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

EXHIBIT
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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree, both from the University of Toledo. I also earned a Master of Arts degree from Luther Rice University. I am a Certified Public Accountant, with a practice license, a Certified Management Accountant, and a Chartered Global Management Accountant. I am a member of numerous professional organizations.

I have been an active participant in the utility industry for more than thirty years, both as a consultant and as an employee. Since 1986, I have been a consultant with Kennedy and Associates, providing assistance to consumers of utility services and state and local government agencies in the areas of utility planning, ratemaking, accounting, taxes, financial reporting, financing and management decision-making. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies in the areas of planning, financial accounting and reporting, financing, ratemaking and management decision-making. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions, providing services in the areas of planning, accounting, financial and statistical reporting, and taxes.

I have appeared as an expert witness on utility planning, ratemaking, accounting, reporting, financing, and tax issues before state and federal regulatory commissions and courts on more than two hundred occasions. In addition to consumers of electricity and natural gas utility services, I have represented state and local ratemaking agencies or their Staffs, including the Louisiana Public Service Commission, Georgia Public Service Commission and various Cities with original rate jurisdiction in Texas. I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. My qualifications and regulatory appearances are further detailed in Kollen Exhibit___(LK-1).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of GCC Dakotah, 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, the

"Black Hills Industrial Intervenors" or "BHII").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address (1) the claimed base revenue deficiency and requested rate increase of $14.634 million set forth in the Company's application (the "Application") and (2) the revised revenue deficiency and requested rate increase of $6.891 million set forth in the proposed Settlement Stipulation (the "Proposed Settlement") between the Company and the Commission Staff ("Staff") filed in this docket on December 8, 2014. I recommend numerous adjustments to the base revenue deficiency in each of the Application and the Proposed Settlement necessary to ensure that the Company's rates are just and reasonable.

Q. What support has the Company and Staff provided for the Proposed Settlement?

A. The Proposed Settlement states how the Company and Staff have resolved certain issues and incorporates various schedules. To support the Proposed Settlement, the Staff developed and provided to BHII an Excel spreadsheet that provides some details regarding the calculation of the rate increase in the Proposed Settlement. Although the spreadsheet incorporates the adjustments reflected in the Proposed Settlement, it does not include all calculations or source all adjustment amounts. Nor does the spreadsheet provide any descriptions or testimony in support of the adjustments that were included or the reasons why certain adjustments proposed by BHII and shared during Proposed Settlement discussions with the parties were not accepted.

Q. Please summarize your testimony.

A. While I agree (in whole or in part) with the resolution of certain issues reflected in the Proposed Settlement, I recommend that the Commission reject both the base rate increase requested by the Company in its Application and the base rate increase set forth in the Proposed Settlement. Because evidence in the Application and responses to BHII information requests demonstrate that the Company's rates have grown increasingly uncompetitive,[1] BHII refused to sign on to the Proposed Settlement. As demonstrated below, the Proposed Settlement between the Company and the Staff is woefully inadequate. It fails to address or properly resolve certain issues that, if addressed and resolved properly, would substantially reduce the revenue requirement necessary to set rates at just and reasonable levels.

Taken together, the recommendations set forth in my testimony support a *reduction* in the Company's current base rates of at least $5.258 million (as opposed to the *significant and unnecessary increase* in base rates proposed by the Company in its Application and by the Company and Staff in the Proposed Settlement). Thus, I recommend that the Commission (1) reduce the $14.634 million increase requested by the Company in its Application by $19.893 million

[1] As of 2012, and compared to other investor owned utilities in South Dakota, Black Hills Power had the highest average residential rate, the highest average commercial rate, and the third highest industrial rate. Source: U.S. Energy Information Administration; http://www.eia.gov/electricity/data.cfm#sales

and (2) reduce the $6.891 million increase agreed to by the Company and Staff in the Proposed Settlement by $12.149 million. The reductions that I recommend reflect the return on equity of [redacted] set forth in the Proposed Settlement.

I recommend that the Commission adopt numerous adjustments to both the Company's requested increase and the Proposed Settlement increase. I summarize the revenue requirement effects of these adjustments on the following table.

The first column in the table starts with the Company's claimed revenue deficiency set forth in its Application and then shows the revenue requirement effect of each adjustment to the Company's request that I recommend. If the Commission starts with the Company's request, then it should adopt the adjustments that I recommend in this column.

The second column starts with the Company's claimed revenue deficiency set forth in its Application and then shows the revenue requirement effect of each adjustment identified and reflected in the Proposed Settlement. I included this column in the event the Commission starts with the Proposed Settlement so that it can directly compare my recommendations for each issue with the comparable adjustments, if any, reflected in the Proposed Settlement.

The third column represents the incremental effect of the adjustments that I recommend, as shown in the first column, in the event the Commission starts with the Proposed Settlement and the Commission adopts my adjustments and quantifications.

Docket No. EL14-026
Black Hills Power, Inc.
South Dakota Retail Revenue Requirement
Summary of BHII Recommendations
Compared to Company's Filing and Proposed Settlement With Staff
($ Millions)

	BHII Recommend Compared to Company Filing	Proposed Settlement	BHII Recommend Compared to Proposed Settlement
Black Hill Power Company Requested Rate Increase	14.634	14.634	
Adjustments			
Rate Base			
Remove Company's Double Count of Spare Parts for CPGS	(0.132)		(0.132)
Remove NOL ADIT	(1.414)	(0.026)	(1.388)
Adjust Retired Steam Plants Regulatory Asset - NBV	0.043		0.043
Reduce or Remove Retired Steam Plants Regulatory Asset - Def Decom	(0.894)	0.388	(1.282)
Extend Storm Damage Amortization to Ten Years and Subtract ADIT	(0.102)	(0.179)	0.077
Remove Regulatory Asset - 69kV LIDAR Surveying Project	(0.057)	(0.046)	(0.011)
Adjust Accumulated Depr. and ADIT Related to Restatement of Net Negative Salvage	0.019		0.019
Adjust Accumulated Depr. and ADIT Related to CPGS Life Span Extension	0.006		0.006
Adjust Rate Case Regulatory Asset		(0.036)	0.036
Operating Income			
Remove FutureTrack Workforce	(0.676)	(0.344)	(0.332)
Remove Employee Additions/Eliminations Identified on Schedule H-1 Line 5	(1.266)	(0.096)	(1.169)
Remove Additional Pension Plan Expense Based on 5 Year Average	(1.247)	(0.289)	(0.958)
Remove Incentive Compensation Tied to BHC Fin'l Peformance	(1.554)	(0.666)	(0.888)
Remove Proforma Increased Affiliate Allocations from BHUH	(1.846)	0.527	(2.373)
Remove Settlement Adjustment to Increase Affiliate Allocations from BHSC		1.132	(1.132)
Extend Retired Steam Plants Amortization Expense	(0.582)		(0.582)
Reduce Amortization Expense on Atlas Storm Damage Regulatory Asset	(0.414)	(0.512)	0.098
Retired Steam Plants Decommissioning Amortization Expense	(1.956)	(0.487)	(1.469)
Remove 69kV LIDAR Surveying Project Amortization Expense	(0.130)	(0.066)	(0.064)
Extend CPGS Life Span (Depr Expense)	(0.338)	(0.314)	(0.024)
Correct Steam and Other Production Net Salvage (Depr Expense)	(1.132)		(1.132)
Remove Company's Double Count of Spare Parts for CPGS (Depr Expense)	(0.033)		(0.033)
Adjust Rate Case Regulatory Asset Amortization		(0.083)	0.083
Adjustment to Weather Normalization Revenue	(0.380)	(0.380)	-
Adjustment to Allocated Neil Simpson Rent Revenue and Expense	(0.219)	(0.219)	-
Adjustment to Neil Simpson Common Steam Allocation	(0.244)	(0.244)	-
All Other Proposed Settlement Changes Combined		(0.217)	0.217
Rate of Return			
Reduce Cost of Debt to Reflect Lower Interest Rate on New Debt Issue	(0.885)	(0.925)	0.040
Reflect Proposed Settlement Capital Structure	(0.216)	(0.226)	0.010
Reduce Return on Equity - Proposed Settlement	(4.245)	(4.435)	0.191
Total Adjustments to Company's Request	(19.893)	(7.744)	
Net Rate Increase/(Reduction) Recommendation	(5.258)	6.891	
Total Differences Between BHII Recommendation and Proposed Settlement			(12.149)

Q. In the Rate of Return section of the preceding table, the effects on the revenue requirement for each adjustment are less pursuant to your recommendations in the first column compared the Proposed Settlement in the second column. Please explain why this is the case.

