Minnesota Energy Resources Corporation
2685 145th Street West
Rosemount, MN 55068
www.minnesotaenergyresources.com

February 20, 2018

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

VIA ELECTRONIC FILING

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

Docket No. G011/M-17-588

Reply Comments of Minnesota Energy Resources Corporation

On January 29, 2018, the Department of Commerce, Division of Energy Resources ("Department") submitted Comments in the above-referenced docket, requesting that Minnesota Energy Resources Corporation ("MERC" or the "Company") provide additional information in Reply Comments.

In its Comments, the Department recommends that the Commission approve MERC's peak day analysis as submitted[1] but states that it will provide additional recommendations regarding MERC's Demand Entitlement in Response Comments, once the Company has provided the requested information. MERC thanks the Department for its review, agrees with the Department's recommendation that the Company's proposed peak day analysis be approved, and submits the additional information requested in these Reply Comments. In particular, the Department requested that the Company provide additional information in Reply Comments regarding the following:

1. Further information and justification regarding the reasonableness of the Company's reserve margin;

2. How MERC's system performed in terms of reliably serving customers during the cold weather experienced from December 15, 2017, to January 20, 2018;

[1] Department Comments at 11.

3. The consolidation of the MERC-Albert Lea and MERC-NNG purchased gas adjustment ("PGA") areas and corrections to MERC-NNG's demand entitlement schedules to accurately reflect consolidation of the Albert Lea PGA;

4. An updated cost comparison using the October 2017 PGA;

5. Clarification regarding the incorporation of MERC's Esko and Balaton new areas; and

6. Further explanation regarding the error MERC identified in its storage contract rates.

MERC addresses each of the Department's requests for additional information below. Additionally, MERC submits restated and corrected demand entitlement schedules with this petition, attached and filed concurrently in excel format. A summary of the updates and revisions is provided below and MERC has identified revisions in yellow highlighting in the Attachments.

Reserve Margin

First, with respect to the MERC-NNG reserve margin for the 2017-2018 heating season, the Department states that MERC's proposed reserve margin of negative 0.19 percent is incorrect and the corrected reserve margin is negative 0.55 percent as reflected in Table 2 and Attachment 2, Page 2 of the Department's Comments. MERC agrees with the Department's calculation.

Filing	Total Entitlement (Dth)	Design-day Estimate (Dth)	Difference (Dth)	Reserve Margin %	Percentage Point Change From Previous Year
August 1, 2017	266,317	266,825	(508)	(0.19)%	(1.53)%
November 1, 2017	266,317	266,825	(508)	(0.19)%	(1.53)%
Department	266,317	267,783	(1,466)	(0.55)%	(2.07)%

The difference between the reserve margin calculation submitted by the Company and the Department's reserve margin calculation is the design day estimate. In particular, MERC submitted its NNG design day calculation of 266,825 Dth. MERC agrees with the Department that the correct MERC-NNG design day should be 267,783, resulting in a reserve margin calculation of negative 0.55 percent.

The Company's initial reserve margin calculation had inadvertently excluded the Ortonville peak day from the total MERC-NNG design day requirement. Ortonville's load is not served by the NNG pipeline but is included in the MERC-NNG PGA. MERC has corrected this error in the updated Attachment 1 and 3, which are attached and filed concurrently in excel format.

While a negative 0.55 percent reserve margin is not ideal, MERC had limited options available to cover the difference and ultimately determined that under the circumstances, including a very conservative estimate for Esko and Balaton, none of the available alternatives would be preferable to the approach the Company has taken to manage the negative reserve on a day-to-day basis. Based on MERC's evaluation of available alternatives, the size of the negative reserve margin, and the anticipated additional capacity to be added as a result of the Rochester Project beginning in 2018, the Company concluded that managing the reserve margin risk through its day-to-day operations would be the most reasonable course of action for customers. In particular, the Company is prepared to purchase spot market delivered supplies to make up for the peak day capacity deficiency in the event such additional capacity is needed due to peak day conditions.

The Department questions whether other options were available to the Company and could have been considered, beyond the option of entering into a long-term contract with NNG for additional capacity. In particular, the Department notes that MERC did not address whether it could have planned for and obtained capacity via NNG's Electronic Bulletin Board ("EBB") for the typical months of highest risk within the winter season (i.e., December, January, and February). Alternatively, the Department questions whether MERC could have obtained a five-month contract similar to NNG contract 127852 in the volume of 14,383 Dth/day for the 2015/2016 winter season that MERC did not renew. Finally, the Department raises the possibility that MERC could have planned for and purchased third-party delivered contracts.

MERC responds that it did not seek capacity in the secondary market because the secondary market capacity would have been released on a recallable basis and therefore it would not have provided a dependable alternative in a peak day scenario.

The five-month contract MERC entered into during the 2015/2016 winter season is no longer an available option as NNG's system is more fully subscribed (as evidenced by the Northern Lights and Rochester expansion projects). In MERC's experience, NNG has been entering into five-year, max-rate contracts in areas without pipeline competition, the scenario that MERC would be requesting additional capacity under.

Finally, with respect to the Department's third suggested alternative, MERC will use third-party delivered contracts in the spot/daily market as needed to address the negative reserve margin

In sum, MERC's planning was prudent under the circumstances, given available alternatives and the anticipated additional capacity to be added as a result of the Rochester Project beginning in 2018. The Company is confident that the lowest cost alternative taken was also low in risk and still provided for the reliable service of firm customers during the 2017/2018 winter. As the Department correctly states in its Comments, "[u]ltimately, MERC must plan for its design day and ensure that it reliably serves its firm customers under design-day conditions."[2] As discussed in MERC's response to Department Information Request No. 1, included in the Department's Comments as Attachment 8, MERC is very sensitive to the risks presented by a negative reserve margin. Due to mitigating factors, such as a conservative estimate for new load at Esko and Balaton, combined with the very slightly negative reserve margin, and the impending addition of capacity in 2018-2019 as a result of the Rochester Project, MERC believes its approach for managing the negative reserve margin for the 2017-2018 heating season is reasonable. Further, as discussed below, MERC has not had any issues serving both firm and interruptible load through mid-February of the 2017-2018 heating season.

Nevertheless, MERC agrees with the Department that in general, absent the unique circumstances that existed for this heating season, the reserve margin should be positive and MERC anticipates it will be positive in future years based on current forecasts and entitlements.

2017-2018 Heating Season Performance

Second, given MERC-NNG's negative reserve margin for the 2017-2018 winter heating season, and the recent cold spell from approximately December 15, 2017, to January 20, 2018, the Department requested that MERC provide information regarding how its system performed in terms of reliably serving firm customers; what the associated weather was; how close it came to its design-day parameters; what the associated interstate pipeline operating conditions were (e.g., whether there were any operational flow orders, constraints, etc.); and if MERC had difficulty in securing gas supply for and/or reliably serving its firm customers.

During the period from December 25, 2017, through January 5, 2018, weather was consistently 15 to 25 degrees below normal with adjusted Heating Degree Days

[2] Department Comments at 18.

("HDD") ranging from 71 to 85. MERC uses 98 adjusted HDD for its peak day forecast, so temperatures were nearing peak conditions.

MERC's system performed well during this time with no firm capacity deficiency issues. MERC did not have issues securing supply, but did see significant price volatility at times. NNG had a "System Overrun Limit" in place from December 23, 2017 – January 8, 2018 and again January 11 – January 17, 2018. Furthermore, NNG had "Critical Days" in place from December 29, 2017 – January 6, 2018. The Company was able to meet its load reliably and did not receive any penalties for using gas in excess of supply during the cold weather.

Consolidation of MERC-Albert Lea and MERC-NNG PGAs

Many of the Department's requests for additional information, corrections, and clarifications, are related to incorporation of the historical Albert Lea PGA information in the Demand Entitlement schedules. MERC has updated all of its schedules to reflect the consolidated NNG PGA for the 2017-2018 period and to update historical comparisons to provide a comparison to the combined MERC-NNG and MERC-Albert Lea PGA.

As noted in the Department's Comments, this is the first Petition in which the Company was to reflect consolidation of its NNG and Albert Lea systems, which the Commission approved effective July 1, 2017, in Docket No. G011/GR-15-736. To accurately reflect the consolidated MERC-NNG PGA, MERC has updated the attachments as summarized below.

In its Comments at Table 2, the Department also identifies discrepancies between MERC's original Attachments 3 and 7, noting that while MERC's reconciliation in Attachment 8.1 was helpful, MERC did not update and correct its Attachments 3 and 7. The Department also notes that MERC does not explain that it had updated its reallocation of TF12B and TF12V services. MERC responds that it has now updated and reconciled Attachments 3, 7, and 8 to include historical information from MERC Albert Lea and to accurately reflect the TF12B and TF12V allocation.

