BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY DBA XCEL ENERGY FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES

DOCKET NO. EL12-046

Testimony and Exhibits of

David E. Peterson

On Behalf of Commission Staff

November 15, 2012

I. INTRODUCTION

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

A. My name is David E. Peterson. I am a Senior Consultant employed by Chesapeake Regulatory Consultants, Inc. ("CRC"). Our business address is 1698 Saefern Way, Annapolis, Maryland 21401-6529. I maintain an office in Dunkirk, Maryland.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE IN THE PUBLIC UTILITY FIELD?

A. I graduated with a Bachelor of Science degree in Economics from South Dakota State University in May of 1977. In 1983, I received a Master's degree in Business Administration from the University of South Dakota. My graduate program included accounting and public utility courses at the University of Maryland.

In September 1977, I joined the Staff of the Fixed Utilities Division of the South Dakota Public Utilities Commission as a rate analyst. My responsibilities at the South Dakota Commission included analyzing and testifying on ratemaking matters arising in rate proceedings involving electric, gas and telephone utilities.

Since leaving the South Dakota Commission in 1980, I have continued performing cost of service and revenue requirement analyses as a consultant. In December 1980, I joined the public utility consulting firm of Hess & Lim, Inc. I remained with that firm until August 1991, when I joined CRC. Over the years, I have analyzed filings by electric, natural gas, propane, telephone, water, wastewater, and steam utilities in connection with utility rate and certificate proceedings before federal and state regulatory commissions.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN PUBLIC UTILITY RATE PROCEEDINGS?

A. Yes. I have presented testimony in 132 other proceedings before the state regulatory commissions in Alabama, Arkansas, Colorado, Connecticut, Delaware, Indiana, Kansas, Maine, Maryland, Montana, Nevada, New Jersey, New Mexico, New York, Pennsylvania, South Dakota, West Virginia, and Wyoming, and before the Federal Energy Regulatory Commission. Collectively, my testimonies have addressed the following topics: the appropriate test year, rate base, revenues, expenses, depreciation, taxes, capital structure, capital costs, rate of return, cost allocation, rate design, life-cycle analyses, affiliate transactions, mergers, acquisitions, and cost-tracking procedures.

In addition, in 2006 testified twice before the Energy Subcommittee of the Delaware House of Representatives on consolidated tax savings and income tax normalization. Also in 2006, I presented a one-day seminar to the Delaware Public Service Commission ("Commission") on consolidated tax savings, tax normalization and other utility-related tax issues. In the spring of 2011, I co-presented along with Mr. Scott Hempling, the then-director of NRRI, a three-day seminar on public utility ratemaking principles to the Commissioners and Staff of the Washington Utilities and Transportation Commission. Earlier in 2012, I presented a one-day seminar on cost allocation and rate design to the Colorado Office of Consumer Counsel. More recently, I presented a two-day seminar on utility revenue requirements to the Delaware Public Service Commission Staff.

II. SUMMARY

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. My appearance in this proceeding is on behalf of the South Dakota Public Utilities Commission Staff ("Commission Staff").

Q. HAVE YOU TESTIFIED IN OTHER PROCEEDINGS BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION?

A. Yes, I have. Each of my previous testimonies in South Dakota rate cases, however, were when I was on the Commission Staff. While I have assisted the Commission Staff in several rate proceedings in more recent years, this is the first time that I have submitted testimony in South Dakota since leaving the Commission Staff in 1980.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I was asked to assist the Commission Staff in analyzing Northern States Power Company's ("NSP" or "the Company") proposed rate changes for South Dakota retail electric service. Specifically, I am presenting the Commission Staff's recommendations on NSP's proposed adjustment to test year pensions and other employee benefits expenses, its proposed adjustment to nuclear decommissioning expense, its class cost of service study and allocation of the revenue deficiency among rate classes, and its proposed increase in the monthly customer service charge.

Q. ARE YOU FAMILIAR WITH NSP'S FILING IN THIS PROCEEDING?

A. Yes, I am. I have carefully reviewed the Direct Testimonies, Exhibits and workpapers sponsored by the Company's witnesses relating to the issues that I address herein. I also reviewed the Company's responses to data requests of the Commission Staff, again relating to the issues that I address in my testimony

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. Following is a brief summary of my findings and recommendations on the issues that are more fully discussed later in this testimony.

Pensions and Other Employee Benefits: NSP witness Thomas E. Kramer proposed *pro forma* adjustments to test year levels of pension and other employee benefits (i.e., retiree medical, long-term disability and workers compensation insurances) expenses. The basis for Mr. Kramer's adjustments is a January 2012 report prepared by the Company's independent actuary, Towers Watson, which provided a six-year forecast of employee benefit costs for NSP and its corporate affiliates. More recently, the Company received an actuarial report of NSP's 2012 pension expense, but the Company will not know the precise impact of those costs on its South Dakota operations until after December 2012. Mr. Kramer's pension and employee benefits expense adjustments do not meet the known and measurable standard, which the Commission relies on to evaluate *pro forma* adjustments. Therefore, I recommend that Mr. Kramer's proposed pension and other employee benefits adjustments not be included in NSP's South Dakota revenue requirement.

