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

August 1, 2024

VIA ELECTRONIC FILING

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101

Re: In the Matter Minnesota Energy Resources Corporation's Petition for Approval of a Change in Demand Entitlement for its Consolidated System

Docket No. G011/M-24-___

Dear Mr. Seuffert:

In accordance with Minnesota Rules 7825.2910, subpart 2, please find enclosed Minnesota Energy Resources Corporation's (MERC's or the Company's) request to change demand entitlements for its Consolidated purchased gas adjustment area. Please note that any updated information will be provided with MERC's November 1, 2024 filing. MERC is also filing Excel and PDF versions of the attachments.

Pursuant to Minnesota Rule 7825.2910, subpart 3, a Notice of Availability has been sent to all intervenors in the Company's previous two rate cases.

Please contact me at (414) 221-4208 if you have any questions regarding the information in this filing. Thank you for your attention to this matter.

Sincerely yours,

/s/Joylyn Hoffman Malueg
Joylyn Hoffman Malueg
Project Specialist 3
Minnesota Energy Resources Corporation

Enclosures
cc: Service List

ATTACHMENT A

August 1, 2024

To: Service List

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

Notice of Availability

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

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

Joylyn C. Hoffman Malueg
Minnesota Energy Resources Corporation
2685 145th Street West
Rosemount, MN 55068
(414) 221-4208

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

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

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

ATTACHMENT B

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	**Chair**
Hwikwon Ham	**Commissioner**
Valerie Means	**Commissioner**
Joseph K. Sullivan	**Commissioner**
John A. Tuma	**Commissioner**

In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Change in Demand Entitlement for its Consolidated System	Docket No. G011/M-24-___

SUMMARY OF FILING

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation – Consolidated (MERC or the Company), hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC customers served off of the Consolidated system. MERC requests the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) beginning November 1, 2024.

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	**Chair**
Hwikwon Ham	**Commissioner**
Valerie Means	**Commissioner**
Joseph K. Sullivan	**Commissioner**
John A. Tuma	**Commissioner**

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

Docket No. G011/M-24-___

FILING UPON CHANGE IN DEMAND

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation – Consolidated (MERC or the Company), a subsidiary of WEC Energy Group, hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-Consolidated customers served off Centra Pipeline, Viking Gas Transmission, and Great Lakes Gas Transmission (collectively the "Consolidated" pipelines).[1] MERC requests the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) beginning November 1, 2024.

This filing includes the following attachments:

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

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[1] MERC also serves certain of its Minnesota customers off the Northern Natural Gas ("NNG") system. MERC requests approval of a demand entitlement change for the 2024-2025 heating season for its MERC-NNG PGA in a separate docket.

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

I. Summary of Filing

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

II. Service

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

III. General Filing Information

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

Minnesota Energy Resources Corporation
2685 145th Street West
Rosemount, MN 55068
(651) 322-8901

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

Kristin M. Stastny
Taft Stettinius & Hollister LLP
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
KStastny@Taftlaw.com
(612) 977-8656

C. Date of the Filing and Proposed Effective Date

Date of filing: August 1, 2024
Proposed Effective Date: November 1, 2024

D. Statute Controlling Schedule for Processing the Filing

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

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

Joylyn C. Hoffman Malueg

Joylyn C. Hoffman Malueg
Senior Project Specialist
Joylyn.HoffmanMalueg@wecenergygroup.com
2685 145th Street West
Rosemount, MN 55068
(414) 221-4208

If additional information is required, please contact Joylyn Hoffman Malueg at (414) 221-4208.

DATED: August 1, 2024

Respectfully submitted,
MINNESOTA ENERGY RESOURCES CORPORATION

By: /s/ Joylyn C. Hoffman Malueg
Joylyn C. Hoffman Malueg
2685 145th Street West
Rosemount, MN 55068
Telephone: (414) 221-4208

ATTACHMENT C

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	**Chair**
Hwikwon Ham	**Commissioner**
Valerie Means	**Commissioner**
Joseph K. Sullivan	**Commissioner**
John A. Tuma	**Commissioner**

In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Change in Demand Entitlement for its Consolidated System	Docket No. G011/M-24-___

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

I. Introduction

Pursuant to Minnesota Rule 7825.2910, subpart 2 (Filing Upon Change in Demand), Minnesota Energy Resources Corporation - Consolidated (MERC or the Company), a subsidiary of WEC Energy Group, hereby petitions the Minnesota Public Utilities Commission (Commission) for approval of changes in demand entitlements for MERC-Consolidated customers served off Centra Pipeline, Viking Gas Transmission, and Great Lakes Gas Transmission (the "Consolidated" pipelines). MERC requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) beginning on November 1, 2024. Included with this filing are the following Attachments:

Attachment 1: Design-Day Demand Summary

Attachment 2: Sales Forecast

Attachment 3: Current and Proposed Entitlement Levels

Attachment 4: Rate Impact of the Proposed Demand Change

Attachment 5: Financial Option Summary

Attachment 6: Winter Plan

Attachment 7: Entitlement History

Attachment 8: Change in Entitlement Levels and Related Demand Costs

Attachment 9: Actual Throughput and Design-Day Forecast Estimated Throughput

Attachment 10: Customer Counts

Attachment 11: Hedging Summary

Attachment 12: Forecast Methodology

Through this filing, MERC also addresses compliance with Order Points 9 and 10 from the Commission's February 17, 2023 Order in Docket Nos. G999/CI-21-135 and G011/CI-21-611.[2]

II. Discussion

A. MERC's Consolidated Design-Day Requirements

Minnesota Rule 7825.2910, subpart 2(b) requires that a filing upon change in demand include the utility's Design-Day demand by customer class and the change in Design-Day demand, if any, necessitating the demand revision. The Consolidated Design-Day requirement has increased by 588 dekatherms (dth) since November 1, 2023. This represents a 1.03% increase in Design-Day requirement over the 2023-2024 heating season.

[2] Order Point 9 requires discussion of how changes to pipeline capacity affects the Company's supply diversity, and if pipeline capacity comes at a cost premium but increases supply diversity, provide a meaningful cost/benefit discussion of the tradeoff, including a comparison with the least-cost capacity option. Order Point 10 requires MERC to include in its relevant, annual forward-looking gas planning or hedging filings: A) its expected supply mix across different load and weather conditions throughout each month of the upcoming winter season, B) the forecasted minimum, average, and maximum day load requirements, and C) the expected mix of baseload, storage, and spot supply on those days.

Table 1: MERC Proposed Consolidated Reserve Margins For the 2023-2024 Heating Season			
	Reserve Margin 2024-2025 Heating Season	Reserve Margin 2023-2024 Heating Season	Change
Consolidated	11.59%	8.52%	3.07%

For the Demand Entitlement filing effective November 1, 2024, the total Design-Day requirement for MERC – Consolidated is 57,736 dth (Attachment 1). The difference between the total Design-Day requirement and total Design-Day capacity results in an 11.59% reserve margin (Attachment 3). As required by Order Point 9 of the Commission's Order in Docket No. G011/M-15-722, Attachment 3 reflects separate summer and winter demand entitlements for MERC-Consolidated.

B. Gas Supply

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

C. Forecast Methodology for MERC Demand Entitlement November 1, 2024

See Attachment 12.

III. Additional Filing Requirements

A. Daily Design-Day Estimate to Actual Comparison

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

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

includes interruptible and transportation volumes that are located behind MERC citygates. The Design-Day model only calculates firm volumes. MERC does not forecast on a daily/monthly basis utilizing the Design-Day model. The Design-Day model is utilized to calculate the theoretical peak day.

B. Average Customer Counts

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

C. Balancing

Order Point 4 of the Commission's January 21, 2015, Order in MERC's 2010-2011 demand entitlement dockets, Docket Nos. G007/M-10-1166; G007/M-10-1167; G011/M-10-1168; and G011/M-10-1169, required that in future demand entitlement filings, MERC provide a clarification of its statements regarding system balancing and detailed evidence assuring the Commission that the appropriate customer group is paying for any balancing charges or penalties. Additionally, in Docket No. G999/AA-12-756, by Order dated November 14, 2013, the Commission ordered that "prospectively, all regulated natural gas utilities shall recover balancing service costs, and shall credit the utility's penalty revenues and the pipeline's revenue credits, to the commodity portion of the PGA effective with the earliest true-up filing (for revenues) or the earliest monthly PGA (for costs) that can reasonably be implemented."

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

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

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

1. Design-Day Deliverability Changes

As shown in Attachment 3, MERC's Design-Day Deliverability increased by 2,410 dth/day as compared to 2023-2024. This is due to acquiring 2,202 dth of transportation capacity from Great Lakes Gas Transmission ("GLGT"), and updating volumes for the Centra Pipeline contract. The GLGT capacity was acquired to reliably meet the demand behind the GLGT gates. For 2024-25, the volume of the Centra Pipeline contract has been updated to 10,108 Dth/day to reflect the updated peak day estimate for the customers served by Centra Pipeline.

The Commission's February 17, 2023 Order in Docket Nos. G-999/CI-21-135 and G-011/CI-21-611 Requiring Actions to Mitigate Impacts from Future Natural Gas Price Spikes, Setting Filing Requirements, and Initiating a Proceeding to Establish Gas Resource Planning Requirements, requires in Order Point 9 that MERC discuss how changes to pipeline capacity affects the Company's supply diversity, and if pipeline capacity comes at a cost premium but increases supply diversity, provide a meaningful cost/benefit discussion of the tradeoff, including a comparison with the least-cost capacity option. The acquired incremental capacity discussed above did not impact MERC's supply diversity, as the Company increased its capacity with supply to be sourced at the Emerson GLGT supply basin for the volume change on GLGT, and at the Spruce supply basin for the volume change on Centra Pipeline. Further, no other pipeline alternatives are available for the demand being served from GLGT and Centra Pipeline, and Liquefied Natural Gas ("LNG") is not a viable operational or cost effective option for those parts of MERC's system. Therefore, acquiring the additional capacity via an Open Season that GLGT held in December of 2023 provided MERC the opportunity to maintain deliverability for its customers at GLGT's current tariff rates, which are expected to be much less costly than future pipeline expansions. GLGT's Open Season limited the receipt point of the capacity to only the Emerson location, therefore no other options were available. This capacity was awarded at GLGT's current tariff rate, therefore no pipeline demand cost premiums resulted from the capacity purchase. The small capacity increase on the Centra Pipeline was to reflect the updated peak day estimate for the customers served by Centra Pipeline and is a general request of the pipeline for the following year. There are no liquid, viable, alternative supply basins for the small amount of increased capacity, therefore all 10,108 dth/day are met with gas at the Spruce supply basin.

2. <u>Other Demand Entitlement Changes</u>

MERC continues to maintain its storage contracts with ANR Pipeline Storage, as detailed in previous demand entitlement filings and reflected in Attachments 4 (page 2 of 2), 7, and 8. MERC extended both of the ANR Pipeline contracts through March 31, 2028. Small changes to storage volumes and rates will occur to the ANR Storage contract each year as a result of annual fuel rate changes, as reflected in Attachments 4 (page 2 of 2), 7, and 8.

Additionally, MERC notes that Viking Gas Transmission filed a rate case in Docket No. RP23-917 with the Federal Energy Regulatory Commission ("FERC") on July 28, 2023. On August 31, 2023, FERC issued an Order suspending the implementation of Interim Rates by Viking Gas Transmission ("Viking") until February 1, 2024; Viking implemented Interim Rates on February 1, 2024. During February 2024, a settlement agreement was achieved, and on March 1, 2024, FERC issued an order granting Viking to implement Settlement Rates effective as of February 1, 2024 and stating that interim rates are subject to refund. Based on this timing, Viking was able to forego implementation of Interim Rates and implemented Settlement Rates effective February 1, 2024. Therefore no refunds were necessary nor conducted by Viking given that Interim Rates were never implemented. The Settlement Rates are reflected in the Company's demand rates in this filing..

E. Financial Option Units and Premiums

MERC has started its purchases of future contracts and call options for the 2024-2025 winter period. Financial hedge volumes and costs are shown in Attachments 5 and 11 (page 1 and 3). The physical forward start and call option premium costs additionally flow through the spreadsheet in Attachment 4, pages 1 and 2, and in Attachment 8.

In accordance with the Commission's April 9, 2021, Order in Docket No. G011/M-20-833 approving MERC's variance extension request to recover the costs of financial instruments through the PGA, MERC provides the following information:

i. a list of all financial instruments purchased for the upcoming heating season (see Attachment 11);
ii. the cost premium associated with each contract (see Attachment 5);
iii. the size (in dth) of each contract (see Attachments 5 and 11);
iv. the contract date (see Attachment 5);
v. the contract price (see Attachment 11);
vi. an attachment that details the projected total system sales estimates for the upcoming heating season, including all supporting data and assumptions used when calculating the sales forecast, and the total number of volumes hedged using financial instruments for the upcoming heating season (see Attachment 2 and Attachment 6, page 1 of 2); and
vii. a detailed discussion of the anticipated benefits to ratepayers related to MERC's financial instrument contracts, discussed below.

The Consolidated 2024-2025 Winter Portfolio Hedging Plans - Minnesota Energy Resources Corporation for Great Lakes Gas Transmission, Viking Gas Transmission, and Centra Pipeline gas supply purchases are shown on Attachment 6. MERC's hedging strategy covers up to 60% of normal winter volumes; up to 30% through physical storage; and 30% through financial instruments (10% futures and 20% options). The weighted average price of purchased futures contracts of natural gas for the 2024-2025 winter is $3.6461/dth. Please see Attachment 11, page 1 of 3. As shown in Attachment 11, page 2 of 3, MERC projects the ANR storage WACOG to be $2.1787/dth. While MERC still continues with its strategy to purchase call options around a $0.10/dth premium, the overall gas market volatility has pushed the strike price of the purchased call options up to an average of $7.1686/dth. Both the futures and option strike prices are up slightly from winter 2023-24. If the NYMEX contract(s) settle above that price, the options are exercised and the MERC customer gas cost is capped at the average strike price. Please see Attachment 11, page 3 of 3. The remaining winter volumes are purchased at index or market prices. All numbers reflected are natural gas costs only and do not include any transportation, storage, hedge premium, or margin costs.

