

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

Northern States Power Company
Electric Rate Increase Application

Case No. PU-24-376

SETTLEMENT AGREEMENT

This Settlement Agreement (Settlement) is entered into this 18 day of November, 2025, by and between the North Dakota Public Service Commission Advocacy Staff (Advocacy Staff); Northern States Power Company, a Minnesota corporation doing business as Xcel Energy (Xcel Energy, NSP, NSPM, or the Company); and Walmart Inc. (Walmart) (each a Party, and collectively, the Parties). This Settlement will result in just and reasonable rates for the Company's retail electric operations in North Dakota for the 2025 Future Test Year (FTY25). Through this Settlement, the Parties have resolved all issues in the above-captioned Case.

PRELIMINARY STATEMENT

On December 2, 2024, the Company filed its application and supporting testimony in the above captioned Case requesting a \$44.56 million or 19.34 percent net retail revenue increase for its provision of electric service in North Dakota. On July 8, 2025, Advocacy Staff and Walmart filed Direct Testimony in this case, identifying proposed adjustments to the Company's rate request. Advocacy Staff recommended a total rate increase of \$29.59 million, subject to receipt of additional information.

Recognizing the positions of the Parties, and the Company's need for additional revenue to have an opportunity to earn a reasonable rate of return on

the capital invested to serve North Dakota customers, the Parties have conferred and agreed to this Settlement. The revenue requirement and rate design agreed to in this Settlement reflect efforts of the Parties to ensure just and reasonable rates for the Company's provision of retail electric service to its North Dakota customers. The Parties agree that the implementation of the terms of this Settlement will accomplish that goal.

SETTLEMENT TERMS

The Parties agree to the provisions provided below:

I. REVENUE REQUIREMENTS

The Parties agree to an overall test year revenue requirement of \$254.01 million, representing a net revenue requirement increase of \$23.86 million (Settlement Revenue Requirement). The revenue requirement utilizes a weighted average cost of capital (WACC) of 7.30 percent, comprised of a Capital Structure of 52.50 percent equity and 47.50 percent debt (46.71 percent long-term debt; 0.79 percent short-term debt). The return on equity (ROE) is 9.80 percent, the cost of long-term debt is 4.51 percent, and the cost of short-term debt is 5.31 percent. Noted below are adjustments to the Company's \$44.56 million rate-increase request to arrive at the revenue requirement provided for in this Settlement.

A. Test Year Adjustments

For purposes of resolving issues in this proceeding only, and without prejudice to positions the Parties may otherwise take in other proceedings, the Parties agree to a series of test year adjustments as summarized in Schedule 1 and discussed further herein.

1. *Cost of Capital*

To ensure a balance between rate affordability, system reliability, and the Company's financial health, the Parties agree for settlement purposes to an authorized ROE of 9.80 percent for the 2025 test year. The WACC will be calculated using the capital structure proposed by the Company (as detailed above). The Parties recognize that deviations from this capital structure would impact the overall assessment of the Company by public markets and would influence the evaluation of what constitutes a just and reasonable return.

If deviations from the agreed to capital structure do occur, they should be evaluated by the Commission. Therefore, for the period prior to NSP's next rate case, the Company shall notify the Commission of any intent to change the actual capital structure target to which it manages the Company and will provide in such notice its rationale for why such a change is necessary. Further, if such a change in targeted capital structure to which the Company manages its business affairs requires the Company to seek a change in capital structure for ratemaking purposes, the Company shall bear the burden of proof regarding whether it is reasonable to change its capital structure in such proceeding.

Unless, and until such time as, the Commission modifies the Company's cost of capital, the Company will use this Settlement Cost of Capital for its annual transmission and renewable resource rider filings, or any additional riders approved by the Commission. For annual jurisdictional earnings reporting, the Company will use its actual capital structure and actual cost of debt. Changes to the Cost of Capital as provided herein result in a \$2.73 million reduction to the test year revenue requirement.

