I. Introduction

Q. Please state your name, position and business address.

A. My name is Dante Mugrace. I am a Senior Consultant with the regulatory consultant firm of PCMG and Associates, LLC. My business address is 22 Brookes Avenue, Gaithersburg, MD 20877.

Q. Are you the same Dante Mugrace who previously filed Direct Testimony in this Proceeding?

A. Yes. I submitted Direct Testimony on March 1, 2022. My qualifications and experiences are attached to my Direct Testimony.

II. Purpose of Testimony

Q. What is the purposed of your rebuttal testimony?

A. The purpose of my Surrebuttal Testimony is to address the Rebuttal Testimony of Northern States Power Company (NSPC or Company) Gas witnesses Halama, Krug and Zich. I am also making certain adjustments to the proposals in my Direct Testimony and a revised calculation of the Company's revenue requirement that incorporates the effects of my adjustments. To the extent that I do not respond to a particular issue or argument contained within my Surrebuttal Testimony, I defer to my Direct Testimony on those issues.

Q. With your adjustments to your Direct Testimony, what is your revised Company revenue requirement?

A. With my adjustments, which include updated adjustments from the Company on certain revenue requirement issues, and Dr. Griffing's recommended overall rate of return I have calculated a revised revenue requirement of $3,958,994 or a 5.882% increase over current rates. My recommended revenue requirement includes an overall rate of return of 6.91% with a common equity component of 9.54% as recommended by Dr. Marlon Griffing.

Q. Has the Company updated its revenue requirement?

A. The Company is now proposing a revenue requirement increase of $5.993 million, a reduction of $1.966 million from its initial filing. (Exhibit BCH-2 at 1).

Q. Did Mr. Halama concur with you updated revenue requirement adjustment?

A. No. Mr. Halama stated that there was difference of $7,000 and Mr. Halama stated that my revenue requirement should be $3.869 million.

Q. What is your response?

A. The difference of $7,000 is >1% between my recommended revenue requirement increase and the way Mr. Halama's calculated my revenue requirement increase; this could be due to rounding issues and the flow-throughs of various taxes. It is de minimis in nature.

Q. What issues are you accepting from the Company with respect to the Company's rebuttal testimony?

A. I am accepting the following issues and adjustments from the Company in its rebuttal testimony through Company witness Mr. Halama:

- Fargo Capacity Project and related cost adjustments
- AGIS Removal and related cost adjustments
- Depreciation Study - TD&G Update
- Damage Prevention Program (DPP) – duplicative adjustment
- Net Operating Loss
- Cash Working Capital – The final adjustment to Cash Working Capital is a function of the Commission's determination in the final revenue requirement – Schedule S- DM-8
- Federal and State Income Taxes – Tax Depreciation balance – Schedule S-DM-23.

Q. What are the revenue requirement issues that you are not accepting from the Company but are otherwise accepting the adjustment to your recommended balances?

A. The following are the revenue requirement issues that I am not fully accepting or agreeing to, but am accepting certain adjustments that the Company has proposed in its rebuttal testimony:

III. Revenue Requirement Issues

A. O&M Expense Adjustment

Q. What Company adjustments are you addressing that you do not agree with?

A. Mr. Halama did not agree with my historical averages of certain O&M expenses and stated that my adjustments are not appropriate. (Exhibit BCH-2 at 7).

Q. What did Mr. Halama state regarding your historical normalization of certain O&M expenses?

A. Mr. Halama stated that the Company selected a future test year of calendar year 2022 and utilized its forecasted 2022 budget of revenues and expenses as the basis of its 2022 test year. Use of a forecasted budget is consistent with the Company's long-standing practice and is consistent with North Dakota statue and Commission precedent. (Exhibit BCH-2 at 8). Mr. Halama stated that my use of a three-year historical average to determine a significant portion of expenses resulted in a removal of $1.698 million in total O&M expenses from the Company's cost of service. (Exhibit BCH-2 at 9). Mr. Halama stated that my use of a three-year average was not sufficient enough to justify my approach. Mr. Halama stated that my adjustment to certain O&M expenses rather than all O&M expenses along with the use of a 2019-2021 three-year average seems wholly arbitrary and provides no support and calls into question the analytical rigor of my adjustment (Exhibit BCH-2 at 12). Mr. Halama stated that my adjustments were to only non-labor expenses and not to total labor and non-labor O&M expenses. (Exhibit BCH-2 at 13). Mr. Halama stated that my adjustment could eliminate the opportunity for the Company to earn its authorized rate of return due to the rates reflecting O&M expenses significantly below historical actuals, the test year budgeted amount and any discernable trend in O&M costs. (Exhibit BCH-2 at 13). Mr. Halama stated that my methodology results in an outcome that is not credible. (Exhibit BCH-2 at 14). Mr. Halama stated that unlike the Company's electric utility operations where allocation factors can and do change annually and can and do impact overall cost of service, the North Dakota gas jurisdictional costs are primarily direct assigned or allocated based on the design day demand and customer allocation, which do not significantly fluctuate from year to year. (Exhibit BCH-2 at 15).

Q. What is your argument for the use of a three-year average for certain O&M Expenses?

A. I believe the use of a three-year average to set certain O&M expense is an appropriate approach for setting rates for service. I chose the historic years 2018, 9, 2020 and 2021 as these expenses are the most recent expense levels and going further back to include a five-year or an eight-year average would result in stale data and some of the expenses might have changed, been eliminated or are non-recurring. Costs change from year to year, and one of the goals in setting rates for service is to provide for gradualism in the rate setting arena so as to not put stress on ratepayers when costs change from year to year due to sudden increases/decreases incurred by the Company from outside vendors, or in the way the Company allocates its costs from year to year. These types of costs do fluctuate from year to year. Prices do change over time, but not always proportionately. Some costs may be expected to decrease but other costs may be expected to increase. One-time costs or an abnormal cost distribution may reduce costs in a particular year and is a good reason for spreading out one-time costs over time to provide rate stability for customers. As I indicated previously in my testimony, the Company should not expect to recover all of its costs during the test year, the Company is given the opportunity to do so. As Mr. Halama stated, historical averages can be appropriate if certain expenses were generally increasing or decreasing at unusually high or low rates, providing the historical actuals could be shown to demonstrate an appropriate forecasting trend for the future year. (Exhibit BCH-2 at 12). There is no expectation that the Company recover all of its expected future costs in the rate year.

Q. Did you ask the Company to provide the reasoning for the variability related to Gas Production, Gas Distribution and Customer Accounting?

