414 Nicollet Mall
Minneapolis, MN 55401

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October 31, 2025

—Via Electronic Filing and U.S. Mail—

Sasha Bergman
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: SUPPLEMENTAL FILING
CHANGES IN CONTRACT DEMAND ENTITLEMENTS
DOCKET NO. G002/M-25-67

Dear Ms. Bergman:

Northern States Power Company, doing business as Xcel Energy, submits this filing to supplement our August 1, 2025 Petition (Petition) in the above-referenced docket.

In this filing, we include one adjustment with this Supplemental Filing, a rate change from those identified in the Petition. This adjustment decreases costs in Minnesota from the request in our Petition by approximately $25,136. Our total annual system cost is $94,998,605 or $78,041,824 for our Minnesota customers.

As a result, we include the following revised attachments:
- Attachment 1, Schedule 2, Page 1-2
- Attachment 2, Schedule 1, Page 1-2
- Attachment 2, Schedule 2, Pages 1-5

We also provide an update to the Company's hedging transactions and the availability of the peaking plants for the upcoming heating season.

<u>Changes to Resource Cost Levels</u>

First, the Petition noted a need to acquire an additional 4,000 Dth/day of delivered supply service for November through March to meet seasonal peaking needs. Market conditions on Viking have resulted in Viking capacity being sold out for full-path transportation. Since filing the Petition, we acquired the 4,000

Dth/day quantity for the period of December through February. The final agreement also contains savings to customers of $25,136 from the estimate in the Petition.

Update on Hedging Transactions

Updated hedging transactions are presented on the revised **Attachment 3, Schedule 1**. We completed hedging for the 2025-2026 heating season by executing a total of six call options. **Attachment 3, Schedule 1** now reflects all of the current hedging transactions. Total hedging costs for the 2025-2026 heating season are $9,749,126. If natural gas prices rise as they are forecasted to do during the heating season, then it is more likely a portion of our hedges will be exercised.

Update on Peaking Plants

The Company began projects at the Maplewood and Sibley propane-air plants in 2024 to upgrade the facilities and ensure continued safe and reliable gas supply to the system during design day scenarios. Improvements include the complete replacement of: all tank bank gas piping and valves; electrical systems; fire and gas detection and suppression; and instrumentation and measurement devices for each of the 74 propane tanks across both facilities. To do so, the tanks at the plant were completely de-inventoried. As a result of project delays, neither plant is available to start the 2025-2026 heating season. We expect to have storage capacity at Maplewood in late December, and Sibley thereafter. We will provide an update on the plant's status on December 1.

Because the anticipated return of the propane air plants is during (not prior to the start of) the 2025-2026 heating season, the Company has provided a plan below to meet design day conditions if they occur before the plant has enough inventory to meet full output capacity.

First, we note that a design day event is unlikely in November and December. NSP's design day is a 1-in-30-year lowest average temperature and has not occurred since February 1996. Since that time, NSP has experienced several extremely cold events, which have all occurred around Christmas or later in the heating season and have not reached the temperature levels expected during a design day event.[1] Based on records of temperatures dating back to the 1950s, the coldest it has been in the Twin Cities in November is a daily average of -4 degrees Fahrenheit. Therefore, it

[1] Under our DD conditions, the average of the high and the low daily temperatures across all our operations areas would be -26 degrees Fahrenheit.

is quite unlikely that we will experience design day conditions while the output of Sibley is limited.

Additionally, we customarily plan to maintain a transportation capacity reserve margin as close as practicable to either the capability of the largest pump at Wescott used to vaporize LNG or to the capability of either Sibley or Maplewood. This planned reserve margin helps us manage through unanticipated events such as the limited availability or unavailability of the peaking plants. During a period when the plants are limited or unavailable, we first plan to fully utilize the reserve margin transportation capacity as necessary. Our planned transportation reserve margin is 56,625 Dth/day of additional firm transportation capacity during the 2025-2026 heating season, which is greater than the output of one of the propane, however if both plants are unavailable, the planned transportation reserve margin would be less than the output of both plants.

If necessary, the Company would then plan to utilize NNG interruptible capacity service. NNG's interruptible service is subject to availability, and therefore the amount of capacity the Company could secure under this program is not guaranteed. That said, NNG did have interruptible capacity available during the February 2021 Gas Pricing Event (which was not a design day event but was certainly a period of high demand and limited supply). We believe the fact that NNG's interruptible service was available during the February Gas Pricing Event suggests that it would be reasonable for the Company to try to secure interruptible capacity in the event design day conditions were experienced prior to Sibley being able to meet full output. Finally, the Company is also able to utilize the Capacity Sharing Agreement (Docket No. E,G002/M-15-618), which allows the LDC to borrow (at cost) transportation capacity from NSP Generation. NSP Generation has 289,994 Dth/day of firm transportation capacity.

Table 1
Company's Plan for Meeting Design Day Conditions during 2025-2026 Heating Season

Possible Scenarios		1	2	3
Maplewood Inventory Filled?		No	Yes	Yes
Sibley Inventory Filled?		No	No	Yes
Resulting Capacity Needed to Meet DD (Dth/day)		90,000	46,000	0
Plan to Meet DD	**Curtail Interruptible Customers?**	Yes	Yes	Yes
	Utilize Reserve Margin? (56,625 Dth/day)	Yes	Yes	Yes
	Attempt to Utilize NNG Interruptible Service? (unknown Dth/day)[2]	Yes	Yes	Yes
	Utilize Capacity Sharing Agreement (up to 289,994 Dth/day)	Yes	Yes	No

As can be seen from the table above, if there were design day conditions before Sibley and Maplewood are available with full output, then the Company would need to utilize a portion of NSP Generation's pipeline capacity in order to serve its firm natural gas customers. Utilizing NSP Generation's capacity would limit NSP Generation's ability to utilize its natural gas fired generation facilities. Impacted generation facilities could operate on alternative fuels to the extent they were available. Despite that, if NSP Generation did not have enough capacity to meet its customers' electricity need, then it could purchase energy through the MISO market and/or curtail its interruptible electric customers. Once Sibley has its target inventory level the Company will return to its full expected reserve margin.

<u>Miscellaneous</u>
Portions of this filing contain trade secret information, as defined under Minn. Stat. § 13.37. As such, this data is protected from public disclosure and has been marked accordingly. Xcel Energy makes extensive efforts to maintain the secrecy of this information. This information is not available outside the Company except to other parties involved in contracts and to regulatory agencies under the confidentiality provisions of state or federal law, as evidenced by the non-disclosure provisions in the contracts. Xcel Energy also provides this information to state regulatory agencies in the Annual Automatic Adjustment of

[2] Recalling the amount of LNG in storage at Wescott cannot be increased over the heating season, it's worth noting that once the peaking plants are back in service and depending on operating conditions, the Company may still choose to utilize NNG's interruptible service in lieu of operating the peaking plants.

Charges Reports and in the monthly purchased gas adjustment (PGA) filings in the confidential trade secret versions of these reports.

The supply information has economic value to Xcel Energy, its customers, suppliers, and competitors in at least three ways. If suppliers know the terms of Xcel Energy's supply and transportation contracts, they may be able to use this knowledge to fashion bids to Xcel Energy. Suppliers will be reluctant to offer special favorable terms to Xcel Energy if they know other competitors or customers will gain knowledge of the terms and demand similar terms in the future. Competitors of Xcel Energy such as other LDCs also purchase their services. These competitors may be able to leverage knowledge of Xcel Energy's costs to gain similar terms or may offer slightly better prices to suppliers, denying Xcel Energy's access to this gas or other services.

Any of these results would harm Xcel Energy and its natural gas customers. Because Xcel Energy competes for supplies, transportation, storage, and other services in the wholesale market, disclosure would directly harm Xcel Energy by making its delivered supply cost less competitive. To the extent that Xcel Energy supply costs rise, Xcel Energy's regulated sales customers would have to pay higher natural gas rates. This result would not serve the public interest.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists. Please contact me at (612) 330-7681 or lisa.r.peterson@xcelenergy.com or Megan Spear at megan.spear@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

LISA PETERSON
DIRECTOR, REGULATORY PRICING AND ANALYSIS

Enclosures
cc: Service List

Attachments
Effective November 1, 2025

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company	Docket No. G002/M-25-67
DEMAND COST OF GAS IMPACT - NOVEMBER 2025	Contract Demand Entitlements-Petition
Revised from 8/1/25 filing	REVISED Attachment 1, Schedule 2 - Page 1 of 2
Protected data is shaded.	

CHANGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day	Current Monthly Demand Rates	No. of Months	Total Annual Cost
ANR FTS-1 (Nov-Oct)	(66,500)	$ 6.5884	12	$ (5,257,543.20)
ANR FTS-1 (Nov-Oct)	66,500	$ 10.4868	12	$ 8,368,466.40
ANR FTS-1 (Nov-Mar)	(15,171)	$ 6.5884	5	$ (499,763.08)
ANR FTS-1 (Nov-Mar)	15,171	$ 10.4868	5	$ 795,476.21
ANR FTS-1 (Nov-Oct)	(5,433)	$ 6.5884	7	$ (250,563.44)
ANR FTS-1 (Nov-Oct)	5,433	$ 10.4868	7	$ 398,823.49
ANR FTS-1 (Nov-Oct)	(22,000)	$ 6.5884	12	$ (1,739,337.60)
ANR FTS-1 (Nov-Oct)	22,000	$ 10.4868	12	$ 2,768,515.20
ANR FTS-1 (Nov-Oct)	(4,829)	$ 14.0900	12	$ (816,487.32)
ANR FTS-1 (Nov-Oct)	4,829	$ 26.9958	12	$ 1,564,352.62
ANR FSS (Nov-Oct)	(15,226)	$ 2.1126	12	$ (385,997.37)
ANR FSS (Jan-Dec)	15,226	$ 2.5372	12	$ 463,576.89
ANR FSS (Jan-Dec)	17	$ 2.5372	12	$ 517.59
ANRS FSS (Apr-July)	(9,248)	$ 1.4160	5	$ (65,475.84)
ANRS FSS (Apr-July)	9,248	$ 3.4645	5	$ 160,198.48
ANR FTS-1 (Apr-July)	2	$ 10.4868	7	$ 146.82
NNG TFX (Nov-Mar)	1,157	$ 25.7990	5	$ 149,247.22
NNG TFX (Apr-Oct)	1,157	$ 9.6760	7	$ 78,365.92
NNG TFX (Nov-Mar)	4,094	$ 25.7990	5	$ 528,105.53
NNG TFX (Apr-Oct)	4,094	$ 9.6760	7	$ 277,294.81
		[PROTECTED DATA BEGINS		
NNG TFX (Nov-Oct)	6,667			
NNG TFX (Nov-Oct)	3,333			
NNG TFX (Nov-Oct)	3,333			
NNG TFX (Nov-Oct)	1,613			
NNG TFX (Nov-Oct)	1,613			
NNG TFX (Nov-Oct)	7,169			
NNG TFX (Nov-Oct)	7,169			
				PROTECTED DATA ENDS]
GLGT FT- (Nov-Dec)	(3,509)	$ 8.1860	5	$ (143,623.37)
GLGT FT- (Nov-Dec)	3,509	$ 9.1220	5	$ 160,045.49
GLGT FT- (Nov-Dec)	(5,370)	$ 8.1860	7	$ (307,711.74)
GLGT FT- (Nov-Dec)	5,370	$ 9.1220	7	$ 342,895.98
GLGT FT- (Nov-Dec)	(9,248)	$ 8.1860	5	$ (378,520.64)
GLGT FT- (Nov-Dec)	9,248	$ 9.1220	5	$ 421,801.28
Total				$ 7,819,887.41

Supplier Entitlement Changes
Change in Supplier Reservation Fees
[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Total	4,000	$ 387,491.00
Total MN & ND Demand Cost Adjustment		**$ 8,207,378.41**
Minnesota Allocation Factor (MN/ND Allocated Demand)		86.02%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand		**$ 7,060,259.55**

[1]ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v.4.0.1 Effective November 1, 2025
[2]GLGT Volume No. 1, Part 5.0 - Statement of Rates, v.60.0.0, Effective Novemeber 1, 2025
3NNG Seventh Revised Volume No. 1, Twenty First Revised Sheet No. 50, Effective January 1, 2026
4NNG Seventh Revised Volume No. 1, Twenty Fourth Revised Sheet No. 51, Effective January 1, 2026

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Northern States Power Company
Demand Cost Changes from Prior Year
Revised from 8/1/25 filing
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Docket No. G002/M-25-67
Contract Demand Entitlements-Petition
REVISED Attachment 1, Schedule 2 - Page 2 of 2

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2024 SUPPLEMENTAL FILED COSTS				**$50,970,508.65**	**$35,820,718.55**	**$86,791,227.20**				
2024 CHANGES FILED COMPARED TO ACTUAL COSTS										
Total				$ -	$ -	$ -				
2024 ACTUAL COSTS				**$ 50,970,508.65**	**$ 35,820,718.55**	**$ 86,791,227.20**				
CHANGES FOR 2025 FILING										
Contract Demand Entitlement Changes										
ANR FTS-1 (Nov-Oct)	(66,500)	$ 6.5884	12	$ (5,257,543.20)		$ (5,257,543.20)			$ (5,257,543.20)	1
ANR FTS-1 (Nov-Oct)	66,500	$ 10.4868	12	$ 8,368,466.40		$ 8,368,466.40			$ 8,368,466.40	1
ANR FTS-1 (Nov-Mar)	(15,171)	$ 6.5884	5		$ (499,763.08)	$ (499,763.08)			$ (499,763.08)	1
ANR FTS-1 (Nov-Mar)	15,171	$ 10.4868	5		$ 795,476.21	$ 795,476.21			$ 795,476.21	1
ANR FTS-1 (Apr-July)	(5,433)	$ 6.5884	7		$ (250,563.44)	$ (250,563.44)			$ (250,563.44)	1
ANR FTS-1 (Apr-July)	5,433	$ 10.4868	7		$ 398,823.49	$ 398,823.49			$ 398,823.49	1
ANR FTS-1 (Nov-Oct)	(22,000)	$ 6.5884	12	$ (1,739,337.60)		$ (1,739,337.60)			$ (1,739,337.60)	1
ANR FTS-1 (Nov-Oct)	22,000	$ 10.4868	12	$ 2,768,515.20		$ 2,768,515.20			$ 2,768,515.20	1
ANR FTS-1 (Nov-Oct)	(4,829)	$ 14.0900	12	$ (816,487.32)		$ (816,487.32)			$ (816,487.32)	2
ANR FTS-1 (Nov-Oct)	4,829	$ 26.9958	12	$ 1,564,352.62		$ 1,564,352.62			$ 1,564,352.62	2
ANR FSS (Nov-Oct)	(15,226)	$ 2.1126	12		$ (385,997.37)	$ (385,997.37)			$ (385,997.37)	2
ANR FSS (Jan-Dec)	15,226	$ 2.5372	12		$ 463,576.89	$ 463,576.89			$ 463,576.89	2
ANR FSS (Jan-Dec)	17	$ 2.5372	12		$ 517.59	$ 517.59			$ 517.59	2
ANRS FSS (Apr-July)	(9,248)	$ 1.4160	5		$ (65,475.84)	$ (65,475.84)			$ (65,475.84)	1
ANRS FSS (Apr-July)	9,248	$ 3.4645	5		$ 160,198.48	$ 160,198.48			$ 160,198.48	1
ANR FTS-1 (Apr-July)	2	$ 10.4868	7		$ 146.82	$ 146.82			$ 146.82	1
NNG TFX (Nov-Mar)	1,157	$ 25.7990	5		$ 149,247.22	$ 149,247.22	$ 149,247.22			3
NNG TFX (Apr-Oct)	1,157	$ 9.6760	7	$ 78,365.92		$ 78,365.92	$ 78,365.92			3
NNG TFX (Nov-Mar)	4,094	$ 25.7990	5		$ 528,105.53	$ 528,105.53	$ 528,105.53			3
NNG TFX (Apr-Oct)	4,094	$ 9.6760	7	$ 277,294.81		$ 277,294.81	$ 277,294.81			3
		[PROTECTED DATA BEGINS								
NNG TFX (Nov-Oct)	6,667									3
NNG TFX (Nov-Oct)	3,333									3
NNG TFX (Nov-Oct)	3,333									3
NNG TFX (Nov-Oct)	1,613									3
NNG TFX (Nov-Oct)	1,613									3
NNG TFX (Nov-Oct)	7,169									3
NNG TFX (Nov-Oct)	7,169									3
							PROTECTED DATA ENDS]			
GLGT FT- (Nov-Dec)	(3,509)	$ 8.1860	5		$ (143,623.37)	$ (143,623.37)		$ (143,623.37)		4
GLGT FT- (Nov-Dec)	3,509	$ 9.1220	5		$ 160,045.49	$ 160,045.49		$ 160,045.49		4
GLGT FT- (Nov-Dec)	(5,370)	$ 8.1860	7	$ (307,711.74)		$ (307,711.74)		$ (307,711.74)		4
GLGT FT- (Nov-Dec)	5,370	$ 9.1220	7	$ 342,895.98		$ 342,895.98		$ 342,895.98		4
GLGT FT- (Nov-Dec)	(9,248)	$ 8.1860	5		$ (378,520.64)	$ (378,520.64)		$ (378,520.64)		4
GLGT FT- (Nov-Dec)	9,248	$ 9.1220	5		$ 421,801.28	$ 421,801.28		$ 421,801.28		4
Total				$ 5,995,689.07	$ 1,824,198.35	$ 7,819,887.42	$ 2,220,094.57	$ 94,887.00	$ 5,504,905.85	
Supplier Entitlement Changes										
[PROTECTED DATA BEGINS										
										5
										5
										5
										5
										5
									PROTECTED DATA ENDS]	
Total				$0.00	$387,491.00	$387,491.00	$0.00	$387,491.00	$0.00	
TOTAL OF 2025 CHANGES				**$ 5,995,689.07**	**$ 2,211,689.35**	**$ 8,207,378.42**	**$ 2,220,094.57**	**$ 482,378.00**	**$ 5,504,905.85**	
2025 COSTS				**$ 56,966,197.72**	**$ 38,032,407.90**	**$ 94,998,605.62**				
2025 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							82%	18%		6

Footnote

1. Rate change in accordnace with approved Rate Case Settlement (RP25-858), Rate effective November 1, 2025.
2. Annual volume adjustments on ANR transport and storage agreements for fuel. Upstream capacity serves demand in both MN and ND.
3. Acquisition of new capacity on NNG as part of Northern Lights 2025 to meet Design Day requirements of Minnesota customers.
4. Rate change due to ongoing Rate Case (RP25-855), Interim Settlement Rates effective November 1, 2025.
5. Expired peaking supply contract with demand charges in effect November 1, 2025 through March 31, 2026.
6. Upstream/system supply refers to costs that are incurred to serve all customers on the system across MN and ND. For purpocses of this schedule, it is reasonable to split these costs between MN and ND using the overall system jurisdictional factors.

