BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES

STAFF MEMORANDUM SUPPORTING
SETTLEMENT STIPULATION

DOCKET EL14-026

Commission Staff (Staff) submits this Memorandum in support of the Settlement Stipulation (Settlement) of December 8, 2014, between Staff and Black Hills Power Company (BHP or Company) in the above-captioned matter.

BACKGROUND

On March 31, 2014, the Company filed an application with the South Dakota Public Utilities Commission (Commission) requesting approval to increase rates for electric service to customers in its South Dakota retail service territory by approximately $14.6 million annually or approximately 9.27%. A typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month.

BHP's proposed increase was based on a historical test year ended September 30, 2013, adjusted for what BHP believed to be known and measurable changes, a 10.25% return on common equity, and a 8.48% overall rate of return on rate base.

The Commission officially noticed BHP's filing on April 3, 2014, and set an intervention deadline of June 6, 2014. On April 11, 2014, BHP filed revisions to certain pages originally filed in the application. On April 16, 2014, the Commission issued an Order Assessing Filing Fee. On June 6, 2014, a Petition to Intervene of GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively, Black Hills Industrial Intervenors or BHII) was filed. On June 6, 2014, Dakota Rural Action (DRA) also filed a Petition to Intervene. On June 26, 2014, the Commission issued an Order Granting Intervention to Black Hills Industrial Intervenors. On June 26, 2014, the Commission granted intervention to Dakota Rural Action subject to its filing an affidavit, which was filed on June 27, 2014. On September 3, 2014, BHP filed a Notice of Intent to Implement Interim Rates effective on and after October 1, 2014.

On September 4, 2014, BHP filed a Motion for Approval of Settlement Agreement, Confidential Settlement Agreement between Black Hills Power, Inc. and South Dakota Science and Technology Authority (SDSTA), including the associated Third Amendment to Electric Power Service Agreement between Black Hills Power, Inc. and SDSTA, and relevant exhibits. On September 10, 2014, Staff filed its memorandum regarding the Contracts with Deviations. On September 18, 2014, the Commission issued an Order Conditionally Authorizing and Approving Implementation of Contract with Deviations Rates on an Interim Basis.

Settlement discussions between Staff, BHP, BHII, and DRA commenced on October 28, 2014. Thereafter, Staff and BHP (jointly, the Parties) held several settlement discussions in an effort to arrive at a mutually acceptable resolution of the issues presented in BHP's filing. Ultimately, the Parties reached a comprehensive agreement on BHP's overall revenue deficiency and other issues presented in this case including, but not limited to, class revenue responsibilities, rate design, and tariff concerns. BHII and DRA are not parties to the settlement. On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits. On December 12, 2014, the Commission issued a Scheduling Order setting this matter for hearing on January 27-29, 2015. On December 30, 2014, the Commission issued an Order for and Notice of Hearing.

BHII filed Direct Testimony and Exhibits of Lane Kollen and Direct Testimony and Exhibits of Stephen J. Baron on December 30, 2014. No testimony was filed by DRA. This Memorandum supports Staff's view of the settlement. Staff Witness Dave Peterson's direct testimony addresses specific items discussed in Mr. Kollen's testimony and Mr. Baron's testimony.

OVERVIEW OF SETTLEMENT

Staff based its revenue requirement determination on its comprehensive analysis of BHP's filing and information obtained during discovery. Staff accepted some Company adjustments, made corrections where necessary, modified other adjustments, and rejected those that do not qualify as known and reasonably measurable. Lastly, Staff introduced new adjustments not reflected in BHP's filed case.

Company and Staff positions were discussed thoroughly at the settlement conferences. As a result, some positions were modified and others were accepted where consensus was found. Ultimately, the Parties agreed on a comprehensive resolution of all issues. Staff believes the settlement is based on sound regulatory principles and avoids additional costly and unnecessary litigation.

The Parties agree BHP's revenue deficiency is approximately $6,890,746, which results in an approximate 4.35% increase in retail revenue. This revenue requirement and supporting calculations described in this Memorandum and attachments depict Staff's positions regarding all components of BHP's South Dakota jurisdictional revenue requirement.

STAFF OVERVIEW OF SETTLEMENT

Staff's determination of the settlement revenue requirement begins with total Company test year costs for the twelve months ended September 30, 2013, and allocates those total Company amounts to the South Dakota retail jurisdiction. Staff then adjusted the September 30, 2013, test year results for known and measurable post-test year changes. Staff Exhibit___(BAM-1), Schedule 3 illustrates Staff's determination of BHP's *pro forma* operating income under present rates. Staff Exhibit___(BAM-2), Schedule 2 illustrates Staff's calculation of BHP's South Dakota retail rate base, and Staff Exhibit___(BAM-1), Schedule 2 and Staff Exhibit___(BAM-2), Schedule 1 summarize the positions. Staff Exhibit___(BAM-1), Schedule 1 summarizes Staff's determination of BHP's revenue deficiency and total revenue requirement collected through base rates.

The base revenue increase by rate schedule is shown on Staff Exhibit___(PJS-2), Schedule 1. Staff Exhibit___(PJS-2), Schedules 2-1 through 2-5 reflect the settlement base rates for each rate schedule. The comparison between present and settlement rates and resulting bill impacts for the Residential Service rate schedules is shown on Exhibit___(PJS-2), Schedule 3.

Unless otherwise noted, all of the changes discussed below are changes from the Company's filed position.

RATE BASE

Average Rate Base – Both the Company and Staff arrived at a test year average rate base based on an average of the 13 month-end account balances, September 30, 2012, through September 30, 2013.

CPGS Plant Addition – BHP proposed an adjustment to increase plant in service for projected capital costs associated with the Cheyenne Prairie Generating Station (CPGS). The Company included in rate base the actual costs incurred as of December 31, 2013, and estimates of the remaining completion costs. The settlement determination revises the Company's adjustment to reflect actual costs as of October 31, 2014, and reasonably known and measurable changes after October 31, 2014. The settlement also reflects the associated accumulated deferred income taxes. The net effect of these changes is to reduce rate base by approximately $2,156,000.

Test Year Plant In Service Annualization – The Company proposed an adjustment to annualize test year non-revenue producing plant additions that were completed during the test year. The settlement determination revises the Company's adjustment to: 1) Remove the amounts related to eight projects that appear to be revenue producing; and 2) Reduce the amounts related to two projects for contributions made by CenturyLink. The settlement also includes accumulated deferred income taxes arising from these projects. The net effect of these changes is to reduce rate base by approximately $90,000.

Post-Test Year Plant Additions – The Company proposed an adjustment to increase South Dakota test year plant in service for projected non-revenue producing post-test year capital additions anticipated to be in service prior to October 1, 2014. The settlement determination revises the Company's adjustment to reflect actual costs for completed projects in-service as of November 6, 2014. The settlement also includes accumulated deferred income taxes on the post-test year plant additions that are reflected in rate base. The net effect of these changes is to increase rate base by approximately $423,000.

Ben French, Neil Simpson I, & Osage Retirements – BHP proposed an adjustment to remove from rate base the amounts related to the Ben French, Neil Simpson I, and Osage power plants that were retired on or before March 21, 2014, to comply with the Environmental Protection Agency (EPA) Area Source Rules. The settlement accepts this adjustment.

Accumulated Depreciation – The Company proposed an adjustment to increase accumulated depreciation (and thereby to reduce rate base) to reflect one-half of the annual depreciation expense associated with new assets and its new depreciation rates. The settlement revises the Company's adjustment to synchronize the depreciation reserve with the plant additions that are to be included in rate base and to reflect a depreciation rate of 2.98% for CPGS in lieu of the Company's proposed 3.29% rate. The net effect of these changes is to increase rate base by approximately $44,000.

Cash Working Capital – BHP's proposed rate base included an allowance for cash working capital based on a lead-lag analysis. A lead-lag analysis examines the timing of the Company's receipt of service revenues from customers in relation to the Company's payment of expenses to vendors and employees. The Company's cash working capital allowance also included a rate base deduction for tax collections which the Company receives in advance of turning the related payments over to the taxing authorities. Staff carefully examined BHP's revenue lag and expense lead day determinations and made the following modifications, which are consistent with Staff adjustments in prior rate cases:

1. Revised the expense lead days for net payroll, service/holding company charges, other operating and maintenance, FICA, federal income tax, gross receipts tax, federal withholding, and sales tax;
2. Included a separate expense lead for vacation pay;
3. Included a separate expense lead for incentive compensation;
4. Included a separate expense lead for uncollectible accounts expense;
5. Revised revenue lag days to remain consistent with past Staff practice and state statute, and to more accurately reflect the South Dakota jurisdictional revenue lag; and
6. Revised expenses per day to incorporate into the lead-lag analysis the impacts of Staff's recommended adjustments to *pro forma* operating expenses.

These modifications increase rate base by approximately $5,161,000.

Rate Case Expense – Rate case expense included in Docket EL12-061, which includes costs incurred for both Docket EL12-061 and EL12-062 as of July 2, 2013, was amortized over a three-year period beginning June 16, 2013. Interim rates in this case were put into effect on October 1, 2014, leaving approximately 20.5 months of cost recovery until the Docket EL12-061 rate case expenses are completely amortized. The settlement in EL12-061 established a tracker for the potential recovery of the residual costs associated with both dockets in BHP's next rate case filing.

BHP proposed recovery of projected rate case costs for EL14-026, the remaining unamortized rate case expense from EL12-061 and EL12-062, and the residual costs related to EL12-061 and EL12-062, all amortized over a three-year period. BHP also proposed an unamortized amount of $750,046 be included in rate base. The settlement reflects a three-year amortization of $212,861 in actual costs as of November 6, 2014, for docket EL14-026 and $412,797 in actual, unrecovered costs for EL12-061 and EL12-062, for a total amount of $625,657. One-half of the rate case costs, or $369,191, is included in rate base, representing the average unamortized balance over the three year period. The net effect of these changes reduces rate base by approximately $381,000. The settlement also establishes a tracking mechanism for the potential recovery of the residual costs, if any, associated with docket EL14-026 in BHP's next rate case.

Decommissioning Regulatory Asset – The Neil Simpson I, Ben French, and Osage coal-fired power plants are subject to the Environmental Protection Agency (EPA)'s National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (Area Source Rules). After evaluating the options, BHP concluded the most cost effective plan to comply with these rules was to retire Neil Simpson I, Osage, and Ben French by the compliance deadline of March 21, 2014. The decommissioning process began in 2014 and is estimated to be completed by September 2015. In

Docket EL13-036, the Commission issued an order authorizing BHP to transfer the remaining plant balance for the soon to be decommissioned plants into a regulatory asset account.

In this docket, BHP proposed to amortize the estimated costs associated with the retirement and decommissioning of these three generating plants over five years and include the unamortized balance at the end of Year One, or four-fifths of the costs, in rate base. The settlement removes all contingencies that had been included in BHP's decommissioning estimates, revises the amount included for obsolete inventory to agree with the amount removed from working capital, amortizes the regulatory asset over ten years, and includes the average unamortized balance over the first three years in rate base. The net effect of these changes is to decrease rate base by approximately $1,806,000.

Storm Atlas Regulatory Asset – Winter Storm Atlas (Atlas) occurred October 3-5, 2013, causing the worst outages in BHP's 130-year history. Heavy snow and high winds, combined with fully leafed trees, caused significant damage to BHP facilities and left as many as 41,800 customers without power. Repairing this widespread damage far exceeded BHP's normal storm-related costs. In Docket EL13-036, the Commission issued an order allowing BHP to use deferred accounting for costs incurred as a result of Atlas.

In this docket, BHP proposed to include actual costs through December 31, 2013 arising from Atlas, as well as costs through the end of February 2014. The Company also proposed to include costs for a system-wide line inspection driven by Atlas. BHP proposed to amortize these costs over five years and to include the unamortized balance at the end of Year One, or four-fifths of the costs, in rate base. The settlement reflects actual, final Atlas-related costs (excluding employee bonuses) and actual system inspection costs through September 30, 2014, and reflects only the incremental internal labor costs associated with the system inspection. The settlement amortizes the regulatory asset over ten years and includes the average unamortized balance over the first three years in rate base. The net effect of these changes is to decrease rate base by approximately $1,566,000.

Tax Return True-up – BHP's proposed test year allowance for income taxes included "true-up" adjustments to eliminate certain tax events that were recorded during the test year but which were related to periods prior to the test year. It is important to purge from test year operating results for transactions that relate to periods outside of the test year. Therefore, Staff accepts BHP's Tax Return True-up adjustments. Those adjustments are included in the Settlement revenue requirement determination.

NOL Adjustment – Over the past several years, bonus depreciation previously approved by Congress significantly increased BHP's annual tax deductions. The increased deductions, however, exceeded BHP's income resulting in a tax loss. Because of the tax loss position, BHP was not able to utilize all of its allowable deductions in the year they were earned. It had recorded deferred taxes relating to these tax deductions, nevertheless. The accumulated deferred taxes are used as an offset to BHP's rate base. Therefore, it was necessary to adjust BHP's rate base to reflect the unused tax deductions. BHP will now be able to utilize more of its previously unused tax deductions given the revenue increase agreed to by the Parties. The impact of this greater utilization of tax deductions on BHP's rate base has been reflected in the settlement revenue requirement. The result of recalculating this adjustment to reflect the effect of other adjustments incorporated in the settlement is to increase rate base by approximately $641,000.

Other Working Capital – BHP proposed this rate base adjustment to accurately reflect recent investments in a spare transformer for Neil Simpson II, in spare fan motors at the Neil Simpson Complex, in critical spare parts at Cheyenne Prairie Generating Station, and in a new coal stockpile at the Neil Simpson Complex, while removing the test year inventories at the recently retired Ben French, Neil Simpson I, and Osage generating units. The settlement accepts this adjustment while modifying for actual costs and reflecting a more recent 13-month average for materials and supplies, fuel stocks, and customer advances. These modifications increase rate base by approximately $969,000.

69 kV LIDAR Surveying Project – BHP proposed this adjustment to recover Light Detection and Ranging (LIDAR) project costs on its 69 kV system. This survey provided BHP with electronic modeling data to verify proper ground clearances were met and help streamline their vegetation management efforts. The project cost is shared with the joint owners of the transmission system, and BHP proposed to amortize costs associated with the project over five years and to include the unamortized balance, or four-fifths of the cost, in rate base. The settlement reflects a reduction for accumulated deferred income taxes associated with the project, an update to actual project costs and actual contributions from joint owners, and includes the average unamortized balance, or one-half of the cost, in rate base. The result of Staff's revisions reduces rate base by approximately $399,000.

Customer Service Model – This Staff proposed adjustment reflects the rate base reduction for BHP's customer service model changes. With the Belle Fourche and Newell customer service and electric operation service centers being consolidated and moved to Spearfish and Sturgis, respectively, the Newell office is no longer needed. Removing the remaining amounts associated with the Newell office reduces rate base by approximately $9,000.

Sturgis Office & Operations Center – BHP built a new service center in Sturgis to consolidate operations and business offices into one location in the northern hills. As a result, the two existing facilities in Sturgis will be closed. The settlement removes the amounts related to these two facilities as they are no longer needed. This adjustment reduces rate base by approximately $308,000.

Wages & Salaries – BHP's filing included several adjustments to test year payroll expenses, including employee additions. The settlement includes a rate base adjustment associated with one-half of the amount of annual employee salaries charged to capital projects. This adjustment increases rate base by approximately $79,000.

Other Rate Base Reductions – The Company's filing included *pro forma* rate base reduction for: 1) the flow-through of the income tax benefit associated with the repairs deduction that should not be included in rate base; 2) deferred taxes and federal effect of the state NOL that should be removed from rate base since South Dakota does not impose a state income tax; 3) deferred tax liability associated with regulatory asset – unit of property account that should not be included in rate base since the amount in the regulatory asset – unit of property is not included in rate base; and 4) the addition of accumulated deferred income tax associated with the plant that is allocated to BHP from BHSC and BHUH because the assets allocated to BHP are included in rate base. The settlement accepts this adjustment.

OPERATING INCOME

Wages & Salaries – BHP's filing included several adjustments to test year payroll expenses. These adjustments included 1) using 01/28/2014 annualized payroll as a starting point as it was the most recent payroll at the time BHP completed its adjustment; 2) removing the labor costs associated with Neil Simpson I plant personnel who will have part of their time charged to power plants not owned by BHP at the Neil Simpson Complex; 3) a 2014 union wage increase of 3.25%, a 2014 non-union wage increase of 3.50%, a partial year of a 3.5% 2015 union wage increase, and a partial year of a 3.5% 2015 non-union increase; 5) adding the costs associated with open vacancies and additional employees needed for operations; and 6) removing costs associated with employee eliminations.

Staff agreed with the Company's adjustment, except for the amounts included for the 2014 non-union and 2015 union and non-union wage increases and employee additions. The settlement revises the Company's adjustment to 1) reflect a 2014 non-union wage increase of 3.25% in lieu of the Company's proposed budgeted 3.5%; 2) reflect a full year of the 2015 union wage increase of 3.25% in lieu of the Company's proposed partial year of a projected 3.5% wage increase; 3) reflect a full year of the 2015 non-union wage increase of 3.0% in lieu of the Company's proposed partial year of a projected 3.5% wage increase; and 4) reflect employee additions for actual employees hired, including only the portion of employee salaries charged to O&M and adjusting the salaries for the 2015 wage increases. This adjustment reduces operating expenses by approximately $130,000.

Black Hills Corp. / Black Hills Utility Holdings Intercompany Charges – BHP proposed a $2.3 million adjustment to total company test year expenses for charges billed to it from Black Hills Utility Holdings (BHUH) (Adjustment H-5). Staff objected to this adjustment because it did not reflect a known and measurable change in BHP's costs; rather, it was merely BHP's estimate of future costs. Consistent with the Parties' treatment of other operating expenses, including expenses billed to BHP by BHSC, the Parties agreed to recognize known changes in billed costs by the service company through August 31, 2014. That is, the rate case allowance for service company billings reflect BHP's actual costs for the twelve months ended August 31, 2014, excluding amounts associated with vegetation management and reflecting an annualization for customer records and collection expenses associated with a change in allocation factors. The *pro forma* utility holdings costs also reflect an annualization of wage increases for both 2014 and 2015. The effect of these changes is to increase South Dakota operating expenses by approximately $527,000.

Employee Pension & Benefits Adjustment – BHP proposed a $334,319 total company adjustment to test year employee benefits expenses (Adjustment H-6). Within this adjustment, BHP normalized its test year pension expense by averaging the annual expense over the past five years. This normalization adjustment reduced the test year pension expense by $508,454 on a total company level. Staff agreed to BHP's pension expense normalization adjustment if it is to be applied consistently in future rate cases. Staff disagreed with the remainder of BHP's proposed employee benefits adjustment because it is based on estimated future costs rather than known cost changes. The settlement reflects known post-test year changes in employee benefits costs rather than BHP's estimates. It also reflects a normalized level of pension costs based on a five-year average of BHP's actual pension expense. The effect of these changes is to reduce South Dakota operating expenses by approximately $289,000.

Bad Debt Analysis – BHP proposed an adjustment to decrease bad debt expenses based on a three-year uncollectible rate average. The settlement decreases bad debt expense based on a five year uncollectible rate average applied to retail revenues. The net effect of this change increases jurisdictional operating expense by approximately $6,000.

Generation Dispatch & Scheduling – BHP proposed an adjustment to update costs for generation dispatch and scheduling in accordance with the Generation Dispatch and Energy Management

Agreement (GDEMA) which allocates costs to the parties contracting for services based on total capacity of each company. Staff generally agreed with the adjustment but replaced the budgeted costs used by BHP with actual year-end August 2014 costs, while allowing known and measurable increases to labor and labor overhead. Staff also corrected errors to the capacities provided for Black Hills Power and Black Hills/Colorado Electric. The result of Staff's revisions reduces jurisdictional operating expense by approximately $106,000.

Energy Cost Adjustment Expense Elimination – The Company proposed an adjustment to remove all costs that are collected through the Energy Cost Adjustment (ECA) from the test year. The settlement accepts this adjustment.

Neil Simpson Complex Shared Facilities – BHP proposed an adjustment to update revenues and expenses for shared facilities in accordance with the Neil Simpson Complex Shared Facilities Agreement which allocates revenues and expenses to the parties based on net capacity of each company. Staff generally agreed with the adjustment but replaced the budgeted costs used by BHP with actual costs. The result of Staff's revisions reduces jurisdictional operating expense by approximately $74,000 and reduces jurisdictional operating revenue by approximately $136,000.

Removal of Unallowed Advertising – BHP proposed an adjustment to remove advertising expenses that should not be recovered from ratepayers. The settlement accepts this adjustment and further removes additional advertising costs which do not contribute to the provision of safe, adequate, and reliable electric service for South Dakota ratepayers. The effect of this adjustment reduces operating expenses by approximately $4,000.

Power Marketing Adjustment – BHP's adjustment to remove power marketing expenses from the base rate regulated cost of service is found on Statement H, Schedule H-12. The revenue adjustment found in Statement I, page 1, removes the corresponding power marketing revenues from the base rates. The settlement revises the expense adjustment to correct the labor-bonus costs removed and accepts the revenue adjustment. The effect of this adjustment reduces operating expenses by approximately $9,000.

Rate Case Expense – Rate case expense included in Docket EL12-061 (consisting of costs related to Docket EL12-061 and EL12-062) was amortized over a three-year period beginning June 16, 2013. Interim rates in this case were put into effect on October 1, 2014, leaving approximately 20.5 months of cost recovery until the expenses are completely amortized. The settlement in EL12-061 established a tracker for the potential recovery of the residual costs associated with both dockets in BHP's next rate case filing.

BHP proposed recovery of projected rate case costs for EL14-026, the remaining unamortized rate case expense from EL12-061 and EL12-062, and the residual costs related to EL12-061 and EL12-062; amortized over a three-year period. The settlement reflects a three-year amortization of $212,861 in actual costs as of November 6, 2014 for docket EL14-026 and $412,797 in actual, unrecovered amounts for EL12-061 and EL12-062, for a total three-year amortization allowance of $625,657. The net effect of these changes is a reduction in operating expenses by approximately $188,000. The settlement also establishes a tracking mechanism for the potential recovery of the residual costs associated with docket EL14-026 in the next rate case filing.

Vegetation Management Expense – BHP proposed to adjust its test year vegetation management expenses to reflect the amount approved in the stipulation in Docket EL12-061. The settlement accepts this adjustment with a slight modification which updates the allocator to conform to what BHP filed in its Statement N. The result of Staff's revision increases jurisdictional operating expense by approximately $1,000.

CPGS O&M – The Company proposed an adjustment to reflect projected operation and maintenance expense for CPGS during a normal year. The settlement reflects the Company's proposed adjustment, less reagent costs which are recovered through the ECA. This adjustment reduces operating expenses by approximately $28,000.

Ben French Severance Expense – BHP proposed an adjustment to remove the employee severance expense associated with the Ben French plant. The settlement accepts this adjustment.

Neil Simpson Complex Common Steam Allocation – BHP proposed an adjustment to update costs for the operation and maintenance of Neil Simpson Complex common steam facilities where BHP is responsible for costs relating to the capacity associated with Neil Simpson II and its ownership percentage of Wygen III. Staff generally agreed with the adjustment but replaced the budgeted costs used by BHP with actual year end August 2014 costs, while allowing known and measurable increases to labor and benefits. Staff also corrected errors in the capacity shares provided for Black Hills Power and MDU, City of Gillette & Other. The result of Staff's revisions reduces jurisdictional operating expense by approximately $243,000.

Ben French, Osage, & Neil Simpson I O&M Elimination – BHP proposed an adjustment to remove the test year operating and maintenance expenses related to the Ben French, Neil Simpson I, and Osage power plants that were retired on or before March 21, 2014, to comply with the Environmental Protection Agency (EPA) Area Source Rules. The settlement accepts this adjustment.

Future Track Workforce Development – BHP proposed a $721,861 total company expense adjustment (Adjustment H-19) to implement its eight-year Future Track Workforce Development Program. Included in the Company's proposal was a request to defer as a regulatory asset for future recovery all costs associated with the program that exceed the amount included in base rates.

Staff objected to the Company's proposal, both as to the expense to be included in base rates and to BHP's proposal to defer expenses in the future. The Parties agreed to reflect in rates BHP's actual costs for newly hired employees under the Future Track program, without deferrals. The effect of this change is to decrease South Dakota operating expenses by approximately $344,000. The settlement also eliminates the annual reporting requirements proposed in BHP's filing.

69 kV LIDAR Surveying Project – BHP proposed this adjustment to recover Light Detection and Ranging (LIDAR) project costs on its 69 kV system. This survey provided BHP with electronic modeling data to verify proper ground clearances were met and help streamline their vegetation management efforts. The project cost is shared with the joint owners of the transmission system. BHP's share is amortized over five years to correspond with the expected frequency of the survey. Staff's adjustment reflects actual costs of the survey and actual contributions from the joint owners. The result of Staff's revision reduces jurisdictional operating expense by approximately $66,000.

Customer Service Model Adjustment – This adjustment reflects the cost reductions BHP achieved as a result of their customer service model changes. The Belle Fourche and Newell customer service and electric operation services centers were consolidated and moved to Spearfish and Sturgis, respectively. This adjustment removes the salaries and benefits of three customer service representatives and eliminates Belle Fourche and Newell facility costs. The settlement also removes further costs associated with telephone, janitorial labor, and depreciation expense. The result of Staff's revision reduces jurisdictional operating expense by approximately $7,000.

Remove City of Gillette – BHP proposed an adjustment to remove the City of Gillette revenue as it relates to replacement energy. The associated costs are removed as part of the Power Marketing adjustment. The settlement accepts this adjustment.

Unbilled Revenue and Provision for Rate Refunds – Unbilled Revenue reflects an accounting accrual made each month to reflect a portion of the current month usage which is billed in the following month. These accrual entries are reversed out the following month. Provision for Rate Refunds reflects the balance related to interim rates in Dockets EL12-061 and EL12-062. These adjustments remove the entire per books amounts from these two accounts to reflect normal levels. The settlement accepts these adjustments.

Removal of Energy Cost Revenue – The Company proposed an adjustment to remove revenue associated with the ECA as associated energy costs were also removed from the test year. The settlement accepts this adjustment.

PIPR Rate Annualization – The test year revenues contain only a portion of the Phase In Plan Rate revenues established in Docket EL12-062. This known and measurable adjustment is needed to reflect the proper level of revenue and properly match what customers were paying at the end of the test year, thus reducing the revenue deficiency. The settlement accepts this adjustment.

Weather Normalization – BHP's filing contained a weather normalization adjustment of ($644,705). Staff undertook an independent weather normalization analysis and concluded that an adjustment of ($264,403) would be appropriate. Staff's adjustment updated BHP's data to reflect the latest NOAA weather normals for the thirty year base period 1981-2010. Staff also included June in the analysis of cooling load sensitivity, and measured sensitivity in absolute value as a departure from normal, rather than relative variation from monthly normals. Sensitivity was based on regression coefficients correlating usage with departure from normal. BHP accepted Staff's adjustment for settlement purposes. The effect of these changes increases operating revenues by approximately $380,000.

Industrial Contract Service Accrual – BHP proposed this known and measurable adjustment to properly match revenues with test year usage for three of their industrial customers on contract rates. The settlement accepts this adjustment.

EL12-061 Rate Increase Annualization – The test year revenues are based on the rates established in Docket EL09-018; however, rates were changed in Docket EL12-061, effective October 1, 2013. This is a known and measurable change to test year operating results. BHP proposed this adjustment to reflect the proper level of revenue to be received from customers based on the recently approved rates. The settlement accepts this adjustment.

Interest Synchronization – The settlement synchronizes the tax deduction for interest expense with the weighted cost of long-term debt and the historical test year rate base as adjusted for known and measurable changes.

Depreciation Expense – In its March 31, 2014 rate filing, BHP claimed a total company depreciation expense allowance of $3,035,046 related to the Cheyenne Prairie Generating Station based on the then-estimated $92,250,624 total company plant investment at its expected in-service date of October 1, 2014. The expense allowance reflected a composite depreciation accrual rate of 3.29% that assumed a 35-year life span for the plant, allowances for retirements of plant components during the life span and an estimate of removal costs amounting to 4% of the plant investment at the time of its retirement.

The settlement reduces the CPGS depreciation allowance by $349,819 to $2,685,227, on a total company level, to reflect BHP's agreed-upon actual investment in the plant and a composite depreciation accrual rate of 2.98%. The 2.98% composite rate was derived by extending the assumed life span of CPGS from 35 years to a more realistic 40 years judging by life estimates made by other utilities for combined cycle generating units. Other parameters reflected in the 2.98% rate (interim retirements and removal costs) are consistent with the parameters reflected in BHP's existing depreciation accrual rates for its other generating facilities.

The settlement further revises the Company's depreciation adjustment to reflect the effect of the other plant adjustments included in the settlement. The net effect of these changes is to decrease South Dakota jurisdictional operating expenses by approximately $87,000.

Decommissioning Regulatory Asset – The Neil Simpson I, Ben French, and Osage coal-fired power plants are subject to the EPA's National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (Area Source Rules). After evaluating the options, BHP concluded the most cost effective plan to comply with these rules was to retire Neil Simpson I, Osage, and Ben French by the compliance deadline of March 21, 2014. The decommissioning process began in 2014 and is estimated to be completed by September 2015. In Docket EL13-036, the Commission issued an order authorizing BHP to transfer the remaining plant balance for the soon to be decommissioned plants to a regulatory asset.

In this docket, BHP proposed to amortize the estimated costs associated with the retirement and decommissioning of Neil Simpson I, Ben French, and Osage over five years. The settlement removes all contingencies, revises the amount included for obsolete inventory to agree with the amount removed from working capital, and amortizes the regulatory asset over ten years, reducing the annual South Dakota amortization expense by approximately $1,651,000. BHP may track the actual costs incurred and seek recovery, in a future rate case, of decommissioning costs not recovered from customers.

