BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA

In the Matter of the Application of Otter Tail Power Company,
For Authority to Increase Rates for
Electric Service in North Dakota

Case No. PU-08-862

DIRECT TESTIMONY OF MICHAEL J. MAJOROS, JR.

April 2009

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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 Otter Tail Power Company ("OTP") for authority to increase its rates by $6.1 million or 5.14 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 and based on my review and analysis I have identified several monetary and non-monetary adjustments that should be made to the Company's filed request The monetary adjustments, which also incorporate a stipulated 8.62 percent rate of return, would reduce OTP's increase from $6.1 million to a $4.9 million increase.

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

[1] Brause Direct, p.2.

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

Summary of OTP's Filing

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

A. OTP's policy witness, Mr. Brause, proposes a $6.1 million or 5.14 percent rate increase.[2] The Company's revenue requirement witness, Mr. Beithon elaborates that, "Since OTP last set its rates 24 years ago ... two primary drivers have created a need for a rate increase. ... The most significant increases driving the revenue requirement are: a 130 percent increase in North Dakota non-fuel operating and maintenance costs, which is a 5.40 percent increase using a simple average over 24 years; and a 151 percent increase in North Dakota fuel and purchased power costs, a portion of which are not currently recovered through the Fuel Clause Adjustment (FCA).[3] The Company's Notice summarizes the need for the rate increase as "The revenue deficiency is largely a result of increases in rate base and investment-related costs driven by the Company's additional investments in generation and transmission infrastructure since the last general rate application, which employed a 1983 test year."[4]

General Comments

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

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[2] Id.
[3] Beithon Direct, page 3.
[4] Notice, page 2.

A. Yes, in my opinion, a 5.14 percent increase after 24 years reflects a good track record, however, this rate case comes at a time when energy, gasoline and food prices are sharply increasing and the national economy is in a severe recession. Consequently, this is no time to increase ratepayers' bills for unnecessary policy changes and overstated non-cash costs. In fact, it is a time to potentially reconsider prior policies that increased customer rates merely based on theoretical accounting issues rather than core operating and maintenance cost issues. Although I do not advocate the adoption of cash-basis accounting, I do recommend recognition of cash realities when arguments such as intergenerational equity are raised as an issue to extract cash payments from ratepayers for non-cash costs.

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

A. Yes, 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. We have reviewed those responses and conducted independent analyses as a basis for my testimony.

<u>Depreciation</u>

Q. Is depreciation an important aspect of this case?

A. Yes, it is. Ms. Brutlag identifies several adjustments to depreciation expense netting to a $560 thousand increase to a non-cash expense. I disagree with almost all of Ms. Brutlag's depreciation adjustments.

Q. Are there any general principles relating to depreciation that you wish to explicitly identify and address?

A. Yes, there are several. First, depreciation rates are largely set based on forecasts of future costs of removal that are highly suspect under the best of circumstances. There is great uncertainty caused by the fact that these costs will not be incurred until the plant is removed from service. The expected remaining life of the plant is a forecast, the accuracy of which will not be known until the plant is removed years or decades from now. The cost of removing that plant when the remaining life actually ends is a similar forecast of costs from far off in the future.

Typically rate cases involve substantial differences of opinion over the appropriateness of forecasts of costs that will be incurred only a year or two from now. It is hard to imagine that forecasts of removal costs that will be incurred many years after the test year could be any more accurate than the forecasts of costs that will actually arise during this rate case cycle. It does not increase the comfort in these forecasts when the amount a utility claims to have retired in the past represents a very small proportion of the total plant in service today.

Second, the terms "matching" and "intergenerational equity" (or inequity) often arise in discussions of utility depreciation practices and rates. To most accountants "matching" refers to matching revenues to the periods they are earned and costs to the periods in which they are incurred. Company witnesses usually point to the matching principle as a rationale for adopting their proposed depreciation rates. Unfortunately, the inappropriate interpretation of matching does not justify charging current ratepayers for un-incurred future inflation to money not yet spent; yet, that is precisely what OTP proposes.

Intergenerational equity is similar to matching, as it encourages the Commission to assign costs of providing utility service to the same "generation" of ratepayers that benefited from that utility service. In depreciation discussions, intergenerational equity means that the customers who took service while a plant was in service pay the costs associated with that plant, including the cost of removing the plant from service when it reaches the end of its useful life. Assume a piece of equipment will be in service for ten years. Intergenerational equity is achieved if the total costs associated with that plant, including removal costs at the end of its life, are collected from ratepayers during the decade the plant is in service, rather than from those taking service before or after that decade.

For purposes of assessing an intergenerational equity argument, then, the Commission needs to know what "generation" the party has in mind. The test year for a rate case, or even the entire period covered by the authorized rates could be viewed as a "generation." A cost recovery pattern that appears to achieve intergenerational equity from the perspective of a ten-year "generation" of utility ratepayers (that is, those taking service while a particular piece of equipment is in service) may not be equitable when viewed from the perspective of customers who take service early during that generation, yet bear costs that will not arise until much later in the ten-year period.

A third important concept is "straight-line recovery." The concept begs the question "straight-line of what?" To illustrate, assume that the Commission adopts a forecast saying OTP will need to collect $10,000 between 2009 and 2018 to cover the net salvage costs for plant it expects to retire from service in 2018. OTP contends that straight-line recovery must be achieved in nominal dollar amounts, that is, by collecting $1,000 per year for ten years. The Commission should use "real" dollars (that is, inflation-adjusted dollars) to achieve straight-line recovery. The same amount in real dollars is recovered in each of the ten years, but the nominal dollars vary to match inflation for each year (and are paid in dollars subject to that same level of inflation). At the end of the ten-year period, the same amount of nominal dollars is recovered under each of the two approaches. So any assertion that an approach achieves "straight-line recovery" needs to be greeted with the inquiry "in terms of nominal or real dollars?"

Q. Please discuss you specific disagreements with M's. Brutlag's depreciation proposals.

A. First, I disagree with Ms. Brutlag's proposal to allocate accumulated depreciation and depreciation expense to North Dakota rather than directly assigning depreciation as has been the past practice. OTP has been using depreciation rates approved by the Minnesota Commission, but at one point, North Dakota had its own depreciation rates. For reasons I will discuss below, I recommend that North Dakota discontinue blanket approval of Minnesota depreciation rates and adopt its own North Dakota depreciation rates once again. There is no need to discontinue the current practice of directly assigning depreciation. I also disagree with Ms. Brutlag's proposal to increase depreciation expense by $12,095 for depreciation rate changes occurring after the end of 2007. This adjustment reflects nothing more than a decision by the Minnesota Commission to increase North Dakota service rates. I have also reduced M's. Brutlag's proposed depreciation rates, to eliminate the future inflation incorporated into those depreciation rates.

__New Depreciation-Related Information__

Q. Have recent accounting pronouncements revealed any new information relating to depreciation?

A. Yes, recent accounting pronouncements reveal that OTP's prior recognition of future cost of removal in depreciation rates has resulted in significant liabilities to ratepayers.

Q. Do you have any preliminary comments concerning this issue?

A. Yes, it is my understanding that ""The parties have tentatively settled this issue and are working on a final settlement document. As agreed, we are omitting discussions on this issue unless a final settlement cannot be reached or the Commission does not accept the proposed settlement. In the event the settlement is not finalized or accepted for any reason, the parties have agreed LIG will be allowed to file testimony on this issue within five business days of such a determination."

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.[5]

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. The Federal Energy Regulatory Commission ("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.[6] SFAS No. 143 requires reporting

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[5] 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.

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

of non-legal AROs as regulatory liabilities to ratepayers - if the requirements of SFAS 71 are met.[7]

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."[8] For Commission-regulated utilities, this "understanding" has been implicit. Nevertheless, it is sufficiently clear to OTP 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 OTP have any regulatory liabilities relating to non-legal AROs?