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Northern States Power Company
COMPANY DEMAND PROFILE
2025-2026 Heating Season
Revised from 8/1/25 filing
Protected data is shaded.

Docket No. G002/M-25-67
Contract Demand Entitlements-Petition
REVISED Attachment 2, Schedule 1 - Page 1 of 2

Contract No.	Type of Capacity or Entitlement	Current Amount Dth or MMBtu	Proposed Change Dth or MMBtu	Proposed Amount Dth or MMBtu	Contract Length and Expiration Date	Change Description	% of Peak Day Entitlement
	Capacity Entitlements						
112183	NNG TF12 BASE (Max)	104,117	0	104,117	10 yrs - 10/31/27		10.73%
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/27		0.00%
112182	NNG TF12 BASE (Disc)	24,201	4,172	28,373	10 yrs - 10/31/27	Annual Re-Determination	2.92%
112182	NNG TF12 VARIABLE (Disc.)	70,326	(4,172)	66,154	10 yrs - 10/31/27	Annual Re-Determination	6.81%
112183	NNG TF5 (Max)	62,415	0	62,415	10 yrs - 10/31/27		6.43%
112182	NNG TF5 (Disc.)	29,599	0	29,599	10 yrs - 10/31/27		3.05%
111739	NNG TFX (Nov-Mar)	28,500	0	28,500	5 yrs - 3/31/27		2.94%
112185	NNG TFX (Disc. Nov-Mar)	58,184	0	58,184	10 yrs - 10/31/27	Capacity Acquisition	5.99%
112185	NNG TFX (Disc. 12-month)	36,654	11,613	48,267	10 yrs - 10/31/27		4.97%
112185	NNG TFX 5 (Disc)	6,828	0	6,828	10 yrs - 10/31/27		Summer Only
112185	NNG TFX 2 (Disc)	2,503	0	2,503	10 yrs - 10/31/27		Summer Only
112186	NNG TFX 5 (Max)	28,132	1,157	29,289	10 yrs - 10/31/27	Capacity Acquisition	3.02%
112186	NNG TFX 7 (Max)	22,707	1,157	23,864	10 yrs - 10/31/27	Capacity Acquisition	Summer Only
112186	NNG TFX 5 (Disc Nov-Mar)	36,630	0	36,630	10 yrs - 10/31/27		3.77%
112186	NNG TFX 5 (Disc Apr - Jun, Sep-Oct)	20,303	0	20,303	10 yrs - 10/31/27		Summer Only
112186	NNG TFX 2 (Disc July-Aug)	1,000	0	1,000	10 yrs - 10/31/27		Summer Only
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/27		2.58%
122067	NNG TFX (Disc. Nov-Mar)	23,680	7,169	30,849	10 yrs - 10/31/27	Capacity Acquisition	3.18%
122067	NNG TFX 7 (Disc)	23,680	7,169	30,849	10 yrs - 10/31/27	Capacity Acquisition	Summer Only
122068	NNG TFX (Nov-Mar)	10,319	4,094	14,413	10 yrs - 10/31/27	Capacity Acquisition	1.48%
122068	NNG TFX 7 (Max)	10,319	4,094	14,413	10 yrs - 10/31/27	Capacity Acquisition	Summer Only
		[PROTECTED DATA BEGINS					
	VGT to NNG Chisago (1)						
	VGT Pierz to NNG (2)						
	Capacity Release						**PROTECTED DATA ENDS]**
AF0044	VGT FT-A 12 Mos.	32,405	0	32,405	5 yrs - 10/31/26		3.34%
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/26		0.44%
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	5 yrs - 10/31/29		1.03%
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	5 yrs - 10/31/27		1.61%
AF0217	VGT FT-A 12 Mos.	87,213	0	87,213	5 yrs - 10/31/29		8.98%
AF0329	VGT FT-A 12 Mos.	20,200	0	20,200	5 yrs - 10/31/28		2.08%
AF0360	VGT FT-A 12 Mos.	22,000	0	22,000	5 yrs - 10/31/27		2.27%
AF0535	VGT FT-A 12 Mos.	2,500	0	2,500	5 yrs - 11/30/28		0.26%
AF0554	VGT FT-A 12 Mos.	30,000	0	30,000	5 yrs - 11/30/28		3.09%
	WBI FT-1482	8,000	0	8,000	6.5 yrs - 3/30/2032		0.82%
	WBI FT-157	461	0	461	20 yrs - 07/01/33		0.05%
	City Gate Deliveries	20,000	0	20,000	3 yrs - 10/31/28		2.06%
	TBD City Gate Deliveries	0	4,000	4,000	5 mth - 3/31/26		0.41%
	LP Peak Shaving	90,000	0	90,000			9.27%
	LNG Peak Shaving	156,000	0	156,000			16.07%
	Total Design Day Capacity	**942,684**		**970,717**			**100%**
	Heating Season Total	942,684		970,717			
	Non-Heating Season Total	555,147		579,180			

Protected data is shaded. **Miscellaneous Entitlements with Reservation Fees**

Additional Pipeline Entitlements					
ANR FTS-106209 12 Mos. (1)	4,829	0	4,829	3 yrs - 03/31/27	
ANR FTS-106211 (Summer) (1)	5,433	2	5,435	3 yrs - 03/31/27	Annual Fuel Adjustment
ANR FTS-106211 (Winter) (1)	15,171	0	15,171	3 yrs - 03/31/27	
ANR FTS-114492 12 Mos. (1)	66,500	0	66,500	5 yrs - 10/31/28	
ANR FTS-135957 12 Mos. (1)	22,000	0	22,000	10 yrs - 10/31/32	
GLT FT18539 (Winter) (2)	3,509	0	3,509	13 yrs - 03/31/37	
GLT FT18539 (Summer) (2)	5,370	0	5,370	13 yrs - 03/31/37	
GLT Backhaul FT18129 (Nov-Mar) (2)	9,248	0	9,248	13 yrs - 03/31/37	
NNG SMS (3)	30,650		30,650	5 yrs - 10/31/27	
VGT OBA (3)	7,400		7,400	month-to-month	
Supply Entitlements (4)					
[PROTECTED DATA BEGINS					
					PROTECTED DATA ENDS]
Storage Entitlements - Deliverability					
ANR Pipeline Storage	15,226	17	15,243	5 yrs - 3/31/29	Annual Fuel Adjustment
ANR Storage	9,248	0	9,248	6 yrs - 3/31/30	
FDD Service (5)	140,230	0	140,230	5 yrs - 5/31/27	
FDD Service	78,050	0	78,050	15 yrs - 5/31/27	
Storage Entitlements - Capacity					
ANR Pipeline Storage	944,012	1,054	945,066	5 yrs - 3/31/29	Annual Fuel Adjustment
ANR Storage Co	1,165,000	0	1,165,000	6 yrs - 3/31/30	
FDD Service (5)	8,084,975	0	8,084,975	5 yrs - 5/31/27	
FDD Service	4,500,000	0	4,500,000	15 yrs - 5/31/27	

(1) Not included in total peak deliverability -- feeds VGT (capacity not additive).
(2) Not included in total peak deliverability -- feeds NNG (capacity not additive).
(3) Not included in total peak deliverability -- entitlement delivered by or associated with TF or FT-A service.
(4) Supply contracts containing reservation fees.
(5) Capacity expires 6,684,975 Dth in May 2027 & 1,400,000 Dth in May 2028.

Northern States Power Company
MINNESOTA STATE RATE IMPACT
Revised from 8/1/25 filing
Date to implement proposed changes: November 1, 2025
$/Dth