A. The rate base that I recommend is less than the rate base reflected in the Proposed Settlement. I recommend additional adjustments or different quantifications for certain adjustments to rate base than the adjustments reflected in the Proposed Settlement. For example, I recommend that the Commission remove the NOL ADIT from rate base and show the reduction in the revenue requirement based on the Company's requested rate of return. However, the Proposed Settlement does not reflect a similar reduction in rate base for this issue. Thus, despite the fact that the adjustments to the rate of return are the same under my recommendations and pursuant to the Proposed Settlement, the effect is slightly greater pursuant to the Proposed Settlement.

Q. Are there general ratemaking principles that form the basis for many of your recommended adjustments?

A. Yes. First, I recommend that the Commission limit any post-test year adjustments to the twelve month period immediately following the historic test year ending September 30, 2013. Adjustments beyond this twelve month post-test year period are not known and measurable and, in some instances, represent costs that should not be incurred or, if incurred, that should be included in a subsequent rate proceeding. Such adjustments to costs are uncertain. They are opportunistic and selective in that they do not represent a comprehensive or consistent set of adjustments for the period two years after the actual test year. More specifically, the Company did not include all potential corresponding increases in revenues or reductions in costs that would offset the adjustments for projected increases in costs beyond the twelve month post-test year period. By failing to include such revenue increases and cost reductions in its Application, the Company unjustly and unreasonably skewed the proposed base rate increase upward. As discussed below, my understanding of S.D. Admin. Rule 20:10:13:44, is that any proposed adjustments based on projected costs beyond the twelve month post-test year period must be accompanied by projected changes in revenue for the same period. The Company's selective adjustments beyond the twelve month post-test year period may violate South Dakota law.

Second, I recommend that the Commission reject proposed post-test year increases in various expenses that are not justified and that the Company did not demonstrate were necessary and appropriate. The Company bears a special burden to demonstrate that these increases in expenses compared to the historic test year are just and reasonable. Such increases tend to be self-fulfilling and permanent once recovery is assured in rates.

Third, I recommend that the Commission reject adjustments that are not consistent with Commission precedent or policy, that are not justified, and that the Company did not demonstrate were necessary and appropriate.

Q. How is the remainder of your testimony organized?

A. The remainder of my testimony is organized so that it follows the sequence of the issues in the preceding table. On each issue, I will first address the issue as it is reflected in the Company's Application. I then will address the issue as it is reflected in the Proposed Settlement.

II. RATE BASE ISSUES

A. <u>The Commission Should Correct the Double Counting Error in CPGS Spare Parts Inventory</u>

Q. Please describe the error in the CPGS spare parts inventory included in rate base.

A. The Company erroneously included $2.200 million (total plant and total Company) CPGS spare parts inventory in both the CPGS plant in service amounts shown on Schedule D page 2, Schedule D-11, and in the materials and supplies amount shown on Schedule F-4. The CPGS spare parts inventory should be removed from the plant in service amounts.

Q. What are the effects on rate base and the revenue requirement of correcting this error?

A. The correction results in a reduction in the jurisdictional rate base of $1.152 million (BHP owns 58% of the plant), consisting of a reduction in plant in service of $1.157 million, a reduction in accumulated depreciation of $0.017 million and an increase in accumulated deferred income taxes ("ADIT") of $0.012 million.

The calculations and sources of these amounts are detailed on my Exhibit___(LK-2).

The correction reduces the Company's revenue requirement by $0.165 million, consisting of a reduction in the return on rate base of $0.132 million and a reduction in depreciation expense of $0.033 million.

Q. Does the Company agree that this was an error and should be corrected?

A. Yes. The Company agreed that this was an error in response to SDPUC Request No. 6-42, a copy of which I have attached as my Exhibit___(LK-3).

Q. Does the Proposed Settlement properly reflect the correction of this error?

A. Yes.

B. <u>The Commission Should Remove the Asset Net Operating Loss ("NOL") Accumulated Deferred Income Taxes ("ADIT") from Rate Base</u>

Q. Please describe the Company's proposal to include asset NOL ADIT amounts in rate base.

A. The NOL ADIT is the tax effect of the NOL carry-forward, which is stated in the form of taxable losses that can be carried forward to reduce taxable income in subsequent years. The Company included $12.373 million (jurisdictional) and $13.497 million (total Company) in asset NOL ADIT in rate base as shown on Schedule M-1 (lines 12 and 27) based on a thirteen month average in the historic test year, and on Schedule M-2 (line 21) to reflect certain plant additions through

September 30, 2014. The total Company amounts and the jurisdictional amounts are detailed on my Exhibit___(LK-4).

Q. Should the Commission include the asset NOL ADIT in rate base?

A. No. First, as a conceptual matter and as a matter of regulatory principle, the NOL ADIT violates the prohibition against retroactive ratemaking. The NOL ADIT is the result of actual taxable losses in prior years that could not be fully utilized or monetized through carrybacks. However, in prior rate cases, the Company's rates were set to recover the maximum income tax expense under the assumption that there would be no taxable losses. The fact that the Company subsequently actually incurred taxable losses rather than taxable income does not entitle it to include the tax effect of those losses in rate base and earn a return from customers. This would constitute an improper retroactive true-up of a portion of the Company's income tax expense incurred in prior years for ratemaking purposes.

Second, the NOL ADIT is only temporary. The NOL carryforward will be utilized as the Company generates taxable income. Nevertheless, the Company's Application assumes not only that the NOL ADIT will continue to exist, but that it will exist at the same level until rates are reset in the next base rate proceeding. The Company's assumption is incorrect and without valid foundation.

In fact, the Company's Schedule K page 2 indicates that the NOL carryforward that gave rise to the NOL ADIT will be fully utilized *prior to or* *during the first year that rates are effective*. The actual NOL ADIT at September 30, 2013 is equivalent to a $16.996 million NOL carryforward, assuming a 35% federal income tax rate. The Company's Schedule K page 2 indicates that the Company will generate $44.678 million in federal taxable income if its base rate increase is granted in full in this proceeding. Even with zero base rate increase, the Company's filing indicates that taxable income still will be more than sufficient to fully utilize the NOL carryforward either before rates are reset or within the twelve months after rates are reset.

Q. What is the effect on the revenue requirement of removing the asset NOL ADIT from rate base?

A. The effect is a reduction in the revenue requirement of $1.414 million.

Q. As a practical matter, if the Commission decides to include the asset NOL ADIT in rate base, then should the thirteen month average for the historic test year be adjusted to October 1, 2014 in the same manner that the Company adjusted other rate base components to reflect known and measurable adjustments through October 1, 2014?

A. Yes. As I noted previously, the NOL ADIT is a temporary amount that should decline to $0 when the NOL carryforwards are fully utilized. The Commission should not set rates to provide a return on an asset NOL ADIT that either no longer exists or has declined significantly since the historic test year. Adjusting the 13-month average for the historic test year to October 1, 2014, would be consistent with the Company's proposal to adjust certain of its regulatory assets and to increase its plant in service amounts for allegedly known and measurable changes to October 1, 2014.

The October 1, 2014 date is twelve months after the end of the historic test year and the assumed date when rates would be reset in this proceeding. If the Commission allows the Company to selectively adjust other rate base components to October 1, 2014, then it also should ensure that the NOL ADIT is adjusted to that same date, and should do so based on the information in the Application.

Q. Did the NOL ADIT on the Company's balance sheet decline since the beginning of the historic test year?

A. Yes. The NOL ADIT has steadily declined since October 1, 2012, the beginning of the historic test year, toward a $0 balance at October 1, 2014, twelve months after the end of the historic test year. Unlike the updated amounts for regulatory assets and plant in service additions, the Company used the thirteen month balance during the historic test year for the NOL ADIT. This overstates the NOL ADIT that remained at September 30, 2013, the end of the historic test year and at October 1, 2014, because it failed to capture the decline throughout the test year and the continued decline in the twelve month post-test year period. As of September 30, 2013, the NOL ADIT was $5.949 million (jurisdictional) and $6.489 million (total Company).[2]

The NOL ADIT continued to decline from that date through December 31, 2013, when it had declined to $4.363 million (jurisdictional) and $4.760 million (total Company).[3]

Q. How much of the Company's NOL carryforward did it utilize in 2013 and how much will it utilize going forward based on the calculation of taxable income reflected in the Application?

A. The Company had a federal NOL carryforward of $14 million at December 31, 2013.[4] During 2013, the Company utilized $16.708 million of the federal NOL carryforward at December 31, 2012. In other words, the Company had taxable income of $16.708 million, but was able to reduce that to $0 by utilizing the NOL carryforward. This pattern will repeat itself in 2014, although taxable income will be greater in 2014 compared to 2013 due to the unavailability of bonus tax depreciation in 2014. In other words, the Company will be able to utilize the full remaining amount of the NOL carryforward in 2014, all else being equal. I calculated the NOL carryforward that was utilized based on the reduction in the NOL ADIT during 2013. The Company reduced the NOL ADIT during 2013 by $5.207 million (jurisdictional)[5], and by $5.681 million (total Company)[6].

