BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA

In the Matter of the Application of Northern Sates Power Company,
A Minnesota Corporation
For Authority to Increase Rates for
Electric Service in North Dakota

Case No. PU-07-776

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PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MICHAEL J. MAJOROS, JR.

May 2008

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Direct Testimony of Michael Majoros and Charles King

Public Service Commission Advocacy Staff

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Introduction

Q. State your name, position, and business address.

A. My name is Michael J. Majoros, Jr. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"), located at 1111 14TH Street, N.W., Suite 300, Washington, D.C. 20005.

Q. Describe Snavely King.

A. Snavely King is an economic consulting firm founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. Snavely King represents the interests of government agencies, businesses, and individuals who are consumers of telecom, public utility, and transportation services.

We have a professional staff of 12 economists, accountants, engineers and cost analysts. Most of our work involves the development, preparation and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of our 38-year history, members of the firm have participated in more than 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes, Appendix A is a summary of my qualifications and experience. Appendix B contains a tabulation of my appearances as an expert witness before state and Federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Staff of the North Dakota Public Service Commission.

Subject and Purpose of Testimony

Q. What is the subject of your testimony?

A. This case involves a filing by Northern States Power Company ("NSP") for authority to increase its rates by $20.5 million or 13.95 percent.[1] My testimony addresses the increase.

Q. What is the purpose of your testimony?

A. I have reviewed the Company's filing and based upon my findings, I am recommending monetary adjustments to the Company's filed request My adjustments, which also incorporate Mr. King's depreciation and other adjustments relating to certain Minnesota programs, and a stipulated 8.8 percent rate of return, reduce the increase from $20.5 million to a $.2 million reduction.

Prior Experience

Q. Do you have any specific experience in the public utility field?

A. Yes, I have been in the field of public utility regulation since the late 1970's. My testimony has addressed numerous revenue requirement issues. Furthermore, I and other members of my firm specialize in the field of public utility depreciation. We have appeared as expert witnesses on this subject

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[1] Larson Direct, p.2.

before the regulatory commissions of almost every state in the country.

Q. Have you ever testified in any proceedings involving NSP or any of its affiliates?

A. Yes, recently I testified before the Colorado Public Utilities Commission in Docket Nos. 06S-234EG and 06S-656G regarding Public Service Company of Colorado's ("PSCo") electric and gas base rates. I also submitted testimony in NSP's North Dakota Case Nos. PU-400-00-521 and PU-06-525.

<u>Summary of NSP's Filing</u>

Q. Summarize the Company's filing in this case.

A. NSP's policy witness, Mr. Larson, proposes a $20.5 million or 13.95 percent rate increase.[2] The Company's revenue requirement witness, Ms. Heuer elaborates that "the North Dakota jurisdiction's retail electric operations overall retail revenue requirement [is] $167,714,000 and a revenue deficiency of $20,535,000 [was] determined by the cost of service for the 2008 budget test year."[3] The increase incorporates an 11.5 percent return on equity.

<u>General Comments</u>

Q. Do you have any general comments regarding NSP's requested increase?

A. This rate case comes at a time when energy, gasoline and food prices are sharply increasing. In my opinion, this is no time to increase ratepayers' bills for unnecessary policy changes and the like.

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[2] Id.

[3] Heuer Direct, page 1.

NSP's Rationalization for the Increase

Q. How does the Company rationalize the overall increase.

A. Mr. Larson bases the requested increase on three principal factors:

1. Increasing investments in [NSP's] generating assets, including the completion in 2008 of two (out of a series of three) significant coal power plant rehabilitation and repowering projects;[4]
2. Increasing costs at [NSP's] nuclear power plants, including new investments to extend the lives of these plants an additional 20 years; and[5]
3. Increasing investment in [NSP's] transmission infrastructure.[6]

Q. Does NSP's filing include any additional added features?

A. According to Mr. Larson "in addition to the typical rate case issues of cost recovery, [he] proposes two initiatives in this proceeding that will address regulatory matters of current interest to the Commission."[7] These are:

1. *Wholesale Margin Sharing*. Instead of including wholesale margins as an offset to base rates, the Company proposes to keep 15 percent and flow the remaining 85 percent through its proposed fuel cost rider.[8] This

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[4] Larson, page 14.
[5] Id.
[6] Id.
[7] Larson Direct, page 3.
[8] Id., page 4.

policy change will cost ratepayers $2.4 million per year.[9]

2. *MISO Schedule 16 and 17 Costs.* Currently, the Commission has approved, on an interim basis, the recovery of Midwest Independent Transmission System Operator ("MISO") Schedule 16 and 17 costs through the existing FCA. The Company believes this is a reasonable approach, however, it asserts that the Commission expressed a preference in Case No. PU-05-131 concerning Otter Tail Power Company to have these types of costs recovered in base rates.[10] Hence, the Company included them in base rates in its filing. This policy change will cost ratepayers $532 thousand per year in base rate charges.[11]

Q. Does Mr. Larson recognize that his proposed rate increase will cause a hardship for NSP's North Dakota customers?

A. Yes, he does. Mr. Larson acknowledges that "the 13.95 percent [he] is requesting in this proposal is greater than the prior request in [NSP's] last electric rate case," and that "this rate application represents a significant increase in its North Dakota rates," and that "customers are already challenged with significant increases in all of their energy costs."[12] However, based on the fact that "the Company has earned well below its authorized level in 2006 and expects to earn less in 2007 and 2008; it determined it could

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[9] Exhibit___(AEH-1), Schedule 4.
[10] Larson Direct, page 4.
[11] Exhibit___(AEH-1), Schedule 4.
[12] Larson Direct, pages 9 to 10.

not avoid a rate increase."[13]

Q. Have you investigated the Company's rate request?

A. Yes, Mr. King, my assistant and I read the Company's filing and propounded numerous data requests related to the Company's rate request. North Dakota Public Service Commission staff member Mr. Diller also propounded several data requests. Because of this investigation, I recommend that the Company's base rates be decreased by $.2 million as shown on Exhibit___ (MJM-1).

