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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 ELECTRIC SERVICE IN NORTH DAKOTA

Case No. PU-20-441

# DIRECT TESTIMONY OF KARL R. PAVLOVIC

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

April 23, 2021

90 PU-20-441 Filed 04/23/2021 Pages: 24
Prefiled Direct Testimony of Karl Pavlovic and Exhibits - redacted
Public Service Commission Advocacy Staff
Mitch Armstrong, Advocacy Staff Counsel

# 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.

**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. Attachment A 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 regarding cost allocation and rate design and in Case No. PU-17-295 Montana-Dakota Utilities Co., for Authority to

Establish Increased Rates for Natural Gas Service regarding cost allocation and rate design.

**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 electric utilities, I have testified on: (a) integrated resource planning, (b) class cost of service and rate design, (c) FERC jurisdictional stated and formula transmission rates, (d) mergers and acquisitions and (e) electric restructuring within the PJM RTO.

## I. <u>PURPOSE AND ORGANIZATION</u>

**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) the prudence of NSP's acquisition and retirement of certain generation resources, (2) NSP's North Dakota class cost of service study, (3) NSP's North Dakota class revenue responsibility distribution, and (4) NSP's North Dakota rate design.

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

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

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|---|---|
| Exhibit KRP-1: | Statement of Qualifications |
| Exhibit KRP-2: | Case No. PU-15-19, Advocacy Staff Letter of June 3, 2016 |
| Exhibit KRP-3: | Case No. PU-15-98, March 23, 2016 Order |
| Exhibit KRP-4: | Case No. PU-14-810, June 17, 2015 Order |
| Exhibit KRP-5 | Demand Only CCOSS TRADE SECRET |

## II. <u>SUMMARY OF TESTIMONY AND CONCLUSIONS</u>

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. As detailed below, my testimony finds the following.

- NSP's decision to retire Sherco Units 1 and 2 in 2026 and 2023 was not prudent.
- NSP's decision to acquire the MEC II Purchased Power Agreement (PPA) was not prudent.
- NSP's decision to acquire the 187 MW Solar Portfolio was not prudent.
- NSP's Minimum System CCOSS is not consistent with the principle of cost causation regarding minimum system classification of FERC Accounts 364-367.

- NSP's proposed class revenue responsibility distribution based on the Minimum System CCOSS results over allocates the revenue increase to the Residential class and under allocates the revenue increase to the C&I Demand class.
- NSP's proposed tariff customer charges are well above the customer component costs as calculated by the Demand Only CCOSS.

I recommend that the Commission:

- Find the Sherco Units 1and 2 early retirements and the acquisition of the MEC II and 187 MW Solar Portfolio PPAs not prudent;
- Direct NSP to adopt the Demand Only CCOSS;
- Direct NSP to use the Demand Only CCOSS as a guide in determining class revenue responsibility;
- Direct NSP to maintain the current tariff customer charges.

## III. DISCUSSION

### A. ACQUISITION AND RETIREMENT OF GENERATION RESOURCES

**Q. WHAT KINDS OF ECONOMIC ANALYSES DOES NSP USE TO EVALUATE THE IMPACTS OF RESOURCE ADDITIONS AND RETIREMENTS?**

A. NSP uses three economic analysis tools: pro forma analysis and two system simulation modeling tools (Strategist and EnCompass).[1] Pro forma analysis evaluates the costs and benefits attributable to specific resources in isolation from NSP's integrated system, the system simulation modeling tools evaluate the costs and benefits of resource additions and retirements in the context of the operation of NSP's integrated electric system. The

[1] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), pages 4-6.

principal difference between Strategist and EnCompass is that EnCompass models the operation of NSP's system on an hourly basis.

**Q. WHAT METRICS DOES NSP USE IN EVALUATING THE COSTS AND BENEFITS OF RESOURCE ADDITIONS AND RETIREMENTS IN THE OPERATION OF ITS INTEGRATED SYSTEM?**

A. NSP uses two metrics: the present value of the revenue requirement (PVRR) and the present value of societal costs (PVSC). The PVSC metric is the PVRR metric plus externality costs of carbon dioxide and criteria pollutants. The PVSC metric is required by Minnesota Commission regulation.[2] In contrast, the North Dakota Commission " is prohibited from considering quantitative environmental values."[3] That is to say that the Commission does not rely on the PVSC metric in evaluating the costs and benefits of resource additions and retirements.