Nuclear Plant Decommissioning Costs: TLG Services, Inc. of Bridgewater, Connecticut recently completed a nuclear plant decommissioning cost study for NSP. Beginning January 1, 2013, Mr. Kramer proposes to start recognizing the increase in the decommissioning cost accrual projected to be necessary based on the recently-completed decommissioning study. He also proposed a $2,184,000 South Dakota expense adjustment to include in rates the forecasted increase in the accrual requirement. Mr. Kramer proposed an additional adjustment to offset, in part, the increased accrual requirement using funds expected to be received from the Department of Energy ("DOE") under a settlement between the DOE and NSP over the DOE's cost responsibility for storing spent nuclear fuel. After considering the offset provided by the DOE settlement funds, the net increase in the decommissioning cost accrual that Mr. Kramer proposed is $1,015,000 to South Dakota retail operations.

Based on the Commission Staff's examination of TLG's cost estimates it was determined that those cost estimates include significant "contingency allowances" that range, by various activities, from 0 to 75 percent and which aggregate to $17.3 million to the South Dakota retail jurisdiction. For ratemaking purposes in South Dakota, however, contingency allowances have been excluded from NSP's nuclear decommissioning cost accruals since 1981.[1] Moreover, the Commission's rejection of the contingency allowance was upheld by the State Circuit Court, Sixth Judicial Circuit in a 1982 decision.[2] The Commission's prior exclusion of contingency allowances in the nuclear plant decommissioning cost accrual is not addressed in NSP's testimony and exhibits in this proceeding. Nor am I aware of any compelling reason for the Commission to depart from its prior decision to exclude contingency allowances from the decommissioning cost accrual.

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[1] *In the Matter of the Application of Northern States Power Company for Authority to Establish Increased Rates for Electric Service in South Dakota,* Decision and Order, PUC Docket No.F-3382, December 15, 1981.
[2] *In the Matter of the Application of Northern States Power Company for Authority to Establish Increased Rates for Electric Service in South Dakota PUC Docket No.F-3382*, Sixth Judicial Circuit, SD, Memorandum Decision, Civ. 82-6, October 28, 1982.

Therefore, I recommend that contingency allowances be removed from the TLG decommissioning cost estimates for purposes of establishing a new accrual requirement for nuclear plant decommissioning costs. Further, I recommend that Mr. Kramer's proposal to offset the nuclear plant decommissioning cost accrual by funds anticipated to be received from the DOE in settlement of the spent nuclear fuel storage issue be rejected. On January 30, 2012, after examining various ways to return to ratepayers the excess funds previously collected by the Company for spent nuclear fuel storage, the Commission issued an Order in Docket No. EL11-023 adopting the Commission Staff's recommendation to require a one-time billing credit to ratepayers. One of the options that was considered at that time was to use the settlement proceeds (net of litigation costs) as an offset to the Company's revenue requirement in a rate case, similar to what Mr. Kramer is proposing in this case. NSP provided no persuasive reasons for the Commission to depart from its recent ruling on this matter. Thus, Mr. Kramer's proposal to offset, in part, the requested increase in the nuclear plant decommissioning accrual with the DOE refund should be rejected. All DOE funds received by NSP for spent nuclear fuel storage payments, net of prudently incurred litigation costs, should be refunded to South Dakota customers via a one-time billing credit, as previously ordered by the Commission in Docket No. EL11-023.

Class Cost of Service Study – Spread of the Increase: NSP's class cost of service study purports to show that current rates in the residential rate classes produce rates of return that are less than the returns earned from other rate classes and less than the system-wide average rate of return. NSP witness Steven V. Huso relies on these results to allocate the Company's alleged revenue deficiency among the rate classes in a manner that results in an above average percentage increase for the residential class.

NSP's class cost study result showing that residential class rates produce a lower-than-average rate of return is largely driven by the Company's use of the "minimum distribution system" ("MDS") method for classifying and allocating a significant portion of the Company's distribution system based on the relative number of customers served in each class. Since the residential class contains a proportionally higher number of customers than the other classes of service, the MDS classification method disfavors the residential class. I reject the MDS approach for cost classification because it does not reflect the way that NSP plans, constructs, and operates its distribution system. When NSP's cost study is re-run after excluding the MDS classification, the results are reversed. That is, residential class rates produce an above-average rate of return. Therefore, I recommend that the Commission Staff's determination of NSP's revenue deficiency be allocated in a manner that results in a less-than-average percentage increase for Residential customers. The details of my recommended spread of the revenue increase among rate classes are explained later in my testimony.