The Commission's February 17, 2023 Order in Docket Nos. G-999/CI-21-135 and G-011/CI-21-611 Requiring Actions to Mitigate Impacts from Future Natural Gas Price Spikes, Setting Filing Requirements, and Initiating a Proceeding to Establish Gas Resource Planning Requirements, requires in Order Point 10 that MERC includes in its relevant, annual forward-looking gas planning or hedging filings: A) its expected supply mix across different load and weather conditions throughout each month of the upcoming winter season, B) the forecasted minimum, average, and maximum day load requirements, and C) the expected mix of baseload, storage, and spot supply on those days. Attachment 6, page 3, provides this information for the November 2024 through March 2025 period. All load estimates are based on the previous three years observed data, except for the December through February months, in which the Design

Day (i.e. Peak Day) was used to represent the maximum load. While three years of historical data provide a reasonable estimate, conditions can deviate and provide load requirements different from those in the past.

F. PGA Cost Recovery

MERC proposes to begin recovering the costs associated with the change in demand-related costs in its monthly PGA effective November 1, 2024. Rate impacts associated with this change can be found in Attachment 4.

G. Impacts of Telemetry

Throughout the course of the year, a number of customers request to switch from interruptible to firm service. MERC evaluates these requests to determine the impact to its system and upstream entitlement levels. MERC's process requires an evaluation of the system capability before a customer is allowed to switch to firm. As a result, the firm volumes associated with a customer switch fall within the Design-Day parameters and do not impact demand entitlement levels.

IV. Conclusion

MERC respectfully requests that the Commission approve the requested changes to be recovered in the Purchased Gas Adjustment (PGA) beginning November 1, 2024.

DATED: August 1, 2024

Respectfully submitted,

MINNESOTA ENERGY RESOURCES CORPORATION

By: /s/ Joylyn C. Hoffman Malueg
Joylyn C. Hoffman Malueg
2685 145th Street West
Rosemount, MN 55068
Telephone: (414) 221-4208

MINNESOTA ENERGY RESOURCES - Consolidated

DESIGN-DAY DEMAND SUMMARY

November 1, 2024

Consolidated

Design Day Requirement		57,736
Total Peak Day Entitlement		64,429
2023/24 Firm Peak Day Actual Sendout	1/15/2024	46,189
Firm Annual Throughput - Minnesota		5,345,764
No. of Firm Customers		37,898
Department Load Factor Calculation		31.71%

MINNESOTA ENERGY RESOURCES - Consolidated

CONSOLIDATED DESIGN DAY REQUIREMENTS

November 1, 2024

Consolidated

Pipeline Group	2023/24 Customer Count	1/20 Design DDD	Regression Factors Intercept	Slope	Regression Total	Regression Adjustment	1/20 Requirements Regression Load	Firm/Interruptible Contract Demand Units	Total
VGT									
Peak		109	423	124	16,834	1,024	17,858	7	17,866
Off Peak		57	423	124	9,467	1,024	10,491	7	10,499
GLGT									
Peak		105	732	222	28,898	1,296	30,194	51	30,245
Off Peak		57	732	222	16,167	1,296	17,463	51	17,514
Centra									
Peak		107	431	72	9,310	316	9,626	0	9,626
Off Peak		57	431	72	5,164	316	5,480	0	5,480
Total Consolidated									
Peak	37,898	107	1,585	418	55,042	2,636	57,678	58	57,736
Off Peak	37,898	57	1,585	418	30,798	2,636	33,434	58	33,492

MINNESOTA ENERGY RESOURCES - Consolidated

DESIGN-DAY DEMAND PER CUSTOMER
November 1, 2024
Consolidated

Heating Season	No. of Firm Customers	Design Day Requirements	MMBtu /Customer /Day
24/25	37,898	57,736	1.52
23/24	37,428	57,148	1.53
22/23	37,578	56,963	1.52
21/22	37,151	56,403	1.52
20/21	36,580	57,065	1.56
19/20	35,981	56,782	1.58
18/19	35,653	56,470	1.58
17/18	35,965	56,266	1.56
16/17	35,499	55,528	1.56
15/16	34,799	53,075	1.53
14/15	34,397	48,706	1.42
13/14	34,007	50,048	1.47
12/13	33,630	52,289	1.55
11/12	33,384	50,366	1.51

MINNESOTA ENERGY RESOURCES - Consolidated

SUMMER/WINTER USAGE - Dth
PROJECTED 12 MONTHS ENDING JUNE 2025

Consolidated

Class	Summer Apr-Oct	Winter Nov-Mar	Total
General Service	1,343,684	3,981,230	5,324,915
Interruptible	180,366	318,784	499,150
Firm/Interruptible	6,192	14,658	20,849
Total	1,530,242	4,314,672	5,844,914

MINNESOTA ENERGY RESOURCES - Consolidated

ENTITLEMENT LEVELS

November 1, 2024

Consolidated

		Summer			*April/October*			*Winter*		
Capacity Type		2023/24 MMBtu	Change MMBtu	Proposed MMBtu	2023/24 MMBtu	Change MMBtu	Proposed MMBtu	2023/24 MMBtu	Change MMBtu	Proposed MMBtu
FT Western Zone	FT19131	10,130	0	10,130	10,130	0	10,130	0	0	0
FT Western Zone	FT18528	7,600	0	7,600	7,600	0	7,600	7,600	0	7,600
FT Western Zone (5)	FT18528 (5)	0	0	0	0	0	0	3,728	0	3,728
FT Western Zone (5)	FT19129 (5)	0	0	0	0	0	0	20,000	0	20,000
ANR (5) *	130504	0	0	0	0	0	0	20,000	0	20,000
FT Western to Easter Zone	22657	0	2,202	2,202	0	2,202	2,202	0	2,202	2,202
FT-A ZONE 1 - 1	AF0012/AF0537	18,193	0	18,193	18,193	0	18,193	19,291	0	19,291
FT-A ZONE 1 - 1	AF0321	0	0	0	0	0	0	1,500	0	1,500
FT-A ZONE 1 - 1	AF0321	0	0	0	0	0	0	0	0	0
CENTRA FT-1		9,900	208	10,108	9,900	208	10,108	9,900	208	10,108
Total Entitlement		45,823	2,410	48,233	45,823	2,410	48,233	62,019	2,410	64,429
Forecasted Design Day-Adjusted					32,639	853	33,492	57,148	588	57,736
Forecasted Design Day + 5% Reserve								60,006		60,623
Capacity Surplus/Shortage to Design Day					13,184	1,557	14,741	4,871	1,822	6,693
Capacity Surplus/Shortage to Design Day + 5% Reserve								2,013		3,806
Reserve Margin					40.39%	3.62%	44.01%	8.52%	3.07%	11.59%

* This upstream contract does not contribute to peak day deliverability

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

RATE IMPACT OF THE PROPOSED DEMAND CHANGE
November 1, 2024
Consolidated

All costs in $/Dth	Base Cost of Gas G011/MR-22-505 Mar 1, 2024	Demand Charge Demand Filing Nov 1, 2023	Most Recent PGA July 1, 2024	Proposed Effective Nov 1, 2024	Result of Proposed Change: Change from Last Rate Case	Change from Nov 1, 2023 Demand Filing	Change from Last PGA %	Change from Last PGA $
1) General Service Residential Avg. Annual Use:			**86**	**Dth**				
Commodity Cost	$3.9880	$3.1487	$1.0027	$0.9706	-75.66%	-69.17%	-3.20%	($0.0321)
Demand Cost	$0.7380	$0.7802	$0.8402	$0.8883	20.36%	13.85%	5.72%	$0.0481
Commodity Margin	$3.2919	$3.2788	$3.2919	$3.2919	0.00%	0.40%	0.00%	$0.0000
Total Cost of Gas	$8.0179	$7.2077	$5.1348	$5.1508	-35.76%	-28.54%	0.31%	$0.0160
Avg Annual Cost	$691.94	$622.03	$443.13	$444.51	-35.76%	-28.54%	0.31%	$1.38
Effect of proposed commodity change on average annual bills:								($2.77)
Effect of proposed demand change on average annual bills:								$4.15
2) Small C&I Firm, Class 2: Avg. Annual Use:			**694**	**Dth**				
Commodity Cost	$3.9880	$3.1487	$1.0027	$0.9706	-75.66%	-69.17%	-3.20%	($0.0321)
Demand Cost	$0.7380	$0.7802	$0.8402	$0.8883	20.36%	13.85%	5.72%	$0.0481
Commodity Margin	$2.5030	$2.2389	$2.5030	$2.5030	0.00%	11.80%	0.00%	$0.0000
Total Cost of Gas	$7.2290	$6.1678	$4.3459	$4.3619	-39.66%	-29.28%	0.37%	$0.0160
Avg Annual Cost	$5,018.37	$4,281.69	$3,016.92	$3,028.03	-39.66%	-29.28%	0.37%	$11.11
Effect of proposed commodity change on average annual bills:								($22.27)
Effect of proposed demand change on average annual bills:								$33.38
3) Small C&I Interruptible, Class 2: Avg. Annual Use:			**3,586**	**Dth**				
Commodity Cost	$3.9880	$3.1487	$1.0027	$0.9706	-75.66%	-69.17%	-3.20%	($0.0321)
Commodity Margin	$1.5047	$1.3884	$1.5047	$1.5047	0.00%	8.38%	0.00%	$0.0000
Total Cost of Gas	$5.4927	$4.5371	$2.5074	$2.4753	-54.93%	-45.44%	-1.28%	($0.0321)
Avg Annual Cost	$19,698.47	$16,271.31	$8,992.29	$8,877.24	-54.93%	-45.44%	-1.28%	($115.05)
Effect of proposed commodity change on average annual bills:								($115.05)
4) Large C&I Interruptible, Class 3: Avg. Annual Use:			**17,572**	**Dth**				
Commodity Cost	$3.9880	$3.1487	$1.0027	$0.9706	-75.66%	-69.17%	-3.20%	($0.0321)
Commodity Margin	$1.2058	$1.2555	$1.2058	$1.2058	0.00%	-3.96%	0.00%	$0.0000
Total Cost of Gas	$5.1938	$4.4042	$2.2085	$2.1764	-58.10%	-50.58%	-1.45%	($0.0321)
Avg Annual Cost	$91,267.53	$77,391.92	$38,808.65	$38,244.91	-58.10%	-50.58%	-1.45%	($563.74)
Effect of proposed commodity change on average annual bills:								($563.74)

Note: Average Annual Use based on 2023 MERC Gas Rate Design in Docket GR-22-504
Note: Rates do not include the ACA adjustment.

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

RATE IMPACT OF THE PROPOSED DEMAND CHANGE

November 1, 2024

Consolidated

A. ANNUAL SALES -- As approved in Docket No. G011/MR-22-505

Total MERC Consolidated Annual Sales	60,042,105
Total MERC Consolidated Firm Sales	54,005,358

B. MERC-Consolidated'S CURRENT COST OF GAS EFFECTIVE: **01-Nov-24**

1. Consolidated-GS

	Contract #(s)	Season	Monthly Entitlements (Dth)	Months	Rate $/Dth		Contract Costs	Total MERC Consolidated Firm Sales	Rate/Therm
<u>Viking (VGT)</u>									
FT-A ZONE 1 - 1	AF0012/AF0537	Annual	18,193	12	$ 5.6200	=	$1,226,936	54,005,358	$ 0.02272
FT-A ZONE 1 - 1	AF0012	Winter	1,098	3	$ 5.6200	=	$18,512	54,005,358	$ 0.00034
FT-A ZONE 1 - 1	AF0321	Winter	1,500	3	$ 5.6200	=	$25,290	54,005,358	$ 0.00047
(a) VGT Demand							$1,270,738		$ 0.02353
<u>Great Lakes (GLGT)</u>									
FT Western Zone	FT19131	Summer	10,130	7	$ 2.7540	=	$195,286	54,005,358	$ 0.00362
FT Western Zone	FT18528	Annual	7,600	12	$ 2.7540	=	$251,165	54,005,358	$ 0.00465
FT Western Zone	FT18528 (5)	Winter	3,728	5	$ 2.7540	=	$51,335	54,005,358	$ 0.00095
FT Eastern to Western Zone	FT19129 (5)	Winter	20,000	5	$ 6.1000	=	$610,000	54,005,358	$ 0.01130
ANR Upstream	130504	Winter	20,000	5	$ 0.9110	=	$91,100	54,005,358	$ 0.00169
FT Western to Eastern Zone	22657	Annual	2,202	12	$ 8.1860	=	$216,307	54,005,358	$ 0.00401
(b) GLGT Demand							$1,415,193		$ 0.02620
<u>Centra</u>									
CENTRA TRANSMISSION		Annual	10,108	12	$ 14.1070	=	$1,711,123	54,005,358	$ 0.03168
CENTRA MINNESOTA PIPELINES		Annual	10,108	12	$ 3.2990	=	$400,156	54,005,358	$ 0.00741
(c) Centra Demand							$2,111,279		$ 0.03909
Total Demand Cost **(I.e. Sum of Costs from Sections B. 1. (a), (b), and (c))**							$4,797,210		**$ 0.08883**

Consolidated-GS Demand Current Cost of Gas/therm	**$ 0.08883**
Consolidated-GS Commodity Current Cost of Gas/therm	**$ 0.09706**
Total Consolidated-GS Current Cost of Gas/therm	**$ 0.18589**

2. Consolidated - General Service, Interruptible, Firm/Interruptible - Commodity

	Season	Monthly Entitlement (Dth)	Months	Rate ($/Dth)		Contract Costs	Total MERC Consolidated Annual Sales	Rate ($/therm)
ANR Storage	Annual	83,633	12	$ 0.7300	=	$732,628	60,042,105	$ 0.01220
(a) Firm Deferred Delivery Storage Contracts						$732,628		$ 0.01220

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.