2. *Necessary Resources*

The Parties recognize that the integrated NSP System is evolving, consistent with the record in this proceeding and the record in many proceedings prior. This includes known expiration of then existing power purchase agreements (PPAs), the need to meet anticipated demand growth in the 2024-2026 time frame identified in 2012, and other needs. Recognizing that there have been disputes surrounding the evolution of NSP's System and the decisions made to address those issues for many years, the Parties agree that the following resource additions should be deemed prudent and that full recovery of these resources should be permitted as of FTY2025 as follows:

a. Mankato Energy Center II (MEC II)

The Company first brought forth the MEC II PPA, which provides for 345 MW (nameplate) of combined cycle gas generation, for consideration in 2015 in Case No. PU-15-96. The record in that Case identified a system-wide capacity need in the 2024-2026 time frame and the MEC II PPA was not determined to be prudent because the identified need had not yet arisen on the NSP System. The Company has been denied recovery of the MEC II PPA since 2012 even though it has been commercially operable and used and useful in the provision of utility service since 2019. The Parties recognize that the capacity need for which the MEC II PPA was added to the system has now arisen, notwithstanding any other generation retirements or expirations. Therefore, the Parties agree that the Company may recover the capacity and energy costs of the MEC II PPA in base rates and the Fuel Cost Rider, as appropriate. Consequently, there will be no adjustment to the Company's FTY25 revenue requirement with respect to MEC II.

b. Manitoba Hydro PPA

The Parties recognize that the Company has had a long-standing power purchasing partner with Manitoba Hydro. Most recently, the Company and Manitoba Hydro were parties to that certain 375/325 MW System Power Sale Agreement and that certain 350 MW Diversity Sale Agreement and that certain 125 MW System Power Sale Agreement which provided 500 MW of capacity and 350 MW of diversity exchange to the NSP System (Legacy MH Agreements). The Legacy MH Agreements expired on April 30, 2025. The Company and Manitoba Hydro agreed to a 5-year extension to the Legacy MH Agreements on June 13, 2024 (the Manitoba Hydro PPA) which provides 200 MW of summer capacity and 350 MW of diversity exchange capacity for the NSP System. Recognizing the Manitoba Hydro PPA is for a short period of time, preserves necessary capacity for the NSP System, and is at reasonable pricing, the Parties agree that the Company may recover the costs of the Manitoba Hydro PPA. This results in no change to the Company's FTY25 revenue requirement.

c. Cannon Falls PPA

Similar to Manitoba Hydro, the Company has had a long term PPA with Invenergy for the capacity and energy from a 357 MW (nameplate) simple cycle combustion turbine located in Cannon Falls, Minnesota (Legacy Cannon Falls PPA). The Legacy Cannon Falls PPA was set to expire on April 11, 2025. To preserve the capacity from the Cannon Falls facility for the short-term, the Company and Invenergy entered into a roughly 3-year extension of the PPA to May 31, 2028, at similar pricing. Recognizing the need to preserve the capacity for the NSP system, the reasonable pricing, and the short-term nature of the PPA, the Parties agree that the Company may recover the costs of the Cannon Falls PPA in base rates and the Fuel Cost Rider, as appropriate. This results in no change to the

Company's FTY25 revenue requirements.

d. Blue Lake Reciprocating Engines

The Company proposed adding 28 MW of reciprocating engines to the Blue Lake gas fired facility as part of a larger project to retire Unit 3 and improve reliability and resiliency for Units 7 and 8. In addition to preserving capacity on the NSP System, the Company also put forward additional system support reasons why the project is necessary and prudent. In light of the Company's justified need, the Parties agree that the Company may recover the costs of the Blue Lake reciprocating engines and other components of the larger project in rates.

3. *The NSP Nuclear Fleet*

The Company proposed to extend the depreciable life for ratemaking purposes of the Monticello Nuclear Generating Station by 10 years in this Proceeding. Since this proceeding was initiated, the Company also obtained approval for the construction of additional spent fuel storage at its Prairie Island Nuclear Generating Station. Consequently, for this Settlement, the Parties agree it would be appropriate to extend the depreciable life for ratemaking purposes of the Prairie Island Nuclear Generating Station by 20 years. These life extensions result in an overall reduction to the FTY25 revenue requirement of \$4.02 million. The Company shall adjust payments to its Nuclear Decommissioning Trust consistent with the aforementioned nuclear life extensions resulting in a reduction of \$2.25 million to the FTY25 revenue requirement.