**<u>Sherco Units 1 and 2</u>**

**Q. WHAT IS NSP REQUESTING OF THE NORTH DAKOTA COMMISSION REGARDING SHERCO UNITS 1 AND 2?**

A. In 2007 the North Dakota Commission approved a 2034 retirement date for both units, which date has since been the basis of the North Dakota depreciation rates for both units. NSP now requests that the Commission find that NSP's 2015 decision to retire Sherco Unit 1 in 2026 and Sherco Unit 2 in 2023 was prudent at that time and adjust the North Dakota depreciation rates accordingly in this proceeding.

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[2] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 18, lines 12-17.
[3] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 19, lines 6-12.

**Q. ON WHAT BASIS DID NSP MAKE THE DECISION TO RETIRE SHERCO UNITS 1 AND 2 IN 2026 AND 2023, RESPECTIVELY?**

A. NSP relied on its 2015 Updated Plan which showed considerable cost savings on a PVSC basis and the input of Minnesota stakeholders and customers who expressed a need for a quick transition to a cleaner generation fleet.[4]

**Q. AT THAT TIME DID NSP MAKE AN APPLICATION TO THE COMMISSION TO CHANGE THE RETIREMENT DATES FOR SHERCO UNITS 1 AND 2 AND CHANGE THE NORTH DAKOTA DEPRECIATIONS RATES FOR THE UNITS?**

A. No.[5] Consequently, for North Dakota ratemaking purposes, Sherco Units 1 and 2 have continued to accrue depreciation expense on the basis of the 2034 retirement date.

**Q. BASED ON NSP'S 2015 UPDATED PLAN, WAS NSP'S 2015 EARLY RETIREMENT DECISION PRUDENT?**

A. No. On a PVRR basis, the early retirement of the Sherco units resulted in $109-133 million in additional costs.[6] Additionally, as Advocacy Staff noted at the time, future regulatory requirements to reduce carbon emissions were uncertain and early retirement of the Sherco units could well lead to NSP incurring higher costs for replacement generation.[7] Thus, in 2015 when NSP made the Sherco early retirement decision, that decision was not the prudent.[8]

**Q. HAS NSP MADE SUBSEQUENT ANALYSES OF THE EARLY RETIREMENT OF SHERCO UNITS 1 AND 2?**

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[4] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 22, lines 20 to page 21, line 4.
[5] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 21, line 17 to page 22, line 4; see also Exhibit KRP-2, page 2.
[6] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 15, line 25 to page 17, line 8 and Table 1.
[7] Exhibit KRP-2, page 2
[8] Exhibit KRP-2, page 2

A. Yes. In a 2017 analysis the early retirement of the Sherco units resulted in $323-577 million PVRR additional costs. In a 2019 analysis the early retirement of the Sherco units resulted in $17 million PVRR additional costs. In a 2020 analysis the early retirement of the Sherco units resulted in $13 million PVRR cost savings.[9]

**Q. HAS NSP PROVIDED ANY CONTEMPORANEOUS INFORMATION AND DATA THAT WERE NOT BEFORE THE COMMISSION IN 2015?**

A. No.

**Q. WHAT IS YOUR CONCLUSION REGARTDING NSP'S EARLY RETIREMENT DECISION IN 2015?**

A. NSP's decision to retire Sherco Units 1 and 2 in 2026 and 2023 was not prudent.

**Mankato Energy Center II PPA**

**Q. WHAT IS NSP REQUESTING OF THE NORTH DAKOTA COMMISSION REGARDING THE MANKATO ENERGY CENTER II PPA (MEC II PPA)?**

A. NSP is requesting that the Commission find that NSP's 2015 decision to enter into the MEC II PPA was prudent and to allow recovery of the capacity costs in base rates and the energy costs through the FCR.[10] In the event that the Commission denies prudence, NSP requests that the costs of the MEC II PPA be dealt with via the Resource Treatment Framework.[11]

**Q. DID NSP SUBMIT TO THE COMMISSION AN APPLICATION FOR ADVANCED DETERMINATION OF PRUDENCE (ADP) AT THE TIME IT ENTERED INTO THE MEC II PPA?**

[9] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 23, lines 7-22.
[10] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 35, lines 12-14.
[11] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 61, line 23 to page 62, line 8.

