551**
4/11/17	28	23	26	21	25	226,771	**70,296**
4/12/17	17	16	17	18	17	197,384	**53,394**
4/13/17	19	16	17	18	17	178,338	**53,600**
4/14/17	16	8	11	7	10	158,406	**39,894**
4/15/17	13	6	10	12	9	151,602	**37,247**
4/16/17	25	11	12	13	13	164,762	**46,252**
4/17/17	31	13	13	14	16	190,517	**50,842**
4/18/17	29	11	13	13	15	192,190	**48,757**
4/19/17	30	22	22	25	23	216,157	**67,170**
4/20/17	32	23	29	27	27	208,955	**75,846**
4/21/17	18	14	17	19	16	182,615	**52,048**
4/22/17	17	6	12	10	11	156,442	**40,723**
4/23/17	35	6	8	6	11	161,998	**40,381**
4/24/17	28	2	5	16	9	151,105	**35,787**
4/25/17	24	20	10	33	18	183,696	**55,160**
4/26/17	39	31	31	38	33	215,391	**87,488**
4/27/17	42	33	37	34	36	252,464	**94,488**
4/28/17	30	22	27	28	26	210,704	**73,007**
4/29/17	24	19	24	26	23	187,498	**66,769**
4/30/17	28	26	30	37	29	209,696	**79,901**
5/1/17	33	30	30	32	31	241,418	**83,205**
5/2/17	18	12	21	14	17	210,879	**54,563**
5/3/17	11	11	14	17	13	194,248	**45,574**
5/4/17	17	7	10	11	10	173,639	**39,724**
5/5/17	14	5	7	7	7	155,534	**32,800**
5/6/17	25	7	12	6	12	157,963	**42,147**
5/7/17	22	9	12	0	11	157,401	**41,383**
5/8/17	20	5	7	0	7	168,829	**32,773**
5/9/17	10	3	3	7	5	159,263	**27,203**
5/10/17	14	8	11	14	11	164,609	**40,916**
5/11/17	17	9	13	13	12	168,511	**43,419**
5/12/17	11	0	1	0	2	155,737	**21,215**
5/13/17	12	0	0	0	2	137,320	**21,091**
5/14/17	18	0	0	0	2	143,267	**22,766**
5/15/17	16	0	0	0	2	142,168	**22,198**
5/16/17	15	0	0	0	2	139,069	**22,048**
5/17/17	16	6	6	9	8	137,063	**34,176**
5/18/17	23	17	21	20	20	158,477	**60,022**
5/19/17	22	17	24	26	22	166,236	**64,013**
5/20/17	27	20	23	27	23	164,141	**66,879**
5/21/17	22	19	24	20	22	175,587	**63,656**
5/22/17	16	8	8	10	9	159,277	**37,249**
5/23/17	16	13	18	18	16	163,269	**51,669**
5/24/17	18	10	13	14	13	156,335	**44,925**
5/25/17	12	1	5	3	4	146,454	**26,864**
5/26/17	8	0	3	4	3	153,256	**23,484**
5/27/17	3	1	4	6	3	132,197	**24,211**
5/28/17	9	1	5	5	5	133,295	**27,146**
5/29/17	16	7	11	12	10	144,950	**39,709**
5/30/17	18	11	13	13	13	155,479	**44,990**
5/31/17	14	3	4	6	5	149,145	**28,653**
6/1/17	4	0	0	0	1	140,085	**18,520**
6/2/17	2	0	0	0	0	148,479	**17,921**
6/3/17	0	0	0	0	0	144,740	**17,443**
6/4/17	1	0	0	0	0	139,494	**17,593**
6/5/17	11	0	0	0	2	141,945	**20,732**
6/6/17	6	0	0	0	1	136,644	**19,297**
6/7/17	0	0	0	0	0	142,843	**17,443**
6/8/17	2	0	0	0	0	151,905	**17,921**

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6/9/17	3	0	0	0	0	141,382	**18,250**
6/10/17	0	0	0	0	0	123,115	**17,443**
6/11/17	4	0	0	0	1	136,630	**18,520**
6/12/17	0	0	0	0	0	155,388	**17,443**
6/13/17	11	0	0	0	1	145,683	**20,613**
6/14/17	8	0	0	0	1	156,104	**19,925**
6/15/17	1	0	0	0	0	155,694	**17,593**
6/16/17	0	0	0	0	0	152,134	**17,443**
6/17/17	0	0	0	0	0	125,647	**17,443**
6/18/17	5	0	2	3	2	130,630	**21,248**
6/19/17	11	0	2	0	2	137,406	**22,284**
6/20/17	8	0	1	0	2	149,785	**20,868**
6/21/17	3	0	0	0	0	136,017	**18,220**
6/22/17	1	0	1	0	0	142,105	**18,075**
6/23/17	7	1	6	11	5	139,479	**28,300**
6/24/17	9	6	10	9	9	137,320	**35,654**
6/25/17	14	6	10	8	9	136,451	**36,620**
6/26/17	8	2	8	7	6	150,841	**30,228**
6/27/17	2	0	0	0	0	136,929	**17,921**
6/28/17	8	0	0	0	1	138,237	**19,686**
6/29/17	5	0	0	0	1	135,881	**18,848**
6/30/17	2	0	0	2	0	131,639	**18,290**
Totals	8,980	7,127	7,918	7,915	7,835	69,179,284	23,126,133

* Volumes include interruptible and transportation volumes

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

Attachment 10
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MINNESOTA ENERGY RESOURCES - NNG