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: October 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Residential								
Commodity Cost of Gas (WACOG)	$3.7517	$2.4880	$2.3830	$3.4496	-8.05%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$1.2458	$1.1571	$1.1793	$1.2797	2.72%	10.60%	8.51%	$0.1004
February Gas Event	$0.4219	$0.4219	$0.4219	$0.4219			0.00%	$0.0000
Distribution Margin	$3.8024	$2.7493	$3.8024	$3.8024	0.00%	38.31%	0.00%	$0.0000
Total per Dth Cost	$9.2218	$6.8163	$7.7866	$8.9536	-2.91%	31.36%	14.99%	$1.1670
Average Annual Usage (Dth)	84	84	84	84				
Average Annual Total Cost	$775.14	$572.95	$654.51	$752.60	-2.91%	31.36%	14.99%	$98.09
Average Annual Total Demand Cost of Gas	$104.72	$97.26	$99.13	$107.57				**$8.44**
Small Commercial								
Commodity Cost of Gas (WACOG)	$3.7173	$2.4880	$2.3830	$3.4496	-7.20%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$1.2629	$1.1651	$1.1933	$1.2958	2.61%	11.22%	8.59%	$0.1025
Distribution Margin	$3.1143	$2.1974	$3.1143	$3.1143	0.00%	41.73%	0.00%	$0.0000
Total per Dth Cost	$8.0945	$5.8505	$6.6906	$7.8597	-2.90%	34.34%	17.47%	$1.1691
Average Annual Usage (Dth)	224	224	224	224				
Average Annual Total Cost	$1,815.84	$1,312.44	$1,500.90	$1,763.16	-2.90%	34.34%	17.47%	$262.27
Average Annual Total Demand Cost of Gas	$283.31	$261.37	$267.69	$290.69				**$22.99**
Large Commercial								
Commodity Cost of Gas (WACOG)	$3.7173	$2.4880	$2.3830	$3.4496	-7.20%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$1.2188	$1.1344	$1.1565	$1.2544	2.92%	10.58%	8.47%	$0.0979
Distribution Margin	$2.7255	$1.8410	$2.7255	$2.7255	0.00%	48.04%	0.00%	$0.0000
Total per Dth Cost	$7.6616	$5.4634	$6.2650	$7.4295	-3.03%	35.99%	18.59%	$1.1645
Average Annual Usage (Dth)	1,591	1,591	1,591	1,591				
Average Annual Total Cost	$12,192.19	$8,694.14	$9,969.69	$11,822.80	-3.03%	35.99%	18.59%	$1,853.11
Average Annual Total Demand Cost of Gas	$1,939.52	$1,805.21	$1,840.38	$1,996.18				**$155.79**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: October 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Small Interruptible Tier I								
Commodity Cost of Gas (WACOG)	$3.7146	$2.4880	$2.3830	$3.4496	-7.13%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$2.2037	$1.4885	$2.2037	$2.2037	0.00%	48.05%	0.00%	$0.0000
Total per Dth Cost	$5.9182	$3.9765	$4.5867	$5.6533	-4.48%	42.17%	23.25%	$1.0666
Average Annual Usage (Dth)	8,438	8,438	8,438	8,438				
Average Annual Total Cost	$49,938.43	$33,553.70	$38,702.53	$47,702.59	-4.48%	42.17%	23.25%	$9,000.06
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible Tier I								
Commodity Cost of Gas (WACOG)	$3.6590	$2.4880	$2.3830	$3.4496	-5.72%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$1.5414	$0.8478	$1.5414	$1.5414	0.00%	81.82%	0.00%	$0.0000
Total per Dth Cost	$5.2004	$3.3358	$3.9244	$4.9910	-4.03%	49.62%	27.18%	$1.0666
Average Annual Usage (Dth)	53,961	53,961	53,961	53,961				
Average Annual Total Cost	$280,617.56	$179,998.93	$211,761.73	$269,316.06	-4.03%	49.62%	27.18%	$57,554.33
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible Tier I								
Commodity Cost of Gas (WACOG)	$3.6143	$2.4880	$2.3830	$3.4496	-4.56%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$1.3629	$0.7977	$1.3629	$1.3629	0.00%	70.87%	0.00%	$0.0000
Total per Dth Cost	$4.9772	$3.2857	$3.7459	$4.8125	-3.31%	46.47%	28.47%	$1.0666
Average Annual Usage (Dth)	675,109	675,109	675,109	675,109				
Average Annual Total Cost	$3,360,143.69	$2,218,170.52	$2,528,909.49	$3,248,980.31	-3.31%	46.47%	28.47%	$720,070.81
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: October 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Small Interruptible Tier II								
Commodity Cost of Gas (WACOG)	$3.7146	$2.4880	$2.3830	$3.4496	-7.13%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$1.9833	$0.0000	$1.9833	$2.2037	11.11%	0.00%	11.11%	$0.2204
Total per Dth Cost	$5.6979	$2.4880	$4.3663	$5.6533	-0.78%	127.22%	29.47%	$1.2870
Average Annual Usage (Dth)	8,438	8,438	8,438	8,438				
Average Annual Total Cost	$48,079.01	$20,993.95	$36,843.11	$47,702.59	-0.78%	127.22%	29.47%	$10,859.47
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible Tier II								
Commodity Cost of Gas (WACOG)	$3.6590	$2.4880	$2.3830	$3.4496	-5.72%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$1.3872	$0.0000	$1.3872	$1.3872	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$5.0463	$2.4880	$3.7702	$4.8368	-4.15%	94.41%	28.29%	$1.0666
Average Annual Usage (Dth)	53,961	53,961	53,961	53,961				
Average Annual Total Cost	$272,300.08	$134,253.86	$203,444.25	$260,998.58	-4.15%	94.41%	28.29%	$57,554.33
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible Tier II								
Commodity Cost of Gas (WACOG)	$3.6143	$2.4880	$2.3830	$3.4496	-4.56%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
Distribution Margin	$1.2266	$0.0000	$1.2266	$1.3629	11.11%	0.00%	11.11%	$0.1363
Total per Dth Cost	$4.8409	$2.4880	$3.6096	$4.8125	-0.59%	93.43%	33.32%	$1.2029
Average Annual Usage (Dth)	675,109	675,109	675,109	675,109				
Average Annual Total Cost	$3,268,133.14	$1,679,670.15	$2,436,898.95	$3,248,980.31	-0.59%	93.43%	33.32%	$812,081.36
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**

(1) Includes demand smoothing

Summary - Change from most recent PGA

Customer Class	Commodity Change ($/Dth)	Commodity Change (Percent)	Demand Change ($/Dth)	Demand Change (Percent)	Demand Annual Change ($/Dth)	Total Annual Change ($/Dth)	Total Annual Change (Percent)
Residential	$1.0666	44.76%	$0.2407	20.41%	$20.23	$109.89	16.79%
Small Commercial	$1.0666	44.76%	$0.2463	20.64%	$55.25	$294.52	19.62%
Large Commercial	$1.0666	44.76%	$0.2328	20.13%	$370.46	$2,067.79	20.74%
Small Interruptible Tier I	$1.0666	44.76%	$0.0000	NA	$0.00	$9,000.06	23.25%
Small Interruptible Tier II	$1.0666	44.76%	$0.0000	NA	$0.00	$10,859.47	29.47%
Medium Interruptible Tier I	$1.0666	44.76%	$0.0000	NA	$0.00	$57,554.33	27.18%
Medium Interruptible Tier II	$1.0666	44.76%	$0.0000	NA	$0.00	$57,554.33	28.29%
Large Interruptible Tier I	$1.0666	44.76%	$0.0000	NA	$0.00	$720,070.81	28.47%
Large Interruptible Tier II	$1.0666	44.76%	$0.0000	NA	$0.00	$812,081.36	33.32%

DERIVATION OF CURRENT PGA COSTS

Nov. 2025 - Projected Costs (Actual prices will be determined Nov. 1, 2025)*

Revised from 8/1/25 filing

	Demand Cost (Res, Sm & Lg Commercial Firm)	Annual Cost	Winter Cost	Total
1.	MN & ND Total Demand	$56,966,198	$38,032,408	
2.	x Minnesota Design Day Ratio (2025 Demand Entitlement Filing)	86.02%	86.02%	
3.	Annual System Demand Allocation to MN	$49,002,323	$32,737,099	
4.	MN State Design Day (2025 Demand Entitlement Filing)	786,332	786,332	
5.	- Small & Large Demand Billed Dth (2024 Demand Entitlement Filing)	28,540	28,540	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	757,792	757,792	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$47,225,603	$31,529,284	
8.	Demand Billed Cost Allocation (3 - 7)	$1,778,613	$1,187,457	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	618,290,026	465,570,166	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.07638	$0.06772	$0.14410
11.	Demand Cost True-up - Residential, Oct-May			$0.00000
12.	Demand Cost True-up - Commercial, Oct-May			$0.00000
13.	Total Demand Rate - Residential (10 +11)			$0.14410
14.	Total Demand Rate -Commercial (10 + 12)			$0.14410
	Demand Cost (Demand Billed)			
15.	Cost Allocated to Demand Billed (8)	$1,778,613	$1,187,457	$2,966,070
16.	/ Annual Contract Billing Demand (2025 Demand Entitlement Filing)			3,424,800
17.	Monthly Commercial Demand Billed Demand Rate			$0.86606

	Commodity Costs	Monthly Cost
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$31,079,961
19.	x MN Portion of Monthly Retail Sales	84.48%
20.	MN Portion of Monthly Commodity Costs	$26,256,351
21.	MN Budgeted Calendar Month Retail Therm Sales	76,113,610
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.34496

	Total Gas Cost per Therm	
23.	Residential (13 + 22)	**$0.48906**
24.	Small & Large Commercial (14 +22)	**$0.48906**
25.	Small & Large Demand Billed - Demand (17)	**$0.86602**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.34496**

*Commodity costs are projected and for illustrative purposed only.

Attachments
Effective January 1, 2026

Northern States Power Company
DEMAND COST OF GAS IMPACT - JANUARY 2026
Revised from 8/1/25 filing
Protected data is shaded.