Depreciation

Q. Is depreciation an important aspect of this case?

A. Yes, it is. The depreciation expense relating to plant growth is one of Mr. Larson's major reasons for NSP's proposed increase. In fact, Ms. Heuer's Exhibit___ (AEH-1), Schedule 5 reveals that depreciation is NSP's single largest expense after the purchased fuel and power production costs. NSP's depreciation expense exceeds $19.1 million, all of which is non-cash. In other words, depreciation is the largest non-fuel/production expense in this base rate case.

Q. Is it reasonable to conclude that Staff might investigate depreciation in this case?

A. Yes, because depreciation is NSP's largest non-fuel expense, it is reasonable to assume that Staff might investigate depreciation in this case.

Q. Did Staff attempt to investigate depreciation in this case?

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[13] Id., page 10.

A. Mr. King attempted to investigate depreciation, but he ran into a brick wall. A consistent theme of NSP's responses to staff data requests relating to depreciation was to "see the Minnesota depreciation study."

Q. Was Mr. King able to analyze depreciation regardless of these responses?

A. Yes, he was able to make certain adjustments to certain accounts. Nevertheless, in my opinion, this company should be required to file a North Dakota-specific depreciation study to verify the remaining depreciation rates. The credibility of NSP's depreciation claim may be at stake.

<u>Consolidated Taxes</u>

Q. Do you have any other examples of NSP refusing to provide information that might be relevant to a revenue requirement finding in this proceeding?

A. Yes, I do. NSP is a participant in a consolidated federal income tax return. These arrangements can result in the ratepayers of regulated entities subsidizing losses of unregulated affiliates. In other public utility cases, I have read tax allocation agreements between the parties to consolidated tax returns. On more than one occasion, I have seen words requiring a pass through of taxes collected from a regulated entity to the parent and from there to the loss affiliates.

In this case, we submitted several data requests in this regard, only to have NSP decline to respond. For example, in response to Staff 1-78, NSP responded as follows:

> The Company objects to the [consolidated tax] question on the grounds that the North Dakota Public Service Commission uses the stand-alone method to determine taxes for ratemaking, which makes the question irrelevant and unreasonably burdensome, The stand-alone method bases the computation of current and deferred tax expense on the Company's jurisdictional utility income alone, excluding both income and losses from regulated activities in other jurisdictions and non-regulated activities of the Company, its affiliates, and its parent Xcel Energy, Inc.[14]

Q. Did the Company say it would make these materials available if an order in this proceeding protects the non-public nature of this information?

A. The Company said it could not provide the information without such an order.

Q. Has the Commission employed the stand-alone approach in the past?

A. Yes, it has. However, given the experience with energy, gasoline and food price increases, I recommend that the Commission revisit the issue. In a period of dwindling resources and corresponding upward price spirals, the Commission should at least know the magnitude of the consolidated tax subsidy and reconsider whether captive ratepayers should be required to pay anything more than actual taxes. The Commission should consider placing NSP on alert in this proceeding that it intends to visit the consolidated tax issue in the next rate case.

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[14] Response to Staff IR No. 2-33.

New Information

Q. Have recent accounting pronouncements revealed any new information?

A. Recent accounting pronouncements reveal that NSP's prior recognition of future cost of removal in Minnesota depreciation rates has resulted in significant liabilities to ratepayers.

Q. What is the genesis of this new information?

A. The genesis of the new information is the Financial Accounting Standards Board's ("FASB") 2002 Statement of Financial Accounting Standard No. 143 ("SFAS No. 143") which addresses asset retirement obligations (AROs) associated with long-lived plant.[15]

SFAS No. 143's focus is legal obligations to incur a cost when an asset is retired – legal asset retirement obligations ("legal AROs"). SFAS No. 143 considers such obligations to be a component of the original cost of the asset. It requires capitalization and depreciation of the discounted fair value of the estimated asset retirement cost over the asset's life.

SFAS No. 143 also identified a significant regulatory liability resulting from public utilities' past inclusion of excessive future cost of removal and dismantlement factors in depreciation rates. FERC identified these amounts as "non-legal" asset retirement obligations, meaning that the utilities do not have actual legal obligations and liabilities to incur these costs in the future.[16]

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[15] FERC Order No. 631 is that agency's implementation of SFAS No. 143 for regulatory purposes for utility operations subject to that agency's jurisdiction.

[16] FERC Order No. 631, para. 36.

SFAS No. 143 requires reporting of non-legal AROs as regulatory liabilities to ratepayers - if the requirements of SFAS 71 are met.[17]

Q. What conditions create a regulatory liability using GAAP?

A. SFAS 71, ¶11, provides that a regulator's rate actions impose a liability on the utility to its customers (regulatory liability) if the regulator provides "current rates intended to recover cost expected to be incurred in the future with the understanding that if those costs are not incurred, future rates will be reduced by corresponding amounts."[18] For Commission-regulated utilities, this "understanding" has been implicit. Nevertheless, it is sufficiently clear to NSP's parent to warrant creation of the regulatory liability for GAAP financial reporting purposes. Now that SFAS No. 143 has identified the amounts, this Commission should recognize them as the regulatory liabilities they are.

Q. Does NSP have any regulatory liabilities relating to non-legal AROs?

A. Yes, NSP-Minnesota reports a $342 million regulatory liability in compliance with SFAS No. 143 in its December 31, 2007 Form 10-K Report.[19] North Dakota's portion of the regulatory liability is included in that amount.