A. Yes, OTP reports a $57.8 million regulatory liability in compliance with SFAS No. 143 in its December 31, 2007 Form 10-K Report.[9] North Dakota's portion of the regulatory liability is $22.9 million.[10]

Q. What is the nature of this regulatory liability?

A. This liability consists of the cost of removal money OTP collected from ratepayers over and above its actual removal cost expenditures.

Q. What do you recommend?

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[7] SFAS No. 143, paragraph B.73.
[8] SFAS No. 71, ¶11 and 11(b).
[9] December 31, 2007 10-K Report, p. 124.
[10] 39.61% per response to ND 02-212

A. I have three recommendations:

1. This Commission should specifically recognize, on the record, the $22.9 million as a regulatory liability for reporting and ratemaking purposes in North Dakota. It should require OTP to transfer this amount from the North Dakota depreciation reserve to account 254-other regulatory liabilities.
2. This Commission should require OTP to file a North Dakota specific depreciation study.
3. The Commission should also instruct OTP to use the present value approach if it includes future removal and dismantling costs in its calculation of depreciation rates.

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 separate subsidiary records for regulatory analysis and rate setting purposes, it did not specifically recognize a regulatory liability for non-legal AROs. The

$22.9 million North Dakota amount is clearly not identifiable in this rate case other than through my testimony.

As a result, nothing holds OTP 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 OTP accountable.

Regardless of the implied transparency provided by FERC's new requirements, OTP does not even identify or mention these requirements or the issue in its rate case filing. 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 OTP 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 OTP.

It is critical that the Commission require OTP 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 OTP's future FERC Form 1 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. OTP 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.* OTP specifically states that is the "Company's money" in response to ND 02-218 i.

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

A. A. No. OTP emphatically denies that its $57.8 million of excess collections for non-legal AROs constitute a regulatory liability, even though it reports it as such.[11]

Q. Why does OTP take this position?

A. OTP knows that if regulation changes, it will transfer the unspent money to its equity account rather than returning it to ratepayers.

[11] Response to ND 02-218.

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 OTP 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 $57.8 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 OTP would transfer its $57.8 million non-legal regulatory liability into GAAP income?

A. 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 OTP warns it will do in its 2007 10-K Report.

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

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.[12]

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.[13]

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

For its regulated 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 accrued $60 million for these removal costs. The amount is recorded as a regulatory liability.[14]

However, TEP also reported:

> If TEP stopped applying FAS 71 to its remaining regulated operations, it would write off the related balances of its regulatory assets as an expense and

[12] AEP 2003 Annual Report to Shareholders, page 69.
[13] Tucson Electric Power Company December 31, 2004 10 K Report, page K-59.
[14] Id., page K-60.

> its regulatory liabilities as income on its income statement.[15]

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.[16] 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."[17] 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 or future rate decrease should TEP not use the funds for their intended purpose – in that event, they belong to TEP. OTP's ratepayers are subject to the same risks.

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

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[15] Id. (Emphasis added.)

[16] Id., page 12. Public Utilities Fortnightly, Letters to the Editor, April 2006, page 10.

[17] Id.

A. Yes, while still regulated, the telephone industry collected substantial amounts of future cost of removal from its ratepayers through depreciation, just as OTP 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.[18]

Q. Can you provide any definitive additional evidence that OTP will transfer the money in the future?

A. Yes, the U.S. accounting profession is presently moving towards the adoption of International Financial Reporting Standards ("IFRS"). Upon adoption of IFRS, the regulatory liability will disappear into equity.[19]

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

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 OTP 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.

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[18] 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.

[19] See Ready for IFRS?, *Public Utilities Fortnightly*, January 2009 and Fixing Depreciation Accounting, *Public Utilities Fortnightly*, October 2008.

Q. What amortization period do you recommend?

A. I recommend a 10-year amortization period.

OTP's Going-Forward Cost Of Removal Proposals

Q. Please explain what is meant by "cost of removal."

A. The cost of providing utility service includes not only the costs of installing and operating utility plant, but also removing that plant where appropriate at the end of its useful life. Therefore, one of the components of a public utility depreciation rate is a current estimate of future cost of removal (or negative net salvage).

This estimate is typically expressed as a ratio (derived from historical data), that is applied to the current plant balance to provide an estimate of the future cost of removal. This future cost is, in turn, charged to depreciation expense on a straight-line basis over the remaining life of the plant, just as the depreciation of plant investment is charged to expense. A cost of removal ratio increases the overall depreciable cost base because it allocates a portion of the estimated future removal cost to each year of the asset's service life. This process is, by definition, accrual accounting.

Q. Do you object to accrual accounting?

A. No, I do not object to accrual accounting if properly applied.

Q. If you are not raising any objection to the general process of forecasting future costs of removal or net salvage, what does your testimony address and how is it different than what OTP proposes?

A. My testimony focuses on providing the Commission with information it needs to address the inflation issue. To that end, my discussion addresses accrual accounting, matching and intergenerational equity principles. I provide a simple and straight-forward example demonstrating that the present value approach is the approach most consistent with these principles because it properly matches inflation expense to the periods incurred and eliminates the intergenerational inequity inherent in OTP's approach. I do not propose any variation on "expensing" or normalizing removal costs. Accepting OTP's future cost of removal proposals at face value, I merely express them at their present value so current ratepayers will not be charged for future inflation that has not been incurred.

In other words, for plant in service today that will likely be removed from service twenty years from now, both the present value approach and OTP's approach would recover the same total amounts. The present value approach would achieve the same straight-line pattern as OTP's approach for recovery of the original plant investment, and for recovery of the inflation-adjusted amount for the net salvage costs that will be incurred in 2029. The only difference is the cost recovery pattern for the future inflation costs; the present value approach would have the annual amounts increase during the twenty-year period to reflect the effects of inflation (and permit OTP customers to pay in inflated dollars), while OTP would allocate the future inflation costs on a straight-line basis, an outcome that assigns a disproportionate share of those costs to current ratepayers.

Q. Are you challenging any of OTP's proposed lives?

A. No, I am not challenging any of OTP's proposed lives. I think it is more important at this juncture to focus the Commission's attention on how OTP's approach treats future inflation costs. I will show how a simple modification to this treatment can achieve the proper and far more equitable outcome that is consistent with the matching principle, minimizes intergenerational inequity, and has the added advantage of lowering the utility's depreciation rates.

Q. How did OTP arrive at his net salvage or future cost of removal proposals?

A. OTP conducted a "traditional" historical net salvage analysis to estimate future net salvage ratios for each account.

Q. Why do you object to OTP's traditional approach?

A. OTP's approach is front-loaded in its treatment of future inflation costs. It increases the current estimate of future costs of removal for a substantial amount of future inflation. In other words, OTP's approach charges current ratepayers on an undiscounted basis for future inflation. I disagree with OTP's approach from an accounting standpoint as well as from a ratemaking standpoint. Accrual accounting consists of matching costs to the periods in which they are incurred. OTP's approach fails that fundamental test by frontloading future inflation. This defect is why GAAP specifically precludes his approach.

Q. Why does OTP's approach result in inflated future cost of removal estimates?

A. OTP bases his approach on the relationship of current cost of removal expenditures in today's dollars versus the original cost of the plant being retired, calculating a ratio of current cost of removal (in today's dollars) to original cost of plant (in historical dollars). A substantial part of the current cost of removal represents past inflation experienced during the period (often decades) between when the plant was first put in service and when the removal costs were incurred. OTP then applies that ratio to today's plant balances to project the future cost of removal. In this way, the calculation extrapolates into the future all of the past inflation rather than the small portion actually experienced during the test year 2007.

<u>Accrual Accounting</u>

Q. What is accrual accounting?

A. Accrual accounting recognizes or matches revenue to the periods earned and expenses to the periods incurred. Accrual accounting is the foundation of generally accepted accounting principles ("GAAP"). The directives issued by the Financial Accounting Standards Board ("FASB"), such as SFAS No. 143 and FIN 47 set forth in GAAP.