		Season	Annual Sales (Dth)		Rate ($/Dth)	Commodity Cost	Rate Case Sales (therm)	Rate ($/therm)
(b) Remaining Costs to be Reovered via Commodity	Commodity		6,004,211	x	$0.7999	$4,802,948	60,042,105	$ 0.07999
	Viking Balancing	Annual	89,580	x	$1.0000	$89,580	60,042,105	$ 0.00149
	Centra Balancing	Annual	120,000	x	$0.4500	$54,000	60,042,105	$ 0.00090
	Physical Forward Start Premium					$122,160	60,042,105	$ 0.00203
	Call Option Premium					$26,791	60,042,105	$ 0.00045
(c) Consolidated-General Service, Interruptible, Firm/Interruptible: Total Commodity Current Cost of Gas/therm **(I.e. Sum of Costs from Sections B. 2. (a) and (b))**						$5,828,107		**$ 0.09706**

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

Financial Options

Heating Season 2024-2025

Units - Gas Daily Peaker Packages (Physical)

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

Premium - Gas Daily Peaker (Monthly Cost)

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

Units - Futures (Dth)

	November		December		January		February		March		
	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Term Total
1	05/23/24	378	05/22/24	558	05/20/24	458	05/17/24	500	05/15/24	339	67,415
2	06/24/24	324	06/18/24	502	05/20/24	51	06/07/24	400	06/03/24	339	48,602
3	01/00/00	-	01/00/00	-	06/13/24	509	01/00/00	-	01/00/00	-	15,678
4	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
5	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
6	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
7	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
8	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
9	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
10	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
Total		703		1,061		1,019		900		677	131,695

Units - Call Options (Dth)

	November		December		January		February		March		
	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Contract Date	Daily Volume	Term Total
1	05/15/24	798	05/17/24	995	05/20/24	528	05/22/24	945	05/23/24	677	118,654
2	06/03/24	741	06/07/24	995	05/22/24	581	06/18/24	945	06/24/24	677	118,582
3	01/00/00	-	01/00/00	-	06/13/24	528	01/00/00	-	01/00/00	-	16,379
4	01/00/00	-	01/00/00	-	06/18/24	476	01/00/00	-	01/00/00	-	14,741
5	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
6	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
7	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
8	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
9	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
10	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
11	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
12	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	01/00/00	-	-
Total		1,539		1,991		2,113		1,891		1,355	268,357

Premium - Call Option (Monthly Cost)

	November		December		January		February		March		Total	
	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost	Option Premium	Premium Cost
1	$ 0.1000	$ 2,395	$ 0.1000	$ 3,086	$ 0.1000	$ 1,638	$ 0.1000	$ 2,647	$ 0.1000	$ 2,100	$ 0.1000	$ 11,865
2	$ 0.0980	$ 2,179	$ 0.1000	$ 3,086	$ 0.1000	$ 1,802	$ 0.1000	$ 2,647	$ 0.1000	$ 2,100	$ 0.0996	$ 11,814
3	$ -	$ -	$ -	$ -	$ 0.1000	$ 1,638	$ -	$ -	$ 0.1000	$ -	$ 0.1000	$ 1,638
4	$ -	$ -	$ -	$ -	$ 0.1000	$ 1,474	$ -	$ -	$ 0.1000	$ -	$ 0.1000	$ 1,474
5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.1000	$ -	#DIV/0!	$ -
6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.1000	$ -	#DIV/0!	$ -
7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	#DIV/0!	$ -
8					$ -	$ -	$ -	$ -			#DIV/0!	$ -
9					$ -	$ -	$ -	$ -			#DIV/0!	$ -
10					$ -	$ -	$ -	$ -			#DIV/0!	$ -
11					$ -	$ -	$ -	$ -				$ -
12					$ -	$ -	$ -	$ -	$ -	-		$ -
Total	$ 0.0990	$ 4,574	$ 0.1000	$ 6,171	$ 0.1000	$ 6,552	$ 0.1000	$ 5,294	$ 0.1000	$ 4,200	$ 0.0998	$ 26,791

Units - Collar Floor (put)

No Puts were purchased.

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

24/25 Winter Portfolio Plan - MERC Hedging Plan

		Nov-24		Dec-24		Jan-25		Feb-25		Mar-25		Total		Percent
	Purchase	Number	Contract	Number	Contract	Number	Contract	Number	Contract	Number	Contract	Number	Contract	of
System	Month	Contracts	Volume	Contracts	Volume	Contracts	Volume	Contracts	Volume	Contracts	Volume	Contracts	Volume	Requirements
MN Requirements			682,510		933,165		981,091		762,224		636,897		3,995,888	3,995,888
Daily Average			22,750		30,102		31,648		27,222		20,545		132,268	
10%	Futures		68,251		93,316		98,109		76,222		63,690		399,589	
20%	Call		136,502		186,633		196,218		152,445		127,379		799,178	
30%	Storage		204,753		279,949		294,327		228,667		191,069		1,198,766	
40%	Index		477,757		653,215		686,764		533,557		445,828		2,797,122	
Futures														
Contracts	May-24	1	10,000	2	20,000	2	20,000	2	20,000	1	10,000	8	80,000	
	Jun-24	1	10,000	2	20,000	2	20,000	1	10,000	1	10,000	7	70,000	
	Jul-24	1	10,000	2	20,000	2	20,000	1	10,000	1	10,000	7	70,000	
	Aug-24	1	10,000	1	10,000	1	10,000	1	10,000	1	10,000	5	50,000	
	Sep-24	1	10,000	1	10,000	1	10,000	1	10,000	1	10,000	5	50,000	
	Oct-24	1	10,000	1	10,000	1	10,000	1	10,000	1	10,000	5	50,000	
	Total	**6**	**60,000**	**9**	**90,000**	**9**	**90,000**	**7**	**70,000**	**6**	**60,000**	**37**	**370,000**	**9.26%**
Call Options	May-24	3	30,000	3	30,000	4	40,000	3	30,000	2	20,000	15	150,000	
	Jun-24	2	20,000	3	30,000	3	30,000	3	30,000	2	20,000	13	130,000	
	Jul-24	2	20,000	3	30,000	3	30,000	3	30,000	2	20,000	13	130,000	
	Aug-24	2	20,000	3	30,000	3	30,000	2	20,000	2	20,000	12	120,000	
	Sep-24	2	20,000	3	30,000	3	30,000	2	20,000	2	20,000	12	120,000	
	Oct-24	2	20,000	3	30,000	3	30,000	2	20,000	2	20,000	12	120,000	
	Total	**13**	**130,000**	**18**	**180,000**	**19**	**190,000**	**15**	**150,000**	**12**	**120,000**	**77**	**770,000**	**19.27%**
Collars	May-24	0	0	0	0	0	0	0	0	0	0	0	0	
	Jun-24	0	0	0	0	0	0	0	0	0	0	0	0	
	Jul-24	0	0	0	0	0	0	0	0	0	0	0	0	
	Aug-24	0	0	0	0	0	0	0	0	0	0	0	0	
	Sep-24	0	0	0	0	0	0	0	0	0	0	0	0	
	Oct-24	0	0	0	0	0	0	0	0	0	0	0	0	
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.00%**
Index (back financial)														
	Total		**190,000**		**270,000**		**280,000**		**220,000**		**180,000**		**1,140,000**	**28.53%**
Physical Hedges			**0**		**0**		**0**		**0**		**0**		**0**	
Storage			90,000		248,000		279,000		196,000		89,900		902,900	**22.60%**
Prepaid Obl			0		0		0		0		0		0	**0.00%**
			41.03%		55.51%		56.98%		54.58%		42.38%		51.13%	**51.13%**
Term Index	Aug-24	0	0	0	0	0	0	0	0	0	0		0	**0.00%**
	Sep-24	0	0	0	0	0	0	0	0	0	0		0	**0.00%**
	Oct-24	0	0	0	0	0	0	0	0	0	0		0	**0.00%**
Total MN														
Contracts													370,000	**9.26%**
Call Options													770,000	**19.27%**
Costing Collar													0	**0.00%**
Storage													902,900	**22.60%**
Prepaid Obl													0	**0.00%**
Term Index													0	**0.00%**
Month/Daily													1,952,988	**48.87%**
Total													3,995,888	**100.00%**

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

CONSOLIDATED - WINTER PLAN
NOVEMBER 2024 THROUGH MARCH 2025

PHYSICAL FIXED PRICE HEDGES	Deal #	Trigger Locked	Trigger Exercised	Receipt Point	Nov	Dec	Jan (Daily Volumes)	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
	123862	5/15/2024	VGT Emerson 1	7,500	7,500	7,500	7,500	7,500	1,140,000
	123877	5/15/2024	VGT Emerson 1	-	5,365	5,365	5,365	-	488,215
	123886	5/15/2024	CTHI-Spruce	4,000	4,000	4,000	4,000	4,000	608,000
	123887	5/15/2024	CTHI-Spruce	-	3,000	3,000	3,000	-	273,000
	123891	5/15/2024	GLGT Emerson 2	7,500	7,500	7,500	7,500	7,500	1,140,000
	123892	5/15/2024	GLGT Emerson 2	-	2,745	2,745	2,745	-	249,795
	Total Actual Seasonal Index			19,000	30,110	30,110	30,110	19,000	3,899,010
GAS DAILY PACKAGES									
Physical Call Option	123885	5/15/2024	VGT Emerson 1	-	5,000	5,000	5,000	-	
Physical Call Option	123889	5/15/2024	CTHI-Spruce	1,200	1,200	1,200	1,200	1,200	
Physical Call Option	123890	5/15/2024	CTHI-Spruce	-	1,700	1,700	1,700	-	

STORAGE

Injection Month	ANR Volume Injected	Total Volume Injected
May - balance forward	905,076	905,076
June	0	0
July	0	0
August	0	0
Sept	0	0
Oct	0	0
Total	**905,076**	**905,076**

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

CONSOLIDATED WINTER PLAN - SUPPLY MIX
NOVEMBER 2024 THROUGH MARCH 2025

Monthly vs. Daily Pricing	Term Deal Type	Index Location	Receipt Point	Nov	Dec	Jan	Feb	Mar
Monthly Index	Baseload	Nymex LDS	VGT Emerson 1	7,500	7,500	7,500	7,500	7,500
Monthly Index	Baseload	Nymex LDS	VGT Emerson 1	-	5,365	5,365	5,365	-
Monthly Index	Baseload	Nymex LDS	VGT Emerson 1	-	-	-	-	-
Monthly Index	Baseload	Nymex LDS	CTHI-Spruce	4,000	4,000	4,000	4,000	4,000
Monthly Index	Baseload	Nymex LDS	CTHI-Spruce	-	3,000	3,000	3,000	-
Monthly Index	Baseload	Nymex LDS	GLGT Emerson 2	7,500	7,500	7,500	7,500	7,500
Monthly Index	Baseload	Nymex LDS	GLGT Emerson 2	-	2,745	2,745	2,745	-
Daily Index	Call/Swing	Emerson	VGT Emerson 1	-	5,000	5,000	5,000	-
Daily Index	Call/Swing	Emerson	CTHI-Spruce	1,200	1,200	1,200	1,200	1,200
Daily Index	Call/Swing	Emerson	CTHI-Spruce	-	1,700	1,700	1,700	-
			TOTAL BASELOAD	**19,000**	**30,110**	**30,110**	**30,110**	**19,000**
			TOTAL CALL/SWING (MONTH INDEX)	**-**	**-**	**-**	**-**	**-**
			TOTAL CALL/SWING (DAILY INDEX)	**1,200**	**7,900**	**7,900**	**7,900**	**1,200**
			TOTAL STORAGE WITHDRAWAL	**20,072**	**20,072**	**20,072**	**20,072**	**20,072**

SUPPLY MIX - MAX DAY	Nov	Dec	Jan	Feb	Mar
DEMAND	**46,580**	**57,736**	**57,736**	**57,736**	**49,967**
BASELOAD	19,000	30,110	30,110	30,110	19,000
CALL/SWING	1,200	7,554	7,554	7,554	1,200
STORAGE WITHDRAWAL	20,072	20,072	20,072	20,072	20,072
SPOT SUPPLY (DAILY PURCHASE)	6,308	0	0	0	9,695
TOTAL SUPPLY	**46,580**	**57,736**	**57,736**	**57,736**	**49,967**
% MONTHLY PRICE	41%	52%	52%	52%	38%
% DAILY PRICE	0%	13%	13%	13%	22%
% STORAGE WACOG	43%	35%	35%	35%	40%

SUPPLY MIX - AVERAGE DAY	Nov	Dec	Jan	Feb	Mar
DEMAND	**21,714**	**30,337**	**34,937**	**32,472**	**26,665**
BASELOAD	19,000	30,110	30,110	30,110	19,000
CALL/SWING	-	-	-	-	-
STORAGE WITHDRAWAL	2,714	227	4,827	2,362	7,665
SPOT SUPPLY (DAILY PURCHASE)	-	-	-	-	-
TOTAL SUPPLY	**21,714**	**30,337**	**34,937**	**32,472**	**26,665**
% MONTHLY PRICE	100%	99%	86%	93%	71%
% DAILY PRICE	0%	0%	0%	0%	0%
% STORAGE WACOG	12%	1%	14%	7%	29%

SUPPLY MIX - MINIMUM DAY	Nov	Dec	Jan	Feb	Mar
DEMAND	**3,001**	**3,001**	**14,693**	**11,193**	**4,336**
BASELOAD	19,000	30,110	30,110	30,110	19,000
CALL/SWING	-	-	-	-	-
STORAGE WITHDRAWAL	-	-	-	-	-
SPOT SUPPLY (DAILY PURCHASE)	-	-	-	-	-
IMBALANCE ACCOUNT (-)	(950)	(1,506)	(1,506)	(1,506)	(950)
STORAGE INJECT (-)	-	-	-	-	-
REMAINING SUPPLY (LONG GAS)	15,049	25,604	13,912	17,412	13,714
% MONTHLY PRICE	100%	100%	100%	100%	100%
% DAILY PRICE	0%	0%	0%	0%	0%
% STORAGE WACOG	0%	0%	0%	0%	0%

Attachment 7

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

	2020-2021 Consolidated	2021-2022 Consolidated	2022-2023 Consolidated	2023-2024 Consolidated	2024-2025 Consolidated	Proposed Change
Viking Gas Transmission (VGT)						
FT-A ZONE 1 - 1	15,093	15,093	15,093	18,193	18,193	0
FT-A ZONE 1 - 1 Winter Only	1,098	1,098	1,098	1,098	1,098	0
FA-A ZONE 1 - 1 Winter Only	1,500	1,500	1,500	1,500	1,500	0
FA-A ZONE 1 - 1 Winter Only	0	0	1,100	0	0	0
Great Lakes Gas Transmission (GLGT)						
FT Western Zone- Summer Only	10,130	10,130	10,130	10,130	10,130	0
FT Western Zone- Annual	12,600	12,600	7,600	7,600	7,600	0
FT Western Zone- Winter Only	3,728	3,728	3,728	3,728	3,728	0
FT Western Zone- Winter Only	15,030	15,030	20,000	20,000	20,000	0
ANR Upstream	15,000	15,000	20,000	20,000	20,000	0
FT Western to Eastern Zone	0	0	0	0	2,202	2,202
Centra Transmission Holding/Centra Minnesota Pipelines (CTHI/CPMI)						
Centra FT-1	9,600	9,800	9,900	9,900	10,108	208
Total VGT Transportation	17,691	17,691	18,791	20,791	20,791	0
Total GLGT Transportation	31,358	31,358	31,328	31,328	31,328	0
Total CTHI/CPMI Transportation	9,600	9,800	9,900	9,900	10,108	208
Total Transportation	58,649	58,849	60,019	62,019	62,227	208
Total Seasonal Transportation	11,226	11,226	16,196	16,196	16,196	0
Total Seasonal Transportation %	19.14%	19.08%	26.98%	26.11%	26.03%	-0.09%
Other Entitlements not included in Peak Day Deliverability						
AECO Storage	0	0	0	0	0	0
AECO/Emerson Swap	0	0	0	0	0	0
ANR Storage	756,100	756,100	1,004,300	1,006,350	1,003,600	-2,750

