EXHIBIT
20

Direct Testimony and Schedules

Dante Mugrace

Before the North Dakota Public Service Commission

State of North Dakota

In the Matter of the Application of

Northern States Power Company – North Dakota

a Division of Xcel Energy

For Authority to Establish Increased Rates for

Electric Service

Case No. PU-24-376

Overall Revenue Requirement

Rate Base Valuation

Operating Income

July 8, 2025

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PSC Exhibit 20 - Direct Testimony of Dante Mugrace (Public)

Public Service Commission

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I. INTRODUCTION – STATEMENT OF QUALIFICATION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dante Mugrace. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a Senior Consultant with the Economic and Management Consultant Firm of PCMG and Associates, LLC. (PCMG). In my capacity as a Senior Consultant, I am responsible for evaluating and examining rate and rate-related proceedings before various governmental entities, preparing expert testimony and reviewing and making recommendations concerning revenue requirement proposals, as well as offering opinions on economic policy and policy issues and methodologies used to set a value on a utility's rate base and cost of service components of revenue requirements.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE?

A. PCMG is an association of experts in the area of utility regulation and policy, economics, accounting, and finance. PCMG's members have over 75 years of collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water and wastewater utilities that operate under local, state, and federal jurisdictions. PCMG focuses on areas regarding revenue requirement, cost of service, rate design, cost of capital and rate of return. We provide overall analyses on various ratemaking concepts as well as a review of public utility accounting methods used by various public utilities and State commissions. We also evaluate the reasonableness of costs and investments that are used to set rates and measure the value of rate base, whether these costs are prudent, used and useful, and known and measurable in utility operations. Prior to my association with PCMG, I was employed as a Senior Consultant with the consulting firm of Snavely-King Majoros and Associates (SKM) from 2013 to 2015 in the same capacity as PCMG. Prior to SKM, I was employed by the New Jersey Board of Public Utilities (NJBPU or BPU or Board) from 1983 to my retirement in

2011. During my tenure at the NJBPU, I held various Accounting, Auditing, Rate Analyst, Supervisory and Management positions. My last position was Bureau Chief of Rates in the Agency's Water Division. I held this position for nearly 10 years. My CV is attached as Appendix A.

Q. WHAT EXPERIENCE DO YOU HAVE IN THE AREA OF UTILITY RATE SETTING PROCEEDINGS AND OTHER REGULATORY AND UTILITY MATTERS?

A. In my capacity as Bureau Chief of Rates, I was responsible for managing, assigning, directing, and overseeing the rate process regarding the administrative, financial, and managerial functions of the Rates Bureau. My primary duties were to ensure that the utilities had sufficient revenues to cover their operating expenses, while ensuring that those expenses were reasonable, prudent, known and measurable in providing service and benefits to customers, and were in accordance with Board policies, regulatory standards, and prior rate orders. I also was responsible for ensuring that the utilities had the opportunity to earn a reasonable return on their plant investments, including the ability to provide safe, adequate, and proper service at reasonable rates. During my time at the NJBPU, I was involved in hundreds of rate and rate-related proceedings that were resolved either through settlement or through fully-litigated proceedings. In my capacity as a Senior Consultant, I was involved or am currently involved in rate and rate-related proceedings before Commissions in the Commonwealths of Massachusetts and Pennsylvania, and the States of Arkansas, Georgia, Hawaii, Maine, Maryland, New Jersey, New York, North Dakota, Wyoming and Ohio. I was involved in the Generic Proceedings to Establish Parameters for the Next Generation Performance Based Rate Plans before the Alberta Utilities Commission. I have been or am currently involved in matters before the Federal Energy Regulatory Commission ("FERC") regarding transmission formula rate plans.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Master of Business Administration ("MBA") degree with a concentration in Strategic Management from Pace University – Lubin School of Business in New York City, New York. I hold a Master of Public Administration ("MPA") degree from Kean University in Union, New Jersey. I hold a Bachelor of Science ("BS") degree in Accounting from Saint Peter's University in Jersey City, New Jersey.

Q. ON WHOSE BEHALF ARE YOUR TESTIFYING?

A. I am testifying on behalf of the Advocacy Staff of the North Dakota Public Service Commission (NDPSC).

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to evaluate and make a revenue requirement recommendation regarding Northern States Power Company's (NSP or Company) electric base rate case proceeding filed with the North Dakota Public Service Commission (NDPSC or Commission), on December 2, 2024, in Case No. PU-24-376. My overall revenue requirement recommendations are based upon the Company's proposed test year period ending December 31, 2025. The Company has proposed an overall annual revenue requirement increase of $44,556,000 or 19.34% over current retail rate revenues of $230,375,000. Incorporated into my testimony, I have presented findings with respect to the Company's test year rate base, revenues, operating expenses and net income at present rate revenues. I have incorporated and am relying on the recommendations of Ms. Maureen Reno for cost of capital and return on equity, and Dr. Karl Pavlovic for cost of service and rate design and depreciation expenses that may affect my revenue requirement.

Q. HAVE YOU REVIEWED AND EXAMINED THE COMPANY'S TESTIMONY AND ACCOMPANYING EXHIBITS IN THIS PROCEEDING?

A. Yes. I have reviewed NSP's testimony, statements and exhibits, and have also reviewed and relied on the responses to data requests propounded by Advocacy Staff and PCMG.

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I have prepared Schedules DM-1 through DM-24.

Q. PLEASE SUMMARIZE THE RATE RELIEF PROPOSED BY NSP.

A. As previously indicated above, the Company filed an application for an increase in electric service on December 2, 2024, requesting an increase in base distribution rates in the amount of $44,556,000 or 19.34% above current rates.[1] The revenue requirement is predicated upon a future test year ending December 31, 2025, (Exhibit BCH-1 Schedule 7) which include an overall rate of return of 7.56% and a common equity component of 10.30%. The Company has computed an average rate base balance of $816,976,000 based upon average balances of plant investments. The Company's last base rate case was approved in November 2020 by the Commission in Case No. PU-20-441.

Q. HOW DID THE COMPANY COMPUTE ITS PROPOSED REVENUE REQUIREMENT INCREASE OF $44,556,000?

A. The Company has computed its proposed revenue requirement increase by including all revenues and costs at the proposed capital structure, as well as any federal and state credits earned on a total company basis, and then allocating those components to North Dakota based upon the allocation methods as discussion in Company witness Mr. Halama's testimony (BCH-1 at 3). This produced an all-in revenue requirement for the jurisdiction. Rider projects were removed from the base rate request to ensure that there were no double recovery of costs. (BCH-1 at 3). The Company multiplied its proposed average rate base balance of $816,976,000 by the proposed rate of return of 7.56% to arrive at a proposed Operating Income requirement of $61,763,000. The Company then subtracted its Operating Income at present rates of $28,081,000 to arrive at an income deficiency of $33,682,000.[2] The Company then multiplied this amount by

[1] On January 8, 2025, the Commission approved an interim rate increase for the Company's electric service of $27,371,168 or 11.88% over current rates.
[2] Company Exhibit BCH-1 Schedule 7 page 1.

its revenue conversion factor of 1.32284 to arrive at its revenue requirement increase proposal of $44,556,000.

Q. HAVE YOU ACCEPTED THE COMPANY'S PROPOSED TEST YEAR ENDING DECEMBER 31, 2025?

A. Yes.

Q. HAS THE COMPANY UPDATED ITS PROPOSED REVENUE REQUIREMENT INCREASE SUBSEQUENT TO THE DECEMBER 2, 2024, FILING DATE?

A. Yes. On May 9, 2025, the Company provided supplemental testimony related to the Earnings Sharing Mechanism Issues (BCH-2) and Resource Prudence Issues (CJS-2). With respect to the Earnings Sharing Mechanism the Company addressed the refund due to customers to the earnings share mechanism agreed to in settling the prior rate case. (Halama testimony BCH-2 page 1). With respect to Resource Prudence Issues the Company addressed the prudence of actual expenses associated with constructing and acquiring the resources in the Company's Wind Repowering Portfolio, Docket No. PU-20-425 and the Dakota Range Docket No. PU-17-372. In both of the prior cases the Company entered into a settlement with PUC Staff that deemed the resource additions prudent up to an established threshold and reserved for further Commission review the prudence of any costs that exceeded that threshold. (Shaw testimony (CJS-2 page 1).

Q. HAS THE COMPANY'S SUPPLEMENTAL TESTIMONY HAVE ANY EFFECT ON THE REVENUE REQUIREMENT INCREASE PROPOSED?

A. No. The Company did not provide any updated revenue requirement schedules.

Q. PLEASE SUMMARIZE YOUR FINDING AND RECOMMENDATIONS.

A. Based upon the use of the Company's test year period ending December 31, 2025, I have the following recommendations:

1. My recommended rate base balance is $794,953,356, which is $22,022,644 lower than the Company's proposed rate base balance of $816,976,000.

2. My rate of return is based upon the recommendation of Ms. Reno, which recommends an overall return of 6.97%, which includes a common equity component of 9.41%.
3. My recommended operating revenues at present rates is $230,375,000, which is equal to the Company's operating retail revenues at present rates of $230,375,000.[3]
4. My overall revenue requirement increase, based upon an overall rate of return of 6.97%, is $29,586,245 or 12.84%; this is $14,970,162 lower than the Company's overall revenue requirement increase of $44,556,000 or 19.34%.

Q. WHAT ARE THE REVENUE REQUIREMENT IMPACTS WITH RESPECT TO YOUR RATE BASE ADJUSTMENTS AND FOR THE OPERATING EXPENSE ADJUSMENTS?

A. My major Revenue Requirement impacts to the Rate Base and Operating Impact adjustments are as follows and includes the flow through of Federal and State Income Taxes:

Rate Base Adjustments:

- Disallowance of certain Electric Plant of $22,022,644 – Revenue Impact reduction of $2,202,412.
- Return on Equity adjustment (from Company's proposed of 10.30% to Advocacy recommended 9.41% - Revenue reduction impact of $5,057,810.
- **Total Rate Base Revenue reduction Impact - $7,260,222.**

Operating Income Adjustments:

- Normalization of certain Operating Expenses with variances >15%. A disallowance of ($1,945,201).
- Disallowance of Inflation Related adjustments embedded in the Operating Expense categories. ($1,463,555)

[3] Any differences between Mr. Mugrace's schedules and his testimony are due to rounding.

- Disallowance of Incentive Compensation related to LTI- Environmental based and LTI – Time-Based costs. ($887,544).
- Disallowance of Chambers of Commerce, Foundation and Other Donations and Economic Donation costs. ($445,000).
- Total Other – ($182,909).
- Disallowance of Depreciation Expense related to disallowance of certain Electric Plant in Service – ($706,749).
- Disallowance of Amortization Expense related to certain adjustments – ($706,048)
- Disallowance of adjustments to Taxes Other Than Income – ($110,116).
- **Total Operating Income Adjustments – ($6,447,122).**

  Total Rate Base and Operating Income Adjustments – ($13,707,344)

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS JURISDICTIONAL ALLOCATION OF TRANSMISSION?

A. As more fully discussed in Dr. Pavlovic's testimony, the Company uses a 12 Coincident Peak (12CP) demand to allocate its transmission plant and operating expenses to its North Dakota, South Dakota and Minnesota jurisdictions. (Pavlovic Testimony).

Q. WHAT HAS DR. PAVLOVIC RECOMMENDED?

A. Dr. Pavlovic has recommended the use of 1 Coincident Peak (ICP) demand allocator for jurisdictional allocation of transmission costs. (Pavlovic Testimony). Dr. Pavlovic has recommended that the Company apply this 1CP demand allocator it its rebuttal testimony and provide the excel file workpapers. (Pavlovic Testimony).

Q. CAN YOU DETERMINE THE RATE IMPACT WITH RESPECT TO THE USE OF DR. PAVLOVIC'S RECOMMENDED 1CP DEMAND ALLOCATOR?

A. No. As stated in Dr. Pavlovic's testimony, the Company should prepare the revenue requirement impact when filing its rebuttal testimony and provide the excel file workpapers supporting the use of a 1CP demand allocator (Pavlovic Testimony).

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized by documenting and explaining adjustments to various rate base components and net operating income components to arrive at my recommended revenue requirement decrease.

Q. ARE YOU ACCEPTING ANY OF THE COMPANY'S PROPOSED RATE BASE BALANCE AND OPERATING INCOME ADJUSMENTS?

A. Yes. I am accepting certain of the Company's Rate Base balances and certain of the Company's Operating Income adjustments. These adjustments are not identified in my testimony but are identified in my revenue requirement schedules. My testimony reflects the areas of disagreement from that of the Company and the affect these adjustments have on rates.

III. Cost of Capital

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS COST OF CAPITAL?

A. The Company has proposed an overall Cost of Capital of 7.56%. The breakdown of this return is based upon a long-term debt rate of 4.5092%, a short-term debt rate of 5.310% and a common equity component of 10.30%. (WP Volume 3 VI C1. Cost of Capital page 2 of 2).

Q. WHAT IS YOUR RECOMMENDED COST OF CAPITAL?

A. As per Advocacy Staff witness Ms. Reno's recommendation, I am incorporating an overall cost of capital of 6.97% which includes a common equity component of 9.41%. This is shown on Schedule DM-2, and on Ms. Reno's Summary Table WACC.

REVENUE REQUIREMENT ISSUES

IV. Rate Base Issues

A. Electric Plant in Service

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS ELECTRIC PLANT IN SERVICE BALANCE?

A. As shown on Exhibit BCH-1 Schedule 10 the Company proposed an average plant in service balance of $1,778,568,000 as of December 31, 2025. The Company developed this balance by allocating total Company investments proposed in the 2025 test year period to the North Dakota jurisdiction (Exhibit BCH-1 Schedule10). The Company calculated the investment related to the North Dakota jurisdiction using a simple average of projected net plant at the beginning and end of the test year consistent with the method employed in the Company's most recent North Dakota electric rate case (BCH-1 page 22). According to Company witness Mr. Moeller, the Company has forecasted capital additions of $1.5 billion in 2024 and $2.0 billion in 2025. (MPM-1 page 16). The primary drivers of the capital additions in 2024 and 2025 are to provide reliable service to customers and investments in natural gas peaking plants, wind and solar facilities and long-term battery storage. (MPM-1-16).

Q. HOW DID THE COMPANY DEVELOP THE PLANT BALANCES FOR THE END OF THE TEST YEAR 2025?

A. The Company stated that the 2025 ending plant balances were determined by applying the data contained in the 2025 capital budget adjusted for plant additions, retirement, depreciation, salvage and removal costs projected to occur during the test year. (BCH-1 page 22). Mr. Halama stated that the plant balances include capital costs related to nuclear capital related investments and steam costs of removal increases (BCH-1 page 7). Mr. Halama stated that transmission capital costs are included in the Company's plant balances related to the roll-in of transmission projects for the Company's major line rebuild and refurbishment programs and the Bayfield Loop and Huntley Wilmarth projects. (BCH-1 page 7-8). Mr. Halama included capital costs related to distribution capital projects related to expansion of the Company's distribution asset health programs for pole and underground cable replacements. (BCH-1 page 8). Mr. Halama stated that the 2025 test year period includes cost related to the Advanced Grid Intelligence and Security (AGIS) capital and deferred costs for new meters and communication infrastructure. (BCH-1 page 8). Finally, Mr. Halama stated that the 2025 test year includes general and intangible costs for service centers, fleet and increasing technology and cyber security initiatives. (BCH-1 page 9).

Q. HOW DOES THE COMPANY ALLOCATE ITS ELECTRIC PLANT IN SERVICE BALANCE FROM THAT OF THE PARENT COMPANY – XCEL ENERGY AND NORTHERN STATES POWER COMPANY?

A. The Company allocates its Electric Plant in Service (EPIS) balance using jurisdictional allocations and assigning or allocating to the Service Company pursuant to the Utility Services agreement between the Service Company and the Company. (BCH-1 page 38). Mr. Halama stated that the cost allocation and assignment principles have not changed since the Company's last electric rate case and are consistent with the Company's recent Minnesota electric rate case filed on November 1, 2024, with the Minnesota Public Utilities Commission (Docket No. E002/GR-24-320) (BCH-1 page 39). Additional information regarding the allocation process is reflected in BCH-1 Schedule 14 (Cost Assignment and Allocation Manual – CAAM). (BCH-1 page 39). The allocation factors used to allocate capital related items to the North Dakota jurisdictional electric operations income statement and rate base are included in Company filing Volume 3, Section VII. Budget Allocations workpaper B3. The 2025 allocation factors are as follows:

Demand	6.0519%
Energy	6.4219%
Customers	6.0795%

Q. DO YOU HAVE ANY CHANGES OR ADJUSTMENTS TO THE COMPANY'S ALLOCATIONS FACTORS USED IN THE DEVELOPMENT OF THE COMPANY'S REVENUE REQUIREMENT?

A. No. I am accepting the Company's proposed allocation factors that were used in the development of the Company's revenue requirement proposal.

Q. DO YOU HAVE ANY ADJUSMENTS WITH RESPECT TO THE COMPANY'S EPIS BALANCE OF $1,778,568,000? PLEASE SUMMARIZE YOUR ADJUSTMENTS.

A. Yes. I have several adjustments to the Company's EPIS balance for the 2025 test year period.

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS DISTRIBUTION CAPITAL ADDITIONS?

A. The Company has included capital additions of $73.1 million related to Asset Health, AGIS, Wildfire and New Business categories including purchases of reserve transformers. (MPM-1 page 19). Mr. Moeller stated that the LINE Convert Larimore LAR 4kV project at a cost of $8.1 million in 2024 included the equipment and labor required for the conversion of 4kV electric distribution lines served from the 69-4kV Larimore Station in Larimore, North Dakota to 12.5 kV electric distribution lines served from the new Turtle River Substation in Larimore, North Dakota, which is an addition. (MPM-1 page 1). The LINE Convert North Broadway NBY 4 kV project is $4.6 million that was undertaken from 2022 to 2025 and included the equipment and labor required for the conversion of 4 kV electric distribution lines served from the 23.9-4kV North Broadway in Fargo, North Dakota to 23.9 kV electric distribution lines served from the 115.23.9 kV Red River Substation in Fargo, North Dakota. (MPM-1 page 19-20).

<u>Larimore Station</u> – NDPSC Set- 8-14

In response to Set 8-14 the Company provided information related to its Larimore Substation. The Company stated that the in-service date for this project at the time of the July 2024 budget was December 15, 2025. The current in-service projection is now August 30, 2026. Given this update, I recommend disallowing these costs because the in-service date of August 30, 2026, is beyond the Company's test year period of December 31, 2025. The total cost of this project is provided in Company response to Set 8-14 Attachment B in the amount of $13,134,431. My recommendation is shown on my Schedule DM-5.

AGIS – Private LTE Wireless Network Set 8-67

Q. WHAT HAS THE COMPANY PROVIDED RELATED TO ITS PRIVATE LTE WIRELESS NETWORK?

A. The Company proposed developing a private LTE wireless network, which will be developed in stages over the next 10-12 years. (Company Set 8-67). The private wireless network will be deployed in 27 counties across the Company's four operating companies. The Company anticipates that the initiative will be in-service in North Dakota in the 2028 timeframe. The initial phase of these costs included in the rate case is $2,578,170. These costs are related to cellular software, hardware and cellular spectrum. The Company stated that the reason for implementing the private wireless network is to ensure secure, safe and reliable service to customers. The O&M benefits of this initiative are outside this rate case and will be adjusted in a future rate case.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. Given that these costs will not be implemented for full service and operability, I am recommending disallowance of these costs in the amount of $2,578,170. The Company's test year period is year-end December 21, 2025. The Company's implementation of this initiative is in 2028, well beyond the test year period. Additionally, there are no offsetting O&M expense benefits or savings attached to this initiative. It is premature to include these costs in rates until full operability. My recommendation is shown on my Schedule DM-5.

Q. WHAT HAS THE COMPANY INCLUDED WITH RESPECT TO MITIGATION OF WILDFIRES?

A. Mr. Moeller stated that the Company (Xcel Energy) is working to mitigate wildfires risks across all the states in which its operating utilities provide service including North Dakota. The Company's wildfire policy initiatives are a fundamental part of providing safe, reliable and affordable electric utility service and the Company has forecasted $5.1 million in this proceeding to address wildfire risk in North Dakota. (MPM-1 page 20). In response to Company Set 8-57, the Company included approximately $5.790 million of costs related to the Company's initiatives to address wildfire risk in North Dakota. (WFRM Pole Replacement of $396,465; WFRM Equipment Upgrade of $201,379 and WFRM Wildfire Safety Set of $5,191,814).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I reviewed the Company's Wildfire Mitigation Plan (Set 8-057 Attachment A). Given the nature and extent of wildfire that has continue to evolve throughout the United States, I am recommending that the Company recover these costs in rates that will benefit ratepayers by reducing wildfire risk threats.

Q. WHAT HAS THE COMPANY INCLUDED WITH RESPECT TO ITS NUCLEAR CAPITAL IN 2024-2025?

A. Mr. Moeller stated that the Company forecasted $29.2 million in 2024 and $19.3 million in 2025 for dry fuel loading at Prairie Island. For mandated compliance, reliability, improvement and facilities projects across the nuclear fleet, the Company is forecasting $158.2 million in 2024 and $121.2 million in 2025. (MPM-1 page 20). These costs include 2024 baffle former bolt and clevis bolt replacements at Prairie Island and the permanent reservoir installation at Monticello. (MPM-1 page 21). Regarding dry cask storage, the Company relies on safe on-site storage of spent fuel as the Federal government's Yucca Mountain storage is on hold for the foreseeable future and no apparent permanent storage is available. The Company continues to invest in new casks and associated infrastructure. (ADK-1 page 14). With respect to Baffle Former Bolt Replacement, which are used to hold horizontal supports for the cores at both Prairie Island Units, these need to be replaced based upon the age of the bolts and to avoid the need for additional inspections or replacements through the end of the current nuclear license period. (ADK-1 page 14). With respect to Groundwater projects the Company discovered a leak of tritiated water at the Monticello unit and needed to address the issue. The Company replaced the water pipe and two additional pipes in a similar position. Although the Company confirmed this did not cause any health issues, it was replaced and tritiated water is declining. (ADK-1 page 15).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am accepting the Company's costs related to the Dry Cask Storage, Baffle-Former Bolt Replacement and Groundwater Projects. These costs were placed in service beginning June of 2021 through December 2024 and identified in response to CONFIDENTIAL Attachment to Set 8-017.

Q. WHAT DID MR. MOELLER STATE REGARDING CAPITAL ADDITIONS FOR PEAKING PLANTS AND BATTERY STORAGE?

A. Mr. Moeller stated that the Company has budgeted $103.4 million in 2025 for peaking plant Blue Lake units 9-11, replacing the entire Blue Lake Unit 3 capacity with new reciprocating internal combustion engine generator (RICE) capacity. (MPM-1 page 17). Regarding battery storage, the Sherco Long Duration Battery pilot project is a 10 MW battery capable of discharging for 100 hours (1,000 MW hours) and will demonstrate the capacity of new battery technology and potentially lead to larger scale projects. (MPM-1 page 18). The Company has forecasted **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** for this project. This project will receive a Department of Energy grant and has a contingent commitment from Breakthrough Energy Catalyst for a grant in 2026 after completion, which could reduce the overall cost by more that 70 percent. (MPM-1 page 18). The Company has included a balance of **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** to its regulatory amortization as shown on Company Exhibit BCH-1 Schedule 5.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. As more fully explained in my Regulatory Amortization section of my testimony, I am recommending disallowance of the costs related to the Sherco Long-Term Duration Battery project given that the Company withdrew this project due to delay in implementation (Set 20-1). This reduces the UPIS balance by **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** and is shown on my Schedule DM-5.

Q. WHAT ARE YOUR TOTAL ADJUSTMENTS TO THE COMPANY'S EPIS BALANCE?

A. My adjustments reflect a total disallowance of $17,738,581 and is shown on my Schedule DM-5.

B. Accumulated Depreciation

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ACCUMULATED DEPRECIATION?