Q. What is cash basis accounting?

A. Cash basis accounting recognizes revenues and expenses when received or disbursed rather than when earned or incurred.

Q. Does OTP's approach constitute accrual accounting?

A. I do not believe it does, at least to the extent it charges current ratepayers the costs of inflation that may not be incurred for years or even decades. An approach more consistent with accrual accounting would match those future inflation costs to the ratepayers taking utility service at the time the inflation is incurred. OTP's approach does not match inflation costs to the periods incurred.

Q. Do the relatively recent pronouncements of the Financial Accounting Standards Board provide any useful guidance on these questions?

A. I believe they do, even if the questions are arising here in a ratemaking proceeding and the FASB pronouncements apply most directly to financial reporting requirements. But the underlying principles of achieving appropriate "matching" through accrual accounting do not change whether they arise in a ratemaking or financial reporting setting.

OTP is no doubt familiar with the accounting prescribed in SFAS No. 143 and FIN 47, which constitute GAAP. SFAS No. 143 was adopted to establish accounting standards for recognition and measurement of a liability for an asset retirement obligation and any associated asset retirement cost. (SFAS No. 143, ¶ 1.) SFAS 143 provides that where there are no quoted market prices to use for such estimating purposes, a "present value" technique is often the best available substitute. (SFAS No. 143, ¶ 8.) This present value technique prescribed in SFAS 143 directs the discounting of the estimated future cash flows using "credit-adjusted risk-free rate."

OTP may argue that the Commission should not rely on SFAS No. 143 or FIN 47 for purposes of deciding ratemaking issues. However, for purposes of deciding what approach is most consistent with principles of accrual accounting, I submit there is no better source than FAS 143 and the other FASB pronouncements that are, after all, the embodiment of GAAP. And, under FAS 143 companies are not required to report the absolute future value of removal costs, but rather a "present value" of those future costs. For financial reporting purposes, this better enables investors to assess a company's future asset retirement obligations. For ratemaking, it serves a different purpose. Using a present value calculation of the future costs of removal ensures that the future removal cost expenditure is measured in a way that achieves a fair revenue requirement to charge customers during an accounting period. The present value approach treats OTP's study year as the relevant "accounting period" OTP's testimony refers to.

It is important to be clear about this. In other cases in which I have been involved, utilities have characterized the present value approach as seeking to have the Commission adopt SFAS 143 for ratemaking purposes when, in fact, the utility only adopted SFAS S143 for financial reporting purposes.

I am not asking the Commission to adopt SFAS 143 for ratemaking purposes. However, for the purpose of developing an appropriate estimate of the amount of future removal costs to include in today's rates, the underlying principle is consistent with accrual accounting as set forth in GAAP (of which SFAS 143 is a part); whether the estimate is to be used for financial reporting purposes or for establishing a reasonable rate under cost-of-service ratemaking. The amount that should be charged to the "accounting period" is an appropriate share of the present value of the future obligation. The Commission may choose to use something other than the "credit-adjusted risk-free rate" described in SFAS No. 143 for calculating the present value of the future obligation. For example, I recommend the Handy Whitman indices as the basis to make the adjustment. But the underlying principle of accrual accounting and ratemaking remains – future cost of removal is properly measured and matched to the period incurred. In ratemaking, the accounting period is the current year, not the remaining life of the plant.

Q. Can you demonstrate that using the present value approach constitutes accrual accounting and that OTP's approach does not constitute accrual accounting?

A. Yes. Exhibit___ (MJM-1) is a chart I designed to demonstrate those facts. It is a simple single asset example comparing OTP's approach to collecting future inflation versus the present value accrual approach. The example assumes the present value to remove a single structure is $20,000, but that will increase over the structures' 20-year life to $53,066 at a 5 percent inflation rate. As you can see, both OTP's approach and the present value approach accumulate the same $53,066 total amount for future removal costs by the end of the asset's life. The difference is the rate of collection for future inflation costs. The present value approach matches inflation to the periods incurred. OTP's approach front-loads future inflation costs into current periods, and by doing so overcharges ratepayers in the early years and undercharges ratepayers in the later years. This flies in the face of the "intergenerational equity" and accrual accounting concepts; it stands them on their heads.

Q. Is this example intended to show rate base effects?

A. No, the example demonstrates that accrual accounting matches inflation to the periods incurred. Rate base is irrelevant to that demonstration.

Q. Is there any economic rationale that supports matching future inflation to the periods incurred?

A. Yes, the inflation-related portion of the future removal cost will be paid for with cheaper dollars in future years. In terms of nominal dollars, the amount to be paid appears to be higher, but in real (that is, inflation-adjusted) dollars, the same amount is paid now and in the future, all else being equal. In other words, if OTP were to retire and remove all of its assets today, it would incur the present value of OTP's same future cost of removal estimates. When it comes to future inflation costs, "straight-line" cost allocation should be measured in real dollars, not nominal dollars.

Q. Is OTP's approach required under the Uniform System of Accounts ("USOA")?

A. No, nothing in the USOA requires depreciation rates to be based on inflated future costs, or to collect from today's ratepayers the costs of inflation that will not be experienced for years or even decades to come.

Consolidated Taxes

Q. Do you have any other examples of OTP collecting funds in excess of its actual costs?

A. Yes, OTP 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 fact, that is precisely what is called for in OTP's tax sharing agreement.[20]

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

[20] See response to ND 02-58.

subsidy and reconsider whether captive ratepayers should be required to pay anything more than actual taxes. The Commission should place OTP on alert in this proceeding that it intends to revisit the consolidated tax issue in the next rate case.

Summary of Snavely King Adjustments

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

A. Yes, Exhibit___ (MJM-2) summarizes the adjustments. It also incorporates a stipulated 8.62 percent rate of return. The adjusted revenue requirement is $.645 million less than OTP's.

Adjustment No. 1 – Implement Stipulated Rate of Return

Q. Please explain each adjustment.

A. Adjustment No. 1 implements the 8.62 percent rate of return to which the parties have stipulated.

Adjustment No. 2 – Reverse Allocation of Depreciation

Q. Please explain Adjustment No. 2.

A. Adjustment No. 2 reverses Ms. Brutlag's proposal to allocate, rather than directly assign depreciation to North Dakota.

Adjustment No. 3 – Reverse Depreciation Increase Using 2008 Depreciation Rates

Q. Please explain Adjustment No. 3.

A. Adjustment No. 3 reverses the $12,095 depreciation increase Ms. Brutlag proposes to reflect the 2008 Minnesota depreciation rates.

Adjustment No. 4 – Reverse Depreciation Decrease Using Brutlag Proposed Depreciation Rates

Q. Please explain Adjustment No. 4.

A. Adjustment No. 4 reverses the depreciation decrease Ms. Brutlag proposes based on a new study that is yet to be approved by the Minnesota Commission. Even with a decrease these depreciation rates are excessive due to their inclusion of future inflation in the cost of removal estimates.

Adjustment No. 5 – Implement North Dakota Staff Depreciation Rates

Q. Please explain Adjustment No. 5.

A. Adjustment No. 5 implements the North Dakota Staff's recommended depreciation rates. They accept Ms. Brutlag's parameter proposals, but eliminate the future inflation expense from the cost of removal estimates included in the rate calculations.

Adjustment No. 6 – Reduce Depreciation Expense for New Plant

Q. Please explain Adjustment No. 6.

A. Adjustment No. 6 reduces Ms. Brutlag's proposed depreciation expense relating to new plant to conform to the North Dakota Staff's recommended depreciation rates.

Adjustment No. 7 – Charitable Donations

Q. Please explain Adjustment No. 7.

A. Adjustment No. 7 removes charitable donations from the Company's revenue requirement claim. This adjustment results in an $114,816 reduction to the revenue requirement.