Storm Atlas Regulatory Asset – BHP proposed to include its actual Atlas-related costs through December 31, 2013, and its estimated costs through the end of February 2014. The Company also proposed to include costs for a system-wide line inspection necessitated by Atlas. BHP proposed to amortize these costs over five years. The settlement reflects actual, final Atlas-related costs (excluding employee bonuses) and actual system inspection costs through September 30, 2014, and reflects only incremental internal labor costs associated with the system inspection. The settlement amortizes the regulatory asset over ten years. The net effect of these changes is to reduce the annual South Dakota amortization expense by approximately $512,000.

Charitable Contributions – The settlement removes approximately $16,000 in charitable contributions.

Storm Damage – The settlement normalizes storm damage costs to a five-year average. As Atlas was the only major storm event in 2013 and its costs are recovered in a separate adjustment, this normalization adjustment would need to include $0.00 for the 2013 expense, and Staff was concerned that using $0.00 would not reflect an accurate value of normal storm damage expense. Thus, Staff chose the 2008 through 2012 timeframe for this adjustment and increased operating expense by approximately $31,000.

Incentive Compensation – BHP's proposed revenue requirement included approximately $3.8 million for incentive compensation, including amounts billed from the affiliate service company. For settlement purposes, the Parties agreed that incentive compensation paid for achieving financial performance goals will be excluded from BHP's South Dakota revenue requirement. This adjustment reduces South Dakota operating expenses by approximately $666,000.

Economic Development – The Company proposed 100% recovery of economic development expenses included in the test year. The settlement reflects a $100,000 economic development plan, inclusive of labor, to be split 50/50 between shareholders and ratepayers. The adjustment reduces operating expenses by approximately $27,000.

Association Dues – The settlement removes approximately $6,000 in association dues costs associated with donations, lobbying, and various other activities that do not provide for the provision of safe, adequate, and reliable electric service for South Dakota ratepayers.

Custer to Hot Springs Cooperatives Revenues – BHP has a joint ownership agreement with Rushmore Electric and its two members, Black Hills Electric Cooperative and Butte Electric Cooperative, for the co-owned portions of the 69 kV sub-transmission system. Rushmore Electric Power Cooperative, on behalf of itself and its members, pays BHP a monthly fee to ensure that customers of all parties are fairly and accurately responsible for their use of the jointly owned facilities. The settlement includes an adjustment to account for the additional annual revenues BHP will receive associated with the Custer to Hot Springs line. The effect of this adjustment is to increase operating revenues by approximately $90,000.

Workers Compensation – During discovery, BHP proposed an adjustment to normalize workers compensation costs to a five-year average of the costs. The settlement accepts this adjustment, increasing operating expenses by approximately $172,000.

Black Hills Corp./ Black Hills Service Co. Intercompany Charges – BHP's filed case included test year expenses billed to it by its affiliate service company, approximately $20.4 million, without adjustment. Consistent with the parties' treatment of other operating expenses, including expenses billed to BHP by BHUH, the Parties agreed to recognize known changes in billed costs by the service company through August 31, 2014. That is, the rate case allowance for service company billings reflect BHP's actual costs for the twelve months ended August 31, 2014, except for property insurance which is BHP's actual costs for the year October 2014 through September 2015. The pro forma service company costs also reflect an annualization of wage increases for both 2014 and 2015. The net effect of these changes is to increase South Dakota operating expenses by approximately $1,132,000.

Income Tax Adjustment – The Company's filing included pro forma adjustments to income tax for true-up items and items that are not part of the regulated operations of BHP that should therefore not be included in the computation of federal income tax. The settlement accepts this adjustment.

COST OF CAPITAL AND RATE OF RETURN

BHP's initial filing sought an overall rate of return of 8.48 percent, which included an embedded debt cost of 6.45 percent and a capital structure of 53.32 percent equity and 46.68 percent debt. The requested rate of return on equity was 10.25 percent. Staff's analysis initially challenged all three components of the overall rate of return: (1) embedded cost of debt, (2) the capital structure, and (3) the required return on equity.

[Begin Confidential] [redacted] [End Confidential], the settlement overall rate of return is 7.76 percent.

RATE DESIGN ISSUES

The parties agree in principle on all issues regarding rate design and the class revenue distribution. The settlement position reached between Staff and BHP is discussed below.

Class Cost of Service/Spread of the Increase – BHP's filed case included a class cost of service study ("CCOSS"). A CCOSS is useful in assigning revenue responsibility to each rate class that BHP serves in

South Dakota and in designing rates within each class. The allocation methods reflected in BHP's CCOSS are basically the same as those that were reflected in previous CCOSS studies filed by BHP and accepted by Staff and the Commission. In this proceeding, however, BHP introduced the results of a new customer load study based primarily on data obtained from the Company's new AMI meters. The new load data was used in developing the class demand allocation factors used in the CCOSS. The new load data incorporated into the CCOSS indicated that base rates for two of the five customers classes should be increased significantly (Residential – 19.26% and General Service Large/Industrial Contract – 15.44%); base rates to the Water Pumping/Irrigation class should be increased by a small amount (3.45%); and base rates for the remaining two classes should be decreased (General Service – 6.37% and Lighting Service – 15.74%). Rather than implementing these indicated rate changes, BHP proposed a rate moderation plan to avoid adverse rate impacts to the Residential and General Service Large/Industrial Contract customers. Under BHP's moderation plan, no class is to pay less than 75 percent of the system-wide percentage increase and no class is to pay more than 120 percent of the system-wide percentage increase.

Without agreeing specifically with either the results of the CCOSS or BHP's underlying new load research results, the Parties agreed to accept BHP's proposed rate moderation plan by implementing a 75% to 120% percent collar around the system-wide percentage increase. Under this approach, the following class increases result:

Settlement Class Revenue Increases

Class	Percent Increase
Residential	5.04%
General Service	3.46%
General Service Large/Industrial Contract	4.55%
Water Pumping/Irrigation	3.11%
Lighting Service	3.45%
Total	4.35%

Rate Design (Residential Customer Service Charge) – BHP's currently effective monthly customer service charge for the Residential class is $8.75. BHP proposed to increase the present rate to $10.00. In settlement, the parties agreed to increase the Residential monthly customer service charge to $9.25. This represents a 5.71 percent increase in that charge, which is within the range agreed to among the parties for the Residential class as a whole. Staff also believes that a $9.25 monthly service charge is supported by the underlying costs to serve Residential customers.

OTHER ISSUES

Economic Development – The settlement reflects a $100,000 economic development plan, inclusive of labor, to be split 50/50 between shareholders and ratepayers. Under the terms of the settlement the following conditions apply:

- $100,000 total paid equally by ratepayers ($50,000) and shareholders ($50,000);

- Expenses shall include but not be limited to, all South Dakota labor, expenses and monetary contributions deemed to be a benefit to economic development in the BHP South Dakota electric territory;
- On an annual basis, no later than March 1 of each year, BHP will submit for the Commission's approval a filing that describes the actual cost, design and individual benefits of each cost to BHP's Economic Development programs in the previous calendar year and the projected cost, design and individual benefits of each cost to BHP's Economic Development programs in the current calendar year;
- The Commission may determine that some of the programs are not appropriate for purposes of 50% rate recovery;
- If the remaining programs cost less than $100,000 at the end of a program year, the unspent costs shall be "carried over" into the next program year for Commission approval of expenditure or refund; and
- No carry-over shall occur for any amounts spent annually in excess of $100,000.

Energy Cost Adjustment – The Company proposed the following change to the Fuel and Purchased Power Adjustment (FPPA), which is a component of the ECA: 1) to include any difference in ad valorem or property taxes from what is reflected in base rates; 2) to credit 100% of the Company's wholesale contract revenue on October 1, 2014, as agreed to in Docket No. EL12-062; 3) to eliminate the power marketing credit minimum; and 4) to recover 100% of the costs related to short-term planning reserve capacity purchases and sales. Staff agreed with items 1, 2, and 4, but took issue with the elimination of the power marketing credit minimum. The Parties agreed for settlement purposes to reduce the power marketing credit minimum from $2 million to $1 million and increase the power marketing sharing from 65% to 70%.

Major Maintenance Accrual – BHP requested approval of a modification to the major maintenance account to expense a portion of the plant overhaul costs each year based on a plant's planned maintenance cycle. In Docket EL09-018, the settlement allowed BHP to establish a major maintenance account and a regulatory liability for steam plant maintenance and a 7-year cycle was established. The work previously done during the seven year overhaul is now split into two overhauls. There is no change in the existing accrual at this time. The settlement defines major maintenance for steam plants as the expenses incurred during the period of time when a steam turbine generator is opened for maintenance.

Implementation of Rates – The tariffs shown on Exhibit 1 attached to the Settlement are to be implemented for service rendered on or after March 1, 2015. Customer bills will be prorated so that usage prior to October 1, 2014, is billed at BHP's previously effective rates (i.e., the base rate in effect immediately prior to the interim rates implemented on October 1, 2014), and usage on and after October 1, 2014, is to be billed at the new rates established by the settlement.

Interim Rate Refund – Interim rates were implemented on October 1, 2014. Approval of the Settlement will authorize a rate increase less than the interim rate level. The Company agrees to refund customers the difference between interim rates and new rates established by the settlement for usage during the period October 1, 2014 through February 28, 2015. As part of the refund, BHP will include interest, calculated by applying a 7% annual interest to the average refund balance for each month that interim revenues were collected. The Company's Interim Rate Refund Plan is attached to the Settlement as Exhibit 3.

Contract with Deviations – On September 4, 2014, BHP filed a Contract with Deviations between BHP and SDSTA. The Commission approved this Contract with Deviations on an Interim basis. Now that the cost of service and class cost of service study review is complete, Staff and BHP agree the Contract with Deviations may now be finally approved by the Commission, without condition.

RECOMMENDATION

Staff recommends the Commission approve the Settlement for the reasons stated above.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES

STAFF MEMORANDUM SUPPORTING
AMENDED SETTLEMENT STIPULATION

DOCKET EL14-026

Commission Staff (Staff) submits this Memorandum in support of the Amended Settlement Stipulation (Amended Settlement) of February 10, 2015, between Staff and Black Hills Power Company (BHP or Company) in the above-captioned matter.

BACKGROUND:

On March 31, 2014, the Company filed an application with the South Dakota Public Utilities Commission (Commission) requesting approval to increase rates for electric service to customers in its South Dakota retail service territory by approximately $14.6 million annually or approximately 9.27%. A typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month.

BHP's proposed increase was based on a historical test year ended September 30, 2013, adjusted for what BHP believed to be known and measurable changes, a 10.25% return on common equity, and a 8.48% overall rate of return on rate base.

The Commission officially noticed BHP's filing on April 3, 2014, and set an intervention deadline of June 6, 2014. On April 11, 2014, BHP filed revisions to certain pages originally filed in the application. On April 16, 2014, the Commission issued an Order Assessing Filing Fee. On June 6, 2014, a Petition to Intervene of GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively, Black Hills Industrial Intervenors or BHII) was filed. On June 6, 2014, Dakota Rural Action (DRA) also filed a Petition to Intervene. On June 26, 2014, the Commission issued an Order Granting Intervention to Black Hills Industrial Intervenors. On June 26, 2014, the Commission granted intervention to Dakota Rural Action subject to its filing an affidavit, which was filed on June 27, 2014. On September 3, 2014, BHP filed a Notice of Intent to Implement Interim Rates effective on and after October 1, 2014.

On September 4, 2014, BHP filed a Motion for Approval of Settlement Agreement, Confidential Settlement Agreement between Black Hills Power, Inc. and South Dakota Science and Technology Authority (SDSTA), including the associated Third Amendment to Electric Power Service Agreement between Black Hills Power, Inc. and SDSTA, and relevant exhibits. On September 10, 2014, Staff filed its memorandum regarding the Contracts with Deviations. On September 18, 2014, the Commission issued an Order Conditionally Authorizing and Approving Implementation of Contract with Deviations Rates on an Interim Basis.

Settlement discussions between Staff, BHP, BHII, and DRA commenced on October 28, 2014. Thereafter, Staff and BHP (jointly, the Parties) held several settlement discussions in an effort to arrive at a mutually acceptable resolution of the issues presented in BHP's filing. Ultimately, the Parties reached a comprehensive agreement on BHP's overall revenue deficiency and other issues presented in this case including, but not limited to, class revenue responsibilities, rate design, and tariff concerns. BHII and DRA are not parties to the settlement. On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits. On December 12, 2014, the Commission issued a Scheduling Order setting this matter for hearing on January 27-29, 2015. On December 30, 2014, the Commission issued an Order for and Notice of Hearing.

BHII filed Direct Testimony and Exhibits of Lane Kollen and Direct Testimony and Exhibits of Stephen J. Baron on December 30, 2014. No testimony was filed by DRA. On January 15, 2015, Staff filed David E. Peterson's direct testimony that addressed specific items discussed in Mr. Kollen's testimony and Mr. Baron's testimony. On January 15, 2015, BHP submitted rebuttal testimony.

The hearing was held as scheduled on January 27-28, 2015, with Staff, BHP, BHII, and DRA appearing and presenting evidence and argument. At the conclusion of the hearing, the Commission decided to defer taking action on the outstanding issues until its regular meeting on March 2, 2015. On January 29, 2015, the Commission issued a Post-Hearing Procedural Order.

OVERVIEW OF AMENDED SETTLEMENT

Upon hearing arguments from the Parties and the Intervenors and weighing Commission concerns at the hearing, Staff and BHP found it in the best interest of all the Parties to work toward an amended settlement, which would correct the utility holdings allocation oversight presented by BHII. Staff and BHP held a settlement meeting on February 6, 2015, to address this concern. As a result, some party positions were modified and others were accepted where consensus was found. Ultimately, the Parties agreed on a resolution of the issue. The following describes the changes from the originally filed Settlement.

Utility Holdings Allocation Oversight Correction.

As shown on Staff Exhibit___(DEP-2), Schedule 1, the amended cost of service corrects the South Dakota allocation of transmission load dispatch expense, FERC Account 561, for the Black Hills Corporation/Black Hills Utility Holdings Intercompany charges adjustment, reducing the revenue requirement by $286,041. Thus, the Amended Settlement corrects the initial oversight.

Wyodak Operations and Maintenance Adjustment.

The Amended Settlement accepts the $412,988 Wyodak O&M adjustment as provided by BHP in Exhibit JTR-1. This adjustment updates production O&M costs at the Wyodak power plant from $3,045,652 incurred during the test year to $3,458,640 incurred from October 2013 through September 2014. This represents a known and measurable increase to test year expense.

Cash Working Capital, NOL Adjustment, Interest Synchronization, Bad Debt Adjustment

The Amended Settlement uses the same calculation for these adjustments as the Settlement filed on December 9, 2014. However, the revenue requirement value of each adjustment changes based on the resolution of various issues in the case. These adjustments are dependent on the pro forma rate base, expenses and revenues, and were recalculated as a result of the Utility Holdings allocation correction and the Wyodak O&M adjustment.

No Change to Revenue Deficiency

Although Exhibit___(BAM-4), Schedule 1 of the amended cost of service shows a $7,010,894 revenue deficiency, the revenue deficiency in the Amended Settlement will remain at the $6,890,746 level provided in the original Settlement. Thus, the amended cost of service more than supports the revenue requirement agreed upon in the Amended Settlement, and ratepayers will not incur the added rate case expense required to prepare revised rates and tariff sheets.

Additional Moratorium

The Amended Settlement extends the stay-out provision an additional three months from what was agreed to in the original Settlement. Thus, BHP shall not file any rate application for an increase in base rates which would go into effect prior to January 1, 2017. This addition would provide a calendar year test year, should BHP file for an increase at the expiration of the moratorium.

RECOMMENDATION

Staff recommends the Commission approve the Amended Settlement for the reasons stated above.

THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

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IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC., FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES — EL14-026

= =

Transcript of Proceedings
January 27 & 28, 2015

Volume II of II
January 28, 2015
CONFIDENTIAL VERSION

= =

BEFORE THE PUBLIC UTILITIES COMMISSION

CHRIS NELSON, CHAIRMAN
KRISTIE FIEGEN, VICE CHAIRMAN
GARY HANSON, COMMISSIONER

COMMISSION STAFF

John Smith
Karen Cremer
Greg Rislov
Tina Douglas
Katlyn Gustafson

APPEARANCES

Amy Koenig and Lee Magnuson, Black Hills Power, Inc.
Mark Moreno, Andrew Moratzka, and Chad Marriott, Industrial Interveners
Caitlin Collier, Dakota Rural Action
Karen Cremer, Public Utilities Commission Staff

Reported By Cheri McComsey Wittler, RPR, CRR

Mr. Peterson, this is Commissioner Nelson. Several questions.

You have listened to the past day's worth of questions, and several times I've questioned this concept of the five-year normalization. We're seeing that with pension expenses, and I think we also see it with some Worker's Comp costs. And in both of those cases those normalizations benefit the company.

How do you know that there may not be other five-year normalization opportunities that would benefit ratepayers?

What is your analysis process to determine if those opportunities are there and take advantage of those?

THE WITNESS: Yeah. First of all, one is to make it clear that the company itself isn't the primary beneficiary or the only beneficiary of this normalization adjustment.

The expense, the pension expense in particular that is reflected in the Settlement Agreement, reflects nearly a -- or over a $500,000 reduction in expense from the test year level.

But as far as are there other opportunities for -- for normalization that may cut in the opposite direction? Yeah. There's always that possibility in any rate case.

In fact, in nearly all the rate cases that I do for myself, you know, that's one of the analyses I perform is essentially the same thing that was shown on Table 1 of page 16 of my testimony.

I usually ask the utility for five years worth of detailed O&M expenses by account, and I do a variance analysis to identify abnormalities in the test year. And that's part of any rate case review.

CHAIRMAN NELSON: Thank you. I appreciate knowing that.

Let me visit just a minute about Staff's memo comment on weather normalization. Now if I'm understanding this correctly, BHP did a weather normalization adjustment and came up with a reduction figure of 644,000. And Staff did their analysis and only came up with a reduction of 264,000.

Would we have been better off if Staff had not done that analysis?

THE WITNESS: No. That's just the opposite. The company reduced its test year revenues by 644,000 in their adjustment. We reduced it by -- or the Staff reduced it by only 264,000. So the test year -- the going forward, the pro forma revenues under Staff's revenue requirement analysis, showed a higher revenue at existing rates, therefore, a lower revenue deficiency.

CHAIRMAN NELSON: Thank you. I see where my thinking was in error on that, and I appreciate your pointing that out.

I think the only other question I've got, and this goes back to one of Mr. Moratzka's last questions dealing with page 19 of your testimony where we've got this acknowledged error, would you agree that it would be difficult for a Commissioner to approve a settlement that has a known error?

THE WITNESS: Yeah. I could see where it places the Commission in an awkward position. And I can also state that had the Staff been aware of this error during settlement negotiations, it would have been corrected.

CHAIRMAN NELSON: Thank you.

No further questions.

MR. SMITH: Commissioner Fiegen.

COMMISSIONER FIEGEN: Mr. Peterson, one question on your direct testimony that you provided for January 15, I believe it was filed.

On page 17 of 30 you talk about incentive compensation. And the Commission Staff ever since I've seen them work on rate cases and what I get to see anyway is they've been pretty hard on performance based on financial and they have taken that always out of incentive compensation and they continue to do it again.

But in your testimony I can't quite tell. Could you kind of rephrase it for me because it kind of looks like you agree with Mr. Kollen on some of the characteristics that he has put in his direct testimony.

THE WITNESS: Yes. And I think your assessment or understanding of my testimony is probably correct.

The Staff raised issues with the incentive compensation plan the company had and the payments made under the plan.

But in the end through these settlement discussions we agreed to exclude the 666,000 related specifically to financial performance. And this is the way that the issue has been treated for Black Hills on prior settlements and for all other utilities in the state on prior settlements.

But yeah. I have concerns about every utility's incentive compensation plan, not just Black Hills.

COMMISSIONER FIEGEN: Hello.

I have a different mic. I now have Ms. Cremer's mic., and it's a little tricky to run over here.

I still don't understand your testimony, though, on your concerns that you have with incentive pay. And you've agreed with the Staff Settlement, yet you still have some concerns, and I don't -- I just can't quite understand it.

I've read it a couple of times, and I'm still not getting what you're trying to let me know.

THE WITNESS: Well, I'll try to say it again. I'm very critical of many incentive compensation plans. And I will say that Black Hills' incentive compensation plan is much different than most or many other utilities.

Most utilities I have seen have financial triggers in their incentive compensation plan. Those financial triggers work to -- the employees are only compensated if corporate financial goals are met first. In other words, if the stockholders get paid first, and if the workers achieve their performance or safety or customer satisfaction goal, then they'll get their incentive compensation if certain corporate financial targets are met.

Black Hills doesn't have those triggers in their plan. If customer safety goals are met, the employees eligible will receive their incentive compensation regardless of the company's earnings, even if they have negative earnings.

So I applaud Black Hills for having a plan like that. But there are things like service, supplemental and executive retirement programs that grant additional incentive compensation to a very few people that are -- that are -- by definition, exceed the plans that abide to the general body of eligible employees. I'm critical of those types of plans.

So I have a lot of questions and concerns about incentive compensation plans, but in the end the trade-offs in the negotiations involving this issue and other issues, that Staff felt it best to go back to the way that we've treated incentive compensation for all of the utilities and for this utility in prior settlements and include just those related specifically to achieving financial performance goals.

COMMISSIONER FIEGEN: Thank you, Mr. Peterson. Now I understand that you were talking about the utility history in general.

Thank you.

MR. SMITH: Additional Commissioner questions.

CHAIRMAN NELSON: Commissioner Nelson again. I want to follow up on that. And you talked about -- I'm focused on the figure that -- I'm not sure if it's confidential or not, but the figure we talked about yesterday dealing with restrictive stock.

You just mentioned a trade-off. What did the company trade off to get that?

THE WITNESS: Well, I think there were a number of trade-offs. We didn't -- like I say, we don't know exactly what induced Black Hills to accept any of these adjustments that the Staff proposes but we do know that we got a two-year rate moratorium and we got what we believe is a reasonable award on return on equity.

We think we have a fair apportionment of the increases to the rate classes. You know, I think there are a number of benefits to not only residential customers but to the Industrial customers also.

CHAIRMAN NELSON: Thank you. But I've got to just ask a couple of other questions on a couple other issues.

Yesterday we spent some time talking about the FutureTrack program.

Do you believe the settlement legitimately covers the Industrial Interveners' concerns with that program?

THE WITNESS: Yes. I think it should. The Staff did not accept the FutureTrack program the company proposed.

What we did agree to in place of that is to reflect the actual cost of employees actually hired. Not to a target level of employees that they haven't hired or intend to hire at some point in the future but to reflect

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES

DOCKET NO. EL14-026

TESTIMONY OF DAVID E. PETERSON

ON BEHALF OF THE COMMISSION STAFF

JANUARY 15, 2015

I. INTRODUCTION

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

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

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

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

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

Since leaving the South Dakota Commission in 1980, I have continued performing cost of service and revenue requirement analyses as a consultant. In December 1980, I joined the public utility consulting firm of Hess & Lim, Inc. I remained with that firm until August 1991, when I joined CRC. Over the years, I have analyzed filings by electric, natural gas, propane, telephone, water, proposed rates into effect on an interim basis. BHP's interim rates will remain in effect until the conclusion of this proceeding.

III. SETTLEMENT STIPULATION

Q. ARE YOU THE ONLY ONE THAT ANALYZED BHP'S RATE REQUEST FOR THE COMMISSION STAFF?

A. No. The Commission Staff assembled a team of in-house analysts (Brittany Mehlhaff, Patrick Steffensen and Eric Paulson) and three outside consultants, including myself, to analyze BHP's rate increase application. The other two outside consultants are my colleagues at CRC, Robert Towers and Basil Copeland, Jr. This is essentially the same team that analyzed BHP's 2012 filing as well. Together, the Commission Staff team invested literally hundreds of hours analyzing BHP's Application, Testimony, Exhibits, Filing Statements and Workpapers. In addition, the Commission Staff propounded approximately 330 requests to BHP for additional data and information. Each response was carefully reviewed and analyzed by one or more Staff analyst. In addition, the Commission Staff carefully reviewed and analyzed information provided by BHP in response to BHII's approximately 60 discovery requests.

The Commission Staff began its investigation shortly after the Commission officially noticed BHP's rate increase Application on April 3, 2014. That investigation continued until late October 2014 when settlement discussions between the Commission Staff, BHP, BHII and another intervenor, Dakota Rural Action ("DRA")[2], commenced. Settlement discussions continued through

[2] DRA did not file testimony in this proceeding but did participate in settlement discussions that were held.

Commission typically relies on for evaluating post-test year adjustments. Moreover, as with BHP's decommissioning costs discussed earlier in my testimony, BHP's LIDAR costs are also governed and capped by a fixed rate contract. Thus, in my opinion, the costs are sufficiently known and measurable and are appropriately recognized in rates. The five-year amortization period reflected in the settlement was determined because five years is the expected frequency for LIDAR surveying activities. Therefore, it would be inappropriate to employ a ten-year amortization period as Mr. Kollen recommends and thereby burden BHP ratepayers, including BHII members, in years six through ten with costs for two different LIDAR surveys. A five-year amortization simply makes more sense for these costs.

Q. **WHAT DOES MR. KOLLEN RECOMMEND CONCERNING BHP'S PROPOSED ADJUSTMENT FOR PROJECTED EMPLOYEE ADDITIONS AND ELIMINATIONS?**

A. Mr. Kollen recommends the Commission disallow BHP's labor-related cost adjustments because he believes the adjustments ignore the fact that BHP historically has several open positions.

Q. **HOW IS THIS ISSUE TREATED IN THE SETTLEMENT?**

A. The Commission Staff shares Mr. Kollen's concern about recognizing phantom costs in rates for vacant positions. Because of this concern, the settlement includes cost allowances for only filled positions at the time of the Commission Staff's review. That is, cost allowances for vacant positions are not included in the settlement revenue requirement. This treatment should resolve Mr. Kollen's concern.

Q. HOW WAS THE PENSION EXPENSE ISSUE TREATED IN THE SETTLEMENT?

A. The following table shows BHP's pension expense over the last five years.

Table 1
BHP Annual Pension (FAS 87) Expense
2010 Through 2014

2010	$2,925,853
2011	$1,819,156
2012	$3,251,072
2013	$2,709,322
2014	$ 976,122
Five-year average	$2,336,305[3]

As shown in the table above, BHP's 2014 pension expense was unusually low when compared with the previous four years. Because of the significant variability of the expense year-to-year, BHP proposed a normalization adjustment that includes a pension expense allowance based on the average of the annual expenses over the last five years. The settlement incorporates BHP's pension normalization adjustment. The agreed-upon pension expense represents a $508,454 reduction from the test year pension expense, on a total Company basis.

Mr. Kollen considers the pension normalization adjustment "opportunistic" in that it does not reduce the test year expense far enough and it prevents BHP ratepayers from receiving the benefit from the lower pension expense in 2014 that the Company enjoyed. To support his contention, Mr. Kollen stated the Company offered no evidence that the pension expense will swing upward to the five-year average in future years.

[3] See BHP's response to Staff DR1-1; workpapers for Schedule H-6.

In truth, it is Mr. Kollen's position that is opportunistic. It is clear from the table above that BHP's pension expense can be highly variable and subject to major swings each year. Mr. Kollen's recommendation would have the Commission set rates based on BHP's lowest pension cost level in the last five years, with the knowledge based on recent experience that such costs are highly variable year-to-year. An understatement of BHP's pension costs could place the Company in a significant under-recovery position necessitating more frequent rate increases. With a highly variable cost such as the pension expense, to avoid wide swings in over-recovery and under-recovery of the underlying expense, it makes sense to employ a normalization procedure, such as that reflected in the settlement. To avoid any concern that the settlement approach is opportunistic, BHP and the Commission Staff agreed in the Settlement Stipulation to follow the five-year normalization approach for pension expense for the next five years, unless there is an extraordinary event that makes a five-year normalization method unreasonable.

Q. WHAT IS MR. KOLLEN'S CONCERN WITH INCENTIVE COMPENSATION EXPENSES?

A. Mr. Kollen believes the settlement resolution of the incentive compensation issue does not go far enough. In the settlement, $666,000 of the Company's $1.554 million total test year incentive compensation expenses is excluded. This is the amount that BHP identified as being tied to the Company's financial results. In addition to this already excluded amount, Mr. Kollen would also exclude $149,000 in performance plan expenses and $739,000 in incentive restricted stock expenses. Mr. Kollen contends that these additional amounts represent incentive awards that are similar in nature to those excluded in the settlement.

I do not necessarily disagree with Mr. Kollen's characterization of the incentive awards. In fact, I had initially pursued the same issues on behalf of the

Commission Staff earlier in this proceeding. In the end, however, the Commission Staff conceded this issue recognizing that the incentive compensation exclusion embodied in the settlement is essentially the same type of exclusion the Commission has approved for BHP in prior base rate case settlements and for other South Dakota utilities. Therefore, I support the exclusion that is contained in the settlement and recommend that the Commission reject Mr. Kollen's recommendation to expand the exclusion at this time. Of course, the Commission Staff and the BHP are free to revisit this issue in BHP's next base case given the Settlement Stipulation in this proceeding does not establish precedent on the incentive compensation issue.

Q. MR. KOLLEN OPPOSES BHP'S ADJUSTMENTS RELATING TO COSTS ALLOCATED TO IT BY TWO AFFILIATES, BLACK HILLS UTILITY HOLDINGS, INC. ("BHUH") AND BLACK HILLS SERVICE COMPANY, LLC ("BHSC"). WHAT ARE YOUR COMMENTS ON MR. KOLLEN'S CONCERNS?