A. Yes. In response to 4-12, 4-13 and 4-14, for Gas Production, Gas Distribution and Customer Accounting, respectively, I asked the Company for reasonings on the fluctuations from year to year in response to 1-34 Attachment A. The responses were not fully descriptive of the reasoning for the variability of certain expenses. In response to 4-13, the Company stated the variability of distribution expenses was due to many different factors which causes volatility in actual expenses, including weather and weather related incidences, damage prevention locate volumes, contractor prices and compliance requirements. This is the reason for the expense swing of approximately $900,000, and why it is appropriate to normalize these costs.

Q. What did Mr. Halama state as the reason for the Customer Accounting expenses?

A. Mr. Halama stated that the increase in O&M expenses between 2021 and 2022 was due to higher meter reading costs and meter reading management software, driven by the need to upgrade existing meter reading software to integrate with new technologies. (Exhibit BCH-2 at 15). Mr. Halama stated that the Company's investment in technologies through the Company's MyAccount smartphone application and new user experience into the Company's other systems is driving a slight increase in operations and maintenance expenses in the 2022 test year. (Exhibit BCH-2 at 15).

Q. What is your response with regard to Mr. Halama's response related to Customer Accounting and your use of a normalized 3-year average of certain O&M expenses?

A. Historical trends (actual) are a reliable indicator of future costs. I did review all of the Company's O&M Expense categories and found that the majority of these costs have been stable and consistent in prior years ((Purchased Gas, Gas Production, Sales, Economic and Other, and A&G). My adjustments reflect those O&M expenses that vary from year to year, mainly limited to Gas Distribution and Customer Accounting. With respect to the cost changes in the Customer Accounting expense, I did ask for a description of these costs (4-14) but did not get the detailed response that Mr. Halama indicated in his rebuttal testimony

(Exhibit BCH-2) page 15. In addition, given the presence of the COVID-19 pandemic, it is even more appropriate to average out costs so that customers are not greatly impacted by increased expenses, all the more reason that it is appropriate to smooth out costs in times of uncertainty (2020 and 2021 COVID-19 period). Even in 2022, the COVID-19 pandemic is still present, and further uncertainty continues. I am of the opinion that inflationary cost increases and pressures placed upon the Company should not be included as the reason to assert changes in expenses. The Company has not provided any specific areas where such costs have impacted the Company. Inflationary costs are typically blanket type increases used for economic data that are applied to all goods and services that may not be directly related to the Company's operations. It is simply a forecast or prediction of cost adjustments. The Company should not assume that all of its costs will be affected by inflation and are going to be recovered when rates are set for service, even in the case of inflationary pressures. The Company is given the opportunity to recover costs, not a guarantee of full recovery.

B. Labor Adjustment

Q. What has Mr. Halama stated regarding your Labor Normalization?

A. Mr. Halama did not agree with my inclusion of a vacancy rate removal from the Company's 2022 COSS since the Company has not conducted a formal vacancy rate analysis. Mr. Halama stated that the Company has included a negative labor loading rate to account for attrition in workforce, in response to regulatory concerns in other jurisdictions. (Exhibit BCH-2 at 19). Mr. Halama stated that the Company's budgets already include an offset to labor in the 2022 COSS using an attrition rate of 4% on productive labor which was based upon historical attrition and other vacancy rates. Mr. Halama stated that my adjustment is duplicative. (Exhibit BCH-2 at 19).

Q. What is your response?

A. I am still recommending a labor vacancy adjustment. The Company does not have to formally perform such an adjustment in order for one to implement such an adjustment. The Company has not provided any analysis to show that it has incorporated an attrition rate into its COSS for 2022. In response to 1-19, the Company stated that opening positions are filled as soon as possible and that specific dates are unknown, and the list will change throughout the year. The Company cannot determine the anticipated hire date for specific openings. In response to 1-34, the information shows that labor costs are on the decline with an expense total of $6.962 million in 2019 to $3.993 million in 2021, with a slight uptick of $99,865 in the 2022 test year for a total of $4.093 million. In response to 1-17, the information shows that in each year beginning in 2016 and through 2021, on average approximately 153 employees in the NSPM total company have left in each year. I believe this trend will continue through 2022, and it is reasonable to conclude that the labor vacancy will exceed the replacement of employees. Attachment A to 1-19 shows approximately 106 vacancy openings in 2022, far below the 153 average employees leaving the NSPM total company. The Company should provide a list of employee hires that occurred in 2022, and whether any candidates have been identified and will be expected to be hired by the Company.

C. <u>Meter Installation Costs</u>

Q. What did Mr. Halama state regarding my adjustment to the Company's Meter Installation costs?

A. Mr. Halama stated that I used a composite book depreciation rate as opposed to using the actual book lives for the asset and that I assumed the forecasted dollars not having a corresponding impact to tax depreciation and deferred income taxes, which amounts to >$500. (Exhibit BCH-2 at 20).

Q. What is your response?

A. Although the use of composite rates of depreciation to adjust changes in plant is a reasonable and appropriate approach for ratemaking purposes and the setting of rates for service, I am accepting Mr. Halama's use of the actual book lives to calculate the adjustment, since the differences are minimal.

Q. What did Ms. Zich state regarding your adjustment to remove meter installation costs from the 2022 test year COSS?

A. Ms. Zich stated that my 2 percent adjustment escalation was related to the 2019 costs rather than the 2022 cost, which if accepted, would reduce the forecasted 2022 costs below 2019 actual costs. (Exhibit JHZ-2 at 3). Ms. Zich stated that the 2022 cost was $396,270 rather than what I calculated of $388,500 to be 2022 costs.

Q. What is your response?

A. In response to 1-46 the Company provided the cost of an individual meter at $3,500 per meter with no specific calculation for costs proposed in 2022. If the $396,270 is now the actual costs proposed by the Company, the adjustment for removal of the 2 percent becomes $7,770 instead of my proposed $7,617, a difference of $153. I am accepting this increased removal adjustment cost.

Q. What else did Ms. ZIch state regarding your removal of the 2 percent escalation cost?

A. Ms. Zich stated that the 2 percent is appropriate because costs for both materials and labor are increasing. Given the passage of time and the general inflationary pressures that affect both material and labor costs, escalating costs by 2 percent to arrive at cost expected to be incurred in 2022 was appropriate and conservative. (Exhibit JHZ-2 at 3-4).

Q. What is your response?

A. The 2 percent cost escalation is not appropriate as these costs are not justified by actual costs incurred by the Company but rather a blanket increase of overall costs for goods and services. As I indicated previously on the inclusion of inflationary costs, the Company has not provided any specific areas where such costs have impacted the Company.

D. Donations and Chamber of Commerce Dues

Q. What did Mr. Halama state regarding your adjustment to the Company's Donations and Chamber of Commerce Dues?

A. Mr. Halama stated that these dues and donations are normal and expected business expenses that provide benefits to North Dakota ratepayers. Mr. Halama stated that these costs are important mechanisms for supporting the communities and organizations in the area the Company serves. (Exhibit BCH-2 at 21).