Monthly Customer Service Charge: Mr. Huso proposes to increase the residential class monthly service charges by $.75. If approved as proposed, residential overhead customers will pay a $9.00 per month service charge (regardless of usage and, in addition to use charges during the month); underground customers will pay an $11.00 per month service charge. The purported support for the increases in the monthly service charges is NSP's class cost of service study. The indicated service charge deficiency shown in the class cost study is largely a function of the Company's use of the MDS approach for classifying distribution costs on a customer basis and NSP's inclusion of costs in the customer charge that do not vary with the number of customers served. I performed my own analysis of monthly service charge-related costs after removing the effects of the MDS method and excluding costs that do not vary with the number of customers served. My analysis shows that NSP's present monthly service charges already significantly exceed the cost of service. Therefore, I recommend there be no increase in the monthly service charges.

The bases for these findings and recommendations are explained in greater detail in the following sections of my testimony.

Q. WERE YOU ASKED TO ANALYZE ANY OTHER ASPECTS OF NSP'S RATE FILING?

A. Yes, I was. In addition to the four issues previously discussed for which I sponsor specific recommendations, I also analyzed the following aspects of NSP's rate filing:

- Jurisdictional cost allocation;
- Allocation of corporate overhead costs;
- Net operating loss and its impact on the federal income tax allowance;
- Post-retirement benefits other than pensions on a pay-as-you-go basis;
- Depreciation expense adjustments including steam plant remaining life, other production plant remaining life, remaining life for the MN Valley plant; and remaining life for the BL/GC/KG facilities; and
- Voltage discounts.

The Commission Staff is not challenging the Company's treatment of these items in its revenue requirement study. Additional comment on a couple of these issues is in order, however.

Concerning NSP's proposed depreciation adjustments, the five depreciation adjustments made in Mr. Kramer's Exhibit___(TEK-1), Schedule 6b, Columns 30-34, include a $2.95 million reduction in test year depreciation expense to reflect changes in depreciation rates agreed to in the settlement of NSP's last South Dakota base rate proceeding (Docket No. EL11-019) and four additional adjustments to reflect plant remaining life changes that, collectively, reduce depreciation expenses by an additional $721,000.

Concerning the tax adjustments included in NSP's filing to reflect the consequences of its net operation loss for income tax purposes, while the Company's calculations are accurate, the specific level of NSP's adjustments are appropriate only for the level of additional revenue that it seeks in its filing. To the extent the Commission ultimately adopts a revenue requirement that differs from the amount that NSP requests, the net operating loss calculations will have to be modified to reflect that change. As it now stands, Ms. Mehlhaff's revenue requirement study reflects NSP's proposed net operating loss-related adjustments. Those adjustments will be modified once the Commission makes a final determination on the various issues in this proceeding that define a new revenue requirement for NSP's South Dakota's operations. This is the same procedure that the parties followed in NSP's last base rate case in Docket EL11-019 concerning this adjustment.

III. PENSIONS AND OTHER EMPLOYEE BENEFITS

Q. DID NSP PROPOSE ANY ADJUSTMENTS TO THE TEST YEAR LEVEL OF PENSIONS AND OTHER EMPLOYEE BENEFITS EXPENSES?

A. Yes. Mr. Kramer proposed to increase the test year pension expense, as allocated to South Dakota, by $704,000. In addition, Mr. Kramer proposed a $27,000 net reduction from test year levels for retiree medical, long-term disability and workers compensation insurance expenses. Together, Mr. Kramer's proposed adjustments to pensions and other employee benefits expenses result in a $677,000 revenue deficiency for South Dakota retail operations.

Q. ARE MR. KRAMER'S PROPOSED PENSION AND OTHER EMPLOYEE BENEFITS EXPENSE ADJUSTMENTS APPROPRIATE FOR RATEMAKING PURPOSES?

A. No, they are not. Mr. Kramer's adjustments are speculative and do not represent a known and measurable change in NSP's costs. Mr. Kramer derived his proposed expense adjustments from a report dated January 31, 2012, prepared for NSP and its affiliates by Towers Watson, the Company's independent actuary. That report, however, clearly states that the analyses contained therein produces a six-year ***forecast*** of certain employee benefits expenses, not the actual costs of those benefits. Because Mr. Kramer relied on forecasts rather than actual costs to support his pension and other employee benefits expense adjustments, his adjustments do not represent known and measurable increases in NSP's test period costs. More recently, NSP received an actuarial determination of the Company's 2012 pension cost. But, the precise impact of those costs on South Dakota electric retail operations will not be known until after December 2012.