A. BHP initially proposed an adjustment to test year BHUH expenses based on its post-test year operating budget. I had the same concerns as those expressed by Mr. Kollen that the adjustment lacked proper support. That is, I was not willing to recommend the Commission approve an adjustment based solely on BHP's budget projections. During our investigation, however, BHP provided a detailed summary of its most recent annualized expenses from the two affiliated companies[4]. The actual annual amounts billed to BHP are included in the settlement. Thus, the amounts billed to BHP from affiliates that are incorporated into the settlement reflect the Company's actual, known costs.

[4] See BHP's Second Supplemental Response to Staff DR3-96

Mr. Kollen also pointed out in his testimony that certain billings from BHUH were allocated to the South Dakota retail jurisdiction incorrectly on the Commission Staff's revenue requirement schedules. Mr. Kollen is correct. Properly allocating those expenses to South Dakota reduces the indicated revenue deficiency by approximately $286,000.

Q. MR. KOLLEN OBJECTS TO BHP'S PROPOSED DEPRECIATION RATE FOR THE NEW CHEYENNE PRARIE GENERATING STATION BECAUSE IT REFLECTS AN ASSUMED 35-YEAR LIFE SPAN. WHAT IS YOUR RESPONSE?

A. Commission Staff addressed this issue and the Settlement Stipulation reflects the same, longer, 40-year life span recommended by Mr. Kollen.

Moreover, it should be noted that whether it is 35 years or 40 years or some other life span, the life span that serves as the foundation for a depreciation accrual rate for CPGS *is an estimate* and a necessary departure from the principle that all elements of BHP's revenue requirement should be "known and measurable".

Q: WHY IS THAT IMPORTANT?

A. It is important because it is relevant to Mr. Kollen's other depreciation-related objections to the Settlement Stipulation – namely, the salvage estimates reflected in BHP's proposed accrual rates for other production plants and the concept of anticipating these future costs for current recovery. Beginning at page 47 of his testimony, Mr. Kollen declares that (1) the development of the salvage values are flawed and unreliable and then opines (2) that they may represent an undisclosed proposal to change the Commission's policy for recovery of retirement-related cost from after-retirement recovery to before-retirement recovery and (3) the increased negative salvage allowances are not necessary at this time because the

Commission is not required to provide for the recovery of unknown future costs in present utility service rates.

My point here is that, however desirable it might be to have all elements of the revenue requirement based on absolutely known and measurable costs, depreciation allowances must reflect estimates because neither the service life of the asset nor the cost of the act of retirement are known until the asset has been retired. Depreciation allowances represent allocations of capital costs of an asset to the time periods as the asset provides service to customers over a long period of time. In the absence of making such estimates, ratepayers benefitting from the service provided by the asset will avoid these costs and cost recovery would be shifted to future ratepayers not benefitting from that service. I know of nothing that even suggests an existing Commission policy of refusing to recognize these retirement-related costs until after the plant is retired.

Ironically, while objecting to the uncertainty of salvage estimates for other plant and advising that the Commission need not provide for the recovery of costs to be incurred in the future, Mr. Kollen is not reluctant to recommend a depreciation accrual rate for CPGS that includes an allowance for future retirement costs equal to 4 percent of that plant's capital costs as well as factoring in assumed allowances for interim retirements (see Remaining Lives by Account exhibited on the second page of Exhibit ___(LK-16); all are less than the 40-year life span by reason of interim retirements).

Rebuttal Testimony and Exhibit
Jon Thurber

Before the South Dakota Public Utilities Commission
of the State of South Dakota

In the Matter of the Application of
Black Hills Power, Inc., a South Dakota Corporation

**For Authority to Increase Rates
in South Dakota**

Docket No. EL14-026

January 15, 2015

TABLE OF CONTENTS

Exhibits

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jon Thurber, 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota 57701.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Black Hills Utilities Holdings, Inc. ("Utility Holdings"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"). I am Manager of Regulatory Affairs for Black Hills Power, Inc. ("Black Hills Power" or the "Company"). I am responsible for leading all aspects of the regulatory process for Black Hills Power.

Q. FOR WHOM ARE YOU TESTIFYING ON BEHALF OF TODAY?

A. I am testifying on behalf of Black Hills Power.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to explain and support the portions of the Settlement Stipulation ("Settlement Agreement"), reached between Black Hills Power and the South Dakota Public Utilities Commission Staff ("Staff"), that pertain to the: (1) revenue requirement adjustments under South Dakota administrative rule 20:10:13:44; (2) decommissioning regulatory asset and amortization adjustment; (3) LIDAR adjustment, (4) employee additions/eliminations adjustment; (5) utility holdings allocation correction; (6) pension expense adjustment; and (7) new debt issuance. I also explain why the positions advanced by the Black Hills Industrial Intervenors' ("BHII") witness Mr. Lane Kollen on these subjects are not appropriate.

III. REVENUE REQUIREMENT ADJUSTMENTS UNDER SOUTH DAKOTA ADMINISTRATIVE RULE 20:10:13:44.

Q. PLEASE EXPLAIN BLACK HILLS POWER'S APPROACH TO MEASURING ITS REVENUE REQUIREMENT IN THIS CASE.

A. Black Hills Power utilized a twelve month test year based on historical data, ending September 30, 2013. Adjustments for known and measurable items were then made to the historical test year to determine the pro forma costs.

Q. UNDER THE SETTLEMENT AGREEMENT, WERE ADDITIONAL ADJUSTMENTS MADE TO BLACK HILLS POWER'S REVENUE REQUIREMENT?

A. Yes, the Settlement Agreement reflects a variety of adjustments that were made to the Company's filed revenue requirement.

Q. ARE THE ADJUSTMENTS TO BLACK HILLS POWER'S REVENUE REQUIREMENT THAT ARE REFLECTED IN THE SETTLEMENT AGREEMENT CONSISTENT WITH THE REQUIREMENTS OF ARSD 20:10:13:44?

A. Yes. The Company utilized an appropriate test year and made adjustments to its book costs that were based on changes in facilities, operations, and costs that were known with reasonable certainty and measurable with reasonable accuracy and either have been or will become effective within the 24 months following the last month of the test year.

Q. **PLEASE EXPLAIN THE BASIS FOR THE COMPANY'S BELIEF THAT THE ADJUSTMENTS ARE RELATED TO COSTS THAT ARE KNOWN WITH REASONABLE CERTAINTLY AND MEASURABLE WITH REASONABLE ACCURACT?**

A. The end of the historic test year in this filing was September 30, 2013. As such, there have been over fifteen months of changes in facilities, operations and costs that have occurred and would be appropriately adjusted for under the Rule. Furthermore, the vast majority of the adjustments relate to costs that the Company incurred during the 12 months following the historic test year.

Q. **REFERRING TO MR. KOLLEN'S DIRECT TESTIMONY, PAGE 7, LINE 16 THROUGH PAGE 8, LINE 21, DO YOU AGREE THAT THE COMMISSION SHOULD LIMIT ANY POST-TEST YEAR ADJUSTMENTS TO THE TWELVE MONTH PERIOD IMMEDIATELY FOLLOWING THE HISTORIC TEST YEAR ENDING SEPTEMBER 30, 2013?**

A. No, I do not. Mr. Kollen's interpretation of ARSD 20:10:13:44 ignores the plain language of the rule that specifically states that reasonably certain and reasonably accurate adjustments which will become effective within the twenty four months following the last month of the test period are permitted.

Q. MR. KOLLEN INDICATES THAT ADJUSTMENTS ARE NOT PERMITTED UNLESS THE CORRESPONDING PROJECTED CHANGES IN REVENUE ARE INCLUDED IN THE REVENUE REQUIREMENT. PLEASE EXPLAIN WHY A RETAIL REVENUE ADJUSTMENT FOR SALES GROWTH WAS NOT INCLUDED IN THE SETTLEMENT AGREEMENT?

A. It is my understanding that it has been Staff's practice to exclude all revenue producing plant from the plant annualization and post-test year addition adjustments. Revenue producing plant consists primarily of distribution investments. Staff followed this practice in this case. It would therefore be inappropriate for additional revenues to be reflected in the cost of service because the investment needed to serve the sales growth is not included as well. Commission policy has been to reflect any incremental revenue or cost savings associated with post-test year adjustments in the revenue requirement.

Q. MR. KOLLEN CHARACTERIZES THE COMPANY'S ADJUSTMENTS AS OPPORTUNISTIC AND SELECTIVE. DO YOU AGREE WITH HIS CHARACTERIZATION OF THE ADJUSTMENTS THAT HAVE BEEN PROPOSED BY THE COMPANY?

A. No, absolutely not. Contrary to his characterizations, the Company included pro forma cost increases and cost reductions that occurred after the historic test year in the adjustments it made. Some of the material cost reductions, at the total company level, included in the filing were:

- Schedule H-1 Neil Simpson I labor and benefit costs - $746,475;
- Schedule H-6 FAS106 Retiree Healthcare - $168,896;
- Schedule H-6 FAS87 Pension Expense - $508,454;
- Schedule H-11 Advertising Expense - $262,517;
- Schedule H-16 Ben French Severance Expense - $180,861;
- Schedule H-18 Ben French, Osage, Neil Simpson I O&M - $3,753,186;
- Schedule H-21 Customer Service Model Adjustment - $215,934; and
- Statement J Ben French, Osage, Neil Simpson I Depreciation Removal - $1,732,526.

In total, the Company removed over $7,500,000 worth of expenses from the historic test year on an annual basis in the original filing.

Q. IN THE SETTLEMENT AGREEMENT, THE COMPANY AGREED TO UPDATE MANY ADJUSTMENTS IN THE ORIGINAL FILING THAT WERE BASED ON BUDGETS TO REFLECT RECENT ACTUAL COSTS. WERE THERE ANY MATERIAL REDUCTIONS IN EXPENSES AS A RESULT OF THESE UPDATES?

A. Yes, a few of the material cost reductions, at the total company level, were as follows:

- Updated Schedule G-3 to reflect the actual debt issuance and cost – weighted average cost of debt was reduced from 6.45% to 6.08%, for over $1,000,000;
- Updated Schedule H-6 Pooled Medical Costs – approximately $400,000; and

- Updated Schedule H-8 Generation Dispatch and Scheduling Costs – over $300,000.

Clearly, the Company reflected both cost increases and reductions in the original filing and Settlement Agreement. Mr. Kollen's characterization of the Company as opportunistic and selective lacks merit.

Q. SHOULD THE COMMISSION ACCEPT THE ADJUSTMENTS TO THE REVENUE REQUIREMENTS THAT ARE REFLECTED IN THE SETTLEMENT AGREEMENT?

A. Yes, I believe the Commission should accept the adjustments as they were made in conformance with the requirements of ARSD 20:10:13:44.

IV. DECOMMISSIONING REGULATORY ASSET AND AMORTIZATION

Q. DID THE COMMISSION ISSUE AN ACCOUNTING ORDER TO ESTABLISH A REGULATORY ASSET FOR THE COSTS ASSOCIATED WITH DECOMMISSIONING THE NEIL SIMPSON I, OSAGE, AND BEN FRENCH POWER PLANTS?

A. Yes. On January 9, 2014, in Docket EL13-036, the Commission issued an Order approving deferred accounting for the transfer of remaining plant balances and associated inventory for soon to be decommissioned plants to a regulatory asset.

Q. PLEASE EXPLAIN THE DECOMMISSIONING ADJUSTMENT INCLUDED IN THE COMPANY'S FILED POSITION.

A. Black Hills Power proposed to amortize the costs associated with the retirement and decommissioning of the Neil Simpson I, Ben French, and Osage facilities over five years as reflected on Schedule J-2. The unamortized balance of the regulatory asset included in the test year would then be reduced by the accumulated amortization for a full year. The costs associated with the retirement of the units included the unrecovered plant and obsolete inventory. The estimated costs associated with decommissioning the units were provided in Response to SDPUC Request No. 3-23.

Q. WHY DID BLACK HILLS POWER REQUEST RECOVERY OVER A FIVE YEAR PERIOD?

A. The time period provided a balance between the amount of time required to minimize rate impact to customers and matched the expense as best as possible with the customers who have utilized the assets being retired. The proposed amortization period achieved an annual amortization expense that is approximately equivalent to the annual amount that it would cost to continue to operate these facilities.

Q. PLEASE DESCRIBE THE DECOMMISSIONING ADJUSTMENT INCLUDED IN THE SETTLEMENT AGREEMENT.

A. The Settlement Agreement makes the following adjustments to the Company's filed position:

- The obsolete inventory balance was updated to reflect the thirteen month average balance to correlate with the amount removed from working capital.
- The contingencies were removed from the estimated decommissioning costs. The Settlement Agreement grants Black Hills Power the opportunity to seek

recovery, in a future Black Hills Power rate case, of all costs for decommissioning not otherwise recovered from customers.

- An adjustment was made to reflect the accumulated deferred income taxes associated with the decommissioning adjustment. Please refer to the rebuttal testimony of Mr. Robert Hollibaugh for details.
- The amortization period was modified from five to ten years.
- The regulatory asset included in rate base is reduced by one and one-half years of amortization expense to reflect the average unamortized balance over the first three years of the amortization period in rate base.

Q. **ARE THERE ANY ADDITIONAL REVENUES ADDED TO THE TEST YEAR AS A RESULT OF THIS ADJUSTMENT?**

A. There are no additional revenues as a result of retiring and decommissioning the facilities. The salvage value credit was reflected in the lump sum decommissioning bid and resulted in a lower cost to customers.

Q. **MR. KOLLEN STATES THAT DECOMMISSIONING COSTS SHOULD NOT BE INCLUDED IN THE SETTLEMENT AGREEMENT BECAUSE THE COSTS WILL NOT HAVE BEEN INCURRED IN THE TWELVE MONTH PERIOD FOLLOWING THE HISTORIC TEST YEAR. DO YOU AGREE?**

A. No, I disagree with Mr. Kollen for a variety of reasons. First, as I discussed above, I disagree with Mr. Kollen's interpretation of ARSD 20:10:13:44. In particular, the Rule does not limit adjustments to known and measurable costs that were incurred in the twelve months following the historic test year. Second, the vast majority of the decommissioning costs that are reflected in the Settlement Agreement are supported by a fixed price contract that was provided by the Company in response to SDPUC Request No. 3-25. Black Hills Power selected the fixed price contract through a competitive bidding process as the lowest cost proposal that met the technical specification of the request for proposal. Third, the remaining costs that are included in the Settlement Agreement are supported by the Company's engineering cost estimate that was provided in response to SDPUC Request No. 3-23. As a result, the decommissioning costs that are reflected in the Settlement Agreement are known with reasonable certainty and measurable with reasonable accuracy.

Q. **HAS THE COMMISSION ACCEPTED ENGINEERING ESTIMATES FOR DECOMMISSIONING COSTS IN A RECENT APPROVED RATE CASE SETTLEMENT?**

A. Yes. In Docket EL12-046, Northern States Power Company used a decommissioning cost study as the estimate to determine the appropriate decommissioning accrual for its nuclear facilities in advance of incurring the costs. After removing the contingencies, Staff accepted Northern States Power Company's study as the basis for the decommissioning accrual and included the adjustment as part of the rate case settlement ultimately approved by the Commission. Here, the Staff and the Company used the Northern States Power

Company rate case settlement as a guide for the decommissioning adjustment included in this Settlement Agreement.

Q. MR. KOLLEN STATES THAT THE ACCUMULATED DEFERRED INCOME TAX ADJUSTMENT ASSOCIATED WITH THE DECOMMISSIONING REGULATORY ASSET IS INCORRECTLY CALCULATED. DOES THE COMPANY AGREE WITH MR. KOLLEN's POSITION?

A. No. The Company believes Mr. Kollen's treatment of accumulated deferred income tax is incorrect. Mr. Robert Hollibaugh addresses the accumulated deferred income tax calculation in his rebuttal testimony.

Q. ARE THERE ANY OTHER STATEMENTS THAT MR. KOLLEN MADE PERTAINING TO DECOMMISSIONING THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. Mr. Kollen indicates in his direct testimony on page 20, lines 6 – 8, that the Settlement Agreement reflects a ten year amortization of the decommissioning regulatory asset. Then, on page 42, line 23, through page 43, line 1-3, of Mr. Kollen's direct testimony, he states that the Settlement Agreement reflects a five year amortization of the decommissioning regulatory asset. Although I do not know if this inconsistency reflects an oversight in drafting or a misunderstanding of the terms of the Settlement Agreement, to the extent that Mr. Kollen incorporates a five year amortization in his numbers, his assumption is inconsistent with the terms of the Settlement Agreement.

Q. DID THE COMPANY REQUEST AN ORDER FROM THE COMMISSION TO DEFER ANY COSTS ASSOCIATED WITH THE DECOMMISSIONING OF THE RETIRED STEAM PLANTS?

A. No. The Company and Staff filed the Settlement Agreement on December 9, 2014, that established the amortization of decommissioning costs. The Settlement Agreement also grants Black Hills Power the opportunity to seek recovery, in a future Black Hills Power rate case, of all costs for decommissioning not otherwise recovered from customers. Since the Settlement Agreement was filed prior to the end of 2014 and is being considered in this rate proceeding, it was not necessary to request an accounting authority order allowing Black Hills Power to use deferred accounting for costs associated with the decommissioning of the retired steam plants.

Q. DO YOU BELIEVE THE COMMISSION SHOULD ACCEPT THE TREATMENT OF THE DECOMMISSIONING ADJUSTMENT?

A. Yes, I believe the treatment of the decommissioning adjustment that is reflected in the Settlement Agreement is appropriate and in conformance with past practices.

V. LIDAR ADJUSTMENT

Q. PLEASE EXPLAIN THE COMPANY'S FILED LIDAR ADJUSTMENT.

A. For purposes of background, at the time that Black Hills Power filed the pending rate case, it planned to perform LIDAR (Light Detection and Ranging) imaging of all of its 69 kV and 230 kV facilities in 2014. The need for and scope of the LIDAR surveying project is discussed in the direct testimony of Mike Fredrich.

The Company's filed position reflected the estimated cost of the LIDAR surveying project on its 69 kV transmission system. The project cost of $798,000 was shared with the joint owners of the 69 kV system, and Black Hills Power's share was amortized over five years to correspond with the expected frequency of the survey. The Company requested the unamortized amount be included in rate base.

Q. DOES THE SETTLEMENT AGREEMENT REFLECT AN ADJUSTMENT FOR THE LIDAR PROJECT?

A. Yes. The LIDAR project cost was updated to reflect the least cost, competitive bid contract, and the current allocation to the joint owners of the 69 kV systems in South Dakota and Wyoming. Black Hills Power's share of the costs was amortized over five years, and one-half of the unamortized balance was reflected in rate base. The accumulated deferred income taxes associated with one-half of the unamortized regulatory asset was reflected in the Settlement Agreement. The accumulated deferred income tax adjustment is covered in more detail in the rebuttal testimony of Mr. Robert Hollibaugh.

Q. MR. KOLLEN HAS SUGGESTED THAT LIDAR COSTS ARE NOT PROPERLY INCLUDED. DO YOU DISAGREE WITH MR. KOLLEN'S POSITION ON THE LIDAR ADJUSTMENT?

A. Yes. The Company has provided evidence to support the inclusion of these costs as a known and measurable adjustment. The request for proposal selected as part of the competitive bid process for the LIDAR project and the revised pricing was provided as a Supplemental Response to SDPUC Request No. 4-34 on October 15,

2014. The supporting work papers for the allocation of LIDAR costs to Black Hills Power was provided as a Supplemental Response to SDPUC Request No. 4-36, on October 15, 2014. The calculation included the actual allocation of the joint owners of South Dakota 69 kV system using the April 1, 2014, allocation. The Company provided Staff with a revised allocation of LIDAR costs to Black Hills Power on October 21, 2014, to remove the costs associated with the joint owners of the Wyoming 69 kV using the April 1, 2014, allocation. The email and supporting work papers were provided to Staff on October 21, 2014, and were provided in discovery in the Second Supplemental Response to SDPUC Request 4-36 on January 5, 2015.

Q: WHY DOES THE LIDAR ADJUSTMENT INCLUDED IN THE SETTLEMENT AGREEMENT REFLECT A KNOWN AND MEASURABLE ADJUSTMENT?

A. The project costs are based on a fixed price contract that was competitively bid to achieve the lowest cost for customers. The actual cost was approximately half of the original budget. The allocations to the joint owners of the 69 kV system in South Dakota and Wyoming were based on the current allocations in effect. The LIDAR surveying work and data acquisition was completed in the fourth quarter of 2014.

Q. DO COSTS NEED TO BE INCURRED BY OCTOBER 1, 2014, TO BE CONSIDERED KNOWN AND MEASURABLE?

A. No, the fixed price contract with costs incurred within 24 months of the last month of the test period qualify as an appropriate adjustment under ARSD 20:10:13:44. There are no anticipated reductions to test year costs or additional revenues expected as a result of this project.

Q. DO YOU BELIEVE IT IS APPROPRIATE TO REFLECT A TEN YEAR AMORTIZATION PERIOD?

A. No, a five year amortization period corresponds with the expected frequency of the LIDAR survey. A ten year amortization is arbitrary, and the annual amortization allocated to South Dakota of $64,107 based on a 5 year amortization is not of the magnitude that would justify a ten year amortization for rate mitigation purposes.

Q. DID THE COMPANY REQUEST AN ORDER FROM THE COMMISSION TO DEFER ANY COSTS ASSOCIATED WITH THE LIDAR PROJECT?

A. No. The Company and Staff filed the Settlement Agreement on December 9, 2014, that established the amortization of LIDAR costs for the Commission to consider. Since the Settlement Agreement was filed prior to the end of 2014 and is being considered in this rate proceeding, it was not necessary to request an accounting authority order allowing Black Hills Power to use deferred-accounting for costs associated with the LIDAR project.

Q. DO YOU SUPPORT THE TREATMENT OF THE LIDAR ADJUSTMENT THAT IS REFLECTED IN THE SETTLEMENT AGREEMENT?

A. Yes, I do.

VI. EMPLOYEE ADDITION/ELIMINATION ADJUSTMENT

Q. PLEASE EXPLAIN THE COMPANY'S FILED EMPLOYEE ADDITION AND ELIMINATION ADJUSTMENT.

A. Black Hills Power planned to hire nineteen unfilled and new positions as of January 28, 2014, payroll which are necessary to provide electric service to customers. In addition, the Company reflected the elimination of two employees after the January 28, 2014, payroll. The adjustment reflects the net employees' salary and benefit costs.

Q. DID THE SETTLEMENT AGREEMENT REFLECT THE ADJUSTMENT AS FILED?

A. No. Through Staff's audit, costs were only included for positions actually hired at the time of settlement negotiations. Adjustments were also made to reflect the 2015 known and measurable wage annualization and to include only the portion of labor costs charged to expense accounts.

Q. DOES MR. KOLLEN AGREE WITH THIS ADJUSTMENT?

A. No, he does not. Mr. Kollen's recommendation is to remove all costs associated with employee additions and eliminations.

Q. MR. KOLLEN ARGUES THAT THE COMMISSION SHOULD NOT ALLOW BUDGETED EMPLOYEE ADDITIONS IN RATES BECAUSE THEY DO NOT REFLECT ACTUAL EXPERIENCE. ARE MR. KOLLEN'S CONCERNS REGARDING BUDGETED EMPLOYEE

ADDITIONS AND ACTUAL EXPERIENCE ADDRESSED IN THE SETTLEMENT AGREEMENT?

A. Yes. Staff only allowed positions that have been hired. The Company has not recovered costs associated with budgeted employees in rates, so Mr. Kollen's comparison of actual to budget headcounts are invalid.

VII. UTILITY HOLDINGS ALLOCATION CORRECTION

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN THAT THE STAFF REVENUE REQUIREMENT MODEL INCLUDES AN ERROR IN ALLOCATION TO SOUTH DAKOTA FOR TRANSMISSION LOAD DISPATCH COSTS?

A. Yes, the Company agrees that no costs associated with transmission load dispatch, FERC Account 561, should be allocated to South Dakota.

Q. DOES BLACK HILLS POWER BELIEVE THAT THE SETTLEMENT AGREEMENT SHOULD BE MODIFIED TO CORRECT THIS ERROR?

A. No, it does not. Black Hills Power supports the Settlement Agreement and the resulting revenue requirement that has been presented to the Commission. If Staff and Black Hills Power litigated this proceeding, the Company and Staff would likely advocate different positions than what is reflected in Staff's revenue requirement model. Related thereto, on page 2 of the Settlement Stipulation, under Purpose, it states, "The Parties acknowledge that they may have differing views that justify the end result, which they deem to be just and reasonable, and, in light of such differences, the Parties agree that the resolution of any single issue, whether express or implied by the Stipulation, should not be viewed as precedent setting."

Notwithstanding the differences of opinion regarding the costs that comprise the revenue requirement, the Company and Staff ultimately agreed that the total revenue deficiency is $6,890,746. The revenue deficiency is material to the Company. The Company agreed to a two year rate moratorium, which can only be negotiated as part of a Settlement Agreement. The Company used the annual revenues authorized in this Settlement Agreement to determine if it could manage its business through a rate freeze. Black Hills Power agreed to significant concessions in order to reach a comprehensive resolution of all issues in this rate proceeding and as a result believes that the revenue deficiency should be maintained as presented to the Commission.

Q. WOULD THE COMPANY HAVE ACCEPTED THE ALLOCATION CORRECTION DURING SETTLEMENT NEGOTIATIONS?

A. Yes, it would have. However, the Company would also have had the opportunity to negotiate differently on other adjustments or request other adjustments to achieve the revenues necessary to recover its costs and earn a fair rate of return on investments.

Q. DO YOU HAVE ANY EXAMPLES OF COSTS THAT HAVE INCREASED THAT WERE NOT REFLECTED IN THE SETTLEMENT AGREEMENT?

A. Yes. After the Company reached a Settlement Agreement with Staff, it became aware that the production operations and maintenance ("O&M") costs associated with the Wyodak power plant ("Wyodak") were abnormally low during the historic test year and were not reflective of current production O&M costs. The total company Wyodak production O&M cost was $3,390,425 during the historic test year, and these costs were included in the Settlement Agreement. When compared to the costs incurred from October 2013 through September 2014, the total company Wyodak production O&M cost increased $459,738 for a total cost of 3,850,163. Please see Exhibit JTR-1 for details.

Q. PLEASE DESCRIBE THE PRODUCTION O&M COSTS ASSOCIATED WITH WYODAK?

A. Wyodak is operated by the majority owner, PacifiCorp, who invoices Black Hills Power on a monthly basis for the operating costs of the plant. The O&M costs are the routine costs of operating a power plant. Labor costs represent approximately 50% of the O&M costs, and the remainder of the costs is primarily associated with materials and outside services. Materials include production materials such as lime for environmental compliance and consumable items such as filters, piping, motors, and generators. Wyodak uses contractors for many services, such as ash hauling, security, janitorial, plant maintenance, and inspections.

Q. WERE THE ACTUAL PRODUCTION O&M COSTS ASSOCIATED WITH THE WYODAK POWER PLANT ABNORMALLY HIGH FROM OCTOBER 2013 THROUGH SEPTEMBER 2014?

A. No, please see the table below for Wyodak's production O&M costs from October 2010 through September 2014.

	10/1/10 - 9/30/11	10/1/11 - 9/30/12	10/1/12 - 9/30/13	10/1/13 - 9/30/14	4 Year Average
Wyodak O&M	3,566,605	3,560,008	3,390,425	3,850,163	3,591,800

Clearly, the historic test year was less than every other year during the four year period by at least $160,000, and adjusting the test year to the four year average would result in a total company adjustment of over $200,000. In addition, expenses associated with major maintenance outages were normalized during this time period through major maintenance accrual accounting.

Q. WOULD IT BE APPROPRIATE TO ADJUST THE HISTORIC TEST YEAR WYODAK O&M COSTS TO THE FOUR YEAR AVERAGE FROM OCTOBER 2010 THROUGH SEPTEMBER 2014?

A. No, the historic costs have not been adjusted for inflation, wage increases, and benefit changes. Known and measurable adjustments for labor and inflation would need to be reflected in the historic annual amounts in order for a normalization to reflect current costs. Applying three percent annual inflation to the October 2010 through September 2011 Wyodak production O&M expense yields a similar expense as the October 2013 through September 2014 Wyodak production O&M expense. The October 2013 through September 2014 Wyodak production O&M costs are conservative because they do not reflect the annualization of known and measurable wage and benefit changes for 2014 and 2015.

Q. HOW WOULD THE COMPANY PROPOSE TO RESOLVE THE UTILITY HOLDINGS COMPANY TRANSMISSION ALLOCATION ERROR IN STAFF'S MODEL?

A. The Company recommends making no adjustment to the Settlement Agreement. Staff's revenue requirement model reflects many concessions made by Staff and Black Hills Power. However, if the Commission modifies the Settlement Agreement to correct the transmission allocation error, the Company respectfully requests that the Commission also modify the Settlement Agreement to include an adjustment to reflect South Dakota's allocated share of Wyodak's production O&M costs from October 2013 through September 2014, as reflected on Exhibit JTR-1.

VIII. PENSION EXPENSE

Q. DID BLACK HILLS POWER PROPOSE AN ADJUSTMENT TO THE TEST YEAR LEVEL OF PENSION EXPENSE?

A. Yes. The Company proposed to reduce test year total company pension expense by approximately $508,000, as reflected on Schedule H-6. The Company's adjustment is based on a 5 year average of actual pension costs from 2010 – 2014.