Docket No. G002/M-25-67
Contract Demand Entitlements-Petition
REVISED Attachment 1, Schedule 2 - Page 1 of 2

CHANGE IN CONTRACT DEMAND ENTITLEMENTS

Contract Demand Entitlement Changes	Volume Dth/Day		Current Monthly Demand Rates	No. of Months		Total Annual Cost
ANR FTS-1 (Nov-Oct)	(66,500)	$	6.5884	12	$	(5,257,543.20)
ANR FTS-1 (Nov-Oct)	66,500	$	10.4868	12	$	8,368,466.40
ANR FTS-1 (Nov-Mar)	(15,171)	$	6.5884	5	$	(499,763.08)
ANR FTS-1 (Nov-Mar)	15,171	$	10.4868	5	$	795,476.21
ANR FTS-1 (Nov-Mar)	(5,433)	$	6.5884	7	$	(250,563.44)
ANR FTS-1 (Nov-Mar)	5,433	$	10.4868	7	$	398,823.49
ANR FTS-1 (Nov-Oct)	(22,000)	$	6.5884	12	$	(1,739,337.60)
ANR FTS-1 (Nov-Oct)	22,000	$	10.4868	12	$	2,768,515.20
ANR FTS-1 (Nov-Oct)	(4,829)	$	14.0900	12	$	(816,487.32)
ANR FTS-1 (Nov-Oct)	4,829	$	26.9958	12	$	1,564,352.62
ANR FTS-1 (Nov-Oct)	(15,226)	$	2.1126	12	$	(385,997.37)
ANR FTS-1 (Nov-Oct)	15,226	$	2.5372	12	$	463,576.89
ANR FSS (Nov-Oct)	17	$	2.5372	12	$	517.59
ANR FSS (Jan-Dec)	(9,248)	$	1.4160	5	$	(65,475.84)
ANR FSS (Jan-Dec)	9,248	$	3.4645	5	$	160,198.48
ANRS FSS (Apr-July)	2	$	10.4868	7	$	146.82
ANRS FSS (Apr-July)	1,157	$	25.7990	2	$	59,698.89
ANR FTS-1 (Apr-July)	1,157	$	47.7400	3	$	165,705.54
NNG TFX (Nov-Dec)	1,157	$	17.9030	7	$	144,996.40
NNG TFX (Jan-Mar)	4,094	$	25.7990	2	$	211,242.21
NNG TFX (Nov-Dec)	4,094	$	47.7400	3	$	586,342.68
NNG TFX (Jan-Mar)	4,094	$	17.9030	7	$	513,064.17
NNG TFX (Apr-Oct)	(28,500)	$	25.7990	3	$	(2,205,814.50)
NNG TFX (Jan-Mar)	28,500	$	47.7400	3	$	4,081,770.00
NNG TFX (Jan-Mar)	(10,319)	$	25.7990	3	$	(798,659.64)
NNG TFX (Jan-Mar)	10,319	$	47.7400	3	$	1,477,887.18
NNG TFX (Jan-Mar)	(10,319)	$	9.6760	7	$	(698,926.51)
NNG TFX (Apr-Oct)	10,319	$	17.9030	7	$	1,293,187.40
NNG TFX (Apr-Oct)	(28,132)	$	25.7990	3	$	(2,177,332.40)
NNG TFX (Jan-Mar)	28,132	$	47.7400	3	$	4,029,065.04
NNG TFX (Jan-Mar)	(22,707)	$	9.6760	7	$	(1,537,990.52)
NNG TFX (Apr-Oct)	22,707	$	17.9030	7	$	2,845,663.95
NNG TFX (Apr-Oct)	(140,230)	$	3.2345	10	$	(4,535,739.35)
NNG FDD (Jan-Oct)	(78,050)	$	3.2345	10	$	(2,524,527.25)
NNG FDD (Jan-Oct)	140,230	$	4.8003	10	$	6,731,460.69
NNG FDD (Jan-Oct)	78,050	$	4.8003	10	$	3,746,634.15
			[PROTECTED DATA BEGINS			
NNG TFX (Nov-Oct)	6,667					
NNG TFX (Nov-Oct)	3,333					
NNG TFX (Nov-Oct)	3,333					
NNG TFX (Nov-Oct)	1,613					
NNG TFX (Nov-Oct)	1,613					
NNG TFX (Nov-Oct)	7,169					
NNG TFX (Nov-Oct)	7,169					
						PROTECTED DATA ENDS]
GLGT FT- (Nov-Dec)	(3,509)	$	8.1860	5	$	(143,623.37)
GLGT FT- (Nov-Dec)	3,509	$	9.1220	5	$	160,045.49
GLGT FT- (Nov-Dec)	(5,370)	$	8.1860	7	$	(307,711.74)
GLGT FT- (Nov-Dec)	5,370	$	9.1220	7	$	342,895.98
GLGT FT- (Nov-Dec)	(9,248)	$	8.1860	5	$	(378,520.64)
GLGT FT- (Nov-Dec)	9,248	$	9.1220	5	$	421,801.28
Total					$	18,194,602.04

Supplier Entitlement Changes
Change in Supplier Reservation Fees
[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Total	4,000	$	387,491.00
Total MN & ND Demand Cost Adjustment		**$**	**18,582,093.04**
Minnesota Allocation Factor (MN/ND Allocated Demand)			86.02%
MN only Demand Cost Adjustment due to MN/ND Allocated Demand		**$**	**15,984,933.73**

[1]ANR Third Revised Volume No. 1, Part 4.9 - Statement of Rates, v.4.0.1 Effective November 1, 2025
[2]GLGT Volume No. 1, Part 5.0 - Statement of Rates, v.60.0.0, Effective Novemeber 1, 2025
3NNG Seventh Revised Volume No. 1, Twenty First Revised Sheet No. 50, Effective January 1, 2026
4NNG Seventh Revised Volume No. 1, Twenty Fourth Revised Sheet No. 51, Effective January 1, 2026

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Demand Cost Changes from Prior Year
Revised from 8/1/25 filing
Protected data is shaded.

Docket No. G002/M-25-67
Contract Demand Entitlements-Petition
REVISED Attachment 1, Schedule 2 - Page 2 of 2

	Volume	Rate	Months	Annual Cost	Winter Cost	Total Cost	Minnesota Deliverable	North Dakota Deliverable	Upstream/System Supply	Footnote
2024 SUPPLEMENTAL FILED COSTS				**$50,970,508.65**	**$35,820,718.55**	**$86,791,227.20**				
2024 CHANGES FILED COMPARED TO ACTUAL COSTS										
Total				$ -	$ -	$ -				
2024 ACTUAL COSTS				**$ 50,970,508.65**	**$ 35,820,718.55**	**$ 86,791,227.20**				
CHANGES FOR 2025 FILING										
Contract Demand Entitlement Changes										
ANR FTS-1 (Nov-Oct)	(66,500)	$ 6.5884	12	$ (5,257,543.20)		$ (5,257,543.20)			$ (5,257,543.20)	1
ANR FTS-1 (Nov-Oct)	66,500	$ 10.4868	12	$ 8,368,466.40		$ 8,368,466.40			$ 8,368,466.40	1
ANR FTS-1 (Nov-Mar)	(15,171)	$ 6.5884	5		$ (499,763.08)	$ (499,763.08)			$ (499,763.08)	1
ANR FTS-1 (Nov-Mar)	15,171	$ 10.4868	5		$ 795,476.21	$ 795,476.21			$ 795,476.21	1
ANR FTS-1 (Apr-July)	(5,433)	$ 6.5884	7		$ (250,563.44)	$ (250,563.44)			$ (250,563.44)	1
ANR FTS-1 (Apr-July)	5,433	$ 10.4868	7		$ 398,823.49	$ 398,823.49			$ 398,823.49	1
ANR FTS-1 (Nov-Oct)	(22,000)	$ 6.5884	12	$ (1,739,337.60)		$ (1,739,337.60)			$ (1,739,337.60)	1
ANR FTS-1 (Nov-Oct)	22,000	$ 10.4868	12	$ 2,768,515.20		$ 2,768,515.20			$ 2,768,515.20	1
ANR FTS-1 (Nov-Oct)	(4,829)	$ 14.0900	12	$ (816,487.32)		$ (816,487.32)			$ (816,487.32)	1
ANR FTS-1 (Nov-Oct)	4,829	$ 26.9958	12	$ 1,564,352.62		$ 1,564,352.62			$ 1,564,352.62	1
ANR FSS (Nov-Oct)	(15,226)	$ 2.1126	12		$ (385,997.37)	$ (385,997.37)			$ (385,997.37)	1
ANR FSS (Jan-Dec)	15,226	$ 2.5372	12		$ 463,576.89	$ 463,576.89			$ 463,576.89	1
ANR FSS (Jan-Dec)	17	$ 2.5372	12		$ 517.59	$ 517.59			$ 517.59	1
ANRS FSS (Apr-July)	(9,248)	$ 1.4160	5		$ (65,475.84)	$ (65,475.84)			$ (65,475.84)	1
ANRS FSS (Apr-July)	9,248	$ 3.4645	5		$ 160,198.48	$ 160,198.48			$ 160,198.48	1
ANR FTS-1 (Apr-July)	2	$ 10.4868	7		$ 146.82	$ 146.82			$ 146.82	1
NNG TFX (Nov-Dec)	1,157	$ 25.7990	2		$ 59,698.89	$ 59,698.89	$ 59,698.89			5
NNG TFX (Jan-Mar)	1,157	$ 47.7400	3		$ 165,705.54	$ 165,705.54	$ 165,705.54			5
NNG TFX (Apr-Oct)	1,157	$ 17.9030	7	$ 144,996.40		$ 144,996.40	$ 144,996.40			5
NNG TFX (Nov-Dec)	4,094	$ 25.7990	2		$ 211,242.21	$ 211,242.21	$ 211,242.21			5
NNG TFX (Jan-Mar)	4,094	$ 47.7400	3		$ 586,342.68	$ 586,342.68	$ 586,342.68			5
NNG TFX (Apr-Oct)	4,094	$ 17.9030	7	$ 513,064.17		$ 513,064.17				5
NNG TFX (Jan-Mar)	(28,500)	$ 25.7990	3		$ (2,205,814.50)	$ (2,205,814.50)				7
NNG TFX (Jan-Mar)	28,500	$ 47.7400	3		$ 4,081,770.00	$ 4,081,770.00				7
NNG TFX (Jan-Mar)	(10,319)	$ 25.7990	3		$ (798,659.64)	$ (798,659.64)				7
NNG TFX (Jan-Mar)	10,319	$ 47.7400	3		$ 1,477,887.18	$ 1,477,887.18				7
NNG TFX (Apr-Oct)	(10,319)	$ 9.6760	7	$ (698,926.51)		$ (698,926.51)				7
NNG TFX (Apr-Oct)	10,319	$ 17.9030	7	$ 1,293,187.40		$ 1,293,187.40				7
NNG TFX (Jan-Mar)	(28,132)	$ 25.7990	3		$ (2,177,332.40)	$ (2,177,332.40)				7
NNG TFX (Jan-Mar)	28,132	$ 47.7400	3		$ 4,029,065.04	$ 4,029,065.04				7
NNG TFX (Apr-Oct)	(22,707)	$ 9.6760	7	$ (1,537,990.52)		$ (1,537,990.52)				7
NNG TFX (Apr-Oct)	22,707	$ 17.9030	7	$ 2,845,663.95		$ 2,845,663.95				7
NNG FDD (Jan-Oct)	(140,230)	$ 3.2345	10		$ (4,535,739.35)	$ (4,535,739.35)				7
NNG FDD (Jan-Oct)	(78,050)	$ 3.2345	10		$ (2,524,527.25)	$ (2,524,527.25)				7
NNG FDD (Jan-Oct)	140,230	$ 4.8003	10		$ 6,731,460.69	$ 6,731,460.69				7
NNG FDD (Jan-Oct)	78,050	$ 4.8003	10		$ 3,746,634.15	$ 3,746,634.15				7
		[PROTECTED DATA BEGINS								
NNG TFX (Nov-Oct)	6,667									5
NNG TFX (Nov-Oct)	3,333									5
NNG TFX (Nov-Oct)	3,333									5
NNG TFX (Nov-Oct)	1,613									5
NNG TFX (Nov-Oct)	1,613									5
NNG TFX (Nov-Oct)	7,169									5
NNG TFX (Nov-Oct)	7,169									5
							PROTECTED DATA ENDS]			
GLGT FT- (Nov-Dec)	(3,509)	$ 8.1860	5		$ (143,623.37)	$ (143,623.37)		$ (143,623.37)		6
GLGT FT- (Nov-Dec)	3,509	$ 9.1220	5		$ 160,045.49	$ 160,045.49		$ 160,045.49		6
GLGT FT- (Nov-Dec)	(5,370)	$ 8.1860	7	$ (307,711.74)		$ (307,711.74)		$ (307,711.74)		6
GLGT FT- (Nov-Dec)	5,370	$ 9.1220	7	$ 342,895.98		$ 342,895.98		$ 342,895.98		6
GLGT FT- (Nov-Dec)	(9,248)	$ 8.1860	5		$ (378,520.64)	$ (378,520.64)		$ (378,520.64)		6
GLGT FT- (Nov-Dec)	9,248	$ 9.1220	5		$ 421,801.28	$ 421,801.28		$ 421,801.28		6
Total				$ 8,200,023.23	$ 9,994,578.84	$ 18,194,602.07	$ 2,355,066.81	$ 94,887.00	$ 5,504,905.85	
Supplier Entitlement Changes										
[PROTECTED DATA BEGINS										
										8
										8
										8
										8
										8
								PROTECTED DATA ENDS]		
Total				$0.00	$387,491.00	$387,491.00	$0.00	$387,491.00	$0.00	
TOTAL OF 2025 CHANGES				**$ 8,200,023.23**	**$ 10,382,069.84**	**$ 18,582,093.07**	**$ 2,355,066.81**	**$ 482,378.00**	**$ 5,504,905.85**	
2025 COSTS				**$ 59,170,531.88**	**$ 46,202,788.39**	**$ 105,373,320.27**				
2025 CHANGES AS A PERCENTAGE OF SYSTEM RESOURCES							83%	17%		9