Updated Cost Comparison to October 1 Purchased Gas Adjustment

The Department also notes that MERC did not update its comparison of costs in Attachment 4 to the October PGA in its November 1, 2017 Demand Entitlement update and kept it at the July 2017 PGA costs.[3] MERC agrees with the Department's observation and has updated Attachment 4 to reflect the October 1,

[3] Department Comments at 20.

2017, PGA. Additionally, MERC has reviewed Attachment 4 in light of the Department's other comments and recommendations, has revised that attachment, and provides the following responses to the Department:

- The Department notes that the numbers in the "Commodity Cost" row in columns labeled "Demand Charge – Demand Filing November 1, 2016," "Most Recent PGA," and "Proposed Effective November 1, 2017" in Attachment 4 should be corrected.

MERC responds that it has updated the numbers in the "Commodity Cost" row to accurately reflect the November 1, 2016, Demand Entitlement Filing, October 1, 2017, PGA, and November 1, 2017, Commodity Cost, as updated to reflect the correction to storage costs discussed in greater detail below.[4] These costs are now consistent with the Department's Attachment 3, Page 2 of 2, with the exception of the restated November 1, 2017, costs, which reflect the correction to the error in storage costs discussed below. Additionally, as noted in MERC's updated Attachment 4, Page 1 of 3, the commodity cost rates included in this schedule do not include the ACA adjustment.

- The Department notes that the numbers in the "Demand Cost" row in columns labeled "Demand Charge Demand Filing November 1, 2016," "Most Recent PGA," and "Proposed Effective November 1, 2017" in Attachment 4 should be corrected;

MERC responds that it has updated the numbers in the "Demand Cost" row to accurately reflect the November 1, 2016, Demand Entitlement Filing, October 1, 2017, PGA, and Proposed November 1, 2017, Demand Cost to incorporate the MERC-Albert Lea sales. These costs are now consistent with the Department's Attachment 3, Page 2 of 2, with the exception of the demand rates for joint customers. In particular, the Department's Attachment 3, Page 2 of 2, appears to use MERC's old method for calculating the per MDQ rate, which was modified by approval of the Commission in Docket No. G011/GR-15-736. MERC now bills joint service using the general service rate of $0.09328 multiplied by 30 days for nominated firm demand ($27.9843 for Joint DFC).

- The Department notes that the "Demand Costs" of "$27.6780" for the Small Volume Firm and Large Volume Firm customers in the columns labeled

[4] While MERC has updated the Attachments to reflect the corrected commodity costs, MERC is not proposing to modify the charges effective November 1, 2017. Instead, MERC proposes to reflect the true up in its future annual automatic adjustment and true up filings.

"Demand Charge Demand Filing November 1, 2016," "Most Recent PGA," and "Proposed Effective November 1, 2017" in Attachment 4 should be corrected;

MERC responds that it has corrected the "Demand Costs" of $27.6780 for the Small Volume Firm and Large Volume Firm customers under "Base Cost of Gas Jul. 1, 2017" to the corrected rate of $27.8640. MERC has also updated the rates for the Oct. 1, 2017, PGA and proposed effective November 1, 2017 to $28.1280 and $27.9843 respectively. MERC notes that the corrected rate differs from the Department's Attachment 3, Page 2 of 2, as a result of the Commission's October 31, 2017, Order in Docket No. G011/GR-15-736 approving MERC's proposal to charge joint service customers the firm demand cost per therm rate currently charged to general service customers for the non-margin (gas cost) firm portion of their joint service. Previously joint demands were charged on a per MDQ amount. MERC now bills joint service using the general service rate of $0.09328 multiplied by 30 days for nominated firm demand ($27.9843 for Joint DFC).

- The Department notes that the "ANNUAL SALES -- As approved in Docket No. G011/MR-15-748" of 253,351,745 therms in Attachment 4 should be corrected;

MERC responds that it has updated annual sales in Attachment 4 to reflect the combined annual sales for the consolidated MERC-NNG PGA (inclusive of the historical MERC-Albert Lea PGA).

- Finally, the Department notes that "GS-NNG Sales as approved in Docket No. G011/MR-15-748" of 225,057,235 therms in Attachment 4 should be corrected;

MERC responds that it has updated the GS-NNG sales in Attachment 4 to reflect the combined sales for the consolidated MERC-NNG PGA (inclusive of the historical MERC-Albert Lea PGA).

Clarification Regarding Incorporation of Esko and Balaton New Areas

The Department also raises questions regarding the extent to which data related to MERC's new communities of Esko and Balaton are reflected in the Demand Entitlement schedules.

First, the Department asks whether the number of firm customers listed on Attachment 1, page 1 of 3, includes customers from Esko and Balaton and requests that if those customers were excluded, that MERC update that attachment. The number of firm customers identified in Attachment 1 are based on an average of MERC's firm customer counts for the period July 1, 2016, through June 30, 2017. Thus, to the extent customers were on MERC's system during that period, they would be included in the average customer count calculation. Additional customers who have joined the Esko or Balaton new areas since June 30, 2017, will be reflected in MERC's next Demand Entitlement filing calculation of customer counts.

Additionally, the Department asks MERC to clarify whether the data in Attachment 2 reflect data for Esko and Balaton. MERC responds that Attachment 2 does not include any separate forecast for the Esko or Balaton new areas. MERC forecasts for its entire-system, inclusive of projected growth but does not separately forecast sales for new areas.

Correction to Storage Cost Calculation

Finally, the Department requests that MERC provide additional information regarding the error in the storage cost calculation in its 2016-2017 Demand Entitlement. In particular, in its *November Update*, MERC stated that it had identified an error in the storage cost calculation in its 2016-2017 Demand Entitlement and that the error had been corrected in Attachment 8 and Attachment 8.1 to accurately reflect the 2016-2017 storage costs.

In its Comment, the Department states:

> In Docket No. 16-650, MERC filed a letter on May 31, 2017 on the modification of its Storage contracts effective June 1, 2017. The Department filed Supplemental Comments in Docket 16-650 on June 2, 2017 identifying concerns related to contracted rates for the NNG Storage that were above NNG's maximum tariffed rates. Thus, it is unclear whether the changes reflected in MERC's Attachment 8.1 in its *November Update* are as a result of correcting for the previous MERC-Albert Lea PGA system storage units, the modification of the Storage contracts, and correcting for the NNG Storage rates that were above NNG's maximum tariffed rates, or some combination of those 3 changes. The Department requests that MERC, in its Reply Comments, provide a

> detailed explanation for its "correction" referenced in its footnote 2 shown above.[5]

Upon further review, MERC determined that the storage calculations in the 2016-2017 Demand Entitlement was correctly reflected and that the calculation for 2017-2018 was inaccurate. In particular, with the August 1, 2017, filing, MERC combined two lines for storage contract 118657. In making that change, MERC failed to account for the small portion of storage contract 118657 that has higher rates as part of an NNG storage expansion contracted for 2008. Attachment 4, page 2, and Attachment 8 have been corrected to appropriately state these rates on separate lines. This correction results in MERC-NNG's 2017/18 commodity assigned costs in the November 1, 2017, filing having been understated by $213,360. As the correct amount was not reflected in MERC's November 1, 2017, commodity rate as implemented, MERC would propose to address this correction in its future annual automatic adjustment and true-up filings.

Summary of Corrections and Updates to Demand Schedules

MERC thanks the Department for its thorough review and identification of corrections and revisions that should have been reflected in MERC's Demand Entitlement schedules for the NNG PGA. MERC provides the following summary of updates and corrections that are reflected in the revised Attachments.

- Attachment 1, Page 1 of 3, Design Day Demand Summary: The number of firm customers has been updated to include the MERC-Albert Lea customers.[6] As discussed in more detail below, this updated customer count is based on actual customers at the end of June 2017, and does not include potential customers who could be added in the new areas of Esko and Balaton.

- Attachment 1, Page 2 of 3, Design Day Requirements: Customer counts, regression factors, and total design day requirements have been updated to include MERC-Albert Lea and reflect the consolidated MERC-NNG PGA.