Q. What causes the regulatory liability?

A. The cost of removal liability is the removal cost NSP collected from ratepayers, over and above its actual removal cost expenditures.

[17] SFAS No. 143, paragraph B.73.
[18] SFAS No. 71, ¶11 and 11(b).
[19] Northern States Power Company, December 31, 2007 10-K Report, p. 71.

Q. Do you know the amount of the North Dakota component of NSP-Minnesota's regulatory liability for cost of removal?

A. No, I do not. Staff Information Request No. 2-207 asked for that data, but the Company did not provide it. Specifically, IR No. 2-207 asked, "Please provide, along with all supporting workpapers and calculations, the subsidiary accounts of accrued non-legal retirement costs that are required by section 3.3, paragraph 31 of FERC Order No. 631, dated April 9, 2003." NSP's response directed the reader to its response to IR 2-205, which in turn referred to its response to IR 1-39, Schedule H. That response had nothing to do with the issue. I also examined its response to IR 2-139, which may have been the one to which it was referring, but the information was not there either.

Q. Explain the new issues resulting from SFAS NO. 143 and FERC Order No. 631.

A. There are several new issues. One important new issue is the need for the Commission to **<u>recognize</u>** NSP's non-legal ARO reserve as a regulatory liability for regulatory and ratemaking purposes. Although NSP has properly recognized these amounts as regulatory liabilities in its 2007 10-K report, it has not done so for regulatory and ratemaking purposes.

Q. Does NSP disclose the amount of the cost of removal regulatory liability in its 2007 FERC Form 1?

A. NSP did not include the regulatory liability for electric cost of removal in its schedule of Other Regulatory Liabilities on page 278 of its 2007 FERC Form 1.

Instead, it has the following statement in the Notes to Financial Statements section.

> Estimated removal costs for future removal obligations are classified as accumulated depreciation on the utility plant in the FERC presentation and regulatory liabilities in the GAAP presentation.[20]

Q. What do you recommend?

A. The Commission should require NSP to file a stand-alone North Dakota Depreciation study. The Commission should also enforce the separate identification and reporting requirements of FERC Order No. 631, and go one step further and direct NSP to transfer the North Dakota amount to account 254–other regulatory liabilities. Then, the Commission will need to address the issue of what to do about the huge balance in this regulatory liability, and finally, in light of the regulatory liability, the Commission must determine what to include in depreciation on a going-forward basis.

Q. Why is it necessary for the Commission to recognize a regulatory liability for the non-legal cost of removal and dismantlement amounts?

A. Although the FERC has recognized and required isolation of the amount within the utility's accounting system, FERC did not require reporting the amount in FERC Form 1. FERC also failed to require reporting them as regulatory liabilities. FERC deferred these decisions to the states, which are the primary ratemaking bodies. Consequently, while FERC Order No. 631 implies a new transparency by requiring identification of the amounts and maintenance of

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[20] NSP-Minnesota, 2007 FERC Form 1 Report, page 123.1

separate subsidiary records for regulatory analysis and rate setting purposes, it did not specifically recognize a regulatory liability for non-legal AROs. The North Dakota amount is clearly not identifiable in this rate case.

As a result, nothing holds NSP specifically accountable for these excess collections, even though the public accounting profession and the Securities and Exchange Commission recognize that they are regulatory liabilities and that the PSC implicitly holds NSP accountable.

Regardless of the implied transparency provided by FERC's new requirements, NSP does not even identify or mention these requirements or the issue in its rate case filing, and it refused to provide any relevant information. This is an intolerable situation. The accountability must be explicit, and the Commission must establish that accountability.

My experience shows that it is unlikely that all of the amounts collected will be spent for future cost of removal. Nevertheless, even if it was highly probable that NSP might spend all this money for future cost of removal, it is fair and reasonable for the Commission to recognize the ratepayers' claims on these monies until actually spent on their intended purpose. Unless they are explicitly identified as "subject to refund," there is an ongoing and unnecessary risk that they are merely hidden potential income to NSP.

It is critical that the Commission require NSP to explicitly identify and report this regulatory liability and all related activity in all future reports, rate cases and depreciation studies that it files with the Commission. The

Commission should require prominent disclosure of its explicit recognition of this amount as an intrastate regulatory liability in NSP's future FERC Form 1 and 2 reports to ensure sufficient recognition of and transparency concerning these amounts. Without a requirement for separate identification and reporting of these amounts, they are hidden from the ratemaking process and regulatory scrutiny in North Dakota.

Q. What is wrong with continuing to record the regulatory liability as accumulated depreciation?

A. NSP and all utilities consider accumulated depreciation to represent the measure of their capital that they have recovered from their ratepayers. As simplistic as it sounds, *utilities consider any amount in accumulated depreciation to be "their money" even if they collected it for a fictitious future cost.*

Q. Does NSP agree that its collections for non-legal AROs result in a regulatory liability?

A. I do not know. As mentioned earlier, NSP declined to respond to our information request on this issue. However, as the Company explains in its 2006 10-K Report,

> NSP-Minnesota accounts for certain income and expense items in accordance with SFAS No. 71 – "Accounting for the Effects of Certain Types of Regulation." Under SFAS No. 71:
>
> - certain costs, which would otherwise be charged to expense, are deferred as regulatory assets based on the expected ability to recover them in future rates; and

- certain credits, which would otherwise be reflected as income, are deferred as regulatory liabilities based on the expectation they will be returned to customers in future rates.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment.