Q. Why have you made this adjustment?

A. Otter Tail included in its revenue requirement certain charitable donations. These donations are not necessary for the provision of safe, reliable and efficient electric and natural gas service. While it is commendable that the Company is involved in civic and charitable activities, ratepayers should not be expected to finance those activities. As such, I have removed these donations.

Adjustment No. 8 – STB Litigation Expense

Q. Please explain Adjustment No. 8.

A. Adjustment No. 8 removes $40,973 related to litigation before the Surface Transportation Board from the Company's revenue requirement claim.

Q. Why have you made this adjustment?

A. Included in Otter Tail's test year revenue requirement is $40,973 in expense related past litigation before the STB. Because this litigation effort is finished, any expenses related to it will not be ongoing. Therefore, I have removed the $40,973 from the revenue requirement.

Adjustment No. 9 – Economic Development Expense

Q. Please explain Adjustment No. 9.

A. Adjustment No. 9 removes $108,539 related to economic development from the Company's revenue requirement claim.

Q. Why have you made this adjustment?

A. Otter Tail has proposed increasing the amount included in rates for economic development activities to $500,000. The current annual amount included in rates is $315,557, which was approved during the 1988/1989 time frame.[21] According to Company witness Ms. Brutlag, Otter Tail has averaged $513,698 per year since the inception of the program.[22] While this may be true, the amount is skewed by a $1.3 million expenditure in 1995. A more recent calculation using 2004 through 2008 amounts indicates the Company averages $391,461 in economic development expense.

Otter Tail's economic development activities appear to provide a genuine service to the community, including job creation in many cases.[23] This is particularly important in today's economic environment. However, the rate payers being asked to pay for these activities are also victims of the current economy and should not be asked to pay higher rates in order to finance Otter Tail's community involvement.

Because the previous amount was set in 1988/1989, I have updated the amount to Otter Tail's most recent five-year average of $391,461. This results in a $108,539 decrease to the revenue requirement.[24]

<u>Adjustment No. 10 – Employee Awards</u>

Q. Please explain Adjustment No. 10.

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[21] Brutlag, pp. 18-19.
[22] Exhibit___ (BCB-1), Schedule 2.
[23] See Brutlag, p. 19 and response to ND 02-009.
[24] $500,000 included in Company's claim less $391,461 recommended amount.

A. Adjustment No. 10 removes $76,089 related to employee awards, gifts, dinners and similar activities from the Company's revenue requirement claim.

Q. Why have you made this adjustment?

A. In its response to ND 02-126, the Company provided the year 2007 amounts for employee gifts, luncheons, dinners, picnics and awards. The total amount was $85,989. This amount includes $36,456 in annual employee service awards and $15,522 in "token gifts given to each employee attending annual executive forum meetings."[25] A review of the invoices provided shows that the awards purchased ranged from hunting knives to flat screen televisions.[26] While I understand that some companies include these types of activities for employees as morale boosters, I do not believe the rate payers should be asked to finance them. As such, I have removed the amounts. However, of the total, $9,900 related to safety award checks.[27] I have allowed that amount to stay in the revenue requirement.

<u>Adjustment No. 11 – Asset-Based Margins</u>

Q. Please explain Adjustment No. 11.

A. Adjustment No. 11 eliminates asset-based margins which Mr. King recommends be flowed through the fuel clause.

Q. Why have you made this adjustment?

[25] See response to ND 02-126, Attachment 2.
[26] Id., Attachment 1.
[27] Id, Attachment 2.

A. As I stated, Mr. King discusses this adjustment in detail in his testimony. However, I observe that the Ancillary Services Market is up and running, but it just started, consequently, it is probably too early to try and include an amount in base rates. Furthermore, if the margins are not run through the fuel clause adjustment, a perverse incentive could ensue where OTP would be better off setting aside its generating units to provide ASM services and generating ASM revenues (not included in the rate case) and purchasing power for its customers which off course are automatically ran through the FCA.

<u>Adjustment No. 12 – Executive Incentive Pay</u>

Q. Please explain Adjustment No. 12.

A. Adjustment No. 12 removes $150,668 related to executive incentive pay from the Company's revenue requirement claim.

Q. Why have you made this adjustment?

A. Otter Tail has included $358,248 (total company) in executive incentive pay in its revenue requirement calculation. The North Dakota portion of that amount is $150,668. I have removed the entire provision for executive incentives for several reasons. First, as I have discussed several times in my testimony, the current state of the economy should discourage the payment of any bonus plans. Notwithstanding the well-publicized actions of certain companies receiving federal assistance, many companies today are actually instituting pay cuts in order to stay viable during this time. Second, as described in the response to ND 02-102, payment of the executive incentive plan target amount is 60 percent dependent on the achievement of financial goals (regulated return on equity and return on invested capital), which are designed to benefit shareholders, not ratepayers.[28] The remaining 40 percent is dependent on "individual performance." I do not know what areas of "individual performance" are considered, but there is no indication this is safety or service related, unlike the design of the incentive plan for non-executive employees. If Otter Tail wishes to pay its executives an incentive bonus it should be paid for by shareholders, not ratepayers.

Adjustment Nos. 13 and 14 – Reverse OPEB Transition Costs

Q. Please explain Adjustment Nos. 13 and 14.

A. Both of these adjustments relate to SFAS No. 106 costs which, in turn, are costs associated with Other Post Employment Benefits. Mr. Beithon states that "These costs are tracked in two parts – transition costs and current accrual expenses."[29]

Adjustment No. 13 is a reversal of the Company's 2006 elimination of the so-called transition obligation associated with OPEBs. OTP had apparently recorded a receivable in its prepayments account to reflect the amount it intended to charge ratepayers for the transition obligation. In reality, it appears that it had overestimated the amount it needed for OPEB costs, and in fact did not even create a funded liability for these costs, such as it has for

[28] See response to ND 02-102, Attachment 3, p. 2.
[29] Beithon page 32.

its pension obligation. Consequently, upon adoption of SFAS No. 158, it wrote-off the prepayment/receivable.

In this case, OTP proposes to create $1,678,516 of off-book income merely by crediting its retained earnings account and returning the $1,678,516 into prepayments with a corresponding $335,703 annual amortization expense obligation it would like ratepayers to pay. I reject both of those requests. OTP actually funds its OPEBs on a pay-as-you go basis, just as it has done from the very beginning. It does not maintain a cash fund for these costs. Adjustment No. 13 reverses OTP's attempt to reestablish a receivable from ratepayers for prior OPEB costs, and Adjustment No. 14 reverses OTP's amortization of the fictitious transition receivable. In my opinion, the Commission should also require OTP to begin funding its OPEB liability.

Adjustment Nos. 15 and 16 – Flow MISO Amounts Through Fuel Adjustment Change

Q. Please explain Adjustment Nos. 15 and 16.

A. Adjustment Nos. 15 and 16 reflects Staff's position that MISO costs should be flowed through the fuel adjustment charge.

Adjustment No. 17 – Reverse Non-Asset Based Margins

Q. Please explain Adjustment No. 17.

A. Adjustment No. 17 reverses OTP's proposal to include non-asset based margins in the revenue requirement.

Q. Why did you make this adjustment?

A. I made this adjustment because the Company's proposal allocates more cost from the Company's trading department than it does revenues from non-asset based margins.

<u>Adjustment No. 18 – Reverse DSM and Energy Conservation</u>

Q. Please explain Adjustment No. 18.

A. Adjustment No. 18 reverses OTP's DSM and Energy Conservation charges so they can be recovered through a separate rider.

Q. Does this conclude your testimony?

A. Yes, it does.

Experience

Snavely King Majoros O'Connor & Bedell, 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.

"Asset Management – What is it?," American Water Works Association, Pre-Conference Workshop, March 25, 2008.