Q. WHY DID THE COMPANY USE A 5 YEAR AVERAGE AS THE BASIS FOR THE ADJUSTMENT?

A. As provided in response to SDPUC Request No. 1-1, the table below summarizes the actual pension expense from 2010 to 2014:

Year	FAS 87 Cost	Year by Year Variation
2010	$2,925,853	
2011	1,819,156	-37.82%
2012	3,251,072	78.71%
2013	2,709,322	-16.66%
2014	976,122	-63.97%
Average	$2,336,305	

In particular, the annual total company pension expense has ranged between $976,122 and $3,251,072 from 2010 through 2014, and the annual percent change has ranged between a 64% decrease and a 79% increase. The Company proposed normalizing pension expenses as a result of the volatility in expense experienced from year to year.

Q. DOES THE SETTLEMENT AGREEMENT REFLECT A 5 YEAR NORMALIZATION OF PENSION EXPENSE?

A. Yes. As provided in the Settlement Stipulation, the Commission Staff and Black Hills Power agree this normalization period shall be used in future rate cases over the next five years unless there is an extraordinary event that makes a five-year normalization period unreasonable.

Q. IS MR. KOLLEN'S PROPOSED PENSION EXPENSE ADJUSTMENT REFLECTIVE OF NORMAL, ONGOING CONDITIONS?

A. No, I do not believe the total company 2014 pension expense of $976,122 is reflective of normal, ongoing pension expense. The 2014 pension expense was abnormally low compared to the previous four years, and the Company expects future annual pension expense to be significantly higher than the 2014 expense.

Q. MR. KOLLEN CHARACTERIZES THE COMPANY'S PENSION EXPENSE ADJUSTMENT AS "OPPORTUNISTIC." DO YOU AGREE?

A. No, I do not agree with Mr. Kollen's characterization of this adjustment. If the Company in fact was being opportunistic, Black Hills Power would have proposed no adjustment to the test year. As previously mentioned, the Company's proposed adjustment reduced costs by approximately $508,000. In addition, the Staff and the Company agreed to normalize pension expense in future rate cases over the next five years unless there is an extraordinary event that makes a five-year normalization period unreasonable. This condition in the Settlement Stipulation displays a commitment to normalization rather than an opportunistic objective.

Q. IS THERE ANY EVIDENCE THAT PENSION EXPENSE WILL INCREASE IN FUTURE YEARS?

A. Yes. Black Hills Power's actual total company 2015 pension expense is $2,056,581. The actuarial calculation to support the expense was provided as a Supplemental Response to SDPUC 2-13. This information was not available at the time the Company and Staff reached a Settlement Agreement. If the Commission were to accept Mr. Kollen's adjustment to reflect the 2014 pension expense, the Company would be deficient in 2015 at the total company level by over $1,000,000.

The 2015 pension expense shows continued volatility in pension expense, as the 2015 expense was approximately 111% greater than the 2014 expense. The 2015 pension expense supports the reasonableness of the normalized pension expense included in the Settlement Agreement.

IX. NEW DEBT ISSUANCE

Q. PLEASE BRIEFLY DESCRIBE THE NEW DEBT ISSUANCE THAT WAS REFLECTED IN BLACK HILLS POWER'S ORIGINAL FILING.

A. In its rate case Application, the Company reflected an issuance of new bonds to finance the anticipated costs related to the Cheyenne Prairie Generating Station and other capital expenditures. At the time the Application was filed, Black Hills Power anticipated adding approximately $50 million of long-term financing with an estimated all-in cost of debt of 5.67%.

Q. HAS THE COMPANY ACTUALLY ISSUED THE NEW DEBT?

A. Yes, the Company issued $85 million of 30 year First Mortgage Bonds with a coupon rate of 4.43% and an all-in cost of debt of 4.46%. The debt issuance was authorized by the Commission in Docket EL14-034.

Q. WHY IS THE ALL IN DEBT COST DIFFERENT THAN THE COUPON RATE?

A. The all-in debt cost includes the coupon interest rate and the debt issuance costs amortized over the life of the bonds. The debt issuance costs include the underwriting, legal, accounting, and other fees associated with issuing the bonds.

Q. DOES THE SETTLEMENT AGREEMENT REFLECT THE ACTUAL COST OF THE NEW DEBT ISSUANCE IN THE WEIGHTED COST OF CAPITAL?

A. Yes, the actual cost of the new debt is reflected in the Settlement Agreement.

Q. **MR. KOLLEN INDICATES THE ACTUAL DEBT COST IS 4.52% ON PAGE 50, LINES 1-2, OF HIS DIRECT TESTIMONY. IS THIS ACCURATE?**

A. No, it is not. Although Mr. Kollen references Black Hills Power's response to BHII Request No. 5 as support for the actual debt cost he assumed, the response does not support his assumption. Rather, the response states "Black Hills Power entered into an agreement to issue $85 million of 30 year First Mortgage Bonds with a coupon rate of 4.43." Additionally, Mr. Kollen failed to recognize that the Company provided the actual cost of debt in a supplemental response to SDPUC Request No. 2-57 on October 13, 2014.

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

A. Yes, it does.

Before the South Dakota Public Utilities Commission
of the State of South Dakota

In the Matter of the Application of
Black Hills Power, Inc., a South Dakota Corporation

For Authority to Increase Rates
In South Dakota

Docket No. EL14-___.

March 31, 2014

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Exhibits

None

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Laura A. Patterson and my business address is 625 9th Street (4th Floor), Rapid City, South Dakota 57701.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Black Hills Service Company, ("Service Company"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), as the Director of Compensation, Benefits and Human Resources Information Systems ("HRIS"). In my position, I am responsible for partnering with business leaders to design and execute compensation and benefits strategies and plans. I also provide input related to strategic planning, implementation and administration of compensation and benefits programs, executive plans, equity programs, non-qualified plans and other initiatives. My responsibilities also cover employees working for Black Hills Power, Inc. ("Black Hills Power" or the "Company").

Q. PLEASE BRIEFLY SUMMARIZE YOUR ACADEMIC AND PROFESSIONAL BACKGROUND?

A. I have more than 23 years of experience in compensation and benefits, with responsibilities including the development, management, administration and regulatory compliance of such plans. I began my current position as Director of Compensation, Benefits and HRIS for BHC in April 2009. Prior to this position, I spent 6 years as Director of Compensation, Benefits and HRIS and 2 years as Employee Benefits Manager, for PNM Resources, Inc. (PNMR), where I was responsible for managing and administrating all compensation and benefit programs for PNMR, its subsidiaries and for its joint venture business with Cascade Investments, Optim Energy. Prior to working for PNMR, I was employed as a Tax Manager and Human Capital Consultant for four years at Arthur Andersen, a global tax and consulting firm. In this position, I worked with organizations to identify, analyze and apply regulatory rules that govern structure, compliance, and administration of employee benefit plans. Prior to Arthur Andersen, I was employed as a Trust Officer at Mercantile Trust Company from 1995 to 1999 with responsibilities for managing and administration of profit sharing, 401(k), and pension purchase retirement plans sponsored by a wide range of clients. I have a Bachelor of Business Administration degree from the University of Iowa.

Q. HAVE YOU PROVIDED TESTIMONY IN REGULATORY PROCEEDINGS PRIOR TO THIS CASE?

A. Yes. I have previously testified in New Mexico PRC Case No. 06-00210-UT, a gas rate case, in New Mexico PRC Case No. 07-00077-UT, an electric rate case, in Texas PUC Case Docket No. 36025, an electric rate case, in Nebraska PUC Case Docket No. NG-0061, a gas rate case, and in Colorado PUC Case Docket No. 11-AL-382E, an electric rate case. I have also submitted testimony in Black Hills Power's last rate application with the South Dakota PUC, Docket No. EL 12-061. Finally, I testified on behalf of Cheyenne Light before the Commission in Cheyenne Light's 2009 and 2011 electric and natural gas rate proceedings.

Q. DESCRIBE YOUR PROFESSIONAL ASSOCIATIONS.

A. I served on the Corporate Board of Directors of the International Foundation of Employee Benefit Plans and currently serve on the Employee Benefits Committee for the U.S. Chamber of Commerce. I am also a Certified Retirement Services Professional.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. Black Hills Power.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I describe and support the general compensation program for BHC employees, and particularly the employees of Black Hills Power, including the variable compensation program and the equity compensation program. I explain why these programs and their associated costs are reasonable and necessary to attract, motivate and retain well qualified and competent employees to support utility operations. Black Hills Power employees, both non-union and union, participate in the compensation and benefit plans sponsored by BHC.

I also describe and support the general benefits programs and policies for BHC employees, particularly the employees of Black Hills Power, including the health, welfare and retirement benefits, and explain why those programs and their associated costs are reasonable and necessary.

My testimony specifically supports employee compensation related adjustments, including base salary, variable compensation, equity compensation, retiree healthcare, pension plan, pooled medical, and 401(k) plan, that are part of the overall benefits adjustment. Finally, my testimony will explain the adjustments related to personnel due to the suspension of operations at certain facilities.

II. COMPENSATION PHILOSOPHY AND PROGRAMS

Q. WHAT IS BHC'S GENERAL COMPENSATION PHILOSOPHY?

A. BHC's long-term success depends on operational excellence, providing reliable products and services to our customers, and investing wisely to ensure present and future strength. BHC's strength allows us to invest in our utility infrastructure and systems to improve the safe, reliable and affordable service our customers and communities depend on. To consistently achieve these outcomes, BHC must attract, motivate and retain employees to achieve appropriate business results. For these reasons, BHC promotes a compensation program that supports the overall operational excellence and customer service objectives, based on principles designed to:

- attract, motivate, retain and encourage the development of highly qualified employees;
- provide compensation that is competitive;
- promote the relationship between pay and performance;
- promote overall performance that is linked to our customers and shareholders; and
- recognize and reward individual performance appropriately.

All compensation programs are designed to be strategically aligned, externally competitive, internally equitable, personally motivating, cost effective and legally compliant.

Q. PLEASE DESCRIBE BHC'S COMPENSATION PROGRAMS.

A. There are two primary components to the compensation program – Base Salary and Variable Pay programs.

- Base Salary: Base salary represents the fixed portion of an employee's total cash compensation opportunity. Base salary compensation is determined by the market value of the job, the experience level of the employee, and specific performance standards and competencies. Base salaries are reviewed on an annual basis and merit salary increases are based on individual performance and contributions. Base rates of pay for Black Hills Power's union employees are established under the terms of the collective bargaining agreement with the International Brotherhood of Electrical Workers ("IBEW") Local 1250.
- Variable Pay: Variable Pay is pay that is "at risk" and is not fixed or guaranteed. Variable Pay is only earned and awarded based on achievements against specific performance-based goals. All BHC employees (non-union and union) participate in the Annual Incentive Plan (AIP) which is described in detail later in this testimony.

Q. PLEASE EXPLAIN BHC'S PHILOSOPHY ON BASE PAY COMPENSATION.

A. Base pay is intended to reflect the median of the market for similar positions in similar companies. Overall, our goal is to target direct compensation (base salary and variable pay / annual incentives) at the median of the appropriate market when our operating results approximate average in relation to our peers.

There are twenty-three (23) pay grades which are used for all non-executive, non-union jobs. Each grade has a minimum, midpoint, and a maximum pay level. This means that the pay ranges within the grades are competitive with what other companies pay for similar positions. All jobs are compared to the market, where data exists, and placed in the grade where the midpoint of the range is closest to the average market rate for that job. In 2009, Towers Watson conducted an independent market review of the BHC's positions and benchmarked each position. Each position was placed in the appropriate salary grade, reflecting the market median values. Subsequent to the Towers Watson study, the BHC Human Resources Compensation Department periodically reviews each position in the company and compares it to credible market survey data to ensure that current compensation remains within the competitive range.

Market rates are determined by utilizing compensation survey data where companies report actual compensation paid to employees by position. The survey most widely used by BHC is from Towers Watson, as they are recognized nationally as the leader in the energy services / utility market place.

Q. IN ADDITION TO THE TOWERS SURVEY, ARE THERE ANY OTHER SURVEYS THAT BHC UTILIZES TO ENSURE THAT ITS OVERALL COMPENSATION IS COMPETITIVE IN COMPARISON WITH OTHER COMPANIES?

A. Yes. BHC also utilizes surveys conducted by Aon Hewitt, Mercer, the Edison Electric Institute (EEI), ECI, the EAPDIS LLC, Ed Powell, and other surveys, including several specific to wages by state. The surveys provide compensation and other data for each position by company size, revenue, and number of employees so that BHC can match each of its positions to positions in the market that are most similar in duties and most similar for the company size/revenue.

Q. HOW DO THE COMPANY'S COMPENSATION STRATEGIES COMPARE TO THE CURRENT MARKET?

A. The BHC Compensation Department reviews the pay structure annually to see how the structure and pay practices reflect the market. As of October 21, 2013, the average base pay for non-union employees of Black Hills Power was 95% of the market median, indicating Black Hills Power employees' base pay rates were lower than the market median. Compensation is considered to be competitive to the market at a range of 95% to 105% of the market median, so compensation for Black Hills Power is at the lower end of this range.

Q. DOES BHC HAVE A VARIABLE COMPENSATION COMPONENT OF ITS TOTAL COMPENSATION PHILOSOPHY?

A. Yes. The Black Hills Corporation Annual Incentive Plan (the "AIP" or the "Plan") is designed to motivate and reward employees for achieving and exceeding goals that benefit our customers and our shareholders. The AIP is designed to reward eligible employees, including both non-union and union employees of Black Hills Power, who contribute to the success of the BHC and/or their assigned Business Unit; reward employees who contribute to the quality of service provided to customers including, but not limited to, the provision of safe, reliable and affordable service; motivate work performance and behavior that supports the Corporation's financial and non-financial goals and increase the employee's understanding of the Corporation's business objectives and performance.

III. <u>COMPANY ANNUAL INCENTIVE PLAN</u>

Q. PLEASE DESCRIBE BHC'S ANNUAL INCENTIVE PLAN.

A. The purpose of BHC's AIP is to promote BHC's pay for performance philosophy, to provide competitive incentive opportunities that are consistent with other companies in the industry, and to focus employees on important performance objectives. The AIP is an important component of the total pay package necessary to ensure BHC is competitive with market practices for employees. In addition, the AIP directly links pay with performance, and therefore total compensation expense varies with BHC's performance on measures important to the customers, and provides a tool to align employees' interests with customer and community interests.

Q. WHO IS ELIGIBLE TO PARTICIPATE IN THE AIP?

A. All regular full-time and part-time employees, both union and non-union, who are hired and working by October 1 of the plan year are eligible to participate in the Plan for that plan year. Part-time employees who work a minimum of 20 hours per week are eligible for a pro-rata award based on their actual wages for hours worked. Pro-rata awards for the number of months actively employed at each eligibility level during the plan year will also be paid to Participants who are hired, promoted, retire or have other job changes during the year.

Q. WHAT PERFORMANCE GOALS ARE MEASURED UNDER THE AIP?

A. An eligible employee can earn an incentive award based on that employee's performance toward goals designed to achieve business unit operational performance targets. The components of the incentive award for the test year were as follows:

- An employee could qualify for up to 50% of the maximum possible award for goals tied to customer satisfaction, cost control, safety, reliability, operations efficiency, expense reductions and other operational measures;
- An employee could qualify for up to 25% of the maximum possible award for the achievement of direct business unit operating income goals, including initiatives on cost control, continuous improvement and improvements in operations efficiencies; and
- An employee could qualify for up to 25% of the maximum possible award if BHC realizes established earnings per share ("EPS") targets.

Each goal is measured independently. Goal performance that meets or exceeds the threshold level will be used to calculate the incentive award. Achievement of financial results is not a condition to award incentive for achievement of other goals. An employee can earn from 0 to 1.50 times the target percentage incentive based on achievement against each of the AIP goals. Performance below threshold results in a zero payout for the associated goal. Achievement of a goal's "target" performance results in a payout of 100% of the payment relative to that goal. There is also a Maximum payout, which means that if performance exceeds target, no more than 1.50 times the target payment will be made relative to that goal.

Q. HOW DOES THE AIP PROVIDE VALUE TO CUSTOMERS?

A. The AIP provides direct and indirect value to customers in a number of different ways. For example, AIP goals are aligned with BHC's high-level objectives and strategic framework. Business unit goals are primarily designed to improve the performance of utility operations by focusing on improvements to operational excellence, safety, reliability, and customer satisfaction. Examples of Black Hills Power's business unit goals include:

- Continuous improvement in results from customer satisfaction surveys. These results are measured each quarter.
- Service reliability metrics.
- Increase in number of completed service orders per day.
- Reduction in labor cost per service order.

- Reductions in O&M expense resulting from Continuous (Process) Improvement projects.
- Reduction in number of lost time accidents, preventable vehicle accidents, and OSHA recordable accidents.

BHC must maintain a skilled and motivated workforce in order to provide safe, reliable and affordable service and products. To do so, it is important to pay our employees at rates competitive to rates paid by similar utilities and other companies with which we compete for employees. Because the actual base salaries for Black Hills Power's employees fall somewhat below the market median levels, total compensation would be significantly less competitive without the incentive plan component. An employee's total cash earnings potential (base salary *plus* AIP incentive award) depends on both competitive base salary and on a competitive AIP incentive compensation opportunity awarded for the achievement of key operating and strategic goals.

Q. HOW WOULD AVERAGE BASE SALARIES BE AFFECTED IF AIP INCENTIVES WERE ELIMINATED?

A. If BHC did not offer employees the opportunity to earn AIP incentive compensation, BHC would need to make-up the difference by increasing base salaries in at least an equivalent amount, which would result in higher fixed costs for salaries and benefits. An alternative to variable compensation would be for BHC to raise all employees base pay to reflect the median variable compensation earnings provided by other utilities. While this would provide a competitive total compensation rate that is "fixed and measurable", it would de-link those costs with customer performance measures and increase overall costs as many of our benefits are also tied to base pay rates.

Q. DO YOU BELIEVE THAT THE AIP IS AN IMPORTANT ELEMENT OF EMPLOYEE RETENTION?

A. Yes. If BHC were to eliminate its variable pay program and did not replace that compensation with base pay, employees would be much less likely to stay with BHC because their total compensation would significantly lag what other utilities were paying for the same positions. Coupling this risk with the loss of experience that Black Hills Power will realize over the next eight years due to retirements, results in a significant and immediate business risk.

Q. ONE OF THE INCENTIVE GOALS UNDER THE AIP RELATES TO THE COMPANY'S OPERATING INCOME OR EARNINGS PER SHARE ("EPS") PERFORMANCE. DO CUSTOMERS BENEFIT FROM COMPANY EPS PERFORMANCE IN LINE WITH INCENTIVE PLAN TARGETS?

A. Yes. Earnings Per Share is an easily recognized benchmark for successful and productive companies that are meeting their customers' needs. They provide company-wide objective measures of performance that cannot reasonably be separated from customer interest. Both shareholders and customers benefit from strong EPS performance - - they are not mutually exclusive. Two primary drivers of EPS are expense management and debt costs. Customers benefit from receiving service from a company that is able to effectively manage its costs. When the Company is managing its costs, rate cases are less frequent. When a rate case is required, the requested increase is less than would otherwise be required.

Q. DO INDIVIDUAL EMPLOYEES CONTRIBUTE TO THE COMPANY'S EPS PERFORMANCE?

A. Yes. Each employee primarily contributes to the financial success of the Company through the prudent actions he or she takes to control costs, work efficiently, and drive operational excellence. By setting an EPS target, and monitoring company performance against the target throughout the year, employees receive immediate feedback regarding performance. Providing incentive compensation related to meeting financial performance drives employees to cost-conscious behavior that is beneficial to customers.

Q. HOW ELSE DO CUSTOMERS BENEFIT FROM A STRONG EPS RECORD?

A. As described in the Direct Testimony of Brian G. Iverson, Black Hills Power must maintain financial integrity to access capital at reasonable costs. A strong financial position provides the financial flexibility necessary to meet the ongoing demand for utility services. Credit ratings agencies compare quantitative measures of a company's financial performance, including EPS, to determine a company's credit ratings. These ratings have a direct impact on the cost of Company's debt, both for acquiring debt and refinancing higher cost debt, which directly impact customer rates. Through strong EPS performance, the Company is able to maintain or even improve its credit ratings, resulting in a lower cost of debt for customers. Because Company earnings are such an important consideration in rating agency evaluations of the Company, it is critical that employees receive incentives to maintain strong financial performance, which ultimately results in lower costs for customers.

IV. COMPANY LONG-TERM INCENTIVE PROGRAM

Q. PLEASE DESCRIBE BHC'S LONG-TERM INCENTIVE PROGRAM.

A. The Company provides a long-term incentive program on a limited basis to key employees who are responsible for various aspects of management and business results. These long-term incentives include restricted stock and performance share awards. Restricted stock is granted to key employees and vests ratably over a 3-year period. The purpose of the 3-year vesting period for both the restricted stock and the performance shares is to get retention of key employees.

Performance shares, if any, are based on achievement against established criteria measured over a 3-year period and are made at the conclusion of that 3-year period. The performance share component measures relative performance of BHC against other utilities - - it is about operational performance and metrics. BHC focuses on top quartile performance in all areas and performs at this level on a sustained basis. This operational excellence is recognized by the market and using performance measures to compare BHC to its peers provides focus for key employees in these areas. This operational excellence also results in lower costs to customers in very direct ways. For example, BHC's continued high performance for power plant availability is recognized by the market with higher stock performance, but impacts the customers directly through lower cost of service, high reliability, and high customer satisfaction.

Both forms of equity grants under the long-term incentive program are intended to provide participants with incentives for excellent performance, to promote teamwork and to motivate, retain and attract the services of participants who make significant contributions to the success of the company and its operational goals.

V. INDUSTRY COMPENSATION COMPARISONS

Q. DO OTHER COMPANIES IN THE UTILITY INDUSTRY USE COMPARABLE VARIABLE AND LONG-TERM COMPENSATION MECHANISMS?

A. Yes. Other utilities do provide incentive or variable compensation as part of their compensation packages, as do companies in other industries. Other utilities also provide key employees with long-term incentives designed to retain these key employees and to motivate them to achieve operational and strategic goals. Without similar annual and long-term plans, BHC's total compensation package would not be competitive with other utilities and BHC would be at risk for retention of its key employees.

Q. ARE YOU AWARE OF ANY STUDIES THAT SUPPORT THIS CONCLUSION?

A. Yes. Aon Hewitt Associates, an international business consulting firm that specializes in compensation issues, conducted a survey of broad-based variable pay plans in 2013 titled "Variable Compensation Measurement (VCM) Report – U.S. Edition," which includes 125 companies, including 25 energy / utility companies. Results from the survey indicate the following:

- 90% of participating companies offered at least one broad-based variable compensation plan covering 99% of total U.S. employees, an increase from 89% in 2007 and from 80% in 2002 as companies continue to turn to variable pay as a means to attract, retain and award performance. All energy / utility companies offer at least one broad-based variable incentive plan and all cover 100% of their employees.
- 74% of the participating companies in the survey have an annual incentive program with a plan design similar to BHC's AIP, where awards are based on the combined achievement of Company financial and business unit operating performance.
- 88% of the participating companies reported the benefits realized from their variable pay plan and the improved business results outweighed the cost.
- Notable outcomes reported by companies with a variable pay plan similar to the AIP include reduced costs, increased productivity, increased quality, increased customer satisfaction, and increased employee morale.

Other surveys published in 2012-2013 include:

- Mercer: 93% of employers provide short-term incentive or variable pay plans, an increase from 78% in 2004.

- World at Work: 84% of employers provide short-term incentive or variable pay plans, an increase from 77% in 2004. Of those providing a short-term incentive plan, 98% of hourly employees (average payout was 5%) and 100% of salaried employees (average payout was 12%) are eligible under the plan.
- Buck Consulting: 87% of utilities in the survey provide a short-term incentive plan to all employees.
- Kenexa: 88.5% of energy and utility companies in the survey provide a short-term incentive plan to all employees.

Q. **HOW DOES BHC MAKE IMPROVEMENTS TO ITS AIP?**

A. Through its annual strategic and operational planning process, BHC routinely evaluates the effectiveness of the plan in meeting its goals. These goals are modified and continually refined to drive continued operational excellence and performance improvements. BHC also continuously evaluates the AIP design to ensure that it remains competitive and comparable to other utilities.

VI. COMPANY RECOVERY OF EMPLOYEE COMPENSATION EXPENSES

Q. **SHOULD THE COMPENSATION MERIT INCREASE BE APPROVED?**

A. Yes. Recovering the actual amount of employee compensation expense is necessary to attract and retain the high quality of employees that are needed to serve the customers of Black Hills Power. Under existing economic conditions, independent surveys reflected that more than 97% of US-based companies will award merit pay increases during 2014, with an average budget of 3% to 4%. Non-union employee pay changes are effective each March, with the most recent increase effective March 4, 2013 and the next scheduled merit increase to be effective March 3, 2014. The company has a non-union merit increase budget for 2014 of 3.50%. The union salary increases for the period April 1, 2013 through March 30, 2014 range from 3.0% to 3.5% by position and the wage increase will be 3.25% effective April 1, 2014. Increases in employee compensation are known and measurable, and these increases in employee compensation are supported by extensive reviews of competitive market data.

Without merit increases, BHC would further lag the median pay for these positions, significantly increasing retention and performance risk, and the company will incur higher costs for turnover and related issues. A summary of independent surveys regarding merit pay follows:

- Mercer: The survey of 634 employers reflects that energy and utility employers plan to provide merit increases to employees in 2014, with an average budgeted increase ranging from 3.0% to 4.0%.
- Aon Hewitt: The 2013-2014 survey of 1,096 employers reflects planned 2014 merit increases, with an average budget of 3.1%. The energy and utility employers in the survey reflect a merit budget average of 3.7%.
- Towers Watson: The 2013-2014 survey of 633 employers reflects planned 2014 merit increases, with an average budget of 3.1%. This survey does not reflect utility specific information.

- World at Work: The 2013-2014 survey of 1,834 employers reflects a 3.1% merit increase budget average for 2014 across all industries. The average merit increase budgets for energy and utility companies average up to 4.1%.

Simply put, the merit increases and the union wage increases will be incurred, and the overall compensation to Black Hills Power employees is fair and competitive as tested against prevailing market comparisons.

Q. **SHOULD THE COMPENSATION INCREASE BE APPROVED FOR UNION EMPLOYEES?**

A. Recovering the actual amount of employee compensation expense is necessary – as described above – to attract and retain the high quality of employees that are needed to serve the customers of Black Hills Power.

The ratified contract between Black Hills Power and the IBEW Local 1250 Local Bargaining Unit requires an increase in union employee compensation of 3.0% to 3.5% depending on job classification effective April 1, 2013; and an increase of 3.25% effective April 1, 2014. Black Hills Power's union employees also participate in the AIP under the terms of the contract. Accordingly, the April 1, 2014 rate increase of 3.25% and AIP compensation for union employees is representative of the amount that Black Hills Power will be obligated to pay while its rates will be in effect. Black Hills Power's union employee compensation adjustment qualifies as a known and measurable change over the four-year contract.

VII. COMPANY BENEFITS AND PERIODIC REVIEW

Q. PLEASE DESCRIBE THE BENEFIT PLANS THAT BHC PROVIDES TO ITS BLACK HILLS POWER EMPLOYEES?

A. BHC offers a combination of company-provided and voluntary benefits. Employees are enrolled in certain company-provided benefits automatically and BHC pays the costs (for example, short-term and long-term disability benefits). Employees choose whether or not to participate in the voluntary benefits and they pay a portion or all of the costs. These company-provided and voluntary benefit programs consist of: (1) medical, dental and vision plans, (2) flexible spending accounts, (3) life insurance and accidental death and dismemberment insurance, (4) paid time off, (5) retirement, and (6) other benefits including educational assistance, holidays and other time away from work, business travel accident insurance, rewards & recognition and wellness programs.

Q. WHAT BENCHMARKING HAS BEEN CONDUCTED TO EVALUATE COST/PERFORMANCE LEVELS?

A. BHC solicits a number of independent reviews from external organizations and consulting firms such as Towers Watson, Aon Hewitt, Mercer, etc. These reviews cover a wide range of compensation and benefit program designs and costs including compensation and benefit programs, HR function administrative expenses, and market data for positions. BHC compares its benefit programs and costs with companies from the utility sector and from general industry to ensure the company can attract and retain employees with the necessary skills. BHC utilizes multiple nationally recognized third-party surveys and also conducts customized surveys where appropriate and necessary. These benchmarking surveys allow BHC to evaluate the competitiveness and efficiencies of its benefit programs and costs compared to other companies in the market. If a program does not meet performance, cost or efficiency expectations, it is reviewed to determine the root cause and the options or alternatives available. BHC closely monitors market practices and benchmark data for costs to maintain competitive and cost effective programs.

Q. WHAT TYPE OF OVERSIGHT IS IN PLACE TO ENSURE THAT BHC'S COMPENSATION AND BENEFIT PROGRAMS ARE THOSE THAT ARE MOST BENEFICIAL FOR THE SUPPORT OF THE OPERATING COMPANIES' UTILITY SERVICE?

A. The BHC Human Resources Department, in partnership with the business unit leaders and company management, develop annual budgets and long-range plans (5 years), including compensation, benefit and other programs supporting the business' goals and objectives. HR and key operating personnel manage these budgets and review all programs for effectiveness, cost and any proposed modifications. All costs are modeled to determine impacts to cost and are benchmarked against the market parameters to ensure competitiveness, cost effectiveness, and reasonableness.

Q. ARE YOU AWARE OF OTHER STATE COMMISSIONS THAT HAVE APPROVED THE EMPLOYEE COMPENSATION AND BENEFIT STRUCTURE PROPOSED IN THIS PROCEEDING?

A. Yes. Through rate case settlements and contested proceedings, commissions in Nebraska, Iowa, Wyoming and Colorado in both gas and electric rate cases have approved this employee compensation and benefit structure. BHC places emphasis on maintaining a common employee compensation structure and program. The same is true for its proposal related to its employees living in or supporting our Black Hills Power customers.