Footnote
1. Rate change in accordnace with approved Rate Case Settlement (RP25-858), Rate effective November 1, 2025.
2. Contract renewal at maximum tariff rate.
3. Annual volume adjustments on ANR transport and storage agreements for fuel. Upstream capacity serves demand in both MN and ND.
4. Rate change as a result of applying discount agreements
5. Acquisition of new capacity on NNG as part of Northern Lights 2025 to meet Design Day requirements of Minnesota customers.
6. Rate change due to ongoing Rate Case (RP25-855), Interim Settlement Rates effective November 1, 2025.
7. Rate change due to ongoing Rate Case (RP25-989), Interim Settlement Rates effective January 1, 2026
8. Expired/Replaced peaking supply contract with demand charges in effect November 1, 2025 through March 31, 2026.
9. Upstream/system supply refers to costs that are incurred to serve all customers on the system across MN and ND. For purpocses of this schedule, it is reasonable to split these costs between MN and ND using the overall system jurisdictional factors.

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
COMPANY DEMAND PROFILE
2025-2026 Heating Season
Revised from 8/1/25 filing
Protected data is shaded.

Docket No. G002/M-25-67
Contract Demand Entitlements-Petition
REVISED Attachment 2, Schedule 1 - Page 1 of 2

Contract No.	Type of Capacity or Entitlement	Current Amount Dth or MMBtu	Proposed Change Dth or MMBtu	Proposed Amount Dth or MMBtu	Contract Length and Expiration Date	Change Description	% of Peak Day Entitlement
	Capacity Entitlements						
112183	NNG TF12 BASE (Max)	104,117	0	104,117	10 yrs - 10/31/27		10.73%
112183	NNG TF12 VARIABLE (Max)	0	0	0	10 yrs - 10/31/27		0.00%
112182	NNG TF12 BASE (Disc)	24,201	4,172	28,373	10 yrs - 10/31/27	Annual Re-Determination	2.92%
112182	NNG TF12 VARIABLE (Disc.)	70,326	(4,172)	66,154	10 yrs - 10/31/27	Annual Re-Determination	6.81%
112183	NNG TF5 (Max)	62,415	0	62,415	10 yrs - 10/31/27		6.43%
112182	NNG TF5 (Disc.)	29,599	0	29,599	10 yrs - 10/31/27		3.05%
111739	NNG TFX (Nov-Mar)	28,500	0	28,500	5 yrs - 3/31/27		2.94%
112185	NNG TFX (Disc. Nov-Mar)	58,184	0	58,184	10 yrs - 10/31/27	Capacity Acquisition	5.99%
112185	NNG TFX (Disc. 12-month)	36,654	11,613	48,267	10 yrs - 10/31/27		4.97%
112185	NNG TFX 5 (Disc)	6,828	0	6,828	10 yrs - 10/31/27		Summer Only
112185	NNG TFX 2 (Disc)	2,503	0	2,503	10 yrs - 10/31/27		Summer Only
112186	NNG TFX 5 (Max)	28,132	1,157	29,289	10 yrs - 10/31/27	Capacity Acquisition	3.02%
112186	NNG TFX 7 (Max)	22,707	1,157	23,864	10 yrs - 10/31/27	Capacity Acquisition	Summer Only
112186	NNG TFX 5 (Disc Nov-Mar)	36,630	0	36,630	10 yrs - 10/31/27		3.77%
112186	NNG TFX 5 (Disc Apr - Jun, Sep-Oct)	20,303	0	20,303	10 yrs - 10/31/27		Summer Only
112186	NNG TFX 2 (Disc July-Aug)	1,000	0	1,000	10 yrs - 10/31/27		Summer Only
112184	NNG TFX (Disc.)	25,000	0	25,000	10 yrs - 10/31/27		2.58%
122067	NNG TFX (Disc. Nov-Mar)	23,680	7,169	30,849	10 yrs - 10/31/27	Capacity Acquisition	3.18%
122067	NNG TFX 7 (Disc)	23,680	7,169	30,849	10 yrs - 10/31/27	Capacity Acquisition	Summer Only
122068	NNG TFX (Nov-Mar)	10,319	4,094	14,413	10 yrs - 10/31/27	Capacity Acquisition	1.48%
122068	NNG TFX 7 (Max)	10,319	4,094	14,413	10 yrs - 10/31/27	Capacity Acquisition	Summer Only
		[PROTECTED DATA BEGINS					
	VGT to NNG Chisago (1)						
	VGT Pierz to NNG (2)						
	Capacity Release						**PROTECTED DATA ENDS]**
AF0044	VGT FT-A 12 Mos.	32,405	0	32,405	5 yrs - 10/31/26		3.34%
AF0044	VGT FT-A (Nov-Mar)	4,239	0	4,239	5 yrs - 10/31/26		0.44%
AF0103	VGT FT-A 12 Mos.	10,000	0	10,000	5 yrs - 10/31/29		1.03%
AF0037	VGT FT-A 12 Mos.	15,600	0	15,600	5 yrs - 10/31/27		1.61%
AF0217	VGT FT-A 12 Mos.	87,213	0	87,213	5 yrs - 10/31/29		8.98%
AF0329	VGT FT-A 12 Mos.	20,200	0	20,200	5 yrs - 10/31/28		2.08%
AF0360	VGT FT-A 12 Mos.	22,000	0	22,000	5 yrs - 10/31/27		2.27%
AF0535	VGT FT-A 12 Mos.	2,500	0	2,500	5 yrs - 11/30/28		0.26%
AF0554	VGT FT-A 12 Mos.	30,000	0	30,000	5 yrs - 11/30/28		3.09%
	WBI FT-1482	8,000	0	8,000	6.5 yrs - 3/30/2032		0.82%
	WBI FT-157	461	0	461	20 yrs - 07/01/33		0.05%
	City Gate Deliveries	20,000	0	20,000	3 yrs - 10/31/28		2.06%
	TBD City Gate Deliveries	0	4,000	4,000	5 mth - 3/31/26		0.41%
	LP Peak Shaving	90,000	0	90,000			9.27%
	LNG Peak Shaving	156,000	0	156,000			16.07%
	Total Design Day Capacity	**942,684**		**970,717**			**100%**
	Heating Season Total	942,684		970,717			
	Non-Heating Season Total	555,147		579,180			