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

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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

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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

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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	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
2008	New Jersey 1/	GR07110889	New Jersey Natural Gas Co.
2008	North Dakota 37/	PU-07-776	Northern States Power/Xcel Energy
2008	Pennsylvania 3/	A-2008-2034045 et al	UGI Utilities, Inc. / PPL Gas Utilities Corp.
2008	Washington 63/	UE-072300, UG-072301	Puget Sound Energy
2008	Pennsylvania 3/	R-2008-2032689	Pennsylvania-American Water Co. - Coatesville
2008	New Jersey 1/	WR08010020	NJ American Water Co.
2008	Washington 63/ 64/	UE-080416, UG-080417	Avista Corporation
2008	Texas 65/	473-08-3681, 35717	Oncor Electric Delivery Co.
2008	Tennessee 66/	08-00039	Tennessee-American Water Co.

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

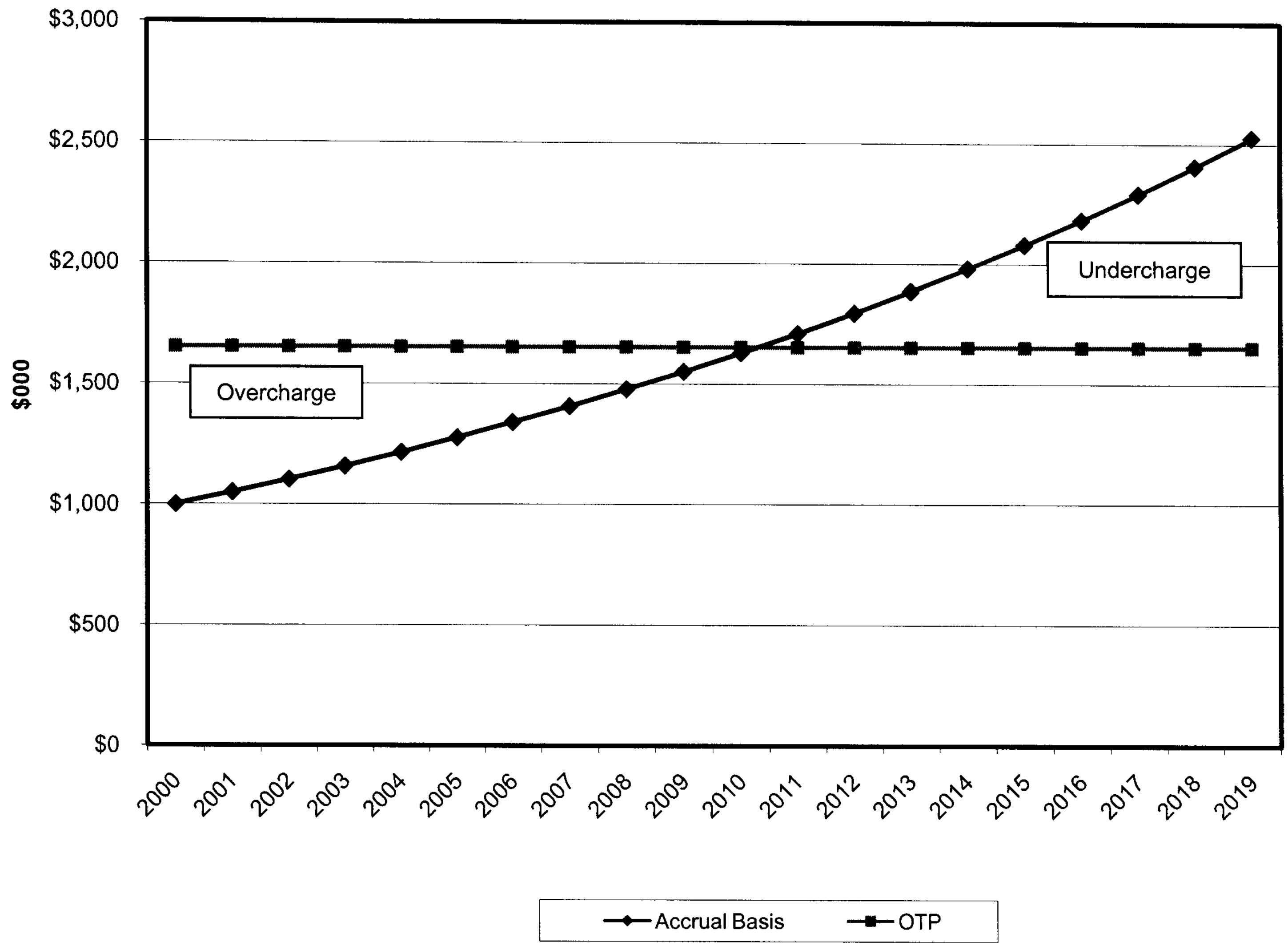
STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central 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	34/ New Mexico Attorney General
2/ West Virginia Consumer Advocate	35/ Environmental Protection Agency Enforcement Staff
3/ Pennsylvania OCA	36/ Kentucky Attorney General
4/ Florida Office of Public Advocate	37/ North Dakota Public Service Commission
5/ Toms River Fire Commissioner's	38/ Kansas Industrial Group
6/ Iowa Office of Consumer Advocate	39/ City of Witchita
7/ D.C. People's Counsel	40/ Kansas Citizens' Utility Rate Board
8/ Maryland's People's Counsel	41/ NIPSCO Industrial Group
9/ Idaho Public Service Commission	42/ Hawaii Division of Consumer Advocacy
10/ Western Burglar and Fire Alarm	43/ Nevada Bureau of Consumer Protection
11/ U.S. Dept. of Defense	44/ GCI
12/ N.M. State Corporation Comm.	45/ Wisc. Citizens' Utility Rate Board
13/ City of Philadelphia	46/ Vermont Department of Public Service
14/ Resorts International	47/ Oklahoma Corporation Commission
15/ Woodlake Condominium Association	48/ National Assn. of State Utility Consumer Advocates
16/ Illinois Attorney General	49/ Nova Scotia Utility and Review Board
17/ Mass Coalition of Municipalities	50/ Florida Office of Public Counsel
18/ U.S. Department of Energy	51/ Maryland Public Service Commission
19/ Arizona Electric Power Corp.	52/ MCI
20/ Kansas Corporation Commission	53/ Transmission Agency of Northern California
21/ Public Service Comm. – Nevada	54/ Florida Industrial Power Users Group
22/ SC Dept. of Consumer Affairs	55/ Sierra Club
23/ Georgia Public Service Comm.	56/ Our Children's Earth Foundation
24/ Delaware Public Service Comm.	57/ National Parks Conservation Association, Inc.
25/ Conn. Ofc. Of Consumer Counsel	58/ Missouri Office of the Public Counsel
26/ Arizona Corp. Commission	59/ The Utility Reform Network
27/ AT&T	60/ Colorado Office of Consumer Counsel
28/ AT&T/MCI	61/ MD State Senator Paul G. Pinsky
29/ IN Office of Utility Consumer Counselor	62/ MD Speaker of the House Michael Busch
30/ Unitel (AT&T – Canada)	63/ Washington Office of Public Counsel
31/ Public Interest Advocacy Centre	64/ Industrial Customers of Northwestern Utilities
32/ U.S. General Services Administration	65/ Steering Committee of Cities
33/ Michigan Attorney General	66/ City of Chattanooga

Comparison of Inflation Expense Patterns



Otter Tail Power Company
Comparison of Accrual Accounting Versus OTP Treatment of Inflation

Line	Assumptions:	Year 1	
	Year 1 (2000) Data	2000	
1	Number of Structures	1	structure
2	Service Life	20	years
3	Average age of structure	0	years
4	Remaining life	20	years
5	Present Value of Disposal Cost Per Structure	$20,000	
6	Present Value of Future Disposal Costs L.1 * L5	$20,000	
7	Future inflation rate	5.00%	Assumed
8	Inflated Value of Future Disposal Costs	$ 53,065.95	
9	Original Cost of Structure	$ 100,000	
10	OTP Approach Recommendation -(L8/L9)	-53.07%	