VIII. ADJUSTMENTS DUE TO SUSPENSION OF CERTAIN OPERATIONS

Q. HAS BLACK HILLS POWER SUSPENDED OPERATIONS AT ANY OF ITS FACILITIES?

A. Yes, Black Hills Power placed its Osage and Ben French facilities into economic shutdown. Black Hills Power has suspended operations at its Neil Simpson I facility. As indicated in the testimony of both Vance Crocker and Mark Lux, these three facilities will be decommissioned as a result of the EPA's National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial and Institutional Boilers.

Q. WHAT ADJUSTMENTS WERE MADE RELATED TO PERSONNEL DUE TO THE SUSPENSION OF OPERATIONS AT THESE FACILITIES?

A: Adjustments have not been made for the employees that were employed at Osage and Ben French when those facilities were placed into economic shutdown. The affected employees retired, took alternate positions with the Company, or left the Company. Black Hills Power has had a labor reduction due to the suspension of operations at Neil Simpson I. However, these employees were retained by Black Hills Power as part of its strategic workforce planning.

More specifically the Neil Simpson I employees have been retained and are assigning part of their time to the common Neil Simpson complex facilities. These employees also direct charge other specific units, such as Cheyenne Light and Black Hills Wyoming, and common facilities for work performed at those facilities. Retention of these critical skills is necessary to ensure the continued provision of safe, reliable and cost-effective service to customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

Rebuttal Testimony
Christopher J. Kilpatrick

Before the South Dakota Public Utilities Commission
of the State of South Dakota

In the Matter of the Application of
Black Hills Power, Inc., a South Dakota Corporation

For Authority to Increase Rates
In South Dakota

Docket No. EL14-026

January 15, 2015

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher J. Kilpatrick. My business address is 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota 57701.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by Black Hills Utility Holdings, Inc. ("Utility Holdings"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), as the Director of Regulatory.

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

A. I am testifying on behalf of Black Hills Power, Inc., ("Black Hills Power" or the "Company").

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to explain and support the portion of the Settlement Stipulation ("Settlement Agreement"), reached between Black Hills Power and the South Dakota Public Utilities Commission Staff ("Staff"), that pertains to corporate allocations. I also explain why the positions advanced by Black Hills Industrial Intervenors' ("BHII") witness Mr. Lane Kollen on this subject are not appropriate.

related to the support of all utility customers. Based on the total call volume and total call minutes, it was determined that the cost driver for these costs is the number of customers. Therefore, the costs should be allocated based upon the Customer Count Ratio. This change in allocation is annualized in the Settlement Agreement.

Q. **MR. KOLLEN PROPOSED AS AN ALTERNATIVE TO THE SETTLED TREATMENT OF THIS ADJUSTMENT THAT THE COMPANY ONLY BE PERMITTED TO RECOVER THE COSTS INCURRED DURING THE HISTORIC TEST YEAR WITH NO ADJUSTMENT. DO YOU AGREE WITH MR. KOLLEN'S PROPOSED ADJUSTMENT TO UTILITY HOLDINGS COSTS?**

A. No. Mr. Kollen's proposed adjustment is flawed because the October 2012 through September 2013 Utility Holdings costs do not reflect current operations costs or any known and measurable increases that have occurred since the end of the test year.

Q. **IN HIS TESTIMONY, MR. KOLLEN IS CRITICAL OF THE INFORMATION THE COMPANY SUPPLIED TO SUPPORT CORPORATE ALLOCATIONS. DID THE COMPANY PROVIDE EVIDENCE OF KNOWN AND MEASURABLE CHANGES?**

A. Yes. The Company provided a description of some of the major cost drivers in the Utility Holdings budgeted increase in the Supplemental Response to BHII Request 6. In the Supplemental Response to SDPUC Request 3-96 provided on October

22, 2014, the Company also provided the actual costs from September 2013 through August 2014 with supporting work papers.

Q. HAVE THE EMAILS REFERENCED IN MR. KOLLEN'S DIRECT TESTIMONY ON PAGE 39, LINES 6 – 9, BEEN PRODUCED IN DISCOVERY?

A. Yes, the Company provided the email responses to Staff's informal discovery and the associated attachments in the Second Supplemental Response to SDPUC Request 3-96, on January 5, 2015. The emails contained the monthly Utility Holdings charges by FERC account from the general ledger for September 2013 through August 2014, a revised calculation of the customer records and collection expense allocation annualization, and the supporting work paper for the labor annualization. Notably, the information reflected in the emails is virtually identical to the information that was produced in October 2014 in the Supplemental Response to SDPUC Request 3-96.

Q. WAS MR. KOLLEN ALSO CRITICAL OF SOME OF THE COST INCREASES THAT ARE REFLECTED IN THE SETTLEMENT ADJUSTMENT?

A. Yes, he was critical of the cost increases to FERC Account 920, administrative salaries, and to FERC account 923, outside services.

Q. PLEASE EXPLAIN THE COST DRIVERS THAT INCREASED THE UTILITY HOLDING CHARGES TO FERC ACCOUNT 920, ADMINISTRATIVE SALARIES, FROM THE TEST YEAR.

Before the South Dakota Public Utilities Commission
of the State of South Dakota

In the Matter of the Application of
Black Hills Power, Inc., a South Dakota Corporation

For Authority to Increase Rates
In South Dakota

Docket No. EL14-026

January 15, 2015

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Kyle D. White, 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by Black Hills Service Company ("Service Company"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), as Vice President of Regulatory Affairs. My areas of responsibility include regulatory affairs for the regulated utility subsidiaries of BHC.

Q. FOR WHOM ARE YOU TESTIFYING ON BEHALF OF TODAY?

A. I am testifying on behalf of Black Hills Power, Inc. ("Black Hills Power" or "Company").

Q. DID YOU PROVIDE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to support the Settlement Stipulation ("Settlement Agreement"), reached between Black Hills Power and the South Dakota Public Utilities Commission Staff ("Staff"). I specifically address: (1) the status of settlement; (2) the FutureTrack Workforce Development program; (3) incentive compensation; and (4) class cost of service. I also explain why the positions taken by the opposing parties on these topics are unpersuasive. Lastly, I reasonable and documented expenses that exceed the approved Future Track regulatory account will be brought before the Commission for reimbursement."

V. INCENTIVE COMPENSATION

Q. HAVE ANY OF THE PARTIES TO THIS RATE CASE DEMONSTRATED THAT INCENTIVE COMPENSATION IS AN "IMPRUDENT" EXPENSE FOR INCLUSION IN BLACK HILLS POWER'S REVENUE REQUIREMENT?

A. No, the BHII's have only alleged through Mr. Kollen's testimony that for subjective reasons the Commission should reject board and management decisions regarding the required compensation practices needed to staff the organization and meet the obligation to serve. No evidence was presented that the total compensation paid to employees was imprudent or unreasonable based upon what the market pays employees for similar positions.

Q. IS IT COMMISSION PRECEDENT TO DENY RECOVERY OF INCENTIVE COMPENSATION EXPENSE TIED TO OPERATING AND FINANCIAL PERFORMANCE, AS MR. KOLLEN STATES ON PAGE 35 OF HIS TESTIMONY?

A. Although I am not aware of a specific Commission decision regarding the inclusion of incentive compensation for determining a utility's revenue requirement, I do know that the Commission has approved rate case settlements where the revenue requirement included expenses for employee incentive compensation. In fact, some of Mr. Kollen's clients in this docket have been parties to prior settlements approved by the Commission that included incentive compensation expense within the revenue requirement.

Q. MR. KOLLEN STATES ONE OF THE REASONS TO DENY RECOVERY OF INCENTIVE COMPENSATION EXPENSE IS THAT, "THE COMPANY'S FINANCIAL PERFORMANCE IS A DIRECT FUNCTION OF THE REVENUES RECOVERED FROM CUSTOMERS, INCLUDING THE RATE INCREASES THAT ARE AUTHORIZED BY THE COMMISSION." DO YOU SHARE THIS VIEW?

A. Revenues are an important component of the financial performance of all businesses. What Mr. Kollen has failed to acknowledge is that a company's ability to serve customers and meet customer demands is also a direct function of the revenues recovered from customers. If revenues are inadequate to support the needs of the business, then changes to the business must occur or customer and or owner expectations will not be met. He also fails to acknowledge that the financial performance of any company is also a direct function of how well the company controls costs and expenses. Effective cost controls in a business where revenue levels are regulated is a critical aspect of avoiding even higher rate requests in the future.

Q. ON PAGE 36 OF MR. KOLLEN'S TESTIMONY HE STATES, "THERE IS AN INHERENT CONFLICT BETWEEN LOWER RATES AND GREATER FINANCIAL PERFORMANCE." DO YOU AGREE?

A. No. Financial performance is not solely the result of rate increases. Financial performance (profitability) for a utility is primarily influenced by the level of its expenses. Profitability can be enhanced through efficiency and lowering of costs, increasing sales or increasing prices.

Q. ANOTHER POINT MR. KOLLEN MAKES IS THAT, "THE REVENUE REQUIREMENT SHOULD NOT EMBED RECOVERY OF AN EXPENSE THAT IS BASED ON PERFORMANCE" BECAUSE, "IF THE COMPANY IS ENSURED RECOVERY OF THE EXPENSE FROM CUSTOMERS, THEN THERE IS NO PERFORMANCE THAT IS AT RISK OR THAT MUST BE ACHIEVED IN ORDER TO RECOVER THAT EXPENSE." DO YOU AGREE?

A. No, I do not. The Company's incentive compensation practices are designed to incent and reward employees for achieving planned operating and financial results. The practices are designed to encourage employee initiative and other behaviors that will result in a sustainable and successful company. There are numerous benefits for customers when a company's employees receive incentive income to achieve these results.

Q. MR. KOLLEN TELLS THE COMMISSION IT "SHOULD NOT INCENTIVIZE THE COMPANY TO SEEK GREATER RATE INCREASES AND ACT AGAINST THEIR CUSTOMERS' INTERESTS." DO YOU BELIEVE THAT FUTURE SOUTH DAKOTA REGULATORS WOULD FAIL TO SET JUST AND REASONABLE RATES IF THE

COMMISSION APPROVED A SETTLEMENT THAT INCLUDES EXPENSES FOR INCENTIVE COMPENSATION?

A. No. The Staff and the Commission have demonstrated exceptional competence in auditing and assessing Black Hills Power's business and ensuring that rate changes are just and reasonable. If Mr. Kollen's premise is that incentive compensation leads to more frequent rate increases, then this would have come to be true once the Company began utilizing incentive compensation practices. Black Hills Power's rate case history does not support this outcome.

Q. MR. KOLLEN STATES ON PAGE 36 OF HIS TESTIMONY, "THIS FORM OF INCENTIVE COMPENSATION IS PRIMARILY DIRECTED TOWARD ACHIEVING SHAREHOLDER GOALS, NOT CUSTOMER GOALS." DO YOU AGREE?

A. No. As explained in the direct testimony of Laura Patterson, incentive compensation is a component of most utilities' and corporations' direct compensation paid to attract and retain qualified employees. Our employment locations are frequently in the less populated locations of the Country. This means employees coming to these locations will have few local employment options if they choose to leave. Their spouses will also see their employment options limited. Historically, we could expect employees to stay and "earn" their pension. This retention mechanism has diminished since the Corporation froze its defined benefit pension plan. With these factors already in play, a competitive total direct compensation offering is essential for meeting our obligation to serve South Dakota electric customers.

Q. MR. KOLLEN STATES THAT BOTH THE RESTRICTED STOCK EXPENSE AND THE PERFORMANCE PLAN EXPENSE ARE TIED TO THE COMPANY'S FINANCIAL PERFORMANCE. IS THE RESTRICTED STOCK EXPENSE TIED TO FINANCIAL PERFORMANCE?

A. No. As explained in Ms. Patterson's direct testimony on page 14, "restricted stock is granted to key employees and vests ratably over a 3-year period. The purpose of the 3-year vesting period for both the restricted stock and the performance shares is to get retention of key employees." Once restricted stock is granted to a key employee the only requirement for pay-out is the employee's continued employment.

Q. HAS BLACK HILLS POWER BEEN GRANTED RECOVERY OF INCENTIVE COMPENSATION EXPENSES IN OTHER JURISDICTIONS?

A. Yes, last summer the Wyoming Public Service Commission approved a settlement with the Office of Consumer Advocate that included 100% of the requested incentive compensation in the revenue requirement.

Q. DOES THE SETTLEMENT WITH STAFF INCLUDE 100% OF THE COMPANY'S INCENTIVE COMPENSATION COSTS?

A. No, as Mr. Kollen points out, $666,000 has been removed from expense for determining the proposed revenue requirement.

Q. IF THE COMMISSION ACCEPTED MR. KOLLEN'S POSITION AND REMOVED THE REMAINING INCENTIVE COMPENSATION FROM THE UTILITY'S REVENUE REQUIREMENT, WHAT WOULD BE THE RESULT?

A. I believe he has recommended, on page 35, that the entire incentive compensation expense be disallowed. This would be the equivalent of the Commission lowering Black Hills Power's authorized return on equity by in excess of 20 basis points. The substance, depth and nature of Mr. Kollen's testimony in no way justifies a punitive outcome for the Company for utilizing normal and reasonable employee compensation practices that are prevalent across the utility industry and other companies in the Black Hills region. For the Commission to remove from the Settlement Agreement incentive compensation expense would be contrary to the principle of utility regulation which requires a utility be allowed a reasonable opportunity to recover actual costs prudently incurred in providing service to its customers. The Settlement Agreement as presented will result in just and reasonable rates for Black Hills Power's South Dakota customers.

VI. <u>CLASS COST OF SERVICE</u>

Q. MR. WHITE, HAVE YOU READ THE ANSWER TESTIMONY FILED ON BEHALF OF BHII BY MR. BARON?

A. Yes, I have.

BEFORE THE SOUTH DAKOTA
PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC., A SOUTH DAKOTA CORPORATION, FOR AUTHORITY TO INCREASE RATES IN SOUTH DAKOTA	) DOCKET NO. EL14-026

DIRECT TESTIMONY AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

BLACK HILLS INDUSTRIAL INTERVENORS

PUBLIC DOCUMENT

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

DECEMBER 2014

going forward.

C. The Commission Should Remove the Company's Adjustment to Increase Pension Expense Based on Five-Year Average

Q. Please describe the Company's request to increase pension expense based on a new methodology compared to the 2014 known and measurable expense.

A. The Company proposes a new, five-year average methodology to calculate pension expense instead of using the 2014 pension expense, which is known and measurable and consistent with the Commission's historic approach to reflect such changes within the twelve month post-test year period.

The pension expense in the test year was $2.608 million ($2.845 million total Company). The Company's new methodology results in adjusted pension expense of $2.142 million. In contrast, the actual known and measurable 2014 pension expense is $0.895 million. The Company's request exceeds the actual known and measurable 2014 pension expense by $1.247 million without justification.

Q. Should the Commission adopt a new methodology for pension expense in this proceeding?

A. No. First, the Company's proposed adjustment is nothing more than an opportunistic response to the reduction in the expense in 2014. The Company has offered no evidence that the pension expense will swing upward to the five year average in future years. Thus, the proposed adjustment reflects nothing

M. Other Proposed Settlement Issues

Q. **Are there other issues specifically identified in the Proposed Settlement with which you agree and that you recommend the Commission adopt?**

A. Yes. The Proposed Settlement includes an adjustment of $0.380 million to increase revenues for the effects of weather normalization, an adjustment of $0.219 million to reduce the allocation of the Neil Simpson rent revenue and expense, and an adjustment of $0.244 million to reduce the allocation of the Neil Simpson common steam plant. I recommend that the Commission adopt those proposed adjustments.

IV. MISCELLANEOUS ISSUES

A. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

PUBLIC DOCUMENT - CONFIDENTIAL DATA REDACTED

1976 WL 419254 (S.D.P.U.C.), 18 P.U.R.4th 291

Re Northwestern Public Service Company

(F-3055)

South Dakota Public Utilities Commission

December 29, 1976

Before P. K. Ecker, chairman, and Jack Weiland and Norma Klinkel, commissioners.

By the COMMISSION:

Northwestern Public Service Company, hereinafter company, of Huron, South Dakota, a supplier of retail electric service to customers in South Dakota, on July 17, 1975, filed with the South Dakota Public Utilities Commission, hereinafter PUC *292 or commission, new electric rate schedules proposing an annual rate increase of $8,450,000 to be placed into effect September 1, 1975.

The PUC received an attorney general's opinion as to whether or not the PUC had jurisdiction over the company's rate filing. In the opinion dated August 15, 1975, the attorney general of South Dakota concluded that the PUC could not accept the new rate schedules insofar as they were applicable to municipalities which had entered orders regarding prior company rate applications that were then and continue to be under appeal in South Dakota courts. On August 19, 1975, the company petitioned the South Dakota supreme court for a writ of mandamus requiring the PUC to take jurisdiction of, and act upon, the company's rate application. After hearing thereon on September 17, 1975, the South Dakota supreme court issued its order granting the prayer for relief requested by the company.

On September 29, 1975, the PUC issued its order of suspension suspending the new rate schedules, but pursuant to statute, permitted the company to implement the rate increases effective October 18, 1975, conditional upon the filing of a bond to assure consumers any refunds of amounts collected in excess of what ultimately be found to be just and reasonable herein. Pursuant to said order, the company began implementing the increased rates, under bond, in billing cycles to customers on and after October 18, 1975. By orders dated November 10 and November 13, 1975, the PUC directed the company to collect the increased rates only with respect to the actual service rendered by the company on and after October 18, 1975, and not billing cycles on and after October 18, 1975. This resulted in a refund by the company to its customers of the rate increases which were improperly obtained by the company because of its billing cycle, as opposed to its rendering electric service, method of collection.

Petitions to intervene in this proceeding were filed by the South Dakota Electric Consumers consisting of a consortium of seven municipalities in South Dakota, and by the Department of Commerce and Consumer Affairs, state of South Dakota. The PUC granted both petitions to intervene.

Thereafter, a procedural schedule was worked out which provided for the filing of testimony, the hearing thereon, and the briefing subsequent thereto. The PUC also scheduled a series of consumer input hearings in regard to the application of the company.

On the 27th day of September, 1976, the public utilities commission issued its decision and order in the above-entitled proceeding. On the 12th day of October, 1976, Northwestern Public Service Company appealed said decision and order to the circuit court, sixth judicial circuit, state of South Dakota. Thereafter, a hearing was conducted on the 27th day of October, 1976, before the Honorable Robert A. Miller concerning whether or not said appeal should be dismissed pursuant to, and in accordance with, the public utilities commission's motion to dismiss, and regarding whether a stay pending final disposition by the court should be entered. The court held that said proceeding should be remanded to the public utilities commission for rehearing upon the assertions made in the affidavit of Al Schmidt, president of Northwestern Public Service Company, submitted for the first time on appeal. Thereafter, specifications of error were filed by company, and the commission ordered that staff and intervenors reply *293 thereto. Further, the commission ordered that company, staff, and intervenors reply to all said submissions of each to the other on or before the 7th day of December, 1976, and that each file and serve proposed findings of fact, conclusions of law, and order for commission consideration. Upon careful review and examination of the proposed findings of fact, conclusions of law, and order submitted by company, commission staff, and SDEC, the commission finds that the proposed findings and conclusions submitted by company and commission staff should be rejected. The commission further finds that proposed findings and conclusions submitted by SDEC are in substantial accordance with the commission's disposition of this proceeding and certain portions thereof have been incorporated in the commission's decision and order entered today.

Discussion and Analysis

I.

Rate Base

1. Year-end versus Average Rate Base .

The company argues that the end-of-period rate base is a better predictive model for the future and that even the end-of-period calculations will understate actual investment while the proposed rates are in effect. The company further argues that inflation and attrition will have their effect and that the use of an end-of-period rate base is the best way to attempt to alleviate those problems. The company also states that the matching of revenues and expenses to rate base is not a regulatory necessity and that the company had computed revenues and expenses to match an end-of-period rate base. The company asserts that this would result in a small excess of revenues over expenses although no actual figures were ever provided by the company in this regard.

The staff and SDEC argue that the use of an average rate base is the only accurate method of properly matching revenues and expenses with rate base. South Dakota Electric Consumers further argue that customer growth and revenue growth are just as inevitable as investment growth; and that average test-year investment produces accurate test-year revenues. The staff argues that the company's failure to present a comprehensively normalized cost of service consistent with company's end-of-period rate base is sufficient, in and of itself, to preclude the use of end-of-period rate base.

In its specification of error upon rehearing and affidavit and exhibits of Al Schmidt, company assigns as error the PUC's adoption of an average rate base and rejection of a year-end rate base. The company therein advances no new evidence, but rather simply restates its previous arguments made to the commission. The commission finds that company has not sustained its burden of proof regarding this matter.

It is fundamental to a proper test year or test period that investment and operating costs and revenues match and be consistent each with the other. Unless costs and revenues match, the test year or period is not a proper one for fixing just and reasonable rates. The relationship between costs and revenues for the test period used and the validity of that relationship is one of the most crucial aspects this commission must consider in determining just and reasonable rates. The inclusion of costs without matching revenues will produce *294 excessive rates, while the inclusion of revenues without matching costs will deny the utility just and reasonable rates.

This fundamental rate-making principle of matching costs and revenues applies whether an average or year-end rate base is used. Neither company, staff, nor intervenor deny the absolute necessity for matching costs and revenues.

The evidence adduced at hearing established that the average rate base previously adopted by this commission matches costs and revenues and that the matching principle has not been adhered to by the company in the year-end rate base it proposes in this proceeding. Company did not propose to roll into the test year increased sales levels that would be achieved through the use of an enlarged year-end plant. Company does not deny that it did not completely match costs and revenues, but it argues that its failures in this respect are insignificant. However, no evidence was ever introduced by company regarding this matter and company simply failed to sustain its burden of proof.

Company apparently argues that because its investment in plant is increasing, a year-end rate base methodology is warranted. However, steadily increasing investment in plant alone does not warrant the use of the year-end method. Again, a proper matching of costs and revenues is still required and necessary to avoid the distorting impact of large additions to plant.

The allegations contained in the affidavit of Al Schmidt and in the specifications of error upon rehearing that average rate base employed by the commission ignores company investment upon which company claims it is entitled to a return is without merit. The average rate base deprives the company of nothing to which it is entitled, but rather is the only method advanced in this proceeding which provides a proper matching of costs and revenues.

2. Depreciation Adjustment for Big Stone Plant

Both the staff and SDEC deducted from rate base the average of an estimated year's depreciation for Big Stone plant. The company argues that, since the Big Stone plant was actually not in service during most, if not all, of the test year, such an adjustment for depreciation deprives the company of the opportunity to earn a return on, and recover for, the amount included in said adjustment.

The staff argues that recognition of the Big Stone plant in rate base requires that such an adjustment for depreciation be made. The staff also argues that the logical conclusion of the company's theory would require that the entire Big Stone plant not be recognized in rate base at all.

South Dakota Electric Consumers argues that the failure to make an adjustment for depreciation would result in the ratepayer paying twice for such depreciation, once as an expense and once through a return earned by the company on rate base.

Because the Big Stone plant was not in service during the test period, under accepted regulatory practice, and investment in Big Stone could justifiably have been excluded from rate base in its entirety. However, because of the magnitude, timing, and operational impact of this new plant on Northwestern Public Service Company's system, staff and SDEC recommended that the investment in Big Stone be included in rate base as though it had been in service during *295 the entire test period. In its decision and order, the commission adopted staff and SDEC's recommendation.

Company does not contest the inclusion in rate base of the investment it made in Big Stone plant, except to the extent that it objects to an average rate base, the same having been previously addressed above. The company asserts that the commission erred in reflecting in the provisions for accumulated depreciation a full year's depreciation expense for Big Stone plant. Company's position is untenable in that it is axiomatic that the inclusion of the investment in Big Stone in rate base requires that depreciation not be ignored. Company simply cannot have the investment included in rate base and depreciation associated therewith ignored. Moreover, if company's position were to prevail, it would totally violate the principle that requires matching of investments, revenues, and expenses in regulatory proceedings.

3. Allowance for Funds Used during Construction

The company argues that its allowance for funds used during construction, hereinafter AFUDC, calculation is a net of tax calculation and is determined by reasonable procedure. The company argues that any restatement of AFUDC is improper in that it would require a retroactive effect and would further require the company to restate in its books any resulting adjustments for all prior periods in question. The company further argues that there is no support in the record for the restatements of AFUDC proposed by the staff in the staff's briefs.

The staff argues that, if company is using a net of tax rate for its AFUDC calculations, flow through of the tax benefits associated with such construction is an incorrect procedure. The staff in its briefs, recalculated the company's AFUDC rates to what it determined to be a gross rate using proposed Federal Power Commission methods. The staff further argues that a net of tax rate for such calculations results in a disservice to the ratepayer. It is the staff's further position that the staff's calculations of a gross rate are the only proper calculations to be used in this proceeding.

South Dakota Electric Consumers argues that the company has not shown that it uses an aftertax rate in its calculations. South Dakota Electric Consumers further argues that if the rate is deemed inadequate by the company, it is within the company's power to change such rate accordingly. South Dakota Electric Consumers states that its witness established the capitalization rate as being arbitrary by the introduction of a 'plug figure' as the imputed cost rate of common equity in order that the company could attain a predetermined total. Further, SDEC contends that the company's witness, Mr. Walker, conceded that the company was using incremental costs to determine its AFUDC rate which would clearly result in double counting by the company.

Company contends that the interest rate it uses on borrowed funds to compute AFUDC is a 'net of tax' or 'aftertax' rate. In its specifications of error upon rehearing and in the affidavit of Al Schmidt, company assigns as error the commission's determination that the interest used by the company is not a 'net of tax' rate.

Company made the identical argument with respect to the AFUDC rate in two rate proceedings which were held by the SDEC consortium of cities when said cities had jurisdiction over electric retail *296 rates prior to the 1st day of July, 1976. The cities rejected the company's claim in each of the two rate cases and company appealed same. On appeal to the respective circuit courts, the cities' decisions were affirmed in their entirety, including the determination that company's AFUDC rate was not a 'net of tax' rate. Company has persisted in this position in this proceeding, but clearly has not sustained its burden of proof in regard thereto.

Company's calculation of its alleged 'aftertax' AFUDC rate is a contrived rate at best. Although company was requested to provide extemporaneous work papers showing the manner in which the AFUDC rate had been originally established, company failed to do so. The evidence adduced at hearing discloses that company's after the fact calculation is arbitrary. For example, the imputed cost rate of common equity is a 'plug figure' which is introduced into the calculation at whatever stage is necessary in order to attain a predetermined answer.

Company witness Walker admitted on cross-examination a fatal deficiency in the alleged 'net of tax' AFUDC rate utilized by company. Said rate is based upon the incremental costs of new capital issuances each year. Inasmuch as those incremental costs are also included in the overall cost of capital on which the rate of return is computed, the effect of company's methodology is to account for the same costs twice. Hence, there is a double counting effect in regard to the company's methodology, and this simply cannot and will not be allowed by this commission.

4. Construction Work in Progress

The company claims that it is unable to earn a proper return on construction work in progress, hereinafter CWIP, for which no AFUDC is claimed unless such CWIP is allowed in rate base. The company contends that accounting for such AFUDC, given the nature of the construction project, is not justified from a practical standpoint. Further, the company contends that the argument of the staff and SDEC that such property is not used and useful to the ratepayer is in error as such property is very likely to be in service while the new rates are in effect.

South Dakota Electric Consumers argues that this CWIP should never be included in rate base because such plant is not currently used and useful. South Dakota Electric Consumers further argues that whether or not the company charges AFUDC thereon is within the company's own discretion.

The staff argues that SDCL 49-34A-19 precludes the recognition of any type of CWIP in rate base.

Company proposed to include in the rate base CWIP on which the company had elected not to capitalize AFUDC. The commission excluded all CWIP from the rate base whether or not AFUDC was capitalized thereon. Company has assigned as error the exclusion from the rate base of CWIP on which no AFUDC was capitalized.

The commission adheres to its exclusion of CWIP. Construction work in progress is excluded because the property is not in service; i.e., is not used and useful in serving current ratepayers. The fact that AFUDC has not been taken on some of the CWIP has no relevance in regard to this issue. The decision not to capitalize AFUDC on certain CWIP is company's decision. There is no prohibition to capitalizing AFUDC on all CWIP. Company has the right to make the choice, but it may not *297 thereafter attempt to have the ratepayers pay a return on investment by company that is not devoted to rendering electric service to the ratepayers as a consequence of company's aforementioned decision.

The issue of whether CWIP should be included in rate base has not been settled among regulatory commissions. However, this commission finds that the proper treatment is to exclude CWIP from rate base, and this commission adheres to that view in this proceeding. Exclusion of CWIP in no manner deprives the company of any property rights or of anything else to which it is entitled from the ratepayers. However, the inclusion of CWIP in rate base imposes unwarranted and excessive costs on the ratepayers.

5. Fuel Inventory

The company argues that it is necessary to reprice fuel inventories using the average quantity of fuel on hand multiplied by the price for such fuel at the end of the test year. It is the company's position that such a technique will best predict the company's investment in fuel inventories while the new rates are in effect in that fuel prices appear to be rising. Further, although such repricing results in a higher amount than the actual investments for the nine-month period following the test year, the company did not reprice materials and supplies because of the complexity involved. If such repricing of materials and supplies had occurred, the materials and supplies inventory of the company would have more than made up for the difference in the excess costs claimed by the company as a result of the repricing of its fuel inventory.

South Dakota Electric Consumers argues that the company should be allowed to earn a return only on actual investment rather than on replacement or current values.

The staff argues that the company should only be allowed a return on actual investment, not upon replacement value. The staff further argues that, to the extent increased fuel costs are recovered through the fuel adjustment clause, a double recovery would clearly result to the company.