Customer Counts by PGAC Class - July 1, 2015 through June 30, 2016

Tariff Rate Class	Rate Designation	Jul-16 Average Customers	Aug-16 Average Customers	Sep-16 Average Customers	Oct-16 Average Customers	Nov-16 Average Customers	Dec-16 Average Customers	Jan-17 Average Customers	Feb-17 Average Customers	Mar-17 Average Customers	Apr-17 Average Customers	May-17 Average Customers	Jun-17 Average Customers	Annual Average Customers
GS- Residential	MERC000001	169,238	169,904	170,514	169,770	170,562	170,112	171,193	170,326	170,589	170,973	171,673	172,370	170,602
GS-C&I <1,500 therms/yr (Small)	MERC000005	6,268	6,809	6,576	6,550	6,611	6,611	6,643	6,596	6,608	6,569	6,569	6,674	6,590
GS-C&I <1,500 therms/yr (Small) Emmons, IA	MERC000013	1	1	1	1	1	1	1	1	1	1	1	1	1
GS-C&I >1,500 therms/yr (Large)	MERC000009	9,694	10,294	10,067	9,905	9,946	9,916	10,072	9,953	10,009	10,003	10,042	10,019	9,993
GS-C&I >1,500 therms/yr (Large) Emmons, IA	MERC000014	3	3	3	4	3	3	3	3	2	2	2	2	3
Small Volume Interruptible (SVI)	MERC000015	271	412	249	352	296	305	295	260	329	285	282	289	302
Small Volume Interruptible w/Joint (SVJ)	MERC000019	2	6	3	5	6	2	5	3	3	3	3	3	4
Large Volume Interruptible (LVI)	MERC000022	42	88	39	74	62	66	62	53	68	59	57	58	61
Large Volume Interruptible w/Joint (LVJ)	MERC000026	2	0	0	1	1	1	1	1	1	1	2	2	1
Total		185,521	187,517	187,452	186,662	187,488	187,017	188,275	187,196	187,610	187,896	188,631	189,418	187,557

MINNESOTA ENERGY RESOURCES - NNG

Projected Fixed Cost - November 2017 through March 2018

Futures Contracts WACOG

Futures 10,000 Dth/contract 30 31 31

Minnesota Energy Resources Corporation
2017-2018 Demand Entitlement
MERC-NNG

Nov-17

Deal Number	Purchase Date	Trade Number	Number Contracts	Physical Volume	Strike Price	Strike Cost	LDS Settle*	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/15/17	49759	7	70,000	$ 3.4930	$ 244,510	$ 2.8540	$ 199,780	$ 44,730		$ -	$ 244,510
2	06/07/17	50816	5	50,000	$ 3.1410	$ 157,050	$ 2.8540	$ 142,700	$ 14,350		$ -	$ 157,050
3	07/11/17	52115	5	50,000	$ 3.1320	$ 156,600	$ 2.8540	$ 142,700	$ 13,900		$ -	$ 156,600
4	08/01/17	53035	5	50,000	$ 2.9000	$ 145,000	$ 2.8540	$ 142,700	$ 2,300		$ -	$ 145,000
5	09/05/17	54467	5	50,000	$ 3.0500	$ 152,500	$ 2.8540	$ 142,700	$ 9,800		$ -	$ 152,500
6	10/03/17	55666	5	50,000	$ 2.8970	$ 144,850	$ 2.8540	$ 142,700	$ 2,150		$ -	$ 144,850
7				-		$ -	$ 2.8540	$ -	$ -		$ -	$ -
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Total			32	320,000		$ 1,000,510		$ 913,280	$ 87,230		$ -	#########
						$ 3.1266		$ 2.8540	$ 0.2726		$ -	$ 3.1266
NNG	26	81.25%	26	260,000	$ 3.1266	$ 812,914	$ 2.8540	$ 742,040	$ 70,874	$ -	$ -	$ 812,914
Other-Cons	6	18.75%	6	60,000	$ 3.1266	$ 187,596	$ 2.8540	$ 171,240	$ 16,356	$ -	$ -	$ 187,596
Total	32	100.0%	32	320,000	$ 3.1266	$ 1,000,510	$ 2.8540	$ 913,280	$ 87,230	$ -	$ -	#########

Dec-17

Deal Number	Purchase Date	Trade Number	Number Contracts	Physical Volume	Strike Price	Strike Cost	LDS Settle*	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/25/17	50414	10	100,000	$ 3.5020	$ 350,200	$ 3.0650	$ 306,500	$ 43,700		$ -	$ 350,200
2	06/21/17	51426	10	100,000	$ 3.1630	$ 316,300	$ 3.0650	$ 306,500	$ 9,800		$ -	$ 316,300
3	07/21/17	52599	7	70,000	$ 3.2220	$ 225,540	$ 3.0650	$ 214,550	$ 10,990		$ -	$ 225,540
4	08/24/17	53972	7	70,000	$ 3.1910	$ 223,370	$ 3.0650	$ 214,550	$ 8,820		$ -	$ 223,370
5	09/19/17	55041	7	70,000	$ 3.3370	$ 233,590	$ 3.0650	$ 214,550	$ 19,040		$ -	$ 233,590
6	10/17/17	56048	7	70,000	$ 3.1620	$ 221,340	$ 3.0650	$ 214,550	$ 6,790		$ -	$ 221,340
7				-		$ -	$ 3.0650	$ -	$ -		$ -	$ -
8												
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14												
15												
Total			48	480,000		$ 1,570,340		########	$ 99,140		$ -	########
						$ 3.2715		$ 3.0650	$ 0.2065		$ -	$ 3.2715
NNG	40	83.33%	40	400,000	$ 3.2715	$ 1,308,617	$ 3.0650	########	$ 82,617	$ -	$ -	########
Other-Cons	8	16.67%	8	80,000	$ 3.2715	$ 261,723	$ 3.0650	$ 245,200	$ 16,523	$ -	$ -	$ 261,723
Total	48	100.0%	48	480,000	$ 3.2715	$ 1,570,340	$ 3.0650	########	$ 99,140	$ -	$ -	########