Attachment 8

MINNESOTA ENERGY RESOURCES - CONSOLIDATED

Change in Costs due to November 1, 2024 Change in Entitlement Levels and Related Demand Costs

	2023/24 Entitlements	2024/25 Entitlements	Entitlement Change	2024/25 Rate	Months	2023/24 Total Annual Cost	2024/25 Total Annual Cost	Total Annual Cost Change
Costs Assigned in Demand Charge								
Viking Pipeline								
FT-A ZONE 1 - 1 - AF0012/AF0537	18,193	18,193	0	$ 5.6200	12	$830,911	$1,226,936	$396,025
FT-A ZONE 1 - 1 - AF0012	1,098	1,098	0	$ 5.6200	3	$12,537	$18,512	$5,975
FT-A ZONE 1 - 1 - AF0321	1,500	1,500	0	$ 5.6200	3	$17,127	$25,290	$8,163
						$0		
GLGTPipeline								
FT Western Zone - FT19131	10,130	10,130	0	$ 2.7540	7	$195,286	$195,286	$0
FT Western Zone - FT18528	7,600	7,600	0	$ 2.7540	12	$251,165	$251,165	$0
FT Western Zone - FT18528 (5)	3,728	3,728	0	$ 2.7540	5	$51,335	$51,335	$0
FT Eastern to Western Zone - FT19129 (5)	20,000	20,000	0	$ 6.1000	5	$610,000	$610,000	$0
ANR Upstream - 130504	20,000	20,000	0	$ 0.9110	5	$91,100	$91,100	$0
FT Western to Eastern Zone - 22657	0	2,202	2,202	$ 8.1860	12	$0	$216,307	$216,307
CENTRA Pipeline								
CENTRA TRANSMISSION	9,900	10,108	208	$ 14.1070	12	$1,675,912	$1,711,123	$35,211
CENTRA MINNESOTA PIPELINES	9,900	10,108	208	$ 3.2990	12	$391,921	$400,156	$8,235
Total Costs Assigned to Demand Charge						**$4,127,294**	**$4,797,210**	**$669,916**
Costs Assigned in Commodity Charge								
Storage Service								
Open	0	0	0	$ -	0	$0	$0	$0
Open	0	0	0	$ -	0	$0	$0	$0
ANR Storage	1,006,350	1,003,600	-2,750	$ 0.7300	12	$735,478	$732,628	-$2,850
Balancing								
VGT Balancing Agreement	7,465	7,465	0	$ 1.0000	12	$89,580	$89,580	$0
Union Balancing	10,000	10,000	0	$ 0.4500	12	$54,000	$54,000	$0
Physical Forward Start Premium						$254,156	$122,160	-$131,996
Call Options Premium						$84,499	$26,791	-$57,708
Total Costs Assigned to Commodity Charge						**$1,217,713**	**$1,025,159**	**-$192,554**

Attachment 9

MINNESOTA ENERGY RESOURCES - Consolidated

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
Consolidated

Design Day:	
Base	1,585
Variable	418

Date	38.14% Bemidji Adjusted HDD	23.16% Cloquet Adjusted HDD	14.84% Fargo Adjusted HDD	23.86% Intl. Falls Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Firm Through-Put **
7/1/23	0	0	0	0	0	18,920	**1,585**
7/2/23	0	0	0	0	0	19,873	**1,585**
7/3/23	0	0	0	0	0	20,922	**1,585**
7/4/23	4	0	0	1	2	19,007	**2,285**
7/5/23	14	8	5	14	11	23,042	**6,386**
7/6/23	1	2	0	1	1	21,975	**2,013**
7/7/23	8	0	1	7	5	20,826	**3,682**
7/8/23	2	5	0	4	3	19,245	**2,654**
7/9/23	0	0	0	1	0	19,997	**1,639**
7/10/23	9	7	3	10	8	29,113	**4,963**
7/11/23	11	5	4	8	8	28,697	**4,926**
7/12/23	5	4	0	4	4	25,648	**3,206**
7/13/23	1	0	0	2	1	26,165	**1,827**
7/14/23	1	0	0	0	0	19,801	**1,759**
7/15/23	5	5	0	10	5	17,650	**3,834**
7/16/23	6	3	2	5	5	17,722	**3,552**
7/17/23	7	4	1	3	4	20,893	**3,463**
7/18/23	0	1	0	1	0	20,407	**1,688**
7/19/23	0	4	0	0	1	19,159	**1,940**
7/20/23	1	0	0	0	0	17,795	**1,670**
7/21/23	0	0	0	0	0	13,229	**1,585**
7/22/23	0	0	0	0	0	12,698	**1,585**
7/23/23	0	0	0	5	1	14,163	**2,044**
7/24/23	0	0	0	0	0	19,686	**1,585**
7/25/23	0	0	0	0	0	22,479	**1,585**
7/26/23	0	0	0	0	0	23,716	**1,585**
7/27/23	0	0	0	0	0	18,761	**1,585**
7/28/23	0	1	0	3	1	19,918	**1,901**
7/29/23	7	5	0	6	5	20,656	**3,769**
7/30/23	4	3	0	2	2	22,425	**2,621**
7/31/23	0	0	0	2	0	27,434	**1,740**
8/1/23	0	0	0	0	0	27,622	**1,585**
8/2/23	0	0	0	0	0	27,387	**1,585**
8/3/23	0	0	0	0	0	26,687	**1,585**
8/4/23	0	0	0	0	0	19,412	**1,585**
8/5/23	0	0	0	0	0	18,071	**1,585**
8/6/23	1	0	0	0	0	21,430	**1,670**

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Date	38.14% Bemidji Adjusted HDD	23.16% Cloquet Adjusted HDD	14.84% Fargo Adjusted HDD	23.86% Intl. Falls Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Firm Through-Put **
8/7/23	0	0	0	1	0	23,524	**1,689**
8/8/23	0	0	0	2	0	25,424	**1,740**
8/9/23	6	5	0	7	5	24,326	**3,671**
8/10/23	0	0	1	3	1	26,339	**1,971**
8/11/23	2	2	0	3	2	18,046	**2,338**
8/12/23	6	2	0	3	3	12,909	**3,038**
8/13/23	7	2	2	7	5	13,038	**3,734**
8/14/23	0	6	0	2	2	18,838	**2,398**
8/15/23	0	0	0	0	0	20,249	**1,585**
8/16/23	0	0	0	0	0	20,053	**1,585**
8/17/23	4	7	0	9	5	20,131	**3,769**
8/18/23	0	0	0	0	0	14,009	**1,585**
8/19/23	0	0	0	0	0	12,012	**1,585**
8/20/23	5	0	1	3	3	14,023	**2,713**
8/21/23	3	2	0	5	3	20,958	**2,718**
8/22/23	0	3	0	4	2	23,031	**2,334**
8/23/23	0	4	0	1	1	24,722	**1,999**
8/24/23	0	0	0	0	0	23,838	**1,585**
8/25/23	0	0	0	1	0	16,756	**1,640**
8/26/23	4	14	0	11	8	15,600	**4,722**
8/27/23	4	6	0	2	4	16,122	**3,049**
8/28/23	0	0	0	2	0	21,913	**1,741**
8/29/23	4	5	0	9	5	25,217	**3,694**
8/30/23	0	3	0	1	1	22,881	**1,884**
8/31/23	0	0	0	0	0	20,297	**1,585**
9/1/23	0	0	0	0	0	15,242	**1,585**
9/2/23	0	0	0	0	0	14,061	**1,585**
9/3/23	0	0	0	0	0	20,913	**1,585**
9/4/23	0	0	0	0	0	20,186	**1,585**
9/5/23	1	0	5	0	1	23,456	**1,963**
9/6/23	19	10	8	12	14	26,829	**7,235**
9/7/23	9	14	0	15	10	23,245	**5,860**
9/8/23	1	8	0	3	3	18,420	**2,718**
9/9/23	10	3	3	10	7	17,370	**4,514**
9/10/23	6	8	0	5	5	20,807	**3,846**
9/11/23	11	8	9	13	10	25,808	**5,907**
9/12/23	18	22	8	22	18	28,192	**9,289**
9/13/23	10	16	2	16	12	29,665	**6,459**

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Date	38.14% Bemidji Adjusted HDD	23.16% Cloquet Adjusted HDD	14.84% Fargo Adjusted HDD	23.86% Intl. Falls Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Firm Through-Put **
9/14/23	5	4	1	7	4	27,575	**3,455**
9/15/23	5	5	1	11	6	25,670	**3,927**
9/16/23	15	12	12	14	13	21,967	**7,147**
9/17/23	8	9	3	12	9	21,640	**5,200**
9/18/23	1	7	0	5	3	24,864	**2,933**
9/19/23	0	6	0	2	2	24,633	**2,410**
9/20/23	0	0	0	0	0	23,572	**1,585**
9/21/23	0	0	0	0	0	26,241	**1,585**
9/22/23	0	3	0	3	1	21,029	**2,175**
9/23/23	5	7	0	5	5	18,728	**3,487**
9/24/23	6	8	3	7	6	17,137	**4,211**
9/25/23	10	9	2	6	8	24,620	**4,759**
9/26/23	4	4	0	8	4	23,062	**3,348**
9/27/23	5	5	0	8	5	23,548	**3,761**
9/28/23	3	6	0	3	3	22,868	**2,857**
9/29/23	8	5	0	11	7	19,739	**4,394**
9/30/23	4	3	0	2	2	21,051	**2,620**
10/1/23	0	3	0	0	1	18,352	**1,841**
10/2/23	0	0	0	0	0	22,798	**1,585**
10/3/23	0	0	0	0	0	22,275	**1,585**
10/4/23	15	11	6	13	12	26,338	**6,802**
10/5/23	22	16	16	19	19	28,669	**9,561**
10/6/23	24	24	23	26	24	28,658	**11,671**
10/7/23	27	24	21	24	25	26,984	**11,845**
10/8/23	25	25	16	26	24	27,677	**11,573**
10/9/23	29	24	23	25	26	33,552	**12,375**
10/10/23	23	23	20	23	22	33,218	**10,963**
10/11/23	26	26	16	25	24	36,475	**11,645**
10/12/23	19	18	12	19	18	39,085	**8,923**
10/13/23	22	21	22	19	21	38,248	**10,411**
10/14/23	27	23	20	27	25	36,575	**12,139**
10/15/23	23	20	19	22	21	32,141	**10,431**
10/16/23	21	30	15	21	22	43,726	**10,858**
10/17/23	16	18	7	16	15	36,495	**7,819**
10/18/23	16	17	14	15	16	37,376	**8,137**
10/19/23	21	19	11	18	18	37,210	**9,278**
10/20/23	11	17	7	14	12	30,093	**6,716**
10/21/23	17	17	13	19	17	29,409	**8,648**

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Date	38.14% Bemidji Adjusted HDD	23.16% Cloquet Adjusted HDD	14.84% Fargo Adjusted HDD	23.86% Intl. Falls Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Firm Through-Put **
10/22/23	15	16	12	16	15	30,465	**7,837**
10/23/23	13	14	14	14	14	35,222	**7,322**
10/24/23	23	16	25	25	22	40,723	**10,730**
10/25/23	23	21	23	24	23	40,717	**11,120**
10/26/23	30	24	34	31	29	44,883	**13,908**
10/27/23	44	35	47	41	41	45,639	**18,910**
10/28/23	46	43	45	43	44	48,582	**20,056**
10/29/23	48	43	44	46	46	50,226	**20,700**
10/30/23	44	44	42	43	43	56,195	**19,592**
10/31/23	48	44	43	46	46	56,804	**20,665**
11/1/23	37	40	37	41	39	52,602	**17,732**
11/2/23	35	33	36	37	35	53,815	**16,205**
11/3/23	44	41	37	43	42	49,314	**19,135**
11/4/23	39	37	30	43	38	43,518	**17,534**
11/5/23	31	27	23	34	30	37,690	**13,950**
11/6/23	37	30	31	36	34	47,268	**15,916**
11/7/23	34	33	29	37	34	48,345	**15,606**
11/8/23	31	30	28	31	30	48,598	**14,218**
11/9/23	39	34	33	36	36	53,601	**16,693**
11/10/23	39	33	32	37	36	45,958	**16,558**
11/11/23	37	33	31	37	35	45,627	**16,365**
11/12/23	29	26	25	30	28	40,980	**13,245**
11/13/23	24	22	24	29	25	40,766	**12,031**
11/14/23	22	20	22	23	22	45,147	**10,834**
11/15/23	23	19	20	23	22	42,213	**10,698**
11/16/23	33	25	37	34	32	51,771	**14,916**
11/17/23	34	34	28	34	33	44,803	**15,422**
11/18/23	34	30	25	34	32	42,171	**14,838**
11/19/23	27	28	18	30	27	40,539	**12,708**
11/20/23	29	29	29	27	28	44,032	**13,438**
11/21/23	41	39	37	43	41	53,241	**18,557**
11/22/23	45	43	40	43	43	48,919	**19,602**
11/23/23	57	52	54	55	55	50,752	**24,558**
11/24/23	49	48	47	49	48	49,882	**21,853**
11/25/23	45	45	42	46	45	50,123	**20,445**
11/26/23	57	52	54	55	55	60,190	**24,603**
11/27/23	64	64	60	66	64	70,030	**28,143**
11/28/23	47	54	39	51	48	56,330	**21,804**