4. *Disallowed Resources*

The Parties recognize that for the purposes of achieving Settlement, Sherco Solar 1, 2, and 3 will be disallowed from recovery as part of the FTY25. This

reduces the FTY25 revenue requirement by \$3.13 million. The Company may seek prospective recovery of Sherco Solar 1, 2, and 3 in a future rate case, but may not seek to recover the costs of Sherco Solar 1, 2, and 3 or other new solar projects through the Renewable Energy Rider (RER) prior to its next rate case.

The Parties further recognize the policy concerns raised with the Company's plan to extend the depreciable lives of its Red Wing and Wilmarth refuse-derived fuel plants. Recognizing that these plants have been used and useful and recovered in rates for many years, the Parties agree that the depreciable lives of these plants will not be extended for ratemaking purposes consistent with North Dakota policy priorities. This increases the FTY25 revenue requirement by \$641,000.

5. *NSP's Coal Fleet*

The Company acknowledges that the Commission and other Parties continue to express concern with the Company's decision to retire its existing coal fleet, namely the Allen S. King Plant (King), and Units 1, 2, and 3 of the Sherburne County Generating Station (Sherco) before the end of their North Dakota depreciable lives. The Parties recognize, however, that the Company retired Sherco Unit 2 in 2024, plans to retire Sherco Unit 1 in 2026, Sherco Unit 3 in 2030 and King in 2028. For purposes of setting a just and reasonable revenue requirement for FTY25 and to help ensure that the rates the Company charges its North Dakota customers better reflect North Dakota's policy preference, the Parties agree that the Company's North Dakota rates shall reasonably reflect a negotiated cost of service based on the concept that test-year rates should be reflective of the NSP Coal Fleet remaining in service for the remainder of their North Dakota approved depreciable lives. To that end, the Parties agree that the FTY25 revenue

requirement is modified as follows:

- The FTY25 revenue requirement will reflect the currently approved North Dakota depreciable lives of Sherco Units 1, 2, and 3, and King reducing the FTY25 revenue requirement by \$8.47 million;
- The FTY25 revenue requirement will reflect the Company's ability to earn a return on the undepreciated rate base amounts attributable to the Coal Fleet;
- The FTY25 revenue requirement will also reflect 2025 O&M and all capital additions to the Coal Fleet since the prior rate case, as provided for in the Company's initial Application in this Case;
- The FTY25 revenue requirement will be adjusted upward by \$5.00 million to reflect what the Parties have negotiated as a reasonable amount to estimate what costs would have been had the Company not planned to retire the Coal Fleet earlier than their North Dakota Depreciable lives (the Coal Adder). The Coal Adder has been agreed to by the Parties in the nature of a settlement amount as the Parties recognize that it is not possible to accurately calculate a "what if" scenario. With that said, the Parties intend the Coal Adder to represent the following:
 - A just and reasonable revenue requirement for the FTY25 by identifying what costs could have been in 2025 and not attempting to develop an amount that would have reflected all costs to the Company had the Coal Fleet been in operation through the end of its depreciable lives;
 - Certain capital additions that would have been made since the last rate case but were otherwise cancelled due to the shortened lives of the

Coal Fleet;

- Certain capital additions that would need to be made in anticipation of longer lives of the Coal Fleet but were never budgeted;
- The impact to rate base and depreciation expense for the FTY25 test year from the previous two bullets; and
- Additional incremental operations and maintenance expenses that would have been incurred based on historic amounts inflated to 2025 dollars.

6. *Timing Adjustments*

To reflect changes to certain capital additions forecasted to be placed in service during 2025 but whose schedules have been changed, the FTY25 revenue requirement is adjusted by \$1.79 million to remove the revenue requirement attributed to the Sherco Battery Project and the Larimore substation project.