A. In the same manner as the Company developed its EPIS balance, the Company performed the same analysis with respect to its Accumulated Depreciation or Depreciation Reserve amount by averaging the beginning and ending test-year balances. The Company proposed an average depreciation reserve balance of $810.710 million as shown on Company Exhibit BCH-1 Schedule 5. The Company then adjusted the Production and General Assets (remaining lives), the Production and Transmission Riders, Transmission, Distribution and General and Common changes to the Depreciation Study, and Precedential adjustments totaling a decrease of $475,000. The Company's proposed updated Accumulated Depreciation balance is calculated at $810.234 million (Company Exhibit BCH-1 Schedule 5).

Q. DO YOU HAVE ANY ADJUSMENTS WITH THE WAY THE COMPANY DEVELOPED ITS ACCUMULATED DEPRECIATION BALANCE?

A. Yes. In response to Data Request Set 8-31, the Company objected to this request as being overly broad and unduly burdensome as it would require the Company to review records dating back decades to determine historical depreciation rates. Given this objection, my adjustments reflect estimations and approximations related to my accumulated depreciation adjustments to the Company's EPIS balance.

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS DEPRECIATION EXPENSE, WHICH AFFECTS THE ACCUMULATED DEPRECIATION IN THE TEST YEAR PERIOD 2025?

A. Mr. Moeller stated that he has proposed several changes affecting depreciation expense for production assets resulting from changing the remaining lives and updating the dismantling cost that is the basis of the negative salvage value. For transmission, distribution, general and intangible assets, he has proposed changes to the average remaining life depreciation rates based upon the underlying changes to the average service life retirement curves and net salvage value. (MPM-1 page 22-23).

Q. WHAT ARE THE SPECIFIC ADJUSTMENTS MR. MOELLER HAS MADE WITH RESPECT TO THE CHANGE IN DEPRECIATION EXPENSE?

A. Mr. Moeller made adjustments to the following assets:

Steam Production – Shortening the remaining lives of Allen S. King, Sherco Unit 1 and 3, retirement of Sherco Unit 2 and increasing the negative net salvage rates for all Steam Production plants;

Nuclear Production – 10-year life extension of Monticello;

Other Production – Extending the life of ten wind farms from 25 to 35 years;

Transmission, Distribution, General and Intangible (TD&G) – Updating new average service lives, retirement curves, net salvage rates, and depreciation rates for all assets in accordance with the most recent depreciation study and requesting initial parameters for several new accounts or subaccounts of assets. (MPM-1 page 23).

Table 2 (page 25) and Table 3 on page 32 of Mr. Moeller's testimony reflects the summary breakdown of the depreciation expense and remaining lives, respectively.

Q. WHAT ADJUSTMENTS TO THE COMPANY'S ACCUMULATED DEPRECIATION BALANCE DO YOU HAVE REGARDING YOUR ADJUSTMENTS TO THE COMPANY'S EPIS BALANCE?

A. As stated in response to Set 20-1, the Company has removed the UPIS Investment related to its Sherco Battery Investment. The associated Accumulated Depreciation Expense is **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).** I reflect this adjustment which is shown on my Schedule DM-6.

Given that I adjusted the Company's Larimore Station, the Sherco Battery Pilot Program and the LTE wireless Private Network, I am making the associated adjustments related to the accumulated depreciation balance. My adjustment is $698,051 **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)**. With respect to the Company's adjustments to its various remaining lives of its production assets and the updates to its TD&G assets, and as fully discussed in Dr. Pavlovic's testimony it is unclear from the data and evidence in the record how the Company made the adjustments to its various Depreciation Expense changes. The Company should provide the data and information in its rebuttal testimony. As of now, I am including the Company's various proposed Depreciation Expense adjustments. I reserve my right to update my testimony to amend my revenue requirement recommendation once the Company has provided the information. Dr. Pavlovic will provide his recommendation and overview with respect to the Company's proposed Depreciation adjustments. My adjustment is shown on my Schedule DM-6.

C. Accumulated Deferred Income Taxes (ADIT)

Q. WHAT HAS THE COMPANY PROPOSED REGARDING ITS ACCUMULATED DEFERRED INCOME TAXES?

A. The Company has proposed an ADIT balance of $150,287,000 as shown on Exhibit BCH-1 Revised Schedule 10. Mr. Halama stated that inter-period differences exist between book and taxable income treatment of certain accounting transactions, and these differences typically originate in one period and reverse in one or more subsequent periods. (BCH-1 page 24). The largest difference typically is the extent to which accelerated income tax depreciation exceeds book depreciation during the early years of an asset's service life. The ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in previous periods. (BCH-1 page 24).

Q. HOW DID THE COMPANY ARRIVE AT THE TEST YEAR BALANCE 2025?

A. As shown on Company Exhibit BCH-1 Schedule 5 and in response to NDPSC-8-38, the Company began with an unadjusted test year balance of $196,604,116 and made adjustments to the deferred tax asset (DTA) – Net Operating Loss average balance of ($31,603), DTA State Tax Credit of ($40,042) and DTA Federal Tax Credit ($46,245,091) to arrive at a Test Year balance of $150,287,380.[4] Mr. Halama stated that this amount represents the simple average of the projected beginning and ending test year ADIT balance and complies with Internal Revenue Service (IRS) tax regulations. Mr. Halama stated that Sec. 1.167(l) of the tax code defines a pro-rated schedule for the extent average accumulated deferred income taxes can reduce rate base to comply with the tax normalization requirements of the Code when forecast information is used in setting rates. (BCH-1 page 24-25).

Q. HAS THE COMPANY PROVIDED THE DEVELOPMENT OF THE ADJUSTMENTS WITH RESPECT TO EACH COMPONENT OF ITS ADIT BALANCES?

A. No. According to the Company, it utilizes the Utilities International Regulatory Information System to develop the cost of service models and testimony schedules; therefore, some live excel model versions of schedules are not

[4] See also workpaper Volume 3 III P1-1 Summary Test year 2025.

available. (Data Response 8-38 and 12-1). The information is system generated in a black box without workpapers or underlying formulae.

Q. WHAT IS YOUR RESPONSE?

A. The Company is responsible for supporting its revenue requirement increase with sufficient information and evidence so that the parties to the proceeding can properly evaluate the adjustments, analyze the data and provide a full and complete review of the filing and the related quantitative information. This is not a valid reason for the Company to assert. The Company has paid for this service and thus has access to the products and services that were used to develop the revenue requirement increase. Without the backup workpapers in excel format it would be nearly impossible to determine how the calculations were made and generated in the development of the revenue requirement.

Q. DO YOU HAVE ANY ADJUSTMENTS REGARDING THE COMPANY'S METHODOLOGY ON THE DEVELOPMENT OF ITS ADIT?

A. As stated above, I am unable to evaluate the methodology used by the Company with respect to its ADIT balance and the related adjustments. My adjustments are my best estimations and approximations with the information provided by the Company.

Q. WHAT SPECIFIC ADJUSTMENTS DO YOU HAVE REGARDING YOUR ADJUSTMENTS TO THE COMPANY'S EPIS BALANCE?

A. Given that I adjusted certain EPIS balances, I am making the associated (estimations and approximations) adjustments related to the Company's ADIT balance. These adjustments reflect the flow through of my adjustments related to my changes to the Company's EPIS balance and Accumulated Depreciation. My adjustments reflect **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** as stated in response to Set 20-1. My total adjustment is ($1,237,958). I utilized the Company's Composite Tax Rate of 24.40% for purposes of my adjustments.[5] My adjustments are shown on Schedule DM-7.

D. Construction Work in Progress (CWIP)

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO CWIP?

A. As shown on Company Exhibit BCH-1 Schedule 3, the Company has proposed a CWIP balance of $4,772,000. According to Mr. Halama CWIP balances included in rate base are short-duration projects (any capital project that is deemed routine and finishes work within a month) that do not accrue Allowance for Funds Used During Construction (AFUDC). (BCH-1 page 23). The rate base balance of CWIP reflects a simple average of projected short-term CWIP beginning and ending test year balances. The simple average was calculated using the June 30, 2024, actual CWIP balance. Mr. Halama stated that construction expenditures and transfers to plant-in-service during the remaining months of 2024 were netted against the June 30, 2024, balance to derive a beginning test year balance. The beginning test year CWIP was adjusted to reflect projected construction expenditures and transfers to plant in service during the 2025 test year to obtain the ending test year CWIP balance. (BCH-1 page 23). In response to Set 4-12, the Company stated that in order for short-term CWIP to be included in rate base, the Company identifies discrete projects which are less than 30 days in duration and therefore not eligible for AFUDC. The Company takes the discrete projects as a percentage of all CWIP projects by functional class and applies that percentage to the CWIP balance to determine the overall short-term CWIP.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Company should update its CWIP balance given that these expenditures are short-term in nature (within a month). I am disallowing the balance of the CWIP of $4,772,000 for now, but request that the Company update its projections related

[5] Workpaper Volume 3 V 08. State and Federal Income Tax

to CWIP as well as the breakdown of these CWIP balances associated with certain short-term plant projects. My adjustment is shown on my Schedule DM-3.

E. Cash Working Capital (CWC)

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO CASH WORKING CAPITAL (CWC)?

A. The Company has proposed a CWC balance of ($5,329,000) as shown on Exhibit BCH-1 Schedule 8. CWC requirements have been determined by applying the results of a comprehensive lead/lag study to the projected test year revenues and expenses. (BCH-1 page 27). This approach has been consistent with methods used in the most recent North Dakota electric rate case. (BCH-1 page 27). Mr. Halama stated that the Company's lead/lag study has been updated since the Company's last North Dakota electric rate case to include the twelve months ending December 31, 2023. (BCH-1 page 28). Mr. Halama stated that the negative balance indicates that the overall revenue collections occur sooner than the date when the associated costs of service are paid. On average, more cash requirements are being provided by customers and vendors. The negative CWC reduces rate base to compensate customers for funds provided to meet CWC requirements. (BCH-1 page 28).

Q. DO YOU HAVE ANY ADJUSTMENTS IN THE WAY THE COMPANY HAS COMPUTED ITS CWC BALANCE?

A. No. I accept the Company's methodology but have adjustments related to my recommended adjustment to the Company's proposed revenues and expenses.

Q. WHAT ARE YOUR ADJUSTMENTS?

A. Based upon my adjustments to the Company's Rate Base components, the Operating Income and the Operating Expenses, I have calculated a CWC balance of ($4,905,639) This is shown on Schedule DM-8. (NDPSC-8-39)

F. Non-Plant Assets and Liabilities

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO NON-PLANT ASSETS AND LIABILITIES?

A. The Company has proposed a Non-Plant Assets and Liabilities balance of $7,655,000 as shown on Exhibit BCH-1 Schedule 10. This balance represents book/tax timing differences associated with non-plant assets and liabilities and is reflected in the determination of current and deferred income tax provisions and ADIT balances. The balance of $7,655,000 is primarily comprised of assets that have increased the test year rate base by $7,655,000. (BCH-1 page 26-27).

Q. DO YOU HAVE ANY ADJUSTMENTS RELATED TO THE COMPANY'S PROPOSED NON-PLANT ASSETS AND LIABILITIES?

A. I am accepting the Company balance for its Non-Plant Assets and Liabilities of $7,655,000. This is shown on my Schedule DM-9.

G. Regulatory Amortizations

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS REGULATORY AMORTIZATIONS?

A. The Company proposed a balance of $33,174,000 of Regulatory Amortization as shown on Company Exhibit BCH-1 Schedule 15. A breakdown of these Regulatory Amortizations are shown on WP Volume 3 III P1-1. Summary Test Year page 4. This balance is comprised of the following accounts: (See response to 4-14)

(BEGIN CONFIDENTIAL)

[redacted]

[redacted]

(END CONFIDENTIAL)

Total	**($33,174,000)**

(1) AGIS Deferral Amortization - $5,481,000

Q. PLEASE EXPLAIN THE AGIS DEFERRED REGULATORY AMORTIZATION?

A. According to Mr. Krug the AGIS or Advanced Grid Intelligence and Security initiative is a group of related investments in the technology that is used to operate the distribution system. (ADK-1 page 12). These components include advanced metering infrastructure (AMI) smart meters, the field area network (FAN) that is used to communicate with those meters and the advanced distribution management system (ADMS) used to operate the electrical distribution system. (ADK-1 page 12). One of the outcomes agreed to in the Commission approved settlement that resolved the prior rate case was that the AGIS capital and operations and maintenance (O&M) expenses were placed in deferral. The Company was allowed to propose a reasonable amortization period for recovery of the deferral in a future rate case assuming that the foundational AGIS investments are either in service or are forecasted to be during the rate case test year. (ADK-1 page 12).

Q. WHAT IS THE STATUS OF AGIS IN NORTH DAKOTA?

A. According to Mr. Nickell (CSN-1 page 18), the Company has nearly completed the rollout of the AGIS initiative in North Dakota. The ADMS is fully deployed and operational and all of the FAN devices are installed. The deployment of new AMI software and integrations is complete, and the Company will complete the AMI meter installations in North Dakota by the end of the 2025 test year. (CSN-1 page 18). The foundational AGIS components are in place and full deployment will be completed within the test year. (CSN-1 page 18).

Q. WHAT HAS THE COMPANY PROPOSED TO RECOVER IN THIS RATE PROCEEDING?

A. According to Mr. Nickell the Company previously agreed to defer all capital-related and O&M expenses for its AGIS initiative in the Commission approved settlement that resolved the prior electric rate case (PU-20-441). (CSN-1 page 19). Mr. Nickell indicated that the settlement agreement generally provided that capital expenditures and O&M expenses associated with the AGIS initiative should be deferred until such time as all foundational elements of AGIS were in service. (CSN-1 page 19). The agreed deferral of the AGIS initiative costs was designed to treat the Company's capital and O&M expenses as if they were capital expenditures included in CWIP, whereby an allowance for funds used during the deferral were treated similar to AFUDC. (CSN-1 page 19). The Company has included $5,481,000 of regulatory amortization and an annual amortization recovery of $997,000 as shown on Company Exhibit BCH-1 Schedule 5 and 6, respectively. The Company is proposing to recover these costs over a six-year amortization period. (DR 8-70).

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S AGIS INITIATIVE?

A. I am recommending acceptance of the Company's balance related to its AGIS project of $5,481,000. I am also recommending that these AGIS assets be amortized over a 10-year period based upon other IT capex. My adjustment is shown on my Schedule DM-9. (a ten-year amortization period would be a recovery of $598,000 per year instead of $997,000 per year. In response to Set 12-15 which refers to Exhibit MPM-1 Schedules 5 and 8, the Company's identifies various computer software having an average life from 3 years to 15 years, and network equipment having an average life of 5 years. Extending the amortization period to 10-years would align with other IT and Networking assets. The Company has not specifically provided a reason use a the six-year amortization period.

(2) The <u>PI EPU Deferral</u>

Q. PLEASE EXPLAIN THE PI EPU DEFERRAL

A. According to the response to Data Request 8-43, the adjustment related to the Prairie Island Extended Power Uprate (PI EPU) collects the revenue requirement of abandoned project costs over the remaining life of the plant. As the plant continues to depreciate, the associated revenue requirement continues to decrease. In the Company's prior rate case proceeding (PU-20-441), the settlement document allowed the Company to recover the revenue requirement of the abandoned plant over the remaining life of Prairie Island.

Q. WHAT AMOUNT IS THE COMPANY PROPOSING TO RECOVERY IN RATES?

A. As shown on Company's Exhibit BCH-1 Schedule 5, the Company booked $2,722,000 as the balance remaining in the PI EPU Deferral to be recovered over the remaining life of the plant.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the disallowance of these costs and in response to 8-43 the Company identified that these project costs were previously abandoned after deciding not to pursue them. Although the Company stated that in the prior rate case the Company inferred that the Settlement document did not specifically address the recovery of the PI EPU costs, the Company determined that these costs should be recovered over the remaining life of the Prairie Island costs. I believe that costs that do not provide service to customers should not be included in rates for recovery. These costs were abandoned by the Company and decided not to invest in this project to its completion. The Company is continually requesting recovery of a project that is not used and useful in the provision of utility service. My adjustment is shown on my Schedule DM-9.

(3) <u>NOL Tax Reform ADIT ARAM (Average Rate Base Assumption Method)</u>

Q. PLEASE EXPLAIN THE NOL TAX REFORM ADIT ARAM

A. The NOL Tax Reform ADIT ARAM is related to the Commission Order in Case No. PU-18-155, which approved the Company's proposed amortization level included in the Tax Cut and Jobs Act (TCJA) refund calculation. This ADIT ARAM is being amortized over 23 years. (BCH-1 page 53). The Company has included a Regulatory Amortization balance of $2,835,000 as shown on Company Exhibit BCH-1 Schedule 5. The associated amortization expense results in a 2025 cost recovery of $308,000. (See Workpaper Volume 3 VIII A27. NOL Tax Reform ADIT ARAM).

Q. WHAT IS YOUR RECOMMENDATION?

A. I am accepting the Company's balance of $2,835,000. My adjustment is shown on my Schedule DM-9.

(4) The <u>RER PTC Amortization</u>

Q. PLEASE EXPLAIN THE RER PTC AMORTIZATION

A. As stated in response to Set 12-14, the RER PTC Amortization balance of ($43,315,000) is the average balance of the regulatory liability for North Dakota's share of Production Tax Credits. In response to Set 2-7, the Company utilized the Levelized Credit Method (LCM) to normalize production tax credits (PTC). This approach stemmed from the Commission and Staff's request to evenly distribute PTCs prospectively in the Company's Renewable Energy Rider (RER) (Case No. PU 19-329). The Commission approved the Company's RER rate on February 19, 2020.

Q. WHAT HAS THE COMPANY PROPOSED AND INCLUDED RELATED TO THE RER PTC AMORTIZATION?

A. As shown on Company Exhibit BCH-1 Schedule 5 the Company proposed a balance of ($43,315,000) related to the RER PTC Amortization. (See Workpaper Volume 3 III PI-1 Summary Test Year 2025 page 4 of 7 and Workpaper A9). This represents the average of the December 2024 balance ($38,094,783) and the

December 2025 balance ($48,534,458). (Workpaper Volume 3 VIII A9 PTC Amortization page 7 and 8).

Q. WHAT IS YOUR RECOMMENDATION?

A. I accept the Company's balance of ($43,315,000). My recommendation is shown on my Schedule DM-9.

(5) <u>Sherco Storage</u>

Q. PLEASE EXPLAIN THE COMPANY'S SHERCO STORAGE?

A. The Sherco Long Duration Battery pilot project is a 10 MW battery capable of discharging for 100 hours. The pilot project aims to demonstrate the potential of new battery technology, potentially leading to larger scale projects. (Moeller testimony page 18). The Sherco Long Duration Battery pilot project will receive a Department of Energy grant and has a contingent commitment from Breakthrough Energy Catalyst for a grant in 2026 after completion of the project. The grant funding could reduce the overall cost of the project by more than 70 percent. (Moeller testimony page 18).

Q. WHAT HAS THE COMPANY PROPOSED?

A. As shown on Company Exhibit BCH-1 Schedule 5, the Company has proposed a balance of (**BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** (See also Workpaper Volume 3 III P1-1 Summary Test Year 2025 and Volume 3 III P4-3 Sherco Battery page 1).

Q. HAS THE COMPANY PROVIDED ANY UPDATED INFORMATION ON THIS PILOT PROJECT?

A. Yes. In response to Set 20-1, The Company's partner for this project, Form Energy, has successfully brought its flagship factory online, but has experienced manufacturing adjustments related to scaling operations. The result of these adjustments has delayed the expected project completion date. The estimated in-service date was December 2025; the new commercial operation date is now early

2027. The shift in timing moves this investment beyond the test year being analyzed in this proceeding. For the 2025 test year, this reduces the revenue requirement by approximately **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** as reflected in Attachment A. The Company will make this adjustment to the deficiency in its Rebuttal Testimony.

Q. WHAT IS YOUR RECOMMENDATION?

A. Given this new information, I am recommending that this investment be removed from the Company's revenue requirement. These adjustments flow through my revenue requirement schedules.

V. Operating Income Issues

A. Operating Revenues

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS OPERATING REVENUES AT PRESENT RATES?

A. The Company has proposed Operating Retail Revenues at Present Rates of $230,374,819 as shown on Exhibit BCH-1 Schedule 3. (See Workpaper Volume 3 IV R1. Revenue Summary). The Company has proposed Other Operating Revenues of $62,537,550 as shown on Exhibit BCH-1 Schedule 3. (See Workpaper Volume 3 IV R1. Revenue Summary). The Electric Retail Revenues are comprised of Residential, Commercial & Industrial, Public & Highway, Other Sales to Public Authorities, Fuel Revenues and RER / TCR Rider Revenues. The Other Operating Revenues include such items as Interchange Revenues, Other Electric Revenues, Other Operating Revenues, Transmission Revenues, Fuel Revenues, Asset and Non-Asset Based Revenues and various Precedential Adjustments.

Q. HOW DID THE COMPANY DEVELOP ITS REVENUES FOR THE TEST YEAR PERIOD ENDING 2025?

A. Mr. Halama stated that test year retail sales levels assumed normal weather. (BCH-1 page 29).

Q. WHAT WEATHER NORMALIZATION PERIOD HAS THE COMPANY USED TO DEVELOP ITS SALES REVENUES?

A. The Company has utilized a 20-year averaged heating degree days (HDD) and Temperature – humidity index (THI) (BSL-1 page 18-19). The use of a 20-year weather normalization period takes into consideration economic and demographic indicators, weather, and historical number of customers from June 2009 through May 2024. The model was simulated over the forecast period expressed in 20-year average degree days). (BSL-1 page 18-19).

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S OPERATING REVENUES AT PRESENT RATES?

Yes. As I removed the Sherco Battery Investment from the revenue requirement calculation, the response to Confidential Set 20-1 reflects an adjustment to Operating Revenues of **(BEGIN CONFIDENTIAL)** [redacted]**(END CONFIDENTIAL).** In Company WP – Volume 3 IV R4 Other Revenue, the Company reflected a balance of **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL).** I am utilizing this balance to make my adjustment to the Company's Operating Revenue- Other Non-Retail. This is shown on my Schedule DM-10.

B. Operating and Maintenance Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS OPERATING AND MAINTENANCE EXPENSE?

A. As shown on Exhibit BCH-1 Schedule 3 and on Schedule 11, the Company proposed a total Operating and Maintenance Expense (O&M) balance for the 2025 test year of $182,009,000.[6] This balance is composed of various accounts related to Fuel and Purchased Energy, Power Production/Regional Markets, Transmission, Distribution, Customer Accounting/Customer Service, Sale/Economic Development and Administrative and General. This balance includes the Company specific adjustments in each of the accounts listed above,

[6] Any differences between Company Operating Expenses and Mr. Mugrace's Operating Expenses are due to rounding issues.

and as shown on Exhibit BCH-1 Revised Schedule 6. Company witness Mr. Halama stated that the corporate forecast from July 2024 was used to prepare the O&M forecast in this case. The July budget included 6 months of actuals for 2024 and 6 months of forecast for 2024 and is the most recently available 2025 forecast that could be used to prepare this case. The July 2024 forecast was developed consistent with corporate budgeting protocols. (BCH-1 page 31).

Q. WHAT WERE THE COMPANY'S REASONS TO FORECAST INCREASED COSTS IN ITS OPERATING EXPENSES?

A. According to Mr. Krug, business areas may use projections of future costs based upon historic costs incurred or trending of historic costs as their budgeting methodology. (Data Response Set 8-8). Spending guidelines are communicated to business areas as well as increases in base wages and salary rates and specific unit costs that can be used to estimate costs for various business services. Information is also provided to the business areas about general escalation-based indices for employment costs and producer prices. Information is not readily available about the extent to which a particular business area utilized the indices in its budgeting process. Mr. Krug has provided indices related to Labor and Non-Labor escalation factors:

Year	Labor	Non-Labor
2023	4.41%	1.54%
2024	4.09%	2.18%
2025-2023	3.42%	1.81%
2024-2033	3.48%	1.85%

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S OVERALL OPERATING AND MAINTENANCE EXPENSES?