	Straight Line Recovery of Original PV of Future Removal			Inflation to Original Cost of Future Removal				Annual Expense		
Year	Original Cost of Future Removal BOY	Depreciation Expense	Accumulated Depreciation EOY	PV of Future Cost BOY	Inflation Expense	PV of Cost EOY	Cumulative Inflation	Accrual Basis Annual Expense	OTP Annual Expense	OTP Inflation Matching
2000	$20,000	$1,000	$1,000.00	$ 20,000.00	$1,000.00	$21,000.00	$1,000.00	$2,000.00	$2,653.30	$1,653.30
2001	20,000	1,000	2,000.00	21,000.00	1,050.00	22,050.00	2,050.00	2,050.00	2,653.30	1,653.30
2002	20,000	1,000	3,000.00	22,050.00	1,102.50	23,152.50	3,152.50	2,102.50	2,653.30	1,653.30
2003	20,000	1,000	4,000.00	23,152.50	1,157.63	24,310.13	4,310.13	2,157.63	2,653.30	1,653.30
2004	20,000	1,000	5,000.00	24,310.13	1,215.51	25,525.63	5,525.63	2,215.51	2,653.30	1,653.30
2005	20,000	1,000	6,000.00	25,525.63	1,276.28	26,801.91	6,801.91	2,276.28	2,653.30	1,653.30
2006	20,000	1,000	7,000.00	26,801.91	1,340.10	28,142.01	8,142.01	2,340.10	2,653.30	1,653.30
2007	20,000	1,000	8,000.00	28,142.01	1,407.10	29,549.11	9,549.11	2,407.10	2,653.30	1,653.30
2008	20,000	1,000	9,000.00	29,549.11	1,477.46	31,026.56	11,026.56	2,477.46	2,653.30	1,653.30
2009	20,000	1,000	10,000.00	31,026.56	1,551.33	32,577.89	12,577.89	2,551.33	2,653.30	1,653.30
2010	20,000	1,000	11,000.00	32,577.89	1,628.89	34,206.79	14,206.79	2,628.89	2,653.30	1,653.30
2011	20,000	1,000	12,000.00	34,206.79	1,710.34	35,917.13	15,917.13	2,710.34	2,653.30	1,653.30
2012	20,000	1,000	13,000.00	35,917.13	1,795.86	37,712.98	17,712.98	2,795.86	2,653.30	1,653.30
2013	20,000	1,000	14,000.00	37,712.98	1,885.65	39,598.63	19,598.63	2,885.65	2,653.30	1,653.30
2014	20,000	1,000	15,000.00	39,598.63	1,979.93	41,578.56	21,578.56	2,979.93	2,653.30	1,653.30
2015	20,000	1,000	16,000.00	41,578.56	2,078.93	43,657.49	23,657.49	3,078.93	2,653.30	1,653.30
2016	20,000	1,000	17,000.00	43,657.49	2,182.87	45,840.37	25,840.37	3,182.87	2,653.30	1,653.30
2017	20,000	1,000	18,000.00	45,840.37	2,292.02	48,132.38	28,132.38	3,292.02	2,653.30	1,653.30
2018	20,000	1,000	19,000.00	48,132.38	2,406.62	50,539.00	30,539.00	3,406.62	2,653.30	1,653.30
2019	20,000	1,000	20,000.00	50,539.00	2,526.95	53,065.95	33,065.95	3,526.95	2,653.30	1,653.30
		$20,000.00			$33,065.95			$53,065.95	$53,066.00	

Comparison of Inflation Expense Patterns

Year	Accrual Basis Annual Inflation	OTP Annual Inflation
2000	$1,000.00	$1,653.30
2001	1,050.00	1,653.30
2002	1,102.50	1,653.30
2003	1,157.63	1,653.30
2004	1,215.51	1,653.30
2005	1,276.28	1,653.30
2006	1,340.10	1,653.30
2007	1,407.10	1,653.30
2008	1,477.46	1,653.30
2009	1,551.33	1,653.30
2010	1,628.89	1,653.30
2011	1,710.34	1,653.30
2012	1,795.86	1,653.30
2013	1,885.65	1,653.30
2014	1,979.93	1,653.30
2015	2,078.93	1,653.30
2016	2,182.87	1,653.30
2017	2,292.02	1,653.30
2018	2,406.62	1,653.30
2019	2,526.95	1,653.30

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
JURISDICTIONAL FINANCIAL SUMMARY SCHEDULE

Line No.	Description	Company Proposed 2007 Test Year	SK Recommended 2007 Test Year	Difference
		a	b	c=b-a
1	Average Rate Base	$187,173,203	$187,745,238	$572,035
2	Operating Income (Before AFUDC)	$12,942,144	$13,185,453	$243,309
3	Allowance for Funds Used During Construction (AFUDC)	-	-	-
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$12,942,144	$13,185,453	$243,309
5	Overall Rate of Return (Line 4 / Line 1)	6.91%	7.02%	
6	Required Rate of Return	8.89%	8.62%	
7	Operating Income Requirement (Line 1 x Line 6)	$16,639,698	$16,183,640	($456,058)
8	Income Deficiency (Line 7 - Line 4)	$3,697,554	$2,998,186	($699,367)
9	Gross Revenue Conversion Factor	1.645413	1.645413	
10	Revenue Deficiency (Line 8 x Line 9)	$6,084,004	$4,933,256	($1,150,749)
11	Retail Related Revenues Under Present Rates	$118,309,177	$118,309,177	$0
12	Percent Increase Needed in Overall Revenue (Line 10 / Line 11)	5.14%	4.17%	

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Line No.	Description	Company Proposed 2007 Test Year	Adj 2 Reverse Dep Allocation	Adj. 3 Reverse 2008 Dep Rates	Adj. 4 Reverse Co. 2009 Dep Rates	Adj. 5 Staff Depreciation Rates	Adj. 6 Reduce Dep Expense for New Plant	Adj. 7 Charitable Contributions	Adj. 8 STB Litigation
	OPERATING REVENUES								
1	Retail Revenue	$ 118,309,177	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Electric Operating Revenue	13,804,432	-	-	-	-	-	-	-
3	**TOTAL OPERATING REVENUE**	$ 132,113,610	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OPERATING EXPENSES								
4	Production Expenses	$ 67,714,739	$ -	$ -	$ -	$ -	$ -	$ -	$ (40,973)
5	Transmission Expenses	4,467,061	-	-	-	-	-	-	-
6	Distribution Expenses	6,727,802	-	-	-	-	-	-	-
7	Customer Accounting Expenses	4,728,770	-	-	-	-	-	-	-
8	Customer Service and Information Expenses	2,185,290	-	-	-	-	-	-	-
9	Sales Expenses	701,476	-	-	-	-	-	-	-
10	Administration and General Expenses	13,557,519	-	-	-	-	-	-	-
11	Charitable Contributions	114,816	-	-	-	-	-	(114,816)	-
12	Depreciation Expense	10,716,072	(268,864)	(12,095)	209,145	(1,339,694)	(54,650)	-	-
13	General Taxes	3,957,594	-	-	-	-	-	-	-
14	**TOTAL OPERATING EXPENSES**	$ 114,871,139	$ (268,864)	$ (12,095)	$ 209,145	$ (1,339,694)	$ (54,650)	$ (114,816)	$ (40,973)
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$ 17,242,470	$ 268,864	$ 12,095	$ (209,145)	$ 1,339,694	$ 54,650	$ 114,816	$ 40,973
16	**INCOME TAX EXPENSE**								
17	Investment Tax Credit	$ (476,372)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Deferred Income Taxes	213,186	-	-	-	-	-	-	-
19	Income Taxes	4,563,512	105,462	4,744	(82,037)	525,496	21,437	45,037	16,072
20	**TOTAL INCOME TAX EXPENSE**	$ 4,300,326	$ 105,462	$ 4,744	$ (82,037)	$ 525,496	$ 21,437	$ 45,037	$ 16,072
21	**NET OPERATING INCOME**	$ 12,942,144	$ 163,402	$ 7,351	$ (127,108)	$ 814,198	$ 33,213	$ 69,779	$ 24,901
22	Allowance for Funds Used During Construction	-	-	-				-	-
23	**TOTAL AVAILABLE FOR RETURN**	$ 12,942,144	$ 163,402	$ 7,351	$ (127,108)	$ 814,198	$ 33,213	$ 69,779	$ 24,901
24	**TOTAL RATE BASE**	187,173,203	1,053,257	12,095	(209,145)	1,339,694	54,650	-	-
25	Otter Tail Rate of Return	8.89%							
26	Stipulated Rate of Return Adjustment 1.	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%
27	Rate Base Effect	$ (505,368)	$ 90,791	$ 1,043	$ (18,028)	$ 115,482	$ 4,711	$ -	$ -
28	Revenue Conversion Factor	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413
29	Incremental Revenue Requirement	$ (831,539)	$ (119,476)	$ (10,380)	$ 179,481	$ (1,149,677)	$ (46,898)	$ (114,816)	$ (40,973)