If restructuring or other changes in the regulatory environment occur, NSP-Minnesota may no longer be eligible to apply this accounting treatment, and may be required to eliminate such regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on NSP-Minnesota's results of operations in the period the write-offs are recorded.[21]

NSP-Minnesota's Consolidated Financial Statements are prepared in accordance with the provisions of SFAS No. 71, as discussed in Note 1 to the Consolidated Financial Statements. Under SFAS No. 71, regulatory assets and liabilities can be created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of the business that is not rate regulated cannot use SFAS No. 71 accounting. If changes in the utility industry or the business of NSP-Minnesota no longer allow for the application of SFAS No. 71 under GAAP, NSP-Minnesota would be required to recognize the write-off of regulatory assets and liabilities in its consolidated statement of income.[22]

Removal Costs – NSP-Minnesota accrues an obligation for plant removal costs for generation, transmission and distribution facilities. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal

[21] Northern States Power Company, December 31, 2007 10-K Report, pp. 44-45.
[22] Northern States Power Company, December 31, 2007 10-K Report, p. 70 (emphasis added).

> regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long periods over which the amounts were accrued and the changing of rates through time, NSP-Minnesota has estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Accordingly, the estimated amounts of future removal costs are considered regulatory liabilities under SFAS No. 71. Removal costs as of December 31, 2007 and 2006 were $342 million and $355 million, respectively.[23]

NSP-Minnesota reports a $342 million regulatory liability for cost of removal as of December 31, 2007.[24] Given that NSP-Minnesota can only create a regulatory liability consistent with the letter and spirit of SFAS No. 71, the Company must have determined (at least for financial reporting purposes) that, in its management's judgment, the amounts it has collected but not yet spent for costs of removal are "probable" of being credited to ratepayers through the ratemaking process. SFAS No. 71 clarifies that the phrase "credited to ratepayers" means "if those costs are not incurred, future rates will be reduced by corresponding amounts."[25]

NSP-Minnesota does agree that both GAAP and the SEC recognize this fact, and in order to get a "clean" audit opinion, it must report the amount

[23] Northern States Power Company, December 31, 2007 10-K Report, p. 66 (emphasis added).
[24] Id.
[25] SFAS No. 71, ¶11b.

as a regulatory liability as long as it remains regulated, and subject to cost-based rate base/rate of return regulation.

Q. Why did you emphasize the proviso "as long as it remains regulated and subject to cost-based, rate base/rate of return regulation"?

A. The Edison Electric Institute and several individual utilities fought hard to avoid having either the FASB or FERC require the identification and reporting of the regulatory liability that I have just described. If fact, notice the qualification and warning built into NSP-Minnesota's 2006 10-K Report as quoted above.

I am concerned because if NSP-Minnesota were to be deregulated, or if regulation were to change from "cost-based" to some form of alternative "price-based" regulation, history tells us the Company would have every interest in immediately transferring its $342 million regulatory liability into its GAAP income. This amount could well disappear from the scene unless the Commission protects it on behalf of ratepayers. Therefore, this amount must be specifically designated as a regulatory liability for ratemaking purposes.

Q. Why do you believe that NSP-Minnesota would transfer its $342 million non-legal regulatory liability into GAAP income?

A. As NSP-Minnesota warns in its 2007 10-K Report, it will transfer the regulatory liability into GAAP income because that is what GAAP requires. If deregulated, or if regulation changes significantly, the provisions of SFAS No. 71 will no longer apply. The regulatory liability amount will flow immediately and explicitly to GAAP income, because SFAS No. 143 requires it to flow to income if it is not payable to ratepayers. This is what some electric utilities did when their production plants were deregulated, and this is what NSP-Minnesota warns it will do in its 2007 10-K Report.

Q. Do you have any credible evidence of such treatment?

A. Yes, American Electric Power had several of its production plants deregulated. It immediately transferred $473 million from accumulated depreciation into income relating to those deregulated plants.[26]

In another example, Tucson Electric Power Company ("TEP") stated that:

> TEP had accrued $113 million for final decommissioning of its generating facilities. ... this amount was reversed for 2002 and included as part of the cumulative effect adjustment of accounting adjustment when FAS 143 was adopted on January 1, 2003.[27]

This means that TEP transferred non-legal AROs into income.

For its <u>regulated</u> operations, which include the transmission and distribution portions of its business, TEP continued to apply SFAS 71. As a result, TEP recorded the cost of removal collected for regulated non-legal AROs as a regulatory liability.

> As of December 31, 2004, TEP had accrued $67 million for the net cost of removal of the interim retirements from its transmission, distribution and general plant. As of December 31, 2003, TEP had

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[26] AEP 2003 Annual Report to Shareholders, page 69.

[27] Tucson Electric Power Company December 31, 2004 10 K Report, page K-59.

> accrued $60 million for these removal costs. The amount is recorded as a regulatory liability.[28]

However, TEP also reported:

> If TEP stopped applying FAS 71 to its remaining regulated operations, it would <u>write off</u> the related balances of its regulatory assets as an expense and its regulatory liabilities as income on its income statement.[29]

The term "write off" is a euphemism for transferring the money to income.

Q. Is TEP aware that you have used the quotation above to make the point that given the chance a utility will transfer the regulatory liability to income?

A. Yes, in November 2005, the Public Utilities Fortnightly published an article I wrote concerning the issues at hand in this proceeding. The article included the quotation from TEP's 2004 10-K Report. Subsequently, Karen G. Kissinger, TEP's Vice President, Controller & Chief Compliance Officer responded to my article.[30] Ms. Kissinger leveled several attacks against my logic, but her last sentence corroborated the risk to ratepayers that I identified in the article. Ms. Kissinger finished her letter saying: "Ratepayers are not entitled to a refund of costs recognized to provide services they have already received."[31] That means that TEP believes that its ratepayers should pay it money in advance for future costs of removal, with no expectation of a refund

[28] Id., page K-60.
[29] Id. (Emphasis added.)
[30] Id., page 12. Public Utilities Fortnightly, Letters to the Editor, April 2006, page 10.
[31] Id.

or future rate decrease should TEP not use the funds for their intended purpose – in that event, they belong to TEP. NSP's ratepayers are subject to the same risks.