Q. What is your recommendation?

A. I see no benefit to the ratepayers of North Dakota. These types of costs do not benefit the ratepayers in the Company's North Dakota service territory but rather are regional in nature. The Company should not be in the business of financially supporting causes that are not customer specific and organizations with non-ratepayer service. I see no nexus of benefits between these types of costs and the provision of safe and reliable utility service. If the Company wants to be good corporate citizens, then the shareholders of the Company can provide the dollars to support these causes and not burden ratepayers with them. The Company should not have unfettered access to ratepayer money for which ratepayers receive no benefit, and do not have a say of where their ratepayer monies are going to or providing support for.

Q. What did Mr. Krug state regarding your removal of these costs?

A. Mr. Krug stated that the expenses in question are appropriate and provide benefits for North Dakota, including the North Dakota customers. The Chamber of Commerce dues facilitate communications with an important category of customers, and charitable contributions are a normal and expected expense for a business, particularly for a corporation of Xcel's Energy size and prominence in the community. (Exhibit ADK-1 at 16). Mr. Krug stands by the Company's request for recovery of 50 percent of these costs which the Company believes is reasonable given the Commission's historic resistance to allowing full recovery of these types of costs. (Exhibit ADK-1 at 16).

Q. What is your response?

A. As I indicated previously, these costs should not be funded by ratepayer money, but rather through state, local, federal and civic and municipal organizations. The Company should not be using ratepayer money to show that it is a good corporate citizen and believes in these causes. While I commend the Company for contributing to these causes, the shareholders should be funding these costs and not ratepayers.

E. <u>Economic Development Donations</u>

Q. What did Mr. Halama state regarding your removal of the Company's Economic Development Donations?

A. Mr. Halama stated that the economic development in question provides benefits for North Dakota, including Xcel Energy customers. Mr. Halama requested that the Commission continue to support economic development efforts on behalf of the communities the Company serves.

Q. What is your recommendation?

A. As I stated in my direct testimony, I do not believe these types of costs should be recovered from ratepayers. These are considered non-regulatory utility expenses that support regional and local economic development and do not provide any utility related benefits to the ratepayers of North Dakota. The ratepayers do not have a say as to which type of donations their ratepayer dollars support. It is not the responsibility of the Company to be the savior of economic development issues and regional and local problems. The Company has not shown or provided what benefits utility ratepayers in North Dakota receive or how these ratepayers are benefitting from these contributions. If the Company wants to participate in giving back to the community, the Shareholders of the Company should fund these causes and receive a tax benefit through the corporate entity.

F. <u>Incentive Compensation</u>

Q. What did Mr. Halama state regarding your removal of the increase to the Company's Incentive Compensation adjustment?

A. Mr. Halama stated that the Company's scorecard is used to determine the level of incentive compensation that will be paid in the subsequent year. The incentive compensation associated with the applicable scorecard, are accrued in the year the incentive is earned. The 2021 Corporate Scorecard determined the level of incentive to be paid in 2022, which was accrued in 2021. The 2021 Corporate Scorecard results have no impact on the 2022 test year. (Exhibit BCH-2 at 22).

Q. What did Mr. Halama state regarding the 2022 Corporate Scorecard?

A. Mr. Halama stated that the incentive compensation included in the 2022 test year will be based on the 2022 Corporate Scorecard. The actual payment of the incentive expense included in the 2022 test year COSS will be paid in March 2023, based upon the 2022 Corporate Scorecard. (Exhibit BCH-2 at 22).

Q. What is your recommendation?

A. Any type of incentive compensation included in the Company's test year COSS should not be included and recovered by ratepayers. As I stated in my direct testimony, the Company has not provided any evidence that these costs benefit ratepayers, but rather these costs are used to retain and maintain employees at the senior and executive level. The Company can provide any level of incentive type pay to its employees with the shareholders paying for or funding these costs. In addition, Mr. Halama stated that the 2022 Corporate Scorecard costs will be paid in March 2023, which is beyond the test year period (out of period adjustment) and should not be included in the revenue requirement.

Q. What did Mr. Krug state regarding your Incentive Compensation removal?

A. Mr. Krug stated that these costs are known and measurable because they represent the Company's forecasted LTI costs in the 2022 future test year. (Exhibit ADK-1 at 15). These costs are no different than other test year costs that the Company has forecasted which Mr. Mugrace agreed are known and measurable. Mr. Krug stated that the LTI program is an important tool that allows the Company to attract and retain key, senior leaders and ensure they effectively manage the Company consistent with the customer focused goals of environmental excellence and efficient management. (Exhibit ADK-1 at 15).

Q. What is your argument?

A. As I indicated previously in my testimony, the Company has not provided any support nor evidence that shows the Incentive Compensation benefits customers. These costs predominately are for retain and maintaining key executives from not leaving the Company. Given that the Company's Scorecard results have not occurred, there is no way to determine if these key executives have met the goals of the program, not whether the goals of the program are beneficial to ratepayers. Finally, these payouts will occur in 2023, well beyond the 2022 test year period, and thus are considered an out of period adjustment.

G. Income Tax Tracker

Q. What did Mr. Halama state regarding the costs related to the recovery of the Income Tax Tracker?

A. Mr. Halama stated that he did not agree with my 5 year amortization period related to the Company's recovery of its Income Tax Tracker. Mr. Halama stated that the Company proposed a three-year amortization period to match the period the Company expects rates to remain in effect as a result of this rate case. (Exhibit BCH-2 at 23).

Q. What is your recommendation?

A. My adjustment to the amortization period of 5 years was based upon the Company's prior rate case proceedings filed with the Commission. The Company has filed rate case proceedings with the Commission, on average every five-years. It is appropriate to use that time period to amortize the associated expenses related to the Income Tax Tracker. There is no assurance that the Company will actually file its next base rate case proceeding within a three-year period.

H. <u>Rate Case Expenses</u>

Q. What did Mr. Halama state regarding the costs associated with Rate Case Expenses?

A. In the same manner as Mr. Halama proposed to amortize the Company's Income Tax Tracker, he proposed the same 3 year recovery period for Rate Case Expenses. (Exhibit BCH-2 at 24).

Q. What is your response to Mr. Halama?

A. In the same manner as I recommended the Income Tax Tracker to be amortized over a 5 year period, I am utilizing the same 5 year period for Rate Case Expenses. There is no assurance that the Company will file its next base rate case proceeding within a three-year period.

I. <u>Property Taxes</u>

Q. What did Mr. Halama state regarding your historical three-year average of Property Taxes?

A. Mr. Halama did not agree with my use of an historical three-year average as he stated that this does not consider the investments the Company has made in the system over the last three years and is not consistent with how Property Tax valuations and assessments are prepared by the North Dakota Office of the State Tax Commissioner. (Exhibit BCH-2 at 25).