A. I have adjustments to certain of the Company's overall O&M Expense balance that do not include specific adjustments the Company has made and proposed as shown on Exhibit BCH-1 Revised Schedule 4 and Schedule 6. My overall adjustments to the Company's certain O&M Expense incorporate the use of a three-year normalization adjustment and the disallowance of certain Inflation-related adjustments as reflected in Company Data Response 8-8.

Q. WHY ARE YOU USING A NORMALIZATION ADJUSTMENT TO CERTAIN OF THE COMPANY'S OVERALL O&M EXPENSES?

A. A review of the Company's O&M Expenses (Data Response Set 8-52 and Set 12-5 Set 12-8 and Set 14-1) shows that certain of the Company's balances for the periods 2022-2024 fluctuate and vary from year to year. In other accounts, the balances during the same period appear to be abnormal and irregular from what the Company is proposing to utilize and set in the test year 2025 period. In other areas there are negative balances or no prior costs accounted for. I reviewed the Company's response to Data Response Set 8-52, Set 12-5 , Set 12-8, and Set 14-1 which the Company provided a breakdown of costs for each of its operating expense categories. The use of a three-year normalization period smooths out fluctuations in setting rates going forward. Prior costs can also show and provide a trend of expenses that were incurred by the Company to determine the reasonableness of the adjustments in costs going forward.

The response to Data Request Set 12-8 and Set 14-1 indicates that some of the expenses are variable in nature and can change from period to period. It is appropriate to normalize these types of costs to set rates in this proceeding. Finally, certain costs are usually out of the Company's control in that they relate to outside vendors or third-party providers. I set a baseline variance of 15% or greater in determining my adjustments for each of the Company's operating expense categories. I based my variation percentage upon the basic accounting principle that a material variance of at least 12% is considered a major variance and requires explanations as to the reasoning for the variance. Variances are useful in determining whether expected or forecasted costs are in line with actual costs that have been incurred.

Q. DID YOU ASK THE COMPANY FOR AN EXPLANATION WHY CERTAIN COSTS HAVE FLUCTUATED FROM YEAR TO YEAR?

A. Yes. In response to Data Request Set 12-7, which referred to Company witness Mr. Halama testimony page 10, provided the principal changes in O&M costs for the 2021 test year, and 2023 actual test year, by category for the 2025 test year period. Total O&M expenses increased by $9.3 million from the 2021 test year to the 2025 test year, and by $8.7 million from the 2023 test year to the 2025 test year. Mr. Halama stated that wind O&M expense associated with placing new wind farms into service have been added to the Company's generation portfolio, including internal and external labor with the addition of nuclear related fees also driving additional increases. (Halama testimony page 11). Mr. Halama stated that the increase in transmission interchange operating expenses increased by $2.1 million and $2.8 million as compared to the 2021 test year and the 2023 actual test year, respectively. This was due to an increase in network transmission expenses driven by increased loads and rates. (Halama testimony page 12). With respect to A&G costs, the 2025 test year revenue requirement included $4.7 million and $1.2 million increase as compared to the 2021 test year and the 2023 actual test year, respectively due to increases in Company labor costs and insurance costs. (Halama testimony page 13). O&M expenses increased because of the tight labor market and a hardening insurance market, particularly in the areas of conventional property and excess liability insurance coverage. (Halama testimony page 13).

Q. UTILIZING YOUR THREE-YEAR NORMALIZATION APPROACH WHAT IS YOUR OVERALL ADJUSTMENT TO THE COMPANY'S O&M EXPENSE?

A. As more fully reflected on Schedule DM-11a, my three-year normalization adjustments to certain operating expenses is an overall decrease of $1,945,201. This three-year average includes non-labor expense only and does not include the inflation adjustments that I have identified further down in my testimony.

Q. HOW DOES THE COMPANY CALCULATE AND ALLOCATE ITS LABOR COSTS?

A. As explained in response to Data Request Set 4-30, the Company is directly charged or allocated labor costs by expense categories using the 2024 July Forecast (six-months of actual and six-months of forecast) and the 2025 test year.

Labor costs include base salary, overtime, and benefits of internal employees. The Company's budgeted process is completed at a total expense level and not appropriate to analyze labor costs.

Q. WHAT DID THE COMPANY OBJECT TO WHEN ASKED TO BREAK DOWN LABOR COSTS BY THE VARIOUS CATEGORIES ADDRESS ABOVE?

A. The Company objected to providing the detailed breakdown as it stated it was overly broad and unduly burdensome and is not relevant to and beyond the scope of this proceeding and not reasonably calculated to lead to the discovery of admissible evidence.

Q. WHY ISN'T THE COMPANY ABLE TO PROVIDE THE INFORMATION AS REQUESTS IN SET 4-30?

A. According to the response to Set 4-30, the Company serves more than 1.5 million customers across North Dakota, South Dakota, Minnesota and uses a variety of different allocations that apply to labor costs. The costs of certain employees employed or allocated to the Company are not allocated to North Dakota. The Company stated that the request seeks large volumes of detailed information in a format not readily kept by the Company which would require a special study to produce and some of the information requested is not relevant to this rate case.

Q. WHAT IS YOUR RESPONSE?

A. The Company is responsible and obligated to support its costs by providing sufficient reliable evidence supported by valid documentation for its adjustments to its cost expense categories, including labor and labor-related expenses. The fact that the request may provide a burden to the Company should not be a factor nor a valid reason in not responding to a request seeking information to valid the Company's costs through discovery. With respect to relevance, it should be up to the Commission Staff and its consultants to determine whether the information is meaningful, purposeful and applicable in the setting of rates for utility service.

Q. WHAT INFORMATION WAS PROVIDED WHEN THE COMPANY WAS ASKED ABOUT THE ACTUAL NUMBER OF EMPLOYEES ALLOCATED FROM XCEL ENERGY TO THE NORTH DAKOTA JURISDICTION?

A. In response to Data Request 8-51, I asked the Company to provide a list of employees that have been allocated to the North Dakota jurisdiction for the periods 2020-2024 by expense category. The response was that the Company does not allocate a number of employees to its jurisdictions and each employee's time is accounted for consistent with the Cost Assignment and Allocation Manual filed with Company witness Halama's direct testimony (BCH-1 Schedule 14).

In response to Set 12-6 Attachment A the Company provided a schedule of total NSPM employee headcount for the years 2022 -2024. The Company provided a schedule showing the allocation of employees to the North Dakota jurisdiction. The Company provided a schedule of employees by job titles, and functions by the North Dakota jurisdiction. Approximately 83 employees are bargaining employees and approximately 28 employees are non-bargaining employees for a total count of 111 employees. Although Attachment A does not reflect the time period of this breakdown, I assume this is for the test year 2025.

Q. WHAT IS YOUR RECOMMENDATION?

A. I am unable to evaluate or analyze the labor costs with the information provided by the Company as it does not include salary levels as requested in Set 12-6 a) nor whether which employees are directly or indirectly allocated to the North Dakota jurisdiction. Given that the Company is unable or unwilling to provide the required documentation to fully review the Company's labor cost and the way the Company assigns employees to the North Dakota jurisdiction, I am recommending that the Commission direct the Company to provide a detailed analysis with supporting documentation as to the average number of employees assigned (directly and indirectly) from NSP-M to the North Dakota jurisdiction in each of the Company's labor categories. I am also recommending that this analysis include the following:

- Complete job titles with job descriptions of each employee by function and operations (direct and indirectly) allocated to the North Dakota jurisdiction.
- When any employee has more than one job description and title and provide the headcount in the grouping related to the North Dakota jurisdiction.

- Provide the average fully burdened cost (salary, incentive compensation, benefits, etc.,) of a headcount by function and operation in the North Dakota jurisdiction
- Provide these costs for each labor expense category.
- Provide this information in a Live Microsoft Excel spreadsheet format with all cells enabled and formulae intact.

Q. PLEASE ADDRESS YOUR INFLATION OR ESCALATION RELATED ADJUSMENTS UNDER EACH EXPENSE CATEGORY.

A. My Inflation-related adjustments are reflect in Schedules DM-13 through DM-18. With respect to the disallowance of Inflation adjustments, I do not find these types of adjustments to be known and measurable in setting rates for service. These types of cost adjustments do not provide a good method to adjust costs as they adjust them to reflect an overall broad, blanket-type economic adjustment. Therefore, the costs would be adjusted for the inflation of goods and services that may or may not be directly related or attributable to costs and services incurred by the Company. Inflation adjustments do not address any particular or individual expense category but are simply broad-based forecasts and predictions of cost estimates. As costs for goods and services fluctuate over time, applying inflation adjustments to costs is not a proper methodology for setting rates for utility service.

My adjustments related to the disallowance of Inflation adjustments (Non-Labor related) are as follows: (Set 8-8)

		Company Balance	Inflation	Adjustment	PSC Staff Recommended
1.	Power Production	$44,556,000	1.81%	($806,464)	$43,749,536
2.	Transmission	$18,332,727	1.81%	($331,822)	$18,000,905
3.	Distribution	$ 4,647,431	1.81%	($ 84,119)	$ 4,563,312
4.	Customer Acct.	$ 4,342,392	1.81%	($ 78,597)	$ 4,263,794
5.	Customer Service	$ 302,364	1.81%	($ 5,473)	$ 296,891
6.	Sales, Econ & Other	$ 373,945	1.81%	($ 6,768)	$ 367,177
7.	Admin. & General	$ 8,304,533	1.81%	($150,312)	$ 8,154,221
	Total Adjustments			($1,463,555)	

These adjustments are reflected on my Schedule DM-11, and Schedules DM-13 through DM-19.

My adjustments related to normalization of expenses are as follows and are detailed on my Schedule DM-11a: (Set 14-1)

		Normalized
1.	Power Production	$314,530
2.	Transmission	($994,832)
3.	Distribution	($49,691)
4.	Customer Accounting	($851,007)
5.	Customer Service	$11,261
6.	Sales	($170,104)
7.	Administrative & General	($205,358)

These adjustments are reflected on my Schedule DM-11, and Schedules DM-13 through DM-19.

Q. PLEASE ADDRESS YOUR SPECFIC ADJUSTMENTS TO THE COMPANY'S CERTAIN EXPENSE ADJUSTMENTS.

A. Below are my specific adjustments and recommendations with respect to the Company's Precedential and Ratemaking Adjustments along with adjustments identified in discovery:

C. Fuel and Purchased Energy Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS FUEL AND PURCHASED ENERGY EXPENSES?

A. As shown on Company Exhibit BCH-1 Schedule 6, the Company proposed an Unadjusted balance of $84,046,000 related to Fuel and Purchased Energy. The Company did not make any adjustments (Precedential and Ratemaking) to the Company's Test Year 2025 period.

Q. WHAT IS YOUR RECOMMENDATION?

A. I am accepting the Company's balance of $84,046,000 for its Fuel and Purchased Energy Costs. This is shown on my Schedule DM-12.

D. Power Production Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS POWER PRODUCTION EXPENSES?

A. The Company has proposed an Unadjusted balance of $44,556,000 (Company Exhibit BCH-1 Schedule 6). The Company made several Precedential adjustments of approximately ($478,000) as shown on Company Exhibit BCH-1 Schedule 4 and 6. These adjustments reflect the removal of the Wind Farms for Community North, (WP-A5- ($36,950)); Jeffers Wind Farm removal (WP-A6- ($60,437)); and the Northern Wind projects removal (WP-A7 – ($167,127)). These three adjustments total $264,514. The Company has removed $213,130 related to the Company's LT Incentive Removal (WP-A4). The Company also proposed an adjustment of ($44,000) related to the removal of the Rider TCR. (Exhibit BCH-1 Schedule 6). The Adjusted balance is calculated at $44,034,356.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S POWER PRODUCTION EXPENSES?

A. I do not have any adjustments but for my normalization and removal of inflation-related costs as described above. I am accepting the Company's Precedential adjustments totaling approximately $478,000 and the Company's adjustment of $44,000 related to the Rider – Renewable Energy removal (RER). My recommendation is shown on my Schedule DM-13.

E. Transmission Expenses

Q. WHAT HAS THE COMPANY PROPOSED REGARDING ITS TRANSMISSION EXPENSES?

A. The Company has proposed an Unadjusted balance of $26,294,000 as reflected on Company Exhibit BCH-1 Schedule 6. The Company decreased this balance by $6.783 million to reflect the removal of the Transmission Cost Recovery (TCR) Rider. Mr. Halama stated that the Company removed the costs and revenues associated with the TCR Rider from the test year jurisdictional cost of service for the ongoing projects and MISO RECB that will continue cost recovery in the Rider after the implementation of final rates in this case. (Halama testimony page 58). The adjustment prevents double recovery of the costs, and therefore no cost impact is associated with the 2025 test year revenue requirement. The Company will continue recovering these proposed costs in the TCR rider.

Q. WHAT ARE YOUR ADJUSTMENTS?

A. I am accepting the Company's adjustment to its TCR Rider of ($6.783 million). As discussed above, I am making adjustments related to my normalization adjustment and my removal of inflation related adjustments. This is shown on my Schedule DM-14.

F. Distribution Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS DISTRIBUTION EXPENSE?

A. The Company has proposed an Unadjusted and an Adjusted balance to its Distribution Expenses of $7.391 million, shown on Exhibit BCH-1 Schedule 6.

Q. WHAT ARE YOUR ADJUSTMENTS?

A. But for my adjustments related to the normalization of certain expenses and the disallowance of inflation-related adjustments, I am accepting the Company's remaining expense balance. This is shown on my Schedule DM-15.

G. Customer Accounting Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS CUSTOMER ACCOUNTING EXPENSES?

A. The Company proposed an Unadjusted balance of $5,146,000. The Company increased this balance by $221,000 to account for bad debt expense (labeled as EDBadDebt), The Adjusted balance of $5,367,000 is shown on Exhibit BCH-1 Schedule 6 and WP-A11.

Q. WHAT HAS BEEN THE COMPANY'S EXPERIENCE RELATED TO BAD DEBTS?

A. The Company stated that the original calculation for 2025 bad debt expense was generated during the budget process and is a function of projected revenues multiplied by the bad debt ratio for NSPM. (BCH-1 page 46). Mr. Halama stated that an analysis was performed to update the bad debt expense based upon the revenue deficiency in the 2025 test year. An adjustment is needed to incorporate the updated bad debt amount into the revenue requirement which best reflects test year costs. (BCH-1 page 46). The Company has included $221,000 of bad debt expense calculating this balance by the proposed revenue requirement of $44,556,037 times the uncollectible ratio of 0.50%.

Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S PROPOSED BAD DEBT EXPENSE?

A. I adjusted the bad debt expense in relation to my revenue requirement recommendation, using a bad debt expense ratio of 0.50% as shown on Company WP Volume 3 VIII A11 Bad Debt Expense. My adjustment is shown on my Schedule DM-16 and reflects a balance of $123,958.

H. Customer Service & Information Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS CUSTOMER SERVICE & INFORMATION EXPENSES?

A. The Company proposed an Unadjusted and an Adjusted balance of $351,000 to its Customer Service & Information Expenses, which is shown on Exhibit BCH-1 Schedule 6. Included in that balance are costs related to the Company's Electric Vehicle Program/adoption (Data Set 8-77).

Q. WHAT ARE YOUR ADJUSTMENTS?

A. I am recommending the disallowance of the Electric Vehicle initiative costs as reflected in Data Set 8-77 of $131,000. The Company stated that there are no active Electric Vehicle Programs in North Dakota at this time. There are $131,000 of costs included in the 2025 test year to support future developments including potential electric vehicle programs. I believe these costs are not known and measurable and provide no customer benefits given the fact that there are no active Electric Vehicle Programs in North Dakota. Customers should not be paying for costs which provide no positive benefits to them. My adjustments are shown on my Schedule DM-17.

I. Sales, Economic Development & Other Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO SALES, ECONOMIC DEVELOPMENT AND OTHER EXPENSES?

A. As shown on Exhibit BCH-1 Schedule 4 and Schedule 6, the Company proposed an Unadjusted Balance related to Sales, Economic Development and Other Expenses of $282,000. To that balance, the Company added $113,000 related to Economic Donations to arrive at an adjusted balance of $395,000.

Q. WHAT IS INCLUDED IN THE COMPANY'S $113,000 ECONOMIC DEVELOPMENT DONATIONS?

A. Company Witness Mr. Halama (Exhibit BCH-1 page 48) stated that the Company makes contributions to several regional and local economic development organizations for the purposes of maintaining and improving the long-term economic health of communities in its service territory or retaining employment opportunities and expanding the state and local tax base. In response to Data Response Set 4-28, the Company stated that there is no further breakdown or description of these donations These costs are the estimate of financial contributions expected during 2025. The Company can, through a donation, provide communities or organizations involved in community and economic development with either an operating grant or a one-time investment in a special project that supports the community and economic development efforts of its communities. (BCH-1 page 48). (Set 4-28) (Set 8 – 23)

Q. WHAT IS YOUR POSITION ON ECONOMIC DEVELOPMENT DONATIONS?

A. I do not believe that ratepayers should pay for these types of costs in rates. These expense items are akin to charitable contributions. The Company is a utility company servicing certain parts of North Dakota. The Company should not be expensing costs related to non-utility type services. Additionally, ratepayers do not have a say in what type of donations they are paying for and its unknown whether ratepayers receive any benefit for these contributions. These types of costs should not be included in the revenue requirement proposed by the Company. The Company should pay for these costs, below the line, and receive the tax benefits through the corporate entity. This balance is shown on Schedule DM-18.

Q. WHAT IS YOUR RECOMMENDATION?

A. I am recommending the removal of the entire $113,000 of Economic Development Donations from the Company's Sales, Economic Development and Other Expenses balance. This is shown on Schedule DM-18.

J. Administrative & General Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS ADMINISTRATIVE AND GENERAL EXPENSES?

A. As shown on Exhibit BCH-1 Schedule 4 and 6, the Company proposed an Unadjusted Balance of $21,269,000, and an Adjusted Balance of $20,914,000. These adjustments reflect Precedential Adjustments which the Company has not changed from the Commission's Order in the Company's previous completed electric rate cases (Exhibit BCH-1 page 45). The Company has also reflected Ratemaking Adjustments that relate to specific adjustments in this instant proceeding. I will address each of these Precedential and Ratemaking Adjustments below.

Q. WHAT SPECIFIC PRECEDENTIAL ADJUSTMENTS HAS THE COMPANY PROPOSED IN THIS PROCEEDING?

A. The Company has proposed the following Precedential Adjustments:

Precedential Adjustments

Advertising -	($242,000)	WP A1
Association Dues -	($ 36,000)	WP A2
Customer Deposits -	$ 3,000	WP A3
Incentive Pay – LT	($938,000)	WP-A4
Pension Non-Qualified SERP -	($ 2,000)	WP A8
Total	**($1,215,000)**[7]	

[7] Differences due to rounding issues

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO THE COMPANY'S PRECEDENTIAL ADJUSTMENTS?

A. My adjustments to each of the Company's Precedential Adjustments are as follows:

a. <u>Advertising –($242,000) WP-A1</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ADVERTISING EXPENSE?

A. The Company proposed to reduce its Advertising Expense by $242,000 as shown on Company Exhibit BCH-1 Schedule 4 and Schedule 6. The Company began with an Advertising Expense balance of $509,394 and reduced this amount by $242,093 resulting in a recoverable amount of $267,301 (WP-A1). In response to Data Request 4-26, the Company included all Advertising Expense related to Mandated Inserts and Safety Advertising for recovery in the 2025 test year. The Company removed Advertising related to general Advertising.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO ADVERTISING EXPENSES?

A. I am accepting the Company's adjustment reducing the Advertising Expense balance by $242,000. These costs are related to customer communications, conservation, safety, customer programs and mandated regulatory notices. This is shown on my Schedule DM-19.

b. <u>Association Dues – ($36,000) WP-A2</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ASSOCIATION DUES?

A. The Company proposed reducing its Association Dues by $36,000. The Company doesn't budget association dues at the organization level but rather uses past year actuals to forecast the costs for dues. (Data Request 4-26). The Company developed the amount of the reduction by using the 2023 actual association dues spent rather than a forecast of the spending in the 2025 test year.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO ASSOCIATION DUES?

A. I am recommending a reduction of $46,844, or an additional reduction of $10,844 as shown on WP-A2. It appears that the Company does not provide a breakdown of these costs at the organizational level. Until such time as the Company can provide and identify these costs more precisely, I recommend utilizing the reduction of $46,844. This is shown on page 42 of 42 under Column ND Electric Excluded.

c. **Customer Deposits - $3,000 – WP-A3**

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO CUSTOMER DEPOSITS?

A. The Company proposed an adjustment of $3,000 related to Customer Deposits. This is shown on Exhibit BCH-1 Schedule 4 and on WP A3 page 2 of 5. The Company stated that it treats customer deposits as customer – supplied capital and has included interest expense on customer deposits to pay a return on that investment. (WP-A3). The average balance of customer deposits are deducted from rate base and at the same time operating expenses are increased to permit recovery of interest paid on these deposits.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am accepting the Company's Customer Deposit adjustment of $3,000.

d. **Incentive Compensation Pay Removal LTI–($938,000) WP-A4 (WP-A16 WP-A17**

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS INCENTIVE COMPENSATION?

A. The Company has proposed reducing Incentive compensation related to the Company's LTI of $938,000. (Company Exhibit BCH-1 Schedule 4 and Schedule 6 and WP-A4). The Company removed costs related to Performance Share Plan and Deferred Compensation and Restricted Stock Units totaling $937,711[8] under the A&G expense category. (See response to Set 8-19, 20, 21, 22 (turnover rates). According to Mr. Halama treatment of the removal of the Incentive Compensation Pay LTI has not changed from the Commission's Order in the Company's previous completed electric rate cases. (BCH-1 page 45). The Company stated that it is not seeking rate recovery for the Performance Share Plan or the Restricted Stock Units (WP-A4).

Q. WHAT IS YOUR RECOMMENDATION?

A. Given that the Commission has directed the Company to reduce this balance in a prior Order, I am accepting this adjustment.

e. **Pension Non-Qualified SERP –($2,000)(WP-A8)**

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO PENSION NON-QUALIFIED SERP?

A. The Company has proposed a reduction of $2,000 which excludes all non-qualified pension expenses related to the Company's Supplemental Executive Retirement Plan (SERP). The Company stated that this treatment is consistent with the Company's last rate case in PU-20-441.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

[8] Differences between the $938,000 and the $937,711 balances are due to rounding issues.

A. I am accepting the Company's adjustment in the reduction of $2,000 as shown on Company Exhibit BCH-1 Schedule 4 and Schedule 6.

Q. WHAT ARE THE OTHER SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED IN THIS PROCEEDING?

A. The Company has proposed the following Ratemaking Adjustments:

<u>Ratemaking Adjustments</u>

a.	Aviation	($120,000)	WP-A10
b.	Dues – Chamber of Commerce	$ 33,000	WP-A12
c.	Foundational -Other	$ 299,000	WP-A13
d.	LTI-Environmental	$ 211,000	WP-A16
e.	LTI-Time Base Incentive	$ 589,000	WP-A17
f.	Incentive Compensation	($151,000)	WP-A15

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S RATEMAKING ADJUSTMENTS ABOVE?

A. My adjustments to each of the Company's Ratemaking Adjustments are as follows:

a. **<u>Aviation – ($120,000) (WP-A10)</u>**

Q. WHAT HAS THE COMPANY PROPOSED REGARDING ITS AVIATION EXPENSES?

A. The Company proposed to include 50% of the aviation – related costs allocated to the North Dakota jurisdiction. These costs were incurred in lieu of commercial aviation transportation and help facilitate the efficiency use of executive time. (WP A10). The Company has removed $121,000 of Aviation related expenses. Mr. Halama stated that the aviation – related costs are related to the operation of two Xcel Energy corporate aircraft for use by Company personnel. (BCH-1 page 46).

Q. WHAT REASONS WERE GIVEN BY THE COMPANY IN THE USE OF ITS CORPORATE AVIATION COSTS?

A. According to Mr. Krug, aviation costs are incurred as part of its normal operations. The use of corporate airplanes allow for efficient transportation of key employees that require significant travel, including by allowing them to work while traveling to a degree that would otherwise be impracticable. (ADK-1 page 23). The Company stated it removed any non-business travel from the trips for which it seeks recovery and is only requesting 50% of the expenses to bring them closer in line with the costs of traveling using commercial airlines. (ADK-1 page 23).