Company included an amount for fuel inventory in the rate base based upon repricing of the average quantity of fuel on hand during the test year at fuel prices in effect at the end of the test year. The commission rejected the repriced fuel inventory and included fuel inventory in the rate base at the average of the actual investment in fuel inventory during the test year. The commission finds no reason whatsoever for changing its earlier findings in regard to this matter and rejects the company's assignments of error with respect thereto.

Initially, it is to be noted that the use of an amount for fuel inventory based on prices at the end of the test period is inconsistent and in conflict with the use of averages in determining other items of rate base.

Secondly, spot pricing or spot conditions are also inappropriate methods to be utilized for rate-making purposes. Spot pricing or spot conditions simply do not reflect the conditions that may prevail over a period of time.

Finally, company has in effect proposed a replacement value for fuel inventory. Since depreciated original cost—i.e., an actual investment—must by statute be the basis for this commission's determination, company's proposal is rejected.

*298 *6. Construction-related Materials and Supplies*

The company argues that there is no double counting for such materials and supplies because in a possible future rate case, such items would not appear in inventory but rather in plant in service. The company further argues that the withdrawal of an item from such inventory will probably result in replacement which would restore said inventory to its former level which is nothing more than additional investment, not double counting. The company also argues that the investment in such items is a continuing one and that the only practical way to compensate investors for the use of such capital is to include these items in rate base.

South Dakota Electric Consumers argues that it is not appropriate to include construction-related materials and supplies in rate base just as it is not appropriate to include any other construction work in progress in rate base. South Dakota Electric Consumers further argues that these materials will become a part of CWIP and will eventually earn a return as plant in service.

The staff argues that SDCL 49-34A-19 precludes rate base treatment of such construction-related materials and supplies in their entirety.

The commission previously ruled that construction materials and supplies are not properly included in rate base of company. In its specifications of error upon rehearing, company takes exception to this exclusion. The commission rejects company's assignment of error regarding this matter and again finds and determines that construction-related materials and supplies are to be excluded from company's rate base.

This issue concerns the appropriate working capital allowance for the materials and supplies component thereof which constitutes part of company's rate base. Working capital allowance is an allowance for operations, not construction. Consequently, only those items which are applicable to ongoing or continuous day-to-day operations of company are properly included in the materials and supplies component of working capital.

Materials and supplies used in the company's construction program are capitalized and become part of plant in service on which the ratepayers pay a return. If they were also to be included in working capital, which becomes a part of rate base, ratepayers would then be paying a return on the same investment in plant twice; i.e., once when the materials and supplies are included in rate base as part of working capital and again when those materials and supplies become part of plant in service. Hence, the commission concludes that it is totally proper and necessary to exclude such materials and supplies from rate base.

7. Three Per Cent Investment Tax Credit

The company argues that it has properly treated the 3 per cent investment tax credit through the use of normalization with subsequent amortization. The company further argues that, as shown in later legislation, the company's treatment of such tax credit amounts is the one intended by Congress.

South Dakota Electric Consumers argues that such amounts should be immediately flowed through to operating income on the basis that ratepayers should be charged each year only for income taxes actually paid by a utility. South Dakota Electric Consumers further argues that state commissions are *299 not prohibited from flowing through such amounts immediately and that any subsequent action taken by Congress in regard to the flow through of such credits does not apply.

The staff argues that the company has failed to establish that such normalized taxes would ever be paid by the company. The staff emphasizes that the PUC does have discretionary authority to approve tax normalization if it is shown that a true tax deferral will occur as opposed to a permanent tax savings by the company. The staff concludes that the company has not proven that normalization would result in a true tax deferral.

The 1962 Revenue Act, 26 USCA §§38, 46 to 48, inclusive, provided an investment tax credit. The credit was in no sense a tax deferral but rather a complete tax break in the amount of the credit. Company charged the ratepayers with those taxes that would have been paid if there had been no such investment tax credit and reflected the actual tax savings in the balance sheet as unamortized investment credit. By charging ratepayers for federal income taxes that company has never paid and will never be required to pay, company has accumulated a balance of deferred investment tax credits. Said balance in the unamortized investment tax credit account represents ratepayer contributions resulting from the practice of collecting from ratepayers amounts which are never paid by company in taxes to the federal government. Neither investors nor the federal government has attributed any amount to the balance of said account.

Because the company is amortizing the balance in its deferred investment tax credit account over the service life of its property, the full amount of the current balance will eventually be credited to the ratepayers in the form of reduction in taxes charged to them. However, during the interim period, company has the use of the funds made available by ratepayers in the amount of the balance in the account in the form of plant investment. If the unamortized balance in the account is not deducted from the company's rate base, ratepayers will be required to pay a return on plant investment made with ratepayer-contributed funds. A comparable situation arises wherein the company issues debt securities and will eventually repay the amount of the indebtedness. However, unlike the treatment company proposes for the deferred investment tax credit account, in the area of debt securities, the obligation for company to repay the principle in no manner nullifies the requirement that company pay interest on the debt until repayment is made. The commission found and determined on the evidence before it that the unamortized balance of investment tax credits deferred under the 1962 Revenue Act should be deducted from the company's rate base. Company, in its specifications of error, assigns error to this ruling. The commission rejects this assignment of error by company.

Company has argued that the rate base reduction is contrary to good regulatory practice. The commission finds the opposite to be true. When the 1962 Investment Tax Credit statute was enacted, various regulatory commissions provided for the treatment of the credit in two manners. Several jurisdictions provided that the tax saving would be immediately 'flowed through' to operating income; i.e., that the ratepayer would be charged during each year only for income tax actually incurred by the utility.

Company has not implemented the *300 'flow-through' method. Rather, company has treated the tax saving under the other generally adopted method—i.e., 'normalization'—wherein the ratepayer is charged a fictitious tax expense and the excess tax charges are accumulated in a deferral account and flowed back to income over the period of the service life of the property giving rise to the credit.

Company also asserts that rate base reduction in the amount of the unamortized balance is contrary to the intent of Congress because of later congressional enactments; i.e., §203(e) of the 1964 amendment to the 1962 Revenue Act and the 1971 Revenue Act. However, the aforementioned 1964 enactment was applicable only to federal regulatory agencies, and the 1971 enactment does not address any regulatory matters related to the 1962 Investment Tax Credit provision. The commission finds that company's argument has no merit and reaffirms the commission's earlier decision that rate base deduction of unamortized investment tax credits is proper and is not in conflict with federal law.

8. *Working Capital*

The company argues that SDEC's working capital allowance is improper in this case. The company's basic argument in this regard appears to be that the formula relied upon by SDEC is one which already takes into account all factors in the cash working capital formula. Therefore, the consideration of any discrete items already taken into account by the formula, such as ad valorem taxes, results in double counting to the company's detriment. The company further argues that SDEC has failed to show that the accruals which it uses in the formula represent actual funds. The company also contends that if such an allowance is to be made, compensating bank balances must be taken into account and that by so doing, would result in a positive rather than a negative cash working capital allowance. Specifically, in its initial brief, the company cites four basic defects in SDEC's approach. The first defect cited by the company is that funds accrued for current liabilities are not a proper source for financing materials and supplies. Secondly, in the alternative, even if such financing were possible, SDEC has not made proper calculations in making its determination. Thirdly, that SDEC did not use a proper working capital formula in that it did not consider the cost of compensating bank balance requirements. Funds are not available to finance materials and supplies in that accruals do not necessarily represent funds available to the company.

South Dakota Electric Consumers argues that the 45-day formula is one that was developed prior to the age of computerized billing and is stacked in favor of the utility. South Dakota Electric Consumers therefore argues that available offsets should be used to reduce rate base whether the reduction be greater or lesser than the rate base inclusion for cash working capital.

The staff argues that the working capital approach taken by SDEC is incorrect because it fails to acknowledge the impact of the Big Stone plant on the cost of service. The staff further argues that the correct application of the effects of Big Stone plant would result in a negative working capital of approximately 50 per cent of that shown in SDEC's case.

In response to the staff's position, SDEC asserts that its calculation did include the effects of Big Stone plant and that the staff's development of a cash *301 working capital allowance improperly included fuel and purchased power.

Neither the affidavit of Al Schmidt nor company's specifications of error upon rehearing delineate the exact assignment of error company claims respecting the commission's decision regarding working capital.

A working capital allowance is properly includable in company's rate base only to the extent that funds for the working capital requirement are supplied by investors because investors are entitled to earn a return on the funds they so supply for working capital purposes just as investors are entitled to a return on the funds they provide that are invested by company in plant used and useful in rendering electric service to company's South Dakota consumers.

Alternatively, if working capital funds are available to the company through ratepayer contributions, those contributions relieve investors of the necessity of providing additional working capital funds to company. To the extent that working capital requirements are met through ratepayer contributions, the working capital allowance is properly reduced by that amount. If the working capital allowance included in rate base were not reduced by such ratepayer contributions, ratepayers would be paying a return to company on funds that the ratepayers had themselves contributed.

When ratepayer contributions are in such amounts as to exceed the working capital requirement of company, not only is it proper to exclude any working capital allowance from rate base, but, in addition, it is proper to reduce the rate base by the amount that ratepayer contributions exceed the working capital requirement. This deduction in company's rate base is proper in that ratepayer contributions, to the extent that they exceed working capital requirements, relieve the investors of providing capital funds for investment in plant. If the excess over working capital requirements were simply ignored, ratepayers would again be called upon to pay a return on investment in plant derived from the ratepayers' own contributions.

Company's witness also recognized the propriety of ignoring or disregarding ratepayer contributions in determining whether a working capital allowance was needed, and if so, in what amount. However, company made no reduction in rate base for ratepayer contributed funds in excess of company's working capital requirements. Moreover, ratepayer contributed funds even exceeded the amount required for materials and supplies for working capital purposes. Yet, company erroneously failed to offset this working capital requirement for materials and supplies and further erroneously failed to give full effect to the ratepayer contributions.

The commission in its previously entered decision and order adopted the formula utilized by SDEC witnesses and the results thereof in determining the working capital requirement and allowance in light of ratepayer contributions made to company. South Dakota Electric Consumers' witness developed a cash working capital requirement utilizing an assumed 45-day lag between the payment of company costs and the collection of revenues from customers. Said assumption is a commonly utilized method in utility regulation in the absence of a lead-lag study performed by a particular utility. Moreover, usage of the formula proposed by SDEC is favorable to company in that it overstates the cash working capital requirements anyway.

*302 South Dakota Electric Consumers' witness also determined the amount of working capital available to company through ratepayer contributions resulting from the fact that company receives revenues from its ratepayers which reimburse company for certain costs long in advance of the time when company utilizes such funds to pay those costs. As noted by SDEC's witness, company collects from its ratepayers taxes—e.g., ad valorem, unemployment, and social security—substantially in advance of the time when such amounts collected must be used to pay those taxes.

The commission holds that company is entitled to include in rate base a working capital requirement, but only to the extent that it is not supplied by ratepayer contributions. In this proceeding, ratepayer contributions were properly used to offset both company's cash and materials and supplies working capital requirements.

II.

Increased Payroll and Pension Expense

The company argues that this adjustment is necessary in that it is an actual increase in costs to the company because, in order for an employee to become more productive, increasing capital expenditure and other costs are necessarily incurred by the company. The company further argues that the staff's Exhibit No. 9 actually shows an increasing labor cost for per kilowatt-hour of energy sales.

The staff argues that the salary increases resulted in increased productivity. The staff further argues that even if such increases did not result in increased productivity, the company's management should not have approved the increases initially. Further, the staff argues that any capital expenditures which result in increased productivity have already been recognized in the staff's rate base and rate of return recommendations.

South Dakota Electric Consumers only contested the amount of the increase and the company has recognized that it was in error in its original calculation. The company has accepted SDEC's calculation in regard thereto.

Company increased payroll and pension expenses to reflect a full year of wage and pension increases granted during and after the test-year period. In its decision and order, the commission disallowed company's adjustment. Company specifies the commission's ruling as error in its specifications of error upon rehearing.

Company claims that incurred increased payroll and pension expenses are allowable even though such increased costs have been offset by increases in productivity. This commission finds that it is proper to disallow test period adjustments for wage and salary increases on the basis of increased productivity where, on a unit of sales basis, the cost of labor has not increased despite increased wages and related expenses. The evidence before the commission fully supports this finding that increased productivity has, in fact, offset payroll and related increases. Accordingly, the commission rejects the adjustment proposed by company in regard thereto.

Moreover, as previously noted, part of the adjustment company would make to test-year wages and pension costs were incurred beyond the test period. The commission finds that it is improper to increase test-year costs on the basis of an out-of-period increase in costs without at *303 the same time taking into account the revenue side of the equation which reflects increases in the post-test period. While costs may go up, so may sales and revenues. Without matching costs and revenues, the test period is improperly distorted. This commission will not allow such distortion.

III.

Advertising and Miscellaneous General Expenses

The commission found that the amounts spent by company for advertising were reasonable, but that miscellaneous general expenses as proposed by company included certain items which were not necessary for the rendition of electric service and which company conceded. Upon full review of the record and the subsequent submissions by company, commission staff, and intervenors, the commission finds that its previously entered findings regarding this matter are proper.

IV.

Regulatory Expense

The company contends a two-year amortization period for such expenses is proper given the company's recent history. The company further contends that the disallowance of excessive regulatory expenses by SDEC is improper in that the SDEC witness did not know the recent rate case experience of the companies he used for comparison purposes. Finally, the company contends that the SDEC witness failed to identify any specifically improper expenditure the company has made in regard to rate cases, and, hence, SDEC has failed to prove that any of the company's regulatory expenses are excessive.

South Dakota Electric Consumers argues that the company has not adequately supported its claimed expenses for regulatory cases and that based upon SDEC's comparisons, the company should be allowed a smaller regulatory expense than that proposed by the company.

The staff recommended a three-year amortization period, but did not argue for implementation of the same in its briefs.

The commission adopted the recommendation of SDEC for an annual rate case expense allowance of $50,172. The commission further found that amortization thereof should be made over a three-year period, said amortization period not having been proposed by SDEC in regard to its recommendation.

South Dakota Electric Consumers' recommendation of $50,172 was based upon a comparison of the regulatory expense level claimed by the company with the average regulatory expenses experienced by other electric utility companies and company was double the amount of said average. South Dakota Electric Consumers' witness testified that on the basis of the comparisons he had made and his experience in regulatory matters, company's claimed $230,257 was excessive. South Dakota Electric Consumers' witness went on to state that he was not proposing that the company not spend said amount, but rather that the ratepayers should not be charged for excessive expenditures by company.

Company, in its specifications of error upon rehearing, contends that the commission erred in disallowing the amortization of $223,533 of regulatory expense per annum and that amortization *304 of the amount recommended by the SDEC over a three-year period was erroneous and in conflict with the amount recommended by SDEC.

The commission finds that the company's assignment of error regarding the level of rate case expense should be rejected. However, the commission finds that amortization of the amount recommended by SDEC was in error. The amount of $50,172 recommended by the SDEC witness and adopted by the commission is an annual amount. Hence, it is not appropriate for said amount to be amortized over a three-year period.

Secondly, the decrease to booked rate case expense of $167,081 shown on Attachment I, Appendix E [omitted herein] of the commission's decision and order entered on the 27th day of September, 1976, should, accordingly, have been shown as $116,909 rather than the $150,357.

With respect to the allowance of $50,172, the commission finds that SDEC's evidence in regard thereto was the most credible, and that said amount was amply supported in the record before this commission. The commission finds that company's excessive rate case expenditures cannot and shall not be charged to ratepayers.

V.

Computation of Income Tax Allowance

The company argues that normalization of income tax expense for the income tax effect of interest and other overhead related to the company's construction program should be allowed. The company presented in its rebuttal testimony five basic reasons why flow-through is improper and unsound. It has restated these arguments at pages 107 and 108 of its initial brief. The company further argues that the 'phantom tax' language used in regard to flow through is deceptive and that arguments based thereon merely are assertions that flow through should be applied because it will produce lower rates for the present. The company further argues that Order No. 530-B of the Federal Power Commission fully supports the company's view that normalization benefits both utilities and their ratepayers. Finally, the company argues that current ratepayers do not finance current construction, and consequently, said ratepayers should not receive the tax benefits related thereto.

South Dakota Electric Consumers argues that these deductions are available to the company in computing its federal income tax liability and that the company would have those deductions totally ignored and require ratepayers to pay an amount for federal income taxes which the company will not actually incur. South Dakota Electric Consumers also argues that, as stated above, the company has not shown that it uses an aftertax rate for AFUDC calculations. South Dakota Electric Consumers also states that the company's witness conceded that under the normalization method, additions to the deferral account each year will exceed withdrawals as long as the company continues to grow.

The staff argues that the same analysis as used by the staff for the investment tax credit equally applies to this issue.

Company proposes in this proceeding to obtain an income tax allowance in cost of service that is calculated without regard to the fact that company deducts construction overhead items and interest expense on indebtedness incurred in the construction program when filing its income tax returns. Company utilizes *305 'normalization' to describe its request for an income tax allowance in cost of service in excess of that which it will actually pay, notwithstanding the total lack of normality inherent therein. South Dakota Electric Consumers and the staff opposed the so-called normalization of the tax effect of these current tax deductions. South Dakota Electric Consumers' witness testified that normalization constitutes a deviation from the cost concept.

The commission rejected the company's position. Company contends that said rejection was error. The commission disagrees and reaffirms its previously entered findings in regard to this matter. There is ample authority for this commission's action, and the record before this commission establishes that 'normalization' is inappropriate in this proceeding.

The fallacy of company's position lies in company's failure to recognize that it is fully compensated for the use of its borrowed funds during the period of construction and that company's ratepayers pay that compensation. Under the Uniform System of Accounts, plant under construction is recorded as utility plant, although not as plant in service. This commission has found that construction work in progress is not properly included in rate base. However, all borrowed funds, whether or not used for construction, are included in company's capitalization in the development of a fair rate of return. The cost of debt in equity funds used for construction purposes is capitalized and accounted for as an investment in plant, as are capitalized construction overheads. When the plant does in fact become operational, it is accounted for as plant in service. From then on, depreciation expense in the capitalized construction funds is charged to the ratepayers. The entire amount of the capitalized fund is, thus, recovered by the company over the depreciable life of its property. Until the full recovery is made, a return is charged to ratepayers on the full undepreciated balance of these capitalized funds.

Construction overheads and interest deduction associated with borrowed funds for construction work in progress are available to the company as a deduction in computing its federal income tax liability. Moreover, company uses the interest deduction in current overhead costs in computing its federal income tax it would pay if the deduction were ignored. Company's position would require Company's position would require that these tax deductions be ignored and would require ratepayers to pay an amount in rates to company for federal income taxes which company will not incur; i.e., to pay an imputed income tax liability. The commission further finds that the benefit to the present ratepayers of the deductions will be lost entirely if said deductions are not given effect in the present cost of service because the same are available only in the year incurred.

The company argues extensively that the interest rate it uses on borrowed funds is an 'aftertax' rate and that the SDEC and staff treatment of the proposed income tax allocation results in 'double counting.' This position is untenable for three reasons. First, company's evidence does not establish that an 'aftertax' rate is used as has been previously discussed herein. Secondly, company, not SDEC or staff, decides the rate at which construction funds are to be capitalized, and it is within the discretion of the company to change the rate if it is deemed inadequate. Finally, company cannot rely on its own selection of *306 an inadequate capitalization rate, if the same be such, to justify before this commission adoption of its position.

Even if company had to sustain its burden of proof regarding the rate at which it capitalizes its AFUDC as an 'aftertax' rate, which it has not done, that fact would not in itself be determinative of this issue. This commission finds that the proper treatment is to flow the tax deduction through to consumers in the year that the deduction is actually realized.

Company argues that 'normalization' provides future ratepayers the benefit of all tax deductions relating to capitalized interest and construction overheads. However, company's witness conceded that under normalization treatment, additions to the deferral account each year will exceed withdrawals therefrom so long as company remains a growing concern. Hence, the net effect is that the method results in an absolute tax saving for company, not merely a tax deferral, and the benefits therefrom are never attained in their entirety by either present or future generations of ratepayers. Moreover, as testified to by SDEC's witness, any reduction of rates to future ratepayers would not be a certainty, but would rather be dependent upon the filing of annual applications by company.

Finally, company relies on Opinion No. 11 of the Accounting Principles Board in support of its position regarding this issue. Accounting Principles Board No. 11 is, by its own terms, not relevant to the accounting to be utilized by a regulated public utility. Secondly, APB No. 11 expressly disapproves of the net of tax valuation that company purports to utilize.

This commission rejects company's proposed interperiod allocation of the tax effects of the deductibility of capitalized construction overheads and debt interest in that the same is contrary to acceptable regulatory practice.

VI.

Power Supply Costs

The company argues that the figure it presented on an estimated basis is the proper one to use in this proceeding. The company further argues that the figure used is vital because the proposed fuel adjustment clauses of both the staff and SDEC will not adjust the rates charged for all changes in purchased power costs. The company further states that the estimates of the staff the SDEC recommended in this proceeding are unreliable. Further, the company contends that the staff and SDEC defend their estimates by saying that they relied upon information obtained by the company. However, the company argues that the staff and SDEC should have arrived at exactly the same results that the company did, which the staff and SDEC clearly did not.

South Dakota Electric Consumers argues that its calculation is the proper one in that it is reasonable, and even conservative in favor of the company.

The staff argues that its calculation is the proper one and that the SDEC witness failed to consider market considerations applicable to the sale of surplus Big Stone capacity. The staff further argues that its witness conducted a detailed study of the power supply costs of the company which takes into account all factors, and therefore, that the staff's conclusions should be the ones adopted in this proceeding.

There is no dispute that the inclusion of Big Stone plant in the test period rate *307 base requires an adjustment to operating income to reflect the fact that excess off-peak generation capacity will be available from the plant and that the company will be selling off-peak capacity and energy from Big Stone to other members of the MAPP Pool and even off-pool utilities. The controversy relates to the magnitude of this adjustment. The commission adopted SDEC's adjustment and company specifies this as error. The commission rejects company's assignment of error regarding this matter and affirms its prior ruling.

Evidence was adduced at hearing that in normal operation, the annual generation of Big Stone is expected to be 3,202,800 mwh. South Dakota Electric Consumers' witness testified that the company's 32.5 per cent share of said generation represents 1,040,910 mwh. South Dakota Electric Consumers' witness further found that based on company data, company would sell 568,002 mwh of energy to other members of the MAPP Pool. South Datota Electric Consumers' witness established the price of these intersystem sales at 11.0 mills per kwh, said price reflecting the average price to pool members at which company was selling surplus power during the latter months of 1975 as well as the total estimated cost to company to produce energy at Big Stone. The amount of revenue so generated was rolled into the company's pro forma operating income figures by SDEC's witness.

Company challenges the price at which the intersystem sales will be made and the level of energy sales to be made by company to MAPP Pool members. With respect to the average price of 11.0 mills per kwh, the commission finds that said price is amply supported by the evidence. Company's calculation of participation power averages to a cost of 13.76 mills per kwh and that company's weighted average cost to pool members of participation power and economy energy is 12.32 mills per kwh. With respect to the level of Big Stone economy energy sales, company offered evidence to establish that there is only a limited market for said sales within the MAPP Pool. However, company's evidence did not establish a realistic or accurate picture of the requirements of MAPP Pool members.

The level of expected generation from Big Stone for a normal year used by SDEC's witness was furnished by Big Stone's management. Obviously, an estimated level of generation means the existence of an equivalent energy market. The commission finds that Big Stone's management would not estimate a generation level that could not be utilized absent evidence to the contrary.

VII.

Ad Valorem Taxes Related to CWIP

The company argues that the bookkeeping burden of capitalizing such a small amount of ad valorem taxes is not justified. Consequently, recording such a current expense is a practical solution for a minor matter. The company also disputes the amount of CWIP SDEC claims is subject to said tax.

South Dakota Electric Consumers argues that capitalization of such amounts is allowed by the Uniform System of Accounts and should not be taken as a current expense.

The staff agrees with the SDEC position and further argues that the tax law does not allow expenses for such taxes to be currently taken.

The commission found and concluded that ad valorem taxes related to CWIP, *308 which the company had expensed, should be capitalized. Company does not actually deny the necessity for capitalization of such taxes, but rather argues that capitalization of the amounts involved is not worth the effort. However, this commission cannot ignore the erroneous expensing of the ad valorem taxes and, therefore, rejects company's position.

VIII.

Fuel Adjustment Clause

The company has proposed a fuel adjustment clause which would be adjusted as the combined cost of fuel and purchased power varied from the base cost provided for in said clause. The company contends, that such a clause is required in that estimates are necessarily made in regard to purchased power costs until the Big Stone plant has been in service for a longer period of time than at present. It is further argued by the company that such a clause is the fairest to both ratepayer and the company. The company further argues that the fuel adjustment clauses presented by SDEC and the staff do not reflect the actual costs incurred by the company after the proposed rates in this case would become effective.

South Dakota Electric Consumers argues that its proposed fuel adjustment clause is more complete that that of the staff and that the clause proposed by the company is too general in that it contains virtually no information indicating the manner in which the adjustment factor is to be calculated or what fuel costs are to be taken into account. South Dakota Electric Consumers further argues that purchased power is not a proper component of a fuel adjustment clause.

The staff argues that the fuel adjustment clause proposed by the company would ignore revenues associated with surplus capacity from the Big Stone plant and would only allow the ratepayer the opportunity to realize the benefits of the Big Stone plant capacity by assuming all of the risks concomitant with same. The staff further argues that such an arrangement would take all of the risks associated with Big Stone plant from the shareholder and place them upon the ratepayer. The staff concludes that its fuel adjustment clause is the proper one to accept in this proceeding.

The commission reaffirms and readopts its previously entered findings regarding the propriety and validity of SDEC's fuel adjustment clause.

IX.

Rate of Return

The primary issue in this proceeding regarding rate of return relates to the fair rate of return on common equity. The commission found that 12 per cent is a fair rate of return on common equity and that the overall fair rate of return is 9.23 per cent. Company, in its specifications of error upon rehearing, contends that the rate of return on common equity and the overall rate of return are inadequate and are consequently unlawful.

Upon full consideration of the affidavit of Al Schmidt, the specifications of error upon rehearing filed by company, the subsequent responses by company, staff, and intervenors, and the entire record herein, the commission finds that the 12 per cent and 9.23 per cent are, respectively, the fair rate of return on common equity and the fair overall rate of return, and the commission hereby reaffirms its earlier determination in regard thereto.

*309 Company witness Monteau recommended a cost rate for common stock equity in the 15 per cent-16 per cent range. Staff witness Wilson recommended 12 per cent, that being the highest percentage within the 11 per cent to 12 per cent range which he found to be the zone of reasonableness. Staff witness Wilson testified that allowing a return on equity as low as 11.25 per cent was justified.

Company witness Monteau first analyzed the relationship between common stock market and book values and the rates of equity returns experienced by a large group of utility companies. He then made a discounted cash-flow analysis of investor assumptions and expectations. After applying a 7.5 per cent factor for the cost of financing and market pressure, Monteau concluded that the average of his discounted cash-flow calculations was 14.86 per cent. Without ever precisely stating the derivation of his recommendation, Monteau found a cost of equity to range between 15 per cent to 16 per cent.

South Dakota Electric Consumers established that Monteau had in this proceeding departed from the methodology he had utilized in proposing a rate of return when testifying in rate proceedings before the SDEC municipalities. In the earlier proceedings he had suggested a comparison-of-earnings approach on the ground that the best measure of the cost of common equity capitalized in the relationship of earnings to book value of representative utilities over a period of years. The average equity returns of his comparison companies, the same being utilized in this proceeding, were in the neighborhood of 12 per cent over a period of years. Hence, if the analysis Monteau had utilized in the municipality rate proceedings had been recommended by him in this proceeding, his recommended equity return allowance would not have been significantly higher than the 12 per cent found fair and reasonable by Dr. Wilson.

Staff witness Wilson started with a comparison of the equity earnings of comparable companies. He found that 44 comparison combination gas and electric companies earned from 10.5 per cent to 12.2 per cent on their equity during the five-year period 1970 to 1974, inclusive, and that 45 small electric utilities of the same general size of company averaged 10.9 per cent on equity in 1974 and below 12 per cent in most prior years since 1970. Wilson further found that 40 large utilities with operations of at least 75 per cent electric averaged from 11.4 per cent to 12.5 per cent on equity earnings during the same 1970 to 1974, inclusive, period, and that the same group of 40 with the elimination of subsidiaries of holding companies earned from 10.7 per cent to 11.9 per cent on equity in the same time period.

Wilson testified that circularity is inherent in viewing only comparison companies with earnings subject to regulatory determination. Wilson further testified that comparison-of-earnings test for utilities should not be the only standard in a study of the cost of common equity capital. Hence, Wilson next testified on earnings on proprietary capital experienced by a group of unregulated business firms. He noted that these companies are more risky than company because they, unlike company, do not have monopoly franchises. Wilson, however, found that such an analysis would be helpful in establishing guidelines concerning the cost of common equity capital. After compiling data for a large variety of manufacturing industries *310 from 1961 through the first portion of 1975, Wilson found many unregulated firms with 11 per cent or less rates of return on book equity, including many highly successful firms in more risky industries. The all industry average for the 1961 to 1974 period was 11.4 per cent earnings on equity; and for the twelve months ended September 30, 1975, the average was 12 per cent.

On the basis of his comparison of utility and nonutility earnings, witness Wilson concluded that rates of return on common equity in excess of 12 per cent were not required to attract capital or to fairly compensate company's common equity holders for their investment.