Q. What is your response?

A. My adjustment to Property Taxes is based upon the Company's response to 1-24. The 2019-2021 Property Taxes have fluctuated from $1.301 million in 2019, a reduction to $1.190 million in 2020 or 8.5%, and an increase to $1.283 million in 2021, or 7.8%. The Company then adjusted its Property Taxes to $1.587 million, an increase of $0.304 million or 24%. The Company's Plant in Service balance grew from $164 million in 2020, an increase of 17%, to $192.5 million in 2021; and $222.6 million in 2022, an increase of 15.7%. Given that Company allocations do change from year to year, it may not appear that the Company's tax bill of $1.587 million will be realized or whether the allocation from NSPM to the North Dakota jurisdictional service will adjusted and allocated accordingly. As indicated in response to 1-24 the Company stated that these valuations do not reflect the full amount of Property Taxes included in rates. The Company should provide an update with respect to the level of Property Taxes associated with the North Dakota jurisdictional service area.

J. Payroll Taxes

Q. What did Mr. Halama state regarding your adjustment to the Company's Payroll Taxes?

A. Mr. Halama stated that my adjustment is not appropriate as it relates to labor and incentive, and if the Commission accepts the Company's position on the recovery of these adjustments, the adjustment becomes unnecessary. (Exhibit BCH-2 at 25).

Q. What is your response?

A. If the Commission agrees with the Company with respect to adjustments made by me for labor and incentive, I am in agreement with Mr. Halama that my payroll adjustment becomes unnecessary.

K. Federal and State Income Taxes

Q. What did Mr. Halama state regarding your adjustment to the Company's Federal and State Income Taxes?

A. Mr. Halama stated that the Company reviewed my calculations and identified errors in my schedules related to operating income adjustments, plant additions related to changes in tax depreciation and deferred tax expense and interest synchronization to reflect the weighted cost of debt and rate base. (Exhibit BCH-2 at 27). Mr. Halama stated that these errors resulted in about $710,000 of underestimated revenue requirement for the test year. (Exhibit BCH-2 at 27-28).

Q. What is your response?

A. I corrected my errors through my surrebuttal testimony and exhibits. My recommended Federal and State Income Taxes represent the flow-throughs of my adjustments to Rate Base and Operating Income. While these flow-throughs may not be exact, they are correctly calculated. The differences are due to rounding of certain expenses, and the use of composite rates for various tax expense adjustments. As Mr. Halama stated, the final calculations of Federal and State Income Taxes to be included in the test year will be a function of the final approved levels of revenues, expenses and rate base as well as weighted cost of capital approved by the Commission. (Exhibit BCH-2 at 28).

Q. Does this conclude your Surrebuttal Testimony?

A. Yes. I reserve the right to update my surrebuttal testimony in the event the Company revises its rebuttal filing.

REVENUE REQUIREMENT

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References	
1	**Average Rate Base**	**$ 124,227,000**	**$ (1,642,969)**	**$ 122,584,031**		
2	Present Rate Income	$ 3,919,000	$ 1,558,758	$ 5,477,758		
3	AFUDC	$ -		$ -		
4	**Total Available for Return**	**$ 3,919,000**	$ 1,558,758	**$ 5,477,758**		
5	Present Rate of Return	3.155%		4.469%		
6	Required Return	7.450%		6.91%		
7	**Operating Income Requirement**	**$ 9,254,912**	**$ (784,355)**	**$ 8,470,557**		
			$ -	$ -		
8	**Income Deficiency**	**$ 5,335,912**	**$ (2,343,113)**	**$ 2,992,799**		
9	Gross Revenue Conversion Factor	1.322840		1.322840	(2)	
10	**Revenue Deficiency**	**$ 7,058,557**	**$ (3,099,563)**	**$ 3,958,994**		$ 966,195 To Schedule DM-23
11	Present Rate Revenues	$ 67,303,000		$ 67,302,687		
12	Percentage Increase	10.488%		5.882%		
	Total Revenue Requirement			**$ 71,261,681**		

(1) Company Exhibit BCH-1 Schedule 7
(2) Company Exhibit BCH-1 Schedule 3A

State Income Tax Rate	4.310000%
Federal Income Tax Rate	21.000000%
Effective Tax Rate	20.090000%
Composite Tax Rate	**24.400000%**
Revenue Conversion Factor	**1.322837**

Differences due to rounding

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule S-DM-2

WEIGHTED AVERAGE COST OF CAPITAL

(1) Company Proposed

		Ratios	Cost of Capital	Weighted Average
1	LT Debt	47.03000%	4.09550%	1.92611%
2	ST Debt	0.43000%	1.09000%	0.00469%
3	Common Equity	52.54000%	10.50000%	5.51670%
4	**Total Capital**	**100.00000%**		**7.44750%**
5	rounded			7.45000%

(2) ND PSC Advocacy Staff

		Ratios	Cost of Capital	Weighted Average
6	LT Debt	47.570%	4.100%	1.950%
7	ST Debt	0.430%	1.090%	0.005%
8	Common Equity	52.000%	9.540%	4.961%
9	**Total Capital**	**100.000%**		**6.91%**

(1) Company WP C1
(2) Exhibit MFG-16

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule S-DM-3

AVERAGE RATE BASE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Gas Plant in Service				
1	Production	$ 5,340,000	$ -	$ 5,340,000	
2	Transmission	$ 3,909,000	$ -	$ 3,909,000	
3	Distribution	$ 181,046,000	$ (607,617)	$ 180,438,383	
4	Gas Storage	$ 9,341,000	$ -	$ 9,341,000	
5	General	$ 14,757,000	$ -	$ 14,757,000	
6	Common	$ 8,463,000	$ -	$ 8,463,000	
7	**Total Gas Plant In Service**	**$ 222,856,000**		**$ 222,248,383**	
8	Depreciation Reserve	$ 82,973,000	$ (71,337)	$ 82,901,663	
9	**Net Gas Plant In Service**	**$ 139,883,000**	**$ (536,280)**	**$ 139,346,720**	
10	Gas Plant Held for Future Use	$ -	$ -	$ -	
11	Construction Work in Progress	$ 188,000	$ -	$ 188,000	
12	**Accumulated Deferred Income Taxes**	**$ 19,783,000**	**$ (15,981)**	**$ 19,767,019**	
13	Cash Working Capital	$ 648,000	$ (1,100,670)	$ (452,670)	
14	**Subtotal**	**$ 120,936,000**	**$ (1,620,969)**	**$ 119,315,031**	
	Other Rate Base Items				
15	Materials and Supplies	$ 150,000	$ -	$ 150,000	
16	Fuel Inventory	$ 2,098,000	$ -	$ 2,098,000	
17	Non-Plant Assets & Liabilities	$ 1,463,000	$ -	$ 1,463,000	
18	Customer Advances	$ (1,340,000)	$ -	$ (1,340,000)	
19	Customer Deposits	$ (42,000)	$ -	$ (42,000)	
20	Prepaids and Other	$ 523,000	$ -	$ 523,000	
21	Regulatory Amortization - ITT/ADIT ARAM	$ 440,000	$ (23,000)	$ 417,000	WP A15
22	**Total Other Rate Base Items**	**$ 3,292,000**	**$ (23,000)**	**$ 3,269,000**	NDPSC 1-32
23	**Total Average Rate Base**	**$ 124,228,000**	**$ (1,643,969)**	**$ 122,584,031**	