Therefore, I recommend that Mr. Kramer's adjustments be rejected. Ms. Mehlhaff has reflected the impact of my recommendation on NSP's South Dakota revenue requirement on her Exhibit___(BAM-1), Schedule 3, page 5.

IV. NUCLEAR PLANT DECOMMISSIONING COSTS

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF NSP'S RATE PROPOSALS CONCERNING NUCLEAR PLANT DECOMMISSION COSTS.

A. In December 2011, TLG Services, Inc. ("TLG") completed a study for the Company of costs for decommissioning activities expected to be incurred at the end of NSP's nuclear facility useful lives. Mr. Kramer proposed to increase NSP's present annual decommissioning cost accrual effective January 1, 2013, based on the results of the TLG study. Thus, Mr. Kramer proposed a corresponding $2,184,000 increase in the South Dakota retail decommissioning cost accrual for ratemaking purposes. Mr. Kramer then reduced that increase by $1,169,000, to reflect the return to ratepayers of funds anticipated to be received from the DOE resulting from NSP's settlement with the DOE on the issues surrounding the storage costs of spent nuclear fuel. Thus, on a net basis, Mr. Kramer's determination of NSP's South Dakota retail revenue requirement reflects a $1,015,000 increase in the annual nuclear plant decommissioning cost accrual.

Q. IN YOUR PREVIOUS RESPONSE YOU IDENTIFIED THE TWO ADJUSTMENTS THAT MR. KRAMER IS PROPOSING TO THE COMPANY'S PRESENT ANNUAL DECOMMISSIONING COST ACCRUAL. DO YOU AGREE WITH BOTH ADJUSTMENTS?

A. No, I do not. I disagree with both adjustments.

Q. REFERRING FIRST TO THE DOE REFUND ADJUSTMENT THAT MR. KRAMER PROPOSED, WHAT IS YOUR ISSUE WITH THIS ADJUSTMENT?

A. I disagree with Mr. Kramer's DOE settlement offset proposal because both the incurrence of the associated cost and the subsequent refund are related to the storage of spent nuclear fuel and not to NSP's future decommissioning costs.

I agree with the Company that the DOE settlement proceeds should be returned to ratepayers, because it was the ratepayers who had to bear the unwarranted costs. However, the Commission has already made a reasoned decision on the disposition of the DOE settlement proceeds. In Docket EL11-023 where this matter was considered, the Commission unanimously approved the Commission Staff's recommendation that the proceeds then received, net of litigation expenses, should be fully rebated to customers via a one-time billing credit and that future settlement proceeds should be refunded using the same one-time bill credit method. This process is transparent to ratepayers and it provides them with compensation at a time that more closely relates to the time ratepayers were required to pay what has now been determined to be excessive costs. The one-time bill credit also eliminates any uncertainty about the amount of any future DOE payments.

Q. WHAT IS YOUR DISAGREEMENT WITH MR. KRAMER'S OTHER ADJUSTMENT TO THE ANNUAL DECOMMISSIONING COST ACCRUAL?

A. The decommissioning cost estimates prepared by TLG and used by the Company to develop the accrual consist of detailed engineering estimates for the specific activities involved in the decommissioning process, but these explainable cost estimates are then inflated for unexplainable "contingencies." By this process, the $2.057 billion engineering estimates for decommissioning Monticello and the two Prairie Island nuclear facilities are inflated by 17.6 percent, or by $361.6 million, for contingencies. About $17.3 million (4.8 percent) of the contingencies are allocated for recovery from South Dakota ratepayers. However, the South Dakota Commission has previously held that such contingencies should not be included in NSP's decommissioning accrual. The Commission's 1982 decision in Docket No. F-3382 to exclude a contingency allowance in rates was later upheld by the Circuit Court, Sixth Judicial Circuit, in Memorandum Decision Civ 82-6. Subsequently, all Commission-approved rate case settlements have explicitly excluded contingency allowances from the decommissioning cost accrual.[3]

Q. DO TLG'S CURRENT DECOMMISSIONING COST ESTIMATES REFLECT THE SAME CONTINENCY ALLOWANCES THAT NSP CLAIMED IN PREVIOUS SOUTH DAKOTA RATE CASES?

A. No. In SDPUC Docket No. F-3382, the Company claimed an across-the-board contingency allowance equal to 25 percent of the total engineering cost estimate. The contingency allowances claimed in this proceeding vary among the decommissioning tasks and range from 0 percent to 75 percent of the component engineering cost estimate. Overall, the composite of these allowances is 17.6 percent of the engineering cost estimates.