Jan-18

Deal Number	Purchase Date	Trade Number	Number Contracts	Physical Volume	Strike Price	Strike Cost	LDS Settle*	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/22/17	50129	11	110,000	$3.6910	$ 406,010	######	$ 351,340	$ 54,670		$ -	$ 406,010
2	06/19/17	51295	11	110,000	$3.2370	$ 356,070	######	$ 351,340	$ 4,730		$ -	$ 356,070
3	07/18/17	52342	10	100,000	$3.4030	$ 340,300	######	$ 319,400	$ 20,900		$ -	$ 340,300
4	08/21/17	53755	9	90,000	$3.2790	$ 295,110	######	$ 287,460	$ 7,650		$ -	$ 295,110
5	09/14/17	54871	8	80,000	$3.3510	$ 268,080	######	$ 255,520	$ 12,560		$ -	$ 268,080
6	10/18/17	56094	8	80,000	$3.2010	$ 256,080	######	$ 255,520	$ 560		$ -	$ 256,080
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15												
Total	Total		57	570,000		$ 1,921,650		########	$ 101,070		$ -	$ 1,921,650
						$ 3.3713		$ 3.1940	$ 0.1773		$ -	$ 3.3713
NNG	47	82.46%	47	470,000	$3.3713	$ 1,584,518	######	########	$ 83,338	$ -	$ -	$ 1,584,518
Other-Cons	10	17.54%	10	100,000	$3.3713	$ 337,132	######	$ 319,400	$ 17,732	$ -	$ -	$ 337,132
Total	57	100.0%	57	570,000	$3.3713	$ 1,921,650	######	########	$ 101,070	$ -	$ -	$ 1,921,650

Feb-18

Deal Number	Purchase Date	Trade Number	Number Contracts	Physical Volume	Strike Price	Strike Cost	LDS Settle*	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/17/17	49891	10	100,000	$ 3.5490	$ 354,900	$ 3.2030	$ 320,300	$ 34,600		$ -	$ 354,900
2	06/08/17	50852	10	100,000	$ 3.3440	$ 334,400	$ 3.2030	$ 320,300	$ 14,100		$ -	$ 334,400
3	07/12/17	52186	9	90,000	$ 3.3040	$ 297,360	$ 3.2030	$ 288,270	$ 9,090		$ -	$ 297,360
4	08/07/17	53248	8	80,000	$ 3.1580	$ 252,640	$ 3.2030	$ 256,240	$ (3,600)		$ -	$ 252,640
5	09/07/17	54612	7	70,000	$ 3.3250	$ 232,750	$ 3.2030	$ 224,210	$ 8,540		$ -	$ 232,750
6	10/05/17	55760	7	70,000	$ 3.2560	$ 227,920	$ 3.2030	$ 224,210	$ 3,710		$ -	$ 227,920
7				-		$ -	$ 3.2030	$ -	$ -		$ -	$ -
8				-		$ -	$ 3.2030	$ -	$ -		$ -	$ -
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15												
Total			51	510,000		$ 1,699,970		########	$ 66,440		$ -	#########
						$ 3.3333		$ 3.2030	$ 0.1303		$ -	$ 3.3333
NNG	42	82.35%	42	420,000	$ 3.3333	$ 1,399,975	$ 3.2030	########	$ 54,715	$ -	$ -	#########
Other-Cons	9	17.65%	9	90,000	$ 3.3333	$ 299,995	$ 3.2030	$ 288,270	$ 11,725	$ -	$ -	$ 299,995
Total	51	100.0%	51	510,000	$ 3.3333	$ 1,699,970	$ 3.2030	########	$ 66,440	$ -	$ -	#########

Mar-18

Deal Number	Purchase Date	Trade Number	Number Contracts	Financial Volume	Strike Price	Strike Cost	LDS Settle*	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1	05/19/17	50037	9	90,000	$ 3.5110	$ 315,990	$ 3.1640	$ 284,760	$ 31,230		$ -	$ 315,990
2	06/14/17	51117	7	70,000	$ 3.1960	$ 223,720	$ 3.1640	$ 221,480	$ 2,240		$ -	$ 223,720
3	07/17/17	52310	3	30,000	$ 3.2720	$ 98,160	$ 3.1640	$ 94,920	$ 3,240		$ -	$ 98,160
4	07/17/17	52311	3	30,000	$ 3.2730	$ 98,190	$ 3.1640	$ 94,920	$ 3,270		$ -	$ 98,190
5	08/10/17	53394	6	60,000	$ 3.1960	$ 191,760	$ 3.1640	$ 189,840	$ 1,920		$ -	$ 191,760
6	09/12/17	54768	6	60,000	$ 3.3302	$ 199,810	$ 3.1640	$ 189,840	$ 9,970		$ -	$ 199,810
7	10/12/17	55962	6	60,000	$ 3.1900	$ 191,400	$ 3.1640	$ 189,840	$ 1,560		$ -	$ 191,400
8				-		$ -	$ 3.1640	$ -	$ -		$ -	$ -
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15												
Total			40	400,000		$ 1,319,030		########	$ 53,430		$ -	########
						$ 3.2976		$ 3.1640	$ 0.1336		$ -	$ 3.2976
NNG	33	82.50%	33	330,000	$ 3.2976	$ 1,088,200	$ 3.1640	########	$ 44,080	$ -	$ -	########
Other-Cons	7	17.50%	7	70,000	$ 3.2976	$ 230,830	$ 3.1640	$ 221,480	$ 9,350	$ -	$ -	$ 230,830
Total	40	100.0%	40	400,000	$ 3.2976	$ 1,319,030	$ 3.1640	########	$ 53,430	$ -	$ -	########

Total

Deal Number	Purchase Date	%	Number Contracts	Physical Volume	Strike Price	Strike Cost	LDS Settle	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1			47	470,000	$3.5566	$ 1,671,610	######	########	$ 208,930	$ -	$ -	$ 1,671,610
2			43	430,000	$3.2268	$ 1,387,540	######	########	$ 45,220	$ -	$ -	$ 1,387,540
3			34	340,000	$3.2881	$ 1,117,960	######	########	$ 58,120	$ -	$ -	$ 1,117,960
4			32	320,000	$3.1697	$ 1,014,310	######	$ 995,870	$ 18,440	$ -	$ -	$ 1,014,310
5			33	330,000	$3.2687	$ 1,078,680	######	########	$ 51,860	$ -	$ -	$ 1,078,680
6			33	330,000	$3.1818	$ 1,050,000	######	########	$ 23,180	$ -	$ -	$ 1,050,000
7			6	60,000	$3.1900	$ 191,400	######	$ 189,840	$ 1,560	$ -	$ -	$ 191,400
8			0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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Total			228	#######		$ 7,511,500		########	$ 407,310		$ -	$ 7,511,500
						$ 3.2945		$ 3.1159	$ 0.1786		$ -	$ 3.2945
NNG	188	82.46%	188	#######	$3.2945	$ 6,193,693	######	########	$ 335,852	$ -	$ -	$ 6,193,693
Other-Cons	40	17.54%	40	400,000	$3.2945	$ 1,317,807	######	########	$ 71,458	$ -	$ -	$ 1,317,807
Total	228	100.0%	228	#######	$3.2945	$ 7,511,500	######	########	$ 407,310	$ -	$ -	$ 7,511,500