(1) Company Exhibit BCH-1 Schedule 15

differences due to rounding

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule S-DM-4

OPERATING INCOME STATEMENT

		(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	Present Rates ND PSC Advocacy Staff	References
	Operating Revenues						
1	Retail Revenues	$ 67,303,000	$ 7,059,000	$ 74,362,000	$ -	$ 67,302,687	
2	Interdepartmental	$ -		$ -	$ -	$ -	
3	Other Operating	$ 550,000	$ -	$ 550,000	$ -	$ 550,384	
4	**Total Operating Revenues**	**$ 67,853,000**	**$ 7,059,000**	**$ 74,912,000**	**$ -**	**$ 67,853,071**	DM-9
	Operating Expenses						
5	Purchased Gas	$ 43,934,000		$ 43,934,000	$ -	$ 43,934,429	DM-12
6	Gas Production & Storage	$ 635,000		$ 635,000	$ -	$ 635,473	DM-13
7	Gas Transmission	$ 387,000		$ 387,000	$ (44,477)	$ 342,523	DM-14
8	Gas Distribution	$ 5,129,000		$ 5,129,000	$ (923,211)	$ 4,205,789	DM-15
9	Customer Accounting	$ 1,613,000		$ 1,613,000		$ 1,311,454	DM-16
10	Customer Service & Other	$ 149,000		$ 149,000	$ 10,771	$ 159,771	DM-17
11	Sales, Econ Development & Other	$ 10,000		$ 10,000	$ (7,645)	$ 2,355	DM-18
12	Administrative & General	$ 2,508,000		$ 2,508,000		$ 2,471,170	DM-19
	Vacancy Rate Adjustment				$ (173,413)	$ (173,413)	1-34/20/17
13	**Total Operating Expenses**	**$ 54,365,000**	**$ -**	**$ 54,365,000**	**$ (1,475,449)**	**$ 52,889,551**	
14	Depreciation Expense	$ 6,892,000	$ -	$ 6,892,000	$ (72,132)	$ 6,819,868	DM-20
15	Amortization Expense	$ 440,000	$ -	$ 440,000	$ (166,994)	$ 273,006	DM-21
16	Taxes Other Than Income	$ 2,401,000		$ 2,401,000	$ (346,090)	$ 2,054,910	DM-22
17	State Income Taxes	$ (29,000)	$ 304,243	$ 275,243	$ 88,688	$ 59,688	DM-23
18	Federal Income Taxes	$ (135,000)	$ 1,418,499	$ 1,283,499	$ 413,289	$ 278,289	DM-23
19	**Total Taxes**	**$ 2,237,000**	**$ 1,722,742**	**$ 3,959,742**	**$ 155,887**	**$ 2,392,887**	
20	**Total Expenses**	**$ 63,934,000**	**$ 1,722,742**	**$ 65,656,742**	**$ (1,558,687)**	**$ 62,375,313**	
21	AFUDC	$ -	$ -	$ -		$ -	
22	**Total Operating Income**	**$ 3,919,000**	**$ 5,336,258**	**$ 9,255,258**	**$ 1,558,758**	**$ 5,477,758**	
						$ 2,992,799	
23	Rate Base	$ 124,228,000		$ 124,228,000		$ 122,584,031	
24	Rate of Return	3.155%		7.4502%		6.91%	
				$ 9,255,258		$ 8,470,557	

(1) Company Exhibit BCH-1 Schedule 11

differences due to rounding

GAS PLANT IN SERVICE

		(1) Company Proposed Unadj.	Adjustments	Company Proposed Adj.	Adjustments	ND PSC Advocacy Staff	References
1	Gas Manufactured Plant	$ 5,340,000	$ -	$ 5,340,000		$ 5,340,000	
2	Gas Storage	$ 9,341,000	$ -	$ 9,341,000		$ 9,341,000	
3	Gas Transmission	$ 3,909,000	$ -	$ 3,909,000		$ 3,909,000	
4	Gas Distribution	$ 181,046,000	$ -	$ 181,046,000	$ (607,617)	$ 180,438,383	ND PSC 1-46/49
5	General	$ 11,871,000	$ -	$ 11,871,000		$ 11,871,000	ND PSC 4-7/4-9
6	Common	$ 11,348,000	$ -	$ 11,348,000		$ 11,348,000	
7	**Total Gas Plant In Service**	**$ 222,855,000**	**$ -**	**$ 222,855,000**	**$ (607,617)**	**$ 222,247,383**	ND PSC 1-44/45

(1) Company Exhibit BCH-1 Schedule 5

Meter Installation costs - outside $3,500 x 111 - $388,500 1-46 (relocation) 1-46
Meter exchange costs $453 X 12,525 = $5,673,825 1-47
Cost to exchange a module $72 x 12,525 = $901,800 commencing in 2023 1-48
Fargo Project located in Gas Distribution
Capital Additions 1-55 and 1-56
AGIS adjustment 1-62
Wescott - Spring of 2022, Sibley - Maplewood and Delta V

ACCUMULATED DEPRECIATION

	(1) Company Unadjusted	Adjustments	Company Proposed	Adjustments	ND PSC Advocacy Staff	References
Gas Manufactured Plant	$ 2,420,000	$ (45,000)	$ 2,375,000	$ -	$ 2,375,000	WP A8
Gas Storage	$ 8,010,000	$ 29,000	$ 8,039,000	$ -	$ 8,039,000	WP A8
Gas Transmission	$ 1,683,000	$ 3,000	$ 1,686,000	$ -	$ 1,686,000	WP A9
Gas Distribution	$ 59,581,000	$ 50,000	$ 59,631,000	$ (71,337)	$ 59,559,663	WP A9
General	$ 5,559,000	$ 47,000	$ 5,606,000	$ -	$ 5,606,000	WP A9
Common	$ 5,619,000	$ 17,000	$ 5,636,000	$ -	$ 5,636,000	WP A9
Total Accumulated Depreciation	**$ 82,872,000**	**$ 101,000**	**$ 82,973,000**	**$ (71,337)**	**$ 82,901,663**	