A. Yes. In 2015 in Case No. PU-15-96, NSP submitted the MEC II PPA to meet an expected need in the 2023-2024 timeframe based on the 2015 Updated Plan,[12] In the PU-15-96 proceeding it was shown that the expected need in 2023-2024 timeframe was largely driven by NSP's plan to retire Sherco Units 1 and 2 in 2026 and 2023, which early retirement the Commission had not found to be prudent.[13]

**Q. DID THE COMMISSION FIND THAT THE MEC II PPA WAS A PRUDENT ACQUISITION?**

A. No. The Commission found that NSP had not shown the acquisition of the MEC II PPA to be prudent, as it would require North Dakota customers to pay for unneeded capacity for a significant portion of the contract and that the load forecasts and other assumptions upon which NSP relied were continually subject to change and might or might not occur.[14]

**Q. HAS NSP UPDATED THE FORECAST AND OTHER FACTORS IT USED IN ITS 2015 ANALYSIS OF THE MEC II PPA IN ITS PU-15-96 APPLICATION?**

A. No. NSP states that it would not be appropriate to update the forecast and other factors in evaluating whether the MEC II PPA was prudent in 2015 and, in any event, more recent forecasts shift the need out only slightly.[15]

**Q. THAT POINT NOTWITHSTANDING, HAS NSP PROVIDED ANY ADDITIONAL ANALYSES THAT IT PURPORTS BEAR ON THE PRUDENCE OF THE MEC II PPA?**

A. Yes. NSP conducted a comparative analysis of the annual cost of a greenfield Combined Cycle (CC) over the 2025-2039 timeframe versus (1) the annual cost of the MEC II PPA

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[12] Exhibit KRP-3, page 2, Finding of Fact 6.
[13] Exhibit KRP-3, page 3-4, Findings of Fact 13 and 14.
[14] Exhibit KRP-3, page 4, Finding of Fact 15 and Conclusion of Law 2.
[15] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 56, lines 4-26.

over the 2019-2039 timeframe, (3) the annual cost of the MEC II PPA with first six years amortized over the balance of the contract (i.e., the 2019- 2025 cost amortized over the 2026-2039 cost), and (4) the MISO 2020-2021 cost of new entry escalated at 1.5% annually.[16]

**Q. WHAT DOES NSP'S COMPARATIVE ANALYSIS SHOW?**

A. NSP's comparative analysis shows that (1) the MEC II PPA cost is slightly less than MISO new entry cost over the period 2019-2039, (2) that the amortized MEC II PPA cost is significantly greater than the new entry cost over the period 2025-2039, and (3) the greenfield CT cost is significantly greater than the amortized MEC II PPA cost over the 2025-2039 period.[17]

**Q. HAS NSP PROVIDED ANY CONTEMPORANEOUS INFORMATION AND DATA THAT WERE NOT BEFORE THE COMMISSION IN 2015?**

A. No.

**Q. WHAT IS YOUR CONCLUSION REGARTDING THE MEC II PPA?**

A. NSP's decision to enter into the MEC II PPA was not prudent.

<u>**187 MW Solar Portfolio PPAs**</u>

**Q. WHAT IS NSP REQUESTING OF THE NORTH DAKOTA COMMISSION REGARDING THE 187 MW SOLAR PORTFOLIO?**

A. NSP is requesting that the Commission find that NSP's 2014 decision to enter into the Solar Portfolio PPAs was prudent and allow recovery of the PPAs through the FCR.[18]

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[16] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 57, line 1 to page 61, line 9 and Figure 3.
[17] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 59, Figure 3.
[18] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 78, lines 4-6 and page 82, lines 3-5.