Q. HAS THE COMPANY PROVIDED A COMPARISON OF COSTS BETWEEN VEHICLE USE AND AIRPLANE USE AND COMMERCIAL AIRPLANE USE?

A. In response to Data Request Set 4-26, the Company stated that it does not have a comparison of aviation and Xcel Energy vehicle use, as the two are used for different purposes. Vehicles are used by employees who travel more than 1,200 miles per month for business purposes. Xcel Energy's aircraft are typically used for long-distance travel, which is important for Xcel given its geographical spread. Xcel Energy serves customers in eight different states from the desert Southwest to Western Wisconsin and a portion of the Upper Peninsula of Michigan.

Q. WHAT BENEFITS DID THE COMPANY STATE IN THE USE OF AVIATION – CORPORATE AIRCRAFT?

A. In response to Data Request 4-26, the Company stated that if commercial aircraft and ground travel were used, key company employees would spend much more time in transit. The use of Company aircraft benefits employees regarding time savings, increased in-flight productivity, scheduling convenience, lower stress and fatigue and personal security.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am recommending disallowing all Aviation Costs from rates, an additional adjustment of $121,000 or a total disallowance of $242,000. Mr. Krug noted that key employees use Xcel Energy's aircraft and are typically used for long distance travel. Although these travel flights appear to be specifically used for North Dakota operations as reflected on Company WP A10- Aviation page 3 of 3 and given the fact that the Company has not provided or prepared a cost-benefit analysis (commercial airplane usage and corporate airplane usage) there is no way to determine whether a 50% reduction in Company aircraft would be sufficient or reasonable. While I am not condoning aircraft use per se, I am of the opinion that commercial costs are much less costly than the use of corporate aircraft. The savings that are inured to the use of corporate aircraft as stated by Mr. Krug can also be found in using commercial flights.

b. Dues-Chamber of Commerce - $33,000 (WP-A12)

Q. WHAT HAS THE COMPANY INCLUDED IN ITS DUES - CHAMBERS OF COMMERCE?

A. The Company has included Dues – Chambers of Commerce costs in the amount of $33,000 as a 2025 test year expense (WP-12) and also shown on Company Exhibit BCH-1 Schedule 4 and 6. Company witness Mr. Halama stated that these costs include membership dues paid to various Chambers of Commerce in North Dakota and provide an essential link between the Company and the communities it serves and allows for improved utility service. (BCH-1 page 47). Because membership in these organizations provides benefits to all utility customers, recovery of membership dues paid to Chambers of Commerce is appropriate. (BCH-1 page 47).

Q. WHAT ARE YOUR ADJUSTMENTS?

A. I am recommending no recovery because this type of cost does not benefit North Dakota ratepayers. This cost mainly serves to advance the policy positions before State and Governmental agencies and to communicate its corporate citizenship initiatives. Ratepayers should not be required to pay for such costs which provide no benefit to utility service. It also appears that these costs are geared toward being present in the communities, providing a welcoming atmosphere, small town attention and recognition, tourism, professional interests, hometown promotions and bringing businesses and communities together (WP-A12). None of these costs represent customer-oriented benefits to the ratepayers of North Dakota. Further, the Company has not provided whether these Chambers of Commerce costs have actually provided customer benefits to the North Dakota ratepayers. (Set 8-23)

c. <u>Foundation and Other Donations -$299,000 (WP-A13)</u>

Q. WHAT HAS THE COMPANY INCLUDED IN ITS FOUNDATION AND OTHER DONATIONS?

A. The Company has included $299,000 of costs related to Foundation and Other Donations. (Company Exhibit BCH-1 Schedule 4 and Schedule 6). The Company is proposing to include charitable contributions benefiting the State of North Dakota in the test year. Mr. Halama stated that an analysis was performed on contribution details to ensure that only amounts contributed to charities and institutions that could be associated with the Company's electric service territory in the North Dakota jurisdiction were included in the cost of service. (BCH-1 page 47).

Q. WHAT IS YOUR RECOMMENDATION?

A. I am recommending that zero dollars related to Foundation and Other Donations be included in the cost of service. The Company has not provided a breakdown of these costs, but rather allocations of costs between and among NSPM and its subsidiaries. Charitable Contributions in general, should be removed from the Company's cost of service because ratepayers do not have determine what type of contributions they are paying for. These types of payments do not benefit ratepayers, and as I stated above in the Chambers of Commerce section, only benefits the Company as being good corporate citizens. These costs should be funded below the line by the shareholders of the Company and receive a tax benefit through the corporate entity. The Company stated that these costs *benefit* the State of North Dakota, and not specifically the *ratepayers* of the Company or the service territories the Company provides electric service to. The Company should not be allowed to make customers pay for charitable contributions, especially those costs that do not provide specific benefits to its ratepayers. (Set 8-23)

Q. PLEASE EXPLAIN THE COMPANY'S LONG-TERM INCENTIVE (LTI) PROGRAM?

A. According to Mr. Krug, the LTI is an incentive-based program that is available to the Company's most senior and executive level employees. Less than five percent or exempt and non-bargaining employees are eligible for the LTI. (ADK-1 page 20). The LTI is intended to incentivize senior employees to effectively manage the Company towards its overall corporate goals and in the best interest of customers and shareholders. The LTI provides a long-term incentive to Company leaders through the grant of Xcel Energy Inc. equity. (ADK-1 page 20). The employees who receive an LTI tend to be those who have a higher level of influence in the Company's direction and strategy and are also employees who are in positions that can be expensive and time consuming to fill. The LTI program helps retain these key employees and is necessary for Xcel Energy to remain competitive in the labor market. (ADK-1 page 20). The Company has three different LTIs: (1) Environmental Performance; (2) Shareholder Return and; (3) Time Based. These will be discussed below. The Company is not seeking recovery of its Shareholder Return.

d. LTI Environmental Incentive - $211,000

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS LTI RELATED TO ENVIRONMENTAL?

A. The Company is proposing to recover $211,000 related to its Environmental Incentive Program as shown on Company Exhibit BCH-1 Schedule 4 and 6 and WP – A16. In response to Data Request 8-19, the Company is proposing to include a 20% base salary cap in 2024 and 2025 which would be an increase in the recovery from the 15% of the base salary cap in 2023. Company witness Mr. Krug stated that the Company should be allowed to recover the environmental portion of its LTI expenses which is the portion of the program tied into the achievement of the Company's environmental goals. Xcel Energy stated that the technologies it would implement would result in efficiencies, allow for a lower cost of capital and remove fuel costs addition to environmental and other benefits. (ADK-1 page 21). Mr. Krug stated that it is reasonable to recover the environmental components of LTI because they are consistent with key customer-focused goals of environmental excellence and efficient management and are necessary for the retention of key senior leaders. (ADK-1 page 21). See WP A-16)

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. In response to data 8-19, since the goals for the 2025 LTI measures will occur in 2026, it is unknown whether the goals will be achieved until such time as the Company publishes its proxy in April 2026. In response to data Set 8-21, the environmental portion of the LTI depends on the achievement of those goals and thus unknown at this time. Also, in response to Data Set 8-22, the Company had a 20% turnover rate in 2024 related to retirements and employees pursuing other opportunities. It appears that the LTI incentive that was implemented to reduce turnover of key employees fell short of expectations. There I am recommending disallowance of the LTI- Environmental expense of $211,000. My adjustment is shown on my Schedule DM-19.

e. **<u>LTI- Time Based Incentive - $589,000</u>**

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS LTI-TIME BASED INCENTIVE?

A. The Company is proposing to recover $589,000 of Time-Based Incentive as shown on Company Exhibit BCH-1 Schedule 4 and 6 and WP-A-17. Company witness Mr. Krug stated that Time Based Incentive is the portion of the LTI program tied to the length of key employees' service with the Company. Mr. Krug stated that customers benefit from the Company's ability to retain institutional knowledge and capabilities of key employees. (ADK-1 page 20). In response to Data Request 8-19, the Company is proposing to include a 20% base salary cap in 2024 and 2025 that would increase the recovery of the 15% base salary cap in 2023.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. It is my opinion that these types of incentive should not be recovered from ratepayers. These types of incentives do not appear to provide customer-oriented benefits to ratepayers but rather incentivize key employees to stay with the Company. In response to Data Request Set 8-22, implementation of this program did not reduce turnover rates for key employees and in fact 20% of the key employees did not remain with the Company. The Company should be responsible for absorbing these costs and not pass them onto ratepayers. My adjustment is shown on my Schedule DM-19.

f. <u>AIP Incentive Compensation – ($151,000)</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS AIP INCENTIVE COMPENSATION ADJUSTMENT FOR 2025?

A. The Company stated that it has adjusted the Incentive Compensation to reflect exclusion of the Annual Incentive Plan costs above 20% of base pay by $151,000. (Company Exhibit BCH-1 Schedule 4 and 6 and WP-A15). Mr. Halama referred to the testimony of Mr. Krug with respect to additional recovery of certain incentive compensation expenses (BCH-1 page 49) and ADK-1 page 20).

Q. WHAT INFORMATION HAS THE COMPANY PROVIDED TO SUPPORT ITS EXCLUSION OF 20% OF BASE PAY?

A. Workpaper WP-A15 reflected the change from the excess of 15% of base salary of $238,544 in 2025 to the excess of 20% of base salary of $151,248 in 2025 or an adjustment of $87,296. It is unclear where the reasoning to adjust the excess of base salary from 15% to 20% is reflected in the filing. In Mr. Krug Schedule 2 attached to his testimony, the 15% of base pay was based upon a settlement agreement in the Company's 2012 Electric Rate Case (PU-12-813). In response to Data Request Set 8-19, the Company reflected the AIP base salary cap increasing from 15% in 2023 and 20% in 2024 and 2025.

Q. WHAT RECOMMENDATION DO YOU HAVE?

A. I am recommending that the Company maintain the excess cap of 15% of base salary in the test year period. I find no reasoning or supporting evidence in the filing that supports the need to increase the excess cap to 20%. My recommendation adjusts the AIP from ($151,000) to ($238,544) or an adjustment of ($87,296). This is shown on my Schedule DM-19.

K. Depreciation Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO DEPRECIATION EXPENSE?

A. The Company proposed an Unadjusted Depreciation Expense balance of $69,395,000 as shown on Exhibit BCH-1 Schedule 6. The Company proposed a Depreciation Expense balance in the TY 2025 of $75,002,000, after making $5,607,000 of adjustments related to Precedential Adjustments of $1,003,000, and adjustments to its proposed Depreciation Study for (1) remaining life all other - $743,000; (2) remaining life – base load $6,443,000 and (3) Transmission, Distribution, and General - TD&G ($89,000). Company witness Mr. Moeller stated that the Company is requesting a revision to the remaining lives related to its coal, nuclear, other and hydro production plants. (MPM-1 page 2). Mr. Moeller stated that the Company is proposing changes to its production, transmission, distribution, electric general and intangible, and common general and intangible assets. (MPM-1 page 2). (MPM-1 page 25 Table 2). The Company made the following adjustments to derive its proposed Depreciation Expense balance (Data Response 8-53):

Unadjusted Balance	**$69,394,581**
Precedential Adjustments:	
Pre-Funded Production- Base Load	$ 5,864
Pre-Funded Production - Peaking	$ 703
Production – Base Load Energy	$ (901,865)
Production – Peaking	$ (108,062)
Sub-total	**$ (1,003,360)**

Depreciation Study –	
Remaining Life – All Other	$ 743,190
Remaining Life – Base Load	$ 6,443.224
TD&G	$ (88,590)
Sub-Total	**$ 7,097,824**
Rider – RER	$ (81,031)
Rider – TCR	$ (405,584)
Sub-Total	**$ (486,615)**
Adjusted Balance	**$75,002,430**

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S PRECEDENTIAL ADJUSTMENTS?

A. I am accepting the Company's Precedential Adjustments of ($1,003,360).

Q. WHAT OTHER ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S PROPOSED DEPRECIATION EXPENSE BALANCE?

A. As I made adjustments to disallow the Company's Larimore Station and the LTE Wireless Network, I am making a corresponding adjustment to the associated Depreciation Expense. For the Larimore Station my Depreciation Expense adjustments is a reduction of $356,816 using the Company's proposed Depreciation rates. For the LTE Wireless Network my Depreciation Expense is a reduction of $332,106 using the Company's proposed Depreciation rates. My reasoning for these disallowances were explained in the EPIS section of my testimony.

Q. WHAT IS YOUR FINAL ADJUSTMENT TO THE COMPANY'S DEPRECIATION EXPENSE?

A. As I made adjustments to the Company's Sherco Battery Investment, I am also making a corresponding adjustment of **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** to remove the depreciation expense associated with this Investment. (Confidential response Set 20-1). My total adjustment to Depreciation Expense is ($707,179) shown on my Schedule DM-20.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S DEPRECIATION STUDY THAT ADJUSTS THE COMPANY'S VARIOUS PRODUCTION LIVES AS INDICATED ABOVE?

A. As more fully discussed by Dr. Pavlovic in his testimony, I am including the Company's adjustments to the various production lives for purposes of developing my revenue requirement. Dr. Pavlovic has recommended that the Company calculate the appropriate proforma adjustments to its Depreciation Expense and Depreciation rates for its steam production plant to the Company's current Depreciation Expense and Depreciation rates and expenses. Therefore, I reserve my right to update my revenue requirement proposal once the Company has provided the proper information and data to evaluate the development of its various Depreciation Expenses.

L. Amortization Expense

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS AMORTIZATION EXPENSE?

A. The Company has proposed a total Amortization Expense of $12,722,000 (Exhibit BCH-1 Schedule 6). The breakdown is as follows:

	Unadjusted Balance	**$ 327,000**
	Precedential Adjustment	$10,440,000
a).	Prairie Island EPU Uprate	$ 308,000
b).	NOL ADIT ARAM	$ 183,000
c).	AGIS Deferral	$ 997,000
f).	Rate Case Expenses	$ 468,000
	Total	**$12,722,000**

Q. WHAT HAS THE COMPANY INCLUDED IN THE $10,440,000 RELATED TO ITS PRECEDENTIAL ADJUSTMENTS?

A. In response to Data Set 13-1, the Company stated that the $10.440 million of Precedential adjustments are related to PTC amortizations for the 2025 test year. In response to Data Set 2-7, the Company provided the calculations that reflect the normalized production tax credits consistent with the Company's last electric rate case in Docket No. PU-20-441, and stems from the Commission and Staff's request to evenly distribute production tax credits (PTC) as per the 2020 Renewable Energy Rider (RER) (Case No. PU-19-329).

Q. WHAT IS YOUR RECOMMENDATION?

A. After review of Data Set 2-7, I am accepting the Company's calculations related to the PTC credits of $10,440,000.

a). <u>Prairie Island EPU Uprate - $308,000</u>

Q. WHAT HAS THE COMPANY PROPOSED REGARDING THE PRAIRIE ISLAND EPU UPRATE?

A. Mr. Halama stated that this amortization includes the impact of the abandoned PI EPU project costs over the remaining life of the plant through an amortization expense consistent with the outcome of the Company's last electric rate case. (Halama Testimony page 53-54). In response to Data Set 8-43, Company witness Mr. Shaw discussed the prudent decision to invest in the project and the subsequent prudent decision to abandon the project. In the prior rate case and consistent with the settlement the Parties agreed that all Company proposals not explicitly addressed in the settlement are agreed to and shall be implemented as proposed by the Company.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S PRAIRIE ISLAND EPU UPRATE AMORTIZATION OF $308,000?

A. I am continuing to recommend disallowing the $308,000 of amortization expenses related to the Company's Prairie Island EPU Uprate. My adjustment is reflected on Schedule DM-21. As I recall, this Project was abandoned and terminated based upon a business decision by the Company. Therefore, the risk of this abandonment should stay with the Company and not be passed onto ratepayers. This Project has never been used in the provision of electric utility service. Although the parties in the prior rate proceeding agreed to this issue, I am continuing to recommend the disallowance of these costs in rates. My recommendation is shown on my Schedule DM-21.

b). **NOL ADIT ARAM - $183,000**

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS NET OPERATING LOSS, ACCUMULATED DEFERRED INCOME TAXES, AVERAGE RATE ASSUMPTION METHOD OF $183,000?

A. The Company is proposing to amortize the NOL ADIT ARAM over a 23-year period. The Commission's Order in PU-18-155 approved the Company's proposed amortization level included in the Tax Cuts and Jobs Act (TCJA) refund calculation. (Halama Testimony page 53). This adjustment is shown on Company Exhibit BCH-1 Schedule 6.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am accepting the Company's proposal related to the $183,000 amortization expense related to the NOL ADIT ARAM. My adjustment is shown on Schedule DM-21.

c). **AGIS Deferral - $997,000**

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS AGIS DEFERRAL AMORTIZATION?

A. Mr. Halama stated that in the Commission approved Settlement in Case No. PU-20-441, the Company agreed to defer all capital and O&M expenses for its AGIS Initiative until the next rate case. (Halama Testimony page 52). In WP A26 the Company provided a breakdown of the AGIG Deferral balance of $997,000. The Company included $4,557,131 of Capital costs and $1,422,388 of O&M Costs for a total of $5,979,519. The Company then divided this balance by 6 years to arrive at an annual recovery of $996,587.

Q. WHEN WAS THE AGIS INITIATIVE INITIALLY IMPLEMENTED AND PLACED IN SERVICE?

A. In response to Data Request Set 8-64, the AGIS Initiative components had different deployment timeframes and is in a unique stage of development. The Company began implementing components of the AGIS in 2017 (Advanced Distribution Management System or ADMS) which was fully placed in service in 2022 and is currently being used to enhance the operation of the distribution system in North Dakota. The Geospatial Information System (GIS) was completed and in service in 2024. The Advanced Metering Infrastructure (AMI) completed the software and integrations in March 2025 and is planning to complete the deployment of AMI meters in 2025. The Company has installed 83,778 meters with about 14,683 meters remaining to be installed in 2025. The Field Area Network (FAN) was completed in 2025 with less than 10 remaining to be installed and completed in 2025. The Fault Location Isolation and Service Restoration (FLISR) components will continue to be installed through 2025. The Company included costs for plant in service through 2025 in the test year and plans to complete the FLISR deployment in 2027.

Q. WHAT IS THE STATUS OF THE AGIS IN NORTH DAKOTA?

A. Company witness Mr. Nickell stated that the Company has nearly completed the rollout of the AGIS Initiative in North Dakota and the ADMS and FAN devices are installed, the AMI software and integrations are completed, and the Company will complete the AMI meter installation in North Dakota by the end of 2025. (Nickell Testimony page 18). In the Settlement Agreement in Case No. PU-20-441 the Company agreed to defer the AGIS costs until such time as all foundations elements of AGIS were in service. The deferral was designed to treat the Company's capital and O&M expenses as if they were capital expenditures included in CWIP.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am accepting the Company's inclusion of AGIS. However, I am recommending that the amortization period be extended to a period of 10 years based upon other amortization periods shown on Data Response 12-15. The Company has not specifically stated how the 6-year amortization period was developed. My adjustment reflects an annual recovery of $597,952 or a reduction of $399,048 based upon a 10-year amortization period. This is shown on my Schedule DM-21.

f). Rate Case Expenses $468,000

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS RATE CASE EXPENSES?

A. The Company has proposed to recover about $1.403 million ($1.403 million / 3 three years or $468,000) of projected direct costs associated with this rate case docket and a three-year amortization period. This three-year amortization period is consistent with the Company's requested amortization period in prior cases. (Halama Testimony page 54).

Q. WHAT IS YOUR RECOMMENDATION?

A. I am accepting the Company's proposed rate case expense balance of $1.403 million. The Company should provide updated actual costs to date, when available. This is shown on my Schedule DM-21.

M. Taxes Other Than Income Taxes

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO TAXES OTHER THAN INCOME TAXES?

A. As shown on Company Exhibit Schedule 3 page 2 of 4, and in Exhibit BCH-1 Revised Schedule 6, the Company proposed total Taxes other Than Income Taxes of $1,882,000.[9] The breakdown representing the balance is as follows:

a)	Property Taxes – Net	$11,279,000
b)	Deferred Income Taxes and ITC	($11,319,000)
c)	Payroll / Other	$ 1,922,000
	Total	**$ 1,882,000**

[9] Any differences due to rounding.

Q. HAVE YOU REVIEWED THE COMPANY'S METHODOLOGY WITH RESPECT TO THE DEVELOPMENT AND CALCULATIONS OF THE COMPANY'S PROPOSED BALANCE RELATED TO ITS TAXES OTHER THAN INCOME TAXES?

A. Yes. As I stated previously according to the Company, the Company utilizes Utilities International Regulatory Information System to develop the cost of service models and produce testimony schedules, therefore, some LIVE excel model versions of schedules are not available. (Data Response 8-38 and 12-1). The information is system generated and are not workpapers with underlying formulae. Given this information my adjustments reflect my best estimations and approximations with the information provided by the Company.

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO THE COMPANY'S TAXES OTHER THAN INCOME TAXES.

A. I am making the following adjustments to the Company's Taxes other than Income Taxes:

a) Property Taxes

Q. WHAT HAS THE COMPANY PROPOSED REGARDING PROPERTY TAXES?

A. The Company has proposed a balance to its Property Taxes of $11,470,000 as reflected on Company Exhibit BCH-1 Schedule 6.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. Since I disallow certain EPIS projects related to the Larimore Station and the AGIS LTI Private Network, I am making an adjustment to disallow property taxes association with the Company's proposed electric plant in service balance. I utilized the Company's proposed plant in service balance of $1,778,568,000 and divided that balance by the Company's recommended Property Taxes of $11,470,000 to arrive at a Property Tax percentage of 0.64490%. I then multiplied my adjustment of $15,712,601 by the Property Tax percentage of 0.644905% to arrive at an adjustment of $101,331. This is shown on my Schedule DM-22.

<u>b) PI-EPU Amortization</u>

Q. WHAT ADJUSTMENT DO YOU HAVE WITH RESPECT TO THE COMPANY'S PI-EPU AMORTIZATION?

A. Since I made adjustments to disallow the PI EPU Uprate Recovery in the Company's EPIS Balance, and other various adjustments to that, I am adjusting the related Deferred Income Tax associated with it. I am removing $112,000 (WP A19) to arrive at a zero balance. (Schedule DM-22).

<u>c) Payroll – (Adj.) $ 1,922,000</u>

Q. WHAT ADJUSTMENT DO YOU HAVE WITH RESPECT TO THE COMPANY'S PAYROLL BALANCE?

A. I did not adjust the Company's Labor balance. I adjusted the Company's Incentive Compensation. I am making the associated adjustment to the Company's Payroll Taxes and Others. I utilized the Company's O&M Labor assigned to the North Dakota jurisdiction and the Company's proposed Payroll of $1,923,000 to arrive at a 10.436% ratio. I then took the adjusted Incentive Compensation and multiplied the balance by 10.436% to calculate a Payroll adjustment of $92,624. I reduced the Company's proposed Payroll Expense by that amount to arrive at my Payroll Expense balance of $1,830,376. For the Aviation related Payroll, since I removed all Aviation related expenses, I am removing an additional $1,000 of Payroll Expense.

Q. WHAT IS YOUR LAST ADJUSTMENT TO THE COMPANY'S TAXES OTHER THAN INCOME?

A. As I removed the Sherco Battery Investment from the revenue requirement calculation, I am removing the associated Taxes other than Income Taxes of **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)** as shown in response to Confidential Set 20-1.

Q. WHAT IS YOUR TOTAL ADJUSTMENT RELATED TO THE COMPANY'S TAXES OTHER THAN INCOME TAXES?

A. My adjustment is a decrease of $111,116 or a balance of $1,770,884. This is shown on Schedule DM-22.

N. State Income Taxes

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS STATE INCOME TAXES?