In short, based on the Company's filing, there should be no remaining asset NOL ADIT at October 1, 2014. Thus, even if the Commission decides to

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[2] Schedule M-1 page 2.

[3] Black Hills Power Company 2013 FERC Form 1 page 234, attached as my Exhibit___(LK-5).

[4] *Id.*, page 123.13, attached as my Exhibit___(LK-6).

[5] From $9.570 million (jurisdictional) at the beginning of the year to $4.363 million (jurisdictional) at the end of the year.

[66] From $10.441 million (total Company) at the beginning of the year to $4.760 million (total Company) at the end of the year.

allow an asset NOL ADIT in rate base, which would violate the prohibition on retroactive ratemaking, the amount at October 1, 2014 should be $0 as a practical matter.

Q. What amount of NOL ADIT was included in the rate base reflected in the Proposed Settlement?

A. The Proposed Settlement reflects a slight reduction of $0.226 million in the NOL ADIT compared to the Company's Application. This slight reduction in the NOL ADIT included in rate base had the effect of reducing the Company's revenue requirement by a mere $0.026 million.

Q. Is there any justification for including any NOL ADIT in rate base in the Proposed Settlement?

A. No, for the reasons that I previously discussed.

C. <u>The Commission Should Reduce Regulatory Asset - Deferred Decommissioning on Retired Plants</u>

Q. Please describe the Company's requested regulatory asset and amortization expense for decommissioning costs on its retired coal-fired power plants.

A. The Company included $7.824 million in rate base for its estimated costs to decommission the retired Osage, Neil Simpson I and Ben French power plants, net of accumulated depreciation and an incorrectly calculated adjustment to reduce ADIT. The Company also included $1.956 million in amortization expense based on a proposed five year amortization period. I provide the details of the Company's request, including the source of the amounts that I cited, on my Exhibit___(LK-7).

Q. When does the Company plan to spend the estimated amounts?

A. The Company plans to begin decommissioning activities at the Ben French plant in January 2015 and complete the activities in September 2015. It planned to begin activities at the Neil Simpson 1 plant in November 2014 and complete the activities in June 2015. It planned to begin activities at the Osage plant in August 2014 and complete the activities in April 2015.[7]

Q. Did the Company seek or obtain an order to defer decommissioning costs that have been incurred to date?

A. No.

Q. Should the Commission include the estimated decommissioning costs as a regulatory asset in rate base and allow amortization expense in this proceeding?

A. No. The Company's request is premature and overreaching. The Company had not yet incurred most of the decommissioning costs that it seeks to include in rate base as of October 1, 2014, twelve months after the end of the historic test year. In addition, the Company's request includes estimated costs through September

[7] Direct Testimony of Mr. Mark Lux at 18-19.

2015, some twenty-four months after the end of the historic test year. Thus, these amounts should not be included in rate base in this proceeding.

Instead, the Commission should authorize the Company to defer these decommissioning costs as regulatory assets and address the recovery of the costs in the Company's next base rate proceeding.

Q. Is there support in South Dakota law for excluding estimated costs that would be incurred after the end of the 12-month historical test year?

A. Yes. My understanding of S.D. Admin. Rule 20:10:13:44, is that the Commission is not permitted to allow adjustments that would become effective unless they are based on changes in facilities, operations, or costs which are known with reasonable certainty and measurable with reasonable accuracy at the time of filing. Moreover, it is my understanding that any such adjustment to costs must be accompanied by expected changes in revenue for the same period. The Company has not provided evidence that any estimated costs that would be incurred after the end of the 12-month historical test year were known with reasonable certainty or measurable with reasonable accuracy at the time that the Company filed its Application, and the Company has not provided any adjustments to revenue for the same period.

Q. If the Commission allows the estimated decommissioning costs in rate base and authorizes recovery of amortization expense, should it correct the ADIT error?

A. Yes. The Commission should correct the ADIT error. The Company incorrectly calculated the ADIT offset for the regulatory assets shown on Schedule M-2 as an asset ADIT of $0.762 million (total Company). Specifically, the Company failed to include the deduction for the entire decommissioning cost under the column titled "tax depreciation" on line 35 of Schedule M-2. If this deduction is properly reflected, the ADIT related to the regulatory asset for decommissioning should be $3.423 million (jurisdictional, using an 89.83% production plant allocation factor) or $3.811 million (total Company).

The Company will be able to deduct the entirety of the estimated $10.887 million (total Company) decommissioning costs for income tax purposes when the costs are incurred. This deduction will create a book/tax temporary difference. The ADIT is equal to 35% of the book/tax temporary difference. The Company estimates that it will incur all decommissioning costs related to these retired plants by September 2015.

If the Commission includes the entirety of the costs that the Company estimates it will incur by September 2015 in rate base, then the Commission should also reflect the offsetting ADIT in 2015 as a subtraction from rate base.

Q. What is the effect on the revenue requirement if the Company's ADIT error is corrected?

A. The effect is a reduction of $0.391 million in the Company's claimed revenue requirement, using the Company's requested grossed-up rate of return ($3.423 million times 11.43%).

Q. Does the Proposed Settlement correct the error in the ADIT?

A. No. If the Commission adopts the Proposed Settlement, then it should modify it to correct the error in the ADIT.

Q. If the Commission allows the estimated decommissioning costs in rate base and authorizes recovery of amortization expense, should it make any adjustments in addition to correcting the ADIT error?

A. Yes; the Commission should make two other adjustments. First, the Commission should remove the contingencies from the decommissioning cost estimate. By definition, contingencies are not known and measurable. If the Commission allows the estimated decommissioning costs in rate base and the amortization in expense, then it should use the Company's best estimate for the decommissioning cost, not an inflated estimate that includes contingencies. The contingencies included in the Company's estimated decommissioning costs are $0.956 million, according to the Company's response to Staff DR 3-23.

Second, the Commission should exercise its discretion to use a longer amortization period to minimize the effect on customers. In this case, a ten-year amortization period will achieve this objective. The Company's proposed five-year amortization period is unnecessarily short. If the Commission includes the estimated decommissioning costs in rate base, then the Company will earn a return on the unamortized regulatory asset regardless of the amortization period.

Q. What is the effect on the revenue requirement of eliminating the contingencies and using a ten year amortization period?

A. A 10-year amortization period will reduce the Company's revenue requirement by $1.162 million. The calculations are detailed on my Exhibit____(LK-8).

Q. Does the Proposed Settlement reflect your recommendation to remove contingencies and use a ten year amortization period?

A. Yes.

D. <u>The Commission Should Correct Accumulated Deferred Income Taxes Due to Regulatory Asset for Storm Costs</u>

Q. Did the Company reflect the correct ADIT due to the regulatory asset for storm costs as a reduction to rate base?

A. No. The Company failed to reflect the ADIT on storm costs in excess of the casualty loss deduction on Schedule M-1 or Schedule M-2.

Q. Does the Company agree that this was an error and should be corrected?

A. Yes. The Company acknowledged this error in response to BHII Request No. 26, although its quantification of the error was not correct. I have attached a copy of the Company's response to BHII Request No. 26 as my Exhibit___(LK-9).

Q. Why is the Company's quantification of the ADIT error incorrect?

A. The Company should have treated the entirety of the regulatory asset as a temporary difference. However, in its response to BHII Request No. 26, the Company reduced the temporary difference by the amount of the estimated casualty loss, as well as an additional amount, apparently to reflect changes in its estimated costs compared to its Application. Those amounts should be included in the temporary difference.

Q. What is the effect on the revenue requirement of correcting this error, using the regulatory asset quantified by the Company in its Application?

A. Using the Company's proposed five-year amortization period, the Company's claimed revenue deficiency should be reduced by $0.132 million. The Company should have reflected $1.159 million in ADIT as a reduction in rate base in its filing, using the five-year amortization period proposed in its Application.

If, however, the Commission adopts a ten-year amortization period, as I propose, then the Company's claimed revenue requirement should be reduced by $0.516 million, consisting of a reduction of $0.102 million due to the net change in rate base (increase in ADIT and reduction in accumulated amortization) and a reduction of $0.414 million in amortization expense to reflect the longer amortization period. The calculation of these amounts is detailed on my Exhibit___(LK-10).

Q. Was this error corrected in the Proposed Settlement?

A. Yes. However, the Proposed Settlement includes the effect of reducing the regulatory asset amount for various costs before computing the effects of including the ADIT as a reduction to rate base. The Proposed Settlement reflects a reduction in the revenue requirement of $0.179 million based upon the net reduction in rate base, including the reduction in the regulatory asset and the subtraction of the ADIT based on the adjusted regulatory asset.