(1) Company Exhibit BCH-1 Schedule 5

ACCUMULATED DEFERRED INCOME TAXES

		(1) Company Unadjusted	Adjustments	Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	Production	$ (77,000)	$ 12,000	$ (65,000)	$ -	$ (65,000)	WP A8
2	Transmission	$ 718,000	$ (1,000)	$ 717,000	$ -	$ 717,000	WP A9
3	Distribution	$ 17,469,000	$ (14,000)	$ 17,455,000	$ -	$ 17,455,000	WP A9
4	Gas Storage	$ (416,000)	$ (8,000)	$ (424,000)	$ (14,981)	$ (438,981)	WP A8
5	General	$ 1,266,000	$ (19,000)	$ 1,247,000	$ -	$ 1,247,000	WP A9
6	Common	$ 625,000	$ 1,000	$ 626,000	$ -	$ 626,000	WP A9
7	Net Operating Loss	$ (93,000)	$ -	$ (93,000)	$ -	$ (93,000)	
8	Non-Plant Related	$ 319,000	$ -	$ 319,000	$ -	$ 319,000	
9	**Total Accumulated Deferred Income Taxes**	**$ 19,811,000**	**$ (29,000)**	**$ 19,782,000**	**$ (14,981)**	**$ 19,767,019**	

(1) Company Exhibit BCH-1 Schedule 15

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule S-DM-8

	CASH WORKING CAPITAL	(1) Lead/Lag Days	Company Dollars	Dollar x Days	Adjustments	ND PSC Advocacy Staff	References
1	**Fuel Expenses**	39.09119	$ 14,442,000	$ 564,554,966	$ 1,152,877,375	$ 1,717,432,341	4-3
	Labor						
2	Regular Payroll	11.890587	$ 3,409,000	$ 40,535,011	$ (173,413)	$ 38,473,031	DM-4
3	Incentive	248.81	$ 37,000	$ 9,205,970	$ (28,039)	$ 2,229,586	
4	Pension & Benefits	37.23	$ 647,000	$ 24,087,810	$ -	$ 24,087,810	
			$ 4,093,000	**$ 73,828,791**	**$ (9,038,364)**	**$ 64,790,427**	
5	All Other Operating Expenses	22.73988	$ 37,080,000	$ 843,194,750		$ 207,581,798	4-3
6	Property Taxes	357.9199	$ 1,587,000	$ 568,018,881		$ 450,486,576	
7	Employer's Payroll Taxes	31.6197	$ 263,000	$ 8,315,981		$ 7,902,041	
8	Gross Earnings Tax	38.8962	$ 1,214,000	$ 47,219,987		$ 47,219,987	
9	Federal Income Taxes	37.005	$ (386,000)	$ (14,283,930)		$ (4,995,675)	
10	State Income Taxes	36.9156	$ (83,000)	$ (3,063,995)		$ (1,070,552)	
			$ 39,675,000	**$ 1,449,401,675**		**$ 707,124,174**	
11	**Total**		**$ 58,210,000**	**$ 2,087,785,432**		**$ 2,489,346,943**	
12	Net Annual Expense (365)			$ 5,719,960		$ 6,820,129	
13	Revenues	40.2998	$ 67,303,000	$ 2,712,297,439		$ 2,712,284,826	
14	Late Payment		$ 155,000	$ -		$ -	
15	Miscellaneous Services	40.389	$ 118,000	$ 4,765,902		$ 4,765,902	
16	Rentals	-50.009	$ 211,000	$ (10,551,899)		$ (10,551,899)	
17	**Total**		**$ 67,787,000**	**$ 2,706,511,442**		**$ 2,706,498,829**	
18	Net Annual Amount (365)			$ 7,415,100		$ 7,415,065	
19	Expense/Revenue Factor			85.87%		85.87%	
20	Allocated Revenue			$ 6,367,489		$ 6,367,459	
21	**Net Cash Working Capital**			**$ 647,529**		**$ (452,670)**	

(1) Company Exhibit BCH-1 Schedule 8

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule S-DM-9

OPERATING REVENUES

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	Residential Service	$ 26,797,199	$ -	$ 26,797,199	
2	Commerical/Industrial	$ 31,901,891	$ -	$ 31,901,891	
3	Small Interruptible Service	$ 2,194,889	$ -	$ 2,194,889	
4	Large Interruptible Service	$ 6,408,708	$ -	$ 6,408,708	
5	Interruptible	$ -	$ -	$ -	
6	Firm Transportation Service	$ -	$ -	$ -	
7	**Total Present Rate Revenues**	**$ 67,302,687**	**$ -**	**$ 67,302,687**	
8	Other Gas Revenues	$ 550,384	$ -	$ 550,384	1-33
9	**Total Operating Revenues**	**$ 67,853,071**	**$ -**	**$ 67,853,071**	

(1) Company WP R2 Present Revenues
Differences due to rounding

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule S-DM-10

OPERATION & MAINTENANCE EXPENSES - WORKSHEET

	Three-Year Normalize Non-Labor	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	Purchased Gas Expense	$ 43,934,429	$ -	$ 43,934,429	DM-12
2	Gas Production & Storage	$ 289,489	$ -	$ 289,489	DM-13
3	Gas Transmission	$ 304,359	$ (44,169)	$ 260,190	DM-14
4	Gas Distribution	$ 3,278,109	$ (901,253)	$ 2,376,856	DM-15
5	Customer Accounting	$ 1,217,726	$ (301,166)	$ 916,560	DM-16
6	Customer Service & Information	$ 140,217	$ 11,853	$ 152,070	DM-17
7	Sales, Econ Develop & Other	$ 8,872	$ -	$ 8,872	DM-18
8	Administrative & General	$ 1,099,071	$ -	$ 1,099,071	DM-19
9	**Total**	**$ 50,272,272**	**$ (1,234,735)**	**$ 49,037,537**	

(1) Company WP O2-3 Jurisdictional Alloc.
Diffferences due to rounding

check for vacancy rate - 1-17 and 1-15
check for hires in 1-19 - trade secret for salaries
review 1-34 without labor

PURCHASED GAS

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 43,934,429**		**$ 43,934,429**	
2	Adjustments	$ -		$ -	
3	Precedential Adjustments	$ -		$ -	
4	**Adjusted Balance**	**$ 43,934,429**	**$ -**	**$ 43,934,429**	

(1) Company Schedule BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule S-DM-13

GAS PRODUCTION & STORAGE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 635,473**		**$ 635,473**	
2	Adjustments	$ -	$ -	$ -	ND PSC 4-12
3	Precedential Adjustments	$ -	$ -	$ -	
4	**Adjusted Balance**	**$ 635,473**		**$ 635,473**	ND PSC 1-51

(1) Company Exhibit BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation
Wescott, Maplewood & Sibley Plants