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Date	38.14% Bemidji Adjusted HDD	23.16% Cloquet Adjusted HDD	14.84% Fargo Adjusted HDD	23.86% Intl. Falls Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Firm Through-Put **
11/29/23	36	32	32	35	34	49,242	**15,883**
11/30/23	42	41	41	47	43	59,592	**19,649**
12/1/23	45	42	38	46	43	52,114	**19,737**
12/2/23	42	36	37	45	41	47,726	**18,559**
12/3/23	37	35	37	35	36	45,832	**16,766**
12/4/23	37	35	40	34	36	53,118	**16,788**
12/5/23	42	43	38	42	42	55,886	**19,003**
12/6/23	34	36	26	33	33	51,322	**15,365**
12/7/23	29	29	17	32	28	40,909	**13,159**
12/8/23	34	29	37	31	32	43,238	**15,157**
12/9/23	47	42	48	44	45	54,070	**20,540**
12/10/23	48	47	46	47	47	57,051	**21,413**
12/11/23	53	48	51	49	51	63,647	**22,761**
12/12/23	56	49	48	57	53	67,342	**23,904**
12/13/23	45	40	41	47	44	59,587	**19,860**
12/14/23	24	29	27	26	26	45,883	**12,519**
12/15/23	33	31	31	34	33	46,395	**15,214**
12/16/23	36	33	40	36	36	45,942	**16,548**
12/17/23	56	51	48	52	53	55,866	**23,537**
12/18/23	57	55	53	54	55	65,104	**24,691**
12/19/23	40	40	38	42	40	57,183	**18,397**
12/20/23	40	39	33	43	40	59,084	**18,109**
12/21/23	36	34	31	33	34	53,394	**15,830**
12/22/23	33	30	31	31	32	41,712	**14,819**
12/23/23	29	26	26	28	28	36,022	**13,120**
12/24/23	32	23	43	28	31	36,328	**14,426**
12/25/23	38	29	42	37	36	40,615	**16,844**
12/26/23	33	33	33	34	33	48,967	**15,482**
12/27/23	34	35	34	35	34	52,835	**15,957**
12/28/23	42	39	38	38	40	53,987	**18,288**
12/29/23	39	35	36	39	38	50,021	**17,368**
12/30/23	48	45	49	45	47	52,783	**21,085**
12/31/23	51	48	48	52	50	52,552	**22,533**
1/1/24	45	47	41	45	45	50,754	**20,362**
1/2/24	44	40	39	45	43	55,186	**19,374**
1/3/24	53	49	49	54	52	67,885	**23,225**
1/4/24	52	50	45	52	51	67,445	**22,727**
1/5/24	41	41	39	47	42	53,781	**19,184**

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1/6/24	53	46	56	49	51	57,490	**22,712**
1/7/24	63	56	62	60	61	63,845	**26,914**
1/8/24	56	45	58	58	54	68,778	**24,236**
1/9/24	52	45	55	50	51	64,641	**22,762**
1/10/24	56	43	58	49	51	61,894	**23,063**
1/11/24	74	61	71	60	67	76,698	**29,633**
1/12/24	75	68	79	71	73	74,115	**32,095**
1/13/24	84	76	88	78	81	77,183	**35,610**
1/14/24	88	81	82	82	84	81,635	**36,820**
1/15/24	88	82	82	84	85	83,960	**37,031**
1/16/24	76	73	71	76	74	81,120	**32,692**
1/17/24	75	73	67	76	74	81,141	**32,355**
1/18/24	81	72	70	76	76	84,731	**33,373**
1/19/24	81	74	70	77	77	79,169	**33,699**
1/20/24	79	69	71	71	74	70,637	**32,372**
1/21/24	55	55	51	52	54	62,471	**24,061**
1/22/24	48	45	45	51	48	56,507	**21,512**
1/23/24	44	40	40	43	42	55,432	**19,299**
1/24/24	38	36	35	36	37	55,226	**16,868**
1/25/24	39	32	36	35	36	53,593	**16,707**
1/26/24	39	34	42	38	38	49,843	**17,548**
1/27/24	44	37	37	39	40	47,771	**18,363**
1/28/24	38	35	32	34	35	44,257	**16,364**
1/29/24	35	34	28	36	34	48,969	**15,762**
1/30/24	33	36	31	35	34	53,158	**15,725**
1/31/24	31	27	25	30	29	47,855	**13,639**
2/1/24	33	35	28	41	35	53,415	**16,107**
2/2/24	40	39	30	42	39	51,850	**17,773**
2/3/24	37	41	31	38	37	49,479	**17,200**
2/4/24	35	36	32	35	35	50,285	**16,278**
2/5/24	38	24	32	36	33	52,362	**15,591**
2/6/24	33	29	28	33	31	48,703	**14,614**
2/7/24	32	30	24	32	30	46,120	**14,197**
2/8/24	39	31	37	36	36	50,307	**16,724**
2/9/24	52	49	44	52	50	58,381	**22,569**
2/10/24	46	45	47	49	47	52,018	**21,138**
2/11/24	44	43	39	43	43	47,683	**19,380**
2/12/24	42	42	37	49	43	53,299	**19,601**

Attachment 9

MINNESOTA ENERGY RESOURCES - Consolidated

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
Consolidated

Design Day:	
Base	1,585
Variable	418

Date	38.14% Bemidji Adjusted HDD	23.16% Cloquet Adjusted HDD	14.84% Fargo Adjusted HDD	23.86% Intl. Falls Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Firm Through-Put **
2/13/24	43	42	38	46	43	57,565	**19,388**
2/14/24	50	41	46	48	47	60,683	**21,245**
2/15/24	63	57	53	63	60	68,694	**26,749**
2/16/24	64	63	56	61	62	69,998	**27,488**
2/17/24	48	45	38	48	46	56,298	**20,772**
2/18/24	52	45	37	54	49	56,671	**21,887**
2/19/24	39	40	33	45	40	57,773	**18,179**
2/20/24	32	28	32	35	32	50,449	**14,934**
2/21/24	32	29	28	34	31	45,946	**14,578**
2/22/24	39	32	29	43	37	46,515	**17,032**
2/23/24	52	54	44	56	52	57,309	**23,390**
2/24/24	33	41	26	36	35	45,612	**16,167**
2/25/24	44	38	32	47	42	49,412	**18,990**
2/26/24	30	25	35	31	30	47,962	**14,107**
2/27/24	70	57	79	72	69	75,045	**30,373**
2/28/24	72	64	63	76	70	75,828	**30,667**
2/29/24	49	50	39	62	51	59,707	**22,794**
3/1/24	28	26	25	29	27	44,482	**13,008**
3/2/24	32	27	30	36	31	43,648	**14,733**
3/3/24	43	33	36	41	39	48,150	**17,925**
3/4/24	50	40	45	51	47	59,000	**21,363**
3/5/24	43	33	43	46	41	56,582	**18,884**
3/6/24	42	33	37	40	39	56,665	**17,863**
3/7/24	48	41	44	46	45	58,645	**20,448**
3/8/24	48	43	42	47	46	59,426	**20,693**
3/9/24	45	44	36	45	43	50,193	**19,646**
3/10/24	32	33	24	36	32	44,135	**14,974**
3/11/24	19	16	18	19	18	43,382	**9,247**
3/12/24	26	19	20	28	24	42,682	**11,493**
3/13/24	28	23	22	34	27	43,610	**13,013**
3/14/24	29	32	25	29	29	42,111	**13,645**
3/15/24	30	30	25	33	30	40,806	**14,139**
3/16/24	50	46	42	51	48	49,996	**21,729**
3/17/24	56	52	54	55	54	55,197	**24,310**
3/18/24	44	44	39	44	43	52,027	**19,732**
3/19/24	54	46	47	55	51	56,969	**22,967**
3/20/24	56	53	49	59	55	62,034	**24,448**
3/21/24	46	45	45	49	46	55,910	**20,959**

Attachment 9

MINNESOTA ENERGY RESOURCES - Consolidated

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
Consolidated

Design Day:	
Base	1,585
Variable	418

Date	38.14% Bemidji Adjusted HDD	23.16% Cloquet Adjusted HDD	14.84% Fargo Adjusted HDD	23.86% Intl. Falls Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Firm Through-Put **
3/22/24	55	50	47	55	53	57,045	**23,608**
3/23/24	47	46	42	52	47	54,129	**21,399**
3/24/24	47	44	45	46	46	53,699	**20,640**
3/25/24	53	45	51	53	51	59,714	**22,828**
3/26/24	56	54	54	55	55	68,328	**24,658**
3/27/24	56	51	48	54	53	65,743	**23,818**
3/28/24	47	45	35	50	46	55,289	**20,631**
3/29/24	38	38	28	41	37	52,288	**17,223**
3/30/24	36	33	32	35	34	49,052	**15,990**
3/31/24	40	30	31	42	37	45,562	**16,956**
4/1/24	30	34	27	33	31	48,428	**14,642**
4/2/24	32	36	29	32	33	53,101	**15,184**
4/3/24	34	31	30	32	32	56,885	**15,034**
4/4/24	32	32	24	30	30	49,094	**14,293**
4/5/24	25	31	14	29	26	41,872	**12,359**
4/6/24	23	28	12	24	23	38,580	**11,115**
4/7/24	24	27	24	19	24	39,139	**11,494**
4/8/24	30	28	25	27	28	47,041	**13,326**
4/9/24	20	21	14	28	21	41,312	**10,424**
4/10/24	17	17	12	21	17	37,368	**8,772**
4/11/24	27	19	20	20	22	39,583	**10,900**
4/12/24	24	25	14	27	23	37,034	**11,365**
4/13/24	11	14	6	19	13	30,043	**6,889**
4/14/24	22	20	7	23	19	30,273	**9,693**
4/15/24	13	14	7	16	13	36,092	**7,080**
4/16/24	23	28	18	21	23	42,814	**11,142**
4/17/24	28	26	22	29	27	46,570	**12,883**
4/18/24	38	30	34	36	35	51,068	**16,250**
4/19/24	41	39	37	38	39	51,855	**17,988**
4/20/24	31	30	27	33	31	43,440	**14,341**
4/21/24	17	17	12	18	16	33,223	**8,456**
4/22/24	15	14	8	14	14	29,637	**7,251**
4/23/24	31	26	22	30	28	35,715	**13,336**
4/24/24	17	29	10	20	20	33,474	**9,780**
4/25/24	8	18	0	9	10	33,266	**5,568**
4/26/24	20	19	18	14	18	36,504	**9,178**
4/27/24	26	25	21	28	25	36,911	**12,210**
4/28/24	32	37	25	31	32	43,133	**14,802**

Attachment 9

MINNESOTA ENERGY RESOURCES - Consolidated

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
Consolidated

Design Day:	
Base	1,585
Variable	418

Date	38.14% Bemidji Adjusted HDD	23.16% Cloquet Adjusted HDD	14.84% Fargo Adjusted HDD	23.86% Intl. Falls Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Firm Through-Put **
4/29/24	27	31	24	31	29	41,021	**13,548**
4/30/24	21	22	19	21	21	37,088	**10,298**
5/1/24	16	18	10	22	17	35,573	**8,640**
5/2/24	21	26	19	18	21	37,250	**10,489**
5/3/24	20	13	17	19	18	33,481	**8,962**
5/4/24	21	22	16	24	21	31,048	**10,301**
5/5/24	13	13	3	15	12	27,896	**6,635**
5/6/24	4	12	0	4	5	30,375	**3,719**
5/7/24	14	20	11	14	15	36,458	**7,850**
5/8/24	11	19	3	10	11	35,802	**6,366**
5/9/24	13	25	4	16	15	31,926	**7,820**
5/10/24	19	17	9	19	17	31,958	**8,680**
5/11/24	1	3	0	5	2	25,090	**2,605**
5/12/24	14	7	6	13	11	24,580	**6,150**
5/13/24	15	14	8	17	14	30,697	**7,626**
5/14/24	9	17	0	11	10	29,679	**5,706**
5/15/24	15	19	10	9	14	31,439	**7,246**
5/16/24	13	16	2	21	14	27,829	**7,454**
5/17/24	0	10	0	6	4	22,838	**3,169**
5/18/24	10	3	8	8	8	24,720	**4,758**
5/19/24	9	3	8	5	7	28,889	**4,325**
5/20/24	3	8	2	8	5	32,112	**3,865**
5/21/24	14	15	11	11	13	36,053	**7,088**
5/22/24	17	18	4	27	17	36,684	**8,900**
5/23/24	15	7	2	16	12	32,178	**6,437**
5/24/24	20	25	15	19	20	29,532	**10,033**
5/25/24	17	4	8	20	13	21,982	**7,171**
5/26/24	8	11	1	10	8	17,290	**5,051**
5/27/24	12	10	5	13	11	19,383	**6,104**
5/28/24	15	14	13	15	15	25,139	**7,768**
5/29/24	5	15	0	7	7	26,702	**4,468**
5/30/24	2	4	5	0	2	26,136	**2,606**
5/31/24	7	2	2	6	5	25,061	**3,492**
6/1/24	10	7	0	10	8	0	**4,830**
6/2/24	1	0	0	0	0	0	**1,673**
6/3/24	0	0	0	2	0	0	**1,743**
6/4/24	0	3	0	0	1	0	**1,893**
6/5/24	3	3	0	4	3	0	**2,755**

Attachment 9

MINNESOTA ENERGY RESOURCES - Consolidated

Daily Total Throughput Data - July 1, 2023 through June 30, 2024
Consolidated

Design Day:	
Base	1,585
Variable	418

Date	38.14% Bemidji Adjusted HDD	23.16% Cloquet Adjusted HDD	14.84% Fargo Adjusted HDD	23.86% Intl. Falls Adjusted HDD	100.00% Weighted Adjusted HDD	Actual Total Through-Put *	Estimated Firm Through-Put **
6/6/24	13	12	3	15	12	0	**6,546**
6/7/24	6	3	0	7	5	0	**3,572**
6/8/24	7	3	0	4	4	0	**3,279**
6/9/24	20	16	4	15	16	0	**8,200**
6/10/24	4	6	0	4	4	0	**3,141**
6/11/24	0	5	0	4	2	0	**2,473**
6/12/24	0	0	0	1	0	0	**1,638**
6/13/24	3	3	0	10	4	0	**3,238**
6/14/24	0	6	0	0	1	0	**2,134**
6/15/24	0	5	0	0	1	0	**2,100**
6/16/24	4	1	0	3	2	0	**2,550**
6/17/24	0	5	0	0	1	0	**2,095**
6/18/24	7	0	4	6	5	0	**3,557**
6/19/24	6	6	0	11	6	0	**4,240**
6/20/24	4	8	0	6	5	0	**3,620**
6/21/24	0	5	0	0	1	0	**2,098**
6/22/24	1	11	0	2	3	0	**2,982**
6/23/24	2	1	0	3	2	0	**2,227**
6/24/24	0	0	0	0	0	0	**1,585**
6/25/24	0	0	0	0	0	0	**1,585**
6/26/24	13	8	5	14	11	0	**6,125**
6/27/24	0	1	0	2	0	0	**1,793**
6/28/24	1	0	0	6	2	0	**2,260**
6/29/24	14	14	8	14	0	0	**1,585**
6/30/24	2	7	0	6	0	0	**1,585**
Totals	8,998	8,519	7,610	9,149	8,700	13,443,791	4,217,496