E. <u>The Commission Should Remove Regulatory Asset for Estimated 69 kV LIDAR Surveying Project Costs</u>

Q. Please describe the Company's requested regulatory asset and amortization expense for estimated LIDAR surveying costs.

A. The Company included $0.502 million in rate base for its estimated costs to perform a LIDAR survey of its 69kV distribution system, net of accumulated depreciation. The Company did not include any ADIT offset to the requested regulatory asset even though it represents a book/tax temporary difference. The Company also included $0.137 million in amortization expense based on a proposed five-year amortization period. I have provided the details of the Company's request, including the source of the amounts that I cited, on my Exhibit___(LK-11).

Q. When does the Company plan to spend the estimated amounts?

A. The Company planned to begin the activities and incur costs by "by the end of 3Q 2014," according to its response to BHII Request No. 20 dated July 7, 2014. The response has not been updated. I have attached a copy of the Company's response to BHII Request No. 20 as my Exhibit___(LK-12).

Q. Has the Company sought or obtained an order to defer any costs that have been incurred to date?

A. No. According to its response to BHII Request No. 20, if the Commission does not issue its decision in this proceeding before the end of 2014, the Company plans to make a separate request to the Commission to defer the LIDAR costs as a regulatory asset.

Q. Should the Commission include the estimated LIDAR survey costs as a regulatory asset in rate base and allow amortization expense in this proceeding?

A. No. The Company's request is premature and overreaching. The Company has provided no evidence that it incurred these costs prior to October 1, 2014, or within the 12 months after the end of the historic test year. They are not known and measurable.

Instead of including these costs in this proceeding, the Commission should authorize the Company to defer the survey costs as a regulatory asset and address the recovery of the costs in the Company's next base rate proceeding.

Q. If the Commission allows the estimated LIDAR survey costs in rate base and authorizes recovery of amortization expense, do you have an alternative recommendation?

A. Yes. First, the Commission should correct the ADIT error in the Company's filing. The Company failed to include the related ADIT on Schedule M-1, which it acknowledged in response to BHII Request No. 20. The ADIT should be $0.176 million ($0.502 million times 35%), which will reduce the Company's claimed revenue deficiency by $0.020 million ($0.176 million times 11.43%) if the Commission adopts the Company's proposed five-year amortization period.

Second, the Commission should exercise its discretion to use a longer amortization period to minimize the effect on customers. In this case, a ten-year amortization period will achieve this objective. The Company's five-year amortization period is unnecessarily short. If the Commission includes the estimated survey costs in rate base, then the Company will earn a return on the unamortized regulatory asset regardless of the amortization period.

Q. What is the effect of your alternative recommendation to use a ten-year amortization period?

A. If the Commission adopts a ten-year amortization period, it will reduce the Company's revenue requirement by $0.080 million. This includes the effects on amortization expense and the effects of extending the amortization period on the correction of the ADIT error. The calculations are detailed on my Exhibit____(LK-13).

Q. Does the Proposed Settlement correct the error in the ADIT?

A. No. If the Commission adopts the Proposed Settlement, then it should correct the error in the ADIT regardless of whether it adopts a five-year or ten-year amortization period.

Q. Does the Proposed Settlement reflect your alternative recommendation to use a ten-year amortization period?

A. No. The Proposed Settlement reflects the Company's proposed five-year amortization period. If the Commission adopts the Proposed Settlement, then it should modify the Proposed Settlement to reflect a ten-year amortization period for the reasons that I described.

III. OPERATING INCOME ISSUES

A. <u>The Commission Should Remove Estimated Costs for FutureTrack Workforce Program</u>

Q. Please describe the Company's request to increase payroll and related expenses for its FutureTrack Workforce program.

A. The Company proposes an increase in payroll and related expenses of $0.676 million for its FutureTrack Workforce program. The Company proposes a deferral mechanism so that any costs that it incurs in excess of the annual amount authorized will be deferred as a regulatory asset. Ostensibly, this is a program whereby the Company plans to add staffing in anticipation of future employee retirements, even though the Company has experienced retirements throughout its history and has historically trained and promoted employees or retained new employees to replace retired employees on a recurring basis.

Q. Doesn't the Company and don't other utilities already continually assess their workforce requirements, hire younger and less skilled employees, train them, and then promote them as openings become available regardless of the reasons for the openings?

A. Yes. There is nothing new here that justifies or supports the Company's request. This has been and will continue to be the Company's practice and the nature of the workforce planning and implementation process throughout the industry.

Q. If there are positions that require specialized education and/or skills, what is the current standard industry practice?

A. Current standard industry practice is to hire employees with the appropriate education and/or skills to meet a company's needs when they are needed. This may require hiring employees who have obtained technical training at community colleges with specialized programs and may require hiring employees that have other specialized college and university training and expertise in professional areas.

Typically, new employees enter a company with less experience, but in a junior level position. They are promoted as they gain experience and as positions open up due to other promotions, transfers, resignations/terminations, and retirements.

Q. One aspect of the Company's proposal is to recruit high school students and "more mature workers" and provide them with scholarships to South Dakota vocational schools. Please comment.

A. There is no reason why the Company needs to actively recruit high school students or offer scholarships. Potential employees already have access to technical and vocational programs. Presumably, these programs are offered because there is student demand for those programs, even without such scholarships. In any event, the Company has provided no evidence that the practice is necessary or the only way that it can recruit or fill entry-level positions at the Company. As I noted previously, the Company has been able to recruit and fill entry-level positions since its inception without such a program and without incurring the expense that it proposes in this proceeding.

Q. Should the Commission allow the Company to recover its proposed FutureTrack Workforce program costs?

A. No. The Company has provided no evidence that its program and the associated expenses are necessary for its public utility operations or that it cannot or will not be able to hire qualified employees when they need them. There is nothing new here that the Company does not already do in the normal course of business, including hiring younger and less experienced employees, who then grow into higher level positions when those positions are vacated for any reason, not just retirements.

The Company has access to employees with the appropriate training and experience to meet its staffing requirements. Training programs are already available to students at vocational and community colleges. For example, Mitchell Technical Institute ("MTI"), located in Mitchell, SD, has vocational programs for electrical construction and maintenance, electric utilities and substation technology, power line construction and maintenance, utilities technology – power line. The link to the latter MTI program is https://www.mitchelltech.edu/programs/on-campus/energy-production-transmission/utilities-technology-power-line. MTI also offers scholarships and career services.

As yet another example, Lake Area Technical Institute ("LATI"), located in Watertown, SD, offers a vocational program for energy operations to train operations technicians.

In addition, on-the-job training programs are embedded into the Company's daily operations. There is no compelling evidence that these training programs are insufficient or need to be expanded in the manner proposed by the Company.

The Commission should not impose costs on the Company's customers to resolve problems that do not actually exist.

Q. If the Commission allows the Company to recover any amount for the FutureTrack Workforce program, should the Commission nevertheless deny the Company's request to defer costs in excess of the expense allowed current recovery?

A. Yes. The Commission should limit the recovery of these costs for at least three reasons. First, the Company's request is inappropriately open-ended. In other words, it wouldn't matter what amount was allowed in rates in this proceeding because the Company could defer any amount that it incurred in excess of the amount allowed and then recover it in subsequent proceedings.

Second, the Company has not proposed a measurement baseline that defines how the payroll and related expenses associated with this program can be and will be differentiated from any other payroll and related expenses. The Company's proposal to "track" the costs in a regulatory asset account does not address or cure this fundamental problem because the costs that will be identified and tracked in this manner still will not be subject to any defined or objective measurement baseline.

Third, the Company is not adequately incentivized to operate efficiently if there is no defined measurement baseline and it can defer (and later recover) any amount in excess of the allowed amount. The Company will no longer be at risk for increased expenses for payroll between rate cases. Such a scenario is not in the public interest. The better policy is to determine and provide recovery of the just and reasonable payroll and related expenses for the test year and to allow the Company to manage its payroll and related expenses between rate cases with the proper incentives to ensure that the costs are minimized. Under the present approach, the Company is incentivized to operate efficiently. While it cannot immediately recover or defer increases in payroll and related expenses, it can retain the savings from productivity gains that it achieves between rate cases.

Such a balancing is in the public interest.

Q. Does the Proposed Settlement adopt the Company's proposal?

A. Yes, in part. The Proposed Settlement allows the Company to recover $0.344 million in FutureTrack Workforce program expense. However, the Proposed Settlement does not address the Company's proposal to maintain a regulatory asset account or authorize the Company to defer amounts in excess of the $0.344 million that the Proposed Settlement proposes be allowed in the base revenue requirement.

Q. Even if the Commission adopts the adjustment to increase expense reflected in the Proposed Settlement, should the Commission specifically reject the Company's proposal to maintain a regulatory asset account and defer amounts in excess of the amount allowed in the base revenue requirement?