*Prices from 10/18/17 NYMEX market

MINNESOTA ENERGY RESOURCES - NNG

Projected Storage Cost - November 2017 through March 2018

Month/ Year	K#118657 NNG Storage (Dth)	LS Power K#132024 NNG Storage (Dth)	LS Power K#132112 NNG Storage (Dth)	Total NNG Storage (Dth)	Projected NNG WACOG	K#118657 NNG Storage Cost	K#132024 NNG Storage Cost	K#132112 NNG Storage Cost	Total NNG Storage Cost	AECO Storage GLGT/VGT Centra Emerson	AECO Storage GLGT/VGT Centra Emerson WACOG	AECO Storage GLGT/VGT Centra Emerson Cost
Nov-17	489,384	48,750	97,500	635,634	$ 2.6781	$ 1,310,638	$ 130,559	$ 261,119	$ 1,702,316			
Dec-17	1,229,734	122,500	245,000	1,597,234	$ 2.6781	$ 3,293,398	$ 328,072	$ 656,144	$ 4,277,614			
Jan-18	1,229,734	122,500	245,000	1,597,234	$ 2.6781	$ 3,293,398	$ 328,072	$ 656,144	$ 4,277,614			
Feb-18	1,229,734	122,500	245,000	1,597,234	$ 2.6781	$ 3,293,398	$ 328,072	$ 656,144	$ 4,277,614			
Mar-18	489,384	48,750	97,500	635,634	$ 2.6781	$ 1,310,638	$ 130,559	$ 261,119	$ 1,702,316			
Total	4,667,969	465,000	930,000	6,062,969	$ 2.6781	$ 12,501,469	$ 1,245,335	$ 2,490,669	$ 16,237,473	-		

Month/ Year	NNG Storage Volume (Dth)	NNG Indexes Price	NNG Indexes Cost
Nov-17	635,634	$ 2.8170	$ 1,790,580
Dec-17	1,597,234	$ 3.0785	$ 4,917,084
Jan-18	1,597,234	$ 3.4065	$ 5,440,976
Feb-18	1,597,234	$ 3.3700	$ 5,382,677
Mar-18	635,634	$ 3.0290	$ 1,925,335
Total	6,062,969	$ 3.2091	$ 19,456,653
			$ 3,219,180

Month/ Year	AECO Storage Volume (Dth)	Total AECO Market WACOG	Total AECO Market Cost
Nov-17	0		$ -
Dec-17	0		$ -
Jan-18	0		$ -
Feb-18	0		$ -
Mar-18	0		$ -
Total	0		$ -
			$ -

Max NNG-MERC Storage (Storage plan withdrawals through Apr 18)	6,062,969	6,519,321	06/30/17Storage Balance - NNG-MERC	1,261,867	19.36%	1,173,536
Max AECO Storage (Storage plan withdrawals through Apr 18)	-	947,820	06/30/17 Storage Balance - AECO	0	0.00%	0

Month/ Year	K#118657 NNG Storage (Dth)	LS Power K#132024 NNG Storage (Dth)	LS Power K#132112 NNG Storage (Dth)	Total NNG Storage (Dth)	Projected K#118657 NNG WACOG	Projected K#132024 NNG WACOG	Projected K#132112 NNG WACOG	WACOG NNG Cost	Projected NNG Indexes Price	Projected NNG Index Cost	Projected Storage (Savings)/ Cost
Nov-17	489,384	48,750	97,500	635,634	$ 2.6781	$ 2.6781	$ 2.6781	$ 1,702,316	$ 2.8170	$ 1,790,580	$ (88,265)
Dec-17	1,229,734	122,500	245,000	1,597,234	$ 2.6781	$ 2.6781	$ 2.6781	$ 4,277,614	$ 3.0785	$ 4,917,084	$ (639,470)
Jan-18	1,229,734	122,500	245,000	1,597,234	$ 2.6781	$ 2.6781	$ 2.6781	$ 4,277,614	$ 3.4065	$ 5,440,976	$ (1,163,363)
Feb-18	1,229,734	122,500	245,000	1,597,234	$ 2.6781	$ 2.6781	$ 2.6781	$ 4,277,614	$ 3.3700	$ 5,382,677	$ (1,105,064)
Mar-18	489,384	48,750	97,500	635,634	$ 2.6781	$ 2.6781	$ 2.6781	$ 1,702,316	$ 3.0290	$ 1,925,335	$ (223,019)
Total	4,667,969	465,000	930,000	6,062,969	$ 2.8092	$ 2.8092	$ 2.8092	$ 16,237,473	$ 3.1285	$ 19,456,653	$ (3,219,180)