Q. Does NSP-Minnesota make a similar statement regarding charging to income the amounts recorded as regulatory liabilities should it no longer be able to apply SFAS No. 71 to its operations?

A. Yes, as quoted above, NSP-Minnesota's 2007 10-K Report warns, "If changes in the utility industry or the business of NSP-Minnesota no longer allow for the application of SFAS No. 71 under GAAP, NSP-Minnesota would be required to recognize the write-off of regulatory assets and liabilities in its consolidated statement of income."[32]

Q. Have any other industries transferred non-legal ARO amounts into income?

A. Yes, while still regulated, the telephone industry collected substantial amounts of future cost of removal from its ratepayers through depreciation, just as NSP wants to continue doing. Upon deregulation and the adoption of SFAS No. 143, the major telephone companies transferred $11.5 **billion** from accumulated depreciation into their net income.[33]

Q. What should the Commission do with the cost of removal regulatory liability on a going-forward basis?

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[32] Northern States Power Company, December 31, 2007 10-K Report, p. 70.

[33] Pre-tax gains of SBC ($5.9 billion), Verizon ($3.5 billion), Qwest ($0.4 billion), BellSouth ($1.3 billion) and Sprint ($0.4 billion). See SBC, Verizon, Qwest, BellSouth and Sprint's 2003 10K Reports and 2003 Annual Reports to Shareholders.

A. There are a number of alternatives to the treatment of the regulatory liability on a going-forward basis. The Commission could require continued maintenance as a permanent rate base offset representing customer-provided capital, or amortization back to ratepayers over some specified amortization period. I prefer an amortization, because I do not believe NSP will ever spend all of this money on future cost of removal, and as long as the money remains in the Company's hands, it will do whatever it can to convert the regulatory liability to income.

Q. Are you recommending an amortization of the cost of removal regulatory liability in this case?

A. Yes, I am. I have estimated the North Dakota portion of NSP's cost of removal regulatory liability by using its accumulated depreciation allocation as a basis for the split. Based on conversation with Staff, I recommend a 10-year amortization period.

<u>Summary of Snavely King Adjustments</u>

Q. Do you have a summary of your individual adjustments to the Company's filed revenue requirement?

A. Yes, Exhibit___ (MJM-1) summarizes the adjustments. It also incorporates Mr. King's recommendations, my recommendations and a stipulated 8.8 percent rate of return. The adjusted revenue requirement is $20.5 million less than NSP's. This reduces the overall increase to a $.2 million decrease.

Q. What types of adjustments are you making?

A. I am making three types of adjustments: operating income ("OI") adjustments, rate base ("RB") adjustments, and revenue requirement "(RR") adjustments. This last category of adjustments consists of adjustments for which the Company has merely provided a single revenue requirement number. Hence, I have reflected them as lump sum reductions to the revenue requirement.

Q. Please explain each adjustment.

A. First I will explain the operating income adjustments, then I will explain the rate base adjustments.

Operating Income Adjustments

OI Adjustment No. 1 implements the 8.8 percent rate of return to which the parties have stipulated.

OI Adjustment Nos. 2, 3, 4, and 5 reverses NSP's policy change proposals relating to wholesale margins. These adjustments are not necessary, and in my personal opinion, 100 percent of the margins should be passed through the FCA in order to offset the ever-increasing cost of fuel and purchased power. In any event, the adjustments are not necessary.

OI Adjustment No. 6 similarly reverses NSP's proposed policy change relating to MISO Schedules 16 and 17. NSP's adjustment merely serves to increase revenue requirements in this case and is not necessary.

OI Adjustment No. 7 reverses NSP's charitable income adjustment. As Ms. Heuer states, "Chartable contributions have not been included in electric base rates in North Dakota."[34] The fact that a portion of these may have slipped through in previous gas cases does not justify a policy change here.

OI Adjustment No. 8 reverses NSP's Renewable Development Fund ("RDF") amortization adjustment. The RDF is a Minnesota program and expenditure. It should not be charged to North Dakota customers.

OI Adjustment No. 9 reverses NSP's private fuel storage ("PFS") amortization proposal. This project relates to money spent in an attempt to store spent nuclear fuel within the Goshute Indian tribal land in Utah. I understand the project is stalled. Nevertheless, the North Dakota Public Service Commission has not approved the project.

OI Adjustment No. 10 reduces NSP's nuclear fueling outage expenses to actual 2008 levels. The PSC approved NSP's plan for amortizing nuclear fuel outage costs and the actual 2008 costs are $811,935. The Company has included $2,492,000 in refueling outage expenses for the 2008 test year. Hence, I have reduced NSP's nuclear outage expense by $1,680,065.

OI Adjustment No. 11 reverses the expenses relating to NSP's Pole and Cable replacement programs. Instead of charging these amounts to expense, NSP should charge them to its' huge cost of removal reserve I discussed earlier. The same holds true for the capitalized components of these costs. They should be charged to the cost of removal reserve rather than to plant in service

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[34] Heuer Direct, p. 47.

and then depreciated. The cost of removal reserve is embedded in NSP's accumulated depreciation account.

OI Adjustment No. 12 reduces NSP's incentive compensation adjustment to reflect the 15 percent of base pay limit established in NSP's last Minnesota Order.

OI Adjustment No. 13 implements Mr. King's recommended depreciation rates.

OI Adjustment No. 14 reflects a 10-year amortization of NSP's North Dakota cost of removal regulatory liability.

OI Adjustment No. 15 is Mr. King's adjustment to remove the rehabilitation of the Allen King plant.