A. Yes, for the reasons that I previously discussed. The Commission should specifically and clearly reject the Company's deferral proposal to ensure that there is no ambiguity in future proceedings when the Company might seek to recover such deferrals.

B. <u>The Commission Should Remove the Company's Adjustment for Employee Position Additions/Eliminations</u>

Q. Please describe the Company's request to increase payroll and related expenses for additional projected employee positions.

A. The Company seeks recovery of $1.266 million in payroll and related expenses for additional employee positions as shown on Schedule H-1. The $1.266 million is based on the labor and related expenses for 17 open positions.[8]

This request is in addition to the request for increases in payroll and related expenses related to the FutureTrack Workforce program.[9] This amount does not include the Company's proposed adjustments for wage increases or the Neil Simpson I labor costs also shown on Schedule H-1, which I do not address in my testimony.

In the only testimony on this issue, Company witness Mr. Jon Thurber describes the calculation of the adjustment (including the wage adjustments, Neil Simpson I labor costs, and open positions): "These amounts are calculated using an average of union negotiated wage increases and expected non-union wage increases, together with the costs associated with open vacancies and additional employees needed for operations."[10]

Q. How does the Company's request to increase labor and related expenses for open positions compare to its actual history of open positions?

A. The Company's actual history for the last several years indicates that it is not likely to fill all the open positions or actually incur the requested expense. In all

[8] Company response to BHII Request No. 18 (Attachment 18 "Positions by Dept" tab), a copy of which is attached as my Exhibit___(LK-14).

[9] The Company's response to BHII Request No. 18 states "The additional costs on Schedule H-1 are for current open positions to be filled as soon as possible. They do not include any positions related to FutureTrack."

[10] Direct Testimony of Jon Thurber at 17.

months, at least since January 2011, the Company has had open positions.[11] The number of open positions ranged from 5 to 42 in any one month and averaged 19 each month since January 2011. The open positions ranged from 18 to 42 and averaged 26 each month during the test year.[12]

Q. What should the Commission conclude?

A. The Commission should conclude that the request to increase payroll and related expenses is not justified. It is not consistent with the Company's actual experience. The Company has consistently maintained an average of 19 open positions, which is more than the 17 reflected in its adjustment to increase labor and related expenses.

Q. Is there another factor that the Commission should consider?

A. Yes. The Company's request represents an 11% increase in labor and related expense compared to the labor expense without the proposed adjustment. Thus, the Company is requesting an 11% increase simply assuming away its history of maintaining a significant number of open positions.

Q. What is your recommendation?

A. I recommend that the Commission reject this adjustment. It is not justified and it is contrary to the Company's history of 19 to 26 open positions on average. The Commission should not assume that the Company will change its historic practice

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[11] Company's response to SDPUC Request No. 5-14.
[12] *Id.*

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 more than speculation. It certainly does not reflect a known and measurable change. The actual 2014 expense is the best evidence of the post-test year known and measurable change in the expense compared to the historic test year.

Second, the Commission should be careful not to adopt an adjustment in this proceeding to accommodate the Company that could be considered precedent for other utilities.

Third, the Company has already received the benefit of the lower pension expense this year and will unjustly continue to receive the benefits of lower pension expense if it is allowed excessive recovery based on its new methodology. The Company has not offered to defer the difference between the pension expense reflected in its rates and the actual pension expense this year or to share it with customers. The Company has proposed a new methodology solely to recover more in revenues than its most recent actual pension expense.

Q. Does the Proposed Settlement reflect the Company's proposed new methodology?

A. Yes. If the Commission adopts the Proposed Settlement, then the Commission should revise the pension expense to the actual 2014 expense for the reasons previously described.

D. <u>The Commission Should Remove All Incentive Compensation Tied to Financial Performance From Base Rates</u>

Q. Please describe the Company's incentive compensation expense tied to BHC financial performance.

A. The Company seeks recovery of $1.554 million in incentive compensation expense tied to operating and financial performance. In response to discovery, the Company provided the South Dakota incentive compensation expense and the portion of the expense that was "tied to operating and financial criteria for the test year."[13] In its response, the Company listed the total expense for BHP, Black Hills Service Company, LLC ("BHSC"), allocated to BHP, and Black Hills Utility Holdings, Inc. ("BHUH"), allocated to BHP for each incentive compensation plan and listed the portion of the expense that it determined was "tied to operating and financial criteria for the test year." The expenses identified by the Company as meeting the operating and financial criteria summed to $0.666 million and included a portion of the performance plan expense. However, the Company excluded 0.149 million in performance plan expenses and the entirety of the $0.739 million in incentive restricted stock expense.

Q. Is it Commission precedent to deny recovery of incentive compensation expense tied to operating and financial performance?

A. Yes. This is appropriate for several reasons. First, the Company's financial performance is a direct function of the revenues recovered from customers,

[13] SDPUC Request No. 2-11 (Confidential Attachment G).

including the rate increases that are authorized by the Commission. There is an inherent conflict between lower rates and greater financial performance. Incentive compensation tied to operating and financial performance. The Commission should not incentivize the Company to seek greater rate increases and act against their customers' interests. This expense should be a shareholder cost.

Second, the revenue requirement should not embed recovery of an expense that is based on performance, regardless of whether it is based on operating or financial performance. 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.

Third, this form of incentive compensation is primarily directed toward achieving shareholder goals, not customer goals. Thus, the cost should be borne by shareholders, not customers.

Q. Are the restricted stock expense and the performance plan expense tied to the Company's financial performance?

A. Yes. The restricted stock expense and performance plan expense represent awards of stock, units, or cash based on the performance measures listed in the Company's Confidential 2005 Omnibus Incentive Compensation Plan in Section 12.1, which consist primarily of financial performance measures.[14]

[14] Id., Confidential Attachment 2-11A.

Q. Should the Commission deny recovery of the incentive compensation expense tied to the Company's "operating and financial criteria," including the restricted stock expense and the entirety of the performance plan expense?

A. Yes, for the reasons that I previously cited.

Q. Does the Proposed Settlement reflect any adjustment to remove incentive compensation expense?

A. Yes. However, the Proposed Settlement removes only the $0.666 million in incentive compensation expense "tied to operating and financial criteria" identified by the Company in response to SDPUC 2-11. Inexplicably, the Proposed Settlement allows the Company to include $0.739 million in incentive restricted stock expense and $0.149 million in performance plan expenses in its revenue requirement, despite the fact that these are incentive compensation expenses that are similar in nature to the expenses that were removed. The Commission should be consistent and remove all similar incentive compensation expense tied to the financial performance of the Company, BHC, and BHUH.

E. <u>The Commission Should Remove Company Adjustment to Increase Affiliate Allocations from BHUH</u>

Q. Please describe the Company's request to increase the test year affiliate allocations from BHUH.

A. The Company proposes to increase the affiliate allocations from BHUH by

$1.846 million compared to the historic test year. The Company provided adjustments by FERC account on Schedule H-5, although it did not provide any other support for these adjustments in its filing. The Company provided a further breakdown of the adjustments between direct and allocated expenses in response to BHII Request No. 6. The Company appears to have started with projected expenses for the twelve months ending September 2015 and then adjusted those expenses. The Company provided no additional workpapers in support of its proposed adjustments in this response.

Q. What is the magnitude of the proposed increase in affiliate allocations from BHUH?

A. The Company proposes a 19% increase over the historic test year expense, based on Schedule H-5. The largest dollar increases are in account 920 "administrative salaries" (21%) and account 923 "outside services" (56%). Based on these numbers, the adjustments apparently reflect additional staffing and/or salary increases and increased use of outside services.

Q. Should the Commission adopt this adjustment?

A. No. There is no justification for the proposed increase and the magnitude of the increase is unreasonable on its face. The best evidence of the reasonable expense is the test year itself unless there are identifiable known and measurable changes that should be reflected. However, the Company did not provide any evidence of any identifiable known and measurable changes in its filing or in response to

BHII discovery.

Q. Does the Proposed Settlement reflect any reduction in the Company's proposed increase to the affiliate allocations from BHUH?

A. No. To the contrary, the Proposed Settlement inexplicably *increases* the Company's proposed adjustment by $0.527 million to $2.373 million. The Proposed Settlement spreadsheet refers to emails from Jon Thurber to the Staff in support of the adjustments reflected in the Proposed Settlement, but these have not been provided to BHII, or otherwise included in the record. In addition, the Proposed Settlement spreadsheet appears to incorrectly include an allocation to SD of transmission load dispatch costs in account 561 that was not allocated to SD in the Company's Application.[15] The SD allocation for account 561 is shown as $0 on Schedule N-1 page 13 line 64 of the Company's Application. The incorrect allocation in account 561 adds $0.286 million to the Proposed Settlement revenue requirement.