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Line No.	Description	Adj. 9 Economic Development	Adj. 10 Employee Awards	Adj 11. Asset-Based Margins	Adj. 12 Mgmt Incentives	Adj. 13 Reverse OPEB Prepayments	Adj. 14 Remove OPEB Transition Costs	Adj. 15 Reverse MISO	Adj. 16 Reverse MISO Amort.
	OPERATING REVENUES								
1	Retail Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Electric Operating Revenue	-	-	(8,508,499)	-	-	-	-	-
3	**TOTAL OPERATING REVENUE**	$ -	$ -	$ (8,508,499)	$ -	$ -	$ -	$ -	$ -
	OPERATING EXPENSES								
4	Production Expenses	$ -	$ -	$ (4,375,390)	$ -	$ -	$ -	$ (256,990)	$ (309,019)
5	Transmission Expenses	-	-	-	-	-	-	-	-
6	Distribution Expenses	-	-	-	-	-	-	-	-
7	Customer Accounting Expenses	-	-	-	-	-	-	-	-
8	Customer Service and Information Expenses	-	-	-	-	-	-	-	-
9	Sales Expenses	(108,539)	-	-	-	-	-	-	-
10	Administration and General Expenses	-	(76,089)	-	(150,668)	-	-	-	-
11	Charitable Contributions	-	-	-	-	-	-	-	-
12	Depreciation Expense	-	-	-	-	-	-	-	-
13	General Taxes	-	-	-	-	-	-	-	-
14	**TOTAL OPERATING EXPENSES**	$ (108,539)	$ (76,089)	$ (4,375,390)	$ (150,668)	$ -	$ (335,705)	$ (256,990)	$ (309,019)
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$ 108,539	$ 76,089	$ (4,133,109)	$ 150,668	$ -	$ 335,705	$ 256,990	$ 309,019
16	**INCOME TAX EXPENSE**								
17	Investment Tax Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Deferred Income Taxes	-	-	-	-	-	-	-	-
19	Income Taxes	42,574	29,846	(1,621,212)	59,099	-	131,680	100,804	121,213
20	**TOTAL INCOME TAX EXPENSE**	$ 42,574	$ 29,846	$ (1,621,212)	$ 59,099	$ -	$ 131,680	$ 100,804	$ 121,213
21	**NET OPERATING INCOME**	$ 65,965	$ 46,243	$ (2,511,897)	$ 91,568	$ -	$ 204,025	$ 156,186	$ 187,806
22	Allowance for Funds Used During Construction	-	-	-	-	-	-	-	-
23	**TOTAL AVAILABLE FOR RETURN**	$ 65,965	$ 46,243	$ (2,511,897)	$ 91,568	$ -	$ 204,025	$ 156,186	$ 187,806
24	**TOTAL RATE BASE**	-	-	-	-	(1,678,516)	-	-	-
25	Otter Tail Rate of Return								
26	Stipulated Rate of Return Adjustment 1.	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%
27	Rate Base Effect	$ -	$ -	$ -	$ -	$ (144,688)	$ -	$ -	$ -
28	Revenue Conversion Factor	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413	~~1.645413~~	~~1.645413~~
29	Incremental Revenue Requirement	$ (108,539)	$ (76,089)	$ 4,133,109	$ (150,668)	$ (238,072)	$ (335,705)	$ (256,990)	$ (309,019)

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Line No.	Description	Adj. 17 Reverse Non-Asset Based Margins	Adj. 18 Reverse Energy Efficiency	Total SK Adjustments	SK Adjusted 2007 Test Year
	OPERATING REVENUES				
1	Retail Revenue	$ -	$ -	$ -	$ 118,309,177
2	Other Electric Operating Revenue	-	-	(8,508,499)	5,295,933
3	**TOTAL OPERATING REVENUE**	$ -	$ -	$ (8,508,499)	$ 123,605,111
	OPERATING EXPENSES				
4	Production Expenses	$ (674,535)	$ -	$ (5,656,906)	$ 62,057,832
5	Transmission Expenses	-	-	-	4,467,061
6	Distribution Expenses	-	-	-	6,727,802
7	Customer Accounting Expenses	-	-	-	4,728,770
8	Customer Service and Information Expenses	-	(1,000,000)	(1,000,000)	1,185,290
9	Sales Expenses	-	-	(108,539)	592,937
10	Administration and General Expenses	-	-	(226,757)	13,330,762
11	Charitable Contributions	-	-	(114,816)	-
12	Depreciation Expense	-	-	(1,466,158)	9,249,914
13	General Taxes	-	-	-	3,957,594
14	**TOTAL OPERATING EXPENSES**	$ (674,535)	$ (1,000,000)	$ (8,908,882)	$ 105,962,257
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$ 674,535	$ 1,000,000	$ 400,383	$ 17,642,853
16	**INCOME TAX EXPENSE**				
17	Investment Tax Credit	$ -	$ -	$ -	$ (476,372)
18	Deferred Income Taxes	-	-	-	213,186
19	Income Taxes	264,608	392,250	157,073	4,720,585
20	**TOTAL INCOME TAX EXPENSE**	$ 264,608	$ 392,250	$ 157,073	$ 4,457,400
21	**NET OPERATING INCOME**	$ 409,927	$ 607,750	$ 243,309	$ 13,185,453
22	Allowance for Funds Used During Construction	-	-	-	-
23	**TOTAL AVAILABLE FOR RETURN**	$ 409,927	$ 607,750	$ 243,309	$ 13,185,453
24	**TOTAL RATE BASE**	-	-	572,035	187,745,238
25	Otter Tail Rate of Return				
26	Stipulated Rate of Return Adjustment 1.	8.62%	8.62%		
27	Rate Base Effect	$ -	$ -	$ (456,058)	
28	Revenue Conversion Factor	1.645413	1.645413		
29	Incremental Revenue Requirement	$ (674,499)	$ (1,000,000)		

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
DEVELOPMENT OF GROSS REVENUE CONVERSION FACTOR

Definition: The incremental amount of gross revenue required to generate an additional dollar of operating income. Gross earnings fees included.