A. The Company proposed a State Income Tax Expense of $832,000 as shown on Company Exhibit BCH-1 Schedule 3. The Company utilized a 4.31% State Income Tax to arrive at the balance of $882,000. This balance incorporates the State Tax Credit of ($158,000).

Q. HOW DID THE COMPANY COMPUTE ITS STATE INCOME TAX?

A. The Company computed its State Income Taxes by using the Statutory State Tax Rate of 4.31% (Exhibit BCH-1 Schedule 3), and computed total book income, tax additions and deductions to determine the taxable income that is used to calculate federal and state income taxes (Exhibit BCH-1 page 36). The utilization or generation of net operating losses or tax credits impact both deferred federal income taxes and federal and state income taxes.

Q. HOW DID YOU COMPUTE YOUR STATE INCOME TAXES FOR PURPOSES OF THIS PROCEEDING?

A. I utilized the Company's methodology, and the flowthroughs of my adjustments to Operating Revenues, Operating Expenses, Depreciation and Amortization Expense, and Rate Base related adjustments, to compute my recommended State Income Tax adjustment.

Q. WHAT IS YOUR STATE INCOME TAX EXPENSE?

A. My State Income Tax Expense is ($557,757), an increase of $274,240 from the Company's proposed State Income Tax Expense of ($832,000). This is shown on Schedule DM-23.

O. Federal Income Taxes

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS FEDERAL INCOME TAXES?

A. The Company has proposed a Federal Income Tax Expense of ($5,951,000) as shown on Company Exhibit BCH-1 Schedule 3.

Q. HOW DID THE COMPANY COMPUTE ITS FEDERAL INCOME TAX EXPENSE?

A. The Company computed its Federal Income Taxes by using the Statutory Federal Tax Rate of 21.00% and computed total book income, tax additions and deductions, which determine deferred income taxes and the resulting taxable income that is used to calculate federal and state income taxes (Halama Testimony page 32). The utilization or generation of net operating losses or tax credits impact both deferred federal income taxes and federal and state income taxes.

Q. HOW DID YOU COMPUTE YOUR FEDERAL INCOME TAXES FOR PURPOSES OF THIS PROCEEDING?

A. As I calculated the Company's State Income Taxes, I have used the same methodology to calculate the Company's Federal Income Taxes, using the same methodology and the flowthroughs of my adjustments to Operating Revenues, Operating Expenses, Depreciation and Amortization Expenses, and Rate Base related adjustments.

Q. WHAT IS YOUR FEDERAL INCOME TAX EXPENSE?

A. My Federal Income Tax Expense at Present Rate Revenue is ($4,671,645), an increase of $1,278,613 from the Company's proposed Federal Income Tax Expense of ($5,951,000). This is shown on Schedule DM-24.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does. I reserve the right to amend my direct testimony and schedules as discussed above and based on any additional information received.

PCMG and Associates LLC

DANTE MUGRACE

Education

Master Business Administration, MBA Strategic Management, Pace University, Lubin School of Business, New York, NY, 2010

Master Public Administration, MPA, Kean University, Union, NJ, 2001

Bachelor of Science, BS. Accounting, St. Peter's University, Jersey City, NJ, 1983

Position

Senior Consultant – PCMG and Associates	2014 – present
Senior Consultant – Snavely King Majoros and Associates	2013 – 2014
Independent Consultant	2012 – 2013
Bureau Chief/Administrative Analyst/Accountant – New Jersey Board of Public Utilities	1983 – 2011

Professional Experience

Mr. Mugrace has 35 years' experience in all aspects of regulatory accounting and policy including processing, analyzing and evaluating utility rate case petitions before Public Service Commissions. Mr. Mugrace examines and evaluates rate filings, contracts, agreements and rate matters regarding utility operations and provides recommendations as to best course of action. Additionally, Mr. Mugrace analyzes and reviews utility regulatory matters and sets forth recommendations for resolution of issues, calculates total revenue requirement needed to cover operating expenses and rate of return; researches and evaluates regulatory utility matters to assess impact on various classes of customers, regarding rates, service, compliance and cost of service provisions, as well as annual true-up and tracking mechanisms.

Prior to undertaking consulting assignments, Mr. Mugrace was the Bureau Chief Utility Rate Manager for the New Jersey Board of Public Utilities, in which role he managed and assigned tasks to a staff of 12 professionals and supervisory personal in the daily administrative, financial and managerial functions of the Division. Mr. Mugrace's primary duties were to determine whether the utility had sufficient revenues to cover its operating expenses and earn a return on its plant investment and to ensure that the utility provided safe, reliable and continuing utility service to its customers. Mr. Mugrace set rates and charges for utility companies, which had revenues of up to $500 million, and ensured that the revenue requirement provided for recovery of all operating expenses, return on investment and depreciation. Mr. Mugrace was also responsible for reviewing and verifying that the companies' property, plant and equipment (up to $2.5 billion) were used and useful in providing service to its customers. Mr. Mugrace coordinated and met with the New Jersey State Department of Environmental Protection to determine whether water and wastewater utilities were complying with state regulations and were adhering to any regulatory agency directives or orders. Mr. Mugrace developed ways to minimize the rising costs of water utility services by investigating alternative rate structures, analyzing engineering mechanisms and techniques, looking into the feasibility of mergers and acquisitions within the water industry and reviewing financing, and rate alternatives to minimize the impact on ratepayers. Mr. Mugrace was responsible for ensuring that the rate-case process adhered the statutory timeframe for preparing, reviewing and recommending findings to the Board Commissioners on financial operations, costs, revenues and operating expenses, prior to the litigation proceedings. Mr. Mugrace also examined alternative rate recovery mechanisms and clauses, phase-ins of revenue requirements, deferral mechanisms and pass-through of rate charges. Mr. Mugrace assumed the role of Director during transition periods and Administrative changes. Finally, Mr. Mugrace conducted the recruitment and hiring of employees for placement within the Division and the Board.

Professional and Business Affiliations

- Institute of Public Utilities (IPU) Michigan State University (MSU), National Association of Regulatory Utility Commissioners (NARUC), National Association of State Utility Consumer Advocates (NASUCA)

Regulatory Projects and Appearances

1. In Re: Princeville Utilities Company, LLC., for an increase in rates for water and sewer services.
   (Appearance: Accounting and Policy on behalf of the Hawaii Division of Consumer Advocate)
   Hawaii Public Utilities Commission – Case No. 2025-0172

2. In Re: The York Water Company and the York Wastewater Company for an increase in rates for Water and Wastewater services.
   (Appearance: Accounting and Policy Issues on behalf of the Pennsylvania Office of Consumer Advocate)
   Pennsylvania Public Utility Commission – Docket Nos. R-2025-3053442 (Water) and R-2025-3053573 (Wastewater)

3. In Re: Middlesex Water Company for the proposed merger among Middlesex Water Company, Pinelands Water Company and Pinelands Wastewater Company.
   (Appearance: Accounting Issues on behalf of the NJ Division of Rate Counsel).
   NJ Board of Public Utilities -BPU Docket No. WM25050284

4. In Re: New Jersey American Water Company for approval to purchase the Hopewell Township Water System under the Water Infrastructure Protection Act (WIPA)
   (Appearance: Accounting and Policy Issues on behalf the NJ Division of Rate Counsel)
   NJ Board of Public Utilities – BPU Docket No. WM25040191

5. In Re: Columbia Gas of Pennsylvania – Base Rate Proceeding for Gas Utility Service.

(Appearance: Accounting and Policy Issues on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2025-3053499

6. In Re: Northern States Power Company- Minnesota – North Dakota – Request to Change Electric Rates for Service.
(Appearance: Accounting and Policy Issues on behalf of the North Dakota Public Service Commission Advocacy Staff)
North Dakota Public Service Commission (Docket No. PU-24-376

7. In Re: New Jersey-American Water for Approval to Sell a Portion of Real Property located at 185 John F. Kennedy Parkway in the Township of Millburn, County of Essex.
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. WM24090724

8. In Re: New Jersey-American Water for Approval of its Agreement with Shrewsbury Township, NJ for the Purchase and Sale of Water System; Determination that the Purchase Price is Reasonable; Determination that the Transaction costs are Reasonable and; or Such other Approvals as may be Necessary to Complete the Transaction (In accordance with the Water Infrastructure Protection Act (WIPA).
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. WR24100783

9. In Re: Veolia Water New Jersey for Approval of the Proposed Cost Recovery Mechanism Related to the Replacement of Customer/Property Owner Side Lead Service Lines and other Related Approvals.
(Appearance: Account Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WR24100835

10. In Re: Young Brothers, LLC. For Approval of a General Rate Increase and Certain Tariff Changes.
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocate)
Hawaii Public Utilities Commission – Docket No. 2024-0255

11. In Re: Hawaii-American Water Company for Approval of Rate Increases and Revised Rate Schedules and Rules (2024 Filing).
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2024-0038.

12. In Re: South Jersey Gas Company to Revise the level of its Basic Gas Supply Service (BGSS) and Conservation Incentive Program for the year ending September 30, 2025.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. GR24060370.

13. In Re: Public Service Electric and Gas Company 2024/2025 Annual BGSS Commodity Charge filing for its Residential Gas Customers under its Periodic Pricing Mechanism for changes in its Balancing Charge.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. GR24050364.

14. In Re: New Jersey Natural Gas Company for the Annual Review and Revision of its Basic Gas Supply Service and Conservation Incentive Program for Fiscal Year 2025.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. GR24060372.

15. In Re: Public Service Electric and Gas Company for Approval of Changes in its Conservation Incentive Program Rate Filing for 2024.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket No. GR24060369.

16. In Re: Atlantic City Electric Company for Implementation of an Adjustment to its Conservation Incentive Program Rate Mechanism and Associated Customer Class for 2024.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. ER24070548.

17. In Re: Rockland Electric Company – Annual Conservation Incentive Program reconciliation for the period July 1, 2023 to June 30, 2024.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket No. ER24070547.

18. In Re: Public Service Electric and Gas Company for approval of Changes in its Electric and Gas Green Programs Recovery Charges 2024 cost recovery filing.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket No. ER24070484 and GR24070490.

19. In Re: New Jersey American Water Company for approval to Sell a Portion of Real Property located at 185 John F. Kennedy Parkway in the Township of Millburn County of Essex.
(Appearance: Accounting / Consulting Issues on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket No. WM24090724.

20. In Re: Northern States Power Company for Approval of a 2024 Natural Gas Rate Increase. (Appearance: Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff).
    North Dakota Public Service Commission – Docket No. PU-23-367.

21. In Re: FirstEnergy Pennsylvania Electric Company for Approval of a General Base Rate Case increase for Electric Distribution rates for service.
    (Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
    Pennsylvania Public Utility Commission – Docket No. R-2024-3047068

22. In Re: Duquesne Light Company for Approval of a General Base Rate Case to increase Electric Distribution rates for service.
    (Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
    Pennsylvania Public Utility Commission – Docket No.- R-2024-3046523

23. In Re: Peoples Natural Gas Company, LLC for Approval of a General Base Rate Case increases in Natural Gas Service.
    (Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
    Pennsylvania Public Utility Commission – Docket No. R-2023-3044549

24. In Re: Black Hills Energy Arkansas, Inc. (BHEA) and Summit Utilities Arkansas, Inc. (SUA) for a General Change, or Modification in its Rates, Charges and Tariffs
    (Appearance: Incentive Compensation Proposals on behalf of the Attorney General Office)
    Arkansas Public Service Commission – Docket No. (BHEA) - 23-074-U and Docket No. (SUA) - 23-079-U.

25. In Re: Montana Dakota Utilities Co. for Approval to increase Gas Rates for Natural Gas Service in North Dakota
    (Appearance- Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff)
    North Dakota Public Service Commission – Docket No. PU-23-341

26. In Re: Otter Tail Power Company for Approval to increase Electric Rates in North Dakota. (Appearance: Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff)
    North Dakota Public Service Commission – Docket No. PU-23-342

27. In Re: New Jersey-American Water Company for Approval to change the level of its Purchased Water and Purchased Wastewater Treatment Adjustment Clause for 2023.
    (Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities – Docket No. WR23110791

28. In Re: Verified Petition of Jersey Central Power & Light Company to establish a Rate for Rider Lost Revenue Adjustment Mechanism for Sales Losses incurred during Program Year 2 Pursuant to the Energy Efficiency and Peak Demand Reductions Programs (PY Rider LRAM Filing).
    (Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities – Docket No. ER23110865

29. In Re: Fitchburg Gas & Electric Company; The Berkshire Gas Company; Boston Gas Company d/b/a National Grid; Liberty Utilities; Eversource Gas of Massachusetts d/b/a Eversource Energy and; NSTAR Gas Company d/b/a Eversource Energy – 2023 Gas System Enhancement Program Plan Filings. (DPU GSEP-01; DPU GSEP-02; DPU GSEP-03; DPU GSEP-04; DPU GSEP-05; and DPU GSEP-06, respectively)
    (Appearance: Accounting Issues on behalf of the Commonwealth of Massachusetts Office of the Attorney General)
    MA Department of Public Utilities

30. In Re: Northern States Power Company – Advance Determination of Prudence – 345 kV Transmission Line – MN.
    (Appearance: Accounting Issues and Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff.
    North Dakota Public Service Commission – Docket No. PU-23-142.

31. In Re: Northern States Power Company – Advance Determination of Prudence- Brookings Second Circuit Project.
    (Appearance: Accounting Issues and Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff.
    North Dakota Public Service Commission – Docket No. PU-23-295.

32. In Re: Northern States Power Company – Advance Determination of Prudence – 345 kV Big Stone to Sherburne.
    (Appearance: Accounting Issues and Revenue Requirements on behalf of the North Dakota Public Service Commission Advocacy Staff.
    North Dakota Public Service Commission – Docket No. PU-23-329.

33. In Re: Rockland Electric Company – Annual Conservation Incentive Program Filing – Reconciliation for the period July 1, 2022 – June 30, 2023.
    (Appearance: Accounting Issues on behalf the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities – Docket No. ER23070471

34. In Re: Public Service Electric & Gas Company for Approval of Incremental COVID-19 Costs for Recovery through a New Special Purpose Clause and for Authorization to Recovery Uncollectible Costs for Gas Through the Societal Benefits Charge
    (Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities – Docket No. ER23070448

35. In Re: Jersey Central Power & Light Company's Verified Petition Seeking Review and Approval of the Net Deferred Costs Included in its COVID-19 Regulatory Asset and Establishment of a COVID-19 Recovery Charge (JCP&L CRC-Filing)
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23070453.

36. In Re: Aqua New Jersey, Inc. Petition for 2024 PSTAC Rate and True-up for 2021 and 2022 PSTAC.
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR23080576

37. In Re: Public Service Electric & Gas Company for Approval of Changes in its Electric Tax Adjustment Credit and Gas Tax Adjustment Credit 2023 (2023 TAC Filing)
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23090634 and GR23090635

38. In Re: New Jersey – American Water Company for Deferral Accounting Authority for the Costs of Implementing the Clean Energy Act of 2018 Benchmarking Requirements.
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WF23060346

39. In Re: Public Service Electric & Gas Company – Annual BGSS (2023-2024) Commodity Charge Filing for its Residential Gas Customers under its Periodic Pricing Mechanism and for Changes in its Balancing Charge Rate.
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR23060331

40. In Re: Public Service Electric & Gas Company – Electric and Gas Green Programs Recovery Charges 2023. (GPRC).
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23070423 and GR23070424

41. In Re: Public Service Electric & Gas Company – Electric Solar Pilot Recovery Charge (SPRC) for its Solar Loan I Program (2023).
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23060412

42. In Re: Middlesex Water Company for approval of Proposed Cost Recovery of Lead Service Line Replacement Program
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR23050291

43. In Re: Black Hills Wyoming Gas, LLC d/b/a Black Hills Energy for Approval of a General Rate Increase of $19,262,412 to the Retail Gas Rates.
(Appearance: Revenue Requirement on behalf of the Wyoming Office of Consumer Advocate)

Wyoming Public Service Commission – Docket No. 30026-78-GR-23

44. In Re: Pittsburgh Water and Sewer Authority for an Increase in Rates for Water Service, Wastewater Service and Stormwater Service
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2023-3039920 (water), R-2023-3039921 (wastewater), and R-2023-3039919 (stormwater)

45. In Re: Massachusetts Electric and Nantucket Electric Companies d/b/a National Grid – Request for recovery of Incremental Storm related expenses associated with fourteen weather events between February 2020 and December 2020.
(Appearance: Storm Cost recovery (Operating and Maintenance Expenses) on behalf of the Massachusetts Office of Attorney General.
Massachusetts Department of Public Utilities – DPU No. 22-43.

46. In Re: Philadelphia Gas Works – for approval of an Increase in rates for Distribution Gas Service for 2023
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2023-3037933

47. In Re: Lanai Water Company, Inc. for Review and Approval of Rate Increases, Revised Rate Schedules and Charges to its Tariff.
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2022-0233

48. In Re: Hawaii Water Service Company, Inc., For Approval of a General Rate Increase for Its Pukalani Wastewater Division and Certain Tariff Changes
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2022-0186

49. In Re: UGI Utilities – Electric Division for Review of an Electric Base Rate Case proceeding for 2023.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3037368

50. In Re: Southern Maryland Electric Cooperative, Inc. (SMECO) for Authority to Revise its Rates and Charges for Electric Service and Certain Rate Design Changes.
(Appearance: Revenue Requirement on behalf of the Maryland Office of People's Counsel)
Maryland Public Service Commission – Case No. 9688

51. In Re: Public Service Electric and Gas Company – 2022 Electric and Gas Tax Adjustment Credit (TAC)
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket Nos. ER22100667 and GR22100668

52. In Re: Public Service Electric and Gas Company – 2022 Green Program Recovery Charge.
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket Nos. ER22070413 and GR22070414

53. In Re: Rockland Electric Company – Annual Conservation Incentive Program Filing – Reconciliation for the Period July 1, 2021 – June 30, 2022.
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. ER22070469.

54. In Re: Atlantic City Electric Company for Implementation to its Conservation Incentive Program Rate Mechanism and Associated Customer Class Rate (2022)
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. ER22070463

55. In Re: Public Service Electric and Gas Company – 2022/2023 Annual BGSS Commodity Charge filing for its Residential Gas Customers under its Periodic Pricing Mechanism and for changes to its Balancing Charge.
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. GR22060363

56. In Re: Citizens' Electric Company of Lewisburg, PA – 2022 Base Rate Case Proceeding for an Increase in Electric Distribution Rates.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3032369

57. In Re: Valley Energy, Inc. – 2022 Base Rate Case for an Increase in Gas Distribution Rates.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3032300

58. In Re: Berkshire Gas Company – 2021 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office)
Massachusetts Department of Public Utilities – D.P.U. 22-GREC-02

59. In Re: Liberty Utilities (New England Natural Gas Company) 2021 Gas System Enhancement Program Reconciliation Filing.

(Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office)
Massachusetts Department of Public Utilities – D.P.U. 22-GREC-04

60. In Re: Eversource Gas Company (Eversource Energy) 2021 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office)
Massachusetts Department of Public Utilities – D.P.U. 22-GREC-05

61. In Re: South Jersey Gas Company – 2022 Base Rate Case Proceeding for an Increase in rates for Distribution Gas Service.
(Appearance: Revenue Requirement, CWC and Consolidated Income Taxes on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. GR22040253

62. In Re: Public Service Electric and Gas Company – 2022 Electric Conservation Incentive Program (CIP) for changes in its Electric CIP rate for 2022.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER22020035

63. In Re: PECO Energy Company-Gas Division – 2022 Base Rate Case Proceeding for an Increase in rates for Distribution Gas Service.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3031113.

64. In Re: Nova Scotia Power Company- 2022-2024 General Rate Application for an Increase in Rates for Electric Service
(Appearance- Review of COSS – Subcontract with Synapse Energy Economics, Inc. on behalf of the Nova Scotia Utility Review Board)
Nova Scotia Utility and Review Board – Docket No. M10431

65. In Re: Georgia Power Company – 2022 Base Rate Case petition for an Increase in rates for Electric Distribution Service
(Appearance: Review of O&M Expenses for calendar years 2023-2025 on behalf of the Georgia Public Service Commission – Docket No. TBD

66. In Re: UGI Utilities Inc, Gas Division – 2022 Base Rate Case petition for an Increase in Distribution Gas Service Rates
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3030218

67. In Re: Hawaii-American Water Company – Approval of Rate Increases and Revised Rate Schedules for Wastewater Services – 2021
(Appearances: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Service Commission – Case No. 2021-0063

68. In Re: Kalaeloa Water Company – Approval of a General Rate Increase / Adjustments for Water and Wastewater Services – 2021
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Service Commission – Case No. 2021-0005

69. In Re: Northern States Power Company – 2021 Natural Gas Rate Increase Application
(Appearance: Revenue Requirements on behalf of the Advocacy Staff of the North Dakota Public Service Commission – Case No. PU-21-381

70. In Re: Shore Water Company – Petition for an Increase in Rates for Water Service and Other Relief
(Appearance: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. WR21091141

71. In Re: Atlantic City Sewerage Company – Petition for an Increase in Rates for Sewerage Service and other Tariff Changes
(Appearance: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. WR21071006

72. In Re: Gordon's Corner Water Company – Petition for an Increase in Rates and Charges for Water Service
(Appearance: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. WR21070979

73. In Re: The Petition of HPBS Inc., for review and approval of Central Scheduling System (CSS) charge increase and revised CSS Schedule (2021)
(Appearance – Accounting and Revenue Requirement on behalf of the Hawaii Division of Commerce and Consumer Affairs
Hawaii DCCA – Docket No. PTP-2021-001

74. In Re: The Berkshire Gas Company, 2020 Gas System Enhancement Program Reconciliation Filing
(Appearance – Massachusetts Attorney General's Office – Accounting and Revenue Requirement)
Massachusetts Department of Public Utilities – DPU Docket No. 21-GREC-02

75. In Re: Eversource Gas Company of Massachusetts d/b/a Eversource Energy, 2020 Gas System Enhancement Program Reconciliation Filing
(Appearance – Massachusetts Attorney General's Office – Account and Revenue Requirement)
Massachusetts Department of Public Utilities – DPU Docket No. 21-GREC-05

76. In Re: NSTAR Gas Company d/b/a Eversource Energy, 2020 Gas System Enhancement Program Reconciliation Filing
(Appearance: Massachusetts Attorney General's Office – Accounting and Revenue Requirement)
Massachusetts Department of Public Utilities – DPU Docket No. 21-GREC-06

77. In Re: Joint Petition of New Jersey Natural Gas Company and Public Service Electric and Gas Company for Authorization and Approval of a Waiver of Certain Accounting Treatment Pursuant to the Clean Energy Order
(Appearance – New Jersey Division of Rate Counsel – Accounting and Revenue Requirement.
New Jersey Board of Public Utilities – BPU Docket No. EO20030254

78. In Re: Public Service Electric and Gas Company – 2021/2022 Annual BGSS Commodity Charge Filing for its Residential Gas Customers under its Periodic Pricing Mechanism and for Changes in its Balance Charge.
(Appearance – New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. GR21060878

79. In Re: Middlesex Water Company – Petition for Approval of an Increase in Rates for Water Service and Other Tariff Changes.
(Appearances – New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. WR21050813

80. In Re: New Jersey Natural Gas Company – Petition for an Increase in Gas Base Rates and Changes in its Tariff for Gas Service and for a Change to Depreciation Rates for Gas Property and for Approval of a Base Rate Adjustment Pursuant to the NJ RISE and SAFE II Programs.
(Appearances: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket Nos. GR21030679 and GR21030680.

81. In Re: PECO Energy Company – a division of Exelon Corp., for a General Base Rate Case Filing for Electric Operations
(Appearances: Accounting and Policy on behalf of the Pennsylvania Office of the Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2021-3024601

82. In Re: The Pittsburgh Water and Sewer Authority for approval of increased rates and charges for Water, Wastewater and Stormwater services
(Appearance: Accounting and Policy, and Regulatory Policy on behalf of the Pennsylvania Office of the Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2021-3024773 (Water) R-2021-3024774 (Wastewater) and R-2021-3024779 (Stormwater).

83. In Re: Northern States Power Company – 2021 Electric Base Rate Case Increase
(Appearance: Revenue Requirement on behalf of the Advocacy Staff of the North Dakota Public Service Commission)
North Dakota Public Service Commission – Case No. PUC-20-441

84. In Re: Public Service Electric and Gas Company – Approval of a Tax Adjustment Clause (TAC).
(Appearance; Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER20100685 and GR20100686.

85. In Re: Pike County Light and Power Company – Approval to increase base rates for Electric and Gas Service.
(Appearance: Revenue Requirement in behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2020-3022134 (Gas) and R-2020-3022135 (Electric)

86. In Re: Jersey Central Power and Light Company for Approval of JCP&L's Energy Efficiency and Conservation Plan Including Energy Efficiency and Peak Demand Reduction Programs.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090620

87. In Re: Atlantic City Electric Company for Approval of an Energy Efficiency Program, Cost Recovery Mechanism, and Other Related Relief for Plan Years One Through Three.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090621

88. In Re: Rockland Electric Company for Approval of Its Energy Efficiency and Peak Demand Reduction Programs.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090623

89. In Re: Public Service Electric and Gas Company for Approval of Changes in its Electric Green Programs Recovery Charge and its Gas Green Programs Recovery Charge 2020 PSE&G Green Programs Cost Recovery filing

(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER20060467 and GR20060468

90. In Re: Public Service Electric and Gas Company's 2020/2021 Annual BGSS Commodity Charge filing for its Residential Gas Customers under its Pricing Mechanism and for Changes in its Balance Charge
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060379

91. In Re: Public Service Electric and Gas Company's 2020 Annual Margin Adjustment Clause (MAC)
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060384

92. In Re: South Jersey Gas Company for Approval to Revise the Rider H Rate Associated with the Tax Cuts and Jobs Act of 2017
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060382

93. In Re: Berkshire Gas Company -2019 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts -Department of Public Utilities – DPU 20-GREC-02

94. In Re: Bay States Gas Company d/b/a Columbia Gas – 2019 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts – Department of Public Utilities – DPU 20-GREC-05

95. In Re: NSTAR Gas Company – 2019 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts – Department of Public Utilities – DPU 20-GREC-06

96. In Re: South Jersey Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions.
(Appearances: Revenue Requirement and Cash Working Capital) on behalf of the New Jersey Division of Rate Counsel.
New Jersey Board of Public Utilities – Docket No. GR20030243

97. In Re: Jersey Central Power & Light Company for Review and Approval of Increased in, and Other Adjustments to Rates and Charges for Electric Services and approval of Other Proposed Tariff Revisions (Appearance: Revenue Requirement, Cash Working Capital,

Consolidated Income Taxes, LED Conversion and Reliability Roll-In) on behalf of the New Jersey Division of Rate Counsel.
New Jersey Board of Public Utilities – Docket No. ER20020146

98. In Re: The Pittsburgh Water and Sewer Authority for approval of increased rates and charges for water and wastewater service and for approval of a multi-year rate plan. (Appearance: Accounting and Policy, Customer Service and Regulatory Policy) on behalf of the Pennsylvania Office of the Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2020-3017951 and R-2020-3017970.

99. In Re: New Jersey-American Water Company, Inc. for approval of Increased Base Tariff Rates and Charges for Water and Wastewater Services and Other Tariff Revisions. (Appearance: Accounting and Revenue Requirement and Cash Working Capital / Consolidated Income Taxes) on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19121516

100. In Re: Hawaiian Electric Company, Inc., for approval of a General Rate Increase and Revised Rate Schedules and Rules.
(Appearance: Accounting and Revenue Requirement on behalf of the Hawaiian Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2019-0085

101. In Re: Mount Olive Villages Water Company for approval of an Increase in Rates for Water Service and Other Tariff Changes.
(Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19060770

102. In Re: Mount Olive Villages Sewer Company for approval of an Increase in Rates for Sewer Service and Other Tariff Changes.
(Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19060769

103. In Re: Public Service Electric and Gas Company for approval of changes in its Electric Green Programs Recovery and its Gas Green Programs Recovery Charge (2019 PSE&G Green Programs Cost Recovery Filing).
(Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER19070764 and GR19070765

104. In Re: Proposed Amendment to N.J.A.C. 14:9- Adoption by reference to the Uniform System of Accounts for Water Utilities and Wastewater Utilities.
(Appearance: Consulting Services on behalf of the New Jersey Division of Rate Counsel)

New Jersey Board of Public Utilities- Docket Nos. WX19050612 (Water) and WX19050613 (Wastewater)

105. In Re: Public Service Electric and Gas Company's 2019/2020 Annual BGSS Commodity Charge filing for its Residential Gas Customers Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge.
(Appearance: Revenue Requirement and accounting/consulting services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR190600699

106. In Re: Bay States Gas Company d/b/a Columbia Gas of Massachusetts for Approval of a 2018 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts Department of Public Utilities – Docket No. 19-GREC-05

107. In Re: NSTAR Gas Company d/b/a Eversource Energy for Approval of a 2018 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts Department of Public Utilities – Docket No. 19-GREC-06

108. In Re: Public Service Electric and Gas Company for Approval of Gas Rate Base Adjustments Pursuant to its Gas System Modernization Program (April 2019 GSMP)
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR19040522

109. In Re: Kalaeloa Water Company, LLC for Approval of General Rate Case and Revised Rules, Regulations and Rates.
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2019-0057

110. In Re: Elizabethtown Gas Company for Approval of an Increase in Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions.
(Appearance: Revenue Requirement and Other Accounting Issues on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – Docket No. GR19040586

111. In Re: Petition of Peoples Natural Gas Company for Approval of an Increase in Rates for Natural Gas Distribution Service.
(Appearance: Revenue Requirement and Other Accounting Issues on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2018-3006818

112. In Re: Petition of Aqua New Jersey, Inc. for Approval of an Increase in Rates for Water Service and other Tariff Changes.
(Appearance: Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WR18121351

113. In Re: Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Efficiency (CEF-EE) Program on a Regulated Basis.
(Appearance: Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket Nos. GO18101112 and EO18101113.

114. In Re: Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Vehicle and Energy Storage (CEF-EVES) Program on a Regulated Basis. (Appearance – Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. EO18101111.

115. In Re: Petition of New Jersey Natural Gas Company- Request for Deferred Accounting Authority for Costs Related to New Information Technology Systems. (Appearance: Impact on Revenues, prudency of costs on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. GR18101096

116. In Re: Petition for Approval of An Indirect Change in Control of the New Jersey Public Utilities Subsidiaries of SUEZ Water Resources, Inc. and Other Related Approvals.
(Appearance: Impact on Rates, Service, Employees, Positive Benefits on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WM18090982

117. In Re: The Matter of the Merger of Roxbury Water Company into New Jersey American Water Company (Appearance: Impact on Rates, Service and Employees, Positive Benefits on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WM18080904

118. In Re: The Matter of the Application of Maryland-American Water Company for Authorization to Adjust its Existing Schedule of Tariffs and Rates.
(Appearance: Revenue Requirement on behalf of the Maryland Office of People's Counsel)
Maryland Public Service Commission – Case No. 9487

119. In Re: The Matter of the Joint Petition for Approval of an Increase in Rates for Water and Wastewater Service and Other Tariff Changes for SUEZ Water NJ, Inc., Toms River, Inc.,

Arlington Hill, Inc., West Milford, Inc., Matchaponix, Inc., and Princeton Meadows, Inc. (Appearance: Revenue Requirement and the development of Consolidated Income Taxes on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WR18050593

120. In Re: The Matter of the Application of Atlantic City Electric Company to Adjust the Level of its Rider RGGI Rate Associated with its Solar Renewable Energy Certificate Financing Program 2018 (Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. ER18050543

121. In Re: The Matter of the Petition of New Jersey Natural Gas Company's Approval of the Cost Recovery Associated with Energy Efficiency Programs (Appearance; Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No, GR18050585

122. In Re: The Matter of Bay States Gas Company d/b/a Columbia Gas of Massachusetts, 2017 Gas System Enhancement Reconciliation Filing (Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy)
Commonwealth of Massachusetts – Department of Public Utilities – Docket No. D.P.U. 18-GREC-05.

123. In Re; The Matter of NSTAR Gas Company d/b/a Eversource Energy, Gas System Enhancement Program Reconciliation Filing (Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy)
Commonwealth of Massachusetts – Department of Public Utilities – Docket No. D.P.U. 18-GREC-06.

124. In Re: The Matter of the Merger of SUEZ Water NJ, SUEZ Water Toms River, SUEZ Water Arlington Hills, SUEZ Water West Milford, SUEZ Water Princeton Meadows and SUEZ Water Matchaponix (Appearance: Positive Benefits related to the Merger on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WR18030266

125. In Re: The Matter of the Columbia Gas of Pennsylvania for a General Rate Increase in Distribution Gas Service (Appearance; Accounting Issues and Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2018-2647577

126. In Re: The Matter of the New Jersey Board of Public Utilities Consideration of the Tax Cuts and Jobs Act of 2017 – Generic Proceeding (Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. AX18010001

127. In Re: Acquisition of Elizabethtown Gas, a Division of Pivotal Utilities Holdings, Inc. by ETG Acquisition Corp., a Division of South Jersey Industries, Inc., and Related

Transactions. (Appearance: Customer Service Issues/Employee and Labor Relations on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. GM17121309.

128. In Re: Middlesex Water Company – Base Rate Case Proceeding for Water Service. (Appearance: revenue requirement on behalf of the NJ Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket No. WR17101049.

129. In Re: Township of East Brunswick – Sewer Rate Study – (Evaluation of the existing sewer rate structure and examining and quantify costs for future expansion).

130. In Re: Montana-Dakota Utilities – Base Rate Case Proceeding for Gas Service. (Appearance: revenue requirement on behalf of the North Dakota Public Service Commission). NDPSC Docket No. PU-17-295.

131. In Re: Andover Utility Company – Base Rate Case Proceeding for Wastewater Services. (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket No. WR17070726.

132. In Re: Public Service Electric and Gas Company- Approval of Changes in its Electric and Gas Green Programs Recovery Charges "2017 Public Service Electric & Gas Green Programs Cost Recovery Filing. (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket Nos. ER17070724 and GR17070725.

133. In Re: Bay States Gas Company d/b/a Columbia Gas of Massachusetts, 2016 Gas System Enhancement Program Reconciliation Filing, (Appearance: revenue requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy).
Commonwealth of Massachusetts Department of Public Utilities – Docket No. D.P.U. 17-GREC-05.

134. In Re: NSTAR Gas Company d/b/a Eversource Energy, 2016 Gas System Enhancement Program Reconciliation Filing (Appearance: revenue requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy.
Commonwealth of Massachusetts Department of Public Utilities – Docket No. D.P.U. 17-GREC-06.

135. In Re: Petition of Columbia Gas of Maryland – Increase in rates for Distribution Service – (Appearance: revenue requirement on behalf of the Office of People's Counsel) Public Service Commission of Maryland – Case No. 9447

136. In Re: Petition of South Jersey Gas Company – Increase in base rates for gas services – (Appearance: revenue requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR17010071

137. In Re: Petition of UGI Penn Natural Gas – Increase in base rates for gas services – (Appearance: revenue requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utilities Commission Docket No. R-2016-2580030

138. In Re: Petition of PJM Interconnection, LLC. – Mid-Atlantic Interstate Transmission, LLC. Formula Rate Filing. (Appearance on behalf of the Pennsylvania Office of Consumer Advocate).
FERC Docket No. ER17-211-000

139. In Re: Petition of Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company for approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. GR16090826

140. In Re: Petition of SUEZ Water New Jersey, et al – Approval of a Management and Services Agreement pursuant to N.J.S.A 48: 3-7.1 (Appearance on the reasonableness of contract agreements on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WO16080806

141. In Re: Petition of SUEZ Water Arlington Hills Inc. – Approval of an Increase in Rates for Wastewater Services and other Tariff Changes (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR16050510

142. In Re: Petition of Public Service Electric and Gas Company – 2016 Marginal Adjustment Clause (MAC) (Appearance; reconciliation and rate setting on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. GR16060484

143. In Re: Petition of Public Service Electric and Gas Company for Approval of Changes in its Electric Green Programs Recovery Charges and its Gas Green Program Recovery Charges 2016 PSEG Program Cost Recovery Filing
(Appearance: reconciliation and rate setting on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket Nos. ER16070613 and GR16070614

144. In Re: Petition of the Mount Olive Village Sewer Company, Inc., for Approval of an Increase in Rates for Service (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR16050391

145. In Re: Petition of the Mount Olive Village Water Company, Inc. for Approval of an Increase in Rates for Service (Appearance; revenue requirement on behalf of the New Jersey Division of Rate Counsel)

New Jersey Board of Public Utilities Docket No. WR16050390

146. In Re: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Analysis and Advice to Counsel: computation of the revenue requirement and rate impact on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-01

147. In Re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Appearance: computation of the revenue requirement and rate impact on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-05

148. In Re: Petition for Approval of Gas Infrastructure Contract Between Public Service Company of New Hampshire d/b/a Eversource Energy and Algonquin Gas Transmission, LLC (2016) - (Analysis and Advice to Counsel: compliance with statutes and regulations, review of contract, and ratemaking on behalf of the New Hampshire Office of Consumer Advocate)
    NH Public Utilities Commission Docket No. DE 16-241

149. In Re: Central Maine Power Company, Annual Compliance Filing and Price Change (2016) - (Analysis and Advice to Counsel; tax normalization regulatory asset on behalf of the Maine Office of the Public Advocate)
    ME Public Service Commission Docket No. 2016-00035

150. In Re: Bulletin 2015-10 Generic Proceeding to Establish Parameters for the Next Generation PBR Plans (Appearance: productivity adjustments/performance-based ratemaking on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20414

151. In Re: The Matter of Request by Emera Maine for Approval of a Rate Change (2016) - (Appearance: revenue requirement on behalf of the Maine Office of the Public Advocate)
    Maine Public Utilities Commission Docket No. 15-00360)

152. In Re: the Matter of the Joint Application of the Southern Company, AGL Resources Inc., and Pivotal Holdings, Inc. d/b/a Elkton Gas (2015-2016) - (Analysis and advice to counsel: customer service impacts, employee impacts, supplier diversity on behalf of the Maryland Office of People's Counsel)
    MD PSC Case No. 9404

153. In Re: The Matter of the Merger of Southern Company and AGL Inc. (2015-2016) - (Appearance: customer service impacts and employee impacts on behalf of the NJ Division of Rate Counsel)
    New Jersey BPU Docket No. GM15101196

154. In Re: The Matter of the United Water New Jersey, Inc., for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2015-2016) - (Appearance: revenue requirements, rate base issues and operating income on behalf of the NJ Division of Rate Counsel)
New Jersey BPU Docket No. WR15101177

155. In Re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Precedent Agreements with Millennium Pipeline Company, LLC (2015) - (Analysis: review of contract and compliance of the Gas Supply Plan on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-130

156. In Re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Agreements for LNG or Liquefaction Services with GDF Suez Gas NA, LLC; Northeast Energy Center, LLC; Metro LNG, L.P.; and National Grid LNG (2015) - (Analysis: review of contract and compliance of the Gas Supply Plan on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-129

157. In Re: Columbia Gas of Massachusetts CY2014 Targeted Infrastructure Reinvestment Factor (TIRF) Compliance Filing (2015) - (Appearance: computation of the revenue requirement impact on the TIRF on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-55

158. In Re: The Matter of the Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its Targeted Infrastructure Reinvestment Factor (TIRF) for CY 2013 (2014) - (Appearance: computation of the revenue requirement impact on the TIRF)
MA D.P.U. 14-83

159. In Re: The Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc. (Atlantic City Electric Company) (2014-2015) - (Appearance: customer service impacts)
New Jersey BPU Docket No. EM14060581

142. In Re: Public Utilities Commission of Ohio – In the Matter of the Application of Ohio Power Company (American Electric Power Ohio) (AEP Ohio) to Adopt a Final Implementation Plan for the Retail Stability Rider – (Appearance - Accounting Issues) (2014) on behalf of the Ohio Office of Consumer Counsel (OCC)
PUCO Case No. 14-1186-EL-RDR

143. In Re: Public Utilities Commission of Ohio - In the Matter of the Application of Aqua Ohio, Inc. to Increase its Rates and Charges for its Waterworks Service. – Revenue and Rates (2014) - (Appearance: operating income, certain rate base issues and income taxes on behalf of the Ohio Office of Consumer Counsel)
PUCO Case No. 13-2124-WW-AIR

144. In Re: New York Public Service Commission, as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. Revenue Requirement (2013-2014) – (Appearance: revenue requirement, rate base issues and operating income on behalf of the Intervenor, the County of Westchester)
    NYPSC Case Nos. 13-E-0030, 13-G-0031 and 13-S-0032, et al

145. In Re: North Dakota Public Service Commission, - Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota, On-Going Revenue Requirement (2013) - (Appearance: revenue requirement and rate base, operating income, operating and maintenance expenses on behalf of the North Dakota Public Service Commission Staff)
    North Dakota Case No. PU-12-813

146. In the Matter of the Petition of New Jersey American Water Company for Authorization to Implement a Distribution System Improvement Charge (DSIC) Order Denying Petition and Instituting Stakeholder Process (2008) - (Case manager on policy decision and revenue requirement impact on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WO08050358

147. In the Matter of the Joint Petition of the City of Trenton, New Jersey and New Jersey-American Water Company, Inc. for Authorization of the Purchase and Sale of the Assets of the Outside Water Utility System ("OWUS") of the City of Trenton, New Jersey and for Other Relief Order Adopting Initial Decision, (2008) - (Case manager on the revenue requirement impact on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WM08010063

148. In the Matter of the Petition of United Water New Jersey, United Water Toms River, United Water Lambertville, United Water Mid-Atlantic and Gaz de France for Approval as Need for a Change in Ownership and Control (2007) - (Case manager on customer impact, employee impact and impact on rates on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WM06110767

149. In the Matter of the Petition of United Water Arlington Hills Sewerage, Inc. for an Increase in Rates for Wastewater Service and Other Tariff Changes (2009) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WR08100929

150. In the Matter of the Petition of United Water New Jersey Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes, (2009) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
    BPU Docket No. WR08090710

151. In the Matter of the Petition of United Water Toms River, Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2008) - (Case manager on the revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08030139

152. In the Matter of the Joint Petitioners of New Jersey-American Water Company, Inc., S.J. Services, Inc., South Jersey Water Company, Inc. and Pennsgrove Water Supply Company, Inc. for Among Other Things Approval of a Change in Control of South Jersey Water Supply Company, Inc. and Pennsgrove Water Supply Company, Inc. (2007) - (Case manager on the overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM07020076

153. In the Matter of the Petition of Aqua, New Jersey, Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2008) - (Case manager on revenue requirement and the overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR0712095

154. I/M/O the Joint Petition of Thames Water, Aqua Holdings GMBH, on Behalf of Itself and Its Parent Holdings Company, RWE Aktiengesellschaft, Thames Water Aqua US Holdings, Inc., American Water works Company Inc., Thames Water Holdings Incorporated, E 'town Corporation, New Jersey-American Water Company, Inc., Elizabethtown Water Company, the Mount Holly Water Company and Applied Wastewater Management, Inc. for Confirmation that the Board of Public Utilities Does Not Have Jurisdiction Over, or, Alternatively, for Approval of a Proposed Transaction Involving, Among Other Things, the Sale by Thames Water Aqua Holdings GMBH of Up to 100% of the Shares of the Common Stock of American Waterworks Company, Inc. in One or More Public Offerings (2007) - (Case manager on revenue requirement impacts, effect on rates and effect on service on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM06050388

155. In the Matter of the Petition of Elizabethtown Water Company for Approval of an Increase in Rates for Water Service (2007) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR03070510

156. In the Matter of the Petition of New Jersey American Water Company, Inc. for Approval of Increased Tariff Rates and Charges for Water and Sewer Service; Increased Depreciation Rates and Other Tariff Revisions (2008) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08010020

157. In the Matter of Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes (2007) - (Case manager on overall revenue

requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR07040275

158. In the Matter of the Joint Petition of United Water New Jersey, Inc., United Water Arlington Hills, Inc., United Water Hampton, Inc., United Water Vernon Water Hills, Inc., and United Water Lambertville, Inc. for an Increase in Rates and Charges for Water Service and Other Tariff Changes and for Approval to Merge the Operations of the Joint Petitioners into and with United Water New Jersey, Inc. (2007) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR07020135

REVENUE REQUIREMENT

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Average Rate Base**	**$ 816,976,000**	**$ (22,022,644)**	**$ 794,953,356**	
2	Operating Income - Present	$ 28,081,000	$ 4,932,293	$ 33,013,293	
3	AFUDC	$ -		$ -	
4	Total Available for Return	$ 28,081,000	$ 4,932,293	$ 33,013,293	
5	Overall Rate of Return	3.437%		4.153%	
6	Required Return	7.560%		6.966%	
7	**Operating Income Requirement**	**$ 61,763,386**	**$ (6,384,391)**	**$ 55,378,995**	
8	**Income Deficiency**	**$ 33,682,386**	**$ (11,316,684)**	**$ 22,365,701**	
9	Gross Revenue Requirement Factor	1.322840		1.322840	(2)
10	**Revenue Deficiency**	**$ 44,556,407**	**$ (14,970,162)**	**$ 29,586,245**	
11	Revenues at Present Rates	$ 230,375,000	$ -	$ 230,374,818	
12	Percentage Increase	19.341%		12.843%	
	Total Revenue Requirement	**$ 274,931,407**		**$ 259,961,063**	

(1) Company Exhibit BCH-1 Revised Sch. 7
(2) Company Exhibit BCH-1 Schedule 3

State Income Tax	4.310000%
Federal Income Tax	21.000000%
Effective Tax Rate	20.094900%
Composite Tax Rate	24.404900%
Revenue Requirement Factor	**1.322837**

Differences due to rounding

WEIGHTED AVERAGE COST OF CAPITAL

		Ratios	Cost of Capital	Weighted Average
(1)	Company Proposed			
1	LT Debt	46.7100%	4.5092%	2.1062%
2	ST Debt	0.7900%	5.3100%	0.0419%
3	Common Equity	52.5000%	10.3000%	5.4075%
4	**Total Capital**	**100.0000%**		**7.5595%**
(2)	ND PSC Advocacy Staff			
5	LT Debt	49.2100%	4.5100%	2.2194%
6	ST Debt	0.7900%	5.3100%	0.0419%
7	Common Equity	50.0000%	9.4100%	4.7050%
8	**Total Capital**	**100.0000%**		**6.9663%**