*Indexes and projected WACOG based on 7/14/16 market prices

MINNESOTA ENERGY RESOURCES - NNG

Projected Call Option Costs - November 2017 through March 2018

Call/Put Options WACOG

Call/Put Options 10,000 Dth/contract

Minnesota Energy Resources Corporation
2017-2018 Demand Entitlement
MERC-NNG

Nov-17

Deal Number	Purchase Date	Trade Number	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	05/15/17	49760	12	120,000	$ 3.5000	$ 420,000	$ 2.8540	$ 342,480	$ 2.8540	$ 342,480	$ -	$ 0.3060	$ 36,720	$ 379,200
2	06/07/17	50815	12	120,000	$ 3.2500	$ 390,000	$ 2.8540	$ 342,480	$ 2.8540	$ 342,480	$ -	$ 0.2260	$ 27,120	$ 369,600
3	07/11/17	52114	11	110,000	$ 3.2500	$ 357,500	$ 2.8540	$ 313,940	$ 2.8540	$ 313,940	$ -	$ 0.1790	$ 19,690	$ 333,630
4	08/01/17	53040	10	100,000	$ 3.1000	$ 310,000	$ 2.8540	$ 285,400	$ 2.8540	$ 285,400	$ -	$ 0.1000	$ 10,000	$ 295,400
5	09/05/17	54466	10	100,000	$ 3.2000	$ 320,000	$ 2.8540	$ 285,400	$ 2.8540	$ 285,400	$ -	$ 0.0850	$ 8,500	$ 293,900
6	10/03/17	55665	9	90,000	$ 2.9000	$ 261,000	$ 2.8540	$ 256,860	$ 2.8540	$ 256,860	$ -	$ 0.0970	$ 8,730	$ 265,590
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Total			64	640,000		$ 2,058,500		$ 1,826,560		$ 1,826,560	$ -		$ 110,760	$1,937,320
						$ 3.2164		$ 2.8540		$ 2.8540	$ -		$ 0.0538	$ 3.0271
NNG	53	82.81%	53	530,000	$ 3.2164	$ 1,704,695	$ 2.8540	$ 1,512,620	$ 2.8540	$ 1,512,620	$ -	$ 0.1731	$ 91,723	$1,604,343
Other-Cons	11	17.19%	11	110,000	$ 3.2164	$ 353,805	$ 2.8540	$ 313,940	$ 2.8540	$ 313,940	$ -	$ 0.1731	$ 19,037	$ 332,977
Total	64	100.0%	64	640,000	$ 3.2164	$ 2,058,500	$ 2.8540	$ 1,826,560	$ 2.8540	$ 1,826,560	$ -	$ 0.1731	$ 110,760	$1,937,320

Dec-17

Deal Number	Purchase Date	Trade Number	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	05/19/17	50057	17	170,000	$ 3.7500	$ 637,500	$ 3.0650	$ 521,050	$ 3.0650	$ 521,050	$ -	$ 0.2760	$ 46,920	$ 567,970
2	06/14/17	51116	17	170,000	$ 3.2500	$ 552,500	$ 3.0650	$ 521,050	$ 3.0650	$ 521,050	$ -	$ 0.2610	$ 44,370	$ 565,420
3	07/17/17	52309	17	170,000	$ 3.2500	$ 552,500	$ 3.0650	$ 521,050	$ 3.0650	$ 521,050	$ -	$ 0.2740	$ 46,580	$ 567,630
4	08/10/17	53393	17	170,000	$ 3.5500	$ 603,500	$ 3.0650	$ 521,050	$ 3.0650	$ 521,050	$ -	$ 0.1000	$ 17,000	$ 538,050
5	09/12/17	54767	16	160,000	$ 3.5700	$ 571,200	$ 3.0650	$ 490,400	$ 3.0650	$ 490,400	$ -	$ 0.0980	$ 15,680	$ 506,080
6	10/12/17	55961	14	140,000	$ 3.3000	$ 462,000	$ 3.0650	$ 429,100	$ 3.0650	$ 429,100	$ -	$ 0.0910	$ 12,740	$ 441,840
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Total			98	980,000		$ 3,379,200		$ 3,003,700		$ 3,003,700	$ -		$ 183,290	$ 3,186,990
						$ 3.4482		$ 3.0650		$ 3.0650	$ -		$ 0.0542	$ 3.2520
NNG	81	82.65%	81	810,000	$ 3.4482	$ 2,793,012	$ 3.0650	$ 2,482,650	$ 3.0650	$ 2,482,650	$ -	$ 0.1870	$ 151,495	$ 2,634,145
Other-Cons	17	17.35%	17	170,000	$ 3.4482	$ 586,188	$ 3.0650	$ 521,050	$ 3.0650	$ 521,050	$ -	$ 0.1870	$ 31,795	$ 552,845
Total	98	100.0%	98	980,000	$ 3.4482	$ 3,379,200	$ 3.0650	$ 3,003,700	$ 3.0650	$ 3,003,700	$ -	$ 0.1870	$ 183,290	$ 3,186,990

Jan-18

Deal Number	Purchase Date	Trade Number	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	05/18/17	49946	21	210,000	$ 4.0000	$ 840,000	$ 3.1940	$ 670,740	$ 3.1940	$ 670,740	$ -	$0.2790	$ 58,590	$ 729,330
2	06/08/17	50851	20	200,000	$ 3.7500	$ 750,000	$ 3.1940	$ 638,800	$ 3.1940	$ 638,800	$ -	$0.2560	$ 51,200	$ 690,000
3	07/12/17	52185	19	190,000	$ 3.5000	$ 665,000	$ 3.1940	$ 606,860	$ 3.1940	$ 606,860	$ -	$0.2720	$ 51,680	$ 658,540
4	08/07/17	53247	19	190,000	$ 3.9500	$ 750,500	$ 3.1940	$ 606,860	$ 3.1940	$ 606,860	$ -	$0.0950	$ 18,050	$ 624,910
5	09/07/17	54611	18	180,000	$ 4.0000	$ 720,000	$ 3.1940	$ 574,920	$ 3.1940	$ 574,920	$ -	$0.0970	$ 17,460	$ 592,380
6	10/05/17	55759	18	180,000	$ 3.7500	$ 675,000	$ 3.1940	$ 574,920	$ 3.1940	$ 574,920	$ -	$0.0940	$ 16,920	$ 591,840
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Total	Total		115	1,150,000		$ 4,400,500		$ 3,673,100		$ 3,673,100	$ -		$ 213,900	$ 3,887,000
						$ 3.8265		$ 3.1940		$ 3.1940	$ -		$ 0.0486	$ 3.3800
NNG	95	82.61%	95	950,000	$ 3.8265	$ 3,635,196	$ 3.1940	$ 3,034,300	$ 3.1940	$ 3,034,300	$ -	$0.1860	$ 176,700	$ 3,211,000
Other-Cons	20	17.39%	20	200,000	$ 3.8265	$ 765,304	$ 3.1940	$ 638,800	$ 3.1940	$ 638,800	$ -	$0.1860	$ 37,200	$ 676,000
Total	115	100.0%	115	1,150,000	$ 3.8265	$ 4,400,500	$ 3.1940	$ 3,673,100	$ 3.1940	$ 3,673,100	$ -	$0.1860	$ 213,900	$ 3,887,000