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule S-DM-14

GAS TRANSMISSION

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 386,692**		**$ 386,692**	
2	Adjustments - three year average	$ -	$ (44,169)	$ (44,169)	ND PSC 1-34
	Damage Prevention Program	$ -	$ -	$ -	ND PSC 1-53
3	Precedential Adjustments	$ -	$ -	$ -	
4	**Adjusted Balance**	**$ 386,692**	**$ (44,169)**	**$ 342,523**	

(1) Company Exhibit BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation

GAS DISTRIBUTION

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Unadjusted Balance				
1	G Customer MNND Border	$ 2,258,174	$ (775,305)	$ 1,482,869	ND PSC 4-13
2	G Customers	$ 947,014	$ 168,496	$ 1,115,510	
3	G Direct MN	$ -	$ -	$ -	
4	G Direct ND	$ 1,924,193	$ (294,443)	$ 1,629,750	
5	**Total Balance**	**$ 5,129,381**	**$ (901,252)**	**$ 4,228,129**	ND PSC 1-50
6	Damage Prevention Program	$ -	$ (22,340)	$ (22,340)	ND PSC 1-53
7	Precedential Adjustments	$ -	**$ -**	**$ -**	
8	**Adjusted Balance**	**$ 5,129,381**	**$ (923,592)**	**$ 4,205,789**	

(1) Company Exhibit BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation
Fargo Capacity Cost - O&M $18,000 plus $4,600

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule S-DM-16

CUSTOMER ACCOUNTING

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Unadjusted Balance				
1	G Bad Debts	$ 280,729	$ 4,204	$ 284,933	ND PSC 4-14
2	G Customers	$ 932,545	$ (191,159)	$ 741,386	
3	G Direct MN	$ -	$ -	$ -	
4	G Direct ND	$ 399,447	$ (114,312)	$ 285,135	
5	**Total Balance**	**$ 1,612,721**	**$ (301,267)**	**$ 1,311,454**	
6	Adjustments	$ -	$ -	$ -	
7	Precedential Adjustments	$ -	$ -	$ -	
8	**Adjusted Balance**	**$ 1,612,721**	**$ (301,267)**	**$ 1,311,454**	

(1) Company Exhibit BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation
Meter reading costs - 1-48

CUSTOMER SERVICE & INFORMATION

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Unadjusted Balance				
1	G Customers	$ 51,713		$ 51,713	ND PSC 1-34
2	G Direct ND	$ 97,676		$ 97,676	
3	Advertising	$ 40,000		$ 40,000	
4	**Total Unadjusted Balance**	**$ 189,389**	**$ -**	**$ 189,389**	
	Adjustments	$ -	$ 11,853	$ 11,853	DM-10
5	Precedential Adjustments	$ (40,000)	$ (1,471)	$ (41,471)	WP A1 Adv
6	**Adjusted Balance**	**$ 149,389**	**$ 10,382**	**$ 159,771**	ND-PSC 1-39

(1) Company Exhibit BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation

SALES & ECONOMIC DEVELOPMENT

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
Unadjusted Balance				
G Customers	$ 2,355		$ 2,355	
Total Unadjusted Balance	**$ 2,355**	$ -	**$ 2,355**	
Adjustments	$ -	$ -	$ -	ND PSC 1-34
				WP A11 Econ.
Precedential Adjustments	$ 7,382	$ (7,382)	$ -	Donations 1-41
Adjusted Balance	**$ 9,737**	**$ (7,382)**	**$ 2,355**	

(1) Company Exhibit BCH-1 Schedule 6
Company WP O2-3 Jurisdictional Allocation

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule S-DM-19

ADMINISTRATIVE & GENERAL

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Unadjusted Balance				
1	G Customers MNND Border	$ 226,813	$ -	$ 226,813	ND PSC 1-34
2	G Customers MNND Border	$ 2,222,388	$ -	$ 2,222,388	
3	G Direct ND	$ 58,455	$ -	$ 58,455	
4	Other	$ 130,846	$ -	$ 130,846	
5	**Total Unadjusted Balance**	**$ 2,638,502**	**$ -**	**$ 2,638,502**	
6	Adjustments - Other	$ -	$ -	$ -	ND PSC 1-34 1-25/26
	Precedential Adjustments:				
7	Advertising	$ (28,856)	$ -	$ (28,856)	WP A1 Adv. 1-39
8	Customer Deposits	$ 676	$ -	$ 676	WP A3
9	Incentive Pay	$ (17,013)	$ -	$ (17,013)	WP A4
10	Incentive Pay LT	$ (97,348)	$ -	$ (97,348)	WP A5
11	SERP	$ (3,027)	$ -	$ (3,027)	WP A6
12	**Total Precedential Adjustments**	**$ (145,568)**	**$ -**	**$ (145,568)**	
	RM Adjustments				
13	Aviation (100%)	$ (22,003)	$ -	$ (22,003)	WP A7
14	Chamber of Commerce	$ 2,221	$ (2,221)	$ -	WP A10 - 1-40
15	Economic Develop Donations	$ 6,226	$ (6,226)	$ -	WP A12 1-42
16	Incentive Pay - Environmental LTI	$ 17,060	$ (17,060)	$ -	WP A13
17	Incentive Pay - Time Based LTI	$ 10,979	$ (10,979)	$ -	WP A14
18	**Total RM Adjustments**	**$ 14,483**	**$ (36,486)**	**$ (22,003)**	
19	**Adjusted Balance**	**$ 2,507,417**		**$ 2,470,931**	
20	rounding	$ 239		$ 239	
21	**Total**	**$ 2,507,656**	**$ (36,486)**	**$ 2,471,170**	

(1) Company Exhibit BCH-1 Schedule 6
Company O2-3 Jurisditional Allocation
Company Exhibit BCH-1 Schedule 4

Review data responses to 1-6, 1-13, 1-14, 1-15, 1-16, 1-17
Confirm total Gas Employees and the allocate employees who left

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule S-DM-20

DEPRECIATION EXPENSE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 6,845,000**	**$ (16,078)**	**$ 6,828,922**	1-43/4-9
	Remaining Life				
2	Gas Manufactured Production Plant	$ (90,872)	$ -	$ (90,872)	WP A8
3	Gas Other Storage Plant	$ 58,954	$ -	$ 58,954	WP A8
4	**Total Remaining Life**	**$ (31,918)**	**$ -**	**$ (31,918)**	
	Depreciation Study				
5	Gas Distribution - Composite 2.646%	$ 33,481	$ -	$ 33,481	WP A9
6	Gas Transmission - Composite 1.76%	$ 1,767	$ -	$ 1,767	WP A9
7	Common-General - AGIS - 21.68%	$ 17,742	$ -	$ 17,742	WP A9
8	General	$ 27,897	$ -	$ 27,897	WP A9
9	Common-Intangible	$ (6,212)	$ -	$ (6,212)	WP A9
10	Intangible	$ 3,448	$ -	$ 3,448	WP A9
11	**Total Depreciation Study**	**$ 78,123**	**$ -**	**$ 78,123**	
	Updated Depreciation adjustment		$ (55,259)	$ (55,259)	1-43
12	**Adjusted Balance**	**$ 6,891,205**	**$ (71,337)**	**$ 6,819,868**	