Recognizing that the Company's networking project with respect to LTE is continuing to be placed in service, the FTY25 revenue requirement will reflect the Company deferring all capital-related and O&M expenses for its LTE project until such time as all elements of the project are placed in service. The deferral will be designed to ensure that all capital-related and O&M expenses for the LTE project will be treated as if they were capital expenditures included in Construction Work In Process (CWIP), whereby an allowance for funds used during the deferral is provided, similar to the treatment for Allowance for Funds Used During Construction (AFUDC). The LTE deferral will be designed in the same way as the AGIS deferral. This Settlement is without prejudice to the prudence of the Company's LTE project and makes no determination thereupon. The LTE deferral reduces the FTY25

revenue requirement by \$378,000.

7. *O&M Adjustments*

The Parties agree that, for the purposes of determining the test year revenue requirement and for jurisdictional earnings reporting, the following expenses will be adjusted out of the FTY25 revenue requirement, consistent with Advocacy Staff's recommendation: association dues (\$11,000), Chamber of Commerce dues (\$33,000), Xcel Energy Foundation donations (\$299,000), LTI Environmental Incentive (\$211,000), LTI Time Based Incentive (\$589,000), incentive compensation (\$87,000), aviation (\$121,000), and economic development (\$113,000). These reductions result in a \$1.46 million reduction of the test year revenue requirement.

The Parties further agree that, for the purposes of determining the FTY25 revenue requirement, to make additional downward adjustments to FTY25 revenue requirements, consistent with Advocacy Staff's recommendations: O&M normalization (\$154,000); inflation costs other than labor (\$521,000); customer service costs related to the Company's electric vehicle initiative (\$131,000), and CWIP (\$434,000). These reductions and additions result in a \$1.24 million reduction of the FTY25 revenue requirement. Except as otherwise described in this Settlement, these adjustments are without prejudice to the prudence of any of the Company's specific O&M expenses, but, rather, are being made for Settlement purposes only.

The Parties further recognize the Commission's decision in Case No. PU-24-378 and for settlement purposes only and without any prejudice to the reasonableness of such charge, the Parties agree to a downward adjustment of \$517,000 on a revenue requirements basis reflecting the elimination of payments to

the Prairie Island Indian Community in the FTY25 cost of service.

8. Revenue Requirement Corrections and Secondary Calculations

The Parties agree to adopt, for the purposes of determining the test year revenue requirement, the Company's recalculation of its payroll tax, resulting in a \$93,000 reduction. To incorporate all the above adjustments into the Company's revenue requirement calculation, certain secondary calculations must be made, such as Accumulated Deferred Income Taxes (ADIT) prorated for the Internal Revenue Service (IRS), updating cash working capital, and updating the rider removals and rider revenue. These adjustments net to a \$129,000 increase in the test year revenue requirement. The Parties agree to accept the Company's calculation of "secondary" impacts of the various revenue requirement adjustments contained in this Settlement.

9. AGIS Deferral

The Parties accept Advocacy Staff's recommendation to amortize the AGIS Deferral over a period of 10 years. The AGIS Deferral reduces the FTY25 revenue requirement by \$380,000.

B. Ensuring Just and Reasonable Rates

The Parties agree that the rates set in this Settlement are just and reasonable. However, in light of the potential for rates set in this Case to be in effect beyond 2025, the Parties agree to establish an earnings-sharing mechanism. The earnings-sharing mechanism will include a weather normalized adjusted earnings threshold of 10.10 percent ROE. In the event the Company's annual weather normalized adjusted earnings exceed 10.10 percent, the Company will refund to customers 70 percent of the weather normalized adjusted revenue contributing to earnings in excess of 10.10

percent as calculated in the Company's jurisdictional annual reports filed with the Commission. This earnings-sharing mechanism will be in effect for all calendar years prior to the Company's next rate case test year unless a future settlement or Commission Order determines otherwise.