					OtterTail	SK
Line No.	Description				% of Incremental Gross Revenues	% of Incremental Gross Revenues
1	Federal Income Taxes				32.73%	32.73%
2	State Income Taxes				6.50%	6.50%
3	Total Tax Percentage				39.23%	39.23%
4	Operating Income %	=	100% - 39.23%	=	60.78%	60.78%
5	Gross Revenue Conversion Factor	=	100.00% / 60.77%	=	1.645413	1.645413

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 7

REMOVE CHARITABLE CONTRIBUTIONS

Line	Description		
	Expense Adjustment		
1	Charitable contributions included in revenue requirement		$ 114,816
2	Total Expense Adjustment - Pre Tax		$ (114,816)
3	Tax Rate	39.23%	
4	Tax Effect (L. 2 * L. 3)		45,037
5	Adjustment - Post Tax (L. 2 + L. 4)		$ (69,779)
6	Revenue Conversion Factor		1.64541341
7	Revenue Requirement (L. 5 * L. 6)		$ (114,816)

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 8

REMOVE STB LITIGATION EXPENSE

Line	Description		
	Expense Adjustment		
1	STB litigation expense included in revenue requirement		$ 40,973
2	Total Expense Adjustment - Pre Tax		$ (40,973)
3	Tax Rate	39.23%	
4	Tax Effect (L. 2 * L. 3)		16,072
5	Adjustment - Post Tax (L. 2 + L. 4)		$ (24,901)
6	Revenue Conversion Factor		1.64541341
7	Revenue Requirement (L. 5 * L. 6)		$ (40,973)

Source:
02-010(c)

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 9

ADJUST ECONOMIC DEVELOPMENT EXPENSE TO FIVE-YEAR AVERAGE

Line	Description		
	Expense Adjustment		
1	Economic Development expenses included in revenue requirement		$ 500,000
2	Five-Year Average Economic Development expenses		$ 391,461
3	Total Expense Adjustment - Pre Tax		$ (108,539)
4	Tax Rate	39.23%	
5	Tax Effect (L. 3 * L. 4)		42,574
6	Adjustment - Post Tax (L. 3 + L. 5)		$ (65,965)
7	Revenue Conversion Factor		1.64541341
8	Revenue Requirement (L. 6 * L. 7)		$ (108,539)

Calculation of 5-Year Average

2004	$ 322,774
2005	397,489
2006	427,361
2007	427,508
2008	382,173
5-year Avg.	$ 391,461

Source:

Years 2004 through 2007 from Exhibit___(BCB-1), Schedule 2. Year 2008 from response to ND 02-009.

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 10

REMOVE EMPLOYEE AWARDS

Line	Description		
	Expense Adjustment		
1	Total employee gifts, awards, dinners, etc. included in revenue requirement		$ 85,989
2	Less safety awards		$ (9,900)
3	Total to be excluded		$ 76,089
4	Total Expense Adjustment - Pre Tax		$ (76,089)
5	Tax Rate	39.23%	
6	Tax Effect (L. 4 * L. 5)		29,846
7	Adjustment - Post Tax (L. 4 + L. 6)		$ (46,243)
8	Revenue Conversion Factor		1.64541341
9	Revenue Requirement (L. 7 * L. 8)		$ (76,089)

Source:

See response to ND 02-126, Attachment 2.

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 11

REMOVE ASSET BASED MARGINS

Line	Description		Company Proposed Amounts	Snavely King Reccomended Amounts	Total Adjustment
1	Asset-based margin - revenue		$ 8,508,499	$ -	$ (8,508,499)
2	Asset-based margin - expense		4,375,390	-	(4,375,390)
3	Total Net Adjustment - Pre Tax (L. 2 - L. 1)		$ 4,133,109	$ -	$ (4,133,109)
4	Tax Rate	39.23%			
5	Tax Effect (L. 3 * L. 4)				(1,621,212)
6	Adjustment - Post Tax (L. 3 - L. 5)				$ 2,511,897
7	Revenue Conversion Factor				1.64541341
8	Revenue Requirement (L. 6 * L. 7)				$ 4,133,109

Source:

"4A - 2007 ND TY-15 Asset Based Margins Adj.xls"

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 12

REMOVE MANAGEMENT INCENTIVE PAY

Line	Description		Total Company	ND Allocation
	Expense Adjustment			
1	Management incentive pay included in proposal		$358,248	$ 150,668
2	SK recommended management incentive pay		-	-
3	Total Net Adjustment - Pre Tax (L. 2 - L. 1)		$ (358,248)	$ (150,668)
4	Tax Rate	39.23%		
5	Tax Effect (L. 3 * L. 4)			59,099
6	Adjustment - Post Tax (L. 3 - L. 5)			$ (91,568)
7	Revenue Conversion Factor			1.64541341
8	Revenue Requirement (L. 6 * L. 7)			$ (150,668)

Calculation of ND Allocation 1/

Sub Function	Sub-Function Allocator	Sub-Function Amount	ND Allocator	ND Allocation
ADMINISTRATIVE & GENERAL EXPENSES				
SALARIES, SUPPLIES, PENSIONS & BENEFITS				
PRODUCTION	37%	134,056	40.2432%	53,949
TRANSMISSION	15%	53,451	41.2573%	22,052
DISTRIBUTION	24%	84,224	44.0292%	37,083
CUSTOMER ACCOUNTS	18%	64,055	43.2566%	27,708
CUSTOMER SERVICE & INFO	6%	22,462	43.9668%	9,876
Total Management Incentive	100%	358,248		150,668

1/ Allocation factors taken from "4A - 2007 ND TY-12 Labor Annual Increases, KPP, management incentive ADJ.xls."

Depreciation
Staff Adjustments 2, 3, 4, 5 and 6

Adj 2 Reverse Dep Allocation	Adj. 3 Reverse 2008 Dep Rates	Adj. 4 Reverse Co. 2009 Dep Rates	Adj. 5 Depreciation Staff Rates	Adj. 6 Reduce Dep Expense for New Plant
$ -	$ -	$ -	$ -	$ -
-	-	-	-	-
$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
(268,864)	(12,095)	209,145	(1,339,694)	(48,611)
-	-	-	-	-
$ (268,864)	$ (12,095)	$ 209,145	$ (1,339,694)	$ (48,611)
$ 268,864	$ 12,095	$ (209,145)	$ 1,339,694	$ 48,611
$ -	$ -	$ -	$ -	$ -
-	-	-	-	-
105,462	4,744	(82,037)	525,496	19,068
$ 105,462	$ 4,744	$ (82,037)	$ 525,496	$ 19,068
$ 163,402	$ 7,351	$ (127,108)	$ 814,198	$ 29,543
-	-			
$ 163,402	$ 7,351	$ (127,108)	$ 814,198	$ 29,543
1,053,257	12,095	(209,145)	1,339,694	48,611
8.62%	8.62%	8.62%	8.62%	8.62%
$ 90,791	$ 1,043	$ (18,028)	$ 115,482	$ 4,190
1.645413	1.645413	1.645413	1.645413	1.645413
$ (119,476)	$ (10,380)	$ 179,481	$ (1,149,677)	$ (41,716)

Explanations:
Adjustment No. 2 is an exact reversal of OTP Rate Base Adjsument No. (D) and OTP Income Adjustment No. (H
Adjustment No. 3 is an exact reversal of OTP Rate Base Adjusment No. (E) and the related income adjustment t
Adjustment No. 4 is an exact reversal of OTP Rate Base Adjustment (F) and the unbundled portion of its Income
Adjustment No. 5 implements Staff's Revised depreciation rates by ratioing the revised expense to OTP's Propos

a.	OTP Present Depreciation	$	28,173,452	Response to Staff DR 02-172
b.	OTP Proposed Depreciation	$	27,672,037	Response to Staff DR 02-172
c.	1-(L.b./L.a.)		1.7797%	
d.	Staff Expense	$	24,522,162	

e.	1-(L.d./L.b.)		11.4000%
f.	Company proposed change	$	209,145
g.	L.f./L.c.	$	11,751,700
h.	L.g. X L.e.	$	1,339,694

Adjustment No. (I) to reflect Staff's depreciation rates.

i.	L.d./L.b.		88.6%
j.	Company Adj. (I)	$	479,389
k.	Correct Amount (L(i) X L.(j))	$	424,739
l.	Adjustment	$	(54,650)

l)
hat OTP bundeled into its income adjustment (J).
Adjustment (J).
;als as follows: