STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
2021 Natural Gas Rate Increase
Application

Case No. PU-21-381

AFFIDAVIT OF SERVICE BY ELECTRONIC MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Geralyn R. Schmaltz deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **1st day of March 2022,** she sent an electronic message to **eight** addressees, each including an electronic copy in portable document format of:

- **Prefiled Direct Testimony of Karl Pavolic**
- **Prefiled Direct Testimony of Marlon Griffing**
- **Prefiled Direct Testimony of Dante Mugrace**

The electronic mail was addressed as follows:

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

Subscribed and sworn to before me
this **1st day of March 2022.**

SEAL

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

Notary Public

STATE OF NORTH DAKOTA

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AUTHORITY TO INCREASE RATES FOR NATURAL GAS SERVICE IN NORTH DAKOTA

Case No. PU-21-381

DIRECT TESTIMONY OF KARL R. PAVLOVIC

Submitted on Behalf of the Advocacy Staff of the North Dakota Public Service Commission

March 1, 2022

DIRECT TESTIMONY OF

KARL R. PAVLOVIC

QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brookes Avenue, Gaithersburg, MD 20877. I am a Senior Consultant with and the Managing Director of PCMG and Associates LLC.

Q. PLEASE DESCRIBE PCMG.

A. PCMG and Associates LLC (PCMG) is an association of experts in economics, accounting, finance, and utility regulation and policy, with over 75 years collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water, and wastewater utilities. PCMG began operation on January 1, 2015. During its most recent year of operation, PCMG has provided assistance to counsel and/or testimony in regulatory proceedings before Federal Energy Regulatory Commission, the Pennsylvania Public Service Commission, the Maine Public Utilities Commission, the Massachusetts Department of Public Utilities, the New Jersey Board of Public Utilities, and the Hawaii Public Utilities Commission. PCMG is currently providing assistance to the Hawaii Division of Consumer Advocate, the Maine Office of the Public Advocate, the Massachusetts Office of the Attorney General, the New Jersey Division of Rate Counsel, and the Pennsylvania Office of Consumer Advocate.

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Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A to my testimony summarizes my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Exhibit KRP-1 contains a complete list of my engagements as an expert and/or expert witness in matters before state and federal regulatory agencies. I have submitted testimony to the Federal Communications Commission, the Federal Energy Regulatory Commission, the Alaska Public Utilities Commission, the Alberta Utilities Commission, the Corporation Commission of the State of Kansas, the Delaware Public Service Commission, the Hawaii Public Utilities Commission, the Pennsylvania Public Service Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Massachusetts Department of Public Utilities, the North Dakota Public Service Commission, the Maine Public Utilities Commission, and the Public Service Commission of the District of Columbia.

Q. IN WHICH PROCEEDINGS HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?

A. I appeared on behalf of the North Dakota Public Service Commission Advocacy Staff in Case No. PU-12-813 Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota, in Case No. PU-17-295 Montana-Dakota Utilities Co., for Authority to Establish Increased Rates for Natural Gas Service,

and in Case PU-20-441 Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS?

A. I received undergraduate and graduate degrees in Philosophy from Yale College and Purdue University. By education and professional experience I have expertise in formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling. I have knowledge and experience in the areas of commercial and industrial operations in the energy, transportation, and telecommunications industries and am familiar with a wide range of experimental and investigative methods in science and engineering.

Q. PLEASE SUMMARIZE YOUR ELECTRIC AND GAS REGULATORY EXPERIENCE.

For most of my career I have performed analyses and submitted testimony regarding electric and gas utility least-cost planning, reliability, cost of service, rate design, and weather-emergency response. Specifically regarding gas utilities, I have testified on: (a) integrated resource planning, (b) class cost of service and rate design, and (c) various infrastructure operating expense and investment recovery mechanisms.

I. PURPOSE AND ORGANIZATION

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Commission's Advocacy Staff to address Northern States Power (NSP) assertions and proposals in this proceeding regarding (1) depreciation, (2) North Dakota class cost of service study, (3) North Dakota class revenue responsibility distribution, and (4) North Dakota rate design.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have included the following four exhibits:

Exhibit No. KRP-1: Qualifications

Exhibit No. KRP-2: Corrected NDPSC-2-001 Att A CCOSS TRADE SECRET IN ENTIRETY

Exhibit No. KRP-3: Corrected Exhibit CJB-1, Schedule 4

Exhibit No. KRP-4: Corrected Exhibit CJB-1, Schedule 5

II. SUMMARY OF TESTIMONY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony finds the following.

- NSP's proposed depreciation rates are reasonably well supported by the dismantling and depreciation studies.
- The NSP CCOSS' use of a minimum size study to classify a portion of distribution mains as customer-related is inconsistent with the principle of cost causation.
- The NSP CCOSS' use of average and peak demand to allocate transmission, regulator station costs and average and excess demand to allocate distribution mains is inconsistent with the principle of cost causation.

I recommend that the Commission:

- Direct that NSP's distribution mains be classified as wholly demand-related with no customer-related component, consistent with the CCOSS' classification of

production plant, storage plant, transmission plant and regulator stations as only demand-related.

- Direct that NSP's transmission, regulator stations and distribution mains costs be allocated using the Design Day demand method, consistent with the CCOSS' allocation of production and storage costs.

III. DISCUSSION

A. NOTH DAKOTA DEPRECIATION

Q. PLEASE SUMMARIZE NSP'S NORTH DAKOTA DEPRECIATION PROPOSALS.

A. NSP proposes changes to the depreciation parameters (service life and net salvage) for three groups of assets: (1) gas production and storage, (2) gas transmission, distribution and general, and (3) allocated common.[1] The proposed changes to asset service life and net salvage parameters result in reductions to production and storage depreciation expense of $31,918 and allocated common depreciation expense of $49,561 and an increase in transmission, distribution and general depreciation expense of $62,411, producing an overall net reduction of North Dakota test year expense of $19,038.[2] The depreciation proposals rest upon a 2020 dismantling cost study[3] and a depreciation study of NSP's gas and common plant account historical data and balances as of January 1, 2017.[4] The depreciation study was performed using the straight-line, broad group life, remaining life procedure.[5]

[1] Direct Testimony of Laurie J. Wold, page 2, lines 14-15 and Table 1 2022 Test Year Depreciation Expense Changes.
[2] Direct Testimony of Laurie J. Wold, page 2 Table 1; see also page 11 Table 2.
[3] Direct Testimony of Laurie J. Wold, Exhibit LJW-1, Schedule 5.
[4] Direct Testimony of Laurie J. Wold, Exhibit LJW-1, Schedule 8.
[5] Direct Testimony of Laurie J. Wold, Exhibit LJW-1, Schedule 8, page 10.

Q. WHAT IS YOUR ASSESSMENT OF NSP'S PROPOSED DEPRECIATION RATES?

A. The parameters underlying the calculation of NSP's proposed depreciation rates are reasonably well supported by the dismantling study and the depreciation study's life, net salvage, and remaining life analyses.[6] I have no proposed changes to the depreciation rates.

B. NORTH DAKOTA COST OF SERVICE AND RATE DESIGN

Q. PLEASE SUMMARIZE NSP'S NORTH DAKOTA COST OF SERVICE AND RATE DESIGN PROPOSALS.

A. Based on a forecasted 2022 calendar year embedded class cost of service study[7] and a revenue requirement distribution to classes based on the ratemaking principles of cost causation, competitive service pricing and moderation of rate increases,[8] and the cost study's class customer cost results, NSP proposes the following changes in customer rates in Table 1.

[6] Direct Testimony of Laurie J. Wold, Exhibit LJW-1, Schedule 9.
[7] Direct Testimony of Christopher J. Barthol, page 1, lines 24-26.
[8] Direct Testimony of Christopher J. Barthol, page 28, lines 1-5.

Table 1: NSP Rate Design Proposals

Residential (RC 401): 15.0% revenue increase with Delivery Service Charge increased 31% from $18.48/month to $24.28/month;[9]
Commercial and Industrial (RC 403, 410): 10.5% revenue increase with (a) Basic Service Charge increased 16.7% from $30.00/month to $35.00/month and (b) Distribution Charge increased 35.4% from $0.10800/therm to $0.14627/therm;[10]
Small Interruptible (RC 404): 10.0% revenue increase with (a) Basic Service Charge increased 33.3% from $75.00/month to $100.00/month and (b) Distribution Charge increased 28.2% from $0.08800/therm to $0.111279/therm;[11]
Large Interruptible (RC 405): 10.0% revenue increase with (a) Basic Service Charge increased 0.0% from $275.00/month to $275.00/month and (b) Distribution Charge increased 52.58% from $0.05120/therm to $0.07812/therm;[12]

NORTH DAKOTA CLASS COST OF SERVICE STUDY

Q. HAVE YOU EXAMINED NSP'S NORTH DAKOTA CLASS COST OF SERVICE STUDY (CCOSS)?

A. Yes. NSP's CCOSS is a multi-tabbed Excel spreadsheet file[13] that follows the standard class cost of service procedure of first functionalizing costs, second classifying the functionalized costs as directly assignable to certain classes or as demand-related, customer-related or commodity-related, and third allocating to customer classes those functionalized costs that are classified as demand-, customer-, or commodity-related.[14]

Q. HAVE YOU FOUND ANY ERRORS IN THE CCOSS' FUNCTIONALIZATION OF NSP'S GAS COSTS?

A. No. The CCOSS properly functionalizes NSP's gas costs using the FERC Gas Uniform System of Accounts (USoA).

[9] Direct Testimony of Christopher J. Barthol, page 31, Table 6; Exhibit CJB-1, Schedule 7.
[10] Direct Testimony of Christopher J. Barthol, page 31, Table 6; Exhibit CJB-1, Schedule 7.
[11] Direct Testimony of Christopher J. Barthol, page 31, Table 6; Exhibit CJB-1, Schedule 7.
[12] Direct Testimony of Christopher J. Barthol, page 31, Table 6; Exhibit CJB-1, Schedule 7.
[13] PU-21-381 NDPSC-2-001 Att A_Class Cost of Service Study TRADE SECRET IN ENTIRETY.xlsx.
[14] See NARUC Gas Distribution Rate Design Manual (NARUC Gas Manual), 1989, pages 22-24.

Q. HAVE YOU FOUND ANY ERRORS IN THE CCOSS' CLASSIFICATION OF NSP'S FUNCTIONALIZED GAS COSTS?

A. Yes. The CCOSS relies on a minimum system study to classify NSP's distribution mains costs as 66.1% customer-related and the remaining 33.9% classified as 11.7% sales-related and 22.2% excess demand-related.[15] NSP's minimum system study is based on the minimum size main theory which "assumes that there is a … minimum size main necessary to connect the customer to the system" (emphasis added) [16] Under the minimum size theory, "all distribution mains are priced out at the historic unit cost of the smallest main installed, and assigned as customer costs."[17] The NARUC manual noted in 1989, the date of publication, that the minimum size main theory was controversial.[18] While this method of distribution mains classification was once, but no longer is, widespread among gas distribution utilities, there is, from the perspective of cost causation, no theoretical or practical justification for minimum size mains classification.

Q. WHAT IS THE COST CAUSATION THAT DEFINES THE CLASSIFICATION OF GAS DISTRIBUTION ACCOUNTS AS CUSTOMER-RELATED?

A. As clearly articulated in Bonbright's Principles of Public Utility Rates,[19] under the principle of cost causation, customer-related costs are "those operating and capital costs found to vary with number of customers."[20] Operationally defined, customer-related costs are the "costs of connecting another customer or the savings in costs of not

[15] Direct Testimony of Christopher J. Barthol, page 14, line 11 to page 15, line 17.
[16] NARUC Gas Manual, page 22.
[17] NARUC Gas Manual, page 22; Direct Testimony of Christopher J. Barthol, page 14, lines 11-13.
[18] NARUC Gas Manual, page 22.
[19] Bonbright et al, Principles of Public Utility Rates, 1988.
[20] Bonbright, page 490; also see NARUC Manual Electric Utility Cost Allocation Manual, 1992, page 90, "The customer component of distribution facilities is the portion of costs which varies with the number of customers."

connecting the customer."[21] Per the NARUC Gas Manual, customer costs are those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service supplied … [t]hey include the expenses of metering, reading, billing, collecting, and accounting, as well as those cost associated with the capital investment in metering and in customers' service connections."[22] NSP's CCOSS properly classifies the costs of services, meters and house regulators as customer-related. The CCOSS errs only in classifying a portion of the distribution mains costs as customer-related, rather than properly as demand-related.

Q. WHAT IS THE COST CAUSATION THAT DEFINES THE CLASSIFICATION OF GAS DISTRIBUTION ACCOUNTS AS DEMAND-RELATED?

A. As Bonbright also explains, it is theoretically impossible for the capital costs of distribution system facilities upstream of the facilities properly classified as customer-related because the connection of a new customer (or disconnection of an existing customer) has no measurable impact on the costs of those facilities.[23] Since the costs of the distribution facilities upstream of distribution facilities upstream of customer-related facilities do not and cannot vary with the number of customers connected to the distribution system, for the purposes of embedded cost analysis, those costs are properly classified as demand-related, because those costs "var[y] continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load."[24] Per the NARUC Gas Manual, demand related costs "are

[21] Bonbright, page 490.
[22] NARUC Gas Manual, page 22; see also page 23 "only facilities, such as meters, regulators and service taps, are considered to be customer related, as they vary directly with the number of customers on the system."
[23] Bonbright, page 491.
[24] Bonbright, page 492; see also NARUC Electric Manual, page 90, "Classifying distribution plant as a demand cost assigns investment … based upon its contribution to some total peak load ,,, [because] costs are incurred to serve area load, rather than a specific number of customers."

related to maximum system requirements which the system is designed to to serve during short intervals and do not directly vary with the number of customers or their annual usage."[25] NSP's CCOSS properly classifies the costs of production plant, storage plant, transmission plant and regulator stations as demand-related. The CCOSS errs only in classifying a portion of the distribution mains costs as customer-related, rather than properly as demand-related.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CLASSIFICATION OF DISTRIBUTION MAINS IN NSP'S CCOSS?

A. For reasons given above I recommend that NSP's distribution mains be classified as wholly demand-related with no customer-related component, consistent with the CCOSS' classification of production plant, storage plant, transmission plant and regulator stations as only demand-related.

Q. HAVE YOU FOUND ANY ERRORS IN THE CCOSS' ALLOCATION OF NSP'S CLASSIFIED AND FUNCTIONALIZED GAS COSTS?

A. Yes. NSP's CCOSS errs in allocating transmission and regulator station costs using the average and peak demand method[26] and demand-related mains costs using the average and excess demand method.[27] Both of these methods use the average class commodity volume to allocate a portion of the costs, rather than the maximum demand on the system as noted by both Bonbright and the Naruc Gas Manual. The Design Day (coincident demand)

[25] NARUC Gas Manual, pages 23 and 24.
[26] See NDPSC Data Request No. 2-001, Attachment A TRADE SECRET, Tot tab, col. E, rows 140 and 143 and col. C, row 571.
[27] See NDPSC Data Request No. 2-001, Attachment A TRADE SECRET, Tot tab, col. E, rows 145 and 146 and col. C, rows 649 and 659.

method,[28] which NSP's CCOSS uses to allocate production and storage costs, does reflect the maximum demand on the system.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF NSP'S GAS COSTS?

A. For reason given above I recommend that NSP's transmission, regulator station and distribution mains costs be allocated using the Design Day demand method, consistent with the CCOSS' allocation of production and storage costs.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS REGARDING THE CLASSIFICATION AND ALLOCATION OF NSP'S GAS COSTS?

A. Regarding distribution mains classification, NSP's residential rate class have proportionately more customers than its commercial rate classes and significantly less aggregate demand than the commercial classes. Consequently, the CCOSS' class customer allocation of distribution mains costs that the CCOSS erroneously classifies as customer-related results in an unsupported and unjustified over allocation of distribution costs to NSP's residential rate class, which constitutes a interclass subsidization of the commercial & industrial rate classes. Classifying the entirety of NSP's distribution mains costs as demand-related corrects the over allocation.

Regarding allocation of transmission, regulator station and distribution mains costs, the average and peak demand method over allocates costs to the commercial & industrial rate classes, which constitutes an interclass subsidization of the residential rate class. Allocating transmission, regulator stations and distribution mains using the Design Day demand method, corrects the overallocation.

[28] See NDPSC Data Request No. 2-001, Attachment A TRADE SECRET, Tot tab, col. E, rows 138 and 139 and col. C, row 658.

Q. HAVE YOU QUANTIFIED THE IMPACT OF YOUR RECOMMENDATION?

A. Yes. NSP's CCOSS calculates the customer class costs of service in shown in column B Table 1 below. My correction of the classification and allocation errors in NSP's CCOSS described above results in the customer class costs of service shown in column C of Table 2.

Table 2: Comparison of Class Costs of Service ($000)

Rate Class (A)	NSP CCOSS[29] (B)	Corrected CCOSS[30] (C)	Increase (Decrease)
Residential	$35,833	$32,382	($3,451)
C&I Firm	$32,063	$36,114	$4,051
Small & Large Interruptible	$7,715	$7,116	($599)
Total	$75,612	$75,612	-

As can be readily seen in the table, the net impact of correcting the classification and allocation errors and interclass subsidizations is significant decrease in the residential and interruptible rate classes' costs of service and a significant increase in the commercial & industrial rate classes' cost of service.

NORTH DAKOTA CLASS REVENUE REQUIREMENT APPORTIONMENT

Q. WHAT IS NSP'S PROPOSAL REGARDING CLASS REVENUE REQUIREMENT APPORTIONMENT?

A. NSP proposes to apportion or distribute the revenue requirement to customer classes based on cost service adjusted with regard to competitive services and moderation in rate increase.[31]

[29] Direct Testimony of Christopher J. Barthol, page 31, Table 6 CCOSS Costs of Service.
[30] Exhibit KRP-2 Corrected NDPSC-2-001 Att A CCOSS TRADE SECRET IN ENTIRETY
[31] Direct Testimony of Christopher J. Barthol, page 28, lines 1-3; page, 31, Table 6 Proposed Revenue.

Q. DO YOU FIND ANY ERRORS IN NSP'S PROPOSED CLASS REVENUE REQUIREMENT APPORTIONMENT?

A. I find no errors in NSP's proposed method of revenue requirement distribution to customer classes, but disagree with the customer class costs of service on which the proposed revenue requirement distribution is based. See Table 2 above.

Q. HAVE YOU DEVELOPED A CLASS REVENUE RESPONSBILITY BASED ON THE MINIMUM SYSTEM CCOSS AND ADVOCACY STAFF WITNESS MUGRACE'S PROPOSED REVENUE REQUIREMENT?

A. Yes. I have developed customer class revenue requirement distributions based on the corrected class costs of service and Staff Witness Mugrace's recommended revenue requirement. Table 3 compares that class revenue requirement distribution to NSP's proposed class revenue requirement distribution.

Table 3: Comparison of Class Revenue Requirement Apportionment ($000)

Rate Class (A)	NSP Proposed Revenue[32] (B)	Corrected Proposed Revenue[33] (C)	Increase (Decrease)
Residential	$30,817	$26,462	($4,355)
C&I Firm	$35,256	$34,638	($618)
Small & Large Interruptible	$9,464	$9,167	($297)
Total	$75,536	$70,267[34]	($5,269)

As one can see from Table 3, the net impact of the corrected class cost of service and Staff Witness Mugrace's recommended revenue requirement is reductions in the revenue

[32] Direct Testimony of Christopher J. Barthol, page 31, Table 6 Proposed Revenue.
[33] Exhibit KRP-3 Corrected Exhibit CJB-1, Schedule 4.
[34] Direct Testimony of Dante Mugrace, Schedule DM-1.

requirement apportioned to all NSP's rate classes, with the majority of the reduction going to the residential class.

NORTH DAKOTA RATE DESIGN

Q. WHAT ARE NSP'S RATE DESIGN PROPOSALS?

A. NSP is proposing no structural changes to its customer class rate structure.[35] Regarding class tariff charges proposals see Table 1 above.

Q. DO YOU HAVE ANY CRITICISMS OF THE PROPOSED RATE DESIGNS?

A. My only criticism is that they are based on NSP's proposed class revenue requirement distribution. I note that the absence of a volumetric distribution charge for the residential rate class eliminates intraclass subsidization of low volume customers by high volume customers. Table 4 shows my recommended class tariff charges based on the corrected revenue requirement distribution in Table 3 above.

Table 4: Recommended Class Rates[36]

Residential (RC 401): 1.2% revenue decrease with Delivery Service Charge decreased 6.4% from $18.48/month to $17.30/month;
Commercial and Industrial (RC 403, 410): 8.6% revenue increase with (a) Basic Service Charge increased 27.3% from $30.00/month to $38.20/month and (b) Distribution Charge increased 21.8% from $0.10800/therm to $0.13157/therm;
Small Interruptible (RC 404): 4.8% revenue increase with (a) Basic Service Charge increased 33.3% from $75.00/month to $100.00/month and (b) Distribution Charge increased 5.6% from $0.08800/therm to $0.09292/therm;
Large Interruptible (RC 405): 7.2% revenue increase with (a) Basic Service Charge increased 9.1% from $275.00/month to $300/month and (b) Distribution Charge increased 40.3% from $0.05120/therm to $0.07182/therm;

[35] Direct Testimony of Christopher J. Barthol, page 33,
[36] Exhibit KRP-4 Corrected Exhibit CJB-1, Schedule 5.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

PCMG and Associates LLC

KARL RICHARD PAVLOVIC, Ph.D.

Education

Purdue University – MA and Ph.D. in Philosophy

Karl-Ruprecht Universität, Heidelberg, Germany – graduate study

Yale University – BA in Philosophy

Positions

Senior Consultant – PCMG and Associates	2015-Present
Senior Consultant – Snavely King Majoros and Associates	2010-2014
Director – FTI Consulting	2008-2010
President – DOXA, Inc	1994-2008
Partner – Snavely King and Associates	1983-1994
Assistant Professor – University of Florida-Gainesville	1978-1983

Professional Experience

Dr. Pavlovic provides clients with economic and policy analyses of commercial operations and expert testimony in support of litigation, negotiation and strategic planning. His analyses and testimony are distinguished by systematic articulation and testing of assumptions, thorough evaluation of data, innovative application of statistical tools and economic principles, and clarity and precision of presentation. Dr. Pavlovic has provided expert testimony on the operations, costs and revenues of gas and electric utilities, the impacts of restructuring wholesale and retail electric markets, effects of mergers, the operation and competitiveness of petroleum and electric markets, the market valuation of crude oil, electric and gas reliability, and the performance of energy efficiency, renewable energy, and peak reduction programs.

Major projects directed by Dr. Pavlovic have included: analytical assistance to counsel and testimony on all aspects of the restructuring of wholesale and retail electric markets in the Eastern Interconnection; technical representation of the District of Columbia People's Counsel on the DC PSC's Pepco Productivity Improvement Working Group and various PJM working groups; impact evaluation study of pilot energy efficiency and renewable energy programs in the District of Columbia; analysis of petroleum markets, expert testimony, and coordination of technical testimony in the Trans-Alaska Pipeline quality bank litigation; Independent Technical Review of the economic models used by the US Army Corps of Engineers for the Ohio River System Investment Plan; assistance to a major independent telephone company in the formulation and implementation of corporate strategic plans, applications for long-distance authority, and settlement negotiations with major domestic and foreign carriers.

By education and professional experience Dr. Pavlovic has expertise in formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling. With 33 years' experience as a consultant and expert witness, Dr. Pavlovic has in-depth knowledge of

commercial and industrial operations in the energy, transportation, and telecommunications industries and is familiar with a wide range of experimental and investigative methods in science and engineering.

PCMG and Associates LLC

Regulatory Projects and Appearances

1. In re: the Application of Northern States Power Company for Authority to Increase Rates for Natural Gas Service in North Dakota (2021) - (Appearance: depreciation, cost of service and rate design on behalf of the North Dakota Public Service Commission Advocacy Staff)
   ND PSC Case No. PU-21-381

2. In re: Application of San Diego Gas & Electric Company for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2022 and to Reset the Annual Cost of Capital Mechanism (2021) – (Appearance: wildfire risk accounting and ratemaking on behalf of Utility Consumers' Action Network)
   CA Public Utilities Commission Application 21-08-014

3. In re: Petition of HPBS, Inc. for review and approval of Central Scheduling System (CSS) charge increase and revised CSS schedule (2021) – (Appearance: rate design on behalf of the Hawaii Department of Commerce and Consumer Affairs)
   HI DCCA Docket No. PTP-2021-001

4. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2020 Gas System Enhancement Plan Reconciliation Filing (2021) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 21-GREC-06

5. In re: Petition of Eversource Gas Company of Massachusetts d/b/a Eversource Energy for Approval of its 2020 Gas System Enhancement Plan Reconciliation Filing (2021) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 21-GREC-05

6. In re: Petition of Berkshire Gas Company for Approval of its 2020 Gas System Enhancement Plan Reconciliation Filing (2021) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
   MA Department of Public Utilities Docket No. D.P.U. 20-GREC-02

7. In re: the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota (2021) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Advocacy Staff)
   ND PSC Case No. PU-20-441

8. In re: Pike County Light & Power Company 2020 General Base Rate Increase Filing – (Appearance: gas and electric cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
   PA Public Utility Commission Docket Nos. R-2020-3022134 and R-2020-3022135

9. In re: Young Brothers LLC's Application for Approval of a New Cost of Service Model (2020) – (Appearance: cost of service on behalf of the Hawaii Division of Consumer Advocacy)
   HI Public Utilities Commission Docket No. 2020-0135

10. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2019 Gas System Enhancement Plan Reconciliation Filing (2020) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-06

11. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2019 Gas System Enhancement Plan Reconciliation Filing (2020) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-05

12. In re: Petition of Berkshire Gas Company for Approval of its 2019 Gas System Enhancement Plan Reconciliation Filing (2020) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 20-GREC-02

13. In re: Pittsburgh Water and Sewer Authority 2020 General Base Rate Increases 2020 – (Appearance: multi-year rate plan and performance based ratemaking on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket Nos. R-2020-3017970 and R-2020-3017951

14. In re: Commonwealth Edison Company Petition for approval of a Revision to Integrated Distribution Company Implementation Plan Creation of Rate Residential Time of Use Pricing Pilot ("Rate RTOUP") – On Rehearing (2020) – (Appearance: price signal and customer response on behalf of the Illinois Attorney General)
    IL Commerce Commission Docket Nos. 18-1725/18-1824

15. In re: Hawaii Electric Company, Inc. Application for Approval of a General Rate Increase and Revised Rate Schedules and Rules (2019) - (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
    HI Public Utilities Commission Docket No. 2019-0085

16. In re: Application of San Diego Gas & Electric Company for Authority to: (i) Adjust its Authorized Return on Common Equity, (ii) Adjust its Authorized Embedded Costs of Debt and Preferred Stock, (iii) Adjust its Authorized Capital Structure; (iv) Increase its Overall Rate of Return, (v) Modify its Adopted Cost of Capital Mechanism Structure, and (vi) Revise its Electric Distribution and Gas Rates Accordingly, and for Related Substantive and Procedural Relief (2019) – (Appearance: wildfire risk accounting and ratemaking on behalf of Utility Consumers' Action Network)
    CA Public Utilities Commission Application 19-04-017

17. In re: Proposed Amendments to N.J.A.C. 14:9 Adoption of Water and Sewer Uniform System of Accounts (2019) – (Assistance to counsel: water and sewer accounting on behalf of the Division of Rate Counsel)
    NJ Board of Public Utilities Docket Nos. WX19050612 and WX19050613

18. In re: Petition of Public Service Electric and Gas Company for Approval of Gas Base Rate Adjustments Pursuant to its Gas System Modernization Program (2019) – (Assistance to Counsel: infrastructure replacement accounting)
    NJ Board of Public Utilities Docket No. GE19040522

19. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2018 Gas System Enhancement Plan Reconciliation Filing (2019) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 19-GREC-06

20. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2018 Gas System Enhancement Plan Reconciliation Filing (2019) - (Assistance to Counsel: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 19-GREC-05

21. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2019) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9602

22. In re: PECO Energy Company Non-Bypassable Transmission Service Charge (NBT) Semiannual Adjustment (2019) - (Appearance: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    PA Public Utility Commission Docket No. M-2018-3005860

23. In re: PECO Energy Company Transmission Formula Rate Application (2018) - (Appearance: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    Federal Energy Regulatory Commission Docket ER17-1519-000

24. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2017 Gas System Enhancement Plan Reconciliation Filing (2018) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 18-GREC-06

25. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2017 Gas System Enhancement Plan Reconciliation Filing (2018) - (Appearance: prudence/used and useful, accounting, cost of service and rate design on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 18-GREC-05

26. In re: The Application of the Potomac Edison Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2018) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9490

27. In re: Rate Applications of Kansas City Power & Light – Missouri and Kansas City Power & Light – Greater Missouri Operations (2018) – (Appearance: consolidated operations, cost of service and rate design on behalf of the Missouri Office of Public Counsel)
    MO Public Service Commission Case Nos. ER-2018-0145 and ER-2018-0146

28. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2018) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9472

29. In re: Mid-Atlantic Interstate Transmission, L.L.C. 2018 Transmission Formula Rate Protocol Filings (2018) - (Analysis and Advice to Counsel: accounting)
    Federal Energy Regulatory Commission Docket ER17-211-000

30. In re: The Gas Company d/b/a Hawaii Gas Application for Approval of Rate Increases and Revised Rate Schedules and Rules (2017) - (Appearance: cost of service and rate design on behalf of the Hawaii Division of Consumer Advocacy)
    HI Public Utilities Commission Docket No. 2017-0105

31. In re: Montana-Dakota Utilities Co., Application to Increase Natural Gas Rates (2017) - (Appearance: cost of service and rate design on behalf of the North Dakota Public Service Commission Staff)
    ND Public Service Commission Case No. PU-12-813

32. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
MD Public Service Commission Case No. 9455

33. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 17-GREC-06

34. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 17-GREC-05

35. In re: In the matter of the application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2017) - (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
MD Public Service Commission Case No. 9447

36. In re: PJM Interconnection, L.L.C. - PECO Energy Company Transmission Formula Rate Application (2017) - (Analysis and Advice to Counsel: accounting, cost of service and rate design)
Federal Energy Regulatory Commission Docket ER17-1519-000

37. In re: Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed General Increase in Gas Rates (2017) - (Appearance: prudence/used and useful and plant accounting re. accelerated asset replacement program on behalf of the Illinois Citizens Utility Board)
IL Commerce Commission Docket No. 17-0124

38. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) - (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
MD Public Service Commission Case No. 9443

39. In re: PJM Interconnection, L.L.C. - Rockland Electric Company Transmission Rate Application (2017) (Analysis and Advice to Counsel: accounting, cost of service and rate design on behalf of the New Jersey Division of Rate Counsel)
Federal Energy Regulatory Commission Docket ER17-856-000

40. In re: PJM Interconnection, L.L.C. - Mid-Atlantic Interstate Transmission, L.L.C. Transmission Formula Rate Application (2016) - (Analysis and Advice to Counsel: accounting, cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
    Federal Energy Regulatory Commission Docket ER17-211-000

41. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9424

42. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9418

43. 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: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-01

44. 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: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 16-GREC-05

45. 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) - (Appearance: compliance with statutes and regulations, prudence, cost/benefit, and ratemaking on behalf of the New Hampshire Office of Consumer Advocate)
    NH Public Utilities Commission Docket No. DE 16-241

46. 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

47. In re: Bulletin 2015-10 Generic Proceeding to Establish Parameters for the Next Generation PBR Plans (2016) - (Appearance: productivity adjustments/performance based ratemaking on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20414

48. In re: Emera Maine, Proposed Rate Increase in Rates (2016) - (Analysis and Advice to to Counsel: evaluation of management audit of implementation of Customer Information System on behalf of the Maine Office of the Public Advocate)
    ME Public Service Commission Docket No. 2015-00360

49. In re: The Merger of the Southern Company and AGL Resources Inc.- Joint Application of the Southern Company, AGL Resources Inc., and Pivotal Utility Holdings, Inc., d/b/a Elkton Gas (2015-2016) - (Appearance: earnings, synergy savings, rates, operations, supply procurement, safety, and reliability on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9404

50. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of Firm Transportation Agreements with Millennium Pipeline Company, LLC (2015-2016) - (Analysis, Advice to Counsel, and Assistance on Brief: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-142

51. 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 (2015-2016)
    - (Analysis, Advice to Counsel, and Assistance on Brief: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-130

52. 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; Gaz Metro LNG, L.P.; and National Grid LNG (2015- 2016) - (Analysis and Advice to Counsel: compliance with gas supply plan, rates, and reliability on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-129

53. In re: Columbia Gas of Massachusetts CY2014 Targeted Infrastructure Reinvestment Factor Compliance Filing (2015) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 15-55

54. ENMAX Energy Corporation (EEC) 2015-2016 Regulated Rate Option Non-Energy Tariff Application (2015-2016) - (Appearance: cost allocation, rate design, non-energy risk on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20480

55. In the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc. (2014) - (Advice to Counsel: impact on customers on behalf of the New Jersey Division of Rate Counsel)
NJ Board of Public Utilities BPU Docket No. EM1406

56. In re: Application of Baltimore Gas and Electric Company For Adjustments To Its Electric and Gas Base Rates (2014) (Analysis and Advice to Counsel in Settlement: earnings, investment tracker, cost allocation and rate design on behalf of the Maryland Office of People's Counsel)
MD Public Service Commission Case No. 9355

57. In re: Columbia Gas of Massachusetts CY2013 Targeted Infrastructure Reinvestment Factor Compliance Filing (2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 14-83

58. In re: Potential Business Combination of Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C. (2014-2015) - (Analysis and Advice to Counsel: impact on rates and consolidation of rates on behalf of the Louisiana Public Service Commission Staff)
LA Public Service Commission Docket No.U-33244

59. In the Matter of the Application of Ohio Power Company to Adopt a Final Implementation Plan for the Retail Stability Rider (2014) - (Analysis and Advice to Counsel: rate design)
OH Public Utilities Commission Case No. 14-1186-EL-RDR

60. In re: Examination of Long-Term Natural Gas Hedging Proposals (2014-2015) - (Analysis and Advice to Counsel: natural gas procurement on behalf of the Louisiana Public Service Commission Staff)
LA Public Service Commission Docket No.R-32975-LPSC, ex parte

61. In re: 2013 Integrated Resource Planning Process for Southwestern Electric Power Company Pursuant to General Order Dated April, 20, 2012 (2014-2015 - (Analysis and Advice to Counsel: IRP design and evaluation on behalf of the Louisiana Public Service Commission Staff)
LA Public Service Commission Docket No.I-33013 SWEPCO, ex parte

62. In the Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Adopt an Infrastructure Replacement Surcharge Mechanism (2013-2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Maryland Office of People's Counsel)
MD Public Service Commission Case No. 9332

63. In the Matter of the Application of Baltimore Gas and Electric Company for Approval of a Gas System Strategic Infrastructure Development and Enhancement Plan and Accompanying Cost Recovery Mechanism (2013-2014) - (Appearance: PBR tracker design/rates, prudence/used and useful, plant accounting on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9331

64. In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (2013-2014) - (Appearance: earnings, investment tracker design/rates, cost allocation and rate design on behalf of the Delaware Public Service Commission Staff)
    DE Public Service Commission Docket No. 13-115

65. In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota (2013) - (Appearance: cost allocation and rate design on behalf of the North Dakota Public Service Commission Staff)
    ND Public Service Commission Case No. PU-12-813

66. In the Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2013) - (Appearance: expense tracker design/rates and evaluation on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9316

67. In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates (2012) - (Appearance: earnings, investment tracker design/rates, cost allocation and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9299

68. In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (2012) - (Appearance: earnings, investment tracker design/rates, cost allocation and rate design on behalf of the Delaware Public Service Commission Staff)
    DE Public Service Commission Docket No. 11-528

69. ENMAX Energy Corporation (EEC) 2012-2014 Regulated Rate Option Non-Energy Tariff Application (2012-2013) - (Analysis and Advice to Counsel: rate design and non-energy risk on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Application #1608745 Proceeding 2069

70. In the Matter of the Petition of Atlantic City Electric Company for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to *N.J.S.A.* 48:2-21 and *N.J.S.A.* 48:2-21.1 and for Other Appropriate Relief (2011) - (Analysis and Advice to Counsel: depreciation on behalf of the New Jersey Division of Rate Counsel)
NJ Board of Public Utilities Docket No. ER11080469

71. In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service (2011) - (Appearance: investment tracker design/rates, cost allocation and rate design on behalf of the People's Counsel for the District of Columbia)
D.C. Public Service Commission Formal Case No. 1087

72. Electric Transmission Formula Rate Annual Informational Filing of Central Maine Power Company (2011) - (Advice to Counsel: formula transmission rates, cost allocation and rate design on behalf of the Maine Attorney General)
Federal Energy Regulatory Commission Docket No. ER09-934-000 (2011)

73. Electric Transmission Formula Rate Annual Informational Filing of Bangor Hydro Electric Company (2011) - (Analysis, Report and Advice to Counsel: formula rate on behalf of the Massachusetts Attorney General)
Federal Energy Regulatory Commission Docket No. ER09-938-000

74. Pennsylvania Public Utility Commission Office of Consumer Advocate Office of Small Business Advocate v. City of Bethlehem – Bureau of Water (2011) - (Appearance: cost allocation and rate design on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania PUC Docket Nos. R-2011-2244756, C-2011-2246910, and C-2011- 2248241

75. Southern California Edison Company Transmission Owners Tariff (2011) - (Analysis and Advice to Counsel: depreciation on behalf of M-S-R Public Power Agency)
Federal Energy Regulatory Commission Docket No. ER11-2061-000

76. In the Matter of the Petition of Kansas City Power & Light Company for Determination of the Ratemaking Principles and Treatment that Will Apply to the Recovery in Rates of the Cost to be Incurred by KCP&L for Certain Electric Generation Facilities under K.S.A. 66- 1239 (2011) - (Appearance: advance determination of prudence on behalf of the Kansas Citizens' Utility Ratepayer Board)
Kansas Corporation Commission Docket No. 11-KCPE-581-PRE

77. Midwest Independent Transmission System Operator, Inc., and Ameren Illinois Company (2011) - (Analysis and Advice to Counsel: depreciation on behalf of the Wholesale Distribution Service Customer Group)
Federal Energy Regulatory Commission Docket No. ER11-2788-000

Northern States Power Company
Natural Gas Utility - State of North Dakota
Proposed Revenue Apportionment

Case No. PU-21-___
Exhibit___(CJB-1), Schedule 4
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Corrected

	Rate Code	Avg Cust.	Dkt Sales	Present Revenues			Proposed Revenue			Increase					
				Base	Fuel	Total	Base	Fuel	Total	Base	%	Fuel	%	Total	%
Firm Service															
Residential	401	51,811	3,969,079	11,489,515	15,307,684	$26,797,199	$10,752,937	$15,720,345	$26,473,282	-$736,578	-6.4%	$412,661	2.7%	-$323,917	-1.2%
Commercial and Industrial	410	9,092	6,494,932	9,843,987	22,057,904	$31,901,891	$11,992,204	$22,657,878	$34,650,082	$2,148,217	21.8%	$599,974	2.7%	$2,748,191	8.6%
Total Firm Service		60,903	10,464,011	21,333,502	37,365,588	$58,699,090	$22,745,141	$38,378,223	$61,123,364	$1,411,638	6.6%	$1,012,635	2.7%	$2,424,273	4.1%
Interruptible Service															
Small C&I	404	63	569,913	558,374	1,636,515	$2,194,889	$605,355	$1,695,768	$2,301,123	$46,981	8.4%	$59,253	3.6%	$106,234	4.8%
Large C&I	405	25	2,993,984	1,476,382	4,932,326	$6,408,708	$1,757,621	$5,110,911	$6,868,532	$281,239	19.0%	$178,585	3.6%	$459,824	7.2%
Total Interruptible Service		88	3,563,897	2,034,756	6,568,841	$8,603,597	$2,362,976	$6,806,679	$9,169,655	$328,220	16.1%	$237,838	3.6%	$566,058	6.6%
Total Retail		60,991	14,027,908	23,368,258	43,934,429	$67,302,687	$25,108,117	$45,184,902	$70,293,019	$1,739,859	7.4%	$1,250,473	2.8%	$2,990,332	4.4%

Other Gas Revenues

Late Pay Penalties	$155,340	$174,344	$19,004	12.2%
Connection Charges	$113,904	$170,177	$56,273	49.4%
Return Check Charges	$6,516	$6,516	$0	0.0%
Connect Smart	$3,011	$3,011	$0	0.0%
Interchange Gas	$63,229	$63,229	$0	0.0%
Other Gas Revenue	$90,112	$90,112	$0	0.0%
Ltd Firm Sales - Rsrvs & Vols	$120,420	$120,420	$0	0.0%
LP Sales to Others - MN	$0	$0	$0	0.0%
Contr In Aid Cons Tax Gr-Up	$0	$0	$0	0.0%
Other - Miscellaneous	-$2,148	-$2,148	$0	0.0%
Total Other Gas Revenues	$550,384	$625,660	$75,277	13.7%
Total Retail Sales and Other Revenues	**$67,853,071**	**$70,918,679**	**$3,065,609**	**4.5%**

PU-21-381
Exhibit KRP-3

Northern States Power Company
Natural Gas Utility - State of North Dakota
Detail of Customers, Sales, and Present and Proposed Revenues

Case No. PU-21-___
Exhibit___(CJB-1), Schedule 5
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Corrected

Residential Service

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Delivery Services Charge	621,727		$ 18.48	$11,489,515	$ 17.30	$ 10,752,937	$ (736,578)	
Distribution Charge		39,690,789	$ -	$ -	$ -	$ -	$ -	
MGP		39,690,789	$ -	$ -	$ 0.01040	$ 412,661	$ 412,661	
Cost of Gas Charge								
Summer (Apr-Oct)		8,443,492	$ 0.33921	$ 2,864,147	$ 0.33921	$ 2,864,147		
Winter (Nov-Mar)		31,247,297	$ 0.39823	$12,443,537	$ 0.39823	$ 12,443,537		
Total		39,690,789	$ 0.38567	$15,307,684	$ 0.38567	$ 15,307,684	$ -	
Average Customers	51,811							
			Total	$26,797,199		$ 26,473,282	$ (323,917)	-1.20%

Commercial and Industrial Service

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Basic Service Charge	109,101		$30.00	$ 3,273,030	$38.20	$ 4,167,658	$ 894,628	
Distribution Charge		64,949,321	$ 0.10800	$ 7,014,527	$ 0.13157	$ 8,545,281	$ 1,530,754	
Discount		7,242,210	$(0.06125)	$ (443,570)	$ (0.09952)	$ (720,767)	$ (277,197)	
MGP		57,707,111	$ -	$ -	$ 0.01040	$ 599,974	$ 599,974	
Cost of Gas Charge								
Summer (Apr-Oct)		15,634,588	$ 0.33921	$ 5,303,463	$ 0.33921	$ 5,303,463		
Winter (Nov-Mar)		42,072,522	$ 0.39823	$16,754,441	$ 0.39823	$ 16,754,441		
Cost of Gas Charge		57,707,111	$ 0.38224	$22,057,904	$ 0.38224	$ 22,057,904	$ -	
Average Customers	9,092							
			Total	$31,901,891		$ 34,650,050	$ 2,748,191	8.60%

Small Interruptible Service

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Basic Service Charge	758		$ 75.00	$ 56,850	$ 100.00	$ 75,800	$ 18,950	
Distribution Charge		5,699,135	$ 0.08800	$ 501,524	$ 0.09292	$ 529,564	$ 28,040	
MGP		5,699,135	$ -	$ -	$ 0.01040	$ 59,253	$ 59,253	
Cost of Gas Charge		5,699,135	$ 0.28715	$ 1,636,515	$ 0.28715	$ 1,636,515	$ -	
Average Customers	63							
			Total	$ 2,194,889		$ 2,301,132	$ 106,243	4.80%

Large Interruptible Service

	Units		Present		Proposed		Increase	
	Bills	Therms	Rate	Revenue	Rate	Revenue	Amount	Percent
Basic Service Charge	300		$ 275.00	$ 82,500	$ 300.00	$ 90,000	$ 7,500	
Distribution Charge		29,939,839	$ 0.05120	$ 1,532,920	$ 0.07182	$ 2,150,279	$ 617,359	
Discount		12,763,099	$(0.01089)	$ (139,038)	$ (0.03781)	$ (482,620)	$ (343,582)	
MGP		17,176,740	$ -	$ -	$ 0.01040	$ 178,585	$ 178,585	
Cost of Gas Charge		17,176,740	$ 0.28715	$ 4,932,326	$ 0.28715	$ 4,932,326	$ -	
Average Customers	25							
			Total	$ 6,408,708		$ 6,868,570	$ 459,862	7.20%

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
2021 Natural Gas Rate Increase
Application

Case No. PU-21-381

Verification

State Of ___Maryland_____)
) ss.
County Of___Montgomery_____)

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

Karl Richard Pavlovic

Subsribed and sworn to before me this 28th day of February, 2022.

MICHELLE A. PRICE NOTARY PUBLIC MONTGOMERY CO., MD

Michelle Price
Notary Public
My Commission Expires: 3/10/2025

MICHELLE A. PRICE
NOTARY PUBLIC STATE OF MARYLAND
My Commission Expires March 10, 2025

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION
OF NORTHERN STATES POWER CO.
FOR AUTHORITY TO INCREASE RATES
FOR NATURAL GAS SERVICE
IN NORTH DAKOTA

DOCKET NO. PU-20-381

DIRECT TESTIMONY OF

MARLON F. GRIFFING, PH.D.

ON BEHALF OF

NORTH DAKOTA PUBLIC SERVICE COMMISSION ADVOCACY STAFF

MARCH 1, 2022

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EXHIBITS:

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Dr. Marlon F. Griffing. I am a Senior Consultant with the economic consulting firm of PCMG & Associates Inc. ("PCMG"). My business address is 22 Brookes Drive, Gaithersburg, MD 20785.

Q. PLEASE DESCRIBE PCMG.

A. PCMG was founded in 2015 to conduct research on a consulting basis into the rates, revenues, costs, and economic performance of regulated firms and industries. The firm has a professional staff of four with expertise in economics, accounting, and cost analysis. Most of its work involves the development, preparation, and presentation of expert witness testimony before federal and state regulatory agencies.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE, INCLUDING COST-OF-CAPITAL TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment ____ (MFG-1) is a summary of my qualifications, experience, and testimony given before state and federal regulatory agencies regarding cost of capital.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the North Dakota Public Service Commission ("Commission") Advocacy Staff in this proceeding.

Q. WHAT ARE YOUR RESPONSIBILITIES IN THIS COMMISSION PROCEEDING?

A. My responsibility is to determine a fair rate of return on common equity capital and a fair overall rate of return for Northern States Power, a Minnesota corporation ("NSP" or the

"Company"). NSP is a vertically integrated electric and natural gas utility. It is an operating subsidiary of Xcel Energy Inc ("XEL"). Among its operations, NSP provides natural gas distribution service in North Dakota.[1] NSP is seeking an increase in its North Dakota natural gas rates in this docket. NSP witness Dylan W. D'Ascendis testifies regarding cost of capital on behalf of the Company. I respond to the cost of capital testimony of Mr. D'Ascendis.

Q. HOW DO YOU DEVELOP A RECOMMENDED RATE OF RETURN FOR THE COMPANY?

A. To arrive at a recommended overall rate of return ("ROR"), I analyze the Company's requested capital structure and costs for each component of that structure.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- First, I discuss economic considerations and legal precedents underlying the cost of equity in regulatory proceedings.
- Second, I explain how I selected the members of the Comparison Group of companies used in my analysis.
- Third, I provide overviews of the Discounted Cash Flow ("DCF") model and the Capital Asset Pricing Model ("CAPM") analyses.
- Fourth, I perform DCF model and CAPM analyses for the Comparison Group, check them for reasonableness, and recommend a return on equity ("ROE") for the Company.
- Fifth, I recommend a return on equity ("ROE") for the Company and check it for reasonableness.
- Sixth, I recommend a capital structure and ROR for the Company.
- Seventh, I review the Company's rate of return analysis.

[1] Direct Testimony of Dylan W. D'Ascendis on Behalf of Northern States Power Company (September 1, 2021) [hereinafter "D'Ascendis Direct"], page 16, lines 5-16.

- Eighth, I summarize my testimony and recommendations

Q. PLEASE STATE YOUR CONCLUSIONS REGARDING THE COMPANY'S ROE AND ROR.

A. My ROE analysis for NSP produces a value of 9.40 percent. For NSP's capital structure, my analysis shows ratios of 47.57 percent long-term debt, 0.43 percent short-term debt, and 52.00 percent common equity are appropriate. When the ROE of 9.40 percent is included in the recommended capital structure with the Company's costs of long-term debt and short-term debt,[2] the result is an ROR of 6.84 percent.[3]

II. THE COST OF EQUITY IN THE REGULATORY ENVIRONMENT

1. The Role of Economic Theory

Q. WHAT IS THE BASIS IN ECONOMIC THEORY FOR REGULATING CERTAIN INDUSTRIES?

A. According to economic theory, the forces of supply and demand interacting in a competitive environment produce an allocation of resources that yields an optimal mix of goods and services. Firms and individuals maximize profits and satisfaction given the prices and incomes that the interplay of market forces generates. This outcome is described as economically efficient. Put simply, there is no better output of goods and services that can be produced with the available resources.

[2] NSP-MN Regulated Capital Structure, C1. Cost of Capital Schedule, Page 1 of 2.
[3] Exhibit MFG-16 Schedule 3.

Q. DOES THE ECONOMICALLY EFFICIENT OUTCOME OCCUR IN ALL INDUSTRIES?

A. No, several conditions must be present, including many buyers and sellers, identical products, perfect information about prices, and so forth. If these conditions exist, then price is the only way for providers of goods and services to compete in markets. If the conditions for competition do not exist, however, then letting supply and demand work unfettered will not produce the socially desired efficient outcome.

Q. ARE THERE LEGAL OBSTACLES TO COMPETITION IN PUBLIC UTILITY MARKETS?

A. Yes. Even if a firm is willing and able to raise the capital needed to be a viable natural gas distribution company, state and local governments typically have permitting processes that govern where and when utilities can build facilities. Thus, high start-up costs are not the only barrier that must be overcome.

Q. ARE THERE OTHER ASPECTS OF AN ELECTRIC DISTRIBUTION UTILITY'S COSTS THAT RESULT IN FEW SELLERS?

A. Yes. The natural gas utility industry is what is typically known as a declining-cost industry.

Q. WHAT IS A DECLINING-COST INDUSTRY?

A. A declining-cost industry is one where the average cost of service declines over the range of effective demand.

Q. IS A DECLINING AVERAGE COST OF SERVICE SUFFICIENT FOR AN INDUSTRY TO BE TERMED "DECLINING COST?"

A. No. In fact, average costs decline in most industries as production and sales increase. However, in these industries, average cost eventually rises and does so at a sales level that

is smaller than the total demand for the product in a given industry. As a consequence, a few too many firms share the market because, beyond the sales volume at which average costs rise, firms lose, rather than gain, cost advantage.

Q. ARE PUBLIC UTILITIES DECLINING-COST INDUSTRIES?

A. Yes. With their high fixed costs, public utilities have high initial average costs, but as their sales increase, the average cost drops. What qualifies public utilities as a declining-cost industry is that their average costs continue to decline over very high volumes of sales, up to and beyond total, or effective, market demand for the product. This condition creates market failure (when the market produces an outcome that is inefficient). As a natural gas distribution firm increases its sales and market share, its average costs decline, and continue to do so. Thus, the firm with the largest market share has an increasing cost advantage over competitors. In effect, there is not enough room in the market for another distributor. The logical result is a market with one distributor—often referred to as a natural monopoly—not the many firms envisioned in the theory of competition.

Q. HOW HAS SOCIETY RESPONDED TO THE ABSENCE OF COMPETITION IN PUBLIC UTILITY MARKETS?

A. Since sufficient competition does not exist in the markets for public utilities to ensure low prices and adequate service, society has typically turned to regulation to achieve these goals. Firms are granted exclusive franchises to serve areas in return for accepting government regulation of their prices. The government regulators generally are charged with pursuing an outcome that approximates the efficient outcome of the competitive model. Regulation is viewed as a way to decrease prices and increase services provided by a natural monopoly. A challenge for regulators is to set policies that ensure that the

regulated firm provides an appropriate supply of services at reasonable rates. A reasonable rate enables a public utility not only to recover its operating expenses, depreciation, and taxes, but also to compete for funds in capital markets.

2. Standards for Finding a Fair Rate of Return

Q. DO STANDARDS EXIST FOR DETERMINING A FAIR RATE OF RETURN?

A. Yes. Two United States Supreme Court ("Court") cases are the basis for rate of return regulation in the United States. They are the *Bluefield Water Works*[4] and the *Hope Natural Gas*[5] cases. In *Hope*, the Court established the following standards for the return on equity that must be allowed a regulated public utility to provide for a "reasonable return":

> [T]he return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[6]

It can be seen from this excerpt that there are essentially three standards for determining an appropriate return on equity from the standpoint of the equity owners of a regulated utility. The first is the "comparable earnings" standard—the earnings must be "commensurate with the returns on investments in other enterprises having corresponding risks." The second is that earnings must be sufficient to assure "confidence in the financial integrity of the enterprise." The third is that earnings must allow the utility to "attract capital."

[4] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923).
[5] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).
[6] *Id*. at 603.

Q. CAN THE COMPARABLE EARNINGS STANDARD BE APPLIED IN ESTIMATING THE RATE OF RETURN ON EQUITY CAPITAL?

A. No. There is circularity to the comparable earnings standard because the competitive nature of the capital markets virtually ensures that the returns to all enterprises are comparable with each other. Investors establish the price of each traded stock in capital markets based on prospective earnings and perceived risk. The prices for common equity for companies with high earnings are bid up, while the prices for companies with low earnings are bid down. If earnings were the only concern, the ratio of earnings to share prices, the return for investors, would become equal for all companies. However, investors recognize relative risk as they buy and sell common equity shares. For companies with high risk, share prices will be lower; for companies with low risk, share prices will be higher. Thus, the comparable earnings test becomes a nullity: All returns, because they are adjusted for risk, are comparable with all other returns.

Q. HOW IS THIS CIRCULARITY TYPICALLY RESOLVED IN PUBLIC UTILITY REGULATION?

A. In public utility regulation, the conventional procedure for resolving this circularity is to identify the required equity return based on the market value of a utility's stock. That return is combined with the cost of debt, and the blended return to total capital is then applied to a rate base reflective of the book value of the utility's investment. The book value is the accountant's quantification of the depreciated original cost of the utility's assets adjusted for ratepayer contributions such as deposits and deferred taxes. Under this procedure, the market price of a stock is used only to determine the return that investors expect from that stock. That expectation is then applied to the book value of the utility's investment to

identify the level of earnings that regulation will allow the utility's common shareholders to recover.

Q. HOW CAN THE FINANCIAL INTEGRITY AND CAPITAL ATTRACTION STANDARDS ENUNCIATED IN *HOPE* BE APPLIED IN ESTIMATING THE RATE OF RETURN ON EQUITY CAPITAL?

A. If a utility can earn a return on its investment comparable to that required by enterprises of comparable risk, then it should have no difficulty in attracting capital and maintaining credit. Investors would have no reason to pass on purchasing the common equity of such a utility in favor of other investment opportunities. Thus, if the comparable earnings test is met, then the financial integrity and capital attraction standards are met as well.

Q. WHAT IS RISK?

A. Risk is the chance that an investment will lose value. A business, for example, may introduce a new product, supporting it with investment in plant and equipment. There is, of course, no guarantee that consumers will purchase the product, putting the investment in the plant and equipment at risk. The risk investors attach to the company varies inversely with their view as to the probability of the product doing well. In general, the greater the risk of an investment, the greater the return required to attract investors, and vice versa.

Q. DOES SETTING AN ALLOWED RATE OF RETURN MEAN THAT THE UTILITY WILL EARN THAT RETURN?

A. No. There is no guarantee that the utility will earn the allowed rate of return. The utility has the reasonable *opportunity* to earn the allowed rate of return; in practice, the utility may earn more or less than this return, depending on whether and how its management responds to technological and market developments, among other matters.

Q. WHAT SHOULD THE COMMISSION CONSIDER IN SETTING AN APPROPRIATE RATE OF RETURN?

A. The Commission should look to current market conditions as it balances investor and consumer interests. In this case, the rate of return should reflect the condition of the capital markets in which NSP will have to compete with other firms for funding. Historically allowed rates and historical performances are not appropriate inputs in this forward-looking approach. This statement, however, does not mean that historical rates and performance are irrelevant. They are factors because they affect investors' views of a company's prospects and, therefore, the investors' willingness to purchase its common equity shares.

Q. PLEASE EXPLAIN HOW THE METHODS YOU HAVE USED TO DETERMINE THE COST OF COMMON EQUITY CAPITAL FOR THE COMPANY REFLECT CURRENT MARKET CONDITIONS.

A. I used a market-oriented approach to determine the common equity cost for the Company. I analyzed the equity return that investors currently expect to receive from investing in companies with risks similar to the risk of the Company. Many factors influence these investor expectations, among them: past performance of the companies, estimates of how the companies will perform in the future, possible technological change, tax rates, and predicted general economic conditions. As investors decide where to place their funds among the investment options available to them, they weigh the information they have. Then they decide how much to pay to acquire common equity shares, or to turn to the other side of the question, what price will lead them to sell the shares. Either way, the factors are reflected in current prices in capital markets. Thus, my analysis is forward-looking because it relies on investors' current assessment of what is likely to happen with their investments.

Q. WHAT IS THE ROLE OF OPPORTUNITY COSTS IN YOUR ANALYSIS?

A. An opportunity cost is the value of the next best choice forgone as the result of making a decision. Opportunity costs are central to my analysis. As investors decide where to place their assets, they have many opportunities from which to choose in the financial markets. Economic theory says they will choose the opportunity they think will provide them the best return, taking into account the level of risk with which they are comfortable. Thus, for a company to attract capital, its forward-looking fair rate of return must at least equal the expected rate of return for the best alternative opportunity with similar risk.

III. OVERVIEW OF THE RETURN ON EQUITY ANALYSIS

Q. HOW DO YOU KNOW WHAT EQUITY RATE OF RETURN THE COMPANY MUST OFFER TO INVESTORS TO BE AN ATTRACTIVE OPPORTUNITY?

A. No one knows with certainty what specific rate of return the Company must offer to investors that is just sufficient to make the Company an attractive opportunity. However, various methods based on finance theory have been derived for reliably estimating what investors currently think that rate is.

Q. PLEASE IDENTIFY THE METHODS YOU HAVE ADOPTED IN YOUR ROE ANALYSIS.

A. I use the Discounted Cash Flow (DCF) method, which is widely used in utility general rate cases, and is a method relied on by the MPUC in determining rate of return. I also include the results of the Capital Asset Pricing Model (CAPM), combining them with the DCF results for my recommended ROE. I use recently authorized returns for natural gas utility operating companies in U.S. jurisdictions as a check on the reasonableness of the ROE outcome.

Q. PLEASE SUMMARIZE THE DCF METHOD.

A. The DCF model uses the current dividend yield and the expected growth rate of this yield to determine a required rate of return on an investment opportunity. The required rate of return from a DCF analysis is derived from a formula for determining the net present value, or price, of a share of stock. There are several variations of the DCF, but the constant-growth form I have selected assumes that dividends (D) are received at the end of each year, the annual growth rate of dividends (g) is constant forever, and the discount rate for dividends (k) is constant forever. The equation form of this constant-growth DCF model is the following:

$$k = \frac{D_1}{P_0} + g$$

Where:

k is the discount rate, which also is the fair rate of return for equity;

D_1 is the annual dividend one year from the present;

P_0 is the current price of a stock share; and

g is the expected growth rate of the dividend.

Q. HOW IS THE ANNUAL DIVIDEND ONE YEAR FROM THE PRESENT CALCULATED?

A. The annual dividend one year from now is derived by applying the growth-rate estimate (g) to the actual current annual dividend (D_0). The equation form is:

$$D_1 = D_0 * (1 + g)$$

Q. PLEASE DESCRIBE THE ELEMENTS OF THE DCF MODEL.

A. The first element of the DCF model is the dividend-yield component, while the second element is the dividend growth-rate component. The sum of these two components produces the required ROE for a company.

Q. PLEASE DISCUSS THE CAPM METHOD.

A. The premise of the CAPM method is that any risk which is company-specific can be diversified away by investors. Therefore, the only risk that matters is the systematic risk of the stock. This systematic risk is measured by beta (β). Expressed simply, the CAPM assumes the following form:

$$k = r + \beta (k_m - r)$$

Where:

k is the required rate of return for the subject stock;

β is beta, the measure of systematic risk;

r is the rate of return on a riskless asset; and

k_m is the required rate of return on the broad market.

[$(k_m - r)$ is known as the "market risk premium"]

Q. PLEASE CHARACTERIZE THE CAPM METHOD.

A. In the CAPM the required ROE for a company also is the sum of two components. The first of these is the return on a riskless asset. To this base value, a return is added that reflects the additional rate of return earned by other companies in the broad equity market

adjusted for the risk of the subject company relative to the risk of an average company in the market. The subsequent amount thus reflects the risk of the subject company.

Q. DOES YOUR EQUITY RATE OF RETURN ANALYSIS USE FINANCIAL INFORMATION FOR NSP?

A. No. As noted, NSP is an operating subsidiary of XEL. NSP is not publicly traded, so common equity share price information is unavailable. Therefore, a direct DCF analysis cannot be performed on the Company.

Q. DOES YOUR EQUITY RATE OF RETURN ANALYSIS USE OTHER NSP INFORMATION?

A. Yes. NSP has a Standard & Poor's ("S&P") credit rating of A-.[7] This credit rating reflects S&P's evaluation of the risk for the company. It is identical to the S&P credit rating for XEL, but is determined separately. The Company credit rating is one criterion that was applied in selecting natural gas utilities that are similar in risk to NSP.

Q. HOW DO YOU USE THE ROE ANALYSIS TO ESTIMATE THE COMPANY'S REQUIRED RATE OF RETURN?

A. I performed an ROE analysis on a group of natural gas utilities comparable to NSP that are publicly traded and have similar investment risk, as discussed below. The estimated rates of return for members of this group form the basis for my estimate of a fair rate of return for the Company.

[7] Exhibit MFG-2.

IV. SELECTING THE COMPARISON GROUP

Q. PLEASE DISCUSS YOUR PROCEDURE FOR SELECTING THE COMPARISON GROUP.

A. I set out to find a group of companies that are, from the perspective of investors, like NSP. Thus, I wanted firms that are natural gas utility companies that represent approximately the same investment risk as the Company.

Q. PLEASE DESCRIBE HOW YOU FOUND SUITABLE CANDIDATE COMPANIES FOR THE COMPARISON GROUP.

A. I looked at Value Line, a widely used investor service, for companies that Value Line classifies as members of the Natural Gas Utility Industry. The February 25, 2022, edition of the *Value Line Investment Survey* available at the Value Line website included 15 companies in this category.[8]

Q. WAS XCEL ENERGY INC. ONE OF THE 15 COMPANIES IN THE VALUE LINE NATURAL GAS INDUSTRY?

A. No.

Q. WHAT WAS THE NEXT STEP IN YOUR SELECTION PROCESS?

A. I applied screens to the initial set of Value Line Electric Utility companies to ensure that the companies included in my Comparison Group were similar in risk to the risk of the Company. [9]

Q. PLEASE LIST THE CRITERIA YOU APPLIED IN THE SELECTION OF THE COMPARISON GROUP.

A. I applied the following screens to the initial set of Electric Utility companies:

[8] Exhibit MFG-3.
[9] Exhibit MFG-4.

1. U.S.-based firm;
2. shares publicly traded on a stock exchange;
3. a stable record of paying dividends;
4. not be expected to sell, merge into or be acquired by another company, or be engaged in an unusual regulatory proceeding;
5. have a Standard & Poor's ("S&P") credit rating of BBB- (investment grade) or better;
6. have positive growth-rate projections from expert analysts; and
7. have 60 percent or more of the three-year average of net operating income, net income, or operating revenue be derived from regulated natural gas operations.

Q. WHAT IS THE PURPOSE OF APPLYING THE CRITERION THAT THE COMPANIES BE BASED IN THE CONTINENTAL UNITED STATES?

A. I sought companies that face a business environment like that in which NSP operates. The Company's operating utility in this case is in North Dakota and subject to state regulation, statutes, and rules that are similar to those found in the rest of the United States. China Natural Gas was excluded for not being U.S.-based.

Q. WHAT PURPOSE IS SERVED BY REQUIRING THAT THE COMPANIES BE PUBLICLY TRADED?

A. One analytical tool that I used for finding a company's ROE, the DCF model,[10] requires information about common equity share prices, dividends, and growth-rate projections. The requirement that companies be publicly traded ensures that their common equity share

[10] As will be seen in a later section, the forward-looking CAPM as I have applied it incorporates a DCF analysis and, thus, also relies on publicly traded companies.

prices are available. All the Value Line Natural Gas Utility companies were publicly traded.[11]

Q. WHAT PURPOSE IS SERVED BY REQUIRING THAT THE COMPANIES HAVE A STABLE RECORD OF PAYING DIVIDENDS?

A. The DCF model requires dividends as an input. If a company is not paying dividends or has a record of cutting dividends, then its DCF analysis is not reliable. All the companies still under consideration have been consistently paying dividends.[12]

Q. WHY IS IT IMPORTANT THAT COMPANIES INVOLVED IN SALES, MERGERS, OR ACQUISITIONS, USUALLY BE EXCLUDED FROM YOUR ANALYSIS?

A. The share prices of companies involved in sales, mergers or acquisitions can be volatile. Extreme increases in the share prices of companies that are part of sales, mergers, or acquisitions drive down the ROE results in DCF analysis, while extreme decreases in the share prices drive up the ROE results. Neither outcome yields meaningful DCF results. Therefore, it is usually appropriate to exclude such companies from the analysis.

Q. WERE ANY COMPANIES IN THE INITIAL SET INVOLVED IN SALES, MERGERS, OR ACQUISITIONS?

A. Yes. Corning Natural Gas Holding was involved in a merger.[13] In addition, South Jersey Industries ("SJI") announced on February 24, 2022, that it is being acquired by Infrastructure Investments Fund, a unit of J.P. Morgan Investment Management Inc.[14] Therefore, I excluded SJI from the Comparison Group. The announcement of the

[11] Exhibit MFG-3.
[12] China Natural Gas is not paying dividends, but it is already eliminated from consideration.
[13] Exhibit MFG-4.
[14] Exhibit MFG-5.

acquisition came after I performed my ROE analysis, so SJI is shown as part of the Comparison Group.[15] However, its data is not included in the calculations. SJI would not be eligible for the Comparison Group in any analysis conducted after this Direct Testimony is filed, such as Surrebuttal Testimony in this docket, which also was a factor in my decision to exclude it from the current analysis.

Q. WERE ANY COMPANIES IN THE INITIAL SET INVOLVED IN UNUSUAL CIRCUMSTANCES?

A. No.

Q. WHAT IS THE PURPOSE OF USING THE S&P CREDIT RATING AS A SCREEN?

A. S&P's experts incorporate financial risk and business risk into a firm's credit rating. Within these risk categories, S&P assesses such factors for public utilities as competitive advantage, operating efficiency, and scale, scope, and diversity. This last set of factors includes the effects of a utility's markets, service territories, and customer diversity on the company's cash-flow stability, and in turn on its risk level. After considering all the factors, S&P assigns a credit rating to a company. If companies have identical or similar credit ratings as determined by expert analysts, then their relative risks are similar. As S&P states:

> Creditworthiness is a multi-faceted phenomenon. Although there is no "formula" for combining the various facets, our credit ratings attempt to condense their combined effects into rating symbols along a simple, one-dimensional scale. Indeed, as discussed below, the relative importance of the various factors may change in different situations.[16]

[15] Exhibit MFG-13, Schedule 1, and others.
[16] Exhibit MFG-6.

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE S&P CREDIT RATING SCREEN.

A. Regardless of the utility type, I start with the credit rating of the subject company and work out a step at a time from that rating until I found enough companies that meet the other screens to make a group large enough that the results for one company do not dominate the ROE analysis. Please note that the credit rating screen does not require that companies have exactly the same credit rating as the subject company. The credit rating need only be similar to that of the subject company. The narrower the range of the credit rating, the more like the subject company's risk are the risk profiles of the companies within the range. However, the goal of having companies with risk similar to that of the operating company has to be balanced with the goal of having a reasonable number of companies in the Comparison Group so that no one company's result strongly influences the outcome.

Q. WHAT WAS THE RESULT OF YOUR APPLICATION OF THE CREDIT RATING SCREEN IN THIS DOCKET?

A. There were 12 companies remaining from the original group of 15 after the previous screens were applied. Of these utilities, Adams Resources & Energy, RGC Resources Inc., Star Group L.P, and UGI Corp. did not have an S&P credit rating and were excluded.[17] All these natural gas utilities have investment-grade credit ratings from S&P (or an equivalent credit rating). Many large institutional investors require that a company have an S&P investment-grade credit rating to be considered for inclusion in their portfolios. Therefore, companies that do not have investment-grade ratings are excluded by a large share of buyers and are not comparable with companies that do.

[17] China Natural Gas and Corning Natural Gas Holding, already excluded, also did not have S&P credit ratings.

Q. PLEASE DISCUSS THE CREDIT RATINGS OF CHESAPEAKE UTILITIES AND NEW JERSEY RESOURCES.

A. Neither Chesapeake Utilities nor New Jersey Resources has a credit rating from S&P. Chesapeake Utilities does have a rating of "1" from the National Association of Insurance Commissioners. This rating is equivalent to an A- credit rating (or higher) from S&P.[18] As for New Jersey Resources, Moody's has a credit rating for New Jersey Natural Gas, a subsidiary of New Jersey Resources, of A1.[19] This Moody's credit rating is equivalent to an S&P credit rating of A+.

Q. WHAT IS THE RANGE OF THE CREDIT RATINGS FOR THE REMAINING COMPANIES?

A. The eight remaining companies have S&P credit ratings (or an equivalent rating) ranging from BBB- to A+.

Q. YOU REQUIRED THAT ELECTRIC UTILITIES HAVE POSITIVE EARNINGS PER SHARE ("EPS") GROWTH-RATE FORECASTS TO BE INCLUDED IN THE COMPARISON GROUP. WHAT PURPOSE DOES THIS SCREEN SERVE?

A. If the growth-rate projections are negative or missing, then any DCF analysis performed on them is not meaningful. All eight companies still under consideration for the Comparison Group have at least two positive EPS growth-rate forecasts.[20]

Q. FINALLY, YOU REQUIRED THAT MORE THAN 60 PERCENT OF A COMPANY'S THREE-YEAR AVERAGE OF AN INCOME OR REVENUE INDICATOR BE DERIVED FROM REGULATED ELECTRIC UTILITY

[18] Exhibit MFG-7, Schedule 1.
[19] Exhibit MFG-7, Schedule 2.
[20] Exhibit MFG-4.

OPERATIONS TO BE INCLUDED IN THE COMPARISON GROUP. PLEASE EXPLAIN THE PURPOSE OF THIS CRITERION.

A. For the firms to have similar risks, they must operate in similar business environments. The Company is predominantly a regulated natural gas utility operation, so the firms considered for the Comparison Group also must have predominantly regulated operations. This criterion ensures that most of the Comparison Group firms' operations are in the same environment as that of the Company.

Q. WHAT WAS THE OUTCOME OF YOUR APPLICATION OF THIS SCREEN?

A. I included all eight companies in the Comparison Group after applying the operating income/net income/operating revenue screen.[21] One natural gas utility, Chesapeake Utilities, did not strictly meet the 60 percent screen. However, I included it in the Comparison Group because it fell just short of the cutoff. Chesapeake Utilities' regulated income share was 59.4 percent.[22]

Q. PLEASE DESCRIBE THE COMPARISON GROUP AFTER YOUR SCREENING.

A. The Comparison Group is composed of Atmos Energy, Chesapeake Utilities, New Jersey Resources, NiSource, Northwest Natural Holding Company, ONE Gas, Southwest Gas Holdings, and Spire, Inc.[23]

Q. PLEASE COMPARE THE MEMBERSHIP OF MR. D'ASCENDIS'S PROXY GROUP WITH THE MEMBERSHIP OF YOUR COMPARISON GROUP.

A. Mr. D'Ascendis's Proxy Group was composed of seven natural gas utilities. Those companies, including SJI, were members of the Comparison Group. The announcement

[21] Exhibit MFG-8.
[22] Exhibit MFG-9.
[23] Exhibit MFG-10.

regarding SJI came well after D'Ascendis Direct was filed in this proceeding, meaning Mr. D'Ascendis did not have a chance to include that fact in the selection of his proxy group. I included two natural gas utilities that Mr. D'Ascendis did not, Chesapeake Utilities and NISource. I stand by the screens I applied in selecting the Comparison Group and the natural gas utilities included.

V. DCF MODEL OVERVIEW

Q. WHAT IS THE PURPOSE OF A DCF ANALYSIS?

A. The goal of this analysis was to estimate an appropriate, forward-looking rate of return on equity. A DCF analysis requires a determination of expected growth rates and dividend yields in order to estimate this return.

Q. PLEASE DISCUSS EXPECTED GROWTH RATES.

A. Because a DCF analysis is forward-looking, I want to estimate the expected growth rate of dividends. Historical growth rates would be good indicators of the expected growth rate if both of the following are true:

- the dividend payout ratio and the realized rate of return on equity capital were constant in the past and could be assumed to remain constant in the future; and
- any growth in book equity was attributable solely to retained earnings.

If, in practice, these conditions held, then earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BPS") would all grow at the same rate, and the past growth rates for these factors would be the rate at which they would grow in the future.

Q. DID YOU USE HISTORICAL GROWTH RATES IN YOUR ANALYSIS?

A. No. The conditions necessary for historical growth rates to be good indicators of future growth rates are rarely satisfied. Most utilities' returns on equity and payout ratios have not remained constant over time. Further, growth in book value has occurred not only due

to retained earnings, but also due to the issuance of new shares of common stock. Consequently, past growth rates of earnings, dividends, and book equity are frequently unequal. Moreover, an industry may face a changed business environment, thereby making the past a poor basis for projecting the future. Historical growth rates can differ significantly from forward-looking projected growth rates due to such factors as inflation rates, tax rates, the role of an industry in the economy, and the regulatory environment. In view of these limitations of using historical growth rates, I based my estimated growth rates on projected growth rates as publicly provided by "Zacks Investment Research," a respected investor services company, Thomson Financial Network estimates provided on Yahoo! Finance, and "The Value Line Investment Survey."

Q. PLEASE DISCUSS THE DIVIDEND YIELDS USED IN YOUR DCF ANALYSIS.

A. To estimate the required rate of return on equity capital today, I estimated the expected dividend yield, D_1/P_0 where P_0 is the price of a share of common equity today and D_1 is the dividend in the next period. To find the dividends expected a year from now, I multiplied the current annual dividends paid by 1 plus the EPS growth rates for each company. The use of this dividend yield assumes that dividends are distributed at the end of each period (year). Since the current equity share price incorporates all market information considered relevant by investors, generally speaking, non-recent historical prices should be avoided in calculating the dividend yield. However, since share prices are volatile in the short run, it is desirable to use a period long enough to avoid short-term aberrations in the capital market.

Q. WHAT COMMON EQUITY SHARE PRICES DID YOU USE IN YOUR DCF ANALYSIS?

A. I used the average of four weeks of share prices for each natural gas utility. This period achieves the goals of using current information and avoiding cases where short-run volatility causes common-equity share prices to be unrepresentative of the value investors place on a company.

VI. DCF ANALYSIS FOR THE COMPARISON GROUP

1. Constant-Growth DCF Analysis

Q. PLEASE DISCUSS THE REQUIRED RATE OF RETURN FOR THE COMPARISON GROUP.

A. To estimate the required rate of return for the group, I found the expected growth rate, g, and the expected dividend yield, D_1/P_0 for each Comparison Group company. I applied the DCF model to the inputs to find an ROE for each natural gas utility. Finally, I averaged the ROEs to find my DCF ROE for NSP.

Q. WHAT PERIOD DID YOU USE TO ESTABLISH AVERAGE COMMON EQUITY SHARE PRICES FOR THE COMPANIES IN THE COMPARISON GROUP?

A. I used the trading period of January 31, February 25, 2022, to find average common equity share prices. This four-week period is long enough to dampen any short-term aberrations in the capital market. It was also close to the March 1, 2022, date of this Testimony, thus making the results timely. I used closing prices for the Comparison Group member companies obtained at Yahoo! Finance.[24]

[24] Exhibit MFG-11, Pages 1-3.

Q. HOW DID YOU DETERMINE THE DIVIDENDS FOR THE COMPARISON GROUP COMPANIES?

A. I used the dividends that each Comparison Group member company is currently paying as reported by Value Line on February 25, 2022, and by Zacks on February 22, 2022. I used the greater of these two options in my DCF analysis. The dividends were equal from the two sources except that Zacks reported a slightly higher dividend for SJI. (As noted, SJI data is excluded from my ROE analysis).[25]

Q. WHAT ASSUMPTION IS MADE ABOUT THE EXPECTED GROWTH RATE IN THE CONSTANT-GROWTH DCF MODEL?

A. In the constant-growth DCF model, it is assumed that current EPS growth rates continue to infinity. I used, as is commonly done, forecasts of EPS growth rates for five years and assumed those growth rates will continue.

Q. PLEASE DISCUSS THE EXPECTED GROWTH RATE FOR THE COMPARISON GROUP.

A. As noted above, it is appropriate in this proceeding to use only the forecasted growth rates to estimate the expected growth rate to be used in the DCF analysis. Zacks and Yahoo! Finance provide five-year growth-rate projections for EPS and Value Line provides five-year growth rate projections for EPS, DPS, and BPS. To maintain consistency across the sources, I used only the EPS estimates from Value Line.

[25] Exhibit MFG-12.

Q. WHAT INFORMATION DID YOU USE FROM VALUE LINE?

A. I used the Value Line EPS five-year growth projections for the individual firms in the Comparison Group as reported by Value Line in its Investment Surveys of February 25, 2022.[26]

Q. WHAT INFORMATION DID YOU USE FROM ZACKS?

A. I used the Zacks EPS five-year growth projections available February 20, 2022, for the individual firms in the Comparison Group.[27]

Q. WHAT INFORMATION DID YOU USE FROM YAHOO! FINANCE?

A. I used the Yahoo! Finance EPS five-year growth projections available February 20, 2022, for the individual firms in the Comparison Group.[28]

Q. HOW DID YOU COMBINE THE ZACKS, YAHOO! FINANCE, AND VALUE LINE ESTIMATES?

A. I weighted the Zacks, Yahoo! Finance, and Value Line EPS values equally to find my best estimate of the expected growth rate for each company in the Comparison Group.

Q. PLEASE DISCUSS YOUR CALCULATION OF THE EXPECTED DIVIDEND YIELD FOR THE COMPARISON GROUP.

A. The appropriate dividend to use in the constant-growth DCF model is the annual dividend rate at the beginning of the next period (year). I began my estimation of the expected dividend yield by finding the dividends that each Comparison Group member company was currently paying, as noted above.

[26] Exhibit MFG-13, Schedule 1.
[27] *Id.*
[28] *Id.*

Q. PLEASE CONTINUE.

A. Next, I adjusted the annualized dividends for expected growth. The dividends of all the companies in the Comparison Group are expected to increase over the next year. I applied a full year's growth rate for a firm to the annualized dividend and added the product to the annualized dividend yield to transform it into the expected dividend yield.[29] The equation for this operation is:

$$\frac{D_1}{P_0} = \frac{D_0}{P_0}(1+g)$$

Applying this equation to the dividend yield for each company yielded the D_1 values that I use in my estimates.[30]

2. Flotation Costs Adjustment

Q. PLEASE DEFINE FLOTATION COSTS.

A. When companies issue equity, the price paid by investors for the new shares is higher than the revenues per share received by the company. The difference is issuance, or flotation, costs. These costs are the fees and expenses the company must pay as part of the issuance. The return on equity must be adjusted to recognize this difference, or a company will be denied the reasonable opportunity to earn its required rate of return.

Q. DID YOU MAKE A FLOTATION COST ADJUSTMENT FOR THE COMPANY?

A. Yes. My recommended flotation cost adjustment was 0.925 percent. I calculated this value using information from Mr. D'Ascendis.[31] I used the most recent four issuances made by

[29] I followed this rule of applying a full year's growth to the current dividend in my CAPM analysis as well as in this DCF model analysis. My adjustment is larger than that of Mr. D'Ascendis.
[30] Exhibit MFG-13, Schedule 1.
[31] Exhibit ____ (DWD-1), Schedule 12, Page 1 of 1.