In calculating the "weather normalized adjusted earnings," the Company shall:

- Use the established weather normalization method which derives weather coefficients using regression analysis consistent with the Company's latest forecast vintage. These coefficients are applied to the difference of actual and normal weather while factoring in actual customer counts. Normal weather shall continue to be defined as a 20-year historical average. Further, the Company shall not make any exogenous adjustments to its weather normalization such as the "COVID Topside Adjustment" discussed in the Supplemental Direct Testimony of Company witness Benjamin Halama;
- Use actual data for the purposes of calculating the demand allocator; provided, however, that in the event that (1) the actual demand allocator used to calculate earnings in a given year deviates materially from the weather normalized demand allocator used to set rates in this proceeding; and (2) the material deviations are due in whole or in substantial part to weather; and (3) such material deviation causes, in whole or in part, the Company to refund amounts earned above 10.1% ROE pursuant to this settlement; then, the Company may file a request to the Commission to weather normalize the actual demand allocator value for the purposes of calculating any refund amounts;
- Exclude the Coal Adder from total revenue; and

- Exclude from the cost of service the revenue requirement for any and all generation resources (Company owned, PPA, or otherwise under contract) used and useful for the provision of electric service but not being recovered in rates (Unrecovered Resources). The list of Unrecovered Resources as of the date of this Settlement is provided in Schedule 2. For the avoidance of doubt, Unrecovered Resources include any generation resource which is placed into service after the date of this Settlement and is used and useful for the provision of electric service but for which the Company has not obtained full rate recovery from the Commission (including, without limitation, those generating resources which the Company is prohibited from seeking cost recovery prior to its next rate case pursuant to this Settlement, as well as resources for which the Company has not yet sought approval) shall also be excluded from the calculation of weather normalized adjusted earnings.
- Exclude 75% of revenue attributable to the Unrecovered Resources from the Midcontinent Independent System Operator, Inc.'s (MISO) energy and ancillary services markets (Energy Wholesale Revenue); provided, however, that when calculating the system average cost of fuel for the Company's Fuel Cost Rider, the Company shall attribute \$0 to costs (numerator) and 0 MWh to generation volumes (denominator) for such resources or a mathematical equivalent (i.e., a modified system average cost of fuel) so that fuel revenues reflect that such resource is not being recovered in rates but also provides customers a reasonable hedge to market price exposure that is due to the significant amounts of energy production being disallowed from recovery.
- Exclude 75% of the revenue attributable to the Unrecovered Resources from MISO capacity auctions or other capacity markets determined by (x) calculating the North Dakota jurisdictional share of capacity revenue for the

applicable planning year without making any adjustment (Unadjusted Revenue); (y) calculating the North Dakota jurisdiction share of capacity revenue for the applicable planning year that would have been earned if the Unrecovered Resources had not been on the NSP System (Adjusted Revenue); and taking the difference between Unadjusted Revenue and Adjusted Revenue as representing the capacity revenue from such generating resources (Capacity Wholesale Revenue).

- Exclude all Tertiary Revenue (as defined below) attributable to any Unrecovered Resources

For purposes of this Settlement, “Tertiary Revenue” means all sources of funds, the value of any incentives, all third-party sources of revenue, and all other things of value that arise from the Unrecovered Resources and accrue to the Company, excepting Energy Wholesale Revenue and Capacity Wholesale Revenue, but, including, without limitation:

- The value of any Production Tax Credit, Investment Tax Credit, grants, tax abatements, or other governmental incentive – local, state, or federal – the full value of which are to be retained by the Company in the year such credit or incentive is earned (or if not earned till paid, paid) for its own account without any refund to customers;
- The realized value of any renewable energy credit (REC) or other environmental attribute due to sale of RECs or other environmental attributes attributable to the Unrecovered Resources. For the avoidance of doubt, all RECs and other environmental attributes created due to the production of electricity by any Unrecovered Resource shall be the property of the Company with no compensation to customers; and

- Any other sources of revenue (or expense offsets) attributable to the Unrecovered Resources, with such revenue to be retained by the Company (i.e., insurance payments, liquidated damages, replacement energy payments, etc.).

II. RATE DESIGN

The Parties agree to customer class revenue apportionment that reflects class percentage share of total settlement revenue increase consistent with the Company's originally proposed class revenue increases, as shown in Table 2 below.

Table 2
Settlement Revenue Apportionment

	Present Revenue	Proposed Revenue	Proposed Increase	Settlement Present Revenue	Settlement Revenue	Settlement Increase
Residential	\$92,694	\$115,090	24.16%	\$92,614	\$104,581	12.92%
C&I Non-Demand	12,098	14,145	16.92%	12,088	13,182	9.05%
C&I Demand	123,554	143,150	15.86%	123,426	133,897	8.48%
Lighting	2,028	2,431	19.86%	2,026	2,242	10.62%
Total Retail	\$230,375	\$274,817	19.29%	\$230,154	\$253,900	10.32%
Other Increases ¹	\$0	\$114		\$0	\$114	
Total Revenue	\$230,375	\$274,931	19.34%	\$230,154	\$254,015	10.37%

*Amounts may not total due to rounding.