Feb-18

Deal Number	Purchase Date	Trade Number	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	05/25/17	50413	18	180,000	$ 4.2500	$ 765,000	$ 3.2030	$ 576,540	$ 3.2030	$ 576,540	$ -	$ 0.2670	$ 48,060	$ 624,600
2	06/21/17	51425	18	180,000	$ 3.7500	$ 675,000	$ 3.2030	$ 576,540	$ 3.2030	$ 576,540	$ -	$ 0.2710	$ 48,780	$ 625,320
3	07/21/17	52598	18	180,000	$ 3.7500	$ 675,000	$ 3.2030	$ 576,540	$ 3.2030	$ 576,540	$ -	$ 0.2590	$ 46,620	$ 623,160
4	08/24/17	53973	17	170,000	$ 4.6000	$ 782,000	$ 3.2030	$ 544,510	$ 3.2030	$ 544,510	$ -	$ 0.0970	$ 16,490	$ 561,000
5	09/19/17	55043	16	160,000	$ 4.6000	$ 736,000	$ 3.2030	$ 512,480	$ 3.2030	$ 512,480	$ -	$ 0.1000	$ 16,000	$ 528,480
6	10/17/17	56047	16	160,000	$ 4.1000	$ 656,000	$ 3.2030	$ 512,480	$ 3.2030	$ 512,480	$ -	$ 0.1000	$ 16,000	$ 528,480
7				-		$ -	$ -	$ -	$ 3.2030	$ -	$ -		$ -	$ -
8				-		$ -	$ -	$ -	$ 3.2030	$ -	$ -		$ -	$ -
9														
10														
11														
12														
13														
14														
15														
Total			103	1,030,000		$ 4,289,000		$ 3,299,090		$ 3,299,090	$ -		$ 191,950	$3,491,040
						$ 4.1641		$ 3.2030		$ 3.2030	$ -		$ 0.0448	$ 3.3894
NNG	85	82.52%	85	850,000	$ 4.1641	$ 3,539,466	$ 3.2030	$ 2,722,550	$ 3.2030	$ 2,722,550	$ -	$ 0.1864	$ 158,405	$2,880,955
Other-Cons	18	17.48%	18	180,000	$ 4.1641	$ 749,534	$ 3.2030	$ 576,540	$ 3.2030	$ 576,540	$ -	$ 0.1864	$ 33,545	$ 610,085
Total	103	100.0%	103	1,030,000	$ 4.1641	$ 4,289,000	$ 3.2030	$ 3,299,090	$ 3.2030	$ 3,299,090	$ -	$ 0.1864	$ 191,950	$3,491,040

Mar-18

Deal Number	Purchase Date	Trade Number	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	05/22/17	50147	15	150,000	$ 4.5000	$ 675,000	$ 3.1640	$ 474,600	$ 3.1640	$ 474,600	$ -	$ 0.2820	$ 42,300	$ 516,900
2	06/19/17	51294	15	150,000	$ 3.7500	$ 562,500	$ 3.1640	$ 474,600	$ 3.1640	$ 474,600	$ -	$ 0.2720	$ 40,800	$ 515,400
3	07/18/17	52341	15	150,000	$ 3.7500	$ 562,500	$ 3.1640	$ 474,600	$ 3.1640	$ 474,600	$ -	$ 0.3150	$ 47,250	$ 521,850
4	08/21/17	53760	12	120,000	$ 5.0000	$ 600,000	$ 3.1640	$ 379,680	$ 3.1640	$ 379,680	$ -	$ 0.1000	$ 12,000	$ 391,680
5	09/14/17	54868	12	120,000	$ 5.0500	$ 606,000	$ 3.1640	$ 379,680	$ 3.1640	$ 379,680	$ -	$ 0.0980	$ 11,760	$ 391,440
6	10/18/17	56093	12	120,000	$ 4.4000	$ 528,000	$ 3.1640	$ 379,680	$ 3.1640	$ 379,680	$ -	$ 0.0970	$ 11,640	$ 391,320
7														
8														
9														
10														
11														
12														
13														
14														
15														
Total			81	810,000		$ 3,534,000		$ 2,562,840		$ 2,562,840	$ -		$ 165,750	$ 2,728,590
						$ 4.3630		$ 3.1640		$ 3.1640	$ -		$ 0.0469	$ 3.3686
NNG	66	81.48%	66	660,000	$ 4.3630	$ 2,879,556	$ 3.1640	$ 2,088,240	$ 3.1640	$ 2,088,240	$ -	$ 0.2046	$ 135,056	$ 2,223,296
Other-Cons	15	18.52%	15	150,000	$ 4.3630	$ 654,444	$ 3.1640	$ 474,600	$ 3.1640	$ 474,600	$ -	$ 0.2046	$ 30,694	$ 505,294
Total	81	100.0%	81	810,000	$ 4.3630	$ 3,534,000	$ 3.1640	$ 2,562,840	$ 3.1640	$ 2,562,840	$ -	$ 0.2046	$ 165,750	$ 2,728,590

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			83	830,000	$ 4.0211	$ 3,337,500	$ 3.1150	$ 2,585,410	$ 3.1150	$ 2,585,410	$ -	$0.2802	$ 232,590	$ 2,818,000
2			82	820,000	$ 3.5732	$ 2,930,000	$ 3.1140	$ 2,553,470	$ 3.1140	$ 2,553,470	$ -	$0.2589	$ 212,270	$ 2,765,740
3			80	800,000	$ 3.5156	$ 2,812,500	$ 3.1162	$ 2,492,990	$ 3.1162	$ 2,492,990	$ -	$0.2648	$ 211,820	$ 2,704,810
4			75	750,000	$ 4.0613	$ 3,046,000	$ 3.1167	$ 2,337,500	$ 3.1167	$ 2,337,500	$ -	$0.0981	$ 73,540	$ 2,411,040
5			72	720,000	$ 4.1017	$ 2,953,200	$ 3.1151	$ 2,242,880	$ 3.1151	$ 2,242,880	$ -	$0.0964	$ 69,400	$ 2,312,280
6			69	690,000	$ 3.7420	$ 2,582,000	$ 3.1203	$ 2,153,040	$ 3.1203	$ 2,153,040	$ -	$0.0957	$ 66,030	$ 2,219,070
7			0	-	$ -	$ -	$ -	$ -	#DIV/0!	$ -	$ -	$ -	$ -	$ -
8			0	-	$ -	$ -	$ -	$ -	#DIV/0!	$ -	$ -	$ -	$ -	$ -
9														
10														
11														
12														
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14														
15														
Total			461	4,610,000		$17,661,200		##########		##########	$ -		$ 865,650	$ 15,230,940
						$ 3.8311		$ 3.1161		$ 3.1161	$ -		4.90%	$ 3.3039
NNG	380	82.43%	380	3,800,000	$ 3.8295	$14,551,925	$ 3.1159	##########	$ 3.1159	##########	$ -	$0.1877	$ 713,379	$ 12,553,739
Other-Cons	81	17.57%	81	810,000	$ 3.8386	$ 3,109,275	$ 3.1172	$ 2,524,930	$ 3.1172	$ 2,524,930	$ -	$0.1880	$ 152,271	$ 2,677,201
Total	461	82.4%	461	4,610,000	$ 3.8311	$17,661,200	$ 3.1161	##########	$ 3.1161	##########	$ -	$0.1878	$ 865,650	$ 15,230,940