(1) Company Exhibit BCH-1 Schedule 6
Fargo Project located in Gas Distribution
refer to 1-43, updated in Company
rebuttal
Refer to 1-61/63

AMORTIZATION EXPENSE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Unadjusted Balance	**$ -**			
(2)	Income Tax Tracker	$ 9,317	$ (3,727)	$ 5,590	WP A15
	NOL Tax Reform ADIT ARAM	$ 22,547	$ -	$ 22,547	WP A16
(3)	Rate Case Expense Amortization	$ 408,115	$ (163,246)	$ 244,869	WP A17
	Adjusted Balance	**$ 439,979**	**$ (166,973)**	**$ 273,006**	

(1) Company Exhibit BCH-1 Schedule 6

Refer to 1-43 - updated in Company Rebuttal

(2) Income Tax Tracker amortized over 5 years

(3) Rate Case Expense amortized over 5 years

Northern States Power Co. ND - Gas
Test Year Ending 12/31/2022

ND Public Service Commission
Case No. PU-21-381

Schedule S-DM-22

TAXES OTHER THAN INCOME

	(1) Company Proposed		Adjustments		ND PSC Advocacy Staff	References
Property Taxes	**$**	**1,587,442**	**$ (328,818)**	**$**	**1,258,624**	1-24
Payroll Taxes	**$**	**262,844**	**$ (12,935)**	**$**	**249,909**	1-34
Unadjusted Deferred Income Taxes / ITC	**$**	**564,000**	**$ -**	**$**	**564,000**	
Depreciation Study - Remaining Life						
Gas Manufactured Plant	$	25,543	$ -	$	25,543	
Gas Other Storage Plant	$	(16,571)	$ -	$	(16,571)	
Total	**$**	**8,972**	**$ -**	**$**	**8,972**	WP A8
Depreciation Study - TD&G - 28.11%						
Gas Distribution	$	(9,410)	$ -	$	(9,410)	
Gas Transmission	$	(497)	$ -	$	(497)	
Common-General	$	(4,987)	$ -	$	(4,987)	
General	$	(7,841)	$ -	$	(7,841)	
Common-Intangible	$	1,746	$ -	$	1,746	
Intangible Plant	$	(969)	$ -	$	(969)	
Total	**$**	**(21,958)**	**$ -**	**$**	**(21,958)**	WP A9
Adjusted Deferred Income Taxes/ITC	**$**	**551,014**	**$ (4,637)**	**$**	**546,377**	
Total Taxes Other Than Income	**$**	**2,401,300**	**$ (346,390)**	**$**	**2,054,910**	

(1) Company Exhibit BCH-1 Schedule 6

STATE INCOME TAXES
FEDERAL INCOME TAXES

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References	Update	
State Income Taxes						
Current - 4.31%	$ (29,000)	$ -	$ (29,000)	NDPSC 1-38	$ 59,688	To Schedule DM-4
Proposed Revenue Requirement	$ 7,059,000		$ 2,929,911	$ 3,958,994		
Proposed State Income Taxes	$ 304,243		$ 126,279	$ 170,633		
Proposed Balance	**$ 275,243**		**$ 97,279**	$ 230,321		
Federal Income Taxes						
Current - 21%	$ (135,000)	$ -	$ (135,000)	NDPSC 1-38	$ 278,289	To Schedule DM-4
Proposed Revenue Requirement	$ 7,059,000		$ 2,929,911	$ 3,788,361		
Proposed Federal Income Taxes	$ 1,418,499		$ 588,763	$ 795,556		
Proposed Balance	**$ 1,283,499**		**$ 453,763**	$ 1,073,845	$ 337,977	Total Present
Check total	$ 1,558,742		$ 551,042	$ 1,304,166	$ 337,977	$ 966,189 To Schedule DM-1

(1) Company Exhibit BCH-1 Schedule 3A
Differences due to rounding

Company Present	$ (671,153)
O&M Adjustments	$ 2,056,027
	$ 1,384,874
SIT at Present Rates	4.31%
	$ 59,688
FIT at Present Rates	$ 1,325,186
	21.00%
	$ 278,289

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
2021 Natural Gas Rate Increase
Application

Case No. PU-21-381

Verification

State Of New Jersey)
) ss.
County Of Ocean)

Dante Mugrace, being first duly sworn on oath, deposes and states that he has read the testimony and exhibits submitted in the above captioned matters under his name, that they were prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the best of his knowledge and belief.

Dante Mugrace

Dante Mugrace

Subscribed and sworn to before me this 21st day of April 21, 2022.

Notary Public
My Commission Expires: 11/25/24

BRENT N CARTER
Notary Public - State of New Jersey
My Commission Expires Nov 25, 2024

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company 2021 Natural Gas Rate Increase Application	**Case No. PU-21-381**

AFFIDAVIT OF SERVICE BY ELECTRONIC MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Geralyn R. Schmaltz deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **22nd day of April 2022,** she sent an electronic message to **eight** addressees, each including an electronic copy in portable document format of:

- **Prefiled Surrebuttal Testimony of Karl R. Pavlovic**
- **Prefiled Surrebuttal Testimony of Marlon F. Griffing**
- **Prefiled Surrebuttal Testimony of Dante Mugrace**

The electronic mail was addressed as follows:

Zeviel Simpser
Dorsey & Whitney, LLP
simpser.zev@dorsey.com

Dave Sederquist
Xcel Energy
dave.sederquist@xcelenergy.com

Hope Hogan
Administrative Law Judge
hlhogan@nd.gov

John Coffman
John B. Coffman, LLC
john@johncoffman.net

Matt Harris
Xcel Energy
matt.b.harris@xcelenergy.com

Regulatory Records
Xcel Energy
regulatory.records@xcelenergy.com

David Tschider
Tschider & Smith
dtschider@tschider-smithlaw.com

John Schuh
Legal Counsel – ND PSC
jschuh@nd.gov

The addresses shown are the respective addressee's last reasonably ascertainable electronic mail addresses.

Geralyn R Schmaltz

Subscribed and sworn to before me
this **22nd day of April 2022.**

Shelly A Bausk
Notary Public

SEAL

SHELLY A BAUSKE
Notary Public
State of North Dakota
My Commission Expires Sep 01, 2022