**Q. DID NSP SUBMIT TO THE COMMISSION AN APPLICATION FOR ADVANCED DETERMINATION OF PRUDENCE (ADP) AT THE TIME IT ENTERED INTO THE SOLAR PORTFOLIO PPAS?**

A. Yes. In Case No. PU-14-810 NSP submitted Strategist modeling that showed $14 million system-wide PVRR additional costs for the Solar Portfolio and asserted that this was a reasonable cost for the benefits of (1) compliance with future environmental laws and regulations, (2) a hedge against future natural gas prices, and (3) displacement of future energy purchases.[19] The Commission found that the acquisition of the Solar Portfolio was (1) inconsistent with least-cost planning, (2) capacity that would not be needed and in excess of that needed to meet its reserve margin and ensure reliable operation, and (3) lead to increased costs to North Dakota customers without corresponding benefits.[20]

**Q. DID THE COMMISSION FIND THAT THE SOLAR PORTFOLIO WAS A PRUDENT ACQUISITION?**

A. No. The Commission found that NSP had not shown the acquisition of the Solar Portfolio to be prudent and disallowed recovery of the costs through the FCR.[21]

**Q. HAS NSP PROVIDED ANY CONTEMPORANEOUS INFORMATION AND DATA THAT WERE NOT BEFORE THE COMMISSION IN 2015?**

A. No. NSP simply (1) restates the 2015 Strategist modeling PVRR results and benefits,[22] (2) estimates the impact on North Dakota customers of the Solar Portfolio costs versus cost of fossil fuel and other energy,[23] and (3) restates the asserted qualitative benefits. That is to say

[19] Exhibit KRP-4, page 3, Findings of Fact 8 and 10.
[20] Exhibit KRP-4, page 3, Findings of Fact 11-15.
[21] Exhibit KRP-4, page 4; Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), page 80, line 23 to page 81, line 4.
[22] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), pages 86, line 20 to page 89, line 16 and Table 11.
[23] Direct Testimony of Christopher J. Shaw (Exhibit CJS-1), pages 89, line 18 to page 91, line 5 and Table 12.

NSP simply reiterates the basis upon which the Commission found in 2015 that the acquisition of the Solar Portfolio was not prudent and the costs not recoverable from North Dakota customers through the FCR.

**Q. WHAT IS YOUR CONCLUSION REGARTDING SOLAR PORTFOLIO PPAS?**

A. NSP's decision to enter into the Solar Portfolio PPAs was not prudent.

## B. 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[24] 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 energy-related, and third allocating to customer classes those functionalized costs that are classified as demand-, customer-, or energy-related.[25]

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

A. No. The CCOSS properly functionalizes NSP's electric costs using the FERC Electric Uniform System of Accounts (USoA). Capital costs are functionalized in FERC Plant Accounts 310-346 (production), 350-359 (transmission) and 360-373 (distribution); operating expenses are functionalized in FERC Accounts 580-917; administrative and general expenses are functionalized in FERC Accounts 920-935; intangible and general capital costs are functionalized in FERC Accounts 301-303 and 389-399.

[24] Revised Direct Testimony of Michael A. Peppin (Exhibit MAP-1), Exhibit MAP-1 Revised Schedules 3 and 4.
[25] See NARUC Electric Utility Cost Allocation Manual (NARUC Electric Manual), 1992, pages 18-23.

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

A. Yes. The CCOSS relies on a minimum system hybridization of the minimum-size and minimum-intercept methods to classify NSP's electric distribution costs in FERC Accounts 364 (poles, towers & fixtures), 365 (overhead conductors & devices), 366 (underground conduit), 367 (underground conductors & devices) and 368 (line transformers) as both demand-related and customer-related.[26] The minimum-size method assumes that a minimum size distribution system can be built to serve a minimum loading requirement of the customers on the system;[27] the minimum-intercept method assumes a portion of plant related to a hypothetical no-load situation can be identified.[28] Note that both methods simply assume that some portion of the plant costs recorded in Accounts 364-368 is customer-related. While these methods of distribution plant classification were once, but no longer are, widespread among electric distribution utilities, there is, from the perspective of cost causation, no theoretical or practical justification for either method.