Witness Wilson next proceeded to conduct a discounted cash-flow study. He stated that the discounted cash-flow methodology assumes the present value—i.e., what an investor is willing to pay in order to obtain a sum certain amount at some specified time in the future—can be ascertained by adding together the current dividend yield and the shares of common stock and the annual expected growth rate in dividends. Witness Wilson applied this discounted cash-flow test to groups of his comparison companies, and not to the stock of the company itself, in order to eliminate the effects of irregularities attendant with the market behavior of any one particular company's stock.

Witness Wilson found that the annual dividend yield of his comparison companies, calculated as the ratios of dividends paid during the year to average of high and low market prices for the year, were as follows: 44 combination companies, 9.93 per cent; 40 electrics, 9.9 per cent; 45 small utilities, 9.42 per cent. He developed serveral annual dividend gross rates for his groups of comparison companies for several growth periods—namely, 1973–74; 1972–74; 1971–74; 1969–74; and 1964–74—and witness Wilson found that rates of 2.55 per cent to 4.76 per cent in dividend growth were experienced during those various time frames.

On the basis of dividend yields and annual dividend growth rates, witness Wilson concluded that the costs of common equity capital were 11.25 per cent for the combination companies, 11.5 per cent for the large electrics, and 11.7 per cent for the small utilities. On the basis of all of his tests, witness Wilson concluded that the cost of common equity capital for company was in the 11 per cent to 12 per cent range, and suggested reliance on the top of the range to accommodate the company's thin equity ratio.

A critical explanation for the different result reached by Dr. Wilson in his discounted cash-flow study from the end attained by Mr. Monteau is that Mr. Monteau accorded equal weight to the historical experience of each of the ten years used in this study, whereas witness Wilson also made ten-year studies but accorded significantly greater weight to the data of the more current years.

Witness Wilson found fault with witness Monteau's methodology. Witness Wilson pointed out that the book values of the company's common stock is inflated as the result of retention of excessive earnings in past years in which typical regulatory lag operated to the detriment of consumers and by high prices at which company then sold its shares of stock.

In any event, the market price of utility company stock is related to many factors that are beyond the purview of this commission and are outside this commission's control. For example, witness Wilson called attention to a recent NARUC report on the relative efficiencies *311 of electric utilities. Company was classified as relatively inefficient in this report. Although witness Wilson expressed no opinion on the accuracy or fairness of the NARUC study, he noted that the same was an example of a factor which might affect investors that could not be controlled by this commission. This commission finds that the more comprehensive studies conducted by witness Wilson provide a more reliable basis for establishing the fair rate of return on common equity, the same being 12 per cent.

The commission has found nothing in either the affidavit of Al Schmidt nor the specifications of error upon rehearing filed by company which in any manner warrant any change in the previously entered findings of this commission.

X.

End Result

Company argues in its specifications of error upon rehearing that the end result of the PUC's decision and order of September 27, 1976, is constitutionally unlawful. Company provides no specifics to support this allegation unless the specifics are contained in the company's assignments of error with respect to the components of the cost of service such as average versus year-end rate base, rate of return, and other issues raised in this proceeding.

If these are the specifics upon which the company bases its claim, company's claim is without substance. The end result test is not a disembodied test independent of the components that make up the cost of service which lead to the end result of the regulatory adjudication. If each element comprising the cost of service is properly determined, as this commission has found that they are, then the end result is likewise proper.

If the specifics of the company's end result argument rest upon the allegations of the affidavit of Al Schmidt wherein he asserts that the rate increase authorized by the commission does not provide sufficient coverage of preferred stock dividend requirements to permit the issuance of additional preferred stock the argument advanced by company still has no merit.

Company assumes that the coverage it computes, assuming, arguendo, its computations are credible and reliable, is attributable to the inadequacy of the rate increase authorized by the commission. The fact is, however, that the level of earnings is not determinative of the coverage level. A satisfactory level of earnings, which everyone would agree produces a fair return, does not mean that coverage will be at a satisfactory level. Company's witness conceded that declining coverages do not necessarily indicate an inadequacy of earnings. Any financially healthy company can be hard pressed to meet coverage requirements on occasion.

Coverage levels are primarily influenced by two factors. First, by the level of the interest costs; as it increases, coverage will decline. This result will obtain even though coverage in dollars may be substantially greater than in the past. The evidence before this commission so reflects this result. Secondly, and more importantly, is the debt ratio; as the debt ratio increases and the common equity ratio becomes thinner, coverage declines. It is company's low equity ratio, as a consequence of its high debt ratio, which has adversely affected the cost of both equity and debt, and coverage.

Company's witness conceded that company's common equity ratio was *312 much lower than it should have been. In light of a long-term debt ratio of 57.88 per cent, company's witness further conceded that the financial community becomes alarmed when long-term debt ratio rises above the 50 per cent level. Finally, company's witness conceded that an equity ratio of 30 per cent is dangerously low, although company's equity ratio is only 27 per cent.

As the evidence unequivocally demonstrates, company's coverage is not attributable to the level of the revenue increase authorized by this commission. The relatively low coverage ratios are the result of company's own deliberate course of action and conduct in the issuance of debt securities. It is incumbent upon company to remedy its common equity ratio and to reduce its long-term debt ratio. This commission has fully considered company's coverage requirements in reaching its decision in this proceeding.

While coverage provisions of company's indenture and articles of incorporation are considered, such provisions, being the result of private agreements, and in many cases entered into in the distant past, cannot be permitted to dictate excessive rates and may not be utilized to, in effect, usurp this commission's regulatory duties and responsibilities.

This commission finds that the end result of our decision and order entered today is both constitutionally sound and establishes just and reasonable rates.

XI.

Affidavit of Al Schmidt and Exhibits Attached Thereto

The affidavit of Al Schmidt makes allegations about the effect of the commission's decision and order entered on the 27th day of September, 1976, and purports to rely upon the exhibits appended thereto for support of said allegations. However, if the exhibits were to accurately and clearly reflect the effect of the commission's previously entered decision and order, said exhibits would have to be based upon the principles adopted by the commission in said decision and order. It is obvious that the exhibits do not so reflect those principles. For example, the exhibits are based upon an end-of-period rate base whereas the commission found that an average rate base should be utilized in this proceeding. With respect to working capital, the exhibits do not appear to in any manner reflect the effect of the commission's decision and order. The exhibits reflect tax normalization which this commission rejected in its decision and order.

Exhibit No. 2 does not reflect the total earnings of the company, since it is confined to the company's electric it is confined to the company's electric operations. Earnings per share of common must, of course, be based upon the totality of the company's operations, including the effect of company's gas operations.

Exhibit No. 3 purports to show that the rate increase authorized by this commission in its previously entered decision and order produces inadequate preferred stock coverages and thereby does not permit the issuance of additional preferred stock. Exhibit No. 3 contains the same fallacy as did Exhibit No. 2 in that it does not give effect to the totality of the company's operations and earnings. Again, the ability to issue preferred stock is related to total company operations and revenues. Moreover, both said exhibits are based on budgeted figures and *313 do not realistically represent the results of actual company operations. A further illustration of the unreliability of the profferred exhibits is that, contained therein, interest is shown on bank loans at 7 per cent whereas said interest on bank loans in 1976 has been reduced significantly below that percentage.

The exhibits are also based on a period which is not the test period advanced by the company in this proceeding. Moreover, the hearings before this commission on company's application were based upon said test period and this commission entered its decision and order on the 27th day of September, 1976, in regard thereto. Hence, the commission finds that its decision and order entered today as well as its previously entered decision and order must be evaluated in light of the evidenciary record before it which was based upon the test period advanced by company in this proceeding.

Many of the allegations contained in the affidavit of Al Schmidt are also misleading. For example, Par XII of the affidavit asserts that the company supported annual electric revenues of $31,978,549 whereas the commission's decision and order entered on the 27th day of September, 1976, resulted in annual electric revenues of $24,847,542, resulting in a reduction of revenues of $7,131,007. However, there was no reduction of $7,131,007 because the company did not file rate schedules to produce annual electric revenues of that magnitude. The annual revenue reduction from that filed for by company was approximately, $3,750,000.

At Par XVI, the affidavit of Al Schmidt alleges that Exhibit No. 4 demonstrates that the company has not been able to earn the 9.23 per cent rate of return authorized by the commission based on electric rates and end-of-period rate base and that a return of only 7.31 per cent on company's end-of-period rate base for the twelve months ended September 30, 1977, will be realized. The commission has already averred to several defects contained in Exhibit No. 4, including the fact that it is not based on the test period advocated by company during the hearings on company's application, said test period having been adopted by the commission. Additionally, the allegations are based on positions of company which have been rejected by this commission in its previously entered decision and order, such as year-end rate base. Finally, the alleged earnings are not actual earnings for the period utilized by company. Earnings are higher, of course, on an average rate base and on other principles adopted by this commission in its previously rendered decision and order.

It is interesting to note that company's annual reports to stockholders reflect per share earnings on the basis of the average number of shares outstanding during the year. Company and the investment community recognize the necessity for same in that earning power of capital is properly measured by relating earnings during a particular period to the average investment during that period. Company's concept in this case of measuring revenues during a test period with the investment levels that exist at the end of the perios is untenable and does not in any manner reflect a proper matching of the earnings capability of company's investment.

Other portions of the affidavit of Al Schmidt simply reiterate the arguments previously made to this commission which were rejected in this commission's decision and order entered on the 27th day of September, 1976. The affidavit *314 and related exhibits provide no valid test for the commission's previously entered decision and order in that said affivadit and exhibits are based upon rejected and invalid principles.

Finally, the commission feels that the submission of information filed by company on the 17th day of December, 1976, as well as the recently filed November, 1976, monthly report conclusively establish the inherent unreliability of the affidavit and related exhibits of Al Schmidt. Moreover, said submission of information filed by company on the 17th day of December, 1976, further establishes that the allegations contained in the affidavit and related exhibits of Al Schmidt are unfounded and unsupported.

The commission will not further elaborate upon each and every inaccuracy, inconsistency, and misleading allegation contained therein, but simply finds that said affidavit and related exhibits are both meritless and incredulous. The commission further finds that the submission of the affidavit and exhibits of Al Schmidt, and the subsequent developments related thereto, require this commission to direct staff to initiate a complete investigation of this entire matter.

Certain issues have not been contested by company, staff, or SDEC, and will therefore require no further elaboration herein as they are hereby adopted by this commission. The commission, on the basis of all of the testimony, exhibits, briefs, and arguments, and the entire record in this proceeding, including all matters submitted to the commission on rehearing, hereby enters its findings of fact and conclusions of law as follows:

Findings of Fact

I.

That the discussion and analysis above set forth is hereby incorporated as if set forth in full herein.

II.

That the commission hereby readopts and reaffirms its Finding of Fact Nos. I to XXXI, inclusive, and XXXIII to LVII, inclusive, entered on the 27th day of September, 1976, in the commission's decision and order; and that the commission rescinds Finding of Fact No. XXXII contained therein.

III.

That the specifications of error upon rehearing and the allegations in the affidavit of Al Schmidt and related exhibits are without merit and are unsupported in the record before this commission, except for the contention of company that the regulatory expense adopted by the commission should not be amortized.

Conclusions of Law

I.

The commission hereby incorporates the above set forth discussion and analysis as if set forth in full herein.

II.

The commission hereby readopts and reaffirms its Conclusion of Law Nos. I to XX, inclusive, and XXII to XXXIII, inclusive, and hereby rescinds Conclusion of Law No. XXI.

*315 III

That Conclusion of Law No. XXXIV, except as hereinafter provided, is hereby incorporated as if set forth in full herein.

IV.

That Attachment No. 1, Appendix E contained in Conclusion of Law No. XXXIV is rejected and that Revised Attachment No. 1, Appendix E attached hereto, is hereby incorporated as if set forth in full herein.

V.

That the specifications of error upon rehearing, except as relating to Finding of Fact No. XXXII and Conclusion of Law No. XXI be, and the same hereby are, denied.

VI.

That the allegations contained in the affidavit and the related exhibits of Al Schmidt are unfounded and unsupported in the record before this commission.

VII.

Except as modified herein with respect to Finding of Fact No. XXXII Conclusion of Law No. XXI and Attachment No. 1, Appendix E, the commission's decision and order entered on the 27th day of September, 1976, not inconsistent herewith, is hereby readopted, reaffirmed, and incorporated as if set forth in full herein.

End of Document

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AUTHORITY TO ESTABLISH INCREASED RATES FOR ELECTRIC SERVICE IN SOUTH DAKOTA.	)))))	DECISION AND ORDER (F-3382)

On June 15, 1981, Northern States Power Company (NSP) filed with the Commission an application for authority to establish increased rates for its retail electric service in South Dakota. By the terms of its application, NSP sought to increase retail electric revenues by approximately $6,184,000 on an annual basis, which constitutes an overall increase in annual revenues of approximately 20%. NSP serves approximately 46,000 customers in South Dakota. NSP sought to implement its proposed rate increase to become effective on December 15, 1981. On July 21, 1981, the Commission filed its Notice of and Order for Deposit and Procedural Schedule herein. By the terms of that Order a schedule for the filing of testimony and a time for hearing was established. By its Amended Order for and Notice of Procedural Schedule entered on October 2, 1981, the evidentiary hearing set in the case was delayed one day to accommodate a state and federal holiday. On September 30, 1981, the Commission held a consumer input hearing in Sioux Falls, South Dakota. On October 13, 1981, the formal evidentiary hearings in this case were commenced in Pierre. NSP was represented by its counsel David Lawrence of Minneapolis, Minnesota and by Samuel L. Hanson of Briggs and Morgan, Minneapolis, Minnesota. Commission Staff was represented by ..ne F. Gilbert and Doyle D. Estes of Gunderson, Farrar, Aldrich, Warder and DeMersseman, Rapid City, South Dakota.

DISCUSSION

I.

TEST YEAR

A. NSP Position

NSP Witness McIntyre's adjustments to rate base, revenues and expenses are based on 1981 sales levels and associated demands. It is NSP's contention that SDCL Chapter 49-34A does not prohibit usage of partially or fully forecasted test years. Witness McIntyre testified that he had little confidence that Staff's case utilizing historical test year data properly reflects 1981 conditions, and is altogether insufficient for recognizing 1982 conditions. Witness McIntyre then defended his recommended use of forecasted and budgeted data arguing that the complexity and thoroughness of a budget enhances its reliability. He also testified that it is unnecessary for the Staff to develop its own budget but that Staff could fulfill its responsibilities by reviewing the Company's budget in light of historical results, changing conditions and abnormal deviations. NSP further claimed that its budget should be adopted because there have been no serious criticisms of its accuracy, it better reflects cost/revenue relationships, its accuracy can be assessed as actual results occur and it can be corrected in the process, and because serious revenue gaps will occur if historical test years are utilized.

NSP Witness McIntyre testified that other jurisdictions have had good experience using forecasted test years based on NSP's budget, and that the budget has historically proved to be quite reliable in reflecting the near future. Because the budgets are used primarily for operating, planning and conducting Company business, he believed the budget to represent the Company's best efforts to forecast its financial future. NSP also contends that the budgeted data is superior to Staff's historical test year, and further contends that Staff's determinations have failed to work in the past.

B. <u>Staff Position</u>

Staff opposes the use of partially or fully forecasted test years. Staff Witness Rislov testified that the purpose of a rate increase application is to derive cost/revenue relationships that will be in effect for the forthcoming period. He maintained that historical data reflects actual cost/revenue relationships, and when adjusted, is a better indicator of future relationships than a budget. Witness Rislov testified that a budget is based on a series of assumptions, projections and guesses made by 285 department heads, and that given the number of people involved and the possibility of errors on the part of each, budgets may be adequate for planning, but lack sufficient precision for ratemaking.

Staff Witnesses Towers and Rislov pointed out that NSP's claim that their budget performs acceptably in other jurisdictions in an allowed verus earned return sense is meaningless because the budget becomes a self-fulfilling prophecy. Staff claims that NSP can and does time expenditures to their benefit when a forecast test year based on their budget is utilized. Staff believes that NSP may delay expenditures from one budgetary period forward in order to give their budget the appearance of being precise. Staff alleges that due to the adoption of a budget, NSP may receive rate base treatments months before an item becomes used and useful, yet because the item became used and useful within the budget year the budget will maintain the appearance of being correct. Staff asserts that the forecast depends heavily on the forecast of sales in order to establish cost/revenue relationships. Staff believes that sales cannot be forecast accurately due to the present difficulty in forecasting trends.

Staff Witness Rislov testified that historical test years are not "backward looking" in a rate case context. It is Witness Rislov's testimony that historical test years adjusted for known and measurable changes are sound for development of appropriate cost/revenue relationships. Staff Witnesses Towers and Rislov testified that in their opinion, NSP has failed to document known and measurable changes and that NSP is now trying to capitalize on this failure by requesting the Commission to adopt a self-fulfilling budget that offers little economic incentive for being cost-conscious.

Staff asserts in its case that they have recognized more adjustments to NSP's case than they have in the past. Staff Witness Rislov, for example, annualized non-revenue producing plant through July of 1981, a full six months after the test year ended. Witnesses Rislov and Towers additionally testified that NSP could offer known change adjustments occurring prior to the Commission Order.

Staff also noted, contrary to NSP Witness McIntyre's testimony, that usage of forecast test years does not necessarily limit the number of rate increase filings. Staff points out that NSP filed for an increase in rates in Minnesota on July 1, 1981, only two months after Minnesota had issued a rate increase Order.

Staff Witness Rislov further pointed out that the Staff must process a rate case within six months of the date of filing, and that this relatively rapid processing time coupled with known change adjustments should make, in Witness Rislov's view, the test year reasonably reflective of current conditions.

II.

INCOME TAX NORMALIZATION

A. NSP Position

NSP urged the Commission to abandon its past precedent requiring flow-through of income tax benefits and adopt income tax normalization. NSP Witness McIntyre testified that tax normalization better achieves the goal of equity and fairness in rates than does flow-through. One of the reasons given by Witness McIntyre is that tax normalization synchronizes the recognition in rates of the deductibility of an expense with the recognition of the expense itself. In other words, under normalization procedures, income taxes are allocated over the life of the plant giving rise to the tax expense rather than to the construction period when the costs were actually paid. Another reason given by NSP is that flow-through treatment, according to the FERC, costs ratepayers the same as normalization. (However, on rebuttal, NSP argues that according to the Massachusetts Accountants For Public Issues, Inc., normalization is less costly to the customers than flow-through.)

NSP further summarizes certain findings made by the FERC in its Order No. 144 to support Witness McIntyre's contention that normalization is more fair and equitable than flow-through. These findings are:

(1) That normalization balances obligations to insure reasonable rates to ratepayers while maintaining the financial integrity of the utility;

(2) That normalization is more properly cost-based than flow-through;

(3) That tax normalization meets the "actual taxes paid" principle from policy and legal standpoints;

(4) That tax normalization meets the just and reasonable rate standards of the Federal Power Act and Natural Gas Act;

(5) That tax normalization is likely to produce more stable rates over time than flow-through;

(6) That no adverse incentives are given to companies by the use of normalization; and

(7) That issuance of a generic rule resolving the issues will result in administrative efficiency and clarity which will benefit all parties.

NSP Witness McIntyre testified that the idea of a "permanent tax saving" resulting from normalization is not a valid reason for rejecting normalization because no such permanent tax savings results from normalization. The reason there is no such savings is that tax deferrals do reverse, or turn around. Witness McIntyre similarly testified that a growth in the aggregate size of the accumulated deferred tax account does not justify rejection of tax normalization policies because even though the account in the aggregate may be growing, individual timing differences still are reversing continuously.

NSP contends that it must be permitted to utilize normalization in order that its accounting procedures conform to generally accepted accounting principles, in this instance those embodied in APB No. 11.

NSP points out that its other regulating jurisdictions all utilize normalization and that the unique treatment in South Dakota is requiring special accounting treatment that is becoming more complex with time. Hence, NSP argues that because of the FERC comprehensive review of the issue, the treatment given the Company in other jurisdictions, and recent trends in tax law changes favoring normalization, the Commission should reassess its past precedent.

B. Staff Position

The Staff urges the Commission to continue its past precedent requiring flow-through of income tax benefits except where federal law makes it imprudent to do so.

Staff Witness Brown testified that flow-through is desirable because it reflects in utility rates only the actual taxes paid or payable and because it matches costs imposed on the utility with those included in rates. Staff Witness Brown also testified that flow-through is less costly to the customer than income tax normalization. The reason flow-through is less costly is that customers pay currently, under normalization, for federal income taxes the utility will pay, theoretically, only in the later years of the plant life. Hence, time value considerations favor flow-through as the less costly alternative for customers. Also, Staff Witness Brown testified that the cost of capital for a utility is less than the cost of capital for most consumers. Since the customers are given carrying charges on their contribution of federal income taxes in advance of the payment of these taxes to the federal government at the utility's cost of capital rate, most customers will never be fully reimbursed under normalization. Staff further argues that because the type of deductions at issue recur year after year so long as there is a construction program for either new or replacement plant, each year's tax saving generated by construction will in all likelihood exceed any tax currently payable associated with the "turnaround" of deferred taxes related to older plant. Staff explained that the reason total taxes currently payable will not increase over time is that tax savings are generated each year, but reverse very slowly, generally over a period of about 30 years. Moreover, Staff Witness Brown stated that it is reasonable to assume that the utility's tax

Dated at Pierre, South Dakota, this 15th day of December, 1981.

BY ORDER OF THE COMMISSION,
Chairman Fischer, Commissioners
Stofferahn and Solem:

Patricia de Hueck
PATRICIA de HUECK
Executive Secretary

(OFFICIAL SEAL)

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AN INCREASE IN ITS RATES FOR ELECTRIC SERVICE IN SOUTH DAKOTA.	)))))	Docket No. F-3422

STAFF MEMORANDUM IN SUPPORT OF STIPULATION AND SETTLEMENT AGREEMENT BETWEEN NORTHERN STATES POWER COMPANY AND COMMISSION STAFF

On April 15, 1983, representatives of Northern States Power Company ("NSP" or "Company") and Commission Staff ("Staff") met in Pierre to discuss possible settlement of part or all of the issues at contention in this docket. As a result of these negotiations, NSP and Staff have agreed to a settlement level revenue increase of $3,902,000 on an annual basis. This settlement also includes a one and one-half year moratorium on further rate increases, until November 1, 1984.

I.

Positions of the Parties

In its application filed November 17, 1983, NSP sought to increase its annual revenues for electric service by $4,917,000 on the basis of an adjusted test year ended June 30, 1982. On March 28, 1983, Staff filed testimony recommending that the Company be allowed to increase its rates by $1,525,000. On

April 11, 1983, Company filed its rebuttal testimony purporting to justify an increase of approximately $5,515,000. Company's position on rebuttal reflected refinements to certain adjustments originally proposed by Company but rejected by Staff, and certain additional adjustments not included in the Company's initial filing.

II.

Settlement Level Increase

A. Initial Staff Position:

Based on data exchanges with the Company after Staff filed its testimony, Staff conceded corrections to its original position amounting to $728,000. These corrections are shown on the reconciliation exhibit attached to this memorandum. It should be noted that the $200,000 flowthrough error shown as a correction on the reconciliation exhibit was the result of incorrect information provided to Staff by a Company data response. Staff's corrected position, therefore, had the case gone to hearing, would have been $2,253,000.

B. Tyrone Stipulation:

The reconciliation exhibit also shows a Tyrone expense adjustment of $313,000 as an add-on to Staff's initial, corrected position. In addition to the Settlement Agreement resolving outstanding revenue requirement issues, NSP and Staff have also entered into a Stipulation resolving the recovery of

Tyrone cancellation costs. The Stipulation, dated April 15, 1983, is referenced in Article IV of the Settlement Agreement. The Stipulation is also submitted to the Commission for approval in this case.

As the Stipulation sets forth, the Eighth Circuit Court of Appeals' decision in October, 1983 upholding the FERC's approval of NSP's proposed amendment to the Coordinating Agreement between it and NSP (Wisconsin) finally determined the assignment of Tyrone cancellation costs between the two companies. As a result of the Eighth Circuit's ruling, approximately 87% of the $67.1 million in cancellation costs must be borne by NSP (Minnesota). The South Dakota Supreme Court's January 3, 1983 opinion on the Tyrone issue in the appeal of the Commission's decision in Docket F-3353 upheld the Commission's discretionary authority to defer its decision on the retail recovery of Tyrone related costs pending a final ruling from the federal courts on the FERC's decision. Now that the FERC decision has been affirmed and is no longer subject to further judicial review, how Tyrone cancellation costs are to be recovered from South Dakota ratepayers again becomes a question for Commission decision.

In light of the Eighth Circuit's ruling requiring pass-through of Tyrone costs to NSP (Minnesota), Staff has sought to lessen the rate impact of the Tyrone recovery on South Dakota retail customers. Company and Staff have stipulated (1) to a recovery of the Tyrone costs (subject to Commission approval) over a twenty year amortization period, and (2) to a carrying charge on the unamortized balance of those costs which does not include a common equity component. The Stipulation also provides for the recovery of the deferred portion of the amortized loss, as required under the Settlement Agreement in Docket F-3353.

The Stipulation reflects a recognition that the amortization of the Tyrone loss commenced on March 6, 1979 (the date of the Wisconsin Public Service Commission's decision denying Tyrone certification), but that the Company's entitlement to begin recovering the annual amortization expense from South Dakota ratepayers did not begin until November 30, 1980 (the date of the Settlement Agreement in Docket F-3353). Thus, under the Stipulation the Company will absorb the first twenty months' amortization expense (March, 1979 through November, 1980).

The Stipulation further reflects that from the date of the Settlement Agreement in F-3353 (November 30, 1980) until the effective date of the rates in this case (May 1, 1983) recovery of Tyrone related costs from South Dakota customers has been deferred. This deferral resulted from the Commission's Orders in Dockets F-3353 and F-3382. Under the Settlement Agreement in Docket F-3353 and under the Commission's Order in Docket F-3382, however, NSP is entitled to a carrying charge on the deferred amounts to compensate the

Company for the deferral. The Stipulation applies the carrying charge formula contained in the F-3353 Settlement Agreement to the amounts deferred in both previous cases.

In addition to recovery of the deferred portion of the Tyrone loss, the Stipulation also provides for the recovery of the current portion of the cancellation loss, i.e., that portion collectible from May 1, 1983 through the end of the amortization period (approximately March 6, 1999). The Stipulation applies a partial carrying charge to the current portion, similar to interest on a loan, to compensate the Company for the extended recovery period. This carrying charge is computed at the weighted cost of preferred stock plus an allowance for associated income taxes at the prevailing tax rate, and the weighted cost of debt as determined by the most recent Commission NSP rate order. The Stipulation does not reflect a common equity component in the carrying charge.

Exclusion of the common equity component from the carrying charge represents a settlement position between Company and Staff. Initially, Staff had proposed that the loss be recovered over the remaining twenty-seven years of the thirty year amortization period recommended by the Commission in the FERC proceedings, with no carrying charges applied to the unamortized balance. Company sought recovery over the remaining seven years of the "variable" ten year amortization period ordered by the FERC, also with no carrying charges.

For settlement purposes, the Company and Staff have agreed to a twenty year recovery period (seventeen years remaining since March, 1979), and to a carrying charge which excludes the common equity component. Staff believes that the exclusion of the common equity component effects an appropriate sharing of the Tyrone loss between ratepayers and equity stockholders. This exclusion will not require ratepayers to reimburse stockholders for that portion of the rate of return (carrying charge) which would otherwise serve to compensate stockholders for their share of the cost of money required to carry the unamortized balance of the Tyrone loss. Staff's advocacy of this position reflects the recommendation made by the Commission through its Witness Robert G. Towers in the FERC proceedings that the common equity portion of the AFUDC on Tyrone costs be excluded from the recoverable amount.

Staff takes the position that the twenty year recovery and the allowance of a partial carrying charge on the unamortized balance most equitably provides for the recovery of Tyrone related costs from South Dakota ratepayers. If the Commission approves the Stipulation on the Tyrone issue, Company has agreed to jointly move to have the pending appeals of the last two Commission Orders dismissed. Both appeals are currently before the Sixth Circuit Court for Hughes County. The only outstanding issue in each appeal is the treatment of Tyrone expenses. The Commission's approval of the Tyrone stipulation in this case will settle the matter for once and for all. The Stipulation provides a framework for the recovery of Tyrone costs prospectively through the end of the amortization period. In all future NSP rate cases, the amounts of the revenue requirement associated with the Tyrone amortization expense will be calculated on the basis of the Stipulation in this case.

C. Update to Staff Position:

The reconciliation exhibit shows seven amounts listed under the heading "Updates". These represent amounts which Staff accepts as valid add-ons to its initial, corrected position. Staff's acceptance of these amounts is based in some cases on refinements of adjustments initially proposed by Company as part of its application but rejected by Staff in its testimony. The refined adjustments were included in Company's rebuttal testimony. Other amounts were included initially in Company's rebuttal filing. One was presented for the first time during settlement discussions. All of the amounts reflected as updates would have been accepted by Staff had the case gone to hearing. A brief description supporting Staff's acceptance of each follows.

Fuel Stocks, etc.

In NSP's rebuttal presentation, the Company updated the average balance of fuel stocks (repriced), materials and supplies and prepayments to reflect a more current thirteen month average.

Nuclear fuel decommissioning

In NSP's rebuttal, the Company included an additional month's expense associated with its nuclear fuel decommissioning so that a full annual level would be reflected. The initial filing reflected only eleven months of costs.

Pensions

The additional $12,000 for pension costs reflects an annualization of NSP's current pension accrual, which the Staff had initially not reflected on an annualized basis.

Inflation

NSP's initial presentation included no "inflation" adjustment. On rebuttal, however, NSP introduced such an adjustment. The $110,000 reflected as a part of the settlement was constructed similar to the manner in which other "inflation" adjustments which have been approved by the Commission were constructed.