XEL, between 2013-2019.[32] The issuance costs for XEL were markedly lower for these four transactions than they were for prior issuances. Therefore, the recent issuance costs are a better indicator of Xcel's current costs than the set of costs dating back to 1949 that Mr. D'Ascendis used.

Q. HOW WAS THE FLOTATION-COST ADJUSTMENT INCORPORATED INTO YOUR DCF ANALYSIS?

A. The DCF return on equity was modified in the following way to incorporate the adjustment for flotation cost. [33]

$$k = \frac{D_1}{P_0}\left(\frac{1}{1-f}\right) + g$$

Where:

f is the flotation-cost percentage;

and all the other elements of the equation retain their previous meanings.

With the flotation cost of 0.925 percent incorporated, the expected dividend yield becomes the flotation adjusted dividend yield. The adjustment increases the expected dividend yield by about 3.4 basis points. [34]

[32] The four cost percentages were 1.179 percent, 1.097 percent, 1.002 percent, and 0.420 percent. The sum of the four is 3.698 percent, which yields an average of 0.925 percent.
[33] Exhibit MFG-13, Schedule 2. Morin, Roger, *New Regulatory Finance (2006)*, Public Utilities Reports, Inc., Vienna, Virginia, page 328.
[34] Exhibit MFG-13, Schedule 1.

Q. DID YOU INCLUDE A FLOTATION COST ADJUSTMENT IN ALL OF YOUR ROE ANALYSES?

A. Yes. All subsequent ROE analyses presented in this testimony included a flotation cost adjustment.

Q. IS IT APPROPRIATE TO APPLY A MINIMUM STANDARD TO ROE RESULTS PRODUCED BY THE ROE MODELS?

A. Yes. Investors demand a higher return from common equity than from debt to compensate for the greater risk of common equity. The Federal Energy Regulatory Commission ("FERC") uses a minimum standard of the yield for Moody's 10-Year Baa Corporate Bonds plus 20 percent of the CAPM risk premium as a minimum ROE threshold. Investors faced with an ROE for a company below that threshold would choose the less-risky debt over common equity investment in the company. Thus, NSP would not be competing with these companies for capital.

Q. DID YOU REMOVE ANY COMPANIES FROM THE DCF ANALYSIS BECAUSE THEY HAD ROE RESULTS THAT WERE UNREASONABLY LOW?

A. No. The average yield for the Moody's 10-year Baa Corporate Bond Yield Index was 3.58 percent over January 1-28, 2022,[35] while the mean of 20 percent of the CAPM risk premium was 1.95 percent.[36] The sum of the two components of the minimum threshold was 5.53 percent. All the ROEs in the analysis exceeded that value.

[35] Exhibit MFG-14 Schedule 5.
[36] Exhibit MFG-14, Schedule 8.

Q. WHAT ROE DID YOU FIND FOR YOUR CONSTANT-GROWTH DCF ANALYSIS?

A. For the eight companies (SJI excluded), the ROE was 9.53 percent. The median ROE was 9.79 percent.[37]

[37] Exhibit MFG-13, Schedule 1.

2. Multistage DCF Analysis

Q. WHAT ASSUMPTION IS MADE ABOUT THE EXPECTED GROWTH RATE IN THE MULTISTAGE DCF MODEL?

A. In the multistage DCF model it is assumed that the current growth rates are replaced by other growth rates in intervals subsequent to the present period. There are several possible approaches to a multistage analysis, but in many of the variations a long-run gross domestic product ("GDP") growth rate is adopted after the first stage.

Q. WHAT LOGIC SUPPORTS ADOPTING GDP GROWTH RATES AFTER THE FIRST STAGE OF A MULTISTAGE DCF ANALYSIS?

A. The logic for adopting a long-run GDP growth rate after the first stage of a multistage analysis is that a company cannot sustain growth faster than the growth rate of the economy as a whole over the long run.

Q. WHAT WAS YOUR BASIS FOR ASSUMING THAT CURRENT FORECASTED EPS GROWTH RATES WILL NOT CONTINUE AFTER FIVE YEARS?

A. The current five-year EPS growth-rate forecasts reflect growth expected as the U.S. economy rebounds from the recession caused by the COVID-19 pandemic. These growth rates are unsustainable because the economy is making use of productive capacity that was idled by the recession. Once the slack is restored to use, the potential growth level returns to long-run capacity growth rates.

Q. IS THERE ECONOMIC DATA THAT SUPPORT THIS HYPOTHESIS?

A. Yes. The U.S. economy turned sharply downward from long-term trends in the first quarter of 2020 as the pandemic took hold. In 2019, Bureau of Economic Analysis year-over-year

quarterly growth rates for U.S. GDP ranged between 2.1 percent and 2.6 percent.[38] The U.S. GDP growth rates for 2020 were 0.6 percent in the first quarter, -9.1 percent in the second quarter, -2.9 percent in the third quarter, and -2.3 percent in the fourth quarter[39]

Q. PLEASE CONTINUE.

A. Federal Reserve Board projections of annual GDP growth are 5.9 percent for 2021, 3.8 percent for 2022, and 2.5 percent for 2023.[40] These data are consistent with growth rates returning to long-term norms of about 2.0 percent as the U.S. economy climbs out of the pandemic-induced trough. It is reasonable, therefore, to assume that current five-year EPS growth-rate forecasts are pushed above sustainable levels by the burst in economic activity associated with the recovery. For example, the year-over-year GDP real growth rate in the second quarter of 2021 was 12.2 percent.[41] This rate represents recovery from the 9.1 percent decline in GDP that occurred in the second quarter a year earlier. It is not a rate of growth that can be expected to continue. Therefore, long-term GDP growth rates better reflect the long-term trend in EPS growth rates than do current 3- to 5-year EPS projections that reflect the 2021 second-quarter GDP growth rate and near-term projected growth rates.

Q. PLEASE IDENTIFY YOUR LONG-RUN GDP GROWTH RATES.

A. It was my opinion that the second-stage EPS growth rates will be similar to the long-run GDP growth rate forecasts of the Social Security Administration ("SSA") and the Energy Information Administration ("EIA"). I calculated long run GDP growth rates from 2027-2050 from information published by these two agencies.[42] The SSA rate is 3.95 percent,[43]

[38] The BEA and Federal Reserve Board GDP growth rates are "real," inflation-adjusted rates.
[39] Exhibit MFG-13, Schedule 3.
[40] Exhibit MFG-13, Schedule 4.
[41] Exhibit MFG-13, Schedule 3.
[42] The SSA and EIA GDP growth rates are "nominal." They reflect current prices and include inflation.
[43] Exhibit MFG-13, Schedule 5.

while the EIA rate is 4.35 percent.[44] The weighted rate of the two growth rates is 4.20 percent.[45]

Q. PLEASE DISCUSS THE USE OF REAL GDP GROWTH RATES AND NOMINAL GDP GROWTH RATES.

A. I used real and nominal GDP growth rates because that is how the agencies report them. The real rates could be converted to nominal rates by adding inflation rates to them. Doing so would not change the range of change in the rates, which is the important point about the rates. For example, there would still be a nearly 9 percent decrease in GDP from the first quarter of 2020 to the second quarter of 2020 as the inflation rates added would be similar, if not identical. Moreover, the difference between the actual GDP contraction rate in second quarter of 2020 and the projected growth rate for 2021 would also be about the same as inflation would be added to both sets of numbers. It is the large difference between these rates that indicate the room for short-run growth in the U.S. economy, a spurt that is not sustainable in the long run. Further, the long-term GDP growth rates that I used in my multistage ROE analysis are nominal rates, as are the forecasted EPS growth rates with which they are blended.

Q. PLEASE DESCRIBE YOUR MULTISTAGE DCF ANALYSIS.

A. I applied what is sometimes called a blended approach as my multistage DCF analysis. In this approach, all inputs other than the EPS growth rates are the same as in the constant-growth DCF analysis. I continued to use the five-year EPS forecasts in the first stage but used the weighted long-run GDP growth rate as my second-stage EPS input. At that point I blended the two growth rates by weighting the average of the five-year EPS forecasts

[44] Exhibit MFG-13, Schedule 6.
[45] Exhibit MFG-13, Schedule 8.

two-thirds and the long-run weighted GDP growth rate one-third. This approach is set forth in a widely used regulatory handbook.[46]

Q. WHAT IS THE RESULT OF YOUR MULTISTAGE DCF ANALYSIS?

A. For the eight companies (SJI excluded), the ROE was 8.90 percent. The median ROE was 9.09 percent.[47]

Q. HAVE YOU ADJUSTED YOUR DCF ROE TO ACCOMMODATE FACTORS OTHER THAN EPS GROWTH RATE CHANGES?

A. No. The DCF model incorporates factors that affect investors' view of the world. The share price of common equity is the mechanism through which these influences are translated. For example, investors' beliefs about the effect of a pandemic on the economy are translated into common equity share prices. The same is true of the effect on those prices of changes in federal income tax and depreciation rates, such as those implemented in the United States under the 2017 Tax Cut and Jobs Act. Either case affects the ROE of the company. Other factors that are incorporated into share prices are environmental regulations, interest-rate expectations, market volatility, and leverage of companies. Investors will ask for common equity prices that compensate them for the degree of risk that they believe these factors create.

VII. CAPM ANALYSIS FOR THE COMPARISON GROUP

Q. WHAT ARE THE STRENGTHS AND WEAKNESSES OF THE CAPM?

A. The CAPM is theoretically sound, but its application raises some issues. The analysis using CAPM selects a riskless asset, beta, and market risk premium. The ROE analysis can vary

[46] Exhibit MFG-13, Schedule 7; Morin, Roger, *New Regulatory Finance (2006)*, Public Utilities Reports, Inc., Vienna, Virginia, page 309.
[47] Exhibit MFG-13, Schedule 8.

considerably depending on the analyst's choices for these variables. Thus, what at first may seem like a model that is straightforward depends heavily on the particular input values used by an analyst.

Q. PLEASE DESCRIBE THE CAPM VERSION THAT YOU EMPLOYED IN YOUR ROE ANALYSIS.

A. I based my CAPM analysis on the version that the Federal Energy Regulatory Commission ("FERC") first adopted in Opinion 569.[48] This approach addresses potential flaws in the CAPM. The FERC model is forward-looking and includes rules and methods that remove analyst judgment that can cause CAPM analyses conducted at the same time to vary widely. I do not adopt al the FERC procedures, but I follow its outline.

Q. PLEASE IDENTIFY THE RULES FERC APPLIES FOR INCLUDING COMPANIES IN A CAPM ANALYSIS.

A. Starting with the S&P 500 as its base for determining the broad market return, FERC requires that companies included in the market return analysis be paying dividends, an essential part of any DCF analysis. Companies with EPS estimates less than 0 percent and greater than 20 percent are excluded, thereby handling the problem of outliers at either end of the spectrum.

Q. WHAT SOURCE FOR SHORT-TERM EPS FORECASTS FOR S&P 500 COMPANIES DID FERC SPECIFY BE USED IN A CAPM ANALYSIS?

A. FERC specified that the EPS forecasts for S&P 500 companies be from Yahoo! Finance. I included the Yahoo! Finance EPS forecasts in my analysis in this docket.[49]

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[48] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.,* Opinion No. 569, 169 FERC ¶ 61,129 (2019). Issued November 21, 2019, pages 134, 138, 184-185.

[49] The Yahoo! Finance EPS forecasts are IBES EPS forecast values. Yahoo! Finance and IBES are used interchangeably in this testimony.

Q. HAS FERC ADDED A SOURCE FOR SHORT-TERM EPS FORECASTS IN CAPM ANALYSIS IN A SUBSEQUENT OPINION?

A. Yes. In Opinion 569-A, FERC stated that it would consider the use of Value Line short-term EPS forecasts in the CAPM in future proceedings.[50] I included the Value Line EPS forecasts in my analysis in this docket.

Q. PLEASE DISCUSS THE RISK-FREE RATE THAT YOU USED.

A. For the risk-free rate, FERC uses a six-month average of 30-year Treasury bond yields, not forecasts of those bond yields. I departed from this aspect of the FERC analysis. I use an average of 30-year Treasury bond yields like FERC, but for a four-week period, not six months. This treatment of average yields is consistent with how I find average equity prices within the DCF model.

Q. PLEASE EXPLAIN THE CALCULATION OF A CAPM ROE.

A. First, the analyst must select the rate of return for a riskless asset. Short-term assets such as 90-day Treasury Bills are considered to be virtually riskless; the default risk is next to nothing, and the inflation risk is negligible. Equity investors, however, typically have a longer planning horizon than the 90-day maturity of these instruments, so the return on these bills is not suitable for this CAPM process. Long-Term Treasury bonds, on the other hand, match the planning horizon and have yields that are closer to common equity returns. But these instruments are subject to substantial inflation risk and, therefore, are not strictly riskless. Nevertheless, I adopted the 30-year U.S. Treasury yield as my risk-free rate. Its favorable characteristics outweigh its unfavorable characteristics.

[50] *See Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154, ¶¶ 58 (2020).

Q. WHAT PERIOD DID YOU USE FOR THE 30-YEAR TREASURY YIELD IN YOUR CAPM ANALYSIS?

A. I used the average yield on a 30-year Treasury bond for January 1-28, 2022, as my riskless asset rate. This average yield was 2.07 percent.[51] As noted above, I departed from the FERC approach by using a four-week average of recent yields. The six-month period FERC uses includes data that is stale and, therefore, does not reflect investors' current views regarding the future of the economy.

Q. WHY DID YOU USE THE RECENT 30-YEAR TREASURY YIELD IN YOUR CAPM ANALYSIS?

A. Current yields on the 30-year Treasury bond are the best risk-free rate for the CAPM analysis. Much like current common equity share prices reflect all information about factors affecting the value of the shares, so too do current bond yields capture the beliefs of investors as to where yields on the instruments are headed.

Q. WHAT VALUES DID YOU USE FOR BETA (β)?

A. I used the betas for each company in the Comparison Group taken from the Value Line website on February 25, 2022.[52] These beta values are Value Line's latest assessment for each company.

Q. HOW IS BETA (β) INTERPRETED?

A. A beta of 1 indicates that a company's share price will move with the market, while a beta higher than 1 indicates that a stock will be more volatile than the market, and a beta lower than 1 indicates that a stock will be less volatile than the market.

[51] Exhibit MFG-14, Schedule 1.
[52] Exhibit MFG-14, Schedule 2.

Q. WHAT ELSE WAS INVOLVED IN YOUR CALCULATION?

A. The term within parentheses in the CAPM equation is called the "market risk premium (MRP)." It is the difference between the return on a broad market measure and the risk-free rate of return. In other words, the premium that investors require in order to take on risk. As noted above, I already had the risk-free rate. Therefore, I needed to calculate a market rate of return.

Q. WHAT METHOD DID YOU USE TO FIND THE MARKET RETURN?

A. As stated, I use the S&P 500 inputs in finding my market risk premium. FERC prescribes the I/B/E/S EPS forecasts published by Yahoo! Finance, and as noted above, added the Value Line EPS forecasts as an additional source. I downloaded these values from the respective sources on February 7, 2022, and February 8, 2022. I downloaded the dividend yields for the S&P 500 companies from Value Line, also on February 8, 2022. I applied the I/B/E/S EPS growth rates[53] and Value Line growth rates[54] to the dividend yields to find the expected dividend yield, adding a full year's growth.

Q. WHAT WERE THE NEXT STEPS IN FINDING THE CAPM RETURN ON EQUITY?

A. I applied the dividend-paying rule, and the minimum and maximum threshold rules of less than 0 percent and greater than 20 percent to the set of S&P 500 companies. The companies that met the screens in the IBES and Value Line S&P 500 sets are different from one another because the EPS forecasts vary from company to company within the sets.[55]

[53] Exhibit MFG-14, Schedule 3.
[54] Exhibit MFG-14, Schedule 4.
[55] Exhibit MFG-14, Schedule 3 and Exhibit MFG-14, Schedule 4.

Q. WHAT WAS THE FOLLOWING STEP?

A. I weighted the remaining ROEs by the market capitalization for each company. The sum of those individual ROEs is the market return. The value for the IBES set was 14.02 percent.[56] The market risk premium was calculated by subtracting the 2.07 percent return on the 30-year Treasury from the market return. The result of this operation was 11.95 percent for the IBES set. This amount is multiplied by the beta for each Comparison Group company to find that company's CAPM ROE.[57] The corresponding values for the Value Line set are a market return of 9.61 percent,[58] the same 2.07 percent risk-free rate of return, and a market risk premium of 7.54 percent. This amount is multiplied by the beta for each Comparison Group company to find that company's CAPM ROE. [59]

Q. DOES FERC HAVE SCREENS FOR OUTLIER CAPM ROES?

A. Yes. FERC applies Low-End and High-End Test to the CAPM adjusted ROEs. My Low-End Test is the same as the minimum threshold for the DCF ROEs, the four-week average of the Moody's 10-year Baa Corporate Bond Yield Index value of 3.58 percent plus 20 percent of the CAPM risk premium. The High-End Test is 200 percent of the median value of all companies included in the analysis. The values of the outlier tests are different in the IBES and Value Line analyses because of the different market risk premiums produced. However, no CAPM ROEs were removed due to the Low-End or High-End Tests in either of my analyses. I combined the two analyses to find a mean Low-End Test of 5.53 percent. [60] I note again that SJI is excluded from the CAPM ROE analyses.

[56] Exhibit MFG-14, Schedule 3.
[57] Exhibit MFG-14, Schedule 6.
[58] Exhibit MFG-14, Schedule 4.
[59] Exhibit MFG-14, Schedule 7.
[60] Exhibit MFG-14, Schedule 8.

Q. WHAT WAS THE RESULT OF YOUR CAPM ANALYSIS?

A. The mean ROE for my IBES CAPM analysis was 12.34 percent and the median ROE was 11.96 percent.[61] The mean ROE for my Value Line CAPM analysis was 8.56 percent and the median ROE was 8.32 percent.[62] These values include a flotation-cost adjustment of 3.4 basis points.

Q. HAVE YOU INCLUDED A SIZE ADJUSTMENT IN YOUR CAPM ANALYSES?

A. No. I did not include a size adjustment. There are studies that indicate the size adjustment is not appropriate for the CAPM. The studies show that the effect disappears for years at a time and does not manifest itself in the prices investors pay for smaller and larger stocks.[63] Further, the studies that have shown a size effect may be examples of data mining: e.g., start and stop periods for the data to be studied that show a size effect, but the finding cannot be replicated when the span of the study has different beginnings and ends.[64] The studies recommend not making adjustments for an effect that may be transitory, at best, and not one that investors demand in the prices they pay for common equity.

[61] Exhibit MFG-14, Schedule 6.
[62] Exhibit MFG-14, Schedule 7.
[63] Damodaran, Aswath, "The Small Cap Premium: Where is the Beef?" Business Valuation Review, Volume 34, Number 4 (2015).
[64] Ang, Clifford S., "The Absence of a Size Effect Relevant to the Cost of Equity." Business Valuation Review, Volume 37, Number 3 (2018).

VIII. RECOMMENDED ROE

Q. PLEASE SUMMARIZE YOUR ROE RESULTS.

A. I performed four ROE analyses, constant-growth and multistage DCF, and S&P 500 market return constant-growth and multistage CAPM. Those ROE values are:

DCF ROE Mean and Median Results (Without SJI)

	Constant growth	Multistage
Mean	**9.53%**	**8.90%**
Median	**9.79%**	**9.09%**

CAPM ROE Mean and Median Results (Without SJI)

	IBES	Value Line
Mean	**12.34%**	**8.56%**
Mean	**11.96%**	**8.32%**

Q. PLEASE COMMENT ON THE DCF ROE RESULTS.

A. The DCF constant-growth ROE result was higher than the multistage counterpart ROE. This outcome is to be expected given the recent history for GDP of sharply negative growth rates, followed by further negative growth rates (though not as severe), and above-average growth rates. The constant-growth model reflects the short-lived sharp upward bursts in the growth rates as the economy recovers from the contraction. The multistage approach, on the other hand, moderates the influence of these recent negative growth rates by incorporating the lower, steadier positive long-run growth rates.

Q. PLEASE COMMENT ON THE CAPM ROE RESULTS.

A. The CAPM ROE results show greater variability than the DCF ROE results. Whereas the difference between the DCF ROE results from the different approaches is about 1 percent, the difference in the CAPM ROE results from the two sources of EPS growth-rate forecasts is more than 3.60 percent whether comparing the means or the medians. This range of results is common to CAPM analyses.

Q. WHAT WEIGHTS DID YOU ASSIGN TO THE FOUR ROE ANALYSES?

A. The DCF model constant-growth and multistage results were within the range of authorized ROEs from 2019-2021 for U.S. natural gas utilities as reported by Regulatory Research Associates ("RRA") a unit of S&P Global IQ Pro.[65] For this reason, I gave these ROE results the most weight, 37.5 percent each. The IBES S&P 500 CAPM result received the lowest weight, 10 percent. The result of 12.34 percent is more than 2 percent greater than the single highest authorized ROE in the 2019-2021 period. Being outside the range does automatically mean a result is suspect, but such a large discrepancy is an indication the value is not in step with current ROEs. The Value Line S&P 500 CAPM result of 8.56 percent also was outside the range, being 24 basis points lower than the single lowest authorized ROE in the RRA report. Therefore, this CAPM ROE result received a weight of 15 percent. This weight recognizes that the Value Line S&P 500 value was outside the range, but not by as much as the IBES S&P 500 result.[66]

Q. WHAT WAS THE WEIGHTED AVERAGE OF THE FOUR ROE ANALYSES?

A. The weighted average of the four models' means was 9.43 percent.[67]

[65] Exhibit MFG-15.
[66] Exhibit MFG-16, Schedule 1.
[67] *Ibid.*

Q. HOW DID YOU ARRIVE AT A RECOMMENDED ROE FOR NSP?

A. In the present circumstances, recent U.S. economic performance and short-run forecasts support the narrative that EPS forecasts for the next five years are temporarily high and can be expected to decline as growth in the domestic economy returns to typical levels. This scenario does not mean that the U.S. economy is headed for a period of poor performance. Rather, it means that the opportunities for large growth rates due to the presence of unused resources caused by the economic downturn will taper off as the economy returns to greater use of its economic potential. My weighted-average NSP ROE of 9.43 percent fits this scenario.

IX. REASONABLENESS CHECK OF THE RECOMMENDED ROE

Q. HAVE YOU CHECKED THE REASONABLENESS OF YOUR ROE RESULTS?

A. Yes. I checked the reasonableness of my analyses' outcomes by comparing the ROEs with recent ROEs authorized in natural gas rate cases across the United States.

Q. PLEASE EXPLAIN WHICH AUTHORIZED ROES YOU USED TO CHECK THE REASONABLENESS OF YOUR DCF AND CAPM ROES.

A. I collected the set of 2019-2021 authorized ROEs from U.S. natural gas rate cases from S&P Global Market Intelligence's Regulatory Research Associates (RRA).[68]

Q. HOW DO YOU USE THIS SET OF AUTHORIZED ROES?

A. I use the recent authorized ROEs as a basis for evaluating the reasonableness of my ROE results. I did not use it as a substitute for those analyses.

[68] Exhibit MFG-15.

Q. WHY ARE AUTHORIZED ROES NOT A GOOD SUBSTITUTE FOR CURRENT, FORWARD-LOOKING ROE ANALYSES?

A. Recently authorized ROEs reflect the results of rate cases conducted in a variety of environments and at different times. Test years, conditions in capital markets, general economic indicators such as inflation rates, and so forth for previous rate cases can be different and become outdated when compared with these factors for a current rate case. Therefore, recently authorized ROEs should serve only to establish whether a current ROE result is reasonably close to what has happened, not be a substitute for forward-looking analysis based on current conditions.

Q. PLEASE DESCRIBE THE SET OF AUTHORIZED ROES YOU COLLECTED.

A. RRA listed 30 cases for 2019, 34 for 2020, and 42 for 2021 for which an ROE was provided.

Q. PLEASE DISCUSS THE ROE AWARDS MADE IN 2019, 2020, AND 2021.

A. The following table summarizes the authorized ROE results for the cases in 2019, 2020, and 2021.

Summary of ROE Awards for 2019-2021

Year	No. of Cases	Mean ROE	Median ROE	ROE Range
2021	42	9.56	9.60	8.80-10.24
2020	34	9.46	9.50	8.80-10.00
2019	30	9.72	9.72	9.00-10.25

My recommended ROE of 9.43 percent is within the range of each year and slightly below the means and medians for the years. Therefore, I conclude that this ROE is reasonable.

X. RECOMMENDED CAPITAL STRUCTURE AND OVERALL RATE OF RETURN

Q. WHAT DID YOU INCLUDE IN YOUR OVERALL RETURN ANALYSIS AS THE COSTS OF CAPITAL FOR NSP?

A. I accepted the Company's proposed cost of long-term debt of 4.10 percent and short-term debt cost of 1.09 percent as presented in NSP-MN Regulated Capital Structure, C1. Cost of Capital Schedule, Page 1 of 2.

Q. WHAT WAS THE CAPITAL STRUCTURE YOU RECOMMENDED FOR THE NSP?

A. I recommended a capital structure of 47.57 percent long-term debt, 0.43 percent short-term debt, and 52.00 percent common equity.

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED CAPITAL STRUCTURE?

A. To find my recommended capital structure, I calculated the average long-term debt, short-term debt, and common equity ratios for the eight natural gas utilities in the Comparison Group. These average ratios reflected the dollar amount by company for each of the eight quarters from the first quarter of 2020 to the fourth quarter of 2021. The source of the amounts upon which the company ratios were based is S&P Global Market Intelligence.[69]

Q. WHY DID YOU SELECT THESE EIGHT QUARTERS FOR YOUR CAPITAL-STRUCTURE ANALYSIS?

A. I used two years of data to smooth the effects of any quarter that was an outlier. Using two years of data also mitigated any seasonal effects on the capital structures. The fourth

[69] Exhibit MFG-16, Schedule 2.

quarter of 2021 is the most recent quarter for which data were available. Therefore, I began my analysis with data from the first quarter of 2020.

Q. DID YOU MAKE ANY ADJUSTMENTS IN YOUR CAPITAL-STRUCTURE ANALYSIS?

A. Yes. First, I excluded SJI because it is about to be acquired by a unit of J. P. Morgan and Co. Then I excluded the fourth quarter 2021 results because they were available for only three companies. I also calculated the ratios with New Jersey Natural Gas's capital structure substituted for NJR's capital structure to test the effect. I further calculated the ratios with companies with low common-equity ratios or exceptionally high short-term debt ratios excluded. Finally, I calculated long-term debt and common-equity ratios with short-term debt excluded because the high short-term debt ratios might be distorting the outcome.[70]

Q. PLEASE SUMMARIZE THE CAPITAL-STRUCTURE RATIOS IN YOUR ANALYSIS.

A. In all cases but the situation excluding short-term debt, the long-term debt and common-equity ratios were less than 50 percent, usually significantly so. The short-term debt ratios for the companies were unusually high, much higher than NSP's requested short-term ratio of 0.43 percent. This mismatch between the other natural gas companies' short-term debt ratios and NSP's requested short-term debt ratio was the impetus for my analysis excluding short-term debt. In one of the scenarios the ratios were 48.01 percent long-term debt and 51.99 percent common equity. This common-equity ratio is the highest in my analysis. This outcome is what supports my recommended capital structure for NSP.