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[3] See 1988 Settlement Agreement in Docket Nos. F-3764 and F-3780, Article IV and the Settlement Agreement in Docket No. EL90-013, Article IV, which states, "The Settlement Agreement decommissioning cost allowance reflects no contingency allowance in the decommissioning cost estimates…"

Q. HOW DOES THE COMPANY ATTEMPT TO JUSTIFY THE INCLUSION OF THE CONTINGENCY ALLOWANCES IN RATES IN THIS PROCEEDING?

A. Mr. Kramer, who presents NSP's recommendations on the decommissioning cost accrual, makes no mention in his Direct Testimony of the contingency allowance or of the Commission's prior treatment of contingency allowances.

The Executive Summary of the TLG report at page xi of xx states that the contingency allowances are consistent with cost estimating practices and that they make specific provisions for unforeseeable elements of cost within a defined project scope that is "particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur." In addition, the Executive Summary states that the engineering estimates are based on "ideal conditions" and therefore do not account for "the types of unforeseeable events that are almost certain to occur in decommissioning." Therefore, according to the TLG report, "inclusion of contingency is necessary to provide assurance that sufficient funding will be available to accomplish the intended tasks."[4] Elsewhere in the TLG report, the consultant states that the engineering cost estimates are based both on "ideal conditions and maximum efficiency," implying that maximum efficiency is not achievable.[5]

Q. WHY ARE YOU NOT PERSUADED BY TLG'S EXPLANATIONS FOR CONTINGENCIES?

A. First, I do not agree that any extra, non-specific cost allowances should be included as a cushion to assure that there will be sufficient funds for future cost

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[4] See NSP's response to Staff Request 3-12, Attachment B, page 11 of 217.
[5] Ibid. page 42 of 217.

recovery. To clarify my position, it helps to consider the opposite side of the same coin. That is, what assurances do ratepayers have that they will not be required to contribute excessive amounts? Clearly, there are no such assurances for ratepayers under the Company's approach. Moreover, the concern that "unforeseeable events" can only increase costs is a biased view; it is not inconceivable that technology improvements, unforeseeable now, will be developed before the commencement of decommissioning (about 20 years from now) or during decommissioning (expected to be completed in 2066 or 2067) and reduce costs below present engineering estimates. Finally, it is reasonable and proper for ratepayers who will pay these contingency costs to expect the decommissioning contractors to do everything under their power to achieve "maximum efficiency." NSP should not tolerate, nor should it pay for, any wasteful and inefficient practices of their decommissioning contractors.

Q. PLEASE SUMMARIZE WHY YOU RECOMMEND THAT THE COMMISSION CONTINUE TO EXCLUDE THE CONTINGENCY ALLOWANCES FROM THE DECOMMISSIONING COST ACCRUAL.

A. The decommissioning accrual should reflect the best possible engineering estimate of the specific, identifiable costs which are expected to be incurred. Imaginary costs deserve no more place in the accrual than would speculative cost savings. As time passes, decommissioning methods and procedures will evolve and cost increases or costs savings that are now unforeseeable should be reflected in revised, task-specific cost estimates, thus providing for complete cost recovery over the then remaining service lives of the three nuclear generating units.

Ms. Mehlhaff's revenue requirement exhibit reflects the exclusion of contingency allowances from the annual decommissioning cost accrual. Her schedules also reflect removal of the anticipated DOE settlement funds from NSP's base rate determination. My adjustments are summarized on Ms. Mehlhaff's Exhibit___(BAM-1), Schedule 3, page 4, column (ad) and on her Exhibit___(BAM-2), Schedule 2, page 2, column (q).

V. CLASS COST OF SERVICE – SPREAD OF THE INCREASE

Q. HAVE YOU REVIEWED NSP'S COST OF SERVICE STUDIES IN THIS PROCEEDING?

A. Yes, I have. NSP performed both a jurisdictional cost of service study and a class cost of service study. The purpose of the jurisdictional cost study is to allocate a portion of NSP's total utility investments and costs to the South Dakota retail jurisdiction. The class cost study takes the costs that are allocated to the South Dakota retail jurisdiction and further allocates them to the various retail classes (e.g., Residential, Commercial, Industrial, Street Lighting, etc.). The fundamental principle underlying all embedded cost allocation studies is that costs are attributed to jurisdictions and customer groups based on the cost to serve those groups or on relative benefits received by the groups. Costs examined in an allocation study are either directly assigned or allocated. Rationally allocated costs provide a meaningful basis upon which to derive class revenue targets and can be useful in designing rates to be charged within the customer classes.

Q. WHAT ARE THE STEPS INVOLVED IN PREPARING A CLASS COST STUDY?

A. Although the presentation may vary depending on the analyst performing the study, most costs of service studies involve the same three-step process: functionalization, classification, and allocation.

As the name implies, functionalization is the process that divides the utility's investments, revenue and expenses into functional cost categories that are descriptive of the functions they perform in rendering service. For an electric utility, the functional cost categories usually consist of generation, transmission, distribution and customer service. The Uniform System of Accounts provides the starting point to functionalize the utility's investments and expenses.