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Protected data is shaded. **Miscellaneous Entitlements with Reservation Fees**

Additional Pipeline Entitlements					
ANR FTS-106209 12 Mos. (1)	4,829	0	4,829	3 yrs - 03/31/27	
ANR FTS-106211 (Summer) (1)	5,433	2	5,435	3 yrs - 03/31/27	Annual Fuel Adjustment
ANR FTS-106211 (Winter) (1)	15,243	0	15,243	3 yrs - 03/31/27	
ANR FTS-114492 12 Mos. (1)	66,500	0	66,500	5 yrs - 10/31/28	
ANR FTS-135957 12 Mos. (1)	22,000	0	22,000	10 yrs - 10/31/32	
GLT FT18539 (Winter) (2)	3,509	0	3,509	13 yrs - 03/31/37	
GLT FT18539 (Summer) (2)	5,370	0	5,370	13 yrs - 03/31/37	
GLT Backhaul FT18129 (Nov-Mar) (2)	9,248	0	9,248	13 yrs - 03/31/37	
NNG SMS (3)	30,650		30,650	5 yrs - 10/31/27	
VGT OBA (3)	7,400		7,400	month-to-month	

Supply Entitlements (4)
[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Storage Entitlements - Deliverability					
ANR Pipeline Storage	15,226	17	15,243	5 yrs - 3/31/29	Annual Fuel Adjustment
ANR Storage	9,248	0	9,248	6 yrs - 3/31/30	
FDD Service (5)	140,230	0	140,230	5 yrs - 5/31/27	
FDD Service	78,050	0	78,050	15 yrs - 5/31/27	
Storage Entitlements - Capacity					
ANR Pipeline Storage	944,012	1,054	945,066	5 yrs - 3/31/29	Annual Fuel Adjustment
ANR Storage Co	1,165,000	0	1,165,000	6 yrs - 3/31/30	
FDD Service (5)	8,084,975	0	8,084,975	5 yrs - 5/31/27	
FDD Service	4,500,000	0	4,500,000	15 yrs - 5/31/27	

(1) Not included in total peak deliverability -- feeds VGT (capacity not additive).
(2) Not included in total peak deliverability -- feeds NNG (capacity not additive).
(3) Not included in total peak deliverability -- entitlement delivered by or associated with TF or FT-A service.
(4) Supply contracts containing reservation fees.
(5) Capacity expires 6,684,975 Dth in May 2027 & 1,400,000 Dth in May 2028.

Northern States Power Company
MINNESOTA STATE RATE IMPACT
Revised from 8/1/25 filing
Date to implement proposed changes: January 1, 2026
$/Dth

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: October 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Residential								
Commodity Cost of Gas (WACOG)	$3.7517	$2.4880	$2.3830	$3.4496	-8.05%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$1.2458	$1.1571	$1.1793	$1.4200	13.98%	22.72%	20.41%	$0.2407
February Gas Event	$0.4219	$0.4219	$0.4219	$0.4219			0.00%	$0.0000
Distribution Margin	$3.8024	$2.7493	$3.8024	$3.8024	0.00%	38.31%	0.00%	$0.0000
Total per Dth Cost	$9.2218	$6.8163	$7.7866	$9.0939	-1.39%	33.41%	16.79%	$1.3073
Average Annual Usage (Dth)	84	84	84	84				
Average Annual Total Cost	$775.14	$572.95	$654.51	$764.39	-1.39%	33.41%	16.79%	$109.89
Average Annual Total Demand Cost of Gas	$104.72	$97.26	$99.13	$119.36				**$20.23**
Small Commercial								
Commodity Cost of Gas (WACOG)	$3.7173	$2.4880	$2.3830	$3.4496	-7.20%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$1.2629	$1.1651	$1.1933	$1.4396	13.99%	23.56%	20.64%	$0.2463
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$3.1143	$2.1974	$3.1143	$3.1143	0.00%	41.73%	0.00%	$0.0000
Total per Dth Cost	$8.0945	$5.8505	$6.6906	$8.0035	-1.12%	36.80%	19.62%	$1.3129
Average Annual Usage (Dth)	224	224	224	224				
Average Annual Total Cost	$1,815.84	$1,312.44	$1,500.90	$1,795.42	-1.12%	36.80%	19.62%	$294.52
Average Annual Total Demand Cost of Gas	$283.31	$261.37	$267.69	$322.95				**$55.25**
Large Commercial								
Commodity Cost of Gas (WACOG)	$3.7173	$2.4880	$2.3830	$3.4496	-7.20%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$1.2188	$1.1344	$1.1565	$1.3893	13.99%	22.47%	20.13%	$0.2328
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$2.7255	$1.8410	$2.7255	$2.7255	0.00%	48.04%	0.00%	$0.0000
Total per Dth Cost	$7.6616	$5.4634	$6.2650	$7.5644	-1.27%	38.46%	20.74%	$1.2994
Average Annual Usage (Dth)	1,591	1,591	1,591	1,591				
Average Annual Total Cost	$12,192.19	$8,694.14	$9,969.69	$12,037.48	-1.27%	38.46%	20.74%	$2,067.79
Average Annual Total Demand Cost of Gas	$1,939.52	$1,805.21	$1,840.38	$2,210.85				**$370.46**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: October 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Small Interruptible Tier I								
Commodity Cost of Gas (WACOG)	$3.7146	$2.4880	$2.3830	$3.4496	-7.13%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$2.2037	$1.4885	$2.2037	$2.2037	0.00%	48.05%	0.00%	$0.0000
Total per Dth Cost	$5.9182	$3.9765	$4.5867	$5.6533	-4.48%	42.17%	23.25%	$1.0666
Average Annual Usage (Dth)	8,438	8,438	8,438	8,438				
Average Annual Total Cost	$49,938.43	$33,553.70	$38,702.53	$47,702.59	-4.48%	42.17%	23.25%	$9,000.06
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible Tier I								
Commodity Cost of Gas (WACOG)	$3.6590	$2.4880	$2.3830	$3.4496	-5.72%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$1.5414	$0.8478	$1.5414	$1.5414	0.00%	81.82%	0.00%	$0.0000
Total per Dth Cost	$5.2004	$3.3358	$3.9244	$4.9910	-4.03%	49.62%	27.18%	$1.0666
Average Annual Usage (Dth)	53,961	53,961	53,961	53,961				
Average Annual Total Cost	$280,617.56	$179,998.93	$211,761.73	$269,316.06	-4.03%	49.62%	27.18%	$57,554.33
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible Tier I								
Commodity Cost of Gas (WACOG)	$3.6143	$2.4880	$2.3830	$3.4496	-4.56%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$1.3629	$0.7977	$1.3629	$1.3629	0.00%	70.87%	0.00%	$0.0000
Total per Dth Cost	$4.9772	$3.2857	$3.7459	$4.8125	-3.31%	46.47%	28.47%	$1.0666
Average Annual Usage (Dth)	675,109	675,109	675,109	675,109				
Average Annual Total Cost	$3,360,143.69	$2,218,170.52	$2,528,909.49	$3,248,980.31	-3.31%	46.47%	28.47%	$720,070.81
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**

(1) Includes demand smoothing

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: October 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Last Month PGA	Change ($) From Last Month PGA
Small Interruptible Tier II								
Commodity Cost of Gas (WACOG)	$3.7146	$2.4880	$2.3830	$3.4496	-7.13%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$1.9833	$0.0000	$1.9833	$2.2037	11.11%	0.00%	11.11%	$0.2204
Total per Dth Cost	$5.6979	$2.4880	$4.3663	$5.6533	-0.78%	127.22%	29.47%	$1.2870
Average Annual Usage (Dth)	8,438	8,438	8,438	8,438				
Average Annual Total Cost	$48,079.01	$20,993.95	$36,843.11	$47,702.59	-0.78%	127.22%	29.47%	$10,859.47
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Medium Interruptible Tier II								
Commodity Cost of Gas (WACOG)	$3.6590	$2.4880	$2.3830	$3.4496	-5.72%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$1.3872	$0.0000	$1.3872	$1.3872	0.00%	0.00%	0.00%	$0.0000
Total per Dth Cost	$5.0463	$2.4880	$3.7702	$4.8368	-4.15%	94.41%	28.29%	$1.0666
Average Annual Usage (Dth)	53,961	53,961	53,961	53,961				
Average Annual Total Cost	$272,300.08	$134,253.86	$203,444.25	$260,998.58	-4.15%	94.41%	28.29%	$57,554.33
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**
Large Interruptible Tier II								
Commodity Cost of Gas (WACOG)	$3.6143	$2.4880	$2.3830	$3.4496	-4.56%	38.65%	44.76%	$1.0666
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000				$0.0000
February Gas Event	$0.0000	$0.0000	$0.0000	$0.0000			0.00%	$0.0000
Distribution Margin	$1.2266	$0.0000	$1.2266	$1.3629	11.11%	0.00%	11.11%	$0.1363
Total per Dth Cost	$4.8409	$2.4880	$3.6096	$4.8125	-0.59%	93.43%	33.32%	$1.2029
Average Annual Usage (Dth)	675,109	675,109	675,109	675,109				
Average Annual Total Cost	$3,268,133.14	$1,679,670.15	$2,436,898.95	$3,248,980.31	-0.59%	93.43%	33.32%	$812,081.36
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00				**$0.00**