- Attachment 1, Page 3 of 3, Design Day Demand Per Customer: 17/18 customer counts, design day requirements, and MMBtu/customer/day have been updated to include the MERC-Albert Lea customer calculations. This Attachment has also been updated for the historic periods to reflect the

[5] Department Comments at 21.
[6] As discussed above, Attachment 1, page 1 of 3 was also updated to reflect the corrected design day requirement for MERC's NNG PGA of 267,783Dth.

combined MERC-NNG and MERC-Albert Lea information. MERC notes that the combined MERC-NNG and MERC-Albert Lea customer counts and design day requirements were correctly calculated in Attachment 2, Page 2 of 2, of the Department's Comments.

- Attachment 2, Summer/Winter Usage: The data in this Attachment was not revised as both MERC's August 1 and November 1 filing reflected the data for MERC's former Albert Lea PGA system. However, MERC has updated the footnotes to clarify the source of the data reflected.

- Attachment 3, Entitlement Levels: The highlighted cells have been updated to reflect inclusion of the MERC-Albert Lea contract volumes, the forecasted design day has been updated to reflect the correct design day calculation, and the reserve margin calculations have been updated. Attachment 3 has also been updated to accurately reflect the allocation of TF12 capacity between TF12B and TF12V. In Attachment 3, the allocation between base and variable capacity has no impact on reserve margin.

- Attachment 4, Page 1 of 3, Rate Impact of the Proposed Demand Change: As discussed above, the highlighted commodity and demand costs have been updated and the total costs have been updated to reflect inclusion of the MERC-Albert Lea customers and sales and to reflect the correction to the storage costs, as discussed above. Additionally, MERC updated the "Most Recent PGA" data comparison to reflect the October 1, 2017, PGA.

- Attachment 4, Page 2 of 3, Rate Impact of the Proposed Demand Change: The annual sales have been updated to reflect the consolidated MERC-NNG (inclusive of MERC-Albert Lea) PGA as approved in Docket No. G011/MR-15-748; the GS-NNG sales have been updated to reflect the consolidated MERC-NNG (inclusive of MERC-Albert Lea) PGA as approved in Docket No. G011/MR-15-748; the highlighted rates have been updated to reflect the consolidated NNG (inclusive of Albert Lea) PGA. Also, as discussed above, this schedule has been updated to correct for an error in the storage rates related to contract 118657.

- Attachment 4, Page 3 of 3, Rate Impact of the Proposed Demand Change: No changes to MERC's previously filed November 1, 2017, Demand Entitlement schedule.

- Attachment 5, Financial Options: No changes from MERC's previously filed November 1, 2017, Demand Entitlement schedule.

- Attachment 6, Page 1 of 2, NNG Winter Portfolio Plan, Hedging Plan: No changes from MERC's previously filed November 1, 2017, Demand Entitlement schedule.

- Attachment 6, Page 2 of 2, NNG Winter Plan: No changes from MERC's previously filed November 1, 2017, Demand Entitlement schedule.

- Attachment 7, Entitlement History: This attachment has been updated to include the historical MERC-Albert Lea data back to 2015, when MERC first acquired the former IPL customers. In its Comments at Table 2, the Department also identifies discrepancies between MERC's original Attachments 3 and 7 with respect to the allocation of TF12B and TF12V services. MERC has reviewed and verified that Schedule 7 is correct and up to date with respect to this allocation.

- Attachment 8, Change in Costs due to November 1, 2017 Change in Entitlement Levels and Related Demand Costs: This attachment was updated to accurately reflect the consolidated MERC-NNG and Albert Lea historical data. The rates in this attachment were also updated to reflect the consolidated volumes. And, as discussed above, this Attachment has been updated to correct for an error in the storage rates related to contract 118657. Additionally, as discussed above, MERC has reconciled the allocation of TF12B and TF12V to address the Department's reconciliation in Table 2 of its Comments.

- Attachment 9, Daily Total Throughput Data – July 1, 2016-June 30, 2017: Based on the updates to the peak day variables in Attachment 1, page 2, the "Estimated Firm Throughput" in Attachment has changed as it is a calculated value.

- Attachment 10, Customer Counts by PGAC Class: This attachment has been updated to include the MERC-Albert Lea customer counts.

- Attachment 11, Page 1 of 3, Projected Fixed Cost: No changes from MERC's previously filed November 1, 2017, schedule.

- Attachment 11, Page 2 of 3, Projected Storage Cost: The footer on this schedule has been updated to reflect that indexes and projected WACOG are based on July 10, 2017, market prices.

- Attachment 11, Page 3 of 3, Projected Call Option Costs: The footnote was updated to reference that October 18, 2017, rather than October 24, 2016 NYMEX market prices were used.

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,

/s/ Amber S. Lee

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

Enclosure
cc: Service List

MINNESOTA ENERGY RESOURCES - NNG

DESIGN-DAY DEMAND SUMMARY
NOVEMBER 1, 2017
NNG

Design Day Requirement		267,783
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		197,991
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	197,991	197,991	98	17,400	2,147	252,396	15,292	267,688	95	267,783
Total	197,991	197,991								267,783
OFF PEAK										
NNG	197,991	197,991	55	17,400	2,147	146,895	15,292	162,187	95	162,282
Total	197,991	197,991								162,282

* 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	197,991	267,783	1.35
16/17	195,311	262,324	1.34
15/16	192,016	259,076	1.35
14/15	189,078	273,917	1.45
13/14	189,254	258,913	1.37
12/13	187,545	239,325	1.28
11/12	185,890	247,982	1.33
10/11	186,610	234,907	1.26
09/10	185,811	244,601	1.32
08/09	184,568	263,899	1.43

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

Attachment 3

NNG

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	84,709	0	84,709	84,709	0	84,709	84,709	0	84,709
TF5	0	0	0	0	0	0	36,275	0	36,275
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	109,501	0	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	120,541	0	120,541	122,541	0	122,541	266,317	0	266,317
Heating Season Forecasted Design Day-Adjusted							262,324	5,459	267,783
Non-Heating Season Forecasted Design Day				152,070	10,212	162,282			
Heating Season Capacity Surplus/Shortage							3,993	(5,459)	(1,466)
Non-Heating Season Capacity Surplus/Shortage				(29,529)	(10,212)	(39,741)			

*Not included in Heating Season Total entitlement

Reserve Margin			N3	-19.42%	-5.07%	-24.49%	1.52%	-2.07%	-0.55%

Attachment 4
Page 1 of 3

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 Oct 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	$3.3533	$3.0682	$3.0658	$3.0201	($0.2056)	($0.0481)	-1.49%	($0.0457)
Demand Cost	$0.9288	$0.9317	$0.9319	$0.9376	$0.9328	$0.0040	$0.0009	-0.51%	($0.0048)
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	$6.6830	$6.3981	$6.4150	$6.3645	($0.2016)	($0.0336)	-0.79%	($0.0505)
Avg Annual Cost	$577.82	$588.10	$563.03	$564.52	$560.08	($17.74)	($2.96)	-0.79%	($4.44)
Effect of proposed commodity change on average annual bills:									($4.02)
Effect of proposed demand change on average annual bills:									($0.42)
2) Small Vol. Interruptible: Avg. Annual Use:		5,110		Dth					
Commodity Cost	$3.2257	$3.3533	$3.0682	$3.0658	$3.0201	($0.2056)	($0.0481)	-1.49%	($0.0457)
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	$4.2869	$4.0018	$4.0398	$3.9941	($0.2056)	($0.0077)	-1.13%	($0.0457)
Avg Annual Cost	$21,460.47	$21,906.06	$20,449.20	$20,643.38	$20,409.85	($1,050.62)	($39.35)	-1.13%	($233.53)
Effect of proposed commodity change on average annual bills:									($233.53)
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	$3.3533	$3.0682	$3.0658	$3.0201	($0.2056)	($0.0481)	-1.49%	($0.0457)
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	$3.8540	$3.5689	$3.5987	$3.5530	($0.2056)	($0.0159)	-1.27%	($0.0457)
Avg Annual Cost	$60,701.39	$62,242.10	$57,637.74	$58,119.01	$57,380.95	($3,320.44)	($256.79)	-1.27%	($738.06)
Effect of proposed commodity change on average annual bills:									($738.06)
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	$3.3533	$3.0682	$3.0658	$3.0201	($0.2056)	($0.0481)	-1.49%	($0.0457)
Demand Cost	$27.8640	$10.2650	$10.2670	$28.1280	$27.9843	$0.0000	$17.7173	-0.51%	($0.1437)
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	$4.2869	$4.0018	$4.0398	$3.9941	($0.2056)	($0.0077)	-1.13%	($0.0457)
Total Demand Cost	$30.8640	$13.0143	$13.0163	$31.1280	$30.9843	$0.1203	$17.9680	-0.46%	($0.1437)
Avg Annual Cost	$22,232.07	$22,231.42	$20,774.61	$21,421.58	$21,184.46	($1,047.61)	$409.85	-1.11%	($237.12)
Effect of proposed commodity change on average annual bills:									($233.53)
Effect of proposed demand change on average annual bills:									($3.59)
5) Large Vol. Firm: Avg. Annual Use:		16,150		Dth					
		75		DTh					
Commodity Cost	$3.2257	$3.3533	$3.0682	$3.0658	$3.0201	($0.2056)	($0.0481)	-1.49%	($0.0457)
Demand Cost	$27.8640	$10.2650	$10.2670	$28.1280	$27.9843	$0.1203	$17.7173	-0.51%	($0.1437)
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	$3.8540	$3.5689	$3.5987	$3.5530	($0.2056)	($0.0159)	-1.27%	($0.0457)
Total Demand Cost	$30.8640	$13.0143	$13.0163	$31.1280	$30.9843	$30.9843	$17.9680	-0.46%	($0.1437)
Avg Annual Cost	$63,016.19	$63,218.17	$58,613.96	$60,453.61	$59,704.78	($996.61)	$1,090.82	-1.24%	($748.83)
Effect of proposed commodity change on average annual bills:									($738.06)
Effect of proposed demand change on average annual bills:									($10.77)