*Prices from 10/24/16 NYMEX market

Attachment 12: Forecast Methodology for MERC Demand Entitlement Effective November 1, 2017

1. Peak-day

   a. Purpose

Gather data and perform analysis used in the "Petition for Change in Demand" for MERC, otherwise known as the "MERC Demand Entitlement Filings."

   b. Background

MERC customers are served by four pipelines[1]

1. VGT - Viking Gas Transmission system
2. NNG - Northern Natural Gas pipeline
3. GLGT - Great Lakes Gas Transmission pipeline
4. Centra - Centra pipeline

Weather data is obtained from eight weather stations: International Falls, Bemidji, Cloquet, Fargo, Minneapolis, Rochester, Worthington, and Ortonville.

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

	Pipeline	PGA	Weather Station(s)
1	Centra	MERC Consolidated	International Falls
2	Great Lakes Gas Transmission (GLGT	MERC Consolidated	Bemidji
3	GLGT	MERC Consolidated	Cloquet

[1] MERC acquired Interstate Power & Light Company's Minnesota natural gas operations and customers in 2015. The Commission's Order Approving Sale Subject to Conditions in Docket No. G-001,011/PA-14-107 required MERC to maintain the transitioned customers on a separate PGA (MERC – NNG – Albert Lea). Pursuant to the Commission's Order in Docket No. G011/GR-15-736, the NNG and NNG – Albert Lea PGAs were consolidated effective July 1, 2017, and MERC is submitting two demand entitlement petitions (NNG and Consolidated) for the 2017-2018 heating season.

4	Viking Gas Transmission (VGT)	MERC Consolidated	Fargo
5	NNG	MERC NNG	Cloquet
6	NNG	MERC NNG	Minneapolis
7	NNG	MERC NNG	Ortonville
8	NNG	MERC NNG	Rochester
9	NNG	MERC NNG	Worthington

2. Analytical Approach

a. Summary

1. Obtain daily weather data for each weather station.
2. Obtain daily total throughput volumes by pipeline and by weather station.
3. Obtain daily large volume transportation, interruptible, and joint interruptible volumes by pipeline and by weather station (Data A).
4. Obtain daily small volume interruptible volumes by pipeline and by weather station (Data B).
5. Calculate daily "firm" volumes by subtracting both Data A and Data B from total throughput volumes.
6. Perform quality control on volumetric data (e.g., identify missing or bad reads, and, to the extent possible, fix missing or bad reads).
7. Perform firm peak day regressions. In response to comments from the Minnesota Department of Commerce, Division of Energy Resources (Department):
   a. Incorporate a methodology to mitigate the impact of autocorrelation.
   b. Provide a reasonable explanation whenever a regression model is selected that does not have an intercept.

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

3. Process

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 **Data Preparation** Steps consisted of:

- Identify the coldest Adjusted Heating Degree Day (AHDD) for the time period January 1996-December 2016 for each weather station. Note, this is a change in practice from prior analysis that used a rolling 20-year period. The change was included because many weather stations experienced historically cold weather in the January/February 1996 time period and without inclusion of that additional data from January/February 1996, AHDD were materially lower and not reflective of MERC's capacity needs.
- Determine the most recent three years of December through February daily total metered throughput by pipeline and by weather station.
- Determine the most recent three years of December through February daily large volume transportation, interruptible, and joint interruptible volumes by pipeline and by weather station (Data A).
- Determine the most recent three years of December through February daily small volume interruptible volumes by pipeline and by weather station (Data B).

- Review daily total metered throughput, Data A, and Data B, and identify missing or bad reads, and to the extent possible, fix missing or bad reads. To the extent that the data could not be fixed, it was not included in the regressions.
- Subtract both Data A and Data B daily meter readings for all three December through February years from the total throughput for each pipeline and each weather station. Use the resulting net daily metered volumes for regressions. Examples of transportation, interruptible, and joint interruptible meter readings subtracted are paper mills, direct-connects, taconites, and off-system end users. See "Adjusting the Regression Results to a Firm Peak Day Estimate" below.

Each daily weather station data file was searched to find the coldest Adjusted Heating Degree Day (AHDD65) in the last 20 years for the time period January 1996-December 2016. This is a change from prior analysis that used a rolling 20-year period. The change was included because many weather stations experienced historically cold weather in the January/February 1996 time period and without inclusion of that additional data from January/February 1996, AHDD65 were materially lower and not reflective of MERC's capacity needs. 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

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

- For each of the pipelines and weather stations:

1. Gather the net daily metered volumes and weather station data including AHDD65.[2]
2. Add indicator variables for day-type and month. Day-type variables are used to isolate load that changes by day of the week, such as commercial or industrial customers who may change their consumption on weekends when they run fewer shifts. Month indicator variables are used to isolate load that changes based on winter months, such as businesses that are open extra hours in December and resume normal operating hours in January.
3. Perform ordinary least squares linear regressions for the 3-year time frame using the AHDD65 weather variable and the significant indicator variables.
4. In response to comments from the Department, the regression methodology incorporates a process to mitigate the impact of autocorrelation. See section below on autocorrelation.
5. In response to comments from the Department, provide an explanation whenever we choose to use a regression model that does not have an intercept.
6. Summarize the Baseload and Use/AHDD65 and Use/Prior Day AHDD65 from each regression.
7. Calculate a point estimate from each regression based on the baseload value plus the Use/AHDD65 coefficient times the coldest AHDD65 in 20 years and the Use/Prior Day AHDD65 coefficient times the AHDD65 on the day prior to the coldest AHDD65 since January 1996.

iii. **Volume Risk Adjustments**

[2] Temperature and weather data were obtained from DTN (formerly Schneider Electric) via TherMaxx then converted to HDD65 and AHDD65 in an Excel spreadsheet by MERC – Gas Supply. Temperature data is the average of the high and low temperature based on the 9am to 9am gas day. Wind data is the 24-hour average based on the 9am to 9am gas day.

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:

1. **Add back DFC customer selections**

While transportation, interruptible, and joint interruptible 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 Regulatory Affairs department provided historical monthly DFC data for the joint service 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 the Company's Gas Supply department, the Joint Firm/ Interruptible customers who were relying on MERC to provide peak day firm supply were identified and their daily firm capacity volumes were summed by month for each pipeline. The total volumes were then added back to the regression results.

Exhibit 1
Pipeline and Weather Station Regression Notes

A. Large Volume Transportation, Interruptible, and Joint Interruptible Customers

GLGT Paper Mills = Blandon mapped to Bemidji, and Sappi and USG mapped to Cloquet

VGT Lamb Weston mapped to Fargo

NNG Taconites / Direct Connects =

- CCI EMPIRE IND DEL PT 2 TILDEN mapped to Cloquet
- CCI NORTHSHORE mapped to Cloquet

- UNITED TACONITE (was EVELETH TACONITE) mapped to Cloquet
- HIBBING TACONITE CO. mapped to Cloquet
- U.S. STEEL #1 & #2 mapped to Cloquet
- NATIONAL STEEL PELLET mapped to Cloquet
- COTTAGE GROVE TBS LS POWER mapped to Minneapolis
- INLAND STEEL mapped to Cloquet
- HANNA MINING mapped to Cloquet

NNG OSEU (End Users) =

- ARKEMA INC. mapped to Rochester
- MAYO Clinic 1 Fairmount mapped to Worthington
- MAYO Clinic 2 (Franklin Htg) mapped to Rochester
- MAYO Clinic 3 (St Mary's) mapped to Rochester
- ARCHER DANIELS MIDLAND, CO. mapped to Minneapolis
- ASSOCIATED MILK PRODUCTS, INC. mapped to Rochester
- Hawkins Inc. mapped to Minneapolis
- CORRECTIONAL CTR mapped to Minneapolis
- DAIRY FARMERS OF AMERICA mapped to Rochester
- Dick's Sanitation mapped to Minneapolis
- KEMPS LLC mapped to Rochester
- KERRY BIO-SCIENCE mapped to Rochester
- LAKESIDE mapped to Rochester
- MILK SPECIALTIES mapped to Worthington
- LAND OF LAKES mapped to Rochester
- PRO-CORN mapped to Rochester
- SWIFT mapped to Rochester
- SENECA FOODS-ROCHESTER mapped to Rochester
- ENGINEERED POLYMERS mapped to Cloquet
- SANDSTONE FEDERAL CORRECTIONAL INSTITUTE mapped to Cloquet
- Glenville #1 mapped to Rochester
- Agra Resources(Exol) mapped to Rochester
- Halcon Corporation mapped to Rochester
- REG ALBERT LEA, LLC mapped to Rochester
- Zinpro North Branch mapped to Minneapolis

B. Daily Firm Capacity

VGT

- DETROIT LAKES MIDDLE SCHOOL
- ROSSMAN SCHOOL

GLGT

- AMERIPRIDE
- NORTHLAND APTS

NNG

- HENDRICKS HOSPITAL

- BRAND FX BODY INC

4. Autocorrelation Review

The Commission's February 4, 2015, Order in Docket Nos. G011/M-12-1192, G011/M-12-1193, G011/M-12-1194, and G011/M-12-1195, MERC's 2012-2013 demand entitlement dockets, required MERC to check its regression models for autocorrelation and correct the model if autocorrelation is present and to provide a reasonable explanation of its use of no-intercept models if it chooses to use one again in the future.

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

5. Design-Day Model

Order Point 5 of the Commission's January 21, 2015, Order in MERC's 2010-2011 demand entitlement dockets, Docket Nos. G007/M-10-1166, G007/M-10-1167, G011/M-10-1168, and G011/M-10-1169, required that in future demand entitlement filings, MERC provide (1) the determinants used in its Design-Day models that account for each and every impact on usage associated with economic conditions, and (2) a detailed explanation of each and every cause of unexpected changes in usage that might impact the Design-Day calculation, and what, if any, modifications the Company made to its Design-Day numbers. MERC does not forecast its Design Day using economic variables. Additionally, there were no unexpected changes in the Design-Day forecast.

6. Verification of Regression Analysis Results

Order Point 10 of the Commission's April 28, 2016, Order in Docket No. G011/M-15-722 required that MERC verify its regression analysis results in future demand entitlement filings to ensure the results are consistent with the underlying theory the analysis attempts to explain. MERC has carefully reviewed the results of its regression analysis and verified that the results are consistent with the underlying theory the analysis attempts to explain. Please see the May 31, 2016, compliance filing in Docket Nos. G011/M-15-722, G011/M-15-723, and G011/M-15-724 for further discussion of this issue.

ATTACHMENT D

In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Change in Demand Entitlement for its NNG System

Docket No. G011/M-17-588

CERTIFICATE OF SERVICE

I, Kristin M. Stastny, hereby certify that on the 1st day of November~~August~~, 2017, on behalf of Minnesota Energy Resources Corporation (MERC) I electronically filed a true and correct copy of MERC's Petition for Approval of a Change in Demand Entitlement on www.edockets.state.mn.us. Said documents were also served via U.S. mail and electronic service as designated on the attached service list.

Dated this 1st day of November~~August~~, 2017.

/s/ Kristin M. Stastny

Kristin M. Stastny

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