The Parties agree to the tariff changes proposed in the Company's initial filing, as filed in compliance with the Second Amended Settlement Agreement in Case No. PU-12-813. The Parties agree to use the Company's proposed rate design principles in developing final rates to implement the approved revenue requirement contained in this Settlement Agreement, and the Company will implement a \$21.50

¹ Includes changes in late payment fees, winter construction charges, and excess service footage charges.

monthly residential fixed charge.

The Company will file compliance tariff pages setting forth the revised electric rates and tariffs provided by this Settlement Agreement within at least thirty (30) days from the date of approval of this Settlement.

III. JURISDICTIONAL COST ALLOCATION

The Parties agree to the Company's proposed allocation of costs among jurisdictions in which the Company operates.

IV. RESOLUTION OF SUPPLEMENTAL ISSUES

A. COVID Topside Adjustment

The Parties agree that the Company will issue a refund to North Dakota customers of \$781,000 as part of the earning sharing requirements for calendar years 2021 and 2022. These funds were not originally returned to customers because of a topside adjustment the Company made to address the impacts of COVID-19. The refund will be included in the interim rate refund.

B. Wind Repowering

The Company requested to recover all costs for the repowering of the Border Winds, Grand Meadow, Nobles, and Pleasant Valley wind projects. The record reflects that the Settlement in Case No. PU-20-425 determined that the projects, on a portfolio basis, were prudent up to a certain amount. Some of these projects were over budget and some projects were under budget. However, on a portfolio basis, the projects exceeded that certain amount. That said, the Company has sufficiently demonstrated that notwithstanding any portfolio basis cost overages, the project portfolio will provide material customer benefits consistent with the basis for which an advanced determination of prudence was first issued. To that end, the Parties agree that the

Company may recover the actual costs of Border Winds and Pleasant Valley through the RER. This results in an approximate increase in the 2025 and 2026 revenue requirements of \$350,000 and will be included in the Company's 2027 RER true up filing.

C. PRA Revenue

The Parties agree that revenue from previous MISO Resource Planning Auction's attributable to Unrecovered Resources shall be calculated consistent with the Company's proposal.

V. IMPLEMENTATION

The Parties agree that all Company proposals not explicitly addressed in this Settlement are agreed to and shall be implemented as proposed by the Company provided, however, that they shall not be precedential in nature.

VI. INTERIM RATE REFUNDS

Since the Parties have agreed to a base rate increase for 2025 that is lower than the current interim increase, this Settlement will result in an interim rate refund for North Dakota customers. Interim rates went into effect on February 1, 2025. Parties agree that the interim rate level effective as of February 1, 2025, will remain in effect until final rates are implemented. At the time of this Settlement Agreement, the final amount of interim revenues collected is not available. The refund is expected to be issued to customers beginning approximately 30-60 days from the implementation of final rates.

VII. EFFECT ON OTHER PROCEEDINGS

The Parties agree that this Settlement does not address ongoing proceedings in North Dakota Public Service Commission Case No. PU-24-342. The Parties further agree that Case No. PU-24-342 is not impacted by this Settlement and that it will proceed to separate determination

VIII. OTHER TERMS AND CONDITIONS

A. Basis of Settlement

It is agreed that this Settlement is a negotiated settlement agreement subject to approval by the Commission. This Settlement does not establish any principle or precedent or adopt or recommend any specific type or amount of expense or rate base for this or any future proceeding.

B. Effect of the Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related to this Settlement are privileged and may not be used in any manner in connection with proceedings in this Case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any Party for any purpose in this Case or in any other.