Note: Average Annual Average based on NNG Annual Automatic Adjustment Report in Docket No. E,G999/AA-17-493
Note: Commodity Cost Rates do not include ACA adjustment.

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-15-748 269,652,921

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	$ 0.01058
	TF12B (Max Rate) Summer	112495	49,219	7	$ 5.6830	=	$1,957,981	$ 0.00823
	TF12V (Max Rate)	112495	30,290	12	$ 9.0926	=	$3,304,978	$ 0.01389
	TF5 (Max Rate)	112495	36,275	5	$ 15.1530	=	$2,748,375	$ 0.01155
	TF12B (Discount-Winter)	112495	5,200	12	$ 7.4951	=	$467,694	$ 0.00197
	TFX12 (Max Rate)	112486	10,822	12	$ 9.6288	=	$1,250,434	$ 0.00526
	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	$ 0.02634
	TFX5 (Discount)	112486	1,800	5	$ 10.0320	=	$90,288	$ 0.00038
	TFX12 (Discount)	111866	1,283	12	$ 4.8640	=	$74,886	$ 0.00031
	TFX12 (Discount)	111866	8,271	12	$ 5.4720	=	$543,107	$ 0.00228
	TFX12 (Discount)	111866	11,921	12	$ 7.6025	=	$1,087,553	$ 0.00457
	TFX5 (Discount)	111866	379	5	$ 4.8640	=	$9,217	$ 0.00004
	TFX5 (Discount)	111866	2,445	5	$ 5.4720	=	$66,895	$ 0.00028
	TFX5 (Discount)	111866	22,189	5	$ 15.1392	=	$1,679,619	$ 0.00706
	Windom	118657	2,500	12	$ -	=	$0	$ -
	Northwestern Energy		1,035	12	$ 8.3382	=	$103,560	$ 0.00044
	Total Demand Cost						$22,189,727	**$ 0.09328**
	As approved in Docket No. G011/MR-15-748						237,880,096	
	GS-1 Demand Current Cost of Gas/therm							**$ 0.09328**
	GS-1 Commodity Current Cost of Gas/therm							**$ 0.30201**
	Total GS-1 Current Cost of Gas/therm							**$ 0.39529**

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	81,508	12	$ 1.7140	=	$1,676,457	$ 0.00622
FDD - Storage Cycle	118657	939,864.2	5	$ 0.3567	=	$1,676,248	$ 0.00622
FDD - Reservation	118657	5,550	12	$ 3.3157	=	$220,826	$ 0.00082
FDD - Storage Cycle	118657	64,000	5	$ 0.6901	=	$220,832	$ 0.00082
FDD - Reservation	132024	17,345	12	$ 1.7140	=	$356,748	$ 0.00132
FDD - Storage Cycle	132024	200,000	5	$ 0.3567	=	$356,700	$ 0.00132
FDD - Reservation	132112	8,672	12	$ 1.7140	=	$178,374	$ 0.00066
FDD - Storage Cycle	132112	100,000	5	$ 0.3567	=	$178,350	$ 0.00066
Firm Deferred Delivery Storage Contracts						$4,864,534	$ 0.01804

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	$ 0.03892
NBPL	T8673F	50,000	12	$ 6.9958	=	$4,197,500	$ 0.01557
						$14,691,250	$ 0.05448

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	26,965,292	x	$2.2444	$60,520,902	269,652,921	$ 0.22444
SMS-Bal Service	272,160	x	$2.1800	$593,309	269,652,921	$ 0.00220
Physical Forward Start Premium				$53,820	269,652,921	$ 0.00020
Call Option Premium				$713,379	269,652,921	$ 0.00265
GS-NNG, SVI-NNG, LVI-NNG, SJ-NNG, LJ-NNG, SLV Commodity Current Cost of Gas/therm				$66,745,943	269,652,921	$ 0.30201

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

Premium - Gas Daily Peaker (Monthly Cost)

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

Units - Futures (Dth)

	November Contract Date	November Daily Volume	December Contract Date	December Daily Volume	January Contract Date	January Daily Volume	February Contract Date	February Daily Volume	March Contract Date	March 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 Contract Date	November Daily Volume	December Contract Date	December Daily Volume	January Contract Date	January Daily Volume	February Contract Date	February Daily Volume	March Contract Date	March 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 Option Premium	November Premium Cost	December Option Premium	December Premium Cost	January Option Premium	January Premium Cost	February Option Premium	February Premium Cost	March Option Premium	March Premium Cost	Total Option Premium	Total 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	259,076	262,324	**267,783**	5,459
Customer Requirements moving to Transportation						
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	266,317	266,317	**266,317**	0
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	262,782	262,782	**262,782**	0
Factors for All Winter Capacity	100.00%	100.00%	100.00%	100.00%	**100.00%**	
Direct Assigned Entitlements in PGA						
TF12B	49,153	55,019	48,183	48,183	**54,419**	**6,236**
TF12V	26,926	21,060	36,526	36,526	**30,290**	**(6,236)**
TF5	31,515	31,515	36,275	36,275	**36,275**	**0**
TFX12	32,297	32,297	32,297	32,297	**32,297**	**0**
TFX(5)	93,084	123,084	109,501	109,501	**109,501**	**0**
TFX(5) (12-V)						**0**
TFX (April Only)	2,000	2,000	2,000	2,000	**2,000**	**0**
TFX (October Only)	2,000	2,000	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	266,317	266,317	**266,317**	**0**
LP Peak Shaving	0					**0**
Total Design Day Capacity	256,385	266,385	266,317	266,317	**266,317**	**0**
Total Annual Transportation	111,786	111,786	120,541	120,541	**120,541**	**0**
Total Seasonal Transportation	144,599	154,599	145,776	145,776	**145,776**	**0**
Total Percent Seasonal	56.4%	58.0%	54.7%	54.7%	**54.7%**	**0.0%**
Reserve Margin	4.27%	2.06%	2.79%	1.52%	**-0.55%**	**-2.1%**
Total Design Day Capacity w/ contract demand	256,385	266,385	266,317	266,317	**266,317**	0
Factors	28.43%	28.07%	32.40%	29.71%	**30.43%**	0.71%
Other Entitlements not included in Peak Day Deliverability						
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	100,934	107,871	**113,075**	5,204
FDD Storage Capacity	1,123,864	1,093,864	1,163,864	1,163,864	**1,303,864**	60,000
FDD Maximum Storage Quantity	5,619,321	5,469,321	5,819,321	6,219,321	**6,519,321**	300,000
SMS	22,680	22,680	24,380	24,380	**22,680**	-1,700

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	42,983	49,219	6,236	5	$10.2300	$2,198,581	$2,517,552	$318,971
TF12B (Max Rate) Summer	112495	49,219	49,219	0	7	$5.6830	$1,957,981	$1,957,981	$0
TF12V (Max Rate)	112495	36,526	30,290	(6,236)	12	$9.0926	$3,737,320	$3,304,978	($432,342)
TF5 (Max Rate)	112495	36,275	36,275	0	5	$15.1530	$2,748,375	$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	82,688	82,688	0	5	$15.1530	$6,264,856	$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							$22,303,099	$22,189,728	($113,371)