OI Adjustment No. 16 Is Mr. King's High Bridge adjustment.

Rate Base Adjustments

RB Adjustment No. 1, 2 and 3 reverse NSP's Pole and Cable Replacement Program Plant additions, including the related depreciation expense, and then charges the additions to accumulated depreciation as described in Adjustment No. 12 above.

RB Adjustment No. 4 adjusts cash working capital to reflect the operating income adjustment discussed above.

RB Adjustment No. 5 reflects Mr. King's recommendation to exclude accelerated rehabilitation costs at the Allen King plant resulting from the Minnesota ERP.

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RB Adjustment No. 6 is Mr. King's adjustment to restate High Bridge Plant costs to reflect the lower cost alternative of rehabilitation as a coal plant.

RB Adjustment No. 7 Reflects Mr. King's depreciation rate change adjustment.

Revenue Requirement Adjustments

RR Adjustment No. 1 eliminates NSP's expenditures for the mercury control program as explained by Mr. King.

RR Adjustment No. 2 reflects Mr. King's adjustment to refuse derived energy.

RR Adjustment No. 3 reflects Mr. King's recommendation to reduce the cost of the Great Meadows wind farm by 25%.

RR Adjustment No. 4 reflects a 25 percent reduction to the costs of transmission facilities that connect Minnesota wind power generators to the network.

Q. Does this conclude your testimony?

A. Yes, it does.

Michael J. Majoros, Jr.

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.

Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. –
Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

Michael J. Majoros, Jr.

Date	Jurisdiction / Agency	Docket	Utility

Federal Courts

2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority

State Legislatures

2006	Maryland General Assembly 61/	SB154	Maryland Healthy Air Act
2006	Maryland House of Delegates 62/	HB189	Maryland Healthy Air Act

Federal Regulatory Agencies

1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC 53/	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.

State Regulatory Agencies

1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph

Michael J. Majoros, Jr.

1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.

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1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company

Michael J. Majoros, Jr.

2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 40/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company

Michael J. Majoros, Jr.

2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company
2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Florida 50/ 54/	030157-EI	Progress Energy Florida
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.
2006	Colorado 60/	06S-234EG	Public Service Co. of Colorado
2006	Kentucky 36/	2006-00172	Union Light, Heat & Power
2006	Kansas 40/	06-KGSG-1209-RTS	Kansas Gas Service
2006	West Virginia 2/	06-0960-E-42T, 06-1426-E-D	Allegheny Power
2006	West Virginia 2/	05-1120-G-30C, 06-0441-G-PC, et al.	Hope Gas, Inc. and Equitable Resources, Inc.
2007	Delaware 24/	06-284	Delmarva Power & Light Company
2007	Kentucky 36/	2006-00464	Atmos Energy Corporation
2007	Colorado 60/	06S-656G	Public Service Co. of Colorado
2007	California 59/	A.06-12-009, A.06-12-010	San Diego Gas & Electric Co., and Southern California Gas Co.
2007	Kentucky 36/	2007-00143	Kentucky-American Water Co.
2007	Kentucky 36/	2007-00089	Delta Natural Gas Co.
2008	Kansas 40/	08-ATMG-280-RTS	Atmos Energy Corporation

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	33/ Michigan Attorney General
2/ West Virginia Consumer Advocate	34/ New Mexico Attorney General
3/ Pennsylvania OCA	35/ Environmental Protection Agency Enforcement Staff
4/ Florida Office of Public Advocate	36/ Kentucky Attorney General
5/ Toms River Fire Commissioner's	37/ North Dakota Public Service Commission
6/ Iowa Office of Consumer Advocate	38/ Kansas Industrial Group
7/ D.C. People's Counsel	39/ City of Witchita
8/ Maryland's People's Counsel	40/ Kansas Citizens' Utility Rate Board
9/ Idaho Public Service Commission	41/ NIPSCO Industrial Group
10/ Western Burglar and Fire Alarm	42/ Hawaii Division of Consumer Advocacy
11/ U.S. Dept. of Defense	43/ Nevada Bureau of Consumer Protection
12/ N.M. State Corporation Comm.	44/ GCI
13/ City of Philadelphia	45/ Wisc. Citizens' Utility Rate Board
14/ Resorts International	46/ Vermont Department of Public Service
15/ Woodlake Condominium Association	47/ Oklahoma Corporation Commission
16/ Illinois Attorney General	48/ National Assn. of State Utility Consumer Advocates
17/ Mass Coalition of Municipalities	49/ Nova Scotia Utility and Review Board
18/ U.S. Department of Energy	50/ Florida Office of Public Counsel
19/ Arizona Electric Power Corp.	51/ Maryland Public Service Commission
20/ Kansas Corporation Commission	52/ MCI
21/ Public Service Comm. – Nevada	53/ Transmission Agency of Northern California
22/ SC Dept. of Consumer Affairs	54/ Florida Industrial Power Users Group
23/ Georgia Public Service Comm.	55/ Sierra Club
24/ Delaware Public Service Comm.	56/ Our Children's Earth Foundation
25/ Conn. Ofc. Of Consumer Counsel	57/ National Parks Conservation Association, Inc.
26/ Arizona Corp. Commission	58/ Missouri Office of the Public Counsel
27/ AT&T	59/ The Utility Reform Network
28/ AT&T/MCI	60/ Colorado Office of Consumer Counsel
29/ IN Office of Utility Consumer Counselor	61/ MD State Senator Paul G. Pinsky
30/ Unitel (AT&T – Canada)	62/ MD Speaker of the House Michael Busch
31/ Public Interest Advocacy Centre	
32/ U.S. General Services Administration	

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
STAFF Adjustments to
Revenue Deficiency Summary
($000's)