(1) Company Workpaper C1
(2) Ms. Reno Direct Testimony page 8

Northern States Power Co. Electric - ND
Test Year Ending 12/31/2025

ND Public Service Commission
Case No. PU-24-376

Schedule DM-3

AVERAGE RATE BASE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Electric Plant In Service				
1	Production Plant	$ 983,646,000	$ -	$ 983,646,000	
2	Transmission Plant	$ 287,276,000	$ -	$ 287,276,000	
3	Distribution Plant	$ 309,517,000	$ (15,160,411)	$ 294,356,589	
4	General Plant	$ 109,571,000	$ -	$ 109,571,000	
5	Common Plant	$ 88,558,000	$ (2,578,170)	$ 85,979,830	
6	**Total Electric Plant In Service**	**$ 1,778,568,000**	**$ (17,738,581)**	**$ 1,760,829,419**	DM-5
	Reserve for Depreciation				
7	Production Plant	$ 546,266,000	$ (1,000)	$ 546,265,000	
8	Transmission Plant	$ 73,738,000	$ -	$ 73,738,000	
9	Distribution Plant	$ 97,318,000	$ (9,129)	$ 96,952,055	
10	General Plant	$ 53,032,000	$ (159,000)	$ 53,032,000	
11	Common Plant	$ 39,881,000	$ (332,106)	$ 39,548,894	
12	**Total Reserve for Depreciation**	**$ 810,235,000**	**$ (699,051)**	**$ 809,535,949**	DM-6
	Net Utility Plant In Service				
13	Production Plant	$ 437,380,000	$ -	$ 437,381,000	
14	Transmission Plant	$ 213,538,000	$ -	$ 213,538,000	
15	Distribution Plant	$ 212,199,000	$ -	$ 197,404,534	
16	General Plant	$ 56,539,000	$ -	$ 56,539,000	
17	Common Plant	$ 48,677,000	$ -	$ 46,430,936	
18	**Net Electric Utility Plant In Service**	**$ 968,333,000**	**$ (17,039,530)**	**$ 951,293,470**	
19	Electric Utility Plant Held for Future Use	$ -	$ -	$ -	
20	Constuction Work in Progress	$ 4,722,000	$ (4,772,000)	$ -	
21	Accumulated Deferred Income Taxes	$ (150,287,000)	$ 1,238,958	$ (149,048,042)	DM-7
22	Cash Working Capital	$ (5,329,000)	$ 423,361	$ (4,905,639)	DM-8
23	**Sub-Total**	**$ 817,439,000**	**$ (20,099,212)**	**$ 797,339,788**	
	Other Rate Base Items				
24	Materials and Supplies	$ 13,075,000	$ -	$ 13,075,000	DM-9
25	Fuel Inventory	$ 6,413,000	$ -	$ 6,413,000	DM-9
26	Non-Plant Assets/Liabilities	$ 7,655,000	$ -	$ 7,655,000	DM-9
27	Customer Advances	$ (91,000)	$ -	$ (91,000)	DM-9
28	Customer Deposits	$ (40,000)	$ -	$ (40,000)	DM-9
29	Prepaids and Others	$ 5,700,000	$ -	$ 5,700,000	DM-9
30	Regulatory Amortizations	$ (33,174,000)	$ (1,924,432)	$ (35,098,432)	DM-9
31	**Total Other Rate Base Items**	**$ (462,000)**	**$ (1,924,432)**	**$ (2,386,432)**	
32	**Total Average Rate Base**	**$ 816,977,000**	**$ (22,023,644)**	**$ 794,953,356**	

(1) Company Exhibit BCH-1 Schedule 10

OPERATING INCOME STATEMENT

		(1) Company Proposed Present Rates	Rate Adjustments	Company Proposed Final Rates	Adjustments	Present Rates ND PSC Advocacy Staff	References
	Operating Revenues						
1	Retail Revenues	$ 230,375,000	$ 44,556,407	$ 274,931,407		$ 230,374,818	
2	Interdepartmental Revenues	$ -	$ -	$ -			
3	Other Operating Revenues	$ 62,538,000	$ (10,875,407)	$ 51,662,593	$ 37,951	$ 62,575,951	
4	**Total Operating Revenues**	**$ 292,913,000**	**$ 33,681,000**	**$ 326,594,000**	**$ (33,643,231)**	**$ 292,950,769**	
	Operating Expenses						
5	Fuel & Purchased Energy	$ 84,046,000	$ -	$ 84,046,000	$ -	$ 84,046,000	DM-12
6	Power Production	$ 44,034,000	$ -	$ 44,034,000	$ (491,578)	$ 43,498,422	DM-13
7	Transmission	$ 19,511,000	$ -	$ 19,511,000	$ (1,327,068)	$ 18,183,932	DM-14
8	Distribution	$ 7,391,000	$ -	$ 7,391,000	$ (133,596)	$ 7,257,404	DM-15
9	Customer Accounting	$ 5,367,000	$ -	$ 5,367,000	$ (805,555)	$ 4,561,445	DM-16
10	Customer Service & Info.	$ 351,000	$ -	$ 351,000	$ (125,031)	$ 225,969	DM-17
11	Sales Econ Develop & Other	$ 395,000	$ -	$ 395,000	$ (290,323)	$ 104,677	DM-18
12	Admin. & General	$ 20,914,000	$ -	$ 20,914,000	$ (1,707,058)	$ 19,206,942	DM-19
13	**Total Operating Expenses**	**$ 182,009,000**	**$ -**	**$ 182,009,000**	**$ (4,924,209)**	**$ 177,084,791**	(2)
14	Depreciation Expense	$ 75,002,000	$ -	$ 75,002,000	$ (706,749)	$ 74,295,251	DM-20
15	Amortization Expense	$ 12,722,000	$ -	$ 12,722,000	$ (706,048)	$ 12,015,952	DM-21
16	Taxes Other Than Income	$ 1,881,000	$ -	$ 1,881,000	$ (110,116)	$ 1,770,884	DM-22
17	State Income Taxes	$ (832,000)	$ -	$ (832,000)	$ 274,243	$ (557,757)	DM-23
18	Federal Income Taxes	$ (5,951,000)	$ -	$ (5,951,000)	$ 1,279,355	$ (4,671,645)	DM-24
19	**Total Operating Expenses**	**$ 264,831,000**	**$ -**	**$ 264,831,000**	**$ (4,893,524)**	**$ 259,937,476**	
20	AFUDC	$ -		$ -			
21	Total Operating Income	**$ 28,082,000**	**$ 33,681,000**	**$ 61,763,000**	**$ (28,749,707)**	**$ 33,013,293**	
22	**Rate Base**	**$ 816,976,000**		**$ 816,976,000**	**$ (22,022,644)**	**$ 794,953,356**	
23	**Rate of Return**	**3.44%**		**7.56%**		**6.97%**	

(1) Company Exhibit BCH-1 Schedule 3
Company Exhibit BCH-1 Schedule 11
(2) Any differences due to rounding

ELECTRIC PLANT IN SERVICE

	Plant Categories	(1) Company Proposed Unadjusted	Adjustments	Company Proposed Adjusted	Adjustments	ND PSC Advocacy Staff	References
1	Production	$ 1,018,582,000	$ (23,341,000)	$ 995,241,000		$ 995,241,000	
2	Production - (Rider RER)	$ -	$ (11,595,000)	$ (11,595,000)		$ (11,595,000)	
3	Transmission	$ 306,094,000	$ -	$ 306,094,000		$ 306,094,000	
4	Transmission - (Rider RER)	$ -	$ -	$ -		$ -	
5	Transmission - (Rider TCR)	$ -	$ (18,818,000)	$ (18,818,000)		$ (18,818,000)	
6	Distribution - Larimore Station	$ 309,517,000	$ -	$ 309,517,000	$ (13,134,431)	$ 296,382,569	Set 8-14
	(TRADE SECRET DATA BEGINS)						
[redacted]							
8	**(TRADE SECRET DATA ENDS)**					$ -	Set 12-12
9	General	$ 110,610,000	$ -	$ 110,610,000		$ 110,610,000	Set-20-1
10	General - (Rider TCR)	$ -	$ (1,039,000)	$ (1,039,000)		$ (1,039,000)	
11	Common	$ 88,558,000	$ -	$ 88,558,000		$ 88,558,000	
12	**AGIS - LTE Private Network**	$ -	$ -	$ -	$ (2,578,170)	$ (2,578,170)	
13	**Total Electric Plant In Service**	**$ 1,833,361,000**	**$ (31,452,000)**	**$ 1,778,568,000**	**$ (17,738,581)**	**$ 1,760,829,419**	

(1) Company Exhibit BCH-1 Schedule 5

LTE Network		$ 2,578,170	Set 8-67
Account 303 - 15.20% 9.92% 6.74% - 7-10-15 years	$ 1,921,668		
Account 391 - 21.55% - 5 years	$ 656,502		
Maybe include - check discovery			
Larimore			
Transmission -355-356 2.155%	$ 783,180	$ (16,878)	
Distribution -364-362/360-362 2.6167%	$ 12,063,224	$ (315,658)	
General -397 8.43%	$ 288,023	$ (24,280)	
Total	$ 13,134,427	$ (356,816)	

PUBLIC DOCUMENT - TRADE SECRET DATA REDACTED

RESERVE FOR DEPRECIATION

		(1) Company Proposed Unadjusted	Adjustments	Company Proposed Adjusted	Adjustments	ND PSC Advocacy Staff	References
1	Production	$ 545,881,000	$ (3,327,000)	$ 542,554,000	$ -	$ 542,554,000	
2	Production - Remaining Life-All Other	$ -	$ 374,000	$ 374,000		$ 374,000	
	Production - Remaining Life - Base Load		$ 3,378,000	$ 3,378,000		$ 3,378,000	
3	Production - (Rider RER)	$ -	$ (41,000)	$ (41,000)	$ -	$ (41,000)	
4	Transmission	$ 74,345,000	$ -	$ 74,345,000	$ -	$ 74,345,000	
5	Transmission - Depreciation Study	$ -	$ 23,000	$ 23,000	$ -	$ 23,000	
6	Transmission - (Rider RER)	$ -	$ -	$ -	$ -	$ -	
7	Transmission - (Rider TCR)	$ -	$ (630,000)	$ (630,000)	$ -	$ (630,000)	
8	Distribution - Larimore Station	$ 97,354,000	$ -	$ 97,354,000	$ (356,816)	$ 96,997,184	
	(TRADE SECRET DATA BEGINS)						
[redacted]							
10	**(TRADE SECRET DATA ENDS)**			$ -	$ -	$ -	
11	Distribution - Depreciation Study	$ -	$ (36,000)	$ (36,000)	$ -	$ (36,000)	
12	General	$ 53,156,000	$ -	$ 53,156,000	$ -	$ 53,156,000	
13	General - Depreciation Study	$ -	$ 61,000	$ 61,000	$ -	$ 61,000	
	General - Remaining Life - All Other		$ (3,000)	$ (3,000)		$ (3,000)	
	General - Remaining Life - Base Load		$ (156,000)	$ (156,000)		$ (156,000)	
14	General (Rider TCR)	$ -	$ (26,000)	$ (26,000)	$ -	$ (26,000)	
15	Common	$ 39,973,000	$ -	$ 39,973,000	$ -	$ 39,973,000	
16	Common - Depreciation Study	$ -	$ (92,000)	$ (92,000)	$ -	$ (92,000)	
17	AGIS - LTE Private Network			$ -	$ (332,106)	$ (332,106)	
18	**Total Reserve for Depreciation**	**$ 810,709,000**	**$ (475,000)**	**$ 810,234,000**	**$ (698,051)**	**$ 809,535,949**	

(1) Company Exhibit BCH-1 Schedule 5
Differences due to rounding

PUBLIC DOCUMENT - TRADE SECRET DATA REDACTED

PUBLIC DOCUMENT - TRADE SECRET DATA REDACTED

ACCUMULATED DEFERRED INCOME TAXES

		(1) Company Proposed Unadjusted	Adjustments	Company Proposed Adjusted	Adjustments	ND PSC Advocacy Staff	References
	Base Plant	$ 198,034,000	$ -	$ 198,034,000	$ (168,131)	$ 197,865,869	
1	NSPM ADIT Prorate for IRS	$ 66,000	$ -	$ 66,000	$ -	$ 66,000	
2	NSPM-ND Depreciation Study TDG	$ 14,000	$ -	$ 14,000	$ -	$ 14,000	
3	NSPM -ND E Community Wind WF Removal	$ (902,000)	$ -	$ (902,000)	$ -	$ (902,000)	
4	NSPM-ND E Jeffers WF Removal	$ (926,000)	$ -	$ (926,000)	$ -	$ (926,000)	
	(TRADE SECRET DATA BEGINS)						
[redacted]							
	(TRADE SECRET DATA ENDS)						
5	NSPM-ND E Northern Wind WF Removal	$ (1,547,000)	$ -	$ (1,547,000)	$ -	$ (1,547,000)	
6	NSPM-ND Prairie Island EPU Deferral	$ 991,000	$ -	$ 991,000	$ (991,000)	$ -	
7	NSPM Non-Plant	$ 1,700,000	$ -	$ 1,700,000	$ -	$ 1,700,000	
	NSPM-Non-Plant Tax Reform Excess ADIT	$ 349,000	$ -	$ 349,000	$ -	$ 349,000	
	NSPM-Nuclear Outage COA	$ 1,117,000	$ -	$ 1,117,000	$ -	$ 1,117,000	
	NSPM-Remaining Life ND	$ (117,000)	$ -	$ (117,000)	$ -	$ (117,000)	
	NSPM-Remaining Life - King	$ (462,000)	$ -	$ (462,000)	$ -	$ (462,000)	
	NSPM-Remaining Life - Monticello Life Ext.	$ 665,000	$ -	$ 665,000	$ -	$ 665,000	
	NSPM-Remaining Life - Sherco 1	$ (528,000)	$ -	$ (528,000)	$ -	$ (528,000)	
	NSPM-Remaining Life- Sherco 2	$ (467,000)	$ -	$ (467,000)	$ -	$ (467,000)	
8	NSPM-Remaining Life - Sherco 3	$ (136,000)	$ -	$ (136,000)	$ -	$ (136,000)	
9	NSPM-RER Rider	$ (670,000)	$ -	$ (670,000)	$ -	$ (670,000)	
	NSPM-TCR-ND Rider Removal	$ (571,000)	$ -	$ (571,000)	$ -	$ (571,000)	
10	NSPM-TCR-ND Rider Removal	$ (7,000)	$ -	$ (7,000)	$ -	$ (7,000)	
	DTA - NOL Average Balance	$ -	$ (32,000)	$ (32,000)	$ -	$ (32,000)	
	DTA - State Tax Credit	$ -	$ (40,000)	$ (40,000)	$ -	$ (40,000)	
	DTA-Federal Tax Credit	$ -	$ (46,245,000)	$ (46,245,000)	$ -	$ (46,245,000)	
11	**Total Accum. Deferred Income Taxes**	**$ 196,603,000**	**$ (46,317,000)**	**$ 150,286,000**	**$ (1,237,958)**	**$ 149,048,042**	

(1) WP-Volume 3 III P1-1 Summary Test Year 2025
Differences due to rounding

PUBLIC DOCUMENT - TRADE SECRET DATA REDACTED

CASH WORKING CAPITAL

		(1)					
			Company Proposed			ND PSC	
		Lead/Lag Days	Dollars	Dollar x Days	Adjustments	Advocacy Staff	References
	Fuel Expense						
1	Coal/Rail Transport	16.950	$ 10,284,000	$ 174,313,800	$ -	$ 174,313,800	
2	Gas for Generation	38.810	$ 16,376,000	$ 635,552,560	$ -	$ 635,552,560	
3	Oil	11.500	$ -	$ -	$ -	$ -	
4	Nuclear and EOL	0.000	$ 7,882,000	$ -	$ -	$ -	
5	Nuclear Disposal	0.000	$ -	$ -	$ -	$ -	
6	**Total Fuel Expense**		**$ 34,542,000**	**$ 809,866,360**	**$ -**	**$ 809,866,360**	
	Purchased Power						
7	Purchases	39.100	$ 55,097,000	$ 2,154,292,700	$ -	$ 2,154,292,700	
8	Interchange	37.040	$ 12,043,000	$ 446,072,720	$ -	$ 446,072,720	
9	**Total Purchased Power**		**$ 67,140,000**	**$ 2,600,365,420**	**$ -**	**$ 2,600,365,420**	
	Labor & Related						
10	Regular Payroll	12.050	$ 27,738,000	$ 334,242,900	$ -	$ 334,242,900	
11	Incentive	250.470	$ 947,000	$ 237,195,090	$ (887,544)	$ 14,891,944	
12	Pension & Benefits	37.040	$ 4,776,000	$ 176,903,040	$ -	$ 176,903,040	
13	**Total Labor & Payroll**		**$ 33,461,000**	**$ 748,341,030**	**$ (222,303,146)**	**$ 526,037,884**	
14	All Other Operating Expenses	34.490	$ 53,692,000	$ 1,851,837,080	$ (169,835,968)	$ 1,682,001,112	
15	Property Taxes	357.730	$ 11,430,000	$ 4,088,853,900	$ (114,396)	$ 4,047,930,927	
16	Employer's Payroll Taxes	23.840	$ 1,922,000	$ 45,820,480	$ (2,231,998)	$ 43,588,482	
17	Gross Earnings Tax	39.860	$ 3,793,000	$ 151,188,980	$ -	$ 151,188,980	
18	Federal Income Taxes	36.250	$ (7,767,000)	$ (281,553,750)	$ 235,219,036	$ (46,334,714)	
19	State Income Taxes	36.250	$ (1,058,000)	$ (38,352,500)	$ 28,414,526	$ (9,937,974)	
20	State Sales Tax Customer Billings	0.000	$ -	$ -		$ -	
21	**Sub-Total**		**$ 62,012,000**	**$ 5,817,794,190**	**$ 50,642,623**	**$ 5,868,436,813**	
22	**Total Expenses**		**$ 197,155,000**	**$ 9,976,367,000**	**$ (171,660,523)**	**$ 9,804,706,477**	
23	Net Annual Expense		50.602	$ 27,332,512	$ (470,303)	$ 26,862,210	
	Revenues						
24	Retail Revenues	43.110	$ 231,596,000	$ 9,984,103,560	$ -	$ 9,984,103,560	
25	Late Payment	0.000	$ 528,000	$ -		$ -	
26	Misc. Services	43.110	$ 719,000	$ 30,996,090	$ -	$ 30,996,090	
	CIP Incentive	0.000	$ -	$ -			
27	Rentals	(41.110)	$ 344,000	$ (14,141,840)	$ -	$ (14,141,840)	
28	Interchange	37.040	$ 31,706,000	$ 1,174,390,240	$ -	$ 1,174,390,240	
29	Sales for Resale	30.750	$ 19,347,000	$ 594,920,250	$ -	$ 594,920,250	
30	Retail Rev. Lag Days	43.110	$ (40,000)	$ (1,724,400)	$ -	$ (1,724,400)	
31	MISO	14.000	$ 643,000	$ 9,002,000	$ -	$ 9,002,000	
32	Wholesale Lag Days	30.750	$ 17,477,000	$ 537,417,750	$ -	$ 537,417,750	
33	**Total Revenues**		**$ 302,320,000**	**$12,314,963,650**	**$ -**	**$ 12,314,963,650**	
34	Net Annual Amount		40.735	$ 33,739,626	$ 3,374	$ 33,743,000	
35	Expense/Revenue Factor			65.21%		65.07%	
36	Allocated Amount			$ 22,002,964		$ 21,956,570	
37	**Net CWC**			**$ (5,329,548)**	**$ 423,909**	**$ (4,905,639)**	

(1) Company Exhibit BCH-1 Schedule 8

PUBLIC DOCUMENT - TRADE SECRET DATA REDACTED

OTHER RATE BASE ITEMS

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	Materials and Supplies	$ 13,075,000	$ -	$ 13,075,000	
4	Fuel Inventory	$ 6,413,000	$ -	$ 6,413,000	
7	Non-Plant Assets/Liabilities	$ 7,655,000	$ -	$ 7,655,000	
10	Customer Advances	$ (91,000)		$ (91,000)	
13	Customer Deposits	$ (40,000)	$ -	$ (40,000)	
16	Prepaid and Others	$ 5,700,000	$ -	$ 5,700,000	
	Regulatory Amortizations				
19	AGIS Deferral Amortization	$ 5,481,000	$ (99,432)	$ 5,381,568	Set 8-63-71
20	PI EPU Deferral - ND	$ 2,722,000	$ (2,722,000)	$ -	Set 8-43
21	NOL Tax Reform ADIT ARAM- Total	$ 2,835,000		$ 2,835,000	
24	RER PTC Amortization - ND	$ (43,315,000)	$ -	$ (43,315,000)	Set 9-3
	(TRADE SECRET DATA BEGINS)				
[redacted]					
	(TRADE SECRET DATA ENDS)				
26	**Total**	**$ (33,175,000)**	**$ (1,923,432)**	**$ (35,098,432)**	Set 4-14
27	**Total Other Rate Base Items**	**$ (463,000)**	**$ (1,923,432)**	**$ (2,386,432)**	

(1) Company P1-1 Summary TY 2025
Company Exhibit BCH-1 Schedule 3A

PUBLIC DOCUMENT - TRADE SECRET DATA REDACTED

PUBLIC DOCUMENT - TRADE SECRET DATA REDACTED

OPERATING REVENUES

		(1) Company Present Rates	Schedule 4 Adjustments	Company Proposed	Adjustments	Present Rates ND PSC Advocacy Staff	References
	Electric Retail Revenues						
1	Energy Revenues - Res/Com/Ind	$ 166,668,337	$ -	$ 166,668,337		$ 166,668,337	
2	Public/Highway/Lighting	$ 1,331,180	$ -	$ 1,331,180		$ 1,331,180	
	Other Sales to Public Authority	$ 1,226,183	$ -	$ 1,226,163		$ 1,226,163	
	RER Rider	$ 4,939,920	$ (223,807)	$ 4,716,113		$ 4,716,113	
	TCR Rider	$ 3,936,491	$ (997,477)	$ 2,939,014		$ 2,939,014	
	Fuel Revenues	$ 53,494,011		$ 53,494,011		$ 53,494,011	
5		$ -					
6	**Total**	**$ 231,596,122**	**$ (1,221,304)**	**$ 230,374,818**	**$ -**	**$ 230,374,818**	
	Other Operating Revenues						
	Interchange	$ 20,950,859	$ -	$ 20,950,859		$ 20,950,859	
	WF Removal	$ (391,280)		$ (391,280)		$ (391,280)	
7	Connect Smart	$ 333	$ -	$ 333		$ 333	
8	Electric Revenue - Other	$ 527,937	$ -	$ 527,937	$ -	$ 527,937	
	Operating Revenues - Misc.	$ 715,165		$ 715,165		$ 715,165	
9	Operating Revenue- Interchange	$ -	$ -	$ -		$ -	
	Rentals	$ 343,540	$ -	$ 343,540		$ 343,540	
	Other Operating Revenues	$ 788,218	$ -	$ 788,218		$ 788,218	
	Excess Capacity Proceeds	$ (40,059)		$ (40,059)		$ (40,059)	
	Precedential Adjustments	$ 391,285	$ (391,285)	$ -		$ -	
	Depreciation Study-TD&G	$ -	$ 6,523	$ 6,523		$ 6,523	
	Remaining Life - Monticello	$ 663,713	$ (663,713)	$ (663,713)		$ (663,713)	
	Remaining Life- ND - All Other	$ 120,945	$ 120,945	$ 120,945		$ 120,945	
	Remaining Life - Sherco 1/2/3 - King	$ -	$ 1,587,071	$ 1,587,071		$ 1,587,071	
	Benson Biomass	$ 113,003		$ 113,003		$ 113,003	
10	Trading Revenue	$ -	$ -	$ -		$ -	
11	Transmission Revenue	$ 17,483,439	$ -	$ 17,483,439		$ 17,483,439	
	Fuel Revenue	$ 10,729,780		$ 10,729,780		$ 10,729,780	
	Electric Revenue - Asset Based	$ 16,485,307		$ 16,485,307		$ 16,485,307	
	Electric Revenue - Non-Asset Based	$ 2,604,860	$ -	$ 2,604,860		$ 2,604,860	
12	PI EPU Interchange	$ (36,629)	$ -	$ (36,979)		$ (36,979)	
	(TRADE SECRET DATA BEGINS)						
[redacted]							
	(TRADE SECRET DATA ENDS)						
	TCR Rider Removal	$ -	$ (8,186,136)	$ (8,186,136)		$ (8,186,136)	
13	Interchange Decommissioning	$ (562,862)	$ -	$ (562,862)		$ (562,862)	
	Miscellaneous	$ (783,925)	$ -	$ -		$ -	
14	**Sub-Total - Unadjusted**	**$ 70,065,000**	**$ (7,526,595)**	**$ 62,537,322**	**$ 38,629**	**$ 62,575,951**	
22	**Total Company Operating Revenues**	**$ 301,661,122**	**$ (8,748,982)**	**$ 292,912,140**	**$ 38,629**	**$ 292,950,769**	

(1) Company WP - Vol. 3 IV R1 Revenue Requirement Summary
Company WP - Vol. 3 IV R4 Other Revenue