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	81,508	81,508	0	12	$ 1.7140	$1,676,457	$1,676,457	$0
FDD - Storage Cycle	118657	939,864	939,864	0	5	$ 0.3567	$1,676,248	$1,676,248	$0
FDD - Reservation	118657	5,550	5,550	0	12	$ 3.3157	$220,826	$220,826	$0
FDD - Storage Cycle	118657	64,000	64,000	0	5	$ 0.6901	$220,832	$220,832	$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		292,560	272,160	(20,400)	1	$2.1800	$637,781	$593,309	($44,472)
Physical Forward Start Premium							$175,451	$53,820	($121,631)
Producer Demand Payments/Option Premium							$1,063,335	$713,379	($349,956)
Total Commodity Costs							$21,218,301	$20,916,292	($302,009)

MINNESOTA ENERGY RESOURCES - NNG

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

NNG

Design Day:

Base	17,400
Variable	2,147

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	**21,606**
7/2/16	3	0	2	1	1	119,267	**20,007**
7/3/16	0	0	0	0	0	118,351	**17,400**
7/4/16	0	0	0	0	0	124,073	**17,400**
7/5/16	0	0	0	0	0	155,167	**17,400**
7/6/16	0	0	0	0	0	150,273	**17,400**
7/7/16	1	0	0	0	0	151,894	**17,550**
7/8/16	2	0	0	0	0	145,046	**17,880**
7/9/16	0	0	0	0	0	125,662	**17,400**
7/10/16	2	0	0	0	0	114,313	**17,880**
7/11/16	0	0	0	0	0	121,087	**17,400**
7/12/16	0	0	0	0	0	133,973	**17,400**
7/13/16	0	0	0	0	0	120,877	**17,400**
7/14/16	5	0	0	2	1	117,143	**19,236**
7/15/16	4	0	1	0	1	137,475	**18,965**
7/16/16	0	0	0	0	0	115,536	**17,400**
7/17/16	0	0	0	0	0	120,474	**17,400**
7/18/16	0	0	0	0	0	164,474	**17,400**
7/19/16	0	0	0	0	0	149,523	**17,400**
7/20/16	0	0	0	0	0	159,411	**17,400**
7/21/16	0	0	0	0	0	169,741	**17,400**
7/22/16	0	0	0	0	0	159,383	**17,400**
7/23/16	0	0	0	0	0	137,119	**17,400**
7/24/16	0	0	0	0	0	128,533	**17,400**
7/25/16	0	0	0	0	0	159,618	**17,400**
7/26/16	0	0	0	0	0	157,013	**17,400**
7/27/16	5	0	0	0	1	152,327	**18,811**
7/28/16	6	0	0	0	1	147,173	**19,291**
7/29/16	6	0	0	2	1	144,825	**19,511**
7/30/16	0	0	0	0	0	133,540	**17,400**
7/31/16	0	0	0	0	0	124,401	**17,400**
8/1/16	0	0	0	0	0	152,800	**17,400**
8/2/16	0	0	0	0	0	165,672	**17,400**
8/3/16	0	0	0	0	0	152,176	**17,400**
8/4/16	0	0	0	0	0	138,146	**17,400**
8/5/16	1	0	0	0	0	122,449	**17,730**
8/6/16	2	0	0	0	0	118,320	**17,880**
8/7/16	3	0	0	0	0	107,876	**18,150**
8/8/16	0	0	0	0	0	128,201	**17,400**
8/9/16	0	0	0	0	0	136,909	**17,400**
8/10/16	2	0	0	0	0	136,607	**17,880**
8/11/16	0	0	0	0	0	137,271	**17,400**
8/12/16	0	0	0	0	0	119,752	**17,400**
8/13/16	0	0	0	0	0	109,044	**17,400**
8/14/16	0	0	0	0	0	96,958	**17,400**
8/15/16	0	0	0	0	0	115,444	**17,400**
8/16/16	0	0	0	0	0	121,417	**17,400**
8/17/16	0	0	0	0	0	116,285	**17,400**
8/18/16	0	0	0	0	0	108,754	**17,400**
8/19/16	0	0	0	0	0	103,462	**17,400**
8/20/16	8	3	6	7	5	90,642	**28,829**
8/21/16	4	0	3	0	2	102,420	**21,763**
8/22/16	0	0	0	0	0	114,711	**17,400**
8/23/16	0	0	0	0	0	124,458	**17,400**
8/24/16	0	0	0	0	0	134,269	**17,400**
8/25/16	7	0	0	5	1	137,157	**20,527**
8/26/16	2	0	1	2	1	118,876	**18,860**
8/27/16	5	0	1	0	1	104,042	**19,265**
8/28/16	0	0	0	0	0	124,833	**17,400**
8/29/16	0	0	0	0	0	158,567	**17,400**
8/30/16	4	0	0	0	1	147,238	**18,511**
8/31/16	3	0	0	0	0	135,047	**18,180**
9/1/16	6	0	3	1	2	120,978	**22,033**
9/2/16	3	0	3	0	2	113,860	**20,948**
9/3/16	1	0	0	0	0	107,434	**17,550**
9/4/16	0	0	0	0	0	97,344	**17,400**
9/5/16	0	0	0	0	0	101,559	**17,400**
9/6/16	0	0	0	0	0	138,653	**17,400**
9/7/16	2	0	0	0	0	127,110	**17,880**
9/8/16	2	0	0	0	0	125,226	**18,030**
9/9/16	4	0	3	5	3	101,279	**23,143**
9/10/16	8	1	6	3	4	97,358	**26,122**
9/11/16	0	0	0	0	0	94,085	**17,400**
9/12/16	5	0	0	6	1	112,136	**20,422**
9/13/16	17	9	8	17	10	112,697	**39,618**
9/14/16	11	4	3	6	5	111,904	**27,974**

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9/15/16	3	0	0	3	1	95,472	**19,131**
9/16/16	4	0	0	2	1	95,632	**18,906**
9/17/16	12	2	5	1	5	94,526	**27,365**
9/18/16	2	0	0	0	0	90,576	**17,880**
9/19/16	7	0	0	0	1	119,108	**19,351**
9/20/16	5	0	0	0	1	113,338	**18,811**
9/21/16	4	0	0	0	1	109,618	**18,721**
9/22/16	9	0	0	0	1	113,478	**20,101**
9/23/16	7	0	1	0	1	108,287	**20,447**
9/24/16	6	0	0	0	1	94,908	**19,321**
9/25/16	9	8	8	13	9	96,494	**35,920**
9/26/16	15	9	10	13	11	123,792	**40,346**
9/27/16	19	11	10	10	12	127,224	**42,518**
9/28/16	11	12	10	16	11	123,921	**41,908**
9/29/16	10	6	7	12	8	128,198	**34,226**
9/30/16	12	4	3	5	5	121,543	**27,394**
10/1/16	11	3	6	6	6	129,385	**29,476**
10/2/16	9	1	4	1	3	129,498	**24,671**
10/3/16	10	0	1	0	2	131,294	**21,348**
10/4/16	2	0	0	10	1	125,955	**20,281**
10/5/16	17	10	9	13	11	151,183	**40,051**
10/6/16	20	15	15	24	17	145,758	**53,092**
10/7/16	28	25	25	26	26	157,338	**72,413**
10/8/16	29	22	20	24	22	154,969	**64,808**
10/9/16	21	17	15	14	16	143,895	**52,133**
10/10/16	2	1	4	7	3	140,791	**23,694**
10/11/16	17	8	6	19	10	145,564	**37,980**
10/12/16	29	24	30	31	28	175,486	**77,937**
10/13/16	23	21	23	21	22	174,460	**65,143**
10/14/16	13	11	14	9	13	149,216	**44,408**
10/15/16	16	8	7	11	9	140,215	**37,006**
10/16/16	15	6	3	4	6	134,911	**29,809**
10/17/16	16	4	5	10	7	167,367	**31,697**
10/18/16	13	9	10	13	10	178,397	**39,722**
10/19/16	30	19	17	26	21	203,088	**61,646**
10/20/16	26	21	26	26	25	210,708	**70,441**
10/21/16	27	20	23	18	22	175,613	**64,764**
10/22/16	17	12	12	10	12	153,898	**43,898**
10/23/16	28	21	21	23	22	160,729	**64,923**
10/24/16	24	19	20	22	20	175,000	**61,086**
10/25/16	26	20	24	18	22	179,338	**65,126**
10/26/16	28	22	24	22	24	192,371	**68,371**
10/27/16	23	20	25	14	22	185,294	**64,352**
10/28/16	16	4	8	5	8	149,938	**33,506**
10/29/16	23	17	17	23	18	160,032	**56,819**
10/30/16	27	22	24	25	24	173,131	**69,115**
10/31/16	21	13	14	18	15	169,962	**50,361**
11/1/16	24	14	11	16	14	183,410	**47,369**
11/2/16	21	13	15	16	16	190,222	**50,952**
11/3/16	20	12	16	11	15	198,342	**48,562**
11/4/16	16	10	12	8	12	168,867	**42,157**
11/5/16	13	6	10	6	9	151,412	**36,598**
11/6/16	7	7	13	9	10	147,862	**39,024**
11/7/16	17	12	17	19	16	166,101	**50,927**
11/8/16	24	19	23	24	22	180,011	**63,951**
11/9/16	16	15	18	17	17	176,530	**53,174**
11/10/16	21	13	17	16	16	171,771	**52,182**
11/11/16	30	25	29	29	28	196,137	**77,297**
11/12/16	22	20	24	24	22	182,285	**65,453**
11/13/16	14	15	17	19	16	164,931	**52,041**
11/14/16	23	24	27	23	25	183,955	**70,929**
11/15/16	25	21	22	20	22	174,735	**64,369**
11/16/16	24	15	18	15	18	164,123	**55,355**
11/17/16	26	15	12	30	17	167,660	**53,744**
11/18/16	43	34	29	51	35	219,713	**91,873**
11/19/16	50	42	46	50	46	239,663	**115,374**
11/20/16	43	41	42	42	42	251,845	**107,450**
11/21/16	42	35	37	38	37	232,672	**97,389**
11/22/16	37	34	35	35	35	234,728	**92,981**
11/23/16	35	33	34	35	34	218,519	**90,053**
11/24/16	33	32	32	37	32	217,703	**87,054**
11/25/16	34	35	35	28	34	225,346	**90,227**
11/26/16	32	29	31	30	30	208,686	**82,501**
11/27/16	33	27	29	29	29	200,666	**79,545**
11/28/16	27	23	28	35	27	203,478	**76,021**
11/29/16	31	31	34	38	33	219,158	**88,789**
11/30/16	34	31	34	39	34	218,927	**89,486**
12/1/16	39	34	36	37	36	233,555	**93,948**
12/2/16	40	37	39	40	38	242,710	**99,965**
12/3/16	39	37	38	38	38	226,037	**98,332**
12/4/16	36	34	39	32	37	227,289	**95,886**
12/5/16	37	39	42	45	40	229,031	**104,259**
12/6/16	53	53	59	64	57	274,909	**139,049**
12/7/16	53	55	60	66	58	288,743	**142,076**
12/8/16	54	52	59	64	57	310,657	**139,676**
12/9/16	63	58	61	60	60	335,218	**146,470**
12/10/16	62	57	59	58	59	301,660	**143,507**
12/11/16	59	59	58	65	59	301,565	**144,284**
12/12/16	70	71	74	66	71	336,250	**170,586**