Q. Should the Commission adopt the Proposed Settlement adjustment?

A. No. There is no justification for the proposed increase and the magnitude of the increase is unreasonable on its face. The best evidence of the reasonable expense is the test year itself unless there are identifiable known and measurable changes that should be reflected. However, the Company did not provide any evidence of any identifiable known and measurable changes in its filing or in conjunction

[15] Refer to Exhibit___(DEP-1) Schedule 2 line 4 of the Proposed Settlement spreadsheet.

with its supplemental response to Staff discovery. However, if the Commission adopts the Proposed Settlement adjustment, then it should at least correct the apparent allocation error in account 561 that I described previously.

F. <u>The Commission Should Remove Proposed Settlement Adjustment to Increase Affiliate Allocations from BHSC</u>

Q. Did the Company propose an adjustment for increases in affiliate allocations from BHSC in its filing?

A. No.

Q. Does the Proposed Settlement include increases in affiliate allocations from BHSC?

A. Yes. But to my knowledge the Company never notified the parties that it would seek to further increase its base rates to include increases in affiliate allocations from BHSC. The Company informed the parties in a supplemental response to SDPUC Request No. 3-96 that it planned to propose a new adjustment in its rebuttal testimony and attached a revised Schedule H-4 that detailed the proposed new adjustment by FERC account in the same manner that it filed Schedule H-5. However, the Company provided no additional detail in that response. Based on the Proposed Settlement, it appears that the Company provided the Staff with additional information and changes to the revised Schedule H-4 in a series of emails. None of those emails were shared with BHII during settlement negotiations, they have not been provided to BHII since, and they are not included in the record.

Q. What is the magnitude of the proposed increase in affiliate allocations from BHSC reflected in the Proposed Settlement?

A. The Proposed Settlement incorporates a 6.0% increase over the historic test year expense, based on Schedule H-4. The largest increases are (1) a 7.5% increase in account 920 "administrative salaries" and (2) an 11.7% increase in account 921 "office supplies and expenses." These adjustments apparently reflect additional staffing and/or salary increases and increased "office expenses."

Q. Should the Commission adopt this adjustment?

A. No. There is no justification for the proposed increase and the magnitude of the increase is unreasonable on its face. The best evidence of the reasonable expense is the test year itself unless there are identifiable known and measurable changes that should be reflected. However, the Company has not provided any evidence of any identifiable known and measurable changes in its filing or in response to BHII discovery.

G. The Commission Should Extend the Retired Steam Plants Amortization Expense

Q. Please describe the Company's proposal for the amortization of the regulatory asset for the remaining net book value of the retired steam plants and the obsolete inventory for those plants.

A. The Company proposes $1.163 million ($1.295 million total Company) in amortization expense to amortize the regulatory asset for the retired steam plants over five years.

Q. Should the Commission use a five-year amortization period?

A. No. The Commission should use a ten-year amortization period. The Company's proposed five-year amortization period is unnecessarily short. If the Commission includes the regulatory asset in rate base, then the Company will earn a return on the unamortized regulatory asset regardless of the amortization period. When it has discretion, as it does in this case, the Commission should use a longer amortization period to minimize the effect on customers. In this case, a ten-year amortization period will achieve this objective.

Q. What is the effect of your recommendation to use a ten-year amortization period?

A. Using a ten-year amortization period on the regulatory asset for the retired steam plants and obsolete inventory will reduce the Company's revenue requirement by $0.539 million, consisting of a reduction of $0.582 million in amortization expense, net of an increase in the return on rate base (net reduction in accumulated amortization and increase in ADIT) of $0.043 million. The calculations are detailed on my Exhibit____(LK-15).

Q. Does the Proposed Settlement reflect a ten-year amortization period?

yes

A. No. The Proposed Settlement reflects the five-year amortization period proposed by the Company. If the Commission adopts the Proposed Settlement, then it should modify it to use a ten-year amortization period.

H. <u>The Commission Should Reduce the Company's Amortization Expense on the Regulatory Asset for Storm Damage</u>

Q. Please describe the Company's request for amortization expense on the regulatory asset for storm damage.

A. The Company proposes $0.828 million for amortization expense based on a five-year amortization period. I provide the details of the Company's request, including the source of the amounts that I cited, on my Exhibit___(LK-10).

Q. Should the Commission use a five-year amortization period?

A. No. The Commission should use a ten-year amortization period. The Company's proposed five-year amortization period is unnecessarily short. If the Commission includes the regulatory asset in rate base, then the Company will earn a return on the unamortized regulatory asset regardless of the amortization period. When it has discretion, as it does in this case, the Commission should use a longer amortization period to minimize the effect on customers. In this case, a ten-year amortization period will achieve this objective.

Q. What is the effect of your recommendation to use a ten-year amortization period?

A. Using a ten-year amortization period will reduce the Company's revenue requirement by $0.414 million to reflect the reduction in amortization expense of an equivalent amount. The rate base effects from the adjustment, along with the reduction for ADIT, are discussed in the rate base section of my testimony. The calculations are detailed on my Exhibit____(LK-10).

Q. Does the Proposed Settlement reflect a ten-year amortization period?

A. Yes.

I. <u>The Commission Should Remove the Retired Steam Plants Decommissioning Amortization Expense</u>

Q. Did you previously address this issue in the Rate Base Issues section of your testimony?

A. Yes.

J. The Commission Should Remove the 69kV LIDAR Surveying Project Amortization Expense

Q. Did you previously address this issue in the Rate Base Issues section of your testimony?

A. Yes.

K. The Commission Should Extend the CPGS Life Span for Depreciation Expenses

Q. Please describe the Company's proposed life span for the CPGS depreciation rate and expense.

A. The Company proposes a life span for the CPGS of 35 years, a depreciation rate of 3.29%, and $2.726 million in depreciation expense ($3.035 million total Company).

Q. Is the proposed 35-year life span reasonable?

A. No. A 35-year life span is unnecessarily short. A longer life span of 40 to 45 years is within the range of reasonableness supported by the Company's depreciation expert's own analysis. The longer life span reflects the estimated and actual service lives of similar facilities owned by other utilities.[16] The Company's depreciation expert, Mr. John Spanos, in consultation with the Company during his depreciation analysis, determined that an appropriate life

[16] Company response to BHII Request No. 11 (Spanos workpapers and source documents).

span for the facility was 40 years, which the Company appears to have confirmed.[17] Mr. Spanos offered no explanation in his testimony as to why he changed the 40 years set forth in his analysis to the 35 years set forth in the depreciation study attached to his testimony.

Q. What is the effect on the revenue requirement of using a 40-year life span?

A. A 40-year life span for the CPGS depreciation rate and expense will reduce the Company's revenue requirement by $0.332 million, consisting of a reduction of $0.338 million in amortization expense, net of an increase in the return on rate base (net reduction in accumulated amortization and increase in ADIT) of $0.006 million. The calculations are detailed on my Exhibit____(LK-16).

Q. Does the Proposed Settlement reflect a 40-year life span?

A. Yes.

L. The Commission Should Correct the Steam and Other Production Plant Net Salvage for Depreciation Expenses

Q. Please describe the changes in steam and other production plant net salvage reflected in the Company's proposed depreciation rates.

A. The Company proposes significant increases in net negative salvage for its steam and other production plant accounts. Net negative salvage refers to the net of estimated salvage income and cost of removal. Net negative salvage means that

[17] *Id.*, Attachment 11U - BHP and CLFP Projected Plant retirements updated 9-24-13, a copy of which I have attached as my Exhibit___(LK-17).

the projected salvage income is less than the projected cost of removal.

Mr. Spanos applied the net salvage rates to the entire plant balance, which covers not only interim retirements, but also terminal retirements (for decommissioning). Increases in net negative salvage have the effect of increasing the depreciation rates.

The present depreciation rates reflect -5% net salvage rates.[18] The Company proposes to increase these rates to -13% to -22% depending on the plant. I have replicated a summary schedule from the Company's depreciation study showing the net salvage rates and depreciation rates for each plant and each plant account as my Exhibit___(LK-18).

Q. Is this significant increase in net negative salvage for the production plant accounts appropriate?

A. No. First, the basis for the calculation of the terminal net salvage is flawed and unreliable, resulting in an excessive net negative salvage cost and percentage.

Second, this may represent an undisclosed proposal to change the Commission's policy for decommissioning cost recovery from recovery *after* the retirement of the plants (as is the case in this proceeding for the three retired coal-fired plants) to recovery *before* the future retirement of the plants.