Q. WHAT IS THE NEXT STEP IN THE ANALYSIS?

A. The next step is cost classification. In this step, the functionalized costs are classified into one or more cost categories. The cost classifications for an electric utility are class and customer demands, average or annual energy usage, customer-related and sometimes revenue-related.

Q. WHAT IS THE FINAL STEP?

A. The final step is cost allocation. In this step, classified costs are allocated to the various customer groups based on each group's responsibility for the service provided by the utility. Primary allocation factors, which are intended to reflect cost causation, relative usage, or cost responsibility, are used to allocate costs to customer classes. Many of the classified costs are then allocated among the customer groups using the primary cost allocation factors. The remaining costs are allocated to customer groups using secondary allocation factors. The secondary factors are derived from one or more of the primary factors using methods that are consistent with cost causation. For example, after utility plant is allocated, by function, to the various classes using primary allocation factors, property taxes are often allocated to rate classes using the resulting derived secondary allocation factor – net plant in service.

Once all of the investments, revenues, and expenses have been properly functionalized, classified and allocated to the rate classes, earn returns can be calculated for each rate class. Each rate class's earned return is then compared to the utility's overall return earned in the jurisdiction to determine if each class is contributing more or less than its equitable share to the utility's overall rate of return. A class whose earned rate of return is less than the overall return is said to be subsidized by one or more of the other rate classes. The rate class or classes whose rates of return are greater than the overall return are said to be the provider(s) of the subsidy to those classes earning less than the overall rate of return.

Q. WHAT ARE THE RESULTS OF NSP'S CLASS COST STUDY?

A. NSP witness Michael A. Peppin's class cost study is presented in Exhibit___(MAP-1), Schedule 4 and in Statement O of NSP's filing statements. Mr. Peppin's results are summarized in the table below.

NSP – South Dakota Jurisdiction
Class Rates of Return Under Existing Rates
(As Filed)

Service Class	Rate of Return	Indexed Rate of Return
Residential	4.48%	.88
Small General Service	5.85%	1.14
Large General Service and Industrial	5.62%	1.11
Lighting	5.73%	1.13
Total South Dakota	5.08%	1.00

The rates of return shown in the table above were calculated before the interruptible discount revenue shift. The indexed rates of return in the far right column in the table measure the relative performance of each rate class to the South Dakota retail system as a whole, in terms of earned returns. The indexed return is the ratio of each class's earned return to the South Dakota system average earned return. An indexed return of less than 1.0 for any class indicates that the class return is less than the system average. The implication is that such a class is being subsidized by other rate classes.

As it applies to NSP's filed case, Mr. Peppin's class cost study results indicate that residential customers are being subsidized by customers in the other rate classes. Note that the residential indexed class return is less than 1.0. Based on these results, Mr. Huso proposed that residential customers receive a somewhat higher than the system-wide average percentage increase that NSP is requesting in this proceeding. Mr. Huso's proposed class revenue spread does not move the residential class all the way to the state-wide average rate of return, however. Rather, Mr. Huso proposed to remove 25 percent of the difference between class revenue requirements indicated by the class cost study and a uniform percentage increase. The following table summarizes the class increases that Mr. Huso proposed.

NSP-South Dakota Jurisdiction
Company Proposed Spread of Requested Increase
$(000)

Service Class	Increase	Percent Increase
Residential	$ 8,866	12.6%
Small General Service	$ 1,004	11.1%
Large General Service and Industrial	$ 9,311	10.7%
Lighting	$ 187	11.0%
Total South Dakota	$19,369	11.5%

Q. ARE YOU IN AGREEMENT WITH THE PROCEDURES THAT MR. PEPPIN USED IN HIS CLASS COST STUDY?

A. No, not completely. My primary concern with Mr. Peppin's cost study is his use of the MDS approach to classify a portion of NSP overhead and underground lines and line transformers as customer-related.

Q. IS MR. PEPPIN'S USE OF THE MDS APPROACH SIGNIFICANT IN THIS PROCEEDING?

A. Yes, it is. Mr. Peppin used the MDS approach to classify a portion of overhead and underground lines and line transformers as customer-related. Together, these facilities represent 16.0 percent of NSP's total South Dakota gross plant in service and 38.4 percent of NSP's non-production gross plant in service. Moreover, Mr. Huso relies, to some extent, on the MDS in developing the monthly customer charge for each rate class. Thus, the MDS approach is significant for both class cost allocation and for rate design purposes.