PUBLIC DOCUMENT - TRADE SECRET DATA REDACTED

Northern States Power Co. Electric - ND
Test Year Ending 12/31/2025

ND Public Service Commission
Case No. PU-24-376

Schedule DM-11

Operating & Maintenance Expenses
Workpaper - Non-Labor
Three-Year Normalize

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Fuel & Purchased Energy				
1	Fuel	$ 82,957,000	$ -	$ 82,957,000	
2	Deferred Fuel	$ 355,000		$ 355,000	
3	Variable Production Fuel	$ 734,000		$ 734,000	
		$ 84,046,000	**$ -**	**$ 84,046,000**	
	Production				
4	Fixed	$ 31,067,000	$ -	$ 31,067,000	
5	Fixed IA Investment	$ -			
6	Fixed IA O&M	$ 3,366,000	$ -	$ 3,366,000	
7	Variable	$ 230,000	$ -	$ 230,000	DM-13
8	Variable IA O&M	$ 456,000	$ -	$ 456,000	
9	Purchased Demand	$ 8,228,000	$ -	$ 9,827,919	
10	Regional Markets	$ 686,000	$ -	$ 686,000	DM-13
		$ 44,033,000	**$ (491,934)**	**$ 43,498,422**	
11	Transmission IA	$ 9,688,000	$ -	$ 9,688,000	
12	Transmission	$ 9,823,000	$ (1,326,654)	$ 8,496,346	DM-14
		$ 19,511,000	**$ (1,327,068)**	**$ 18,183,932**	
13	Distribution	$ 7,391,000	$ (133,596)	$ 7,257,404	DM-15
14	Customer Accounting	$ 5,367,000	$ (929,513)	$ 4,437,487	DM-16
15	Customer Service / Information	$ 351,000	$ (125,031)	$ 225,969	DM-17
16	Sales, Economic Develop / Other	$ 395,000	$ (290,323)	$ 104,677	DM-18
17	Admininistrative/General	$ 20,914,000	$ (1,707,058)	$ 19,206,942	DM-19
18	**Total**	**$ 182,008,000**	**$ (5,047,167)**	**$ 176,960,833**	
	Subtotal - DR-4-17	$ 97,962,000	$ (5,047,167)	$ 92,914,833	

(1) Exhibit BCH-1 Schedule 3

Acct No.		Actual 2022	Actual 2023	Actual 2024	Test Year 2025	Normalize	<15% $	%
	Administrative/General							
921	Office Supplies	$ 4,210,888	$ 4,430,454	$ 4,487,969	$ 4,610,115	$ 4,376,437	$ (233,678)	-5.069%
922	A&G Transfer /Credit	$ (3,869,193)	$ (4,037,918)	$ (5,089,570)	$ (5,858,612)	$ (4,332,227)	$ 1,526,385	-26.054%
923	Outside Services	$ 1,262,922	$ 1,254,149	$ 1,578,440	$ 1,866,407	$ 1,365,170	$ (501,237)	-26.856%
924	Property Insurance	$ 603,788	$ 448,359	$ 638,863	$ 597,211	$ 563,670	$ (33,541)	-5.616%
925	Injury & Damages	$ 1,078,064	$ 904,030	$ 1,074,751	$ 1,907,310	$ 1,018,948	$ (888,362)	-46.577%
929	Duplicate Charge Credit	$ (369,330)	$ (402,129)	$ (406,681)	$ (415,725)	$ (392,713)	$ 23,012	-5.535%
930.2	Misc. General Exp.	$ 322,156	$ 307,026	$ 273,918	$ 646,895	$ 301,033	$ (345,862)	-53.465%
							$ (209,075)	
	Less Inflation - 1.81%						$ (205,358)	
	Sales Economic Development							
912	Sales Demo & Sales	$ 90,119	$ 176,529	$ 56,350	$ 394,010			
	Less Economic Donations				$ (113,000)			
		$ 90,119	$ 176,529	$ 56,350	$ 281,010	$ 107,666	$ (173,344)	-61.686%
916	Misc. Sales Expense	$ 462	$ 1,106	$ 531	$ 539	$ 700	$ 161	29.808%
							$ (173,183)	
	Less Inflation 1.81%						$ (170,104)	
	Customer Service & Information							
908	Customer Assistant Expense	$ 86,503	$ 259,915	$ 262,542	$ 245,179			
	Less Electric Vehicle Program		$ (131,000)	$ (131,000)	$ (131,000)			
		$ 86,503	$ 128,915	$ 131,542	$ 114,179	$ 115,653	$ 1,474	1.291%
909	Customer Service Instruction Advertising	$ 102,976	$ 108,779	$ 91,866	$ 70,506	$ 101,207	$ 30,701	43.544%
910	Misc. Customer Service	$ 7,114	$ 23,544	$ 18,121	$ 35,496	$ 16,260	$ (19,236)	-54.193%
							$ 11,465	
	Less Inflation 1.81%						$ 11,261	
	Customer Accounting							
902	Customer Accounting Meter Read	$ 1,436,260	$ 1,467,416	$ 1,252,313	$ 2,243,080	$ 1,385,330	$ (857,750)	-38.240%
903	Cust Acct Records & Coll	$ 1,539,553	$ 1,623,690	$ 1,609,478	$ 1,596,510	$ 1,590,907	$ (5,603)	-0.351%
905	Customer Acct Misc	$ 19,482	$ 18,803	$ 19,433	$ 27,899	$ 19,239	$ (8,660)	-31.039%
							$ (866,410)	
	Less Inflation 1.81%						$ (851,007)	
	Distribution Expense							
586	Distribution Operation Meter Exp	$ 24,184	$ 101,611	$ 174,704	$ 150,757	$ 100,166	$ (50,591)	-33.558%
587	Distribution Operation Customer Install	$ 168,089	$ 251,242	$ 181,004	$ (55,483)	$ 200,112		
588	Distribution Operation Misc. Exp	$ 1,164,628	$ 1,100,987	$ 1,173,679	$ 1,029,686	$ 1,146,431	$ 116,745	11.338%
589	Distribution Rents	$ 190,282	$ 202,809	$ 230,506	$ 231,310	$ 207,866	$ (23,444)	-10.135%
							$ (50,591)	
	Less Inflation 1.81%						$ (49,691)	
	Transmission Expense							
561.4	Load Dispatch-Sch	$ 484,197	$ 424,886	$ 505,977	$ 456,498	$ 471,687	$ 15,189	3.327%
561.8	Re/Plan/Standards	$ 187,033	$ 190,406	$ 231,668	$ 228,629	$ 203,036	$ (25,593)	-11.194%
562	Trans Operations Station Exp	$ 301,761	$ 337,965	$ 341,572	$ 163,120	$ 327,099	$ 163,979	100.527%
565	Purchased Power	$ 15,143,043	$ 13,868,021	$ 16,064,299	$ 6,541,664	$ 15,025,121	$ 8,483,457	129.683%
566	Trans Oper Misc Exp	$ 514,259	$ 490,320	$ 627,216	$ 10,204,206	$ 543,932	$ (9,660,274)	-94.670%
567	Trans Rent	$ 73,500	$ 76,016	$ 91,286	$ 87,899	$ 80,267	$ (7,632)	-8.682%
							$ (1,012,838)	
	Less Inflation 1.81%						$ (994,832)	
	Power Production							
502	Steam Expenses	$ 1,043,072	$ 1,030,730	$ 948,541	$ 1,226,258	$ 1,007,448	$ (218,810)	-17.844%
505	Steam Gen Elec Exp Major	$ 278,088	$ 304,707	$ 302,741	$ 62,375	$ 295,179	$ 232,804	373.232%
506	Misc. Steam Power Exp	$ 857,287	$ 791,658	$ 775,233	$ 691,645	$ 808,059	$ 116,414	16.832%
507	Steam Pwr Gen Rents	$ 84,247	$ 86,916	$ 110,096	$ 113,903	$ 93,753	$ (20,150)	-17.690%
520	Nuclear Steam Exp	$ 3,011,629	$ 3,246,410	$ 3,768,812	$ 3,485,613	$ 3,342,284	$ (143,329)	-4.112%
523	Nuclear Elec Exp	$ 174,103	$ 155,624	$ 163,262	$ 183,229	$ 164,330	$ (18,899)	-10.315%
525	Nuclear Gen Rents	$ 316,325	$ 343,962	$ 414,470	$ 396,565	$ 358,252	$ (38,313)	-9.661%
538	Hyd Oper Elec Exp	$ 18,406	$ 1,049	$ 774	$ 7,134	$ 6,743	$ (391)	-5.481%
540	Hyd Oper Rents	$ 1,527	$ 2,303	$ 1,900	$ 1,189	$ 1,910	$ 721	60.639%
548	Other Oper Gen Exp	$ 481,325	$ 480,014	$ 515,778	$ 283,128	$ 492,372	$ 209,244	73.905%
							$ 320,223	
	Less Inflation 1.81%						$ 314,530	
	Total						**$ (1,945,201)**	

FUEL AND PURCHASED ENERGY

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 84,046,000**	**$ -**	**$ 84,046,000**	
2		$ -	$ -	$ -	
3	Precedential Adjustments	$ -	$ -	$ -	
4		$ -	$ -	$ -	
5	**Adjusted Balance**	**$ 84,046,000**	**$ -**	**$ 84,046,000**	

(1) Exhibit BCH-1 Schedule 6

POWER PRODUCTION

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 44,556,000**	$ (491,934)	**$ 44,064,066**	Set 8-8
2	Precedential Adjustments WP-A5	$ (36,950)	$ -	$ (36,950)	
	Precedential Adjustments WP-A6	$ (60,437)	$ -	$ (60,437)	
	Precedential Adjustments WP-A7	$ (167,127)	$ -	$ (167,127)	
3	Long Term Incentive Removal - WP-A4	$ (213,130)	$ -	$ (213,130)	
	Rider TCR	$ (44,000)	$ -	$ (44,000)	
4	Labor Adjustment	**$ -**	$ -	$ -	
		$ (477,644)			
5	Incentive Compensation	$ -	$ -	$ -	
6	Rider - Renewable Energy Rider (RER)	$ (44,000)	$ -	$ (44,000)	
7		$ -	$ -	$ -	
8	**Adjusted Balance**	**$ 44,034,356**	**$ (491,934)**	**$ 43,498,422**	

(1) Exhibit BCH-1 Schedule 6

WP-A-5

TRANSMISSION EXPENSES

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 26,294,000**		**$ 26,294,000**	
	Transmission Cost Recover Rider (TCR)	$ (6,783,000)		$ (6,783,000)	
	Adjusted Balance	**$ 19,511,000**		**$ 19,511,000**	
2	Transmission - Non-Labor	$ 18,332,727	$ (1,326,654)	**$ 17,006,073**	DM-11
3	Labor	$ 1,177,859	$ -	$ 1,177,859	
4			$ -		
5	**Adjusted Balance**	**$ 19,510,586**	**$ (1,326,654)**	**$ 18,183,932**	

(1) Exhibit BCH-1 Schedule 6

DISTRIBUTION EXPENSES

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 7,391,214**		**$ 7,391,214**	
2		$ -	$ -	$ -	
3	Non-Labor	$ 4,647,431	$ (133,810)	$ 4,513,621	
4	Labor	$ 2,743,783	$ -	$ 2,743,783	
5	Storm Damage	$ -	$ -	$ -	Set 8-35
6	Vegetation Management	$ -	$ -	$ -	Set 8-36
7		$ -	$ -	$ -	
8	Adjustments - Other	$ -	$ -	$ -	
9	**Adjusted Balance**	**$ 7,391,214**	**$ (133,810)**	**$ 7,257,404**	

(1) Exhibit BCH-1 Schedule 6

(2) Vegetation Management - Forecast

CUSTOMER ACCOUNTING EXPENSE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 5,146,000**		**$ 5,146,000**	
2	EBadDebt	$ 221,000	$ -		
3	**Adjusted Balance**	**$ 5,367,000**	**$ -**	**$ -**	
		$ -	$ -		
	Non-Labor	$ 4,342,391	$ (929,604)	$ 3,412,787	
4	Labor	$ 1,024,700	$ -	$ 1,024,700	
5					
6	Adjustments - Other	$ -	$ -	$ -	
7	**Adjusted Balance**	**$ 5,367,091**	**$ (929,604)**	**$ 4,437,487**	

(1) Company Exhibit BCH-1 Schedule 6

(2) $ 147,931

CUSTOMER SERVICE & INFORMATION EXPENSE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 351,000**	$ (131,000) $ -	**$ 220,000**	Set 8-77
2	Adjustments	$ -		$ -	
3	**Adjusted Balance**	**$ 351,000**	**$ (131,000)**	**$ 220,000**	
	Non-Labor	$ 302,364	$ 5,788	$ 308,152	
	Labor	$ 48,817	$ -	$ 48,817	
	Adjusted Balance	**$ 351,181**	**$ (125,212)**	**$ 225,969**	

(1) Exhibit BCH-1 Schedule 6

SALES, ECONOMIC DEVELOPMENT AND OTHER EXPENSES

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 282,000**	**$ -**	**$ 282,000**	
2	Economic Develop Donations	$ 113,000	$ (113,000)	$ -	WP A13 5-29/51
3	**Adjusted Balance**	**$ 395,000**	**$ (113,000)**	**$ 282,000**	
	Non-Labor	$ 373,945	$ (176,872)	$ 197,073	
	Labor	$ 20,604	$ -	$ 20,604	
	Adjusted Balance	**$ 394,549**	**$ (289,872)**	**$ 104,677**	

(1) Exhibit BCH-1 Schedule 6

ADMINISTRATIVE & GENERAL EXPENSES

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 21,269,000**	$ -	**$ 21,269,000**	
2		$ -	$ -		
	Precedential Adjustments				
7	NSPM - Advertising -P	$ (242,000)	$ -	$ (242,000)	WP-A1
8	NSPM - Association Dues - P	$ (36,000)	$ (10,844)	$ (46,844)	WP-A2
9	NSPM - Aviation - RM	$ (121,000)	$ (121,000)	$ (242,000)	WP-A10
10	NSPM - Customer Deposits - P	$ 3,000	$ -	$ 3,000	WP-A3
	NSPM - Incentive Pay - LT - P	$ (938,000)		$ (938,000)	WP-A4
11	NSPM - Other	$ -	$ -	$ -	
12	NSPM - Pension Non-Qualified SERP - P	$ (2,000)	$ -	$ (2,000)	WP-A8
13	**Sub- Total**	**$ (1,336,000)**	**$ (131,844)**	**$ (1,467,844)**	
14	Dues - Chamber of Commerce - RM	$ 33,000	$ (33,000)	$ -	WP-A12
15	Foundation and Other Donations - RM	$ 299,000	$ (299,000)	$ -	WP-A13
	LTI-Environmental Incentive - RM	$ 211,000	$ (211,000)	$ -	WP-A16
	LTI-Time Based Incentive - RM	$ 589,000	$ (589,000)	$ -	WP-A17
16	Incentive Compensation - RM	$ (151,000)	$ (87,544)	$ (238,544)	WP-A15
	Sub-Total	**$ 981,000**	**$ (1,219,544)**	**$ (238,544)**	
17	**Adjusted Balance**	**$ 20,914,000**	**$ (1,707,058)**	**$ 19,206,942**	
	Non-Labor	$ 8,304,533	$ (355,670)	$ 7,948,863	
	Labor	$ 12,609,298	$ -	$ 12,609,298	
	Adjusted Balance	**$ 20,913,831**	**$ (355,670)**	**$ 20,558,161**	
(1)	Exhibit BCH-1 Schedule 4 and 6				Set-9-48
					Set 9-50
	Precedential Adjustments	$ (1,215,000)			Set 9-49
	Ratemaking Adjustments	$ 860,000			

PUBLIC DOCUMENT - TRADE SECRET DATA REDACTED

DEPRECIATION EXPENSE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 69,394,581**	$ (332,106)	**$ 68,705,659**	Set 8-67
	Larimore Station		$ (356,816)		Set 12-15
2	**Precedential Adjustments**				
	Pre-Funded Production - Base Load	$ 5,864	$ -	$ 5,864	
	Pre-Funded Production - Peaking	$ 703	$ -	$ 703	
	Production - Base Load Energy	$ (901,865)	$ -	$ (901,865)	
	Production - Peaking	$ (108,062)	$ -	$ (108,062)	
3	**Total Precedential Adjustments**	**$ (1,003,360)**	$ -	**$ -**	Set 8-53
	(TRADE SECRET DATA BEGINS)				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	**(TRADE SECRET DATA ENDS)**	$ -	$ -	$ -	
6		$ -	$ -	$ -	
	Depreciation Study				
7	Remaining Life - All Other	$ 743,190	$ -	$ 743,190	
	Remaining Life - Base Load	$ 6,443,224	$ -	$ 6,443,224	
8	TD&G	$ (88,590)	$ -	$ (88,590)	Set 8-53
	Total Depreciation Study	**$ 7,097,824**			
9	Rider - RER	$ (81,031)	$ -	$ (81,031)	
10	Rider - TCR	$ (405,584)	$ -	$ (405,584)	
	Total Rider Adjustments	**$ (486,615)**			
11	**Adjusted Balance**	**$ 75,002,430**	**$ (707,179)**	**$ 74,295,251**	

(1) Exhibit BCH-1 Schedule 6

PUBLIC DOCUMENT - TRADE SECRET DATA REDACTED

Northern States Power Co. Electric - ND
Test Year Ending 12/31/2025

ND Public Service Commission
Case No. PU-24-376

Schedule DM-21

AMORTIZATION EXPENSE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 327,000**		**$ 327,000**	
	Precedential Adjustments				
	PTC	$ 10,440,000		$ 10,440,000	Set 13-1
2	Prairie Island EPU Amort.	$ 308,000	$ (308,000)	$ -	Set 8-43
3		$ -	$ -	$ -	
4	NOL ADIT ARAM	$ 183,000	$ -	$ 183,000	
5	AGIS Deferral	$ 997,000	$ (399,048)	$ 597,952	Set 8- 63/70/71
6		$ -	$ -	$ -	
7	Rate Case Expenses	$ 468,000	$ -	$ 468,000	Set 8-44
8	**Adjusted Balance**	**$ 12,723,000**	**$ (707,048)**	**$ 12,015,952**	

(1) Exhibit BCH-1 Schedule 6

PUBLIC DOCUMENT - TRADE SECRET DATA REDACTED

TAXES OTHER THAN INCOME TAXES

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Property Taxes				
1	**Unadjusted Balance**	**$ 11,470,000**	**$ (114,396)**	**$ 11,355,604**	
2	Precedential Adjustments	$ (40,000)	$ -	$ (40,000)	
3	Rider TCR	$ (151,000)	$ -	$ (151,000)	
4	**Adjusted Balance**	**$ 11,279,000**	**$ (114,396)**	**$ 11,164,604**	
	Deferred Income Tax and ITC				
5	**Unadjusted Balance**	$ (10,448,000)	$ -	$ (10,448,000)	
	Precedential Adjustments	$ (610,000)	$ -	$ (610,000)	
	PTC Transferability	$ 904,000	$ -	$ 904,000	
	(TRADE SECRET DATA BEGINS)				
	[redacted]				
	(TRADE SECRET DATA ENDS)				
	Remaining Life- All Other	$ (233,000)		$ (233,000)	
	Remaining Life- Base Load	$ (1,856,000)	$ -	$ (1,856,000)	
	PI EPU Amortization	$ (112,000)	$ 112,000	$ -	
	Rider - RER	$ (1,398,000)	$ -	$ (1,398,000)	
	Depreciable Study - TDG	$ 28,000	$ -	$ 28,000	
	Rider - TCR	$ (356,000)	$ -	$ (356,000)	
6	NOL	$ 2,762,000	$ -	$ 2,762,000	
7	**Adjusted Balance**	**$ (11,319,000)**	**$ 96,904**	**$ (11,222,096)**	
	Payroll and Other				
17	Unadjusted Balance	$ 1,923,000	$ (92,624)	$ 1,830,376	
18	Aviation	$ (1,000)	$ (1,000)	$ (2,000)	
19	**Adjusted Balance**	**$ 1,922,000**	**$ (93,624)**	**$ 1,828,376**	
20	**Total Taxes Other Than Income**	**$ 1,882,000**	**$ (111,116)**	**$ 1,770,884**	

(1) Exhibit BCH-1 Schedule 6
Differences due to rounding

Property Tax Rate 0.64490%

PUBLIC DOCUMENT - TRADE SECRET DATA REDACTED

STATE INCOME TAXES

		(1) Company Proposed	Adjustments	Present Rates ND PSC Advocacy Staff	References
1	Total Operating Revenues	$ 292,913,000	$ 37,769	$ 292,950,769	
2	Less: Operating Expenses	$ (182,009,000)	$ 4,924,209	$ (177,084,791)	
3	**Balance**	**$ 110,904,000**	**$ 4,961,978**	**$ 115,865,978**	
4	Depreciation Expense	$ (75,002,000)	$ 706,749	$ (74,295,251)	
5	Amortization Expense	$ (12,722,000)	$ 706,048	$ (12,015,952)	
6	Total Taxes Other Than Income	$ (1,881,000)	$ 110,116	$ (1,770,884)	
7	**Balance**	**$ 21,299,000**	**$ 6,484,891**	**$ 27,783,891**	
	Tax Additions				
8	Book Depreciation	$ 75,002,000	$ (706,749)	$ 74,295,251	
9	Deferred Income Taxes and ITC	$ (11,319,000)	$ 96,904	$ (11,222,096)	
10	Nuclear Fuel Burn	$ 7,526,000	$ -	$ 7,526,000	
11	Nuclear Outage Accounting	$ 3,763,000	$ -	$ 3,763,000	
12	Avoided Interest	$ 3,554,000	$ (29)	$ 3,554,000	
13	Other Book Additions	$ 491,000	$ -	$ 491,000	
14	**Total Tax Additions**	**$ 79,017,000**	**$ (609,845)**	**$ 78,407,155**	
	Tax Deductions				
15	Total Rate Base	$ 816,976,000	$ (22,022,644)	$ 794,953,356	
16	Weighted Cost of Debt	2.148%	1.990%	2.148%	
17	Debt Interest Expense	$ 17,564,984	$ (487,825)	$ 17,077,159	
18	Nuclear Outage Accounting	$ 3,952,000	$ -	$ 3,952,000	
19	Tax Depreciation and Removals	$ 96,133,000	$ -	$ 96,133,000	
	NOL Utilized	$ 243,000	$ -	$ 243,000	
20	Other Tax / Book Timing Differences	$ (1,939,000)	$ -	$ (1,939,000)	
21	**Total Tax Deductions**	**$ 115,953,984**	**$ (487,825)**	**$ 115,466,159**	
22	State Taxable Income	$ (15,637,984)	$ (8,000)	$ (9,275,112)	
23	State Income Tax Rate	4.310%	4.310%	4.310%	
24	State Income Tax - before Credit	$ (673,997)	$ (345)	$ (399,757)	
25	Less State Tax Credit Applied	$ (158,000)	$ -	$ (158,000)	
26	**State Income Tax**	**$ (831,997)**	**$ 274,240**	**$ (557,757)**	

(1) Exhibit BCH-1 Schedule 3

FEDERAL INCOME TAXES

		(1) Company Proposed	Adjustments	Present Rates ND PSC Advocacy Staff	References
1	Federal Taxable Income	**$ (15,637,984)**	$ 6,362,872	**$ (9,275,112)**	WP-A23
2	Less State Tax	$ 831,997	$ (274,240)	$ 557,757	
3	Adjusted Federal Taxable Income	$ (14,805,987)	$ 6,088,632	$ (8,717,355)	
4	Federal Tax Rate	21.00%		21.00%	
5	Federal Income Tax - before Credit	$ (3,109,257)	$ 1,278,613	$ (1,830,645)	
6	Federal Tax Credits	$ (2,841,000)	$ -	$ (2,841,000)	NDPSC 5-44
7	**Federal Income Tax**	**$ (5,950,257)**	**$ 1,278,613**	**$ (4,671,645)**	

(1) Exhibit BCH-1 Schedule 3

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
2025 Electric Rate Increase
Application

Case No. PU-24-376

DECLARATION OF DANTE MUGRACE

Dante Mugrace, under penalty of perjury, states that he has read the testimony and any exhibits submitted in the above captioned matter 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.

Signed on the 8 day of July, 2025 at Toms River, NJ.

Dante Mugrace

Dante Mugrace