Third, the increase in net negative salvage is not necessary at this time. The Commission is not required to provide recovery of unknown future costs in

[18] Present depreciation rates were adopted in Case No. E09-018 based on a depreciation study performed for the Company by Black and Veatch (Exhibit LWL-1 in that proceeding). I have attached pages illustrating the -5% used in that study and reflected in present depreciation rates as my Exhibit___(LK-19).

present rates. The Commission's current policy appears to be determine the appropriate manner of decommissioning (and associated costs) *after* plants are retired. This policy is prudent for ratepayers and still ensures that the Company recovers its costs.

Q. How should the Commission proceed on this issue?

A. The Commission should use the same -5% net salvage rate for these production plant accounts that is reflected in the present depreciation rates. The Company has not justified the significant increases that it proposes or provided any valid rationale to change policy. The Commission should not provide premature recovery of unknown future costs; the Company can seek recovery of decommissioning costs in the future when the method of decommissioning can be assessed and the cost can be determined based on actual bids.

Q. Have you quantified the effect on the revenue requirement of your recommendation?

A. Yes. Using a -5% net salvage rate reduces depreciation rates and reduces depreciation expense and the revenue requirement by $1.132 million. I provide the calculation of the depreciation rates using the -5% net salvage rate and the effects on depreciation expense on my Exhibit___(LK-20).

M. <u>Other Proposed Settlement Issues</u>

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]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[19] BHP response to BHII 5, a copy of which is attached as my Exhibit___(LK-21).

[redacted]

[redacted]

[redacted]

[redacted]

Q. Does that complete your testimony?

A. Yes.

BEFORE THE SOUTH DAKOTA
PUBLIC UTILITIES COMMISSION

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

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

BLACK HILLS INDUSTRIAL INTERVENORS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

DECEMBER 2014

77872079.4 0064944-00002

EXHIBIT___(LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Mr. Kollen has more than thirty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
CF&I Steel, L.P.
Climax Molybdenum Company
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
as of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.

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Date	Case	Jurisdict.	Party	Utility	Subject
4/99	99-02-05	Ct	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.

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12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.

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10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.

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Date	Case	Jurisdict.	Party	Utility	Subject
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.

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12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.

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10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.

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06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.

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02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09 04/09	U-21453, U-20925 U-22092 (Sub J) Direct Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal Supplemental Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc., Attorney General	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
03/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation expense and effects on System Agreement tariffs.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.

**Expert Testimony Appearances
of
Lane Kollen
as of November 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
04/10	2009-00458, 2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.

**Expert Testimony Appearances
of
Lane Kollen
as of November 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11 05/11	38306 Direct Suppl Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.

Expert Testimony Appearances
of
Lane Kollen
as of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	11AL-947E Answer	CO	Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel	Public Service Company of Colorado	Revenue requirements, including historic test year, future test year, CACJA CWIP, contra-AFUDC.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Direct Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.

Expert Testimony Appearances
of
Lane Kollen
as of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT – bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.
01/13	ER12-1384 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.

Expert Testimony Appearances
of
Lane Kollen
as of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.
11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.

EXHIBIT___(LK-2)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Remove Double Count of Spare Parts for CPGS
($ Millions)

	Total Company	South Dakota Retail %	South Dakota Retail
Source: Statements E and J - Response to Staff 6-42			
Double Count of PIS to Remove $2.220 million x 58% BHP Ownership %	(1.288)	89.831% PRODPLT	(1.157)
As Adjusted CPGS Average Depreciation Rate	2.88%	Based on 40 Year Life Span	
Reduce Depreciation Expense to Remove Double Count	(0.037)	89.831% PRODPLT	(0.033)
Accumulated Depreciation One Half of Depreciation Expense Reduction (See Statement E Note 3)	(0.019)		
Decrease Accumulated Depreciation for Expense Reduction The Effect Increases Rate Base	0.019	89.831% PRODPLT	0.017
Accumulated Deferred Income Taxes (See Schedule M-2) Book Depreciation Expense Reduction (100% of Expense Reduction x Tax Rate)	(0.037)		
Federal Income Tax Rate	0.35		
Increase ADIT for Expense Reduction The Effect Decreases Rate Base	(0.013)	89.831% PRODPLT	(0.012)

Computation of Adjusted Depreciation Rate
See BHII 15 Attach b for Computed Rates

	Original Cost	Future Book Accruals	Rem Life at 35 Year Span	Rem Life at 40 Year Span	Annual Accrual	Rate
Acct 341	7,028,693	7,309,841	33.75	38.57	189,521	2.70%
Acct 342	10,543,040	10,964,761	31.5	36	304,577	2.89%
Acct 344	38,657,812	40,204,125	31.61	36.13	1,112,763	2.88%
Acct 345	10,543,040	10,964,761	31.78	36.32	301,893	2.86%
Acct 346	3,514,347	3,654,920	27.37	31.28	116,845	3.32%
	70,286,931				2,025,600	2.88%

EXHIBIT___(LK-3)

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL14-026
RATE CASE

REQUEST DATE : August 12, 2014

RESPONSE DATE : September 5, 2014

REQUESTING PARTY: SDPUC Staff

SDPUC Request No. 6-42:

Cheyenne Prairie Generating Station

Refer to the Company's response to Staff DR 3-34, Attachment 3-34 – Cheyenne Prairie Generating Station.xlsx, CC Detail tab. Regarding the spare parts of $2,220,000 found on line 76:

a) Provide a breakout of the individual spare parts included.
b) Are the spare parts included in the capital costs the same as any spare parts included on Schedule F-4?
c) Explain why these spare parts are capitalized and other spare parts are included as working capital on Schedule F-4.

Response to SDPUC Request No. 6-42:

a) Please refer to the response to SD PUC Request No. 5-3 and Attachment 5-3X for the spare parts inventory.
b) Yes. The spare parts were inadvertently included on both the Cheyenne Prairie Generating Station capital schedule on Schedule D-11 and as materials and supplies on Schedule F-4. This oversight will be corrected and updated schedules will be provided.
c) The spare parts should be included only as part of working capital and will be removed from the capital schedule.

Attachments: None

EXHIBIT___(LK-4)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Remove NOL Carryforward ADIT from Rate Base
($ Millions)

Source: Schedule M-1 and M-2	Total Company	South Dakota Retail %	South Dakota Retail
Remove Acct 190.175 ADIT for NOL Carryforward	(4.765)	91.673% SALWAG	(4.368)
Remove Acct 190.520 ADIT for NOL Carryforward	(9.188)	91.673% SALWAG	(8.423)
Remove Sch M-2 Adjustment for NOL ADIT	0.455	91.673% SALWAG	0.418
Remove Acct 190 ADIT for NOL Carryforward	(13.497)		(12.373)

EXHIBIT___(LK-5)

20140418-8029 FERC PDF (Unofficial) 04/16/2014

THIS FILING IS

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Black Hills Power, Inc.	End of 2013/Q4

20140418-8029 FERC PDF (Unofficial) 04/18/2014

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Black Hills Power, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	DEFERRED COMPENSATION	394,211	358,102
3	VACATION PAYABLE	200,410	150,955
4			
5	FAS 109	191,905	109,128
6			
7	Other	30,260,843	17,010,150
8	TOTAL Electric (Enter Total of lines 2 thru 7)	31,047,369	17,628,335
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	31,047,369	17,628,335

Notes

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Non-qualified Pension Plan	$ 474,783
Retiree Healthcare	3,126,435
PEP AOCI	355,645
Line Extension Deposits	(302,106)
Bad Debt Reserve	547,808
Pension	14,367,933
NOL Carryforward	10,440,671
State Rate Refund Liability	306,672
Other	238,921
Bonus Comp	704,083
Total	30,260,845

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Non-qualified Pension Plan	$ 504,797
Retiree Healthcare	2,726,843
PEP AOCI	258,159
Line Extension Deposits	(290,134)
Bad Debt Reserve	(78,596)
Pension	7,395,989
NOL Carryforward	4,759,905
State Rate Refund Liability	497,613
Other	622,251
Bonus Comp	613,323
Total	17,010,150

EXHIBIT___(LK-6)

20140418-8029 FERC PDF (Unofficial) 04/16/2014

THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Black Hills Power, Inc.	End of 2013/Q4

FERC FORM No.1/3-Q (REV. 02-04)

Name of Respondent Black Hills Power, Inc.	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2013/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2013	2012	2011
Federal statutory rate	35.0%	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(0.3)	(0.3)	(0.4)
Equity AFUDC	—	(0.1)	(0.6)
Flow through adjustments *	(2.5)	(3.5)	(3.4)
Prior year deferred adjustment **	—	3.6	—
Tax credits	(0.8)	—	—
Other	(0.6)	(0.1)	0.1
	30.8%	34.6%	30.7%

* The flow-through adjustments relate primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs that continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and we flowed the tax benefit through to our customers in the form of lower rates as a result of a rate case settlement that occurred during 2010. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit consistent with the flow through method.