* Volumes include interruptible and transportation volumes
** Design Model numbers are used to calculate firm volumes only

Minnesota Energy Resources Corporation
2024-2025 Demand Entitlement
MERC-Consolidated
August 1, 2024

Attachment 10
Consolidated

MINNESOTA ENERGY RESOURCES - Consolidated

Customer Counts by PGAC Class - July 1, 2023 through June 30, 2024

Tariff Rate Class	Rate Designation	Jul-23 Customers	Aug-23 Customers	Sep-23 Customers	Oct-23 Customers	Nov-23 Customers	Dec-23 Customers	Jan-24 Customers	Feb-24 Customers	Mar-24 Customers	Apr-24 Customers	May-24 Customers	Jun-24 Customers	Annual Average Customers
Residential	MERC000002	31,669	31,560	31,485	31,602	32,228	32,649	32,513	32,421	32,607	32,529	32,555	33,786	32,300
Firm Class 1	MERC000006	2,216	2,223	2,228	2,213	2,230	2,286	2,274	2,269	2,260	2,269	2,262	2,375	2,259
Firm Class 2	MERC002221	3,280	3,264	3,269	3,290	3,319	3,373	3,295	3,316	3,337	3,335	3,336	3,503	3,326
Firm Class 3	MERC002231	10	10	10	11	9	9	10	9	9	9	9	10	10
Firm Class 4	MERC002241	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Class5	MERC002251	0	0	0	0	0	0	0	0	0	0	0	0	0
Agricultural Grain Dryer Class 1	MERC002217	12	11	10	13	12	13	15	12	12	16	10	17	13
Agricultural Grain Dryer Class 2	MERC002227	8	8	7	8	8	6	6	6	6	4	4	8	7
Agricultural Grain Dryer Class 3	MERC002237	0	0	0	0	0	0	0	0	0	0	0	0	0
Interruptible Class 2	MERC002222	41	42	30	55	42	38	46	37	41	42	38	27	40
Interruptible Class 3	MERC002232	9	10	9	14	11	8	14	11	8	11	11	6	10
Interruptible Class 4	MERC002242	2	2	2	2	2	2	2	2	2	1	3	1	2
Interruptible Class 5	MERC002252	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm/Interruptilbe Class 2	MERC002223	2	2	2	2	2	2	2	2	2	2	2	1	2
Firm/Interruptilbe Class 3	MERC002233	0	2	1	1	1	1	1	1	1	1	2	2	1
Firm/Interruptilbe Class 4	MERC002243	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm/Interruptilbe Class 5	MERC002253	0	0	0	0	0	0	0	0	0	0	0	0	0
Interruptible Electric Generation Class 1	MERC002218	1	1	2	0	0	0	1	1	1	1	0	0	1
Interruptible Electric Generation Class 2	MERC002228	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		37,251	37,135	37,055	37,211	37,866	38,389	38,177	38,085	38,286	38,219	38,232	39,735	37,970

MINNESOTA ENERGY RESOURCES - Consolidated

Projected Hedged Cost - November 2024 through March 2025

Futures Contracts WACOG

Futures 10,000 Dth/contract

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
			Nov-24									
1	05/23/24	124075	7	70,000	$ 3.4100	$ 238,700	$ 3.2820	$ 229,740	$ 8,960		$ -	$ 238,700
2	06/24/24	125215	6	60,000	$ 3.2970	$ 197,820	$ 3.2820	$ 196,920	$ 900		$ -	$ 197,820
3					$ -	$ -	$ 3.2820	$ -	$ -		$ -	$ -
4					$ -	$ -	$ 3.2820	$ -	$ -		$ -	$ -
5					$ -	$ -	$ 3.2820	$ -	$ -		$ -	$ -
6					$ -	$ -	$ 3.2820	$ -	$ -		$ -	$ -
7						$ -	$ 3.2820	$ -	$ -		$ -	$ -
8						$ -	$ 3.2820	$ -	$ -		$ -	$ -
9						$ -	$ 3.2820	$ -	$ -		$ -	$ -
10						$ -	$ 3.2820	$ -	$ -		$ -	$ -
11						$ -	$ 3.2820	$ -	$ -		$ -	$ -
12						$ -	$ 3.2820	$ -	$ -		$ -	$ -
13						$ -	$ 3.2820	$ -	$ -		$ -	$ -
14						$ -	$ 3.2820	$ -	$ -		$ -	$ -
15						$ -	$ 3.2820	$ -	$ -		$ -	$ -
Total			13	130,000		$ 436,520		$ 426,660	$ 9,860		$ -	$ 436,520
						$ 3.3578		$ 3.2820	$ 0.0758		$ -	$ 3.3578
NNG	31	83.78%	11	108,919	$ 3.3578	$ 365,733	$ 3.2820	$ 357,472	$ 8,261	$ -	$ -	$ 365,733
Other-Cons	6	16.22%	2	21,081	$ 3.3578	$ 70,787	$ 3.2820	$ 69,188	$ 1,599	$ -	$ -	$ 70,787
Total	37	100.0%	13	130,000	$ 3.3578	$ 436,520	$ 3.2820	$ 426,660	$ 9,860	$ -	$ -	$ 436,520

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
			Dec-24									
1	05/22/24	124036	10	100,000	$ 3.6400	$ 364,000	$ 3.7360	$ 373,600	$ (9,600)		$ -	$ 364,000
2	06/18/24	124941	9	90,000	$ 3.7550	$ 337,950	$ 3.7360	$ 336,240	$ 1,710		$ -	$ 337,950
3					$ -	$ -	$ 3.7360	$ -	$ -		$ -	$ -
4					$ -	$ -	$ 3.7360	$ -	$ -		$ -	$ -
5					$ -	$ -	$ 3.7360	$ -	$ -		$ -	$ -
6					$ -	$ -	$ 3.7360	$ -	$ -		$ -	$ -
7					$ -	$ -	$ 3.7360	$ -	$ -		$ -	$ -
8						$ -	$ 3.7360	$ -	$ -		$ -	$ -
9						$ -	$ 3.7360	$ -	$ -		$ -	$ -
10						$ -	$ 3.7360	$ -	$ -		$ -	$ -
11						$ -	$ 3.7360	$ -	$ -		$ -	$ -
12						$ -	$ 3.7360	$ -	$ -		$ -	$ -
13						$ -	$ 3.7360	$ -	$ -		$ -	$ -
14						$ -	$ 3.7360	$ -	$ -		$ -	$ -
15						$ -	$ 3.7360	$ -	$ -		$ -	$ -
Total			19	190,000		$ 701,950		$ 709,840	$ (7,890)		$ -	$ 701,950
						$ 3.6945		$ 3.7360	$ (0.0415)		$ -	$ 3.6945
NNG	43	82.69%	16	157,115	$ 3.6945	$ 580,459	$ 3.7360	$ 586,983	$ (6,524)	$ -	$ -	$ 580,459
Other-Cons	9	17.31%	3	32,885	$ 3.6945	$ 121,491	$ 3.7360	$ 122,857	$ (1,366)	$ -	$ -	$ 121,491
Total	52	100.0%	19	190,000	$ 3.6945	$ 701,950	$ 3.7360	$ 709,840	$ (7,890)	$ -	$ -	$ 701,950

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
			Jan-25									
1	05/20/24	123931	9	90,000	$ 3.8960	$ 350,640	$ 3.9940	$ 359,460	$ (8,820)		$ -	$ 350,640
2	05/20/24	123932	1	10,000	$ 3.8950	$ 38,950	$ 3.9940	$ 39,940	$ (990)		$ -	$ 38,950
3	06/13/24	124819	10	100,000	$ 4.0920	$ 409,200	$ 3.9940	$ 399,400	$ 9,800		$ -	$ 409,200
4					$ -	$ -	$ 3.9940	$ -	$ -		$ -	$ -
5					$ -	$ -	$ 3.9940	$ -	$ -		$ -	$ -
6					$ -	$ -	$ 3.9940	$ -	$ -		$ -	$ -
7					$ -	$ -	$ 3.9940	$ -	$ -		$ -	$ -
8					$ -	$ -	$ 3.9940	$ -	$ -		$ -	$ -
9						$ -	$ 3.9940	$ -	$ -		$ -	$ -
10						$ -	$ 3.9940	$ -	$ -		$ -	$ -
11						$ -	$ 3.9940	$ -	$ -		$ -	$ -
12						$ -	$ 3.9940	$ -	$ -		$ -	$ -
13						$ -	$ 3.9940	$ -	$ -		$ -	$ -
14						$ -	$ 3.9940	$ -	$ -		$ -	$ -
15						$ -	$ 3.9940	$ -	$ -		$ -	$ -
Total	Total		20	200,000		$ 798,790		$ 798,800	$ (10)		$ -	$ 798,790
						$ 3.9940		$ 3.9940	$ (0.0001)		$ -	$ 3.9940
NNG	48	84.21%	17	168,421	$ 3.9940	$ 672,665	$ 3.9940	$ 672,674	$ (8)	$ -	$ -	$ 672,665
Other-Cons	9	15.79%	3	31,579	$ 3.9940	$ 126,125	$ 3.9940	$ 126,126	$ (2)	$ -	$ -	$ 126,125
Total	57	100.0%	20	200,000	$ 3.9940	$ 798,790	$ 3.9940	$ 798,800	$ (10)	$ -	$ -	$ 798,790

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
			Feb-25									
1	05/17/24	123905	10	100,000	$ 3.7260	$ 372,600	$ 3.8280	$ 382,800	$ (10,200)		$ -	$ 372,600
2	06/07/24	124703	8	80,000	$ 3.7520	$ 300,160	$ 3.8280	$ 306,240	$ (6,080)		$ -	$ 300,160
3					$ -	$ -	$ 3.8280	$ -	$ -		$ -	$ -
4					$ -	$ -	$ 3.8280	$ -	$ -		$ -	$ -
5					$ -	$ -	$ 3.8280	$ -	$ -		$ -	$ -
6					$ -	$ -	$ 3.8280	$ -	$ -		$ -	$ -
7					$ -	$ -	$ 3.8280	$ -	$ -		$ -	$ -
8						$ -	$ 3.8280	$ -	$ -		$ -	$ -
9						$ -	$ 3.8280	$ -	$ -		$ -	$ -
10						$ -	$ 3.8280	$ -	$ -		$ -	$ -
11						$ -	$ 3.8280	$ -	$ -		$ -	$ -
12						$ -	$ 3.8280	$ -	$ -		$ -	$ -
13						$ -	$ 3.8280	$ -	$ -		$ -	$ -
14						$ -	$ 3.8280	$ -	$ -		$ -	$ -
15						$ -	$ 3.8280	$ -	$ -		$ -	$ -
Total			18	180,000		$ 672,760		$ 689,040	$ (16,280)		$ -	$ 672,760
						$ 3.7376		$ 3.8280	$ (0.0904)		$ -	$ 3.7376
NNG	43	86.00%	15	154,800	$ 3.7376	$ 578,574	$ 3.8280	$ 592,574	$ (14,001)	$ -	$ -	$ 578,574
Other-Cons	7	14.00%	3	25,200	$ 3.7376	$ 94,186	$ 3.8280	$ 96,466	$ (2,279)	$ -	$ -	$ 94,186
Total	50	100.0%	18	180,000	$ 3.7376	$ 672,760	$ 3.8280	$ 689,040	$ (16,280)	$ -	$ -	$ 672,760

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
			Mar-25									
1	05/15/24	123814	7	70,000	$ 3.2180	$ 225,260	$ 3.3880	$ 237,160	$ (11,900)		$ -	$ 225,260
2	06/03/24	124421	7	70,000	$ 3.2490	$ 227,430	$ 3.3880	$ 237,160	$ (9,730)		$ -	$ 227,430
3					$ -	$ -	$ 3.3880	$ -	$ -		$ -	$ -
4					$ -	$ -	$ 3.3880	$ -	$ -		$ -	$ -
5					$ -	$ -	$ 3.3880	$ -	$ -		$ -	$ -
6					$ -	$ -	$ 3.3880	$ -	$ -		$ -	$ -
7					$ -	$ -	$ 3.3880	$ -	$ -		$ -	$ -
8					$ -	$ -	$ 3.3880	$ -	$ -		$ -	$ -
9					$ -	$ -	$ 3.3880	$ -	$ -		$ -	$ -
10						$ -	$ 3.3880	$ -	$ -		$ -	$ -
11						$ -	$ 3.3880	$ -	$ -		$ -	$ -
12						$ -	$ 3.3880	$ -	$ -		$ -	$ -
13						$ -	$ 3.3880	$ -	$ -		$ -	$ -
14						$ -	$ 3.3880	$ -	$ -		$ -	$ -
15						$ -	$ 3.3880	$ -	$ -		$ -	$ -
Total			14	140,000		$ 452,690		$ 474,320	$ (21,630)		$ -	$ 452,690
						$ 3.2335		$ 3.3880	$ (0.1545)		$ -	$ 3.2335
NNG	34	85.00%	12	119,000	$ 3.2335	$ 384,787	$ 3.3880	$ 403,172	$ (18,386)	$ -	$ -	$ 384,787
Other-Cons	6	15.00%	2	21,000	$ 3.2335	$ 67,904	$ 3.3880	$ 71,148	$ (3,245)	$ -	$ -	$ 67,904
Total	40	100.0%	14	140,000	$ 3.2335	$ 452,690	$ 3.3880	$ 474,320	$ (21,630)	$ -	$ -	$ 452,690