Q. WHAT IS THE MDS?

A. The MDS postulates that there are certain types of facilities that must be installed by the utility to provide customers access to the utility's electrical service, regardless of customer usage requirements. The MDS then classifies the cost of the minimum size of these facilities as customer-related. For example, NSP's MDS calculation for poles re-prices the actual cost of all of the poles presently in service to reflect the cost of the minimum size pole (30 feet) that it has installed on its system. That is, the Company multiplied the average cost of a 30 foot minimum size pole ($150.01 in South Dakota) by the number of poles (of all sizes) that are presently installed (39,007 in South Dakota). The re-priced minimum size pole inventory divided by the NSP's total investment in poles produces the ratio or percentage of NSP's pole investment that Mr. Peppin then classified as customer-related. The remainder of the pole investment was classified as a demand-related cost. A similar procedure was used to re-price NSP's investments in underground lines and line transformers.

Q. WHAT IS YOUR CONCERN ABOUT USING THE MDS TO CLASSIFY A PORTION OF DISTRIBUTION COSTS AS CUSTOMER-RELATED?

A. My objection to the MDS approach is that it does not give appropriate consideration to NSP's actual system design, construction and operation. Having failed to give proper consideration to these important factors, the MDS fails to reflect NSP's cost of service.

Those who support classifying distribution facilities (other than services and meters) on a customer basis do so based on an assertion that some minimum investment is necessary to make electrical service available for each customer, regardless of the customer's peak or annual service requirements. Proponents then argue that this "customer-related" investment should be defined as either: a) the hypothetical cost of the current distribution system revalued using the cost of minimum-sized distribution facilities presently installed on the system (the MDS approach) or; b) the hypothetical cost of distribution plant having no load carrying capability (the so-called "zero-intercept" approach). The minimum size distribution equipment that a utility will install, however, is based on expected customer loads, not on the number of customers served by the utility or minimum service requirements. As for the zero-intercept approach, no utility installs distribution equipment incapable of carrying loads. Rather, the facilities that NSP installs are sized, designed, operated and maintained in order to meet the individual customers' peak and annual service requirements. Neither the MDS nor the zero-intercept variant of the MDS gives appropriate consideration to actual system design, construction and operation. The MDS fails to reflect cost-causation and, therefore, is not a proper cost allocation method.

Q. HAVE YOU RE-RUN MR. PEPPIN'S CLASS COST STUDY TO REFLECT THE EFFECTS OF ELIMINATING THE MDS METHOD?

A. Yes, I have. I re-ran Mr. Peppin's cost study after eliminating the customer classification for the underground and overhead lines and line transformer accounts. Exhibit___(DEP-1) is the output from my revised cost study, at the Company's claimed revenue deficiency and requested rate of return.

Q. WHAT DOES EXHIBIT___(DEP-1) SHOW?

A. The following table summarizes the results of re-running the class cost study after eliminating the MDS customer classification. This table also includes Mr. Peppin's original results reflecting the MDS approach, for comparison.

NSP – South Dakota Jurisdiction

Class Rates of Return Under Existing Rates
With and Without Minimum Distribution System Approach

Service Class	Rate of Return with MDS	Rate of Return without MDS
Residential	4.48%	5.91%
Small General Service	5.85%	7.38%
Large General Service and Industrial	5.62%	4.18%
Lighting	5.73%	4.79%
Total South Dakota	5.08%	5.08%

This table demonstrates that the MDS customer classification is significant to the end result. Under NSP's preferred approach, which includes an MDS customer classification component, it appears that the general service, industrial and lighting classes are all providing subsidies to the residential rate class. After excluding the MDS customer classification, the opposite result is indicated. Without the MDS customer classification, the earned returns for both the residential and small non-demand metered commercial classes (5.91% and 7.38%, respectively) exceed NSP's state-wide overall rate of return (5.08%), indicating that it is the residential and small general service classes that are providing subsidies to the large general service, industrial and lighting classes.

Q. ARE THERE OTHER IMPLICATIONS OF MR. PEPPIN'S USING THE MDS APPROACH FOR COST CLASSIFICATION?

A. Yes, there are. To some degree, Mr. Huso relied on the class cost study results to develop his proposed monthly customer service charges. Because Mr. Peppin improperly classified a significant portion of NSP's distribution costs to the customer category using the MDS approach, the indicated cost of service for the monthly customer service charge is overstated. Eliminating the MDS results from the cost study reduces the monthly customer charge that was indicated in Mr. Peppin's cost study for the Residential class from $17.80 down to $12.54. The difference is significant for the Small Non-Demand General Service class as well. With the MDS, the indicated monthly customer charge is $20.25. Excluding the MDS classification reduces this amount to $14.71. But, even these reduced amounts overstate NSP's costs that should be included in the development of the monthly customer charge, as I explain in the next section of my testimony.

Q. BASED ON THESE RESULTS, WHAT DO YOU RECOMMEND REGARDING THE ALLOCATION OF THE RATE INCREASE AMONG THE VARIOUS RATE CLASSES?