Split Rock Substation

Initially, Staff deleted the adjustments proposed by NSP to annualize its Split Rock substation investment and associated costs because NSP had not taken into account acknowledged load growth which would be serviced by the facilities. At settlement, however, the Company agreed to reduce the amount of its claimed costs by a growth rate, thereby accounting for its anticipated load growth. NSP also outlined more fully at rebuttal that certain aspects of this facility mitigate towards considering it as a facility necessary to assuring system reliability more so than one which accommodated system growth.

Storm damage

Initially, Staff took exception to NSP's construction of a five year period to develop a five year average for storm damage expenses for inclusion in the cost of service. On rebuttal, NSP updated its five year period to the most recent five full calendar year period thereby applying a calendar year average consistent with past methods of averaging these costs.

Non-revenue producing plant

Initially, Staff included non-revenue producing plant additions which were in-service as of January 1983. With the passage of time, NSP was able to update these additions to a period corresponding more closely with the date that rates established in this proceeding will be effective.

D. Settlement Issues:

Were this case to go to hearing, Staff's corrected and updated position would be at $3,096,000. The reconciliation sheet identifies three additional amounts as "settlement position changes". These represent issues which Staff was willing to agree to for settlement purposes in exchange for the eighteen month moratorium in this case.

Excess capacity

The first represents a settlement of the excess capacity adjustment initially proposed by Staff. Instead of the full excess capacity adjustment of $361,000 originally recommended by Staff, which was based on the Company's average investment in generating facilities, Staff has, for settlement purposes only, agreed to an excess capcity adjustment of $157,000 based on the Company's investment in oil-fired generation only. This settlement position change adds back $203,000 to Staff's position, the difference between the original $361,000 adjustment and the settlement level adjustment of $157,000.

Return on equity

In exchange for the eighteen month moratorium, Staff also agreed to an increase in the allowed rate of return on equity from 14% to 14.5%, for settlement purposes only. Staff would point out that 14.5% is the maximum return on equity ever granted by the Commission in a gas or electric rate case. Therefore, Staff's position for settlement does not exceed any previous Commission Order on this issue.

Additional dollars for extended moratorium

In order to procure the extended moratorium agreed to under the Settlement Agreement, Staff agreed to an additional lump sum increase of $297,000. Staff finds this to be a reasonable price for the lengthy moratorium agreed to by Company.

Moratorium

Staff places a substantial value on the eighteen month moratorium which was obtained by entering into this Stipulation.

Based on evidence which is contained in the record in this case concerning the level of non-revenue producing plant which NSP expects to place in service during the remainder of 1983 and concerning other changes in its costs which are expected to occur in 1983 and beyond, Staff does not find it unrealistic to expect that NSP would file another rate increase request as early as November 1983, absent a moratorium. Assuming that NSP at that time could justify a rate increase of at least $1.8 million, which does not appear to be an unrealistic assumption, a rate increase of that magnitude could go into effect in May 1984. However, the moratorium would forestall implementation of this amount until November 1984, a full six months. Delaying the implementation of a minimal rate increase of $1.8 million on an annual basis is worth $900,000 to customers. Obviously, the greater the amount of the rate increase which could be justified, the greater is the value of the moratorium to the consumers.

Dated at Pierre, South Dakota, this 20th day of April, 1983.

Respectfully submitted,

Walter Washington

WALTER WASHINGTON
Assistant Attorney General
Public Utilities Commission
500 East Capitol Avenue
Pierre, South Dakota 57501

On Behalf of Commission Staff

The Regulation of Public Utilities.
Theory and Practice

Charles F. Phillips, Jr.

Part II. The Theory of Public Utility Regulation

CHAPTER 5: THE GOALS, PROCEDURES, AND THEORIES OF PUBLIC UTILLITY REGULATION

We are asking much of regulation when we ask that it follow the guide of competition. As Americans, we have set up a system that indicates we have little faith in economic planning by the government. Yet, we are asking our regulators to exercise the judgment of thousands of consumers in the evaluation of our efficiency, service, and technical progress so that a fair profit can be determined. Fair regulation is now, and always will be, a difficult process. But it is not impossible. —Ralph M. Besse [a1]

One can find several examples to support all four of the major theories of regulation. None, however, provides a general theory of commission regulation, for they lack predictive value. But their development, "spanning more than two decades, serves to indicate the growing importance of equity-related issues as an explanation of the motivation and objectives of regulatory agencies."[70] At the same time, as will become readily apparent in the following chapters, the debate continues over the relative weight to be given by regulatory agencies to equity and fairness considerations vis-a-vis efficiency solutions.

Commission Procedures[71]

Commissions, as previously discussed, have considerable authority to regulate the earnings and rates of many important industries in the economy. Much of their work originates in requests filed by public utilities and in complaints made by customers or competitors. A formal proceeding may be initiated by either a commission or a public utility. In the background of such a proceeding "is a network of state and federal constitutional provisions and principles, general and specific statutes governing procedures at the state and federal levels, the rules and regulations of the commission, prior opinions of the commission, and precedents and usages in other states."[72]

There are two types of proceedings: "rule-making" and "adjudicatory." Rule-making proceedings are usually legislative in effect and are initiated for the purpose of establishing procedures, policies, and practices (*e.g.*, rules of practice and procedure for persons and entities doing business with the commission, uniform systems of accounts, allowed depreciation rates, and safety standards) or to investigate a specific issue (*e.g.*, proper pricing principles, advertising practices, and conservation programs[73]). Rule making generally is applicable to a large group of affected parties and is always looking to the future. Adjudication is initiated for the purpose of settling a contested issue and generally relates to an action which took place in the past. In contrast to rule making, adjudication always involves specifically named persons or entities.

Rule-making and adjudicatory proceedings may be either formal ("on the record") or informal ("off the record").[74] Contested issues are dealt with by formal methods; customer complaints generally are handled by informal methods. A rule-making proceeding may or may not require a formal hearing, depending upon the applicable statutory requirement. In recent years, with workloads increasing rapidly, there have been several attempts made to shorten formal proceedings.

Rule-making Procedures[75]

If the relevant statute requires a formal hearing in a rule-making proceeding, such a proceeding, while legislative in nature, becomes a hybrid and approximates the adjudicatory hearing. In general, rule-making proceedings follow the provisions of the Federal Administrative Procedure Act, which provides:

Sec. 553. *Rule Making*

(a) This section applies, according to the provisions thereof, except to the extent that there is involved –
(1) a military or foreign affairs function of the United States; or
(2) a matter relating to agency management or personnel or to public property, loans, grants, benefits, or contracts.
(b) General notice of proposed rule making shall be published in the *Federal Register*, unless persons subject thereto are named and either personally served or otherwise have actual notice thereof in accordance with law. The notice shall include –
(1) a statement of the time, place, and nature of public rule-making proceedings;
(2) reference to the legal authority under which the rule is proposed; and
(3) either the terms or substance of the proposed rule or a description of the subjects and issues involved.
Except when notice or hearing is required by statute, this subsection does not apply –
(A) to interpretative rules, general statements of policy, or rules of agency organization, procedure, or practice; or
(B) when the agency for good cause finds (and incorporates the finding and a brief statement of reasons thereof in the rules issued) that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest.

(c) After notice required by this section, the agency shall give interested persons an opportunity to participate in the rule making through submission of written data, views, or arguments with or without opportunity for oral presentation. After consideration of the relevant matter presented, the agency shall incorporate in the rules adopted a concise general statement of their basis and purpose. When rules are required by statute to be made on the record after opportunity for an agency hearing, Sections 556 and 557 of this title apply instead of this subsection.
(d) The required publication or service of a substantive rule shall be made not less than 30 days before its effective date, except –
(1) a substantive rule which grants or recognizes an exemption or relieves a restriction;
(2) interpretative rules and statements of policy; or
(3) as other wise provided by the agency for good cause found and published with the rule.
(e) Each agency shall give an interested person the right to petition for the issuance, amendment, or repeal of a rule.

Rule-making proceedings, particularly where a formal hearing is not required, may be relatively brief. Further, many commissions "have a 'constituency' – the groups for whose particular benefit they operate and the groups whose conduct they regulate. These more often than not are organized. Their organizations are consulted and informed during all stages of the rule making."[76] As already noted, rule-making proceedings have been widely used for such purposes as establishing uniform systems of accounts and safety regulations. But there has been a trend toward using such proceedings for other purposes. Two examples are illustrative.

Natural Gas Prices.

In 1974, the Federal Power Commission established a single uniform national base rate for the wellhead price of "new" natural gas in a rule-making proceeding.[77] In its April 11, 1973, notice of proposed rule-making, the commission "made all large producers respondents to the rule-making proceeding, provided for the submission of written comments (submitted under oath) from all interested parties and the named respondents, and was accompanied by a staff study on the estimated nationwide cost of finding and producing new nonassociated natural gas supplies."[78] The rate order was subsequently affirmed,[79] as was another national rate order, issued in 1976.[80]

Rate of Return Determination.

Since 1978, the Interstate Commerce Commission has set a single overall rate of return for the railroad industry, using a rule-making approach.[81] The industrywide rate of return is updated each year. The procedure is as follows:

... All class 1 railroads are automatically made parties to the proceeding and other interested parties may participate if they wish. Notice of the proceeding is given by April 30 of each year, and the railroads, individually or collectively, are required to file cost of capital evidence by June 30. Reply comments are permitted, including cost of capital evidence, and the railroads are given an opportunity to file rebuttal statements. The ICC regulations indicate the type of data required to be filed as evidence (*e.g.*, debt costs, percent of capital financed with debt), but the regulations do not prescribe any particular technique for estimating the cost of capital. The parties are permitted to demonstrate the cost of capital in ways deemed most suitable under conditions prevailing at the time of a particular proceeding.

By October 30, the ICC issues its decision setting the industrywide cost of capital. The single cost of capital figure ... may be used by railroads in their rate filings, or the ICC can authorize departure from use of this rate of return for individual railroads if warranted by special circumstances. Railroads are not allowed to use some portion of the rate of return, like the equity rate of return, and apply that to their individual capital structure. If departure from the generically derived rate of return is permitted, the railroads must use individual company data for all of the components of the overall rate of return. To date, no requests for waiver of the regulation have been made.[82]

Adjudicatory Hearings

Formal adjudicatory hearings are generally held to settle contested issues of fact based on the evidence produced at the hearing (*i.e.*, based "on the record"). The adjudicatory provisions of the Federal Administrative Procedure Act provide:

Sec. 554. *Adjudications*

(a) This section applies, according to the provisions thereof, in every case of adjudication required by statute to be determined on the record after opportunity for an agency hearing, except to the extent that there is involved –
(1) a matter subject to a subsequent trial of the law and the facts de novo in a court;
(2) the selection or tenure of an employee, except an administrative law judge appointed under Section 3105 of this title;
(3) proceedings in which decisions rest solely on inspections, tests, or elections;
(4) the conduct of military or foreign affairs functions;
(5) cases in which an agency is acting as an agent for a court; or
(6) the certification of worker representatives.
(b) Persons entitled to notice of any agency hearing shall be timely informed of –
(1) the time, place, and nature of the hearing.
(2) the legal authority and jurisdiction under which the hearing is to be held; and
(3) the matters of fact and law asserted.
When private persons are the moving parties, other parties to the proceeding shall give prompt notice of issues controverted in fact or law; and in other instances agencies may by rule require responsive pleading. In fixing the time and place for hearings, due regard shall be had for the convenience and necessity of the parties or their representatives.
(c) The agency shall give all interested parties opportunity for –
(1) the submission and consideration of facts, arguments, offers of settlement, or proposals of adjustment when time, the nature of the proceeding, and the public interest permit; and
(2) to the extent that the parties are unable so to determine a controversy by consent, hearing and decision on notice and in accordance with Sections 556 and 557 of this title.
(d) The employee who presides at the reception of evidence pursuant to Section 556 of this title shall make the recommended decision or initial decision required by Section 557 of this title, unless he becomes unavailable to the agency. Except to the extent required for the disposition of ex parte matters as authorized by law, such an employee may not –
(1) consult a person or party on a fact in issue, unless on notice and opportunity for all parties to participate; or
(2) be responsible to or subject to the supervision or direction of an employee or agent engaged in the performance of investigative or prosecuting functions for an agency.
An employee or agent engaged in the performance of investigative or prosecuting functions for an agency in a case may not, in that or a factually related case, participate or advise in the decision, recommended decision, or agency review pursuant to Section 557 of this title, except as witness or counsel in public proceedings. This subsection does not apply –
(A) in determining applications for initial licenses;
(B) to proceedings involving the validity or application of rates, facilities, or practices of public utilities or carriers; or
(C) to the agency or a member or members of the body comprising the agency.
(e) The agency, with like effect as in the case of other orders, and in its sound discretion, may issue a declaratory order to terminate a controversy or remove uncertainty.

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Sec. 556. *Hearings; Presiding Employees; Powers and Duties; Burden of Proof; Evidence; Record as Basis of Decision*

(a) This section applies, according to the provisions thereof, to hearings required by Section 553 or 554 of this title to be conducted in accordance with this section.
(b) There shall preside at the taking of evidence –
(1) the agency;
(2) one or more members of the body which comprise the agency; or

(3) one or more administrative law judges appointed under Section 3105 of this title.

This subchapter does not supersede the conduct of specified classes of proceedings, in whole or in part, by or before boards or other employees specially provided for by or designated under statute. The functions of presiding employees and of employees participating in decisions in accordance with Section 557 of this title shall be conducted in an impartial manner. A presiding or participating employee may at any time disqualify himself. On the filing in good faith of a timely and sufficient affidavit of personal bias or other disqualification of a presiding or participating employee, the agency shall determine the matter as a part of the record and decision in the case.

(c) Subject to published rules of the agency and within its powers, employees presiding at hearings may --

(1) administer oaths and affirmations;

(2) issue subpoenas authorized by law;

(3) rule on offers of proof and receive relevant evidence;

(4) take depositions or have depositions taken when the ends of justice would be served;

(5) regulate the course of the hearing;

(6) hold conferences for the settlement or simplification of the issues by consent of the parties;

(7) dispose of procedural requests or similar matters;

(8) make or recommend decisions in accordance with Section 557 of this title; and

(9) take other action authorized by agency rule consistent with this subchapter.

(d) Except as otherwise provided by statute, the proponent of a rule or order has the burden of proof. Any oral or documentary evidence may be received, but the agency as a matter of policy shall provide for the exclusion of irrelevant, immaterial, or unduly repetitious evidence. A sanction may not be imposed or rule or order issued except on consideration of the whole record or those parts thereof cited by a party and supported by and in accordance with the reliable, probative, and substantial evidence. The agency may, to the extent consistent with the interests of justice and the policy of the underlying statutes administered by the agency, consider a violation of Section 557 (d) of this title sufficient grounds for a decision adverse to a party who has knowingly committed such violation or knowingly caused such violation to occur. A party is entitled to present his case or defense by oral or documentary evidence, to submit rebuttal evidence, and to conduct such cross-examination as may be required for a full and true disclosure of the facts. In rule making or determining claims for money or benefits or applications for initial licenses an agency may, when a party will not be prejudiced thereby, adopt procedures for the submission of all or part of the evidence in written form.

(e) The transcript of testimony and exhibits, together with all papers and requests filed in the proceeding, constitutes the exclusive record for decision in accordance with Section 557 of this title and, on payment of lawfully prescribed costs, shall be made available to the parties. When an agency decision rests on official notice of a material fact not appearing in the evidence in the record, a party is entitled, on timely request, to an opportunity to show the contrary.

Sec. 557. *Initial Decisions; Conclusiveness; Review by Agency; Submissions by Parties; Contents of Decisions; Record*

(a) This section applies, according to the provisions thereof, when a hearing is required to be conducted in accordance with Section 556 of this title.

(b) When the agency did not preside at the reception of the evidence, the presiding employee or, in cases not subject to Section 554 (d) of this title, an employee qualified to preside at hearings pursuant to Section 556 of this title, shall initially decide the case unless the agency requires, either in specific cases or by general rule, the entire record to be certified to it for decision. When the presiding employee makes an initial decision, that decision then becomes the decision of the agency without further proceedings unless there is an appeal to, or review on motion of, the agency within time provided by rule. On appeal from or review of the initial decision, the agency has all the powers which it would have in making the initial decision except as it may limit the issues on notice or by rule. When the agency makes the decision without having presided at the reception of the evidence, the presiding employee or an employee qualified to preside at hearings pursuant to Section 556 of this title shall first recommend a decision, except that in rule making or determining applications for initial licenses --

(1) instead thereof the agency may issue a tentative decision or one of its responsible employees may recommend a decision; or

(2) this procedure may be omitted in a case in which the agency finds on the record that due and timely execution of its functions imperatively and unavoidably so requires.

(c) Before a recommended, initial, or tentative decision, or a decision on agency review of the decision of subordinate employees, the parties are entitled to a reasonable opportunity to submit for the consideration of the employees participating in the decisions --

(1) proposed findings and conclusion; or

(2) exceptions to the decisions or recommended decisions of subordinate employees or to tentative agency decisions; and

(3) supporting reasons for the exceptions or proposed findings or conclusions.

The record shall show the ruling on each finding, conclusion, or exception presented. All decisions, including initial, recommended, and tentative decisions, are a part of the record and shall include a statement of --

(A) findings and conclusions, and the reasons or basis thereof, on all the material issues in fact, law, or discretion presented on the record; and

(B) the appropriate rule, order, sanction, relief, or denial thereof.

(d)(1) In any agency proceeding which is subject to subsection (a) of this Section, except to the extent required for the disposition of ex parte matters as authorized by law --

(A) no interested person outside the agency shall make or knowingly cause to be made to any member of the body comprising the agency, administrative law judge, or other employee who is or may reasonably be expected to be involved in the decisional process of the proceeding, an ex parte communication relevant to the merits of the proceeding;

(B) no member of the body comprising the agency, administrative law judge, or other employee who is or may reasonably be expected to be involved in the decisional process of the proceeding, shall make or knowingly cause to be made to any interested person outside the agency an ex parte communication relevant to the merits of the proceeding;

(C) a member of the body comprising the agency, administrative law judge, or other employee who is or may reasonably be expected to be involved in the decisional process of such proceeding who receives, or who makes or knowingly causes to be made, a communication prohibited by this subsection shall place on the public record of the proceeding:

(i) all such written communications;

(ii) memoranda stating the substance of all such oral communications; and

(iii) all written responses, and memoranda stating the substance of all oral responses, to the materials described in clauses (i) and (ii) of this subparagraph;

(D) upon receipt of a communication knowingly made or knowingly caused to be made by a party in violation of this subsection, the agency, administrative law judge, or other employee presiding at the hearing may, to the extent consistent with the interests of justice and the policy of the underlying statutes, require the party to show cause why his claim or interest in the proceeding should not be dismissed, denied, disregarded, or otherwise diversely affected on account of such violation; and

(E) the prohibitions of this subsection shall apply beginning at such time as the agency may designate, but in no case shall they begin to apply later than that time at which a proceeding is noticed for hearing unless the person responsible for the communication has knowledge that it will be noticed, in which case the prohibitions shall apply beginning at the time of his acquisition of such knowledge.

(2) This subsection does not constitute authority to withhold information from Congress.

Formal hearings -- whether rule making on the record or adjudication -- normally follow these procedures and take time, work, and money. Assume, for example, that Utility X files for a rate increase. The commission will generally suspend the proposed rate increase for a period of time.[83] The company, with the concurrence of the commission or its staff, will generally select a "test year," frequently the latest 12-month period for which complete data are available. The purposes of such a test year are as follows. In the first place, the commission's staff must audit the utility's books. For ratemaking purposes, only just and reasonable expenses are allowed; only used and useful property (with certain exceptions) is permitted in the rate base. In the second place, the commission must have a basis for estimating future revenue requirements. This estimate is one of the most difficult problems in a rate case. A commission is setting rates for the future, but it has only past experience (expenses, revenues, demand conditions) to use as a guide. *"Philosophically, the strict test year assumes the past relationship among revenues, costs, and net investment during the test year will continue into the future."*[84] To the extent that these relationships are not constant, the actual rate of return earned by a utility may be quite different from the rate allowed by the commission.[85] For many years, commissions have adjusted test-year data for "known changes"; *i.e.*, a change that actually took place during or after the test period (such as a new wage agreement that occurred toward the end of the year). More recently, due largely to inflation, a few commissions have modified the traditional historic test-year approach by using a forward-looking test year (either a partial or a full forecast)[86] or by permitting pro forma expense and revenue adjustments.

The case will be set down on the commission's docket for future public hearings, and due notice will be given to the utility's customers.[87] Before the case is called, the utility, the commission's staff, and intervenors (interested parties)[88] will file their testimony (prefiled "canned" testimony). Such testimony usually is presented by outside experts, as well as by both company and staff personnel. Any of the parties in the case may make data requests to the others.[89] When the case is called, the hearing is conducted by an administrative law judge,[90] a panel (one or more) of the commissioners, or the full commission. All witnesses are sworn, the evidence is recorded (transcribed), and witnesses may be questioned by the administrative law judge or commissioners and cross-examined by counsel for the staff and other parties. In some instances, hearings will be held in the community or communities affected. Individual consumers, even though not represented by counsel, are permitted to testify and, in a few states, to cross-examine witnesses.[91]

After all evidence has been received, the record is closed. Briefs may be filed by the various parties. When an administrative law judge presides, an "initial" or "recommended" decision is subsequently issued by the judge.[92] The decision must be written and accompanied by formal findings of fact and conclusions of law. It is then subject to review by the full commission[93] (usually through the filing of briefs that take exception to part or all of the initial decision,[94] but sometimes in an oral presentation). Once the commission has issued its decision and order, petitions may be filed for reconsideration and rehearing.[95] The final commission order, in turn, may be appealed to the courts.

It is not uncommon for important cases to require many days or weeks of hearings and to take a year or more (from date of filing to date of a commission order).[96] When an order is appealed to the courts, another two to four years may be added, particularly when the reviewing court remands the case to the commission.[97] As a result, formal proceedings often involve delay to the disadvantage of many of the parties involved.[98]

Shortened Procedures.[99]

In an attempt to save both time and expense, shortened procedures have been developed. One of the most important and widely used is the prehearing conference, generally called by and held before the presiding administrative law judge. The Rules of Practice of the former Civil Aeronautics Board are typical:

> The purpose of such a conference is to define and simplify the issues and the scope of the proceeding, to secure statements of the positions of the parties, ... to schedule the exchange of exhibits before the date set for hearing, and to arrive at such agreements as will aid in the conduct and disposition of the proceeding. For example, consideration will be given to: (*1*) matters which the Board can consider without the necessity of proof; (*2*) admissions of fact and the genuineness of documents; (*3*) admissibility of evidence; (*4*) limitation of the number of witnesses; (*5*) reducing of oral testimony to exhibit form; (*6*) procedure at the hearings, etc....[100]

Following the prehearing conference, the administrative law judge "shall issue a report of the prehearing conference, defining the issues, giving an account of the results of the conference, specifying a schedule for the exchange of exhibits and rebuttal exhibits, the date of hearings, and specifying a time for the filing of objections to such report."[101] The report is sent to all parties in the proceeding and, based upon their objections, may be revised by the administrative law judge. The final report "shall constitute the official account of the conference and shall control the subsequent course of the proceeding, but it may be reconsidered and

The Regulation of Public Utilities
Theory and Practice

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Part II. The Theory of Public Utility Regulation

CHAPTER 6: ACCOUNTING AND FINANCING

The overriding purposes of the uniform systems of accounts are twofold: uniformity and consistency. In the exercise of their responsibilities, regulatory commissions must investigate and review the operations of utilities within their jurisdiction. For the most part, this requires accounting-oriented information. In order to ensure that the actions of regulators are reasonable and consistent and that utilities are regulated on a comparable basis, uniformity of accounting treatment, as well as consistency of treatment from period to period, is necessary. —Robert L. Hahne and Gregory E. Aliff[a1]

Whether the Commission should make specific classifications to fit exceptional cases lies within the discretion confered, and courts ought not to be called upon to interfere with or correct alleged errors with respect to accounting practice. If we were in disagreement with the Commission as to the wisdom and propriety of the order, we are without power to usurp its discretion and substitute our own. [9]

Uniform systems of accounts, however, developed slowly. [10] Early legislative statutes either made no provision for commission control of accounting methods, or, when provision was made, the commissions often did not act. Massachusetts was the first state to direct its commission to prescribe uniform accounting systems: for railroads in 1876, gas companies in 1885, and electric utilities in 1887. The regulatory agencies of New York and Wisconsin were given jurisdiction over the accounting practices of public utilities in 1905 and 1907, respectively, and they prescribed uniform systems for electric and gas utilities in 1909.

In other instances, public utilities develop their own uniform accounting systems. The National Electric Light Association, an organization of private electric utilities, devised the first important standard classification of electric accounts. In 1907, the Association of American Railway Accountants in cooperation with the Interstate Commerce Commission developed a similar system of accounting for the nations's railroads. In 1913, the ICC established a uniform system for telephone companies (over which it then had jurisdiction), and in 1922, the National Association of Railroad and Utilities Commissioners (NARUC) prescribed uniform systems of accounts for electric and gas companies. These systems served as models, and by 1925, forty states had adopted or approved such uniform classifications. [11] These early systems, though better than no systems at all:

> ... had significant defects. They gave too much accounting authority to the utility companies. When the first draft of the uniform electric system was drawn up in 1920, representatives of private electric companies did much of the work. And the accounting ideas of private electric systems were evident in the final draft of the uniform system. Managers of utility companies could fix, in part, the book valuation standard for property, and could choose the method of depreciation accounting. [12]

Major revisions in accounting control of electric, gas, and telephone companies were made during the depression of the thirties. The Federal Communications Commission adopted in 1935, with only minor modifications, the uniform system for the telephone companies which had been promulgated by the ICC in 1913; and in 1937, the NARUC approved a similar system for intrastate telephone companies. In 1936, systems of accounts were developed for electric companies by the Federal Power Commission and the NARUC, for gas companies by the NARUC, and for holding companies by the Securities and Exchange Commission. Shortly after Congress passed the Natural Gas Act in 1938, the FPC prescribed a uniform system of accounts for all interstate natural gas companies. Since this time, the uniform systems have been modified on numerous occasions – "due to the introduction of new technology of accounting interpretations by professional accounting organizations or regulatory bodies" [13] – but they remain substantially as developed during the thirties.

The uniform systems prescribed by the federal commissions went into effect immediately, but the state commissions had to adopt the systems before they became effective. Today, most of the state commissions have adopted either the federal or the NARUC accounting systems, although they are often modified in detail to fit local situations or problems. Thus, forty-six of the state commissions regulating private electric utilities prescribe the FERC or the NARUC systems of accounts and three prescribe their own systems, while forty-eight of the state commissions regulating telephone companies prescribe the FCC uniform systems of accounts and three prescribe their own systems. [14]

Comparability and Rate Regulation

The ultimate objective of uniform systems of accounts "must be comparability in financial reporting both among companies within a single industry and among companies in different industries, so that substantial factual matters are not hidden from the public view by accounting flexibility." [15] Yet, as is true with almost all regulatory procedures, uniform systems of accounts represent a tool. There are many important differences of opinion with respect to scope, content, and application of the various provisions of any uniform system. Because of alternative accounting principles, uniform accounting standards have not been adopted by the regulatory commissions.[16] Consequently, while there is widespread comparability of financial reports filed by companies within each jurisdiction, interjurisdictional comparisons must be made with some care.[17]

In this connection, it must be kept in mind that a commission

> ... is not bound in its rate proceedings by any system of accounts it may have prescribed or by what is revealed in a review of the systems of accounts. Utility regulation, the making of business decisions, and the determination of values cannot be reduced to an automatic process by which the correct decision can be made by reference to books of accounts.[18]

In rate proceedings, therefore, a commission may (and often does) disallow certain expenditures for ratemaking purposes or may (on occasion) place a value on a utility's property in determining the rate base that exceeds the original cost of that property as shown in the uniform system of accounts. These problems are considered in succeeding chapters.

Finally, it is important to note that while "generally accepted accounting principles" apply to all industries, there are cases where their application results in differences for public utilities because of economic regulation. As noted by Suelflow:

> ... One of the main differences that occurs is in the timing of when certain items enter into net income -- matching of expenses and revenues. For example, extraordinary losses are recognized by nonregulated firms in the accounting period in which they occur; regulated utilities often defer these items, amortizing them over a future time period. While at variance with generally accepted principles, the practice is acceptable, but only if cost recovery is sure. The other possible difference which exists between regulated and nonregulated firms concerns certain charges that may be written off to retained earnings when generally accepted accounting principles would consider the item as a charge against current income of the nonregulated firm.[19]

Uniform Systems of Accounts[20]

The uniform systems of accounts used by regulatory commissions can be illustrated with reference to the uniform system prescribed by the Federal Energy Regulatory Commission (as of 1986) for Major Electric Utilities.[21]

Balance Sheet Accounts.

A condensed balance sheet form is shown in Figure 6-1. On the asset side, the most important account for ratemaking purposes is "Utility Plant."[22] The FERC, along with the other federal and state commissions, requires that property accounts show the original cost of all items entered. It is important to realize, however, that the term "original cost" has a special meaning -- that is, it represents "the cost of such property to the person first devoting it to public service." This definition is not the conventional accounting meaning, for accountants generally value property at its cost to the existing company (the investment cost). Thus, when a utility builds its own plant, the total cost of construction is entered under the appropriate utility plant account. When property is acquired as a gift, it is entered on the basis of the estimated value at the time of donation. But when property is purchased from another company, it is recorded in the plant account on the basis of its original cost, even though the acquiring firm may have paid more or less than this figure for the property.[23]

The costs of additions and improvements are added when incurred, whether paid for from accrued depreciation, retained earnings, or the proceeds of security issues; any excess cost of replacing property in kind over the original cost of the property retired is added to the account. Abandoned property is written off (although it is sometimes amortized over a period of years). The cost of construction work in progress is added.

FIGURE 6-1

Condensed Balance Sheet Accounts