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12/13/16	73	70	75	70	73	334,866	**173,245**
12/14/16	80	77	80	78	79	382,958	**186,290**
12/15/16	70	69	72	69	71	373,684	**168,834**
12/16/16	64	62	61	68	63	339,779	**151,656**
12/17/16	82	80	85	89	84	360,409	**196,935**
12/18/16	78	75	88	85	82	372,217	**194,024**
12/19/16	51	48	63	57	56	292,146	**138,068**
12/20/16	41	38	41	40	40	245,841	**103,560**
12/21/16	42	39	45	45	42	242,668	**108,581**
12/22/16	40	39	44	43	42	240,206	**107,530**
12/23/16	36	32	37	42	36	224,996	**94,255**
12/24/16	45	34	38	41	38	221,052	**99,187**
12/25/16	40	41	43	49	42	224,669	**108,193**
12/26/16	57	54	56	58	56	282,403	**136,616**
12/27/16	57	46	50	45	49	274,849	**122,738**
12/28/16	45	38	43	40	41	251,797	**106,300**
12/29/16	53	44	51	47	49	267,237	**122,432**
12/30/16	54	44	47	44	46	259,010	**117,018**
12/31/16	52	45	53	50	50	262,238	**124,833**
1/1/17	49	41	45	46	45	247,788	**113,070**
1/2/17	41	43	41	53	43	247,341	**109,692**
1/3/17	67	71	72	79	71	336,838	**170,873**
1/4/17	85	75	78	78	78	361,714	**184,637**
1/5/17	82	75	80	78	79	377,996	**186,191**
1/6/17	79	71	76	66	73	372,143	**175,142**
1/7/17	76	68	74	69	72	347,734	**171,207**
1/8/17	68	61	67	60	65	312,905	**156,312**
1/9/17	53	46	47	52	48	274,677	**121,102**
1/10/17	61	54	54	63	56	288,371	**137,888**
1/11/17	72	63	64	69	66	320,488	**158,108**
1/12/17	78	68	69	67	70	333,973	**167,292**
1/13/17	76	66	65	63	67	327,130	**160,436**
1/14/17	59	54	58	48	56	288,652	**137,032**
1/15/17	52	48	56	41	51	262,697	**127,608**
1/16/17	44	43	40	41	41	251,591	**106,075**
1/17/17	39	37	41	42	40	242,487	**102,697**
1/18/17	34	32	41	34	37	224,359	**95,775**
1/19/17	27	32	37	33	34	218,820	**90,003**
1/20/17	32	31	34	33	33	211,290	**87,676**
1/21/17	31	30	34	34	32	205,484	**86,389**
1/22/17	31	30	35	36	33	209,273	**88,324**
1/23/17	33	33	36	36	35	223,841	**91,622**
1/24/17	39	37	38	43	39	227,675	**100,110**
1/25/17	43	41	43	49	43	243,285	**109,872**
1/26/17	48	46	49	56	49	277,125	**122,233**
1/27/17	47	45	52	52	49	278,216	**122,793**
1/28/17	51	43	48	44	46	260,048	**117,128**
1/29/17	58	46	58	40	52	275,720	**130,022**
1/30/17	47	37	45	37	42	260,326	**107,650**
1/31/17	52	45	45	46	46	261,934	**116,482**
2/1/17	68	60	65	61	63	313,686	**153,069**
2/2/17	70	59	64	60	63	330,316	**152,098**
2/3/17	60	53	60	58	58	305,202	**141,184**
2/4/17	51	44	46	48	46	269,236	**116,930**
2/5/17	57	46	50	48	49	279,677	**123,354**
2/6/17	51	41	41	39	42	257,489	**108,035**
2/7/17	65	59	54	65	58	302,300	**142,654**
2/8/17	71	64	67	62	66	328,498	**159,290**
2/9/17	63	56	61	57	59	300,081	**145,045**
2/10/17	38	32	40	28	36	229,113	**93,931**
2/11/17	40	31	32	34	33	217,001	**88,643**
2/12/17	40	35	42	34	38	232,926	**100,037**
2/13/17	33	28	37	32	33	226,315	**88,862**
2/14/17	48	39	42	39	42	243,849	**106,550**
2/15/17	49	40	42	37	41	251,141	**106,383**
2/16/17	37	32	36	22	33	222,754	**88,957**
2/17/17	24	18	27	22	23	184,413	**67,469**
2/18/17	27	20	24	19	23	182,839	**65,850**
2/19/17	27	17	21	16	20	171,856	**60,011**
2/20/17	27	24	27	22	25	195,159	**71,802**
2/21/17	24	19	22	16	21	184,610	**61,834**
2/22/17	33	23	23	23	24	199,557	**69,129**
2/23/17	46	39	39	49	41	248,770	**105,302**
2/24/17	57	53	56	58	55	285,199	**136,213**
2/25/17	50	44	54	49	50	264,213	**124,648**
2/26/17	55	37	49	42	45	258,707	**114,920**
2/27/17	39	29	40	31	36	234,088	**94,284**
2/28/17	42	33	37	37	36	236,467	**95,422**
3/1/17	49	43	50	43	47	270,425	**118,708**
3/2/17	66	47	53	48	53	304,960	**130,511**
3/3/17	53	46	52	45	50	272,707	**123,906**
3/4/17	39	35	41	34	38	227,605	**98,953**
3/5/17	25	15	25	14	21	191,123	**61,763**
3/6/17	33	21	22	21	23	192,953	**67,191**
3/7/17	52	38	35	35	38	235,468	**99,712**
3/8/17	58	42	41	39	43	265,340	**110,334**
3/9/17	64	54	52	58	55	296,833	**134,928**
3/10/17	66	57	57	59	58	334,351	**142,507**
3/11/17	58	54	53	55	54	295,897	**133,296**

MERC

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

MERC

3/12/17	55	52	51	58	53	295,291	**130,607**
3/13/17	57	51	57	63	56	317,540	**137,573**
3/14/17	52	47	56	56	53	306,564	**131,038**
3/15/17	41	45	51	52	48	275,983	**120,040**
3/16/17	36	37	44	34	40	230,838	**102,874**
3/17/17	38	33	35	36	35	227,775	**92,568**
3/18/17	37	31	36	30	34	231,427	**90,401**
3/19/17	30	23	27	16	25	201,700	**70,883**
3/20/17	33	26	24	29	27	218,433	**74,391**
3/21/17	49	39	41	41	42	269,330	**107,061**
3/22/17	41	37	41	38	40	233,366	**102,485**
3/23/17	33	30	32	29	31	225,923	**84,413**
3/24/17	32	27	31	32	30	213,289	**82,182**
3/25/17	35	28	33	32	32	217,906	**85,792**
3/26/17	32	26	29	29	29	227,909	**79,006**
3/27/17	27	18	27	25	24	238,211	**69,434**
3/28/17	19	12	18	18	17	202,283	**53,294**
3/29/17	34	23	29	28	28	212,228	**76,499**
3/30/17	31	28	32	31	30	224,663	**82,209**
3/31/17	23	20	24	24	23	215,256	**66,611**
4/1/17	21	12	17	16	16	176,176	**51,482**
4/2/17	21	15	21	17	19	189,568	**57,580**
4/3/17	22	19	22	21	21	201,340	**62,592**
4/4/17	22	15	18	20	18	189,286	**55,822**
4/5/17	27	21	26	27	25	213,172	**70,876**
4/6/17	30	22	28	26	26	202,723	**73,769**
4/7/17	19	16	18	14	17	180,241	**54,551**
4/8/17	15	5	6	3	7	157,204	**32,028**
4/9/17	19	7	8	17	10	160,268	**39,507**
4/10/17	34	29	28	36	30	226,894	**81,748**
4/11/17	28	23	26	21	25	226,771	**70,450**
4/12/17	17	16	17	18	17	197,384	**53,485**
4/13/17	19	16	17	18	17	178,338	**53,692**
4/14/17	16	8	11	7	10	158,406	**39,935**
4/15/17	13	6	10	12	9	151,602	**37,278**
4/16/17	25	11	12	13	13	164,762	**46,317**
4/17/17	31	13	13	14	16	190,517	**50,924**
4/18/17	29	11	13	13	15	192,190	**48,831**
4/19/17	30	22	22	25	23	216,157	**67,313**
4/20/17	32	23	29	27	27	208,955	**76,021**
4/21/17	18	14	17	19	16	182,615	**52,134**
4/22/17	17	6	12	10	11	156,442	**40,767**
4/23/17	35	6	8	6	11	161,998	**40,424**
4/24/17	28	2	5	16	9	151,105	**35,812**
4/25/17	24	20	10	33	18	183,696	**55,258**
4/26/17	39	31	31	38	33	215,391	**87,707**
4/27/17	42	33	37	34	36	252,464	**94,733**
4/28/17	30	22	27	28	26	210,704	**73,171**
4/29/17	24	19	24	26	23	187,498	**66,910**
4/30/17	28	26	30	37	29	209,696	**80,091**
5/1/17	33	30	30	32	31	241,418	**83,408**
5/2/17	18	12	21	14	17	210,879	**54,659**
5/3/17	11	11	14	17	13	194,248	**45,636**
5/4/17	17	7	10	11	10	173,639	**39,764**
5/5/17	14	5	7	7	7	155,534	**32,815**
5/6/17	25	7	12	6	12	157,963	**42,197**
5/7/17	22	9	12	0	11	157,401	**41,429**
5/8/17	20	5	7	0	7	168,829	**32,788**
5/9/17	10	3	3	7	5	159,263	**27,197**
5/10/17	14	8	11	14	11	164,609	**40,960**
5/11/17	17	9	13	13	12	168,511	**43,474**
5/12/17	11	0	1	0	2	155,737	**21,186**
5/13/17	12	0	0	0	2	137,320	**21,062**
5/14/17	18	0	0	0	2	143,267	**22,743**
5/15/17	16	0	0	0	2	142,168	**22,172**
5/16/17	15	0	0	0	2	139,069	**22,022**
5/17/17	16	6	6	9	8	137,063	**34,195**
5/18/17	23	17	21	20	20	158,477	**60,138**
5/19/17	22	17	24	26	22	166,236	**64,144**
5/20/17	27	20	23	27	23	164,141	**67,021**
5/21/17	22	19	24	20	22	175,587	**63,786**
5/22/17	16	8	8	10	9	159,277	**37,280**
5/23/17	16	13	18	18	16	163,269	**51,754**
5/24/17	18	10	13	14	13	156,335	**44,985**
5/25/17	12	1	5	3	4	146,454	**26,856**
5/26/17	8	0	3	4	3	153,256	**23,464**
5/27/17	3	1	4	6	3	132,197	**24,193**
5/28/17	9	1	5	5	5	133,295	**27,140**
5/29/17	16	7	11	12	10	144,950	**39,750**
5/30/17	18	11	13	13	13	155,479	**45,050**
5/31/17	14	3	4	6	5	149,145	**28,652**
6/1/17	4	0	0	0	1	140,085	**18,481**
6/2/17	2	0	0	0	0	148,479	**17,880**
6/3/17	0	0	0	0	0	144,740	**17,400**
6/4/17	1	0	0	0	0	139,494	**17,550**
6/5/17	11	0	0	0	2	141,945	**20,702**
6/6/17	6	0	0	0	1	136,644	**19,261**
6/7/17	0	0	0	0	0	142,843	**17,400**
6/8/17	2	0	0	0	0	151,905	**17,880**

6/9/17	3	0	0	0	0	141,382	**18,210**
6/10/17	0	0	0	0	0	123,115	**17,400**
6/11/17	4	0	0	0	1	136,630	**18,481**
6/12/17	0	0	0	0	0	155,388	**17,400**
6/13/17	11	0	0	0	1	145,683	**20,582**
6/14/17	8	0	0	0	1	156,104	**19,891**
6/15/17	1	0	0	0	0	155,694	**17,550**
6/16/17	0	0	0	0	0	152,134	**17,400**
6/17/17	0	0	0	0	0	125,647	**17,400**
6/18/17	5	0	2	3	2	130,630	**21,219**
6/19/17	11	0	2	0	2	137,406	**22,260**
6/20/17	8	0	1	0	2	149,785	**20,837**
6/21/17	3	0	0	0	0	136,017	**18,180**
6/22/17	1	0	1	0	0	142,105	**18,035**
6/23/17	7	1	6	11	5	139,479	**28,298**
6/24/17	9	6	10	9	9	137,320	**35,679**
6/25/17	14	6	10	8	9	136,451	**36,649**
6/26/17	8	2	8	7	6	150,841	**30,233**
6/27/17	2	0	0	0	0	136,929	**17,880**
6/28/17	8	0	0	0	1	138,237	**19,651**
6/29/17	5	0	0	0	1	135,881	**18,811**
6/30/17	2	0	0	2	0	131,639	**18,250**
Totals	8,980	7,127	7,918	7,915	7,835	69,179,284	23,173,120

* Volumes include interruptible and transportation volumes

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

Attachment 10
NNG

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
	MERC000101	9,549	9,547	9,598	9,500	9,495	9,430	9,545	9,495	9,498	9,510	9,491	9,539	9,516
	MERC000102	47	42	35	35	38	41	41	42	45	60	52	50	44
	MERC000103	1,147	1,274	1,204	1,170	1,188	1,165	1,164	1,167	1,175	1,151	1,161	1,158	1,177
	MERC000104	38	56	40	48	49	55	47	34	44	37	39	40	44
	MERC000106	15	17	13	20	20	17	14	15	14	14	13	14	16
Total		196,317	198,453	198,342	197,435	198,278	197,725	199,086	197,949	198,386	198,668	199,387	200,219	198,354

MINNESOTA ENERGY RESOURCES - NNG

Projected Fixed Cost - November 2017 through March 2018

Futures Contracts WACOG

Futures 10,000 Dth/contract 30 31 31

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	$ -	$ -		$ -	$ -
8												
9												
10												
11												
12												
13												
14												
15												
Total			32	320,000		$ 1,000,510		$ 913,280	$ 87,230		$ -	$ 1,000,510
						$ 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	$ -	$ -	$ 1,000,510

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												
9												
10												
11												
12												
13												
14												
15												
Total			48	480,000		$ 1,570,340		$ 1,471,200	$ 99,140		$ -	$ 1,570,340
						$ 3.2715		$ 3.0650	$ 0.2065		$ -	$ 3.2715
NNG	40	83.33%	40	400,000	$ 3.2715	$ 1,308,617	$ 3.0650	$ 1,226,000	$ 82,617	$ -	$ -	$ 1,308,617
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	$ 1,471,200	$ 99,140	$ -	$ -	$ 1,570,340

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	$ 3.1940	$ 351,340	$ 54,670		$ -	$ 406,010
2	06/19/17	51295	11	110,000	$ 3.2370	$ 356,070	$ 3.1940	$ 351,340	$ 4,730		$ -	$ 356,070
3	07/18/17	52342	10	100,000	$ 3.4030	$ 340,300	$ 3.1940	$ 319,400	$ 20,900		$ -	$ 340,300
4	08/21/17	53755	9	90,000	$ 3.2790	$ 295,110	$ 3.1940	$ 287,460	$ 7,650		$ -	$ 295,110
5	09/14/17	54871	8	80,000	$ 3.3510	$ 268,080	$ 3.1940	$ 255,520	$ 12,560		$ -	$ 268,080
6	10/18/17	56094	8	80,000	$ 3.2010	$ 256,080	$ 3.1940	$ 255,520	$ 560		$ -	$ 256,080
7												
8												
9												
10												
11												
12												
13												
14												
15												
Total	Total		57	570,000		$ 1,921,650		$ 1,820,580	$ 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	$ 3.1940	$ 1,501,180	$ 83,338	$ -	$ -	$ 1,584,518
Other-Cons	10	17.54%	10	100,000	$ 3.3713	$ 337,132	$ 3.1940	$ 319,400	$ 17,732	$ -	$ -	$ 337,132
Total	57	100.0%	57	570,000	$ 3.3713	$ 1,921,650	$ 3.1940	$ 1,820,580	$ 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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Total			51	510,000		$ 1,699,970		$ 1,633,530	$ 66,440		$ -	$ 1,699,970
						$ 3.3333		$ 3.2030	$ 0.1303		$ -	$ 3.3333
NNG	42	82.35%	42	420,000	$ 3.3333	$ 1,399,975	$ 3.2030	$ 1,345,260	$ 54,715	$ -	$ -	$ 1,399,975
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	$ 1,633,530	$ 66,440	$ -	$ -	$ 1,699,970

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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Total			40	400,000		$ 1,319,030		$ 1,265,600	$ 53,430		$ -	$ 1,319,030
						$ 3.2976		$ 3.1640	$ 0.1336		$ -	$ 3.2976
NNG	33	82.50%	33	330,000	$ 3.2976	$ 1,088,200	$ 3.1640	$ 1,044,120	$ 44,080	$ -	$ -	$ 1,088,200
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	$ 1,265,600	$ 53,430	$ -	$ -	$ 1,319,030

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	$ 3.1121	$ 1,462,680	$ 208,930	$ -	$ -	$ 1,671,610
2			43	430,000	$ 3.2268	$ 1,387,540	$ 3.1217	$ 1,342,320	$ 45,220	$ -	$ -	$ 1,387,540
3			34	340,000	$ 3.2881	$ 1,117,960	$ 3.1172	$ 1,059,840	$ 58,120	$ -	$ -	$ 1,117,960
4			32	320,000	$ 3.1697	$ 1,014,310	$ 3.1121	$ 995,870	$ 18,440	$ -	$ -	$ 1,014,310
5			33	330,000	$ 3.2687	$ 1,078,680	$ 3.1116	$ 1,026,820	$ 51,860	$ -	$ -	$ 1,078,680
6			33	330,000	$ 3.1818	$ 1,050,000	$ 3.1116	$ 1,026,820	$ 23,180	$ -	$ -	$ 1,050,000
7			6	60,000	$ 3.1900	$ 191,400	$ 3.1640	$ 189,840	$ 1,560	$ -	$ -	$ 191,400
8			0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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Total			228	2,280,000		$ 7,511,500		$ 7,104,190	$ 407,310		$ -	$ 7,511,500
						$ 3.2945		$ 3.1159	$ 0.1786		$ -	$ 3.2945
NNG	188	82.46%	188	1,880,000	$ 3.2945	$ 6,193,693	$ 3.1159	$ 5,857,841	$ 335,852	$ -	$ -	$ 6,193,693
Other-Cons	40	17.54%	40	400,000	$ 3.2945	$ 1,317,807	$ 3.1159	$ 1,246,349	$ 71,458	$ -	$ -	$ 1,317,807
Total	228	100.0%	228	2,280,000	$ 3.2945	$ 7,511,500	$ 3.1159	$ 7,104,190	$ 407,310	$ -	$ -	$ 7,511,500

*Prices from 10/18/17 NYMEX market

MINNESOTA ENERGY RESOURCES - NNG

Projected Storage Cost - November 2017 through March 2018

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

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 7/10/17 market prices

MINNESOTA ENERGY RESOURCES - NNG

Projected Call Option Costs - November 2017 through March 2018

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

Call/Put Options WACOG

Call/Put Options 10,000 Dth/contract

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	$ -	$ -		$ -	$ -
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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
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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														
13														
14														
15														
Total			461	4,610,000		$17,661,200		$ 14,365,290		$ 14,365,290	$ -		$ 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	$ 11,840,360	$ 3.1159	$ 11,840,360	$ -	$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	$ 14,365,290	$ 3.1161	$ 14,365,290	$ -	$0.1878	$ 865,650	$ 15,230,940

*Prices from 10/18/17 NYMEX market

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 20th day of February, 2018, on behalf of Minnesota Energy Resources Corporation (MERC) I electronically filed a true and correct copy of the enclosed Reply Comments 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 20th day of February, 2018.

__/s/ Kristin M. Stastny_____
Kristin M. Stastny

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Ahern	ahern.michael@dorsey.com	Dorsey & Whitney, LLP	50 S 6th St Ste 1500 Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_17-588_M-17-588
Michael	Auger	mauger@usenergyservices.com	U S Energy Services, Inc.	Suite 1200 605 Highway 169 N Minneaplis, MN 554416531	Electronic Service	No	OFF_SL_17-588_M-17-588
Elizabeth	Brama	ebrama@briggs.com	Briggs and Morgan	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-588_M-17-588
Jeanne	Cochran	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 St. Paul, MN 55164-0620	Electronic Service	No	OFF_SL_17-588_M-17-588
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_17-588_M-17-588
Seth	DeMerritt	ssdemerritt@integrysgroup.com	MERC (Holding)	700 North Adams P.O. Box 19001 Green Bay, WI 543079001	Electronic Service	No	OFF_SL_17-588_M-17-588
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_17-588_M-17-588
Darcy	Fabrizius	Darcy.fabrizius@constellation.com	Constellation Energy	N21 W23340 Ridgeview Pkwy Waukesha, WI 53188	Electronic Service	No	OFF_SL_17-588_M-17-588
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_17-588_M-17-588
Daryll	Fuentes	dfuentes@usg.com	USG Corporation	550 W Adams St Chicago, IL 60661	Electronic Service	No	OFF_SL_17-588_M-17-588

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Robert	Harding	robert.harding@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	No	OFF_SL_17-588_M-17-588
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-588_M-17-588
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	No	OFF_SL_17-588_M-17-588
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-588_M-17-588
Amber	Lee	ASLee@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	2665 145th St W Rosemount, MN 55068	Electronic Service	No	OFF_SL_17-588_M-17-588
Peter	Madsen	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Bremer Tower, Suite 1800 445 Minnesota Street St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_17-588_M-17-588
Brian	Meloy	brian.meloy@stinson.com	Stinson,Leonard, Street LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-588_M-17-588
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_17-588_M-17-588
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-588_M-17-588

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_17-588_M-17-588
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_17-588_M-17-588
Colleen	Sipiorski	ctsipiorski@integrysgroup.com	Minnesota Energy Resources Corporation	700 North Adams Street Green Bay, WI 54307	Electronic Service	No	OFF_SL_17-588_M-17-588
Kristin	Stastny	kstastny@briggs.com	Briggs and Morgan, P.A.	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-588_M-17-588
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_17-588_M-17-588
Casey	Whelan	cwhelan@usenergyservices.com	U.S. Energy Services, Inc.	605 Highway 169 N Ste 1200 Plymouth, MN 55441	Electronic Service	No	OFF_SL_17-588_M-17-588
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_17-588_M-17-588