[70] Exhibit MFG-16, Schedule 2.

Q. WHAT WAS YOUR RECOMMENDED CAPITAL-STRUCTURE RATIOS FOR NSP?

A. My recommended capital-structure ratios were 47.57 percent long-term debt, 0.43 percent short-term debt, and 52.00 percent common equity.[71] These recommended ratios reflect the ratios I found in my analysis for the Comparison Group and the Company's requested ratios. I adopted NSP's 0.43 percent requested short-term debt ratio. The 51.99 percent common-equity ratio was the highest I found in my analysis, so rounded it to 52.00 percent. I increased the long-term debt ratio to 47.57 percent because that value is close to both the Company's request and the average for the proxy group companies. The Company's requested 52.54 percent common equity was greater than any ratio I found for the Comparison Group, even adjusting for extreme values. Therefore, I recommended reducing the ratio from 52.54 percent to fit better with the mean ratio for the peer companies and moving the 0.54 percent to long-term debt.

Q. WHAT IS THE OVERALL ROR THAT YOU RECOMMENDED FOR THE COMPANY?

A. When my estimated ROE of 9.43 percent was included with the proposed capital structure and the Company's costs for the other capital-structure elements, the ROR is 6.86 percent.[72]

[71] Exhibit MFG-16, Schedule 3.
[72] Exhibit MFG-16, Schedule 3.

XI. REVIEW OF THE COMPANY'S ROE ANALYSIS

1. Comparison Group vs. Proxy Group

Q. PLEASE COMPARE THE MEMBERSHIP OF YOUR COMPARISON GROUP WITH THE MEMBERSHIP OF MR. D'ASCENDIS'S PROXY GROUP.

A. As noted previously, Mr. D'Ascendis's Proxy Group had seven members to my Comparison Group's eight members. There was an overlap of six natural gas utilities.

Q. WHAT EXPLAINS THE DIFFERENCES IN THE MEMBERSHIP OF THE TWO GROUPS?

A. The difference is I included Chesapeake Utilities and NiSource in the Combination Group, while Mr. D'Ascendis did not include them in his Proxy Group.[73] I do not know which of his screens the companies failed.

Q. WHAT FACTORS ACCOUNT FOR THE DIFFERENCES IN THE ROE ANALYSES VALUES?

A. The different dates of the analyses account for some of the difference. EPS growth rates, share prices, dividend amounts, beta values, and risk-free rates can change substantially in a few months. These changes cause ROEs for individual proxy group member companies to be different from what they were a few months before. Thus, even when group memberships overlap, differences occur.

[73] This assumes Mr. D'Ascendis will remove SJI from his group because it is involved in a merger or acquisition. I think it is likely that he will as he has applied that screen in the past.

2. CAPM Analysis

Q. WHAT SOURCES DID MR. D'ASCENDIS USE TO CALCULATE MARKET RETURNS FOR HIS CAPM ANALYSES?

A. Mr. D'Ascendis used estimates provided by Value Line and Bloomberg as proxies for the market index.

Q. DID MR. D'ASCENDIS EXCLUDE COMPANIES NOT PAYING DIVIDENDS FROM HIS BROAD MARKET RETURN ANALYSES?

A. It appears that Mr. D'Ascendis did not exclude companies not paying dividends from his three broad market return analyses. His descriptions of the sources for his market returns do not mention such an exclusion. [74]

Q. PLEASE EXPLAIN WHY MR. D'ASCENDIS' BROAD MARKET RETURN RESULTS WERE FLAWED IF THEY INCLUDED COMPANIES NOT PAYING DIVIDENDS.

A. The constant-growth rate DCF model calculates the price of a dividend-paying stock growing at a constant rate per the following expression: [75]

$$P = \frac{D_1}{1+K} / (1 - \frac{1+g}{1+K})$$

If the stock pays no dividends, D_1 is zero, and the price of the stock is zero, according to the model. Investors cannot purchase equities for this price. Therefore, the DCF model results are not reliable for non-dividend paying companies.

[74] D'Ascendis Direct, page 44, line 17-page 46, line 8.
[75] Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., Vienna, Virginia (2006), page 273.

Q. IS THERE SUPPORT FOR THE PROPOSITION THAT THE DCF MODEL CANNOT BE APPLIED TO COMPANIES NOT PAYING DIVIDENDS?

A. Yes. The following passage is from FERC Opinion No. 569, cited earlier.

> **f. Commission Determination**
> "260. We continue to find reasonable the MISO TOs' proposal to estimate the CAPM expected market return using a forward-looking approach, based on applying the DCF model to the dividend-paying members of the S&P 500. Using a DCF analysis of the dividend-paying members of the S&P 500 is a well-recognized method of estimating the expected market return for purposes of the CAPM model.[563] *The DCF analysis must be limited to the dividend-paying members of the S&P 500, rather than using all companies in the S&P 500, because a DCF analysis can only be performed on companies that pay dividends."*[76] *[Emphasis added]*

Q. WHAT IS THE CONSEQUENCE OF INCLUDING NON-DIVIDEND PAYING COMPANIES IN A DCF ANALYSIS?

A. The consequence of including non-dividend paying companies in a DCF analysis is that the market return value is tainted.[77] As shown, the application of the DCF model to such companies yields ROE results that cannot be defended. Therefore, Mr. D'Ascendis's three broad market returns were flawed, as were the ROE approaches in which they are applied. These included his CAPM analysis as applied to his proxy group and to the set of unregulated companies Mr. D'Ascendis asserts have the same risk level as NSP.

[76] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.,* Opinion No. 569, 169 FERC ¶ 61,129 (2019), page 134.

[77] Dr. Griffing's calculation of the S&P 500 market return shows that many of the initial sets of companies were not paying dividends. (See Exhibit MFG-14, Schedules 3-4). Thus, the inclusion of these companies in calculating the S&P market return is not a minor matter.

Q. PLEASE IDENTIFY ANOTHER DIFFERENCE BETWEEN YOUR APPLICATION OF THE CAPM AND MR. D'ASCENDIS'S APPLICATION OF THE CAPM.

A. Mr. D'Ascendis used forecasted yields for the 30-year U.S. Treasury bond from *Blue Chip Economic Indicators* as his risk-free rate for some versions of his CAPM analysis.[78] My risk-free rate was based on current yields for the 30-year U.S. Treasury bond.

Q. WHAT IS THE RECORD OF *BLUE CHIP* IN FORECASTING ACTUAL 30-YEAR U.S. TREASURY BOND YIELDS?

A. *Blue Chip* forecasts of the 30-year U.S. Treasury bond consistently overstated the actual yields from 2010 until a recent forecast covering the second quarter of 2021 through the first quarter of 2022. With one quarter of results yet to come, that forecast of an average yield of 1.98 percent over the span is 6 basis points less than the running average for three calendar quarters. The previous forecasts, apart from one that was 9 basis points over the actual average yield, ranged from 39 basis points to 146 basis points above the actual average yields.[79] [80]

Q. DO INVESTORS BELIEVE THAT *BLUE CHIP* FORECASTS ARE ACCURATE PREDICTORS OF BOND YIELDS?

A. Given the prolonged period where *Blue Chip* yield forecasts exceeded the actual yields that transpired, it is questionable that investors accept *Blue Chip* forecasts without reservation. Utility company witnesses frequently state that studies show investors do accept the *Blue Chip* forecasts as accurate. However, those studies pre-date the 2009 start of the period

[78] D'Ascendis Direct, page 36, lines 2-20.
[79] Exhibit MFG-17.
[80] Exhibit MFG-18.

where the forecasts have overstated the actual yields. I have looked in an online website, *JSTOR*, that provides access to leading academic journals, including those in economics and finance, for studies that ask investors their beliefs about the accuracy of bond yield forecasts after the forecasts have proved inaccurate for so long. I have not been able to find such a study. The absence of such studies incorporating the poor performance of *Blue Chip* forecasts since 2009 in the record in this docket mean that Mr. D'Ascendis's use of a bond-yield forecast likely overstates what investors believe about the forecasts. Thus, his forecasted risk-free rate of 2.88 percent for his CAPM analysis also was overstated.[81]

Q. WHAT IS THE EFFECT ON CAPM RESULTS OF USING AN OVERSTATED RISK-FREE RATE?

A. An overstated risk-free-rate causes CAPM ROE results to be higher than for applications of the model that use current yields on 30-Year U.S. Treasuries as the risk-free rate.

3. Non-Price Regulated Companies Analysis

Q. PLEASE DESCRIBE MR. D'ASCENDIS'S COMPARABLE RISK ANALYSIS.

A. Mr. D'Ascendis asserted that the comparable risk standard for determining an ROE for a regulated utility such as NPSM can be applied to non-price regulated companies if they are comparable in risk to the subject utility. He formed a proxy group for such companies using Value Line betas and standard errors as screening criteria. The betas and standard errors had to fall within two standard deviations of the values of the same parameters for the natural gas utility Proxy Group companies. He then applied the DCF model, risk premium model, and CAPM to the resulting proxy group of 48 companies. He argued that

[81] D'Ascendis Direct, page 36, lines 14-20.

the ROEs derived were indicators of the level of return required by NSP because the risks were similar.[82]

Q. WHAT ROLE DOES VOLATILITY OF CASH FLOW PLAY IN THE CREDIT RATINGS THAT COMPANIES RECEIVE?

A. Price regulated companies such as the natural gas utilities used by Mr. D'Ascendis and me in our proxy groups tend to have cash flow that is less volatile than the cash flow of non-price regulated companies. S&P considers both level and volatility of profits as it assigns leverage ratings to companies. Firms with lower leverage ratings receive better credit ratings. Therefore, companies with less volatile cash flow receive better credit ratings.

Q. PLEASE ELABORATE.

A. S&P explains in an excerpt from its publication "Key Credit Factors for the Regulated Public Utilities Industry" that in assessing the adequacy of cash flow of a regulated utility that S&P analysts take into account volatility of cash flow, just as they do for other corporate issuers. One measure of volatility is the percentage of cash flow from regulated activities. Utilities, with a higher percentage of their cash flow coming from regulated activities, typically are regarded as less volatile.[83]

Q. PLEASE EXPLAIN HOW S&P COMBINES VOLATILITY RATINGS WITH CASH FLOW IN RATING COMPANIES.

A. S&P includes three tables of different volatility ratings in its credit rating discussion publication "General: Corporate Methodology." The tables show that for a company, regulated or not, to receive a certain leverage rating, it must demonstrate that it meets certain thresholds for core ratios, coverage ratios, and payback ratios. Companies rated

[82] D'Ascendis Direct, page 59, line 4-page 60, line 21.
[83] Exhibit MFG-19, Schedule 1, Pages 1-2.

low in volatility do not have to meet levels as stringent as companies rated medial or standard in volatility do to receive the same leverage rating.[84]

Q. PLEASE PROVIDE AN EXAMPLE.

A. The standard for a company with a low volatility rating to receive a "minimal leverage" rating for the funds from operations ("FFO")-to-debt ratio is 35 percent or better. In contrast, a company with a standard volatility rating has to have an FFO-to-debt ratio of 60 percent or better to receive the same "minimal leverage" rating.[85] Recall that lower volatility is associated with better credit ratings.

Q. PLEASE DESCRIBE HOW HAVING TO MEET A LOWER RATIO TO RECEIVE THE SAME LEVERAGE RATING ADDRESSES RISK LEVELS OF PRICE REGULATED.

A. The FFO-to-debt ratio is one of seven indicators that S&P considers in assigning an overall leverage rating in its credit rating process. A "minimal leverage" rating is associated with higher credit ratings. Thus, a price regulated public utility with its tendency to receive a low volatility rating because a "vast majority"[86] of its cash flow comes from regulated activities will, all other things equal, receive a better leverage rating and better credit rating than will a non-price regulated company. A non-price regulated company by definition does not have a substantial percentage of cash flow coming from regulated activities.

[84] See paragraphs 76-77 of Exhibit MFG-19, Schedule 2, Pages 1-2.
[85] See the shaded areas in the FFO/Debt columns of Table 17 and Table 19 in Exhibit MFG-19, Schedule 2, pages 1-2.
[86] See paragraph 78 of Exhibit MFG-19, Schedule 1, page 2.

Q. HOW CAN NON-PRICE REGULATED FIRMS RECEIVE A CREDIT RATING IDENTICAL TO THAT OF PRICE REGULATED UTILITIES?

A. Firms with less desirable volatility ratings, such as the volatility rating a typical non-price regulated firm is likely to receive, can make up for their greater cash flow uncertainty with higher FFO-to-debt ratios, to name one compensating factor. These firms can achieve higher ratios if they have greater cash flow than price regulated firms. Higher rates of return to equity can produce greater cash flow. Hence, higher return to equity enables the non-price regulated firms to receive credit ratings equal to the credit ratings of their price regulated counterparts.

Q. DOES IT FOLLOW THAT A NON-PRICE REGULATED COMPANY WITH THE SAME CREDIT RATING AS A PRICE REGULATED UTILITY IS A GOOD PROXY FOR THE PRICE REGULATED UTILITY?

A. No. Non-price regulated companies with greater cash flow volatility tend to require greater return on equities than their price-regulated counterparts. As shown above, greater return on equity is a way non-price regulated firms can attain equality in S&P volatility ratings with price regulated utilities and take a step toward the same credit rating. Hence, the non-price regulated firms do not make good proxies for price regulated utilities because of their tendency toward higher rates of return.

Q. DO THESE OBSERVATIONS ABOUT CREDIT RATINGS AND RETURN ON EQUITY ALSO APPLY TO BETA VALUES?

A. Yes. Mr. D'Ascendis states that beta coefficients reflect the market's assessment of market/systematic risk. Further, he says that beta coefficients are derived from regression analyses of market prices. If a non-price regulated firm and a price regulated firm with the

same beta value are alike in all operational aspects other than volatility of earnings, logic indicates that the non-price regulated firm must be equally appealing to investors due to a higher rate of return. Therefore, the ROEs for the companies in Mr. D'Ascendis's proxy group of 48 non-price regulated companies are biased upward relative to the ROEs for natural gas utilities in proxy groups. It is not surprising that they are higher.

XII. SUMMARY

Q. WHAT ARE THE CRITERIA THE COMMISSION SHOULD CONSIDER IN SETTING THE COMPANY'S ROE AND ROR?

A. The Commission should only consider whether the ROE and ROR meet the *Bluefield* and *Hope* criteria for a fair return. Recounting, these criteria include returns that are commensurate with returns being earned on other investments with equivalent risks, a rate of return sufficient to enable the utility to attract capital, and returns sufficient to enable the regulated company to maintain its credit rating and financial integrity. The interpretation of the *Hope* and *Bluefield* criteria is that a company should be given the opportunity to earn an ROE and ROR sufficient to meet these standards.

Q. PLEASE STATE YOUR RECOMMENDED RETURN ON EQUITY AND OVERALL COST OF CAPITAL FOR NSPM?

A. I estimated an ROE of 9.43 percent and an ROR of 6.86 percent.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MARLON GRIFFING, Ph.D.

Education

Ph.D., M.A., B.A., Economics, University of Nebraska-Lincoln

Position

Senior Consultant – PCMG and Associates	2015 – present
Senior Consultant – Snavely King Majoros and Associates	2013 – 2014
Utilities Financial Analyst – Minnesota Department of Commerce	2003 – 2013
Senior Consultant – QSI Consulting	2000 – 2002
Economic Analyst – Nebraska Public Service Commission	1998 – 2000

Professional Experience

Dr. Griffing holds bachelors, masters, and doctoral degrees in economics. Dr. Griffing is well versed in microeconomics, cost/benefit analysis and econometric analysis. He has 21 years' experience as an expert witness and consultant, primarily addressing the cost of capital and capital structure for electric, natural gas, and water utilities. He has also made appearances regarding rate design, competitive effect of mergers, reliability and supply adequacy, and oil-pipeline companies in certificate of need cases. In addition, he managed testimony in two oil-pipeline certificate-of-need cases and arbitrated a telecommunications dispute for the Nebraska Public Service Commission. Dr. Griffing has appeared more than 50 times in cost of capital dockets and other matters before the regulatory agencies of Arkansas, Maine, Maryland, Minnesota, Nebraska, New Jersey, New Mexico, North Dakota, Oklahoma, Pennsylvania, and South Dakota, and the Federal Energy Regulatory Commission.

Cost of Capital

1. In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma (2021) - (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
   Oklahoma Commerce Commission Cause No. PUD 202100164

2. In the Matter of the Application of Hawaii-American Water Company for Approval of Rate Increases and Revised Rate Schedules and Rules (2021) - (Appearance: return on equity, cost of capital on behalf of the Division of Consumer Advocate)
   Hawaii Public Utilities Commission Docket No. 2021-0063

3. Application of San Diego Gas & Electric Company (U902M) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2022 and to Reset the Annual Cost of Capital Mechanism (2021) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the United Consumer Action Network)
   California Public Utilities Commission Proceeding A.21-08-014

4. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of an Increase in Gas Base Rates and for Changes in its Tariff for Gas Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Changes to Depreciation Rates for Gas Property Pursuant to N.J.S.A. 48:2-18 (2021) – (Appearance: cost of capital on behalf of the New Jersey Division of Rate Counsel)
   New Jersey Board of Public Utilities Docket No. ER21030679

5. In the Matter of the Application of Oklahoma Natural Gas Company, a Division of ONE Gas, Inc., for a Review and Change or Modification in Its Rates, Charges, Tariffs and Terms and Conditions of Service (2021) - (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
   Oklahoma Commerce Commission Cause No. PUD 202100063

6. Application of Public Service Company of Oklahoma, An Oklahoma Corporation, for An Adjustment in Its Rates and Charges and the Electric Service Rules, Regulations and Conditions for Service in the State of Oklahoma and to Approve a Performance-Based Rate Proposal (2021) - (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
   Oklahoma Commerce Commission Cause No. PUD 202100055

7. Versant Power f/k/a Emera Maine, Proposed Increase in Distribution Rates (2021) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Maine Office of the Public Advocate)
   Maine Public Utilities Commission Docket No. 2020-00316

8. In the Matter of the Verified Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief (2021) – (Appearance: cost of capital on behalf of the New Jersey Division of Rate Counsel)
   New Jersey Board of Public Utilities Docket No. ER201020746

9. In the Matter of the Petition of Elizabethtown Gas Company to Issue Long-Term Debt and Security Therefor and for Authority to Issue and Sell Short-Term Indebtedness, all through December 31, 2023 (2021) – (Appearance: debt issuance petition on behalf of the New Jersey Division of Rate Counsel)
   New Jersey Board of Public Utilities Docket No. GF20120749

10. Northern States Power Minnesota 2021 Electric Rate Increase Application (2021) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the North Dakota Public Service Commission Staff)
   ND Public Service Commission Case No. PU-20-441

11. Pike County Light & Power Company 2020 General Base Rate Increase (2020) – (Appearance: Cost of Capital on behalf of the Pennsylvania Office of Consumer Advocate)
    Pennsylvania Public Utility Commission – Docket Nos. R-2020-3022134 (Gas) and R-2020-3022135 (Electric)

12. Water Rate Case Consultant for the Maine Public Advocate (2020) – (Appearance: cost of capital on behalf of the Maine Office of Public Advocate in selected cases)
    Docket No. 2021-00053

13. In the Matter of the Petition of South Jersey Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions (2020) – (Appearance: cost of capital on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. GR20030243

14. In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith (2020) – (Appearance: cost of equity on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. ER20020146

15. In the Matter of the Federal Power Act Rule 206 Complaint Against Public Service Electric and Gas Company (2020) – (Appearance: cost of equity on behalf of the New Jersey Division of Rate Counsel)
    Federal Energy Regulatory Commission Docket No. ER09-1257-000

16. In the Matter of the Petition of New Jersey-American Water Company for Approval of Increase Base Tariff Rates and Charges for Water and Wastewater Service and Other Tariff Changes (2019) – (Appearance: cost of equity on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR19121516

17. In the Matter of the Petition of Jersey Central Power & Light Company for Approval of Its Transmission Rates and Transmission Enhancement Charge for Interconnection with PJM Interconnection, L.L.C. (2019) – (Appearance: cost of equity on behalf of the New Jersey Division of Rate Counsel)
    Federal Energy Regulatory Commission Docket No. ER20-227-000

18. Request for Approval of Rate Change, Northern Utilities, Inc. (2019) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Maine Office of the Public Advocate)
    Maine Public Utilities Commission Docket No. 2019-00092

19. Application of San Diego Gas & Electric Company (U902M) for Authority to: (i) Adjust its Authorized Return on Common Equity, (ii) Adjust its Authorized Embedded Costs of Debt and Preferred Stock, (iii) Adjust its Authorized Capital Structure; (iv) Modify its Adopted Cost of Capital Mechanism Structure, and (v) Revise its Electric Distribution and Gas Rates Accordingly, and for Related Substantive and Procedural Relief (2019) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the United Consumer Action Network)
    California Public Utilities Commission Proceeding A.19-04-017

20. In the Matter of the Application of the Empire District Electric Company, a Kansas Corporation, for an Adjustment in its Rates and Charges for Electric Service in the State of Oklahoma (2019) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Office of the Oklahoma Attorney General)
    Oklahoma Commerce Commission Cause No. PUD 201800133

21. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of an Increase in Gas Base Rates and for Changes in its Tariff for Gas Service, Pursuant to **N.J.S.A. 48:2-21** and **48:2-21.1** and for Changes to Depreciation Rates for Gas Property Pursuant to **N.J.S.A. 48:2-18** (2019) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. GR19030420

22. In the Matter of the Petition of Pivotal Utility Holdings d/b/a Elizabethtown Gas Company to Implement an Infrastructure Investment Program (IIP) and Associated Recovery Mechanism (2019) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. GR18011197

23. Commission-Initiated Investigation into Rates and Revenue Requirements Pertaining to Emera Maine, Inc. (2019) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Maine Office of the Public Advocate)
    Maine Public Utilities Commission Docket No. 2019-00019

24. In the Matter of Petition of Aqua New Jersey, Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2018) - (Appearance: return on equity, cost of capital on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR18121351

25. Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in the State of Oklahoma (2018) - (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
    Oklahoma Commerce Commission Cause No. PUD 201800140

26. Commission-Initiated Investigation into Rates and Revenue Requirements Pertaining to Central Maine Power Company (2018) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Maine Office of the Public Advocate)
    Maine Public Utilities Commission Docket No. 2018-00194

27. Application of Public Service Company of Oklahoma, An Oklahoma Corporation, for An Adjustment in Its Rates and Charges and the Electric Service Rules, Regulations and Conditions for Service in the State of Oklahoma and to Approve a Performance-Based Rate Proposal (2018) - (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
    Oklahoma Commerce Commission Cause No. PUD 201800097

28. In Re: The Matter of the Application of Maryland American Water Co. for Authority to Increase Rates and Charges (2018) – (Appearance: Cost of capital on behalf of the Maryland Office of the People's Counsel)
    Maryland Public Service Commission – Case No. 9487

29. In the Matter of Petition of Atlantic City Electric Co. for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service and for Other Appropriate Relief (2018) - (Appearance: return on equity, cost of capital on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. ER18060638

30. In the Matter of Petition of SUEZ Water New Jersey, Inc. for Approval of an Increase in Rates for Water/Sewer Service and Other Tariff Changes (2018) - (Appearance: return on equity, cost of capital on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR18050593

31. In Re: The Matter of the Application of Columbia Gas of Maryland, Inc. for Authority to Increase Rates and Charges (2018) – (Appearance: Cost of capital on behalf of the Maryland Office of the People's Counsel)
    Maryland Public Service Commission – Case No. 9480

32. In Re: The Matter of the Columbia Gas of Pennsylvania for a General Rate Increase in Distribution Gas Service (2018) – (Appearance: Cost of Capital on behalf of the Pennsylvania Office of Consumer Advocate)
    Pennsylvania Public Utility Commission – Docket No. R-2018-2647577

33. In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Tariff Change in Rates and Tariffs (2018) – (Appearance: return on equity, cost of capital on behalf of the Office of the Arkansas Attorney General)
    Arkansas Public Service Commission Docket 17-071-U

34. In the Matter of the Petition of Atlantic City Electric Company for Approval of an Infrastructure Investment Program and Related Cost Recovery Mechanism (2018) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. EO18020196

35. In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma (2018) - (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
    Oklahoma Commerce Commission Cause No. PUD 201700496

36. Application of Fayson Lake Water Company for the Approval of an Increase in Rates and Other Appropriate Relief (2017) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR17101041

37. Petition of Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes, and an Order Authorizing Special Accounting Treatment of Income Tax Refund Proceeds and Future Income Tax Deductions (2017) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR17101049

38. In the Matter of the Petition of New Jersey-American Water Company, Inc. for Approval of an Increased Tariff Rates and Charges for Water and Sewer Service, Change in Depreciation Rates, and Other Tariff Modifications (2017) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR17090985

39. Montana-Dakota Utilities Co., Application to Increase Natural Gas Rates (2017) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the North Dakota Public Service Commission Staff)
    ND Public Service Commission Case No. PU-17-295

40. In the Matter of the Petition of Andover Utility Company, Inc. for Approval of an Increase in Rates for Wastewater Service (2017) – (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR17070726

41. Application of Public Service Company of Oklahoma, An Oklahoma Corporation, for An Adjustment in Its Rates and Charges and the Electric Service Rules, Regulations and Conditions for Service in the State of Oklahoma (2017) - (Appearance: return on equity, cost of capital on behalf of the Office of the Oklahoma Attorney General)
    Oklahoma Commerce Commission Cause No. PUD 201700151

42. In the Matter of the Petition of SUEZ Water Arlington Hills, Inc. for Approval of an Increase in Rates for Wastewater Service and Other Tariffs (2016) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the New Jersey Division of Rate Counsel)
    New Jersey Board of Public Utilities Docket No. WR16060510

43. In the Matter of Request by Emera Maine for Approval of a Rate Change (2016) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Maine Office of the Public Advocate)
    Maine Public Utilities Commission Docket No. 15-00360

44. ENMAX Energy Corporation (EEC) Regulated Rate Option Non-Energy Tariff Application (2015-2016) - (Analysis: cost of capital, risk element identification on behalf of the Alberta Utilities Consumer Advocate)
    Alberta Utilities Commission Proceeding 20480

45. Pennsylvania Public Utilities Commission vs. West Penn Power Co., Pennsylvania Electric Co., Pennsylvania Power Co., and Metropolitan Edison Co. (2014-2015) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return behalf of the Office of the Pennsylvania Consumer Advocate)
    PA Docket Nos. R-2014-2428742-R-2014-2428745

46. In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota (2010-2012) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G007,011/GR-10-977

47. In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota (2010-2011) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. E017/GR-10-239

48. In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Natural Gas Service in Minnesota (2009-2010) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G002/GR-09-1153

49. In the Matter of an Application by CenterPoint Energy Resources Corp., D/B/A CenterPoint Minnesota Gas to Increase Natural Gas Rates in Minnesota (2008-2009) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G008/GR-08-1075

50. In the Matter of Minnesota Energy Resources Corporation's Application for Authority to Increase Natural Gas Rates in Minnesota (2008-2009) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G007,011/GR-08-835

51. In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation and Wholly Owned Subsidiary of Xcel Energy Inc., for Authority to Increase Rates for Natural Gas Service in Minnesota (2006-2007) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G002/GR-06-1429

52. In the Matter of the Application of CenterPoint Energy Resources Corp., D/B/A CenterPoint Energy Minnesota Gas, for Authority to Increase Natural Gas Rates in Minnesota (2005-2006) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G008/GR-05-1380

53. In the Matter of a Petition by Interstate Power and Light Company for Authority to Increase Electric Rates in Minnesota (2005) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. E001/GR-05-748

54. In the Matter of the Petition of Northern States Power Company dba Xcel Energy Request for General Rate Increase (2004-2005) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G002/GR-04-1511

55. In the Matter of the Petition of Great Plains Natural Gas Company's Request for General Rate Increase (2004-2005) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    MN Docket No. G004/GR-04-1487

56. In the Matter of the Petition of CenterPoint Energy Minnegasco, A Division of CenterPoint Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota (2004-2005) - (Appearance: cost of equity, cost of debt, capital structure, overall rate of return on behalf of the Minnesota Department of Commerce)
    Docket No. G008/GR-04-901

Regulatory Projects and Appearances

57. In Re: Township of East Brunswick – Sewer Rate Study – (2017) - (Evaluation of the existing sewer rate structure and examining and quantify costs for future expansion).

58. In re: Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 17-GREC-06

59. In re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2016 Gas System Enhancement Plan Reconciliation Filing (2017) - (Appearance: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
    MA Department of Public Utilities Docket No. D.P.U. 17-GREC-05

60. In re: Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed General Increase in Gas Rates (2017) – (Appearance: prudence/used and useful and plant accounting on behalf of the Citizens Utility Board of Illinois)
    IL Commerce Commission Docket No. 17-0124

61. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2017) – (Appearance: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9443

62. In re: The Application of Delmarva Power and Light Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Analysis and Assistance to Counsel: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9424

63. In re: The Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy (2016) – (Analysis and Assistance to Counsel: cost of service and rate design on behalf of the Maryland Office of People's Counsel)
    MD Public Service Commission Case No. 9418

64. 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 Assistance to Counsel: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 16-GREC-01

65. 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) - (Analysis and Assistance to Counsel: prudence/used and useful and plant accounting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 16-GREC-05

66. 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: forecasting and cost/benefit on behalf of the New Hampshire Office of Consumer Advocate)
NH Public Utilities Commission Docket No. DE 16-241

67. 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

68. In. re: The Merger of the Southern Company and AGL Resources Inc. - Joint Application of the Southern Company, AGL Resources Inc., and Pivotal Utility Holdings, Inc., d/b/a Elkton Gas (2015-2016) - (Analysis: cost of capital, credit ratings, affiliate relationships on behalf of the Maryland Office of People's Counsel)
MD Public Service Commission Case No. 9404

69. 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 (2015-2016) - (Analysis: gas-supply model review, forecasting on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-130

70. 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; Gaz Metro LNG, L.P.; and National Grid LNG (2015-2016) - (Analysis: gas-supply model review, forecasting, large customer loss and retention on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-129

Rate Design

71. In the Matter of Otter Tail Corporation dba Otter Tail Power Company's Application for Authority to Increase Rates for Electric Service in Minnesota (2007-2008) - (Appearance: rate design, revenue requirement on behalf of the Minnesota Department of Commerce)
    MN Docket No. E017/GR-07-1178

Capital Structure

72. In the Matter of the Petition of Greater Minnesota Gas Inc. for Approval of 2011 Capital Structure Petition and Permission to Issue Securities (2011) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
    MN Docket No. G022/S-11-535

73. In the Matter of the Petition of Otter Tail Power Company for Approval of 2011 Capital Structure and Permission to Issue Securities (2011) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
    MN Docket No. G007,011/S-11-392

74. The Petition of Otter Tail Power Company for Approval of 2010 Capital Structure and Permission to Issue Securities (2010) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
    MN Docket No. E017/S-10-292

75. In the Matter of the Greater Minnesota Gas Inc.'s Capital Structure Petition and Compliance with Financial Integrity Order (2010) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
    MN Docket No. G022/S-10-281

76. Interstate Power and Light Company's petition for approval of its proposed capital structure (2009) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
    MN Docket No. E,G001/S-09-607

77. A petition of Interstate Power and Light Company for approval of its proposed capital structure (2008) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
    MN Docket No. E,G001/S-08-540

78. In the Matter of the Annual Capital Structure Filing of Minnesota Energy Resources Corporation (2008) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
    MN Docket No. G007,011/SA-08-329

79. In the Matter of the Annual Capital Structure Filing of Minnesota Energy Resources Corporation (2007) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
    Docket No. G007,011/S-07-352

80. In the Matter of the Annual Capital Structure Filing of Minnesota Energy Resources Corporation (2006-2007) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
    MN Docket No. G007,011/S-06-1013

81. Northern States Power Company's request for approval of its 2006 Capital Structure Prior to Issuing Securities (2005) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
    MN Docket No. E,G002/S-05-1583

82. A petition of Interstate Power and Light Company for approval of its proposed capital structure for calendar year 2005, ending March 31, 2006 (2005) - (Appearance: capital structure on behalf of the Minnesota Department of Commerce)
    MN Docket No. E,G001/S-05-151

Affiliated Interest

83. Petition of Greater Minnesota Gas, Inc. for Approval of an Affiliated Interest Agreement (2010-2011) - (Appearance: analysis of affiliated interests of closely held company, some owners also suppliers on behalf of the Minnesota Department of Commerce)
    MN Docket No. G022/AI-10-1160

84. In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of Affiliated Interest Agreement (2010-2013) - (Appearance: analysis of affiliated interests agreement post-merger on behalf of the Minnesota Department of Commerce)
    MN Docket No. G007,011/AI-10-783

85. In the Matter of the Annual Capital Structure Filing of Minnesota Energy Resources Corporation and Request for Approval of Affiliated Interest Agreement (2009-2010) - (Appearance: capital structure, affiliated interest lending on behalf of the Minnesota Department of Commerce)
    MN Docket No. G007,011/SAI-09-1108

86. Petition for Approval of a Lending Agreement Between Interstate Power and Light Company and Alliant Energy Corporation Pursuant to Section 216B.48 of the Minnesota Statutes and Minnesota Rule 7825.2200 (2008-2009) - (Appearance: intercompany lending on behalf of the Minnesota Department of Commerce)
    MN Docket No. E,G001/AI-08-1323

87. A Petition for Approval of Affiliated Services Agreement Between Interstate Power and Light Company and RMT, Inc. Pursuant to Section 216.48 of the Minnesota Statutes and Minnesota Rule 7825.2200 (2007-2008) - (Appearance: affiliated interests, engineering services on behalf of the Minnesota Department of Commerce)
    MN Docket No. E,G001/AI-07-941

Depreciation

88. Otter Tail Power Company's Request for Approval of its Five-Year Depreciation Study (2008-2009) - (Appearance: depreciation analysis on behalf of the Minnesota Department of Commerce)
    MN Docket No. E017/D-08-1042

89. In the Matter of the Petition of Great Plains Natural Gas Company's Request for Approval of its Five-Year Depreciation Study for 2007 (2007-2008) - (Appearance: depreciation analysis on behalf of the Minnesota Department of Commerce)
    MN Docket No. G004/D-07-740

90. In the Matter of the Petition of Great Plains Natural Gas Company's Request for Approval of its Proposed Remaining Lives, Salvage Rates, and Resulting Depreciation Rates (2006-2007) - (Appearance: depreciation analysis on behalf of the Minnesota Department of Commerce)
    MN Docket No. G004/D-06-700

Certificate of Need

91. In the Matter of the Application of Minnesota Pipeline Company for a Certificate of Need for a Crude Oil Pipeline (2006-2007) - (Appearance: economic impact on behalf of the Minnesota Department of Commerce)
    MN Docket No. PL-5/CN-06-02

92. In the Matter of the Petition of Northern States Power Company dba Xcel Energy dba Xcel Energy Certificate Need to Establish an Independent Spent Fuel Storage Installation at the Monticello Generating Plant (2005-2006) - (Appearance: license renewal, economic impact on behalf of the Minnesota Department of Commerce)
    MN Docket No. E002/CN-05-123

93. In the Matter of a Certificate of Need Application for Great River Energy's Cambridge Station (2005) - (Appearance: economic impact on behalf of the Minnesota Department of Commerce)
    MN Docket No. ET2/CN-05-347

Mergers

94. In the Matter of a Request of Great Plains Natural Gas Co. for the Approval of the Acquisition by MDU Resources Group, Inc., of Intermountain Gas Company (2008) (Appearance: rule variance, sharing savings, regulatory authority, cost of capital on behalf of the Minnesota Department of Commerce)
    MN Docket No. G004/PA-08-813

95. In the Matter of a Request for the Approval of the Acquisition by MDU Resources Group, Inc., and Its Division, Great Plains Natural Gas Co., of Cascade Natural Gas Corporation (2006-2007) (Appearance: sharing savings, regulatory authority, cost of capital on behalf of the Minnesota Department of Commerce)
    MN Docket No. G004/PA-06-1585

Performance-Based Regulation

96. Xcel Energy, Purchased Gas Adjustments compliance filings, 2011-2013 (Assistance: compliance with price-adjustment order on behalf of the Minnesota Department of Commerce)
    MN Docket Nos. monthly

97. Interstate Power and Light, Purchased Gas Adjustment compliance filings, 2004-2006 (Assistance: compliance with price-adjustment order on behalf of the Minnesota Department of Commerce)
    MN Docket Nos. monthly

Manager of Contested-Case Proceedings

98. In the Matter of the Application of Enbridge Energy, Limited Partnership and Enbridge Pipelines (Southern Lights) LLC for a Certificate of Need for the Alberta Clipper and Southern Lights Diluent Pipeline Projects (2007-2008) - (Case Manager: economic impact, public interest and impact on society, advice to counsel, assist on brief on behalf of the Minnesota Department of Commerce)
    MN Docket No. PL-9/CN-07-465

99. In the Matter of the Application of Enbridge Energy (Southern Lights) LLC for a Certificate of Need for a Crude Oil Pipeline for the Southern Lights Project (2007-2008) - (Case Manager: economic impact, public interest and impact on society, advice to counsel, assist on brief on behalf of the Minnesota Department of Commerce)
    MN Docket No. PL-9/CN-07-464

Telecommunications

100. In the Matter of the Petition of Great Plains Communications, Inc. for Arbitration to Resolve Issues Relating to an Interconnection Agreement with WWC License L.L.C. (2003) – (Arbitrator: arbitrated interconnection agreement disputes on behalf of the Nebraska Public Service Commission)
NE Application No. C-2872

101. In the Matter of the Analysis of Qwest Corporation's Compliance with Section 271(c) of the Telecommunications Act of 1999 (1999-2002) – (Appearances: evaluation of Qwest Corporation's opening its operational support systems (OSS) to competitive local exchange carriers on behalf of the Nebraska Public Service Commission, New Mexico Public Regulation Commission Advocacy Staff, and South Dakota Public Utilities Commission Staff)
NE Application No. C-1830, NM Case No. 3269, SD Docket No. TC01-165

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
2021 Natural Gas Rate Increase
Application

Case No. PU-21-381

Verification

State Of Minnesota)
) ss.
County Of Ramsey)

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

Marlon Griffing

Subscribed and sworn to before me this 1st day of March, 2022.

RABECCA M CABELLERO-THOMAS
Notary Public - Minnesota
My Commission Expires Jan. 31, 2025

Notary Public
My Commission Expires: Jan 31, 2025

INTRODUCTION – STATEMENT OF QUALIFICATION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dante Mugrace. My business address is 22 Brookes 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 brings to client engagements a consultative and collaborative approach to the identification of issues and the development of positions with strict adherence to client procedures and deadlines. 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 Public Service 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 in nature, 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

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Public Service Commission Advocacy Staff
Brian Johnson, Advocacy Staff Counsel

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 (Bureau Chief of Rates). 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 in nature, prudent, and 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 to ensure 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 the Commissions in the Commonwealths of Massachusetts and Pennsylvania, and the States of Hawaii, Maine, Maryland, New Jersey, New York, North Dakota, 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. More recently I was involved in the Generic Proceeding instituted by the NJ Board of Public Utilities (NJBPU) regarding the Tax Cuts and Jobs Act of 2017 (BPU Docket No. AX1801001)

regarding the setting of the federal tax adjustments and the adjustment of rates and the impact on the flowback of excess accumulated deferred income taxes. I am currently involved in several proceedings with the NJBPU with respect to the establishment of energy efficiency and peak demand reduction programs in accordance with the NJ Clean Energy Act of 2018 (BPU Docket Nos. QO19010040, QO19060748 and QO17091004).

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. PURPOSED 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 – North Dakota (NSPC or Company) gas base rate case proceeding that was filed with the North Dakota Public Service Commission (NDPSC or Commission) on September 1, 2021 in Case No. PU-21-381. My overall revenue requirement recommendations are based upon the Company's proposed test year period ending December 31, 2022. The Company has proposed an annual revenue requirement increase of $7,059,000 or 10.50% over current rate revenues. 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 Dr. Marlon Griffing for

cost of capital and return on equity, and Dr. Karl Pavlovic for cost of service and rate design 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 NSPC'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-23.

Q. PLEASE SUMMARIZE THE RATE RELIEF PROPOSED BY NSPC.

A. As previously indicated above, the Company filed an application for an increase in electric service on September 1, 2021, requesting an increase in base distribution rates in the amount of $7,059,000 or 10.50% above current rates. The revenue requirement is predicated upon a future test year ending December 31, 2022, (Exhibit BCH-1 Schedule 11) which include an overall rate of return of 7.45% and a common equity component of 10.50%. (Exhibit BCH-1 Schedule 3A). The Company has computed an average rate base balance of $124,227,000 based upon average balances of plant investments. The Company is proposing to include certain costs related to the Settlement Agreement approved by the Commission in Case No. PU-18-156 related to the expense of amortized Fargo manufactured gas plant (MGP) remediation costs of $1.25 million. The Company's last base rate case was approved in 2007 by the Commission in Case No. PU-06-525.

Q. HOW DID THE COMPANY COMPUTE ITS PROPOSED REVENUE REQUIREMENT INCREASE OF $7,059,000.

A. The Company has computed its proposed revenue requirement increase by computing the average rate base (beginning and ending test year balances) and the adding and subtracting average balances related to Cash Working Capital (CWC) materials and supplies, fuel inventory, prepayments and various non-plant

assets and liabilities. The Company multiplied its proposed average rate base balance of $124,227,000 by the proposed rate of return of 7.45% to arrive at a proposed Operating Income requirement of $9,255,000. The Company then subtracted its Operating Income at present rates of $3,919,000 to arrive at an income deficiency of $5,336,000.[1] The Company then multiplied this amount by its revenue conversion factor of 1.32284 to arrive at its revenue requirement increase proposal of $7,059,000.

Q. HAVE YOU ACCEPTED THE COMPANY'S PROPOSED TEST YEAR ENDING DECEMBER 31, 2021?

A. Yes.

Q. HAS THE COMPANY UPDATED ITS PROPOSED REVENUE REQUIREMENT INCREASE SUBSEQUENT TO THE SEPTEMBER 1, 2021 FILING DATE?

A. No.

Q. WHAT HAS THE COMPANY EXPERIENCED REGARDING THE EFFECT OF THE COVID-19 PANDEMIC ON ITS PROPOSED RATE REQUEST?

A. Company witness Mr. Adam Dietenberger in response to data request 1-10 stated that the Company has experienced higher uncollectible accounts expenses in the period during the COVID-19 pandemic when compared to pre-pandemic period. The uncollectible accounts is recognized as a combination of estimating an amount of outstanding accounts receivables that will be unrecoverable and writing off uncollectible accounts not previously reflected in this provision. Mr. Dietenberger stated that as part of the Settlement Agreement in the Company's 2020 electric rate increase in Case No. PU-20-441, the Company agreed to withdraw its requested deferral of COVID-19 related costs, including bad debt and not recover such costs from its North Dakota customers. This withdrawal relates to both electric and gas businesses, for any future electric or gas rate case.

Q. WHAT HAS THE COMPANY EXPERIENCED WITH RESPECT TO ITS DAY-TO-DAY OPERATIONS?

[1] Company Exhibit BCH-1 Schedule 7 page 1.

A. Ms. Zich stated that gas emergency response was not affected and that employees still responded to calls to ensure public and community safety was not compromised. (NDPSC 1-11). The Company was able to prioritize work to minimized contact with the public. Large capital projects were also executed accordingly.

Q. PLEASE SUMMARIZE YOUR FINDING AND RECOMMENDATIONS.

A. Based upon the use of the Company's test year period ending December 31, 2021, I have the following recommendations:[2]

1. My recommended rate base balance is $122,531,000 which is $1,695,900 lower than the Company's proposed rate base balance of $124,227,000.
2. My rate of return is based upon the recommendation of Dr. Marlon Griffing which recommends an overall return of 6.86%, which includes a common equity component of 9.43%.
3. My recommended operating revenues at present rates is $67,853,000 which is the same as the Company's operating revenues at present rates of $67,853,000.
4. My overall revenue requirement increase based upon an overall rate of return of 6.86% is $2,990,332 or 4.443%; this is $4,068,225 lower than the Company's overall revenue requirement increase of $7,059,000 or 10.48%.

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.

[2] Differences due to rounding

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 7.35%. The breakdown of this return is based upon a long-term debt rate of 4.2189%, a short-term debt rate of 1.000% and a common equity component of 10.20%. WP C1- Cost of Capital Schedule).

Q. WHAT IS YOUR RECOMMENDED COST OF CAPITAL?

A. As per Advocacy Staff witness Dr. Griffing's recommendation, I am incorporating an overall cost of capital of 6.86% which includes a common equity component of 9.43%. This is shown on Schedule DM-2, and on Dr. Griffing's Exhibit MFG-16, Schedule 3.

REVENUE REQUIREMENT ISSUES

IV. Rate Base Issues

A. Gas Plant in Service (GPIS)

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

A. As shown on Exhibit BCH-1 Schedule 3A the Company proposed an average plant in service balance of $222,855,000, as of December 31, 2022. The Company has developed this balance starting with total Company investments proposed in the 2021 test year period and allocating investments to the North Dakota jurisdiction. The Company calculated the investment related to the North Dakota jurisdiction by the use of 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 gas rate case (Exhibit BCH-1 page 17). The Company has included costs related to the Fargo Capacity Project that was placed in service on October 13, 2021 ((Data Request 1-49). The need for this Project was explained by the Company is Ms. Zich testimony (Exhibit JHZ-1) page 20. The Company stated that there may be restoration work in the spring of 2022. The total cost of the Fargo Capacity Project was estimated at $27.5 million (Exhibit JHZ-1 page 24) and was operational during the winter of 2021-2022. The Company also included Peaking Plant Investment costs related to the Westcott LNG peaking plant, the Sibley Propane Air facility and the Maplewood Propane Air facility. (Exhibit JLZ-1 page 30). The Company stated that that these types of investments are needed to enhance reliability and maintain compliance with state and federal codes. Ms. Zich stated that the Company has made capital investments in these types of plants since the last base rate case proceeding in 2007. (Exhibit JLZ-1 page 31). Ms. Zich stated that these plant investments include significant refurbishment and replacement of the existing infrastructure in all three facilities to prepare them for continued operations for years to come and this work is occurring in the 2021-2022 timeframe. (Exhibit JLZ-1 page 32).

Q. WHAT OTHER INVESTMENTS HAS THE COMPANY INCLUDED IN ITS TEST YEAR PERIOD?

A. The Company has included costs related to the Inside Meter Move Out Program where the Company will move most of its gas meters still located inside of customer premises to outside locations and replace existing facilities with new meters, connections and regulators. (Exhibit JLZ-1 page 16). This project is required by federal code and allows the Company to more efficiently perform routine required inspections and maintenance of these meter without having to coordinate access or inconvenience to customers. (Exhibit JLZ-1 page 16). The Company is expected to replace over 550 meters outside over a five-year period beginning with 100 meters to be moved in 2022. (Exhibit JLZ-1 page 16). The average cost to move a meter to the outside is about $3,500 (Data Response 1-46). The Company is proposing to institute a Modular Replacement Program that

will address the replacement of current automaking meter reading (AMR) technology, as the Company's current agreement with its meter reading provider will expire in December 2025, and the current technology will no longer be supported (Exhibit JLZ-1 page 17). The new modules will be owned by the Company and the meter reading will be performed by the Company. The program will begin in 2022 and conclude in 2025. (Exhibit JLZ-1 page 17).

Q. HOW DID THE COMPANY DEVELOP THE PLANT BALANCES FOR THE END OF THE TEST YEAR PERIOD 2022?

A. The Company stated that the 2021 ending plant balances were determined by the Company's actual net investments (Plant in Service less Accumulated Depreciation) on the books and records of the Company as of January 31, 2021. The Company budgeted projections for February through December 2021 and applied those projections to the January 31, 2021 balance to arrive at a beginning test year net plant balance. (Exhibit BCH-1 page 17). The ending net plant balances were determined by applying the data contained in the 2022 capital budget to the balance at December 31, 2021 adjusted for plant additions, retirements, depreciation, salvage and removal costs projected to occur during the test year. The result is a simple average or projected plant at the beginning and ending 2022 test year.

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

A. The Company allocates its Gas Plant in Service (GPIS) balance by the use of jurisdiction allocations from NSPM (total utility) to the North Dakota jurisdiction. The jurisdiction cost of service study allocates rate base, capital structure, cost of capital, income taxes and cash working capital from NSPM to the North Dakota jurisdiction (Exhibit BCH-1 page 13). The jurisdiction cost of service schedules for the 2022 test year is shown on Company Schedule 3A (Exhibit BCH-1 page 13). The Operating Income Jurisdiction is shown on Company Exhibit BCH-1 Schedule 13 (11.2872% allocation factor) and the Rate Base Jurisdiction is shown on Company Exhibit BCH-1 Schedule 14 (11.2872% allocation factor).

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 GPIS BALANCE OF $222,855,000?

A. Yes. My first adjustment is related to the Company's inclusion of applying a 2% escalation factor related to the average meter installation costs of $388,500. ($3,500 per meter relocation installation costs times 111, the number of meters expected to be placed outside). I removed the 2% escalation factor or $7,617 ($388,500 / 1.02% minus $380,882 or $7,617), because I believe an escalation factor does not provide true costs of an item, as these types of costs only provide blanket increase of goods and services that may or may not reflect the costs incurred by the Company. My second adjustment is related to the Company's Fargo Capacity Plant Project. This Project included $600,000 of contingency reserves (Data Response 4-9). The Company stated that the contingency reserve is for unknowns and not quantified by individual risk items but is used to cover items not already identified. In response to Data Request 4-7 the Company stated that it does not anticipate any restoration costs in 2022. Therefore, this contingency costs should be removed from the Company's Fargo Capacity Plant Project.

Q. HAS THE COMPANY INCLUDED COSTS TO SUPPORT THE ADVANCED GRID INTELLIGENCE AND SECURITY (AGIS) INITIATIVE?

A. In Exhibit LJW-1 page 20, the Company proposed a new subaccount under FERC Account 397 for smart grid assets used to support the AGIS initiative. The Company has proposed a 10-year average service life with zero net salvage. In response to Data Request 1-62 the Company stated that it will update the costs for removing this project and calculate an update revenue requirement.

Q. WHAT IS YOUR RECOMMENDATION?

A. I am recommending removal of approximately $608,000 from the Company's GPIS balance shown on my Schedule DM-5. As I testified to above, inflation adjustments should not be included in the development of the revenue requirement as these types of costs do not reflect the costs that have actually been incurred by the Company. I am also removing $600,000 related to a contingency reserve related to the Fargo Capacity Plant Project as these costs are unknown and not quantified.

B. Accumulated Depreciation

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

A. In the same manner as the Company developed its GPIS balance, the Company performed the same analysis with respect to its Accumulated Depreciation or Depreciation Reserve amount, by taking the simple average of balances at the beginning and end of test year. The Company proposed an average depreciation reserve balance of $82,973,000 as shown on Company Exhibit BCH-1 Schedule 3A.

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

A. No. I am accepting the Company's methodology as to the development of the Company's Accumulated Depreciation.

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

A. As I removed approximately $608,000 from the Company's UPIS additions related to the meter installation project and the contingency costs related to the Fargo Capacity Plant Project, I am removing the associated Accumulated Depreciation of $16,078 (computations addressed under Depreciation Expense in Section K). 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 $19,782,000 as shown on Exhibit BCH-1 Revised Schedule 15. The Company used an average projected ADIT balance of projected beginning and ending 2022 test year ADIT balances and incorporates IRS tax regulations. (Exhibit BCH-1 page 19). With respect to the TCJA of 2017, the Commission adopted a Settlement in Case No.PU-18-156 that required the Company to amortize its excess plant – related ADIT using the Average Rate Assumption Method (ARAM) and amortize unprotected, excess non-plant related ADIT over a three-year period. Consistent with this requirement, the Company amortized the excess plant related ADIT using ARAM and the excess non-plant related ADIT was amortized over a three-year period ending in 2020, therefore no impact remains in the 2022 test year. (Exhibit BCH-1 page 20).

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

A. No. I am accepting the Company's methodology as to the development of the Company's ADIT.

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

A. My adjustments reflect the flow through of my adjustments related to the Fargo Capacity Plant Project and the adjustment related to the inflation adjustment for the meter installation project and applying a 21% income tax rate to arrive at a balance of $3,376. My adjustment is shown on my Schedule DM-7.

D. 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 $648,000 as shown on Exhibit BCH-1 Revised Schedule 3A. The Company has included certain investments, various non-plant assets and liabilities. (Exhibit BCH-1 page 29). For certain components, the Company has used thirteen-month average balances projected during the test year. For other components, the Company has used a simple average of beginning and ending test year balances. The Company has calculated its CWC by applying the results of a comprehensive lead/lag study to the projected test year revenues and expenses. (Exhibit BCH-1 page 30-31).

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

A. No. I am accepting 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. In response to Data Response 4-3, the Company stated that it inadvertently included in the All Other Operating Expenses fuel expenses. The Company stated that correcting this placement in the CWC calculation reduces the Company's revenue requirement by $122,000. The Company calculated an CWC of ($673,000) and has stated that it will update its filing in its rebuttal testimony. Based upon this response, I have adjusted my CWC accordingly and 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 ($438,738). This is shown on Schedule DM-8.

E. Other Rate Base Items

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

A. The Company proposed other Rate Base Item of $3,292,000 as shown on Exhibit BCH-1 Schedule 3A ($3,940,000 less Cash Working Capital of $648,000).

Q. DO YOU HAVE ANY ADJUSTMENTS RELATED TO THE COMPANY'S PROPOSED OTHER RATE BASE ITEMS?

A. Yes. I have one adjustment related to the Company's Regulatory Amortization for its proposed Income Tax Tracker (WP A15).

(1) Gas Income Tax Tracker – ND $27,951 (Company shows $22,547).

Q. WHAT DOES THIS BALANCE REPRESENT?

A. (1) The Gas Income Tax Tracker – Mr. Halama stated that the Company has concluded tax audits with the IRS and the Minnesota Department of Revenue for tax years ending 2010 through 2016. As a result of the audits the Company paid tax and interest on the disputed amounts. The Company has proposed to collect this amount over three years consistent with rate case expenses. (Exhibit BCH-1 page 39).

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S GAS INCOME TAX TRACKER?

A. My adjustment to the Company Gas Income Tax Tracker – ND is to remove this balance of approximately $23,000. The Company has proposed to earn a return on the unamortized balance and also recover this through an amortization expense of $9,317 over a three-year period. The Company should not be able to earn a return on taxes and interest (carrying costs) and also recover the unamortized balance through the cost of service (amortization expense). Typically these types of costs should only be recovered through an amortization expense. There is no reason why the Company should earn a return and carrying costs that are related to the payment of taxes and interest liabilities (penalties). These audits were for the period (tax years) ending 2010-2016. My adjustment removes $23,000 from

the Company's Regulatory Amortization balance. This adjustment is shown on Schedule DM-3.

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 Revenues at Present Rates of $67,853,000 as shown on Exhibit BCH-1 Schedule 3A. The Gas Retail Revenues are comprised of $67,303,000 plus Other Operating Revenues of $550,000.

Q. HAS THE COMPANY EXPERIENCED ANY IMPACT RELATED TO THE COVID-19 PANDEMIC?

A. Company witness Marks stated that the COVID-19 Pandemic negatively impacted the North Dakota economy in 2020. Non-farm employment declined 12.3 percent. While 2020 experienced the greatest economic impact from the pandemic, the effects will linger throughout 2021 and into the 2022 test year. (Exhibit JEM-1 page 4). Mr. Marks stated that customer count increased by 1.9 percent in 2020 and sales increased by 0.6 percent with Residential sales increasing 3.0 percent and Commercial and Industrial and Interruptible sales decreasing 0.3 percent. (Exhibit JEM-1 page 5). Mr. Mark's expected a reduction in Residential Sales in 2021 relative to the pandemic – inflation levels seen in 2020, and a modest increase in 2022. (Exhibit JEM-1 page 6).

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

A. The Company has utilized a 15-year weather normalization period (Exhibit JEM-1 page 9). Mr. Marks stated that after normalizing for weather, the Company's total gas sales have increased an average 2.4 percent per year during the period 2007-2022, with declines in only two years (Exhibit JEM-1 page 9).

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

A. No, I am accepting the Company's Present Rate Revenues.

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 3A, the Company proposed a total Operating and Maintenance Expense (O&M) balance for the 2022 test year of $54,365,000. This balance is composed of various accounts related to Purchased Gas, Gas Production and Storage, Gas 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, and as shown on Exhibit BCH-1 Revised Schedule 6.

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. My overall adjustments to the Company's certain O&M Expense incorporate the use of a three-year normalization adjustment minus any labor adjustments.

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 shows that certain of the Company's balances for the periods 2019-2021 (Data Request 01-034 Attachment A) 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 2022 period. In other areas there are negative balances or no prior costs accounted for. Data Request 01-034 reflects these fluctuations and variabilities from year to year. A further inquiry of certain expense breakdown categories were asked for and received in Data Request 4-12, 4,13 and 4-14. 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.

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.

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 04-012, 04-013 and 04-014, I asked the Company for a description regarding certain fluctuations. These will be addressed under Section 2, 4 and 5.

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-10, my three-year normalization adjustments (which does not include labor adjustments) is an overall decrease of $1,234,735, or an overall O&M Expense balance of $49,037,537, from the Company's proposed balance of $50,272,272, not including the specific adjustments as outlined in my testimony below under each Expense category, and without labor costs.

Q. PLEASE ADDRESS YOUR AVERAGING ADJUSMENTS UNDER EACH EXPENSE CATEGORY.

A. My averaging adjustment are as follows:

1. Gas Production & Storage

Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S GAS PRODUCTION & STORAGE EXPENSE?

A. In response to Data Request 4-12, I asked the Company for an explanation of the variability related to its Gas Production and Storage balance from $2.1 million in 2019 to $289,000 in 2022. The Company responded by stating that the difference

is related to the Company's $1.25 million of MGP amortization which was not included in the 2021-2022 rate case data in the direct testimony of Mr. Halama. The actual 2019 Gas Production and Storage Expense also included $242,000 in MGP clean-up costs the Company agreed to expense in the event it earned more than the authorized ROE during the remediation phase of the project. Given this information I am accepting the Company's Gas Production and Storage balance of $289,000.

2. Transmission Expense

Q. WHAT IS INCLUDED IN THE COMPANY'S GAS TRANSMISSION EXPENSE?

A. As shown on Data Response 01-034 Attachment A the Company proposed a balance of $304,359 for the test year ending 2022.

Q. WHAT HAS BEEN THE AVERAGE TRANSMISSION EXPENSE BALANCE IN PRIOR YEARS?

A. As shown in response to 01-034 Attachment A, the Company has recorded Gas Transmission costs of $246,098 in 2010, $239,491 in 2020 and $294,982 in 2021.

Q. WHAT IS YOUR ADJUSTMENT?

A. I am recommending averaging out or normalizing these costs over a three-year period from 2019-2021. This reduces the balance by $44,169. This is shown on my Schedule DM-10.

3. Gas Distribution

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

A. As shown in Data Response 01-034 Attachment A, the Company proposed Gas Distribution Expense of $3,278,109 for the test year period ending 2022. This balance does not include Labor Costs.

Q. WHAT HAS BEEN THE AVERAGE GAS DISTRIBUTION EXPENSE IN PRIOR YEARS?

A. The Company recorded $1,890,632 in 2019, $1,965,662 in 2020 and $3,274,274 in 2021.

Q. WHAT HAS THE COMPANY STATED WAS THE CAUSE FOR THE VARIABILITY?

A. In response to 4-13, the Company stated that the variability related to MNND Border costs, GCUstomer costs and GDirectND costs were due to volatility in actual expenses, including weather and weather related incidents, damage prevention locate volumes, contractor prices and compliance requirements. The Company stated that forecasted O&M data in the years 2021 and 2022 reflect estimates related to proposed work in the forecasted year(s) and developed at a high level and therefore does not provide the same level of cost differentiation by allocated methods. The Company stated that comparisons between actual and forecasted O&M at a refined level such as labor/non-labor or jurisdictional allocators may show deviations that do not exist when the O&M Expense is compared in total.

Q. WHAT ARE YOUR ADJUSTMENTS?

A. I am recommending normalizing these costs by averaging these out for the periods (2019-2021). These types of costs that the Company has described above, do vary from year to year and are caused by many difference factors including weather, damage prevention locate volumes, contractor pricing and compliance requirements. Smoothing out these fluctuations provide for an overall level of recurring expenses and cost recoveries going forward. My normalization adjustment is a reduction of $901,252 and is shown on my Schedule DM-15, broken down by MNND Border, G Customers and G Direct ND categories.

4. Customer Accounting

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

A. The Company has proposed a Customer Accounting balance for the test year 2022 of $1,217,726 shown in Data Response 01-034 Attachment A. These costs include Bad Debts, Customer related expenses and Direct charges to North

Dakota. Total costs assigned to this category including Labor Costs were $1,612,721 as shown in Data Request 01-34 Attachment A.

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

A. As explained in Data Response 01-10, the Company has experienced higher uncollectible accounts expense in the period during the COVID-19 pandemic when compared to pre-pandemic period. The Company has recorded incremental provisions amounts monthly to recognize the additional risk of accounts becoming uncollectible due to the impact of the COVID-19 pandemic. In response to Data Request 4-14, the Company stated that these types of costs are directly assigned to jurisdiction whenever possible, and costs are directly assigned to the North Dakota jurisdiction using the GDirectND jurisdiction allocator. The Company broke down these costs further to show the costs related to Labor, Meter Reading, Records and Collections, Uncollectible Bad Debt and Miscellaneous. (04-14 Attachment A).

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S CUSTOMER ACCOUNTING EXPENSE?

A. I am normalizing the Company's Bad Debt Expense over a three-year period (2019-2021). This increases the Company's costs by $4,204. My next adjustment is related to costs related to Supervision, Meter Reading, Record and Collections and Miscellaneous costs. Normalizing these cost by averaging them out using a three-year (2019-2021) average, results in a reduction of $191,159. My final adjustment is related to Direct Costs assigned to the North Dakota jurisdiction related to Meter Reading Expenses and Miscellaneous Costs. Normalizing these costs by averaging them out using a three-year (2019-2021) average results in a reduction of $114,312. My total Customer Accounting Expense adjustment is an overall decrease from $1,217,726 to $916,459 or a reduction of $301,267.

5. Customer Service & Information Expense

Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S CUSTOMER SERVICE AND INFORMATION EXPENSE?

A. I used a simple average of these costs for the periods 2019-2021. The Company has proposed a balance of $140,217 for the test year 2022. My three-year average adjusts the balance to an increase of $11,853 and a proposed 2022 balance of $152,070. This balance is shown on Schedule DM-10.

6. Sales, Economic Development and Other Expenses

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S SALES, ECONOMIC DEVELOPMENT AND OTHER EXPENSES?

A. While I did not average out the Company's balance of $8,872, I do have an adjustment related to the Company's Economic Development Donations of $7,382. This adjustment will be addressed under Section I of my testimony below. This balance is shown on Schedule DM-10.

7. Administrative & General Expenses

Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S ADMINISTRATIVE AND GENERAL EXPENSES?

A. While I did not average out the Company's balance of $1,099,071, I do have adjustments related to several of the Company Precedential and Ratemaking Adjustments, which will be addressed under Section J of my testimony below. My balance is shown on my Schedule DM-10.

C. Purchased Gas Expenses

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S PROPOSED PURCHASED GAS EXPENSES?

A. In reviewing the Company's filing and related data responses to Purchased Gas Expenses, I am accepting the Company's balance $43,934,000 as shown on Company Exhibit BCH-1 Schedule 3A.

D. Gas Production & Storage Expenses

Q. WHAT SPECIFIC ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S REMAINING PROPOSED GAS PRODUCTION & STORAGE EXPENSES?

A. In reviewing the Company's filing and related data responses to Gas Production & Storage Expenses, I am accepting the Company's remaining Gas Production & Storage Expenses.

E. Gas Transmission Expenses

Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH RESPECT TO ITS TRANSMISSION EXPENSES?

A. The Company has initiated a Damage Prevention Program (DPP) that assigns costs to the Company's Transmission, Distribution, Customer Service and A&G expense categories (Data Response 1-53 Attachment A). The Company stated that the DPP helps excavators and customers locate underground gas infrastructure to avoid accidental damage and safety incidents. (Exhibit JLZ-1 testimony page 37). The Company contracts with and relies on internal labor and contractors to implement the DPP, of which the primary purpose is to reduce damage to Company – owned buried facilities caused by excavation. This requirement is further supplemented by state law in North Dakota. (Exhibit JLZ-1 testimony page 37). This program is designed to ensure compliance with state and federal regulations and NSP relies heavily on contractors to perform this work. The Company has stated that damage prevention costs have increased by $400,000 between 2019 and 2020 actuals and are further forecasted to increase by $100,000 between 2020 and 2021, due to the increases attributable to both an increase in the volume of underground locate requests and a higher contract cost per locate due to contractor cost increases. (JLZ-1 testimony page 37-38).

Q. WHAT HAS THE COMPANY PROVIDED TO SHOW THESE COSTS RELATED TO THE DPP?

A. The Company provided breakdown these costs by account number for the periods 2019-2020 actuals, forecasted 221 and FTY 2022. (Data Response 1-53 Attachment A).

Q. WHAT DOES THIS DATA RESPONSE SHOW OR INDICATE?

A. According to the data response 1-53 Attachment A, the majority of the dollar amount related to the DPP were recorded in the Gas Distribution category, particularly in Account No. 874 where the initial cost of this program was $577,153 and increases to $1,131,448 through the FTY 2022. The costs accounted for under the Gas Transmission Expense category (Accounts 851 and 856) were minimal and no projected expenses were proposed in FTY 2022.

Q. WHAT ARE YOUR ADJUSTMENTS RELATED TO THE DPP FOR THE COMPANY'S GAS TRANSMISSION EXPENSE?

A. I am not recommending any adjustment to the Company's Gas Transmission Expense related to the DPP as the Company did not project any costs in the Forecasted 2021 and the FTY 2022.

F. Gas Distribution Expenses

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

A. As previously discussed above under the Gas Transmission Expense, the Company has proposed costs related to its DPP in the amount of $1,131,448 (Data Response 1-53 Attachment A). This expenses is solely related to Distribution Expense – Mains and Services under Account 874.

Q. WHAT ARE YOUR ADJUSTMENTS RELATED TO THE COMPANY'S DPP?

A. I am normalizing this expense by averaging these costs over three years (2019-2021). The Company has provided actual cost for the DPP (2019-2020) and forecasted costs for 2021 and in 2022. Given that the Company's 2021 cost increase was forecasted due to vendor contracts expiring, the labor market was

tight, and insurance premiums increased, and that inaccurate locates performed by Company employees increased, costs should remain consistent and in line with prior costs. The Company is expected to utilize outside contractors as any damages that will occur will be covered by the vendors and not the Company or its employees. (JLZ- 1 testimony page 37). Normalizing these costs over a three year average reduces the balance by $245,950. This is shown on my Schedule DM-15.

G. Customer Accounting Expenses

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

A. The Company did not propose any specific adjustment to its Customer Accounting Expenses. As discussed previously, the only adjustments that I have are related to normalizing certain costs using a three year average.

H. Customer Service & Information Expenses

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

A. The Company removed $40,000 related to its Advertising Expense (WP-A1 and Company Exhibit BCH-1 Schedule 4). The Advertising Expense was related to Conservation DSM costs.

Q. WHAT WERE THE COMPANY'S TOTAL ADVERTISING COSTS PROPOSED IN 2022?

A. As shown on Workpaper A1-Advertising, the Company recorded total Advertising Costs of $100,071. The remaining Advertising Costs included were related to Customer Assistance, Informational and Instructional expense, Economic Development and A&G General Advertising.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S CUSTOMER SERVICE & INFORMATION EXPENSE – ADVERTISING?

A. I am removing $1,471 of Advertising Expense that is related to Economic Development. Since I am recommending removing Economic Development Donations under the Company's Sales, Economic Development & Other Expenses, I am recommending that these costs under Advertising should also be removed. My arguments for removing these costs are as outlined below under Section I. My recommendation is shown on my Schedule DM-17.

I. Sales, Economic Development & Other Expenses

Q. WHAT SPECIFIC ADJUSTMENTS 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 adjustment related to Economic Donations in the amount of $7,382. A breakdown of these balance is shown on Workpaper A11. (portion allocation to ND Gas Jurisdiction).

Q. WHAT IS INCLUDED IN THE COMPANY'S $7,382 ECONOMIC DEVELOPMENT DONATIONS?

A. Company Witness Mr. Halama (Exhibit BCH-1 page 37) stated that the Company makes contributions to a number of regional and local economic development organizations positioned to combine resources 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 NDPSC 1-41, these costs provide financial and collaborative support to local, regional and state organizations. It is an estimate. These costs are used to assist in the strategic advancement of the communities served by the Company for job creation, GDP growth and the overall social well-being for individuals and businesses. Because no 2022 contributions had been made at the time of filing, there is no further breakdown or description of these donations.

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 providing gas utility service to certain parts of North Dakota. The Company should not be expensing costs related to non-utility type services, nor be in a position to support regional and local economic development. These type of initiatives should be provided at the State and Local or even at the Federal level. Additionally, ratepayers do not have a say in what type of donations they are paying for, or whether ratepayers receive any benefit for these contributions. These types of costs should not be included in the revenue requirement proposed by the Company. Given that no 2022 contributions had been made at the time of filing, there is no way to determine exactly how much money was expended in the FTY 2022. The Company should pay for these costs, below the line, and receive the tax benefits through the corporate entity.

Q. WHAT IS YOUR RECOMMENDATION?

A. I am recommending removal of the $7,382 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 SPECIFIC ADJUSTMENTS 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 $2,638,502, Precedential Adjustments of ($145,568) and Ratemaking Adjustments of $14,483, computing to Adjusted Balance of $2,507,656. 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 34). 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 -	($ 28,856)	WP A1
Customer Deposits -	$ 676	WP A3
Incentive Pay	($ 17,013)	WP A4
Incentive Pay LTI	($ 97,348)	WP A5
SERP -	($ 3,027)	WP A6

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

A. I have reviewed each of the Company's Precedential Adjustments, and I am accepting the Company's adjustments totaling ($145,568). This is shown on my Schedule DM-19.

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

A. The Company has proposed five Ratemaking Adjustments:

Ratemaking Adjustments

a.	Aviation	($22,003)	WP A7
b.	Dues - Chamber of Commerce	$ 2,221	WP A10
c.	Economic Development Donations	$6,226	WP A12
d.	Incentive Pay – Environ. LTI	$17,060	WP A13
e.	Incentive Pay – Time Based LTI	$10,979	WP A14

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

A. I adjusted the Company's Ratemaking Adjustments per above and which is reflected on Schedule DM-19.

a. Chamber of Commerce Dues – ($2,221)
b. Economic Development Donations – ($6,226)
c. Incentive Pay Environmental LTI –
d. Incentive Pay Time Based LTI -

a. Dues - Chambers of Commerce

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

A. The Company has included $2,221 of Chamber of Commerce Dues in revenue requirement request. (Workpaper A10 and Company Exhibit BCH-1 Schedule 4). Company witness Mr. Halama stated that these costs provide an essential link between the Company and the communities it serves and facilitate improved utility service (BCH-1 testimony page 36). Mr. Halama stated that because membership in these organizations provide benefits to all utility customers, recovery of membership dues paid to Chambers of Commerce is appropriate. (Exhibit BCH-1 page 36).

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. I am recommending removal the Company's Chamber of Commerce costs of $2,221. Further, in response to Data Request 1-40, The Company has indicated that no 2022 contributions have been made and no breakdown can be provided.

b. Economic Development Donations

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

A. The Company has included $6,226 of costs related to Economic Donations. Company witness Mr. Halama stated that the Company makes contributions to a number of regional and local economic development organizations positioned to combine resources for the purpose of maintaining and improving the long-term health of communities in its service territory or retaining employment opportunities and expanding the state and local tax base. (Exhibit BCH-1 testimony page 37). .

Q. WHAT IS YOUR RECOMMENDATION?

A. I am recommending that the $6,226 costs related to Economic Development Donations be removed from the Company's costs of service. In response to Data Request 1-42, the Company has not contribution any dollars in 2022 and there is not breakdown of these costs. These costs are similar to Charitable Contributions, and in general, should be removed from the Company's cost of service because ratepayers do not have any say of what type of contributions they are paying for. These types of payments do not benefit ratepayers, and as I stated previously in my testimony, and 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 does not have the right to make others pay for charitable contributions, especially those costs that do not provide specific benefits to its ratepayers. My recommendation is shown on my Schedule DM-19.

c. Incentive Pay – Environmental LTI

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO INCENTIVE PAY – ENVIRONMENTAL LTI?

A. According to Company witness Mr. Chamberlain, the Company is seeking to adjust recovery in rates for the Long-Term Incentive program (LTI) in the amount of $17,060 for its Environmental LTI. (Exhibit GPC-1 testimony page 22) (Exhibit BCH-1 Schedule 4) (WP A13). The LTI is available to the Company's senior and executive level employees, of which less than five percent of exempt and non-bargaining employees are eligible for LTI. The LTI is intended to incentivize these senior employees to effectively manage the Company towards its overall goals and in the best interest of customers and shareholders. The LTI is geared toward employees who have a higher influence in the Company's direction and strategy. (Exhibit GPC-1 testimony page 22). The LTI program helps retain key employees and is necessary for Xcel Energy to remain competitive in the labor market. (Exhibit GPC-1 testimony page 22). The Environment portion is tied into achieving the Company's environmental goals which will result in efficiencies, allow for a

lower cost of capital and remove fuel costs in addition to environmental benefits and other benefits. (Exhibit GPC-1 testimony page 23).

Q. DID THE COMPANY PROVIDE ANY INFORMATION WITH RESPECT TO GOAL ACHIEVEMENT AND SCORECARD RESULTS?

A. In response to Data Request 1-14, the Company stated that 2021 Corporate Scorecard final results have not yet been calculated and approved. The Company stated that 2021 Scorecard will determine the payout anticipated on March 9, 2022. (Data Response 1-15). The Company stated that the LTI plans requires a three-year service commitment with the Company which typically occurs in February following the third year of vesting. (Data Response 1-13 and 14).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. Given that the Company's Corporate Scorecard final results will not occur until March 2022, the Company's proposed Annual Incentive related to Environmental LTI is unknown and not measurable. Also, these Annual Incentive costs are geared toward senior and executive level employees from preventing them from leaving the Company, and to maintain and retain these employees as hiring these types of employees are expensive and time-consuming to fill. (Exhibit GPC-1 testimony page 22). In response to Data Request 1-16, the Company provide a schedule of senior and executive employees who left the Company. In the past three years (2019-2021) the Company experienced 2 non-retirement leaves and zero retirement leaves for the NSPM total Company. The Company does not track reasons for terminating employment beyond retirement and these are allocated across each of the associated jurisdictions. Therefore, I am recommending that the Company's Environmental LTI of $17,060 be removed from the Company's A&G expenses. (add more language, discuss with Advocacy Staff). My recommendation is shown on my Schedule DM-19.

d. Incentive Pay – Time Based LTI

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS TIME BASE LTI?

A. The Company has proposed to recover $10,979 based upon an LTI which is a program tied to the length of key employee's service with the Company. The Company stated that it benefits from its ability to retain institutional knowledge and capabilities of key employees. (Exhibit GPC-1 testimony page 23) (Exhibit BCH-1 Schedule 4) (Workpaper A14).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. As more fully discussed above, I am also recommending that the Company's $10,979 related to Time Based LTI be removed from the Company's A&G expenses. These costs area not known and measurable as the Company has not finalized its Scorecard which would determine the payout. This will occur on March 9, 2022. (Data Response 1-15). **(add more language as needed, discuss with Advocacy Staff).** My recommendation is shown on my Schedule DM-19.

K. Labor Adjustments

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

A. As shown on Data Response to 01-034 Attachment A, the Company proposed total Labor Expense of $4,093,208 for all employee categories. The Company allocated these labor costs by direct assignment or allocated to the North Dakota Gas Utility operations. (Exhibit BCH-1 testimony page 25 and 29). The cost allocation and assignment principles are consistent with the Company's recent North Dakota electric rate case filed on November 6, 2020 in Case No. PU-20-441. (Exhibit BCH-1 testimony page 29).

Q. DID THE COMPANY PROVIDE A SCHEDULE OF EMPLOYEES EXPECTED TO BE HIRED BY NSPC-GAS COMPANY IN THE PROJECTED YEAR 2022?

A. Yes. In response to Data Request 1-19, the Company provided a schedule of employees as potential candidates. Positions will be filled as soon as possible, but the specific dates are not known. The Company stated that the position list will also continue to change throughout the year. The Company stated that it cannot determine the anticipated hire data for the specific opening.

Q. HAS THE COMPANY PERFORMED A VACANCY RATE ANALYSIS FOR THE NSPC- GAS UTILITY OPERATIONS?

A. No. The Company stated in response to Data Request 1-18, that it works with leaders in certain areas regarding attrition and the need for posting open positions, the Company does not conduct a formal vacancy rate analysis.

Q. WHAT APPROACH HAVE YOU DETERMINED TO ADJUST LABOR COSTS?

A. I am recommending an adjustment of labor for all O&M labor by functional group by the use of a vacancy rate analysis. I relied on the Company's response to NDPSC 01-034 Attachment which shows the labor costs allocated to the North Dakota's Gas jurisdiction, by Operating Expense account. I relied on the response to Data Requests 1-20 that shows the employee headcount of NSPM-Minnesota for the years 2019-2022. The response to 1-6 which asked for the allocation of employees related to the North Dakota jurisdiction – Gas Utility for the years 2019 – 2022, refers me to Mr. Halama's Exhibit BCH-1 Schedule 12. Finally I reviewed the Company's response to Data Request 1-17 which reflects the level of employees who have left the Company (Non-Retirement and Retirement). Given that the Company allocates its labor costs by jurisdictional allocation, and these can vary from year to year, it is appropriate to adjust these labor costs prospectively. Labor costs can vary from year to year in each of NSPM's service territories and depending on the circumstances and the need to allocate labor, costs can vary.

Q. HOW DID YOU ADJUSTMENT TO THE COMPANY'S TOTAL LABOR COSTS?

A. I began with the number of employees of NSPM – Minnesota (Data Response 1-20) which shows the number of employees from 2019 through 2022. I then allocated these balances by the allocation factor of 11.2872% as shown on Exhibit BCH-1 Schedule 12 to reflect the number of employees allocated to the North Dakota – Gas Operations:

	NSPM	Factor	Allocated to NSPM-ND-Gas
2019	3,186	11.2872%	359
2020	3,118	11.2872%	352

2021	3,285	11.2872%	371		
2022	3,266	11.2872%	369		

I then reviewed the response to Data Request 1-17 which shows the number of NSPM total employees who have left the Company. I divided the number of employees allocated to the North Dakota – Gas Operations in each year by the number of employees who have left the Company to arrive at a vacancy rate as follows:

				Ratio to Total	3 Yr. Avg
2019	120	11.2872%	14	3.899%	
2020	112	11.2872%	13	3.693%	
2021	171	11.2872%	19	5.121%	4.2366%

Q. WHAT WERE YOUR NEXT STEPS?

A. I then took the three year average of 4.2366% and multiplied that ratio by the total Labor costs allocated to the North Dakota – Gas Operations of $4,093,208 shown on Data Request 1-34 Attachment A to arrive at a vacancy adjustment of $173,412. This is shown on my Schedule DM-4.

L. Depreciation Expenses

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

A. The Company proposed an Unadjusted Depreciation Expense balance of $6,845,000 as shown on Exhibit BCH-1 Schedule 6. The Company proposed an adjustment of ($31,918) related to Remaining Life for Gas Manufactured Production Plant and Gas Other Storage plant. (WP A8) The Company proposed an adjustment of $78,123 related to a Depreciation Study for its plant balances

(WP A9). According to Ms. Wold in her testimony Exhibit LJW-1 page 2, these adjustments reduced the Depreciation Expense at the North Dakota jurisdiction by $19,000.