A. My recommendation is similar to Mr. Huso's, i.e., move each class 25 percent of the way towards their indicated cost of service result. The 25 percent limit is intended to reflect the same gradual movement towards cost based rates that Mr. Huso proposed. My recommended revenue spread, however, is based on the class cost study that excludes the MDS customer classification. The Commission Staff's revenue deficiency is also significantly lower than NSP's claimed deficiency. My recommended revenue spread reflects the Commission Staff's determination of NSP's current revenue deficiency, a class cost of service study that excludes consideration of the hypothetical MDS, and 25% movement to the indicated class cost of service. The results of my proposed revenue spread are developed on in my Exhibit___(DEP-2) and are summarized in the following table.

NSP – South Dakota Jurisdiction
Commission Staff's Recommended Spread of the Increase
$(000)

Service Class	Increase	Percent Increase
Residential	$2,533	3.59%
Small General Service	$ 289	3.20%
Large General Service and Industrial	$3,470	4.00%
Lighting	$ 66	3.88%
Total South Dakota	$6,359	3.78%

VI. CUSTOMER SERVICE CHARGE

Q. WHAT CHANGES IS NSP PROPOSING TO MONTHLY CUSTOMER SERVICE CHARGES?

A. Presently, residential overhead customers pay an $8.25 per month customer service charge and residential underground customers pay $10.25 per month. Mr. Huso proposes to increase both of these charges by $.75 per month. Thus, overhead customers will pay $9.00 and underground customers will pay $11.00, if Mr. Huso's proposals are adopted.

Mr. Huso proposes to increase the monthly customer service charge for Small Commercial non-demand metered customers from $9.00 to $10.00.

Q. HOW DOES MR. HUSO ATTEMPT TO JUSTIFY THESE INCREASES?

A. He does so by referencing the results of Mr. Peppin's class cost of service study. For example, Mr. Huso observed that the class cost of service study quantifies a $17.80 fixed customer-related cost of service for the residential rate class. The present average Residential service charge is only 51 percent of this amount. Thus, Mr. Huso proposed a $.75 increase in the residential service charges such that it will increase revenues from the monthly service charge to 55 percent of the observed cost of service.

Q. DO YOU AGREE THAT NSP'S CLASS COST STUDY CORRECTLY QUANTIFIES THE CUSTOMER-RELATED COST OF SERVICE AT $17.80?

A. No, I do not for several reasons. The $17.80 amount reflects all costs in the class cost study that are classified and allocated to the residential rate class based on customer count. The portion of the $17.80 that represents MDS-related costs is $5.26. I explained earlier why I believe it is inappropriate to classify certain distribution costs on a customer basis using the MDS methodology. For the same reason, it is inappropriate to include those costs in a monthly service charge analysis. In addition, the $17.80 amount includes certain costs that are classified on a customer basis but are not directly proportional to the number of customers served. That is, just because a cost is classified on the basis of customer does not axiomatically justify its inclusion in the determination of the monthly service charge. There are certain costs that are classified to the customer component in a class cost study simply because there is no better cost classification method. But, there is no precise nexus between costs classified as customer-related and the costs properly includable in a monthly service charge determination. Finally, the $17.80 amount is overstated because it reflects NSP's proposed rate of return while Commission Staff's determination of NSP's return requirement is much lower.

Q. HAVE YOU ANALYZED THE CUSTOMER-RELATED COSTS THAT ARE PROPERLY INCLUDED IN A MONTHLY SERVICE CHARGE FOR THE RESIDENTIAL AND SMALL COMMERICAL NON-DEMAND METERED RATE CLASSES?

A. Yes, I have. My analysis is summarized on Exhibit___(DEP-3). All of the information included in my analysis comes from my re-run of NSP's class cost of service model excluding the MDS allocations. I also substituted Staff witness Mr. Copeland's recommended rate of return for NSP's proposed rate of return in my analysis.

In my analysis, I defined customer-related costs to include NSP's investments and operating expenses necessary to connect and to maintain and account, regardless of usage. My determination includes a return allowance on NSP's net investment in meters and services as well and meter and service related O&M expenses, related A&G expenses, depreciation, property taxes and income taxes. My analyses show that NSP's present monthly service charges already exceed the embedded cost of service by a significant amount.[6] Therefore, there is no justification for increasing the Company's monthly services charges at this time. In order to avoid adverse rate consequences for some customers that may result if monthly service charges were reduced to the indicated cost of service level, I recommend that present monthly service charges be maintained in each rate class.

[6] My cost analysis shows that the average customer-related cost for the residential class is $6.39 per month. This is significantly below the present weighted average rate for the Residential class of $9.11.

Q. DOES THIS COMPLETE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.