C. Applicability and Scope

This Settlement shall be binding on the Parties and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement does not establish policy or overturn precedent. This Settlement shall not in any respect constitute an agreement, admission, or

determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

D. Effective Date

This Settlement shall be binding on the Parties on the date it is executed by all Parties and all Parties shall be bound to support and defend this Settlement, provided that this Settlement shall be effective on the date of the Commission Order approving this Settlement. The revised rates and tariff agreed to by this Settlement shall be effective as specified herein.

E. Modification

If a Commission Order modifies or conditions approval of this Settlement, it shall be deemed terminated if any Party files a letter with the Commission within three (3) business days of the date of such Order stating that a condition or modification to the Settlement is unacceptable to such party.

F. Mutual Support

Each of the Parties shall support – and not oppose – this Settlement before the Commission.

G. Counterparts

This Settlement may be executed in counterparts with each signature making up the whole.

CONCLUSION

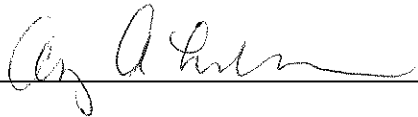
The Parties have agreed to the forgoing terms to resolve all outstanding issues

in the above-captioned Case. These terms are a result of negotiations between the Parties, are in the public interest, and will result in just and reasonable electric rates. For these reasons, the Parties urge the Commission to approve this Settlement.

[SIGNATURE PAGES FOLLOW]

Dated this 18 day of November 2025.

Northern States Power Company,
A Minnesota corporation

By: 

Its: RVP, Regulatory & Pricing

[NSP SIGNATURE PAGE TO SETTLEMENT CASE NO. PU-24-376]

Dated this 19th day of November 2025.

Advocacy Staff of the North Dakota Public
Service Commission

By: Mitchell Armstrong

Its: Counsel

Dated this 18th day of November 2025.

Walmart Inc.

By: Julie A. Clark
Julie A. Clark

Its: Counsel

[WALMART SIGNATURE PAGE TO SETTLEMENT CASE NO. PU-24-376]

SCHEDULE 1

Revenue Requirement Adjustments (\$000)

	2025 Test Year
As Filed Rate Increase	\$ 44,556
1. Lower Authorized ROE to 9.80%	(2,729)
2. Nuclear Fleet	(6,273)
3. Disallowed Resources	(2,486)
4. Coal Fleet	(3,474)
5. Timing Adjustments	(2,169)
6. O&M Adjustments	(3,220)
7. Corrections and Secondary Calculations	36
8. AGIS Deferral	<u>(380)</u>
Total Adjustments	(20,695)
Settlement Revenue Requirement	\$ 23,861

SCHEDULE 2**UNRECOVERED RESOURCES***

1. Adams Wind Generations (20 MW)
2. Aurora Distributed Solar (100 MW)
3. Best Power - St Johns (0.4 MW)
4. Best Power-School Sisters of Notre Dame (0.8 MW)
5. Big Blue Wind Farm, LLC (36 MW)
6. Danielson Wind Farms, LLC (20 MW)
7. Dragonfly Solar (0.8 MW)
8. Ewington Energy Systems, LLC (20 MW)
9. Grant County Windfarm, LLC (20 MW)
10. Hilltop Power, L.L.C. (2 MW)
11. Jeffers Wind Energy Center (50 MW) *
12. Marshall Solar (62.2 MW)
13. North Community Turbines LLC (15 MW) *
14. North Star Solar (100 MW)
15. North Wind Turbines LLC (15 MW) *
16. Ridgewind Power Partners, LLC (25 MW)
17. Slayton Solar, LLC (1.6 MW)
18. Uilk Wind Farm, LLC (4.5 MW)
19. Valley View Transmission (10 MW)
20. Winona County Wind LLC (1.5 MW)
21. Woodstock Municipal Wind, LLC (0.8 MW)
22. Zephyr Wind LLC (30 MW)
23. Sherco Solar 1, 2, and 3 (710 MW)

*In addition to the foregoing list, Unrecovered Resources include any generation resource which is placed into service after the date of this Settlement and is used and useful for the provision of electric service but for which the Company has not obtained full rate recovery from the Commission (including, without limitation, those generating resources which the Company is prohibited from seeking cost recovery prior to its next rate case pursuant to this Settlement, as well as resources for which the Company has not yet sought approval).