Q. WHAT ADJUSTMENTS DID THE COMPANY INCORPORATE THAT RESULTED IN A REDUCTION OF DEPRECIATION EXPENSE?

A. According to Ms. Wold the increase in service lives and changes in net salvage rates decreased the Gas Production and Storage Depreciation by about 32,000 (LJW-1 testimony page 2). Gas Depreciation expenses were decreased by $49,000 in the allocation portion of Common Utility assets and partially offset by $62,000 for the North Dakota jurisdiction that increased Depreciation expense for Gas Transmission, Distribution and General assets. (LJW-1 testimony page 3, and Table 1 page 3 and Table 2 page 11).

Q. WHAT ADJUSTMENT DO YOU HAVE WITH RESPECT TO THE COMPANY'S DEPRECIATION EXPENSE?

A. While I do not have any adjustments related to the Company's Depreciation Study and Remaining Life Adjustments, I do have an adjustment related to the removal of certain plant additions. Since I removed costs related to certain inflation increases and contingency factors that I discussed under my Gas Plant In Service Testimony, I am removing the associated Depreciation Expense. I utilized the Company's composite rate of Depreciation which was computed by the information responded to in Data Request 1-61 (Exhibit LJW-1 Schedule 9), which calculates out to 2.646%. I then multiplied the adjustment to the Gas Plant Additions of $607,617 times the Composite Depreciation rate of 2.646% to arrive at an adjustment of $16,078. This is shown on my Schedule DM-20.

M. Amortization Expense

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

A. The Company has proposed a total Amortization Expense of $439,979 (Exhibit BCH-1 Schedule 6). The breakdown is as follows:

a).	Income Tax Tracker	$ 9,317
b).	NOL ADIT ARAM	$ 22,547
c).	Rate Case Expenses	$408,115
	Total	**$439,979**

a). Income Tax Tracker - $9,317

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS INCOME TAX TRACKER OF $9,317?

A. The Company stated that it has concluded tax audits with the IRS and the Minnesota Department of Revenue for tax years 2010-2016, and as a result of the audits, the Company paid tax and interest on the disputed amounts. The Company is proposing to recover these costs over a three year period consistent with rate case expenses (Exhibit BCH-1 testimony page 39). ($27,951/3). (WP A15).

Q. WHAT IS YOUR RECOMMENDATION?

A. I am accepting the Company's Income Tax Tracker proposal, and the costs allocated to the North Dakota jurisdiction of $27,951. I am recommending an amortization period of 5 years instead of 3 years. This will allow the Company to recover its Income Tax Tracker costs between normalized rate case proceedings. In determining the 5-year period, I relied on the Company's prior rate case applications with the ND Commission which reflected electric rate case filings in 2001, 2004, 2006 and 2021. (Data Response 1-23). The Company has filed rate case petitions on average every five-years. I normalized the period between rate cases (2001-2021) and arrived at an average 5-year period between rate cases. This results in an annual recovery of $5,590. This is shown on Schedule DM-21.

b). NOL ADIT ARAM - $22,547

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS NET OPERATING LOSS, ACCUMULATED DEFERRED INCOME TAXES, AVERAGE RATE ASSUMPTION METHOD OF $22,547?

A. The Company is proposing to amortize the NOL ADIT ARAM over a 23-year period. The Commission's Order in PU-18-156 approved the Company's proposed amortization level included in the Tax Cuts and Jobs Act (TCJA) refund calculation. (Exhibit BCH-1 testimony page 39). (WP A16).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am accepting the Company's proposal related to the $22,547 amortization expense related to the NOL ADIT ARAM. My adjustment is shown on Schedule DM-21.

c). Rate Case Expenses $408,115

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

A. The Company has proposed to recover about $1.224 million ($1.224 million / 3 three years or $408,000) of projected direct costs associated with this rate case docket and a three-year amortization period. (Exhibit BCH-1 testimony page 40). (WP A17).

Q. WHAT IS YOUR RECOMMENDATION?

A. I am accepting the Company's proposed rate case expense balance of $1.224 million. My only adjustment is to extend the amortization period to 5 years consistent with my recommended amortization period for other amortizations in this rate proceeding. This reduces the expense from $408,115 to $244,869, a reduction of $163,246. My adjustment is shown on Schedule DM-21.

N. 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 3A page 2 of 6, and in Exhibit BCH-1 Schedule 6, the Company proposed total Taxes other Than Income Taxes of $2,401,000.[3] The breakdown representing the balance is as follows:

a).	Property Taxes – Net	$1,587,000
b).	Deferred Income Taxes	$ 550,000
c).	Payroll – (Adj.)	$ 263,000
	Total	**$ 2,401,000**

a). Property Taxes – Net - $1,587,442

Q. HOW DID THE COMPANY DEVELOP ITS PROPERTY TAX BALANCE OF $1,587,000?

A. In response to Public Data Request 1-24, the Company is allocated a portion of its Property Taxes from NSPM-Minnesota. The North Dakota Office of the State Tax Commissioner's provides property tax valuation and assessment calculations for 2019, 2020 and 2021. **(These valuation reports are deemed confidential).** The Company's Property Taxes reflect what has been allocated to North Dakota including some plant in Minnesota. These valuations do not reflect the full amount of property taxes included in rates.

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY PROPERTY TAX BALANCE?

A. I am recommending averaging out Property Taxes for the periods 2019-2021 and normalizing these costs. The allocations between and among the NSPM Minnesota vary from year to year as shown in the Attached NDPSC Data Request No. 1-024 Attachment A. Therefore, given that the allocations do change from year to year, it may not appear at face value that Property Taxes are increasing from year to year. In the response to the non-confidential Data Response 1-24 the Company's recorded Property Taxes in 2019 were $1,301,677. In Company Exhibits BCH-1 Schedules 3C, 3B and 3A, the Company recorded $1,190,489 of

[3] Any differences due to rounding.

Property Taxes in 2020, $1,283,706 of Property Taxes in 2021 and $1,587,442 of Property Taxes in the 2022 test year period. Given the fluctuations from year to year, I believe it is appropriate to normalize these costs. The three year average calculates to $1,258,624, (2019 – 2021 Property Tax balances) a reduction of $328,818 from the Company's proposed balance of $1,587,442. My recommendation is shown on my Schedule DM-22.

b). Deferred Income Taxes - $551,000

Q. HOW DID THE COMPANY DEVELOP ITS DEFERRED INCOME TAXES ADJUSTMENT OF $551,000?

A. According to Mr. Halama's testimony (BCH-1) page 25, the Company determined income taxes based on total before 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. The Federal Income Tax rate reflects the 21% rate effective January 1, 2018 with the enactment of the TJCA. Mr. Halama stated that net operating losses (NOL) are created when taxable deductions exceed taxable revenues, and when this occurs, the excess deductions are carried forward to future periods. (Halama Testimony BCH-1 page 26). The NOL required an adjustment that offsets the part of the ADIT rate base reduction that is associated with the accelerated depreciation deductions, which is needed to keep the Company's rate base consistent with the income tax deductions that the Company has been able to use. Keeping a balance of rate base reductions from the ADIT and the use of accelerated depreciation is required under Federal income tax law and part of normalization for both accounting and ratemaking. (Halama Testimony BCH-1 page 26).

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S DEFERRED INCOME TAXES AND ITC BALANCE?

A. I am accepting the Company balance related to its Deferred Tax balance of $551,000. Since I did not make any adjustments to the Company's proposed

Depreciation Study – Remaining Life and Depreciation Study TD&G, I have no adjustments within these categories.

c). Payroll – (Adj.) $263,000

Q. WHAT IS YOUR THIRD ADJUSTMENT PAYROLL TAXES?

A. Since I made adjustments to the Company's Labor balance, and 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 (NDPSC 1-34 Attachment A) of $4,093,208 and the Company's proposed Payroll of $262,844 to arrive at a 6.421% ratio. I then took my adjustments to Labor and Incentive Compensation and multiplied the balance by 6.421% to arrive at a Payroll adjustment of $12,935.

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

A. My adjustment is a decrease of $341,753. This is shown on Schedule DM-22.

O. 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 $275,243 (Schedule DM-23). This is comprised of Current State Income Taxes of ($29,000) and Proposed State Income Taxes of $304,243, shown on Exhibit BCH-1 Schedule 3A.

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 Revised Schedule 3A) and multiplying that rate by the proposed Revenue Requirement of $7,059,000 to arrive at a balance of $304,243. (Company Exhibit BCH-1 Schedule 11).

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

A. I utilized the Company's methodology, and the flow-throughs 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 proposed State Income Tax Expense is $99,883, which is calculated by taking my recommended revenue requirement of $2,990,332 and multiplying that amount by 4.31% to arrive at a balance of $128,883. My total State Income Taxes is $99,883 shown on my Schedule DM-23. The additional State Income Tax is incorporated into my revenue requirement Schedule DM-1 through the Gross Revenue Conversion Factor of 1.322840.

P. 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 $1,283,499. This is comprised of current Federal Income Taxes of ($135,000) and proposed Federal Income Taxes of $1,418,499 shown on Company Exhibit BCH-1 Schedule 3A.

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% (Exhibit BCH-1 Revised Schedule 3A) and multiplying that rate by the Company's proposed Revenue Requirement of $7,059,000 to arrive at a balance of $1,418,499.

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 my recommended Revenue Requirement increase of $2,990,332, I multiplied that amount by 21% to arrive at a proposed Income Tax Expense of $600,904.

Q. WHAT IS YOUR FEDERAL INCOME TAX EXPENSE?

A. My proposed Federal Income Tax Expense is $465,904. This is shown on my Schedule DM-23. My total proposed balance of $465,904 includes the Company's current balance of ($135,000). The additional Federal Income Tax is incorporated into my revenue requirement Schedule DM-1 through the Gross Revenue Conversion Factor of 1.322840.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does. I reserve the right to amend my direct testimony in the event other information becomes forthcoming, subsequent to the filing of this testimony.

REVENUE REQUIREMENT

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Average Rate Base**	**$ 124,227,000**	**$ (1,695,902)**	**$ 122,531,098**	
2	Present Rate Income	$ 3,919,000	$ 2,224,449	$ 6,143,449	
3	AFUDC	$ -		$ -	
4	**Total Available for Return**	**$ 3,919,000**	$ 2,224,449	**$ 6,143,449**	
5	Present Rate of Return	3.155%		5.014%	
6	Required Return	7.450%		6.86%	
7	**Operating Income Requirement**	**$ 9,254,912**	**$ (850,924)**	**$ 8,403,988**	
8	**Income Deficiency**	**$ 5,335,912**	**$ (3,075,372)**	**$ 2,260,539**	
9	Gross Revenue Conversion Factor	1.322840		1.322840	(2)
10	**Revenue Deficiency**	**$ 7,058,557**	**$ (4,068,225)**	**$ 2,990,332**	
11	Present Rate Revenues	$ 67,303,000		$ 67,302,687	
12	Percentage Increase	10.488%		4.443%	
	Total Revenue Requirement			**$ 70,293,019**	

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

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

Differences due to rounding

WEIGHTED AVERAGE COST OF CAPITAL

(1) Company Proposed

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

(2) ND PSC Advocacy Staff

6	LT Debt	47.570%	4.100%	1.950%
7	ST Debt	0.430%	1.090%	0.005%
8	Common Equity	52.000%	9.430%	4.904%
9	**Total Capital**	**100.000%**		**6.86%**

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

AVERAGE RATE BASE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Gas Plant in Service				
1	Production	$ 5,340,000	$ -	$ 5,340,000	
2	Transmission	$ 3,909,000	$ -	$ 3,909,000	
3	Distribution	$ 181,046,000	$ (607,617)	$ 180,438,383	
4	Gas Storage	$ 9,341,000	$ -	$ 9,341,000	
5	General	$ 14,757,000	$ -	$ 14,757,000	
6	Common	$ 8,463,000	$ -	$ 8,463,000	
7	**Total Gas Plant In Service**	**$ 222,856,000**		**$ 222,248,383**	
8	Depreciation Reserve	$ 82,973,000	$ (16,078)	$ 82,956,922	
9	**Net Gas Plant In Service**	**$ 139,883,000**	**$ (591,539)**	**$ 139,291,461**	
10	Gas Plant Held for Future Use	$ -	$ -	$ -	
11	Construction Work in Progress	$ 188,000	$ -	$ 188,000	
12	**Accumulated Deferred Income Taxes**	**$ 19,783,000**	**$ (4,376)**	**$ 19,778,624**	
13	Cash Working Capital	$ 648,000	$ (1,086,738)	$ (438,738)	
14	**Subtotal**	**$ 120,936,000**	**$ (1,673,902)**	**$ 119,262,098**	
	Other Rate Base Items				
15	Materials and Supplies	$ 150,000	$ -	$ 150,000	
16	Fuel Inventory	$ 2,098,000	$ -	$ 2,098,000	
17	Non-Plant Assets & Liabilities	$ 1,463,000	$ -	$ 1,463,000	
18	Customer Advances	$ (1,340,000)	$ -	$ (1,340,000)	
19	Customer Deposits	$ (42,000)	$ -	$ (42,000)	
20	Prepaids and Other	$ 523,000	$ -	$ 523,000	
21	Regulatory Amortization - ITT/ADIT ARAM	$ 440,000	$ (23,000)	$ 417,000	WP A15
22	**Total Other Rate Base Items**	**$ 3,292,000**	**$ (23,000)**	**$ 3,269,000**	NDPSC 1-32
23	**Total Average Rate Base**	**$ 124,228,000**	**$ (1,696,902)**	**$ 122,531,098**	

(1) Company Exhibit BCH-1 Schedule 15

differences due to rounding

OPERATING INCOME STATEMENT

		(1) Company Present Rates	Adjustments	Company Proposed Rates	Adjustments	Present Rates ND PSC Advocacy Staff	References
	Operating Revenues						
1	Retail Revenues	$ 67,303,000	$ 7,059,000	$ 74,362,000	$ -	$ 67,302,687	
2	Interdepartmental	$ -		$ -	$ -	$ -	
3	Other Operating	$ 550,000	$ -	$ 550,000	$ -	$ 550,384	
4	**Total Operating Revenues**	**$ 67,853,000**	**$ 7,059,000**	**$ 74,912,000**	**$ -**	**$ 67,853,071**	DM-9
	Operating Expenses						
5	Purchased Gas	$ 43,934,000		$ 43,934,000	$ -	$ 43,934,429	DM-12
6	Gas Production & Storage	$ 635,000		$ 635,000	$ -	$ 635,473	DM-13
7	Gas Transmission	$ 387,000		$ 387,000	$ (44,477)	$ 342,523	DM-14
8	Gas Distribution	$ 5,129,000		$ 5,129,000	$ (1,146,821)	$ 3,982,179	DM-15
9	Customer Accounting	$ 1,613,000		$ 1,613,000		$ 1,311,454	DM-16
10	Customer Service & Other	$ 149,000		$ 149,000	$ 10,771	$ 159,771	DM-17
11	Sales, Econ Development & Other	$ 10,000		$ 10,000	$ (7,645)	$ 2,355	DM-18
12	Administrative & General	$ 2,508,000		$ 2,508,000		$ 2,471,170	DM-19
	Vacancy Rate Adjustment				$ (173,413)	$ (173,413)	1-34/20/17
13	**Total Operating Expenses**	**$ 54,365,000**	**$ -**	**$ 54,365,000**	**$ (1,699,058)**	**$ 52,665,942**	
14	Depreciation Expense	$ 6,892,000	$ -	$ 6,892,000	$ (16,873)	$ 6,875,127	DM-20
15	Amortization Expense	$ 440,000	$ -	$ 440,000	$ (166,994)	$ 273,006	DM-21
16	Taxes Other Than Income	$ 2,401,000		$ 2,401,000	$ (341,453)	$ 2,059,547	DM-22
17	State Income Taxes	$ (29,000)	$ 304,243	$ 275,243	$ -	$ (29,000)	DM-23
18	Federal Income Taxes	$ (135,000)	$ 1,418,499	$ 1,283,499	$ -	$ (135,000)	DM-23
19	**Total Taxes**	**$ 2,237,000**	**$ 1,722,742**	**$ 3,959,742**	**$ (341,453)**	**$ 1,895,547**	
20	**Total Expenses**	**$ 63,934,000**	**$ 1,722,742**	**$ 65,656,742**	**$ (2,224,378)**	**$ 61,709,622**	
21	AFUDC	$ -	$ -	$ -		$ -	
22	**Total Operating Income**	**$ 3,919,000**	**$ 5,336,258**	**$ 9,255,258**	**$ 2,224,449**	**$ 6,143,449**	
23	Rate Base	$ 124,228,000		$ 124,228,000		$ 122,531,098	
24	Rate of Return	3.155%		7.4502%		6.86%	
				$ 9,255,258		$ 8,403,988	

(1) Company Exhibit BCH-1 Schedule 11

differences due to rounding

GAS PLANT IN SERVICE

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

(1) Company Exhibit BCH-1 Schedule 5

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

ACCUMULATED DEPRECIATION

	(1) Company Unadjusted	Adjustments	Company Proposed	Adjustments	ND PSC Advocacy Staff	References
Gas Manufactured Plant	$ 2,420,000	$ (45,000)	$ 2,375,000	$ -	$ 2,375,000	WP A8
Gas Storage	$ 8,010,000	$ 29,000	$ 8,039,000	$ -	$ 8,039,000	WP A8
Gas Transmission	$ 1,683,000	$ 3,000	$ 1,686,000	$ -	$ 1,686,000	WP A9
Gas Distribution	$ 59,581,000	$ 50,000	$ 59,631,000	$ (16,078)	$ 59,614,922	WP A9
General	$ 5,559,000	$ 47,000	$ 5,606,000	$ -	$ 5,606,000	WP A9
Common	$ 5,619,000	$ 17,000	$ 5,636,000	$ -	$ 5,636,000	WP A9
Total Accumulated Depreciation	**$ 82,872,000**	**$ 101,000**	**$ 82,973,000**	**$ (16,078)**	**$ 82,956,922**	

(1) Company Exhibit BCH-1 Schedule 5

ACCUMULATED DEFERRED INCOME TAXES

		(1) Company Unadjusted	Adjustments	Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	Production	$ (77,000)	$ 12,000	$ (65,000)	$ -	$ (65,000)	WP A8
2	Transmission	$ 718,000	$ (1,000)	$ 717,000	$ -	$ 717,000	WP A9
3	Distribution	$ 17,469,000	$ (14,000)	$ 17,455,000	$ -	$ 17,455,000	WP A9
4	Gas Storage	$ (416,000)	$ (8,000)	$ (424,000)	$ (3,376)	$ (427,376)	WP A8
5	General	$ 1,266,000	$ (19,000)	$ 1,247,000	$ -	$ 1,247,000	WP A9
6	Common	$ 625,000	$ 1,000	$ 626,000	$ -	$ 626,000	WP A9
7	Net Operating Loss	$ (93,000)	$ -	$ (93,000)	$ -	$ (93,000)	
8	Non-Plant Related	$ 319,000	$ -	$ 319,000	$ -	$ 319,000	
9	**Total Accumulated Deferred Income Taxes**	**$ 19,811,000**	**$ (29,000)**	**$ 19,782,000**	**$ (3,376)**	**$ 19,778,624**	

(1) Company Exhibit BCH-1 Schedule 15

CASH WORKING CAPITAL (1)

		Lead/Lag Days	Company Dollars	Dollar x Days	Adjustments	ND PSC Advocacy Staff	References
1	**Fuel Expenses**	39.09119	$ 14,442,000	$ 564,554,966	$ 1,152,877,375	$ 1,717,432,341	4-3
	Labor						
2	Regular Payroll	11.890587	$ 3,409,000	$ 40,535,011	$ (173,413)	$ 38,473,031	DM-4
3	Incentive	248.81	$ 37,000	$ 9,205,970	$ (28,039)	$ 2,229,586	
4	Pension & Benefits	37.23	$ 647,000	$ 24,087,810	$ -	$ 24,087,810	
			$ 4,093,000	**$ 73,828,791**	**$ (9,038,364)**	**$ 64,790,427**	
5	All Other Operating Expenses	22.73988	$ 37,080,000	$ 843,194,750		$ 202,496,941	4-3
6	Property Taxes	357.9199	$ 1,587,000	$ 568,018,881		$ 450,486,576	
7	Employer's Payroll Taxes	31.6197	$ 263,000	$ 8,315,981		$ 7,902,041	
8	Gross Earnings Tax	38.8962	$ 1,214,000	$ 47,219,987		$ 47,219,987	
9	Federal Income Taxes	37.005	$ (386,000)	$ (14,283,930)		$ (4,995,675)	
10	State Income Taxes	36.9156	$ (83,000)	$ (3,063,995)		$ (1,070,552)	
			$ 39,675,000	**$ 1,449,401,675**		**$ 702,039,317**	
11	**Total**		**$ 58,210,000**	**$ 2,087,785,432**		**$ 2,484,262,086**	
12	Net Annual Expense (365)			$ 5,719,960		$ 6,806,197	
13	Revenues	40.2998	$ 67,303,000	$ 2,712,297,439		$ 2,712,284,826	
14	Late Payment		$ 155,000	$ -		$ -	
15	Miscellaneous Services	40.389	$ 118,000	$ 4,765,902		$ 4,765,902	
16	Rentals	-50.009	$ 211,000	$ (10,551,899)		$ (10,551,899)	
17	**Total**		**$ 67,787,000**	**$ 2,706,511,442**		**$ 2,706,498,829**	
18	Net Annual Amount (365)			$ 7,415,100		$ 7,415,065	
19	Expense/Revenue Factor			85.87%		85.87%	
20	Allocated Revenue			$ 6,367,489		$ 6,367,459	
21	**Net Cash Working Capital**			**$ 647,529**		**$ (438,738)**	

(1) Company Exhibit BCH-1 Schedule 8

OPERATING REVENUES

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

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

OPERATION & MAINTENANCE EXPENSES - WORKSHEET

Three-Year Normalize Non-Labor

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

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

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

PURCHASED GAS

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

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

GAS PRODUCTION & STORAGE

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

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

GAS TRANSMISSION

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

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

GAS DISTRIBUTION

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Unadjusted Balance				
1	G Customer MNND Border	$ 2,258,174	$ (775,305)	$ 1,482,869	ND PSC 4-13
2	G Customers	$ 947,014	$ 168,496	$ 1,115,510	
3	G Direct MN	$ -	$ -	$ -	
4	G Direct ND	$ 1,924,193	$ (294,443)	$ 1,629,750	
5	**Total Balance**	**$ 5,129,381**	**$ (901,252)**	**$ 4,228,129**	ND PSC 1-50
6	Damage Prevention Program	$ -	$ (245,950)	$ (245,950)	ND PSC 1-53
7	Precedential Adjustments	$ -	**$ -**	**$ -**	
8	**Adjusted Balance**	**$ 5,129,381**	**$ (1,147,202)**	**$ 3,982,179**	

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

CUSTOMER ACCOUNTING

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

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

CUSTOMER SERVICE & INFORMATION

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

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

SALES & ECONOMIC DEVELOPMENT

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

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

ADMINISTRATIVE & GENERAL

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

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

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

DEPRECIATION EXPENSE

		(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	**Unadjusted Balance**	**$ 6,845,000**	**$ (16,078)**	**$ 6,828,922**	1-43/4-9
	Remaining Life				
2	Gas Manufactured Production Plant	$ (90,872)	$ -	$ (90,872)	WP A8
3	Gas Other Storage Plant	$ 58,954	$ -	$ 58,954	WP A8
4	**Total Remaining Life**	**$ (31,918)**	**$ -**	**$ (31,918)**	
	Depreciation Study				
5	Gas Distribution - Composite 2.646%	$ 33,481	$ -	$ 33,481	WP A9
6	Gas Transmission - Composite 1.76%	$ 1,767	$ -	$ 1,767	WP A9
7	Common-General - AGIS - 21.68%	$ 17,742	$ -	$ 17,742	WP A9
8	General	$ 27,897	$ -	$ 27,897	WP A9
9	Common-Intangible	$ (6,212)	$ -	$ (6,212)	WP A9
10	Intangible	$ 3,448	$ -	$ 3,448	WP A9
11	**Total Depreciation Study**	**$ 78,123**	**$ -**	**$ 78,123**	
12	**Adjusted Balance**	**$ 6,891,205**	**$ (16,078)**	**$ 6,875,127**	

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

AMORTIZATION EXPENSE

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

(1) Company Exhibit BCH-1 Schedule 6

Refer to 1-43 - updated in Company Rebuttal

(2) Income Tax Tracker amortized over 5 years

(3) Rate Case Expense amortized over 5 years

TAXES OTHER THAN INCOME

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
Property Taxes	**$ 1,587,442**	**$ (328,818)**	**$ 1,258,624**	1-24
Payroll Taxes	**$ 262,844**	**$ (12,935)**	**$ 249,909**	1-34
Unadjusted Deferred Income Taxes / ITC	**$ 564,000**	**$ -**	**$ 564,000**	
Depreciation Study - Remaining Life				
Gas Manufactured Plant	$ 25,543	$ -	$ 25,543	
Gas Other Storage Plant	$ (16,571)	$ -	$ (16,571)	
Total	**$ 8,972**	**$ -**	**$ 8,972**	WP A8
Depreciation Study - TD&G - 28.11%				
Gas Distribution	$ (9,410)	$ -	$ (9,410)	
Gas Transmission	$ (497)	$ -	$ (497)	
Common-General	$ (4,987)	$ -	$ (4,987)	
General	$ (7,841)	$ -	$ (7,841)	
Common-Intangible	$ 1,746	$ -	$ 1,746	
Intangible Plant	$ (969)	$ -	$ (969)	
Total	**$ (21,958)**	**$ -**	**$ (21,958)**	WP A9
Adjusted Deferred Income Taxes/ITC	**$ 551,014**	**$ -**	**$ 551,014**	
Total Taxes Other Than Income	**$ 2,401,300**	**$ (341,753)**	**$ 2,059,547**	

(1) Company Exhibit BCH-1 Schedule 6

STATE INCOME TAXES
FEDERAL INCOME TAXES

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
State Income Taxes				
Current - 4.31%	$ (29,000)	$ -	$ (29,000)	NDPSC 1-38
Proposed Revenue Requirement	$ 7,059,000		$ 2,990,332	
Proposed State Income Taxes	$ 304,243		$ 128,883	
Proposed Balance	**$ 275,243**		**$ 99,883**	
Federal Income Taxes				
Current - 21%	$ (135,000)	$ -	$ (135,000)	NDPSC 1-38
Proposed Revenue Requirement	$ 7,059,000		$ 2,990,332	
Proposed Federal Income Taxes	$ 1,418,499		$ 600,904	
Proposed Balance	**$ 1,283,499**		**$ 465,904**	
Check total	$ 1,558,742		$ 565,788	

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

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
2021 Natural Gas Rate Increase
Application

Case No. PU-21-381

Verification

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

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

Dante Mugrace

Dante Mugrace

Subscribed and sworn to before me this 28 day of February, 2022.

Notary Public
My Commission Expires: May 22, 2026

REBECCA RAIMONDO
Notary Public - State of New Jersey
My Commission Expires May 22, 2026