Line	Description	Original Per Company North Dakota Jurisdiction		Restated Per Company North Dakota Jurisdiction		Adjusted Per Staff North Dakota Jurisdiction		
1	Average Rate Base	$	242,100	$	242,100	$	201,050	
2	Operating Income (Before AFUDC)	$	9,794	$	9,775	$	17,341	
3	Allowance for Funds Used During Construction	$	-	$	-	$	-	
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$	9,794	$	9,775	$	17,341	
5	Overall Rate of Return (Line 4 / Line 1)		4.05%		4.04%		8.63%	
6	Required Rate of Return		9.20%		8.80%		8.80%	
7	Operating Income Requirement (Line 1 x Line 6)	$	22,273	$	21,305	$	17,692	
8	Income Deficiency (Line 7 - Line 6)	$	12,479	$	11,530	$	351	
9	Gross Revenue Conversion Factor		1.64555		1.64555		1.64555	
10	Revenue Deficiency (Line 8 x Line 9)	$	20,535	$	18,973	$	578	
11	King Revenue Req. Adjustments					$	(600)	1/
12	Staff Revenue Requirement Excess					$	(22)	
12	Retail Related Revenue Under Present Rates	$	147,179	$	147,179	$	147,179	
13	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)		13.95%		12.89%		-0.01%	

1/	Remove Mercury Emissions Cost	$	(268)	
	Remove Refuse Derived Energy		(173)	
	Remove 25% Grand Meadow		(79)	
	Remove 25% Transmission to Wind Farms		(80)	
	Remove RDF			See OI-No.8
	Total	$	(600)	

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
STAFF Adjustments to
Rate Base Schedules
Rate Base Adjustment Schedules
2008 Unadjusted Test Year versus 2008 Adjusted Test Year
($000's)

Line No.	Description	Per Company Adjusted	Reverse Pole Inspection & Replacement Program RB-1	Reverse Cable Replacement Program RB-2	Charge Pole & Cable Replacements to Acc. Dep. RB-3	Adjust Cash Working Capital RB-4	King's Allen King Plant Adjustment RB-5	King's High Bridge Plant Adjustment RB-6	King's Depreciation Rate Adjustment RB-7	Per Staff
	Electric Plant as Booked									
1	Production	$ 356,704								$ 356,704
2	Transmission	87,557								87,[illegible]
3	Distribution	124,202	$ (92)	$ (250)	$ -					123,[illegible]
4	General	14,538								14,[illegible]
5	Common	24,338								24,338
6	TBT Investment	-								-
7	TOTAL Utility Plant in Service	$ 607,339	$ (92)	$ (250)	$ -	$ -	$ -	$ -	$ -	$ 606,997
	Reserve for Depreciation									
8	Production	$ 234,339							$ (1,830)	$ 232,509
9	Transmission	29,941							(37)	29,904
10	Distribution	48,239	$ (2)	$ (3)	$ (342)				(191)	47,701
11	General	6,955								6,955
12	Common	13,692								13,692
13	TOTAL Reserve for Depreciation	$ 333,166	$ (2)	$ (3)	$ (342)	$ -	$ -	$ -	$ (2,058)	$ 330,761
	Net Utility Plant in Service									
14	Production	$ 122,365					$ (18,987)	$ (22,137)		$ 81,241
15	Transmission	57,616								57,616
16	Distribution	75,964	$ (91)	$ (247)	$ 342					75,968
17	General	7,583								7,583
18	Common	10,646								10,646
19	TBT Investment	-								
20	Net Utility Plant in Service	$ 274,173	$ (91)	$ (247)	$ 342	$ -	$ (18,987)	$ (22,137)	$ -	$ 233[illegible]
21	Utility Plant Held for Future Use	$ -								$ -
22	Construction Work in Progress	$ 4,802								$ 4,802
23	Less: Accumulated Deferred Income Taxes	$ 40,717	$ (1)		$ -					$ 40,716
24	Cash Working Capital	$ 1,136				$ 68				$ 1,204
	Other Rate Base Items:									
25	Materials and Supplies	$ 5,412								$ 5,412
26	Fuel Inventory	2,358								2,358
27	Non-Plant Assets & Liabilities	(6,928)								(6,928)
28	Prepayments	1,127								1,127
29	Customer Advances	(60)								(60)
30	Other Working Capital	797								797
31	Total Other Rate Base Items	$ 2,706	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,706
32	Total Average Rate Base	$ 242,100	$ (90)	$ (247)	$ 342	$ 68	$ (18,987)	$ (22,137)	$ (2,058)	$ 201,050

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
STAFF Adjustments to
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENT SCHEDULES
2008 Unadjusted Test Year versus 2008 Adjusted Test Year
($000's)

Line No.	Description	2008 Base Data	2008 Adjusted(1)	Settlement ROR Change OI-1	Reverse Asset Based Trading-Ratepayer sharing OI-2	Reverse Asset Based Trading-Shareholder sharing OI-3	Reverse Non-Asset Based Trading-Ratepayer sharing OI-4	Reverse Non-Asset Based Trading-Shareholder sharing OI-5
	Operating Revenues							
1	Retail	$ 149,550	$ 147,179		$ 1,800		$ 39	
2	CIP Revenue Adjustment	0	0					
3	Interdepartmental	0	0					
4	Other Operating	40,064	39,525			$ 318		$ 221
5	Gross Earnings Tax	0	0					
6	**Total Operating Revenues**	$ 189,614	$ 186,704	$ -	$ 1,800	$ 318	$ 39	$ 221
	Expenses							
	Operating Expenses:							
7	Fuel & Purchased Energy	$ 79,015	$ 79,015					
8	Power Production	40,491	40,491					
9	Transmission	7,992	7,992					
10	Distribution	5,538	5,655					
11	Customer Accounting	4,343	4,343					
12	Customer Service & Information	406	369					
13	Sales, Econ Dvlp & Other	2	2					
14	Administrative & General	10,819	10,399					
15	Amortization	0	460					
16	Total Operating Expenses	$ 148,606	$ 148,726	$ -	$ -	$ -	$ -	$ -
17	Depreciation	$ 19,151	$ 19,160					
	Taxes:							
18	Property	$ 5,763	$ 5,763					
19	Gross Earnings	0	0					
20	Deferred Income Tax & ITC	1,731	1,738					
21	Federal & State Income Tax	1,420	214	$ 19	$ 706	$ 125	$ 15	$ 87
22	Payroll & Other	1,310	1,310					
23	Total Taxes	$ 10,224	$ 9,025	$ 19	$ 706	$ 125	$ 15	$ 87
24	**Total Expenses**	$ 177,981	$ 176,911	$ 19	$ 706	$ 125	$ 15	$ 87
25	Allowance for Funds Used During Construction	$ -	$ -		$ -		$ -	
26	**Total Operating Income**	$ 11,633	$ 9,793	$ (19)	$ 1,094	$ 193	$ 24	$ 134