Deal Number	Purchase Date	%	Number Contracts	Financial Volume	Strike Price	Strike Cost	LDS Settle	LDS Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
			Total									
1			43	430,000	$ 3.6074	$ 1,551,200	$ 3.6808	$ 1,582,760	$ (31,560)	$ -	$ -	$ 1,551,200
2			31	310,000	$ 3.5558	$ 1,102,310	$ 3.6016	$ 1,116,500	$ (14,190)	$ -	$ -	$ 1,102,310
3			10	100,000	$ 4.0920	$ 409,200	$ 3.9940	$ 399,400	$ 9,800	$ -	$ -	$ 409,200
4			0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5			0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6			0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7			0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8			0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9			0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10												
11												
12												
13												
14												
15												
Total			84	840,000		$ 3,062,710		$ 3,098,660	$ (35,950)		$ -	$ 3,062,710
						$ 3.6461		$ 3.6889	$ (0.0428)		$ -	$ 3.6461
NNG	199	84.32%	71	708,305	$ 3.6461	$ 2,582,539	$ 3.6889	$ 2,612,853	$ (30,314)	$ -	$ -	$ 2,582,539
Other-Cons	37	15.68%	13	131,695	$ 3.6461	$ 480,171	$ 3.6889	$ 485,807	$ (5,636)	$ -	$ -	$ 480,171
Total	236	100.0%	84	840,000	$ 3.6461	$ 3,062,710	$ 3.6889	$ 3,098,660	$ (35,950)	$ -	$ -	$ 3,062,710

*Prices from 6/25/2024 NYMEX market close

MINNESOTA ENERGY RESOURCES - Consolidated

Projected Storage Cost - November 2024 through March 2025

Month/ Year	K#118657 NNG Storage (Dth)			Total NNG Storage (Dth)	Projected NNG WACOG	K#118657 NNG Storage Cost			Total NNG Storage Cost	ANR Storage GLGT/VGT (Dth)	ANR Storage GLGT/VGT WACOG	ANR Storage GLGT/VGT Cost
Nov-24	635,634			635,634	$ 2.4906	$ 1,583,132			$ 1,583,132	90,000	$ 2.1787	$ 196,082
Dec-24	1,597,234			1,597,234	$ 2.4906	$ 3,978,127			$ 3,978,127	248,000	$ 2.1787	$ 540,316
Jan-25	1,597,234			1,597,234	$ 2.4906	$ 3,978,127			$ 3,978,127	279,000	$ 2.1787	$ 607,855
Feb-25	1,597,234			1,597,234	$ 2.4906	$ 3,978,127			$ 3,978,127	196,000	$ 2.1787	$ 427,024
Mar-25	456,352			456,352	$ 2.4906	$ 1,136,606			$ 1,136,606	89,000	$ 2.1787	$ 193,904
Total	5,883,688			5,883,688		$ 14,654,121			$ 14,654,121	902,000		$ 1,965,180

Month/ Year	NNG Storage Volume (Dth)	NNG Index Price	NNG Index Cost
Nov-24	635,634	$ 3.0495	$ 1,938,366
Dec-24	1,597,234	$ 4.6935	$ 7,496,618
Jan-25	1,597,234	$ 6.2140	$ 9,925,212
Feb-25	1,597,234	$ 6.1005	$ 9,743,926
Mar-25	456,352	$ 3.3230	$ 1,516,458
Total	5,883,688		$ 30,620,579
Storage Savings (Cost):			$ 15,966,458

Month/ Year	ANR Storage Volume (Dth)	Emerson Index Price	Emerson Market Cost
Nov-24	90,000	$ 2.8120	$ 253,080
Dec-24	248,000	$ 3.2660	$ 809,968
Jan-25	279,000	$ 3.5240	$ 983,196
Feb-25	196,000	$ 3.3580	$ 658,168
Mar-25	89,000	$ 2.9180	$ 259,702
Total	902,000		$ 2,964,114
			$ 998,934

*Indexes and projected WACOG based on 6/25/2024 market prices and actual wacog through 6/2024

MINNESOTA ENERGY RESOURCES - Consolidated

Projected Hedged Cost - November 2024 through March 2025

Call/Put Options WACOG

Call/Put Options 10,000 Dth/contract

Nov-24

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	05/15/24	123816	14	140,000	$ 4.1500	$ 581,000	$ 3.2820	$ 459,480	$ 3.2820	$ 459,480	$ -	$ 0.1000	$ 14,000	$ 473,480
2	06/03/24	124420	13	130,000	$ 4.6500	$ 604,500	$ 3.2820	$ 426,660	$ 3.2820	$ 426,660	$ -	$ 0.0980	$ 12,740	$ 439,400
3						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
4						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
5						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
6						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
7						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
8						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
9						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
10						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
11						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
12						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
13						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
14						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
15						$ -	$ -	$ -	$ 3.2820	$ -	$ -	$ -	$ -	$ -
Total			27	270,000		$ 1,185,500		$ 886,140		$ 886,140	$ -		$ 26,740	$ 912,880
						$ 4.3907		$ 3.2820		$ 3.2820	$ -		$ 0.0226	$ 3.3810
NNG	63	82.89%	22	223,816	$ 4.3907	$ 982,717	$ 3.2820	$ 734,563	$ 3.2820	$ 734,563	$ -	$ 0.0990	$ 22,166	$ 756,729
Other-Cons	13	17.11%	5	46,184	$ 4.3907	$ 202,783	$ 3.2820	$ 151,577	$ 3.2820	$ 151,577	$ -	$ 0.0990	$ 4,574	$ 156,151
Total	76	100.0%	27	270,000	$ 4.3907	$ 1,185,500	$ 3.2820	$ 886,140	$ 3.2820	$ 886,140	$ -	$ 0.0990	$ 26,740	$ 912,880

Dec-24

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	05/17/24	123904	18	180,000	$ 5.8000	$ 1,044,000	$ 3.7360	$ 672,480	$ 3.7360	$ 672,480	$ -	$ 0.1000	$ 18,000	$ 690,480
2	06/07/24	124704	18	180,000	$ 6.1000	$ 1,098,000	$ 3.7360	$ 672,480	$ 3.7360	$ 672,480	$ -	$ 0.1000	$ 18,000	$ 690,480
3						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
4						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
5						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
6						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
7						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
8						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
9						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
10						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
11						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
12						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
13						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
14						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
15						$ -	$ -	$ -	$ 3.7360	$ -	$ -	$ -	$ -	$ -
Total			36	360,000		$ 2,142,000		$ 1,344,960		$ 1,344,960	$ -		$ 36,000	$ 1,380,960
						$ 5.9500		$ 3.7360		$ 3.7360	$ -		$ 0.0168	$ 3.8360
NNG	87	82.86%	30	298,286	$ 5.9500	$ 1,774,800	$ 3.7360	$ 1,114,395	$ 3.7360	$ 1,114,395	$ -	$ 0.1000	$ 29,829	$ 1,144,224
Other-Cons	18	17.14%	6	61,714	$ 5.9500	$ 367,200	$ 3.7360	$ 230,565	$ 3.7360	$ 230,565	$ -	$ 0.1000	$ 6,171	$ 236,736
Total	105	100.0%	36	360,000	$ 5.9500	$ 2,142,000	$ 3.7360	$ 1,344,960	$ 3.7360	$ 1,344,960	$ -	$ 0.1000	$ 36,000	$ 1,380,960

Jan-25

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	05/20/24	123930	10	100,000	$ 7.7500	$ 775,000	$ 3.9940	$ 399,400	$ 3.5760	$ 357,600	$ 41,800	$ 0.1000	$ 10,000	$ 409,400
2	05/22/24	124037	11	110,000	$ 7.7500	$ 852,500	$ 3.5760	$ 393,360	$ 3.5760	$ 393,360	$ -	$ 0.1000	$ 11,000	$ 404,360
3	06/13/24	124820	10	100,000	$ 8.2500	$ 825,000	$ 3.5760	$ 357,600	$ 3.5760	$ 357,600	$ -	$ 0.1000	$ 10,000	$ 367,600
4	06/18/24	124939	9	90,000	$ 7.6500	$ 688,500	$ 3.5760	$ 321,840	$ 3.5760	$ 321,840	$ -	$ 0.1000	$ 9,000	$ 330,840
5						$ -	$ -	$ -	$ 3.5760	$ -	$ -	$ -	$ -	$ -
6						$ -	$ -	$ -	$ 3.5760	$ -	$ -	$ -	$ -	$ -
7						$ -	$ -	$ -	$ 3.5760	$ -	$ -	$ -	$ -	$ -
8						$ -	$ -	$ -	$ 3.5760	$ -	$ -	$ -	$ -	$ -
9						$ -	$ -	$ -	$ 3.5760	$ -	$ -	$ -	$ -	$ -
10						$ -	$ -	$ -	$ 3.5760	$ -	$ -	$ -	$ -	$ -
11						$ -	$ -	$ -	$ 3.5760	$ -	$ -	$ -	$ -	$ -
12						$ -	$ -	$ -	$ 3.5760	$ -	$ -	$ -	$ -	$ -
13						$ -	$ -	$ -	$ 3.5760	$ -	$ -	$ -	$ -	$ -
14						$ -	$ -	$ -	$ 3.5760	$ -	$ -	$ -	$ -	$ -
15						$ -	$ -	$ -	$ 3.5760	$ -	$ -	$ -	$ -	$ -
Total	Total		40	400,000		$ 3,141,000		$ 1,472,200		$ 1,430,400	$ 41,800		$ 40,000	$ 1,512,200
						$ 7.8525		$ 3.6805		$ 3.5760	$ 0.1045		$ 0.0127	$ 3.7805
NNG	97	83.62%	33.4483	334,483	$ 7.8525	$ 2,626,526	$ 3.6805	$ 1,231,064	$ 3.5760	$ 1,196,110	$ 34,953	$ 0.1000	$ 33,448	$ 1,264,512
Other-Cons	19	16.38%	6.55172	65,517	$ 7.8525	$ 514,474	$ 3.6805	$ 241,136	$ 3.5760	$ 234,290	$ 6,847	$ 0.1000	$ 6,552	$ 247,688
Total	116	100.0%	40	400,000	$ 7.8525	$ 3,141,000	$ 3.6805	$ 1,472,200	$ 3.5760	$ 1,430,400	$ 41,800	$ 0.1000	$ 40,000	$ 1,512,200

Feb-25

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	05/22/24	124038	18	180,000	$ 8.9000	$ 1,602,000	$ 3.8280	$ 689,040	$ 3.8280	$ 689,040	$ -	$ 0.1000	$ 18,000	$ 707,040
2	06/18/24	124940	18	180,000	$ 9.1500	$ 1,647,000	$ 3.8280	$ 689,040	$ 3.8280	$ 689,040	$ -	$ 0.1000	$ 18,000	$ 707,040
3					$ -	$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
4					$ -	$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
5					$ -	$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
6					$ -	$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
7					$ -	$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
8						$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
9						$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
10						$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
11						$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
12						$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
13						$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
14						$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
15						$ -	$ -	$ -	$ 3.8280	$ -	$ -	$ -	$ -	$ -
Total			36	360,000		$ 3,249,000		$ 1,378,080		$ 1,378,080	$ -		$ 36,000	$ 1,414,080
						$ 9.0250		$ 3.8280		$ 3.8280	$ -		$ 0.0111	$ 3.9280
NNG	87	85.29%	31	307,059	$ 9.0250	$ 2,771,206	$ 3.8280	$ 1,175,421	$ 3.8280	$ 1,175,421	$ -	$ 0.1000	$ 30,706	$ 1,206,127
Other-Cons	15	14.71%	5	52,941	$ 9.0250	$ 477,794	$ 3.8280	$ 202,659	$ 3.8280	$ 202,659	$ -	$ 0.1000	$ 5,294	$ 207,953
Total	102	100.0%	36	360,000	$ 9.0250	$ 3,249,000	$ 3.8280	$ 1,378,080	$ 3.8280	$ 1,378,080	$ -	$ 0.1000	$ 36,000	$ 1,414,080

Mar-25

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	05/23/24	124074	14	140,000	$ 8.5500	$ 1,197,000	$ 3.3880	$ 474,320	$ 3.3880	$ 474,320	$ -	$ 0.1000	$ 14,000	$ 488,320
2	06/24/24	125216	14	140,000	$ 7.5500	$ 1,057,000	$ 3.3880	$ 474,320	$ 3.3880	$ 474,320	$ -	$ 0.1000	$ 14,000	$ 488,320
3						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ 0.1000	$ -	$ -
4						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ 0.1000	$ -	$ -
5						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ 0.1000	$ -	$ -
6						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ 0.1000	$ -	$ -
7						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ -	$ -	$ -
8						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ -	$ -	$ -
9						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ -	$ -	$ -
10						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ -	$ -	$ -
11						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ -	$ -	$ -
12						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ -	$ -	$ -
13						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ -	$ -	$ -
14						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ -	$ -	$ -
15						$ -	$ -	$ -	$ 3.3880	$ -	$ -	$ -	$ -	$ -
Total			28	280,000		$ 2,254,000		$ 948,640		$ 948,640	$ -		$ 28,000	$ 976,640
						$ 8.0500		$ 3.3880		$ 3.3880	$ -		$ 0.0124	$ 3.4880
NNG	68	85.00%	24	238,000	$ 8.0500	$ 1,915,900	$ 3.3880	$ 806,344	$ 3.3880	$ 806,344	$ -	$ 0.1000	$ 23,800	$ 830,144
Other-Cons	12	15.00%	4	42,000	$ 8.0500	$ 338,100	$ 3.3880	$ 142,296	$ 3.3880	$ 142,296	$ -	$ 0.1000	$ 4,200	$ 146,496
Total	80	100.0%	28	280,000	$ 8.0500	$ 2,254,000	$ 3.3880	$ 948,640	$ 3.3880	$ 948,640	$ -	$ 0.1000	$ 28,000	$ 976,640