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

A. As clearly articulated in Bonbright's Principles of Public Utility Rates,[29] under the principle of cost causation, customer-related costs are "those operating and capital costs found to vary with number of customers."[30] Operationally defined, customer-related

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[26] Revised Direct Testimony of Michael A. Peppin (Exhibit MAP-1), pages 16-22; see also NARUC Electric Utility Cost Allocation Manual, 1992, pages 90-94,
[27] NARUC Cost Manual, page 90.
[28] NARUC Cost Manual, page 92.
[29] Bonbright et al, Principles of Public Utility Rates, 1988.
[30] 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."

costs are the "costs of connecting another customer or the savings in costs of not connecting the customer."[31] Per the NARUC Electric Manual, the capital costs incurred in connecting a customer to those parts of the electric distribution system that serve more than a single customer (i.e., FERC Accounts 360-368 - land, structures and station equipment, poles, conduit, conductors and transformers) are the capital costs of services (FERC Account 369), meters (FERC Account 370), installations on customer premises (FERC Account 371) and street lighting and signal systems (FERC Account 373) and are properly classified as customer-related.[32] NSP's CCOSS properly classifies the costs in FERC Accounts 369-373 as customer-related. The CCOSS errs only in classifying a portion of the costs in FERC Accounts 364-368 as customer-related, rather than properly as demand-related.

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

A. As Bonbright also explains, it is theoretically impossible for the capital costs in FERC Accounts 360-368 to vary with the number of customers connected to those facilities because the connection of a new customer (or disconnection of an existing customer) has no measurable impact on the costs in FERC Accounts 360-368.[33] Since the cost of the distribution system in accounts 360-368 do not and cannot vary with the number of customers connected to the distribution system, for the purposes of embedded cost analysis, the costs in FERC Accounts 360-368 are properly classified as demand-related,

[31] Bonbright, page 490.
[32] NARUC, page 96.
[33] Bonbright, page 491.

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."[34]

**Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CLASSIFICATION OF ACCOUNTS 364-368 IN NSP'S CCOSS?**

A. For reasons given above I recommend that NSP's FERC Accounts 364-368 be classified as wholly demand-related with no customer-related component, consistent with CCOSS' classification of FERC Accounts 360-363 as only demand-related.

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

A. The only allocation error is the CCOSS' use of class customer allocation of the FERC Account 364-368 costs erroneously classified as customer-related and the allocation of those erroneously classified costs on the basis of class number of customers.

**Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION REGARDING THE CLASSIFICATION OF FERC ACCOUNTS 364-368 AS ONLY DEMAND-RELATED?**

A. 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 the FERC Accounts 364-368 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.

[34] 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."

Classifying the entirety of NSP's FERC Accounts 364-368 costs as demand-related corrects the over allocation.

**Q. HAVE YOU QUANTIFIED THE IMPACT OF YOUR RECOMMENDATION?**

A. Yes. In response to NDPSC 10-8, NSP executed a Demand Only CCOSS with FERC Accounts 364-368 classified as demand-related only and allocated accordingly.[35] Table 1 below compares the class rate of return and indexed rate of return results of NSP's Minimum System CCOSS and the NDPSC 10-8 Demand Only CCOSS.

[35] NSP March 26, 2021 response to NDPSC 10-8, "PU-20-441 NDPSC-10-008 Attachment A TY2021 Live CCOSS File TRADE SECRET IN ENTIRETY.xlsx."

**Table 1 Comparison of Class Rates of Return and Indexed Rates of Return**

| Rate Class | Minimum System CCOSS[36] | | Demand Only CCOSS[37] | |
|---|---|---|---|---|
| Residential | 7.57% | 1.03 | **[TRADE SECRET DATA BEGINS]** [redacted] | 1.19 |
| Non-Demand | 7.69% | 1.05 | [redacted] | 1.17 |
| Demand Secondary | 8.22% | 1.12 | [redacted] | 0.99 |
| Demand Primary | 0.98% | 0.13 | [redacted] | 0.06 |
| Lighting | 2.24% | 0.30 | [redacted] | 0.26 |
| Total | 7.35% | 1.00 | [redacted] **[TRADE SECRET DATA ENDS]** | 1.00 |

As can be readily seen in Table 1, the Residential and Non-Demand classes are significantly above full cost recovery, the Demand Secondary class is slightly below full cost recovery, and the Demand Primary and Lighting classes are significantly below full cost recovery.

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[36] Revised Direct Testimony of Michael A. Peppin (Exhibit MAP-1 Revised), Schedule 4 Revised, page 1, line 30B.
[37] Exhibit KRP-5, page 1, line 30B **TRADE SECRET**.

**Q. WHAT ARE THE CLASS CUSTOMER COMPONENT COST RESULTS OF THE DEMAND ONLY CCOSS COMPARED TO THE MINIMUM SYSTEM CCOSS?**

A. Table 2 below shows the class customer component costs as calculated by the Minimum System CCOSS and the Demand Only CCOSS.

**Table 2 Comparison of Customer Component Costs**

| Rate Class | Minimum System CCOSS[38] | Demand Only CCOSS [39] |
|---|---|---|
| Residential | $15.42 | **[TRADE SECRET DATA BEGINS]** [redacted] |
| Non-Demand | $16.49 | [redacted] |
| Demand Secondary | $24.56 | [redacted] |
| Demand Primary | $46.76 | [redacted] |
| Lighting | $58.28 | [redacted] |
| Total | $16.82 | [redacted] **[TRADE SECRET DATA ENDS]** |

As can be seen in Table 2, the removal of customer-related classification of a portion of the FERC Account 364-368 costs significantly reduces the customer component costs for the Residential, Non-Demand and Demand Secondary classes. I discuss the rate design implications of these reductions below.

[38] Revised Direct Testimony of Michael A. Peppin (Exhibit MAP-1 Revised), Schedule 4 Revised, page 3, line 18.
[39] Exhibit KRP-5, page 3, line 18.

## C. NORTH DAKOTA CLASS REVENUE RESPONSIBILITY

**Q. WHAT IS NSP'S PROPOSAL REGARDING CLASS REVENUE RESPONSIBILITY?**

A. NSP Witness Paluck explains that NSP proposes to base class revenue responsibility on its Minimum System CCOSS and distribute the proposed revenue to classes by moderately moving the Lighting class towards full cost and distributing the Lighting class shortfall to the Residential, Non-Demand and C&I Demand classes, as shown in Exhibit NNP-1 Table 2.[40]

**Q. DO YOU FIND ANY ERRORS IN NSP'S PROPOSED CLASS REVENUE RESPONSIBILITY?**

A. Based on the Minimum System CCOSS results, the proposed class revenue responsibility, as Witness Paluck testifies, "balances the pricing objective of moving customer classes to cost with the pricing objective of rate continuity."[41] However, as I explained above, the Minimum System CCOSS does not accurately allocate costs to classes, over allocating costs to the residential and Non-Demand classes and under allocating costs to the C&I Demand classes.

**Q. HAVE YOU DEVELOPED CLASS REVENUE RESPONSIBILITY BASED ON THE DEMAND ONLY CCOSS?**

A. Yes. Table 3 below shows the results of applying NSP's balanced pricing objectives to the results of the Demand Only CCOSS.

[40] Revised Direct Testimony of Nicholas N. Paluck (Exhibit NNP-1), pages 4-5 and Table 2.
[41] Revised Direct Testimony of Nicholas N. Paluck (Exhibit NNP-1), page 6.

**Table 3 Demand Only Class Revenue Responsibility**

| Class | Present Revenue (000)[42] | Cost of Service (000)[43] | Cost Increase % | Proposed Revenue (000) | Proposed Increase % |
|---|---|---|---|---|---|
| Residential | $83,739 | **[TRADE SECRET DATA BEGINS]** [redacted] | [redacted] | 87,379 | 4.35% |
| Non-Demand | 11,379 | [redacted] | [redacted] | 11,326 | -0.47% |
| C&I Demand | 109,232 | [redacted] | [redacted] | 124,380 | 13.87% |
| Lighting | 2,066 | [redacted] | [redacted] | 2,486 | 20.30% |
| **Total Retail** | **$206,416** | [redacted] | [redacted] **[TRADE SECRET DATA ENDS]** | **$225,570** | **9.28%** |
| **Total /4** | **$206,416** | **$225,613** | **9.30%** | **$225,613** | **9.30%** |

As one can see from Table 3, the total revenue increase is the same as with the Minimum System CCOSS and consistent with the NSP's proposed balancing of the pricing objectives, the Lighting class receives a moderate, but below cost increase, while the Residential, Non-Demand and C&I Demand classes receive a de minimus increase over cost.

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

[42] Revised Direct Testimony of Michael A. Peppin (Exhibit MAP-1 Revised), Schedule 4 Revised, page 2, line 2.
[43] Exhibit KRP-5, page 2, line 8 **TRADE SECRET**.

A. Yes. Table 4 below shows the results of applying NSP's balanced pricing objectives to the results of the Demand Only CCOSS and Advocacy Staff Witness Mugrace's proposed revenue requirement.

**Table 4 Demand Only Class Revenue Responsibility based on Advocacy Staff Recommended Revenue Requirement**

| Class | Present Revenue (000)[44] | Cost of Service (000)[45] | Cost Increase % | Proposed Revenue (000) | Proposed Increase (Decrease) % |
|---|---|---|---|---|---|
| Residential | $83,739 | $81,284 | -2.93% | 81,407 | -2.78% |
| Non-Demand | 11,379 | $10,545 | -7.33% | 10,565 | -7.15% |
| C&I Demand | 109,232 | $115,474 | 5.71% | 115,651 | 5.88% |
| Lighting | 2,066 | $2,705 | 30.91% | 2,383 | 15.33% |
| **Total Retail** | **$206,416** | **$210,007** | **1.74%** | **$210,007** | **1.74%** |
| **Total** | **$206,416** | **$210,050** | **1.76%** | **$210,050** | **1.76%** |

In Table 4 under Proposed Revenue, I have made a moderate movement toward cost for the Lighting class, approximately 50% of the increase in cost, and for the other classes full movement to cost moderated by distribution of the Lighting class shortfall.

## D. NORTH DAKOTA RATE DESIGN

**Q. WHAT ARE NSP'S RATE DESIGN PROPOSALS?**

A. NSP is proposing no structural changes to its base rate structure.[46] Generally customer charges are increased in movement towards full recovery of customer component costs as

44 Revised Direct Testimony of Michael A. Peppin (Exhibit MAP-1 Revised), Schedule 4 Revised, page 2, line 2.
45 Direct Testimony of Dante Mugrace, Schedule DM-1, line 10 Advocacy Staff Revenue Deficiency $3,590,775.
46 Revised Direct Testimony of Nicholas N Paluck (Exhibit NNP-1), page 8.

calculated by NSP's Minimum System CCOSS and the remainder of the revenue increase is distributed the energy and demand charges consistent with the current summer/winter, on/off peak, voltage level relationships.[47]

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

A. I disagree with the proposal to increase customer charges. The customer component costs calculated by the Demand Only CCOSS are significantly reduced for all classes but Lighting as shown in Table 2 above and significantly less than most of the current tariff customer charges.[48] Therefore, I recommend that the current customer charges not be increased in the proposed base rates.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

[47] Revised Direct Testimony of Nicholas N Paluck (Exhibit NNP-1), pages 6-14 and Exhibit Schedule 5 Revised.
[48]

**STATE OF NORTH DAKOTA**

**PUBLIC SERVICE COMMISSION**

| | |
|---|---|
| **Northern States Power Company 2021 Electric Rate Increase Application** | **Case No. PU-20-441 OAH No. 20200422** |

## VERIFICATION

**STATE OF** Maryland )
) **ss.**
**COUNTY OF** Montgomery )

Karl 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 P Pavlovic
Karl Pavlovic

Subscribed and sworn to before me this 21st day of April, 2021.

MICHELLE A. LEASE NOTARY PUBLIC MONTGOMERY CO. MD

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

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