1/ $342 million X 5.37%/10 years

Northern States Power Company, a Minnesota Co
Electric Utility - State of North Dakota
STAFF Adjustments to
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENT
2008 Unadjusted Test Year versus 2008 Adjusted
($000's)

Line No.	Description	Reverse MISO Sch 16 & 17 Margin Adj OI-6	Charitable Contributions OI-7	RDF Amortization OI-8	Private Fuel Storage OI-9	Normalize Nuclear Refueling Costs OI-10	Charge Pole & Cable Replacement Programs to Non-legal AROs OI-11	Reduce Executive Compensation OI-12
	Operating Revenues							
1	Retail	$ 532						
2	CIP Revenue Adjustment							
3	Interdepartmental							
4	Other Operating							
5	Gross Earnings Tax							
6	**Total Operating Revenues**	**$ 532**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Expenses							
	Operating Expenses:							
7	Fuel & Purchased Energy					$ (415)		
8	Power Production							
9	Transmission							
10	Distribution						$ (117)	
11	Customer Accounting							
12	Customer Service & Information							
13	Sales, Econ Dvlp & Other							
14	Administrative & General		(86)					$ (142)
15	Amortization			(170)	(190)			
16	Total Operating Expenses	**$ -**	**$ (86)**	**$ (170)**	**$ (190)**	**$ (415)**	**$ (117)**	**$ (142)**
17	Depreciation						**$ (9)**	
	Taxes:							
18	Property							
19	Gross Earnings							
20	Deferred Income Tax & ITC						$ (7)	
21	Federal & State Income Tax	$ 209	$ 34	$ 67	$ 75	$ 163	60	$ 56
22	Payroll & Other							
23	Total Taxes	**$ 209**	**$ 34**	**$ 67**	**$ 75**	**$ 163**	**$ 53**	**$ 56**
24	**Total Expenses**	**$ 209**	**$ (52)**	**$ (103)**	**$ (115)**	**$ (252)**	**$ (73)**	**$ (86)**
25	Allowance for Funds Used During Construction							
26	**Total Operating Income**	**$ 323**	**$ 52**	**$ 103**	**$ 115**	**$ 252**	**$ 73**	**$ 86**

1/ $342 million X 5.37%/10 years

Northern States Power Company, a Minnesota Co
Electric Utility - State of North Dakota
STAFF Adjustments to
OPERATING INCOME STATEMENT SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENT
2008 Unadjusted Test Year versus 2008 Adjusted
($000's)

Line No.	Description	King Depreciation Rates OI-13	Amortize Cost of Removal Reg. Liab. over 10 years 1/ OI-14	King Removal of Allen Plant Rehab. OI-15	King Adjustment to High Bridge Oi-16	Total Staff Adjustments	Total Per Staff
	Operating Revenues						
1	Retail					$ 2,371.00	$ 149,550.00
2	CIP Revenue Adjustment					-	-
3	Interdepartmental					-	-
4	Other Operating					539	40,064
5	Gross Earnings Tax					-	-
6	**Total Operating Revenues**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2,910**	**$ 189,614**
	Expenses						
	Operating Expenses:						0
7	Fuel & Purchased Energy					(415)	78,600
8	Power Production					-	40,491
9	Transmission					-	7,992
10	Distribution					(117)	5,538
11	Customer Accounting					-	4,343
12	Customer Service & Information					-	369
13	Sales, Econ Dvlp & Other					-	2
14	Administrative & General					(228)	10,171
15	Amortization		$ (1,837)			(2,197)	(1,737)
16	Total Operating Expenses	**$ -**	**$ (1,837)**	**$ -**	**$ -**	**$ (2,957)**	**$ 145,769**
17	Depreciation	**$ (4,115)**		**$ (928)**	**$ (571)**	**$ (5,623.00)**	**$ 13,537.00**
	Taxes:						
18	Property					$ -	$ 5,763
19	Gross Earnings					-	-
20	Deferred Income Tax & ITC					(7)	1,731
21	Federal & State Income Tax	$ 1,614	$ 721			3,949	4,163
22	Payroll & Other					-	1,310
23	Total Taxes	**$ 1,614**	**$ 721**	**$ -**	**$ -**	**$ 3,942**	**$ 12,967**
24	**Total Expenses**	**$ (2,501)**	**$ (1,116)**	**$ (928)**	**$ (571)**	**$ (4,638)**	**$ 172,273**
25	Allowance for Funds Used During Construction						
26	**Total Operating Income**	**$ 2,501**	**$ 1,116**	**$ 928**	**$ 571**	**$ 7,548**	**$ 17,341**

1/ $342 million X 5.37%/10 years