** The adjustment was a non-recurring unfavorable true-up attributable to property related deferred income taxes. The removal of the impact of such an adjustment is more appropriately reflective of the effective rate on a recurring basis.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, included in Other deferred credits and other liabilities on the accompanying Balance Sheet (in thousands):

	2013	2012
Unrecognized tax benefits at January 1	$ 2,078	$ 3,595
Reductions for prior year tax positions	(155)	(1,586)
Additions for current year tax positions	520	69
Unrecognized tax benefits at December 31	$ 2,443	$ 2,078

The reductions for prior year tax positions relate to the reversal through otherwise allowed tax depreciation. The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $0.5 million.

It is our continuing practice to recognize interest and/or penalties related to income tax matters in income tax expense. During the years ended December 31, 2013 and 2012, the interest expense recognized was not material to our financial results.

We file income tax returns in the United States federal jurisdictions as a member of the BHC consolidated group. We do not anticipate that total unrecognized tax benefits will significantly change due to settlement of any audits or the expiration of statutes of limitations prior to December 31, 2014.

At December 31, 2013, we have federal NOL carry forward of $14 million, expiring in 2031. Ultimate usage of this NOL depends upon our ability to generate future taxable income, which is expected to occur within the prescribed carryforward period.

EXHIBIT___(LK-7)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Remove Estimated Decommissioning Costs as a Regulatory Asset
($ Millions)

	Total Company	South Dakota Retail %	South Dakota Retail
Source: Schedule J-2			
Company's Estimated Decommissioning Costs			
Ben French	3.960		
Osage Units 1-3	3.952		
Neil Simpson	2.975		
Total Estimated Costs Set Up as Regulatory Asset	10.887		
Company's Proposed Amortization Period in Years	5		
Company's Proposed Annual Amortization Expense	2.177	89.83% PRODPLT	1.956
Company's Proposed Unamortized Regulatory Asset	8.709	89.83% PRODPLT	7.824
Remove Annual Amortization Expense for Estimated Decommissioning Costs	(2.177)	89.83% PRODPLT	(1.956)
Remove Unamortized Regulatory Asset for Estimated Decommissioning Costs	(8.709)	89.83% PRODPLT	(7.824)

EXHIBIT___(LK-8)

Docket No. EL14-026

Black Hills Power, Inc.

3HII Adjustment to Remove Contingency from Estimated Decommissioning Costs and Amortize Over 10 Year

($ Millions)

Source: Schedule J-2	Total Company	South Dakota Retail %	South Dakota Retail
Company's Estimated Decommissioning Costs			
Ben French	3.960		
Osage Units 1-3	3.952		
Neil Simpson	2.975		
Total Estimated Costs Set Up as Regulatory Asset	10.887		
Less: Contingencies - See Response to Staff DR 3-23	(0.956)		
Estimated Costs Less Contingencies	9.931		
Alternative Change in Amortization to 10 Years	10		
Company's Proposed Annual Amortization Expense	0.993	89.83% PRODPLT	0.892
As Filed Amortization Expense	2.177		
Reduction in Amortization Expense From Filing	(1.184)	89.83% PRODPLT	(1.064)
As Adjusted Unamortized Regulatory Asset	7.754	89.83% PRODPLT	6.965
As Filed Unamortized Regulatory Asset	8.709	89.83% PRODPLT	7.824
Change in Unamortized Regulatory Asset Estimated Decommissioning Costs	(0.956)	89.83% PRODPLT	(0.859)
As Filed Grossed Up ROR			11.43%
Reduction in Return on Rate Base			(0.098)
Reduction in Revenue Requirement			(1.162)

EXHIBIT___(LK-9)

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL-14-026
RATE CASE

REQUEST DATE : April 28, 2014

RESPONSE DATE : July 7, 2014

REQUESTING PARTY: Black Hills Industrial Intervenors

BHII Request No. 26: Reference Schedules J-3, M-1, and M-2. The following questions relate to accumulated deferred income taxes ("ADIT") associated with the proposed regulatory asset amounts for Winter Storm Atlas and the System Inspection Costs.

a. Please indicate whether the Company included ADIT in rate base associated with each of these regulatory assets.

b. If the Company did include the associated ADIT in rate base, please indicate where in the filing this is shown.

c. If the Company did not include the associated ADIT in rate base, please explain why it did not.

d. Please confirm that the Company already has taken some or all of the income tax deductions for the Winter Storm Atlas costs and provide a schedule that shows the amount of the deductions in the 2013 tax year already taken for (1) casualty losses, (2) O&M expenses, and (3) tax depreciation. Please provide the Company's calculations of these deductions, including electronic spreadsheets with formulas intact. Please reconcile the deductions that have been taken to the amounts the Company included in the regulatory asset.

e. Please provide a schedule that shows the amount of the income tax deductions for the Winter Storm Atlas costs in the 2014 tax year that already have been or are estimated to be taken for (1) casualty losses, (2) O&M expenses, and (3) tax depreciation. Please provide the Company's calculations of these deductions, including electronic spreadsheets with formulas intact. Please reconcile the deductions that have been taken to the amounts the Company included in the regulatory asset.

Response to BHII Request No. 26:

a. The reconciliation referred to in response to request d. below provides an itemization of costs included in the rate filing on Sched J-3. A portion of these costs were estimated to be treated as a casualty loss. The deferred income tax effect associated with such treatment has been included in line 47 of Sched M-1 as part of the property related ADIT. The difference between the unamortized regulatory asset and estimated casualty loss deduction does result in a temporary difference for which an ADIT adjustment increasing net deferred tax liabilities will be made. That adjustment should

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have been reflected on Sched M-1 and inadvertently it was not. Such an adjustment is determined to be $792,771 (35% times ($3,310,806-$1,045,745).

b. Please see the response in a. above.

c. Please see the response in a. above.

d. At the time the rate case was filed, an evaluation of Storm Atlas costs was being conducted to make sure there will be proper reporting on the tax return. An analysis of the information that was available at December 31, 2013 indicated an estimated casualty loss of $1,045,745, repair costs of $1,000,000, and capitalized costs of $1,900,000 as a result of Storm Atlas. These costs and the reporting of such costs will be trued up with the filing of the 2013 income tax return in September 2014. Please see Attachment 26d.1 for an estimate of the deductions and costs reflected in the tax accrual. In addition, Attachment 26d.2 provides a reconciliation of the Storm Atlas costs to Schedules D-10 and J-3 included in the rate filing. Also, the schedule indicates how these costs are expected to be accounted for on the 2013 income tax return.

e. The schedules referenced in response d. above reflect the expenses associated with Storm Atlas that will be deducted on the 2013 tax return. Certain operation and maintenance costs and accelerated tax depreciation will be deducted in the 2014 tax year.

Attachments:
26d.1 – Winter Storm Atlas Costs
26d.2 - Amortization

EXHIBIT___(LK-10)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Extend Amortization to 10 Years for Winter Storm Atlas Regulatory Asset
And to Include ADIT in Rate Base
($ Millions)

	Total Company	South Dakota Retail %	South Dakota Retail
Source: Schedule J-3			
Company Estimated Winter Strom Atlas Reg Asset from Winter Storm Atlas Reg Asset	4.139		
Company's Proposed Amortization Period in Years	5		
Company's Amortization Expense	0.828	100.00% Direct Assign	0.828
BHII Recommended Amortization Period in Years	10		
BHII Recommended Amortization Expense	0.414	100.00% Direct Assign	0.414
BHII Recommended Decrease in Amortization Expense	(0.414)	100.00% Direct Assign	(0.414)
BHII Increase in Unamortized Regulatory Asset Balance	0.414	100.00% Direct Assign	0.414
ADIT on Remaining Regulatory Asset Balance			
Company Proposed Reg Asset Balance	4.139		
Less: Adjustment from Above	(0.414)		
Remaining Regulatory Balance After Adjustment	3.725		
Federal Income Tax Rate	35.0%		
ADIT on Regulatory Asset Balance	(1.304)	100.00% Direct Assign	(1.304)
Total Reduction to Rate Base			(0.890)
As Filed Grossed Up ROR			11.43%
Reduction in Return on Rate Base			(0.102)
Reduction in Revenue Requirement			(0.516)

EXHIBIT___(LK-11)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Remove Estimated 69kV Surveying Project as a Regulatory Asset
($ Millions)

	Total Company	South Dakota Retail %	South Dakota Retail
Source: Schedule H-20			
Total Estimated BHP Portion of Costs	0.685		
Company's Proposed Amortization Period in Years	5		
Company's Proposed Annual Amortization Expense	0.137	94.855% Acct 593	0.130
Company's Proposed Unamortized Regulatory Asset	0.548	91.67% SALWAG	0.502
Remove