Total

Deal Number	Purchase Date	%	Number Contracts	Financial Volume	Strike Price	Strike Cost	Option Price	Option Cost	Pent Settle*	Pent Settle Cost	Over/(Under) Market	Premium Per Unit	Premium Cost	Total Cost
1			74	740,000	$ 7.0257	$ 5,199,000	$ 3.6415	$ 2,694,720	$ 3.5850	$ 2,652,920	$ 41,800	$0.1000	$ 74,000	$ 2,768,720
2			74	740,000	$ 7.1068	$ 5,259,000	$ 3.5890	$ 2,655,860	$ 3.5890	$ 2,655,860	$ -	$0.0996	$ 73,740	$ 2,729,600
3			10	100,000	$ 8.2500	$ 825,000	$ 3.5760	$ 357,600	$ 3.5760	$ 357,600	$ -	$0.1000	$ 10,000	$ 367,600
4			9	90,000	$ 7.6500	$ 688,500	$ 3.5760	$ 321,840	$ 3.5760	$ 321,840	$ -	$0.1000	$ 9,000	$ 330,840
5			0	-	$ -	$ -	$ -	$ -	#DIV/0!	$ -	$ -	$ -	$ -	$ -
6			0	-	$ -	$ -	$ -	$ -	#DIV/0!	$ -	$ -	$ -	$ -	$ -
7			0	-	$ -	$ -	$ -	$ -	#DIV/0!	$ -	$ -	$ -	$ -	$ -
8			0	-	$ -	$ -	$ -	$ -	#DIV/0!	$ -	$ -	$ -	$ -	$ -
9			0	-	$ -	$ -	$ -	$ -	#DIV/0!	$ -	$ -	$ -	$ -	$ -
10			0	-	$ -	$ -	$ -	$ -	#DIV/0!	$ -	$ -	$ -	$ -	$ -
11			0	-	$ -	$ -	$ -	$ -	#DIV/0!	$ -	$ -	$ -	$ -	$ -
12			0	-	$ -	$ -	$ -	$ -	#DIV/0!	$ -	$ -	$ -	$ -	$ -
13														
14														
15														
Total			167	1,670,000		$ 11,971,500		$ 6,030,020		$ 5,988,220	$ 41,800		$ 166,740	$ 6,196,760
						$ 7.1686		$ 3.6108		$ 3.5858	$ 0.0250		1.39%	$ 3.7106
NNG	402	83.92%	140.164	1,401,643	$ 7.1852	$ 10,071,149	$ 3.6113	$ 5,061,788	$ 3.5864	$ 5,026,834	$ 34,953	$0.0998	$ 139,949	$ 5,201,737
Other-Cons	77	16.08%	26.8357	268,357	$ 7.0814	$ 1,900,351	$ 3.6080	$ 968,232	$ 3.5825	$ 961,386	$ 6,847	$0.0998	$ 26,791	$ 995,023
Total	479	100.0%	167	1,670,000	$ 7.1686	$ 11,971,500	$ 3.6108	$ 6,030,020	$ 3.5858	$ 5,988,220	$ 41,800	$0.0998	$ 166,740	$ 6,196,760

*Prices from 10/19/2023 NYMEX market close

Attachment 12: Forecast Methodology for MERC Demand Entitlement
Effective November 1, 2024

1. Peak-day

   a. Purpose

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

   b. Background

MERC customers are served by four pipelines[1]

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

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

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

	Pipeline	PGA	Weather Station(s)
1	Centra	MERC Consolidated	International Falls
2	GLGT	MERC Consolidated	Bemidji
3	GLGT	MERC Consolidated	Cloquet
4	VGT	MERC Consolidated	Fargo
5	NNG	MERC NNG	Cloquet
6	NNG	MERC NNG	Minneapolis
7	NNG	MERC NNG	Ortonville
8	NNG	MERC NNG	Rochester
9	NNG	MERC NNG	Worthington

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

2. Analytical Approach

a. Summary

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

3. Process

The Peak Day Process consisted of:

I. Data Preparation
II. Regression Generation of Net Daily Metered Volumes
III. Volume Risk Adjustments
IV. Adjusting the Regression Results to a Firm Peak Day Estimate
V. Firm Peak Day Estimate Gate Station Allocation

i. The **Data Preparation** consisted of:

- Identify the coldest Adjusted Heating Degree Day (AHDD) since January 1996 for each weather station. Note, this is a change in practice from prior analysis that used a rolling 20-year period. The change was included because many weather stations experienced historically cold weather in the January/February 1996 time period and without inclusion of that additional data from January/February 1996, AHDD were materially lower and not reflective of MERC's capacity needs.
- Determine the most recent three years of December through February daily total metered throughput by pipeline and by weather station.
- Determine the most recent three years of December through February daily large volume transportation, interruptible, and joint interruptible volumes by pipeline and by weather station (Data A).
- Determine the most recent three years of December through February daily small volume interruptible volumes by pipeline and by weather station (Data B).
- Review daily total metered throughput, Data A, and Data B, and identify missing or bad reads, and to the extent possible, fix missing or bad reads. To the extent that the data could not be fixed, it was not included in the regressions.
- Subtract both Data A and Data B daily meter readings for all three December through February years from the total throughput for each pipeline and each weather station. Use the resulting net daily metered volumes for regressions. Examples of transportation, interruptible, and joint interruptible meter readings subtracted are paper mills, direct-connects, taconites, and off-system end users. See "Adjusting the Regression Results to a Firm Peak Day Estimate" below.

Each daily weather station data file was searched to find the coldest Adjusted Heating Degree Day (AHDD65) since January 1996. Many weather stations experienced historically cold weather in the January/February 1996 time period; without inclusion of that additional data from January/February 1996, AHDD65 were materially lower and not reflective of MERC's capacity needs. The coldest AHDD65 data since 1996 is included in the table below, along with the AHDD65 conditions on the day prior ("AHDD65-1").

Station	Date	Avg. Temp	Avg. Wind	HDD65	AHDD65	AHDD65-1
Bemidji	1/29/2019	-32	14	97	110	84
Cloquet	1/29/2019	-24	16	89	103	74
Fargo	1/18/1996	-16	34	81	109	85
International Falls	2/2/1996	-34	8	99	107	107
Minneapolis	1/29/2019	-20	17	85	100	71
Rochester	1/29/2019	-20	21	85	104	76
Worthington	1/29/2019	-20	21	85	103	81
Ortonville	1/29/2019	-23	14	88	101	77

This data by weather station was then compared to the AHDD65 data used in the previous demand entitlement filing:

Station	Date	Avg. Temp	Avg. Wind	HDD65	AHDD65	AHDD65-1
Bemidji	2/1/1996	-34	8	99	107	94
Cloquet	2/2/1996	-31	7	96	103	100
Fargo	1/18/1996	-16	34	81	109	85
International Falls	2/2/1996	-34	8	99	107	107
Minneapolis	2/2/1996	-25	8	90	97	92
Rochester	2/2/1996	-27	10	92	101	94
Worthington	1/18/1996	-8	32	73	96	74
Ortonville	1/14/2009	-21	11	86	96	86

While the January, 2019 cold weather outbreak was significant, it was not considered to be as severe as the weather conditions experienced in 1996. With the exception of Worthington, the 1996 weather conditions overall were colder when considering both the current day and the prior day weather conditions. Following is the data by weather station that was ultimately used in MERC's current analysis:

Station	Date	Avg. Temp	Avg. Wind	HDD65	AHDD65	AHDD65-1
Bemidji	2/1/1996	-34	8	99	107	94
Cloquet	2/2/1996	-31	7	96	103	100
Fargo	1/18/1996	-16	34	81	109	85
International Falls	2/2/1996	-34	8	99	107	107
Minneapolis	2/2/1996	-25	8	90	97	92
Rochester	2/2/1996	-27	10	92	101	94
Worthington	1/29/2019	-20	21	85	103	81
Ortonville	1/14/2009	-21	11	86	95	86

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

- For each of the pipelines and weather stations:

  1. Gather the net daily metered volumes and weather station data including AHDD65.[2]
  2. Add indicator variables for day-type and month. Day-type variables are used to isolate load that changes by day of the week, such as commercial or industrial customers who may change their consumption on weekends when they run fewer shifts. Month indicator variables are used to isolate load that changes based on winter months, such as businesses that are open extra hours in December and resume normal operating hours in January.
  3. Perform ordinary least squares linear regressions for the 3-year time frame using the AHDD65 weather variable and the significant indicator variables.
  4. In response to comments from the Department, the regression methodology incorporates a process to mitigate the impact of autocorrelation. See section below on autocorrelation.

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

5. In response to comments from the Department, provide an explanation whenever we choose to use a regression model that does not have an intercept.
6. Summarize the Baseload and Use/AHDD65 and Use/Prior Day AHDD65 from each regression.
7. Calculate a point estimate from each regression based on the baseload value plus the Use/AHDD65 coefficient times the coldest AHDD65 since January 1996 and the Use/Prior Day AHDD65 coefficient times the AHDD65 on the day prior to the coldest AHDD65 since January 1996.

iii. **<u>Volume Risk Adjustments</u>**

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

iv. **<u>Adjusting the Regression Results to a Firm Peak Day Estimate</u>** consisted of:

1. **Add back DFC customer selections**

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

v. **<u>Firm Peak Day Estimate Gate Station Allocation:</u>**

After the data is subdivided, analyzed, and regressed to the nine demand areas, the data is further subdivided to each Gate Station within each of the nine demand areas. To provide a firm peak day estimate for each Gate Station, the following steps are taken:

1. The previous winter's actual historical throughout, by Gate Station, is gathered.
2. Estimated transportation, interruptible, and joint interruptible customer volumes are allocated to each Gate Station. The allocation is determined by which Gate Station has the closest geographical location to the customer.
3. For each Gate Station, using the last winter's data, the estimated coincidental transportation and interruptible Gate Station non-firm throughput total for the same date of the Gate Station's total throughput peak is then subtracted from the total throughput peak value in order to calculate an estimated coincidental peak firm value for each Gate Station.

$$\boxed{\begin{array}{c}\text{Gate Total Throughput Peak – Same Date Location-based estimated Non-Firm Total Throughput =}\\ \text{Coincidental Gate Station Firm Estimate}\end{array}}$$

4. Each of the calculated coincidental peak firm values at each Gate Station are then divided by the new demand area total of the coincidental firm peak day estimates, and then multiplied by the initial demand area firm peak day total.

$$\boxed{\left[\frac{\text{Coincidental Gate Station Firm Estimate}}{\text{Total Demand Area Coincidental Firm Estimate}}\right] \times \begin{array}{l}\text{Regression Demand}\\ \text{Area Firm Estimate}\end{array}}$$

By having the coincidental peak day estimates as a ratio of the intial demand area estimates, the Gate Station peak day estimates continue to maintain the intial demand area estimates that resulted from the regression analyses in steps i. through iv. above.

Exhibit 1
Pipeline and Weather Station Regression Notes

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

GLGT Paper Mills =
- Blandin mapped to Bemidji
- Sappi and USG mapped to Cloquet

VGT Lamb Weston mapped to Fargo

NNG Taconites / Direct Connects =
- CCI EMPIRE IND DEL PT 2 TILDEN mapped to Cloquet
- CCI NORTHSHORE mapped to Cloquet
- UNITED TACONITE (was EVELETH TACONITE) mapped to Cloquet
- HIBBING TACONITE CO. mapped to Cloquet
- U.S. STEEL #1 & #2 mapped to Cloquet
- NATIONAL STEEL PELLET mapped to Cloquet
- COTTAGE GROVE TBS LS POWER mapped to Minneapolis
- INLAND STEEL mapped to Cloquet

NNG OSEU (End Users) =
- ARKEMA INC. mapped to Rochester
- MAYO Clinic 1 Fairmont mapped to Worthington
- MAYO Clinic 2 (Franklin Htg) mapped to Rochester
- MAYO Clinic 3 (St Mary's) mapped to Rochester
- ARCHER DANIELS MIDLAND, CO. mapped to Minneapolis
- ASSOCIATED MILK PRODUCTS, INC. mapped to Rochester
- Hawkins Inc. mapped to Minneapolis
- CORRECTIONAL CTR mapped to Minneapolis
- DAIRY FARMERS OF AMERICA mapped to Rochester
- Dick's Sanitation mapped to Minneapolis
- KEMPS LLC mapped to Rochester
- KERRY BIO-SCIENCE mapped to Rochester
- LAKESIDE mapped to Rochester
- MILK SPECIALTIES mapped to Worthington
- LAND O'LAKES mapped to Rochester
- PRO-CORN mapped to Rochester

- SWIFT mapped to Worthington
- SENECA FOODS-ROCHESTER mapped to Rochester
- ENGINEERED POLYMERS mapped to Cloquet
- SANDSTONE FEDERAL CORRECTIONAL INSTITUTE mapped to Cloquet
- Agra Resources(Exol) mapped to Rochester
- Halcon Corporation mapped to Rochester
- REG ALBERT LEA, LLC mapped to Rochester
- Zinpro North Branch mapped to Minneapolis

B. Daily Firm Capacity

VGT

- DETROIT LAKES MIDDLE SCHOOL
- ROSSMAN SCHOOL

GLGT

- NORTHLAND APTS

NNG

- HENDRICKS HOSPITAL
- BRAND FX BODY INC

4. Autocorrelation Review

The Commission's February 4, 2015, Order in MERC's 2012-2013 demand entitlement dockets[3] required MERC to check its regression models for autocorrelation and correct the model if autocorrelation is present and to provide a reasonable explanation of its use of no-intercept models if it chooses to use one again in the future.

In a regression analysis, using time series data, autocorrelation of the errors is a problem. Autocorrelation of the errors, which themselves are unobserved, can generally be detected because it produces autocorrelation in the observable residuals. (Errors are also known as "error terms" in econometrics.) Autocorrelation violates the ordinary least squares (OLS) assumption that the error terms are uncorrelated. While it does not bias the OLS coefficient estimates, the standard errors tend to be underestimated (and the t-scores overestimated) when the autocorrelations of the errors at low lags are positive. The traditional

[3] Docket Nos. G011/M-12-1192, G011/M-12-1193, G011/M-12-1194, and G011/M-12-1195

test for the presence of first-order autocorrelation is the Durbin–Watson statistic or, if the explanatory variables include a lagged dependent variable, Durbin's h statistic. To correct for this use, MERC used the Yule-Walker estimation method within the SAS software package to employ an AR(1) regression which then showed that the Durbin–Watson statistics are all either close to 2 or above.

5. Design-Day Model

Order Point 5 of the Commission's January 21, 2015, Order in MERC's 2010-2011 demand entitlement dockets[4] required that in future demand entitlement filings, MERC provide (1) the determinants used in its Design-Day models that account for each and every impact on usage associated with economic conditions, and (2) a detailed explanation of each and every cause of unexpected changes in usage that might impact the Design-Day calculation, and what, if any, modifications the Company made to its Design-Day numbers. MERC does not forecast its Design Day using economic variables. Additionally, there were no unexpected changes in the Design-Day forecast.

6. Verification of Regression Analysis Results

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

[4] Docket Nos. G007/M-10-1166, G007/M-10-1167, G011/M-10-1168, and G011/M-10-1169

ATTACHMENT D

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

Docket No. G011/M-24-___

CERTIFICATE OF SERVICE

I, Colleen T. Sipiorski, hereby certify that on the 1st day of August, 2024, on behalf of Minnesota Energy Resources Corporation (MERC) I electronically filed a true and correct copy of MERC's Petition for Approval of a Change in Demand Entitlement on www.edockets.state.mn.us. Said documents were also served via U.S. mail and electronic service as designated on the attached service list.

Dated this 1st day of August, 2024.

/s/ Colleen T. Sipiorski______
Colleen T. Sipiorski

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