(1) Includes demand smoothing

Summary - Change from most recent PGA

Customer Class	Commodity Change ($/Dth)	Commodity Change (Percent)	Demand Change ($/Dth)	Demand Change (Percent)	Demand Annual Change ($/Dth)	Total Annual Change ($/Dth)	Total Annual Change (Percent)
Residential	$1.0666	44.76%	$0.2407	20.41%	$20.23	$109.89	16.79%
Small Commercial	$1.0666	44.76%	$0.2463	20.64%	$55.25	$294.52	19.62%
Large Commercial	$1.0666	44.76%	$0.2328	20.13%	$370.46	$2,067.79	20.74%
Small Interruptible Tier I	$1.0666	44.76%	$0.0000	NA	$0.00	$9,000.06	23.25%
Small Interruptible Tier II	$1.0666	44.76%	$0.0000	NA	$0.00	$10,859.47	29.47%
Medium Interruptible Tier I	$1.0666	44.76%	$0.0000	NA	$0.00	$57,554.33	27.18%
Medium Interruptible Tier II	$1.0666	44.76%	$0.0000	NA	$0.00	$57,554.33	28.29%
Large Interruptible Tier I	$1.0666	44.76%	$0.0000	NA	$0.00	$720,070.81	28.47%
Large Interruptible Tier II	$1.0666	44.76%	$0.0000	NA	$0.00	$812,081.36	33.32%

	Last Rate Case (G002/GR-23-413)	Pending Demand Change (G002/M-24-271)	Last Month PGA: October 2025	Estimated Nov 2025 PGAs with Proposed Demand Entitlement Changes
Commodity COG (WACOG) $/dkt - Resid	$3.7517	$2.4880	$2.3830	$3.4496
Commodity COG $/dkt - Commercial Firm	$3.7173	$2.4880	$2.3830	$3.4496
Commodity COG $/dkt - SVI	$3.7146	$2.4880	$2.3830	$3.4496
Commodity COG $/dkt - MVI	$3.6590	$2.4880	$2.3830	$3.4496
Commodity COG $/dkt - LVI	$3.6143	$2.4880	$2.3830	$3.4496
Summer Demand COG $/dkt - Residential	$0.6966	$0.6762	$0.6937	$0.7933
Winter Demand COG $/dkt - Residential	$1.4175	$1.3156	$1.3347	$1.6160
Summer Demand COG $/dkt - Commercia	$0.6966	$0.6762	$0.6937	$0.7933
Winter Demand COG $/dkt - Commercial	$1.4175	$1.3156	$1.3347	$1.6160
RESIDENTIAL				
Usage - Summer (Dth)	9,090,135	9,677,801	9,467,092	9,090,135
Usage - Winter (Dth)	29,072,177	29,370,534	29,589,048	29,072,177
Usage - Total (Dth)	38,162,312	39,048,335	39,056,140	38,162,312
Demand $ Total	$47,541,018	$45,184,003	$46,059,824	$54,191,842
Blended Demand Rate	$1.2458	$1.1571	$1.1793	$1.4200
SMALL COMMERCIAL				
Usage - Summer (Dth)	1,193,887	1,389,061	1,244,711	1,193,887
Usage - Winter (Dth)	4,374,508	4,513,473	4,395,884	4,374,508
Usage - Total (Dth)	5,568,395	5,902,534	5,640,595	5,568,395
Demand $ Total	$7,032,376	$6,877,209	$6,730,642	$8,016,316
Blended Demand Rate	$1.2629	$1.1651	$1.1933	$1.4396
LARGE COMMERCIAL				
Usage - Summer (Dth)	4,987,964	5,060,732	5,017,506	4,987,964
Usage - Winter (Dth)	13,110,332	12,794,264	13,033,246	13,110,332
Usage - Total (Dth)	18,098,296	17,854,996	18,050,752	18,098,296
Demand $ Total	$22,058,086	$20,254,201	$20,876,117	$25,143,248
Blended Demand Rate	$1.2188	$1.1344	$1.1565	$1.3893

see MN rule 7825.2910, Supb. 2 & 3

TOTAL FIRM NON-DEMAND				
Usage - Summer (Dth)	15,271,986	16,127,594	15,729,309	15,271,986
Usage - Winter (Dth)	46,557,017	46,678,272	47,018,178	46,557,017
Usage - Total (Dth)	61,829,003	62,805,865	62,747,487	61,829,003

DERIVATION OF CURRENT PGA COSTS

Jan 2026 - Projected Costs (Actual prices will be determined Jan. 1, 2026)*

Revised from 8/1/25 filing

		Annual Cost	Winter Cost	Total
	Demand Cost (Res, Sm & Lg Commercial Firm)			
1.	MN & ND Total Demand	$59,170,532	$46,202,788	
2.	x Minnesota Design Day Ratio (2025 Demand Entitlement Filing)	86.02%	86.02%	
3.	Annual System Demand Allocation to MN	$50,898,492	$39,743,639	
4.	MN State Design Day (2025 Demand Entitlement Filing)	786,332	786,332	
5.	- Small & Large Demand Billed Dth (2024 Demand Entitlement Filing)	28,540	28,540	
6.	Non-Demand Billed Design Day Dkt (4 - 5)	757,792	757,792	
7.	Non-Demand Billed Allocation (3 x 6 / 4)	$49,051,126	$38,301,140	
8.	Demand Billed Cost Allocation (3 - 7)	$1,847,366	$1,442,499	
9.	MN Annual / Seasonal Firm Therm Sales (Forecast)	618,290,026	465,570,166	
10.	Demand Unit Cost $/Therm (7 / 9)	$0.07933	$0.08227	$0.16160
11.	Demand Cost True-up - Residential, Oct-May			$0.00000
12.	Demand Cost True-up - Commercial, Oct-May			$0.00000
13.	Total Demand Rate - Residential (10 +11)			$0.16160
14.	Total Demand Rate -Commercial (10 + 12)			$0.16160
	Demand Cost (Demand Billed)			
15.	Cost Allocated to Demand Billed (8)	$1,847,366	$1,442,499	$3,289,865
16.	/ Annual Contract Billing Demand (2025 Demand Entitlement Filing)			3,424,800
17.	Monthly Commercial Demand Billed Demand Rate			$0.96060

	Commodity Costs	Monthly Cost
18.	NNG Annual/Best Effort/Viking/WBI/Xcel Energy Pk Shv	$31,079,961
19.	x MN Portion of Monthly Retail Sales	84.48%
20.	MN Portion of Monthly Commodity Costs	$26,256,351
21.	MN Budgeted Calendar Month Retail Therm Sales	76,113,610
22.	Commodity Unit Cost $/Therm (20 / 21)	$0.34496

	Total Gas Cost per Therm	
23.	Residential (13 + 22)	**$0.50656**
24.	Small & Large Commercial (14 +22)	**$0.50656**
25.	Small & Large Demand Billed - Demand (17)	**$0.96060**
26.	Small & Large Demand Billed - Commodity; All Interruptible (22)	**$0.34496**

*Commodity costs are projected and for illustrative purposed only.

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Protected data is shaded.

Transaction Date	Hedge Instrument	Counterparty	Premium ($/Dth)	Call Strike Price	Put Strike Price	Daily Vol (Dth)	Basis Point	Monthly Volumes (Dth) November	December	January	February	March	Total Volume (Dth)	Total Dollars

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

CERTIFICATE OF SERVICE

I, Victor Barreiro, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

DOCKET NO. G002/M-25-0067

Dated this 31st day of October 2025

/s/

____

Victor Barreiro
Regulatory Administrator

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
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3	Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy		414 Nicollet Mall Fl 5 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-67
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10	Olivia	Carroll	oliviac@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St W1360 St. Paul MN, 55101 United States	Electronic Service		No	M-25-67
11	Joey	Cherney	joey.cherney@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota Street STE 1800 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-67
12	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	M-25-67
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24	Valerie	Herring	vherring@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S. Eighth Street Minneapolis MN, 55402 United States	Electronic Service		No	M-25-67
25	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	M-25-67
26	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN,	Electronic Service		No	M-25-67

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30	Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.		8300 Norman Center Drive Suite 1000 Bloomington MN, 55437 United States	Electronic Service		No	M-25-67
31	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	M-25-67
32	Eric	Lipman	eric.lipman@state.mn.us		Office of Administrative Hearings	PO Box 64620 St. Paul MN, 55164-0620 United States	Electronic Service		No	M-25-67
33	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		Yes	M-25-67
34	Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc		414 Nicollet Mall 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	M-25-67
35	Stephen	Melchionne	stephen.melchionne@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street, Ste. 1400 St. Paul MN, 55101 United States	Electronic Service		No	M-25-67
36	Greg	Merz	greg.merz@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	M-25-67
37	Joseph	Meyer	joseph.meyer@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Bremer Tower, Suite 1400 445 Minnesota Street St Paul MN, 55101-2131 United States	Electronic Service		No	M-25-67

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39	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	M-25-67
40	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-67
41	Travis	Murray	travis.murray@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Ste 1400 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-67
42	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-67
43	Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company		200 1st Street SE PO Box 351 Cedar Rapids IA, 52406-0351 United States	Electronic Service		No	M-25-67
44	Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc.		1900 Cardinal Ln PO Box 798 Faribault MN, 55021 United States	Electronic Service		No	M-25-67
45	Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND		81 E Little Canada Road St. Paul MN, 55117 United States	Electronic Service		No	M-25-67
46	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	M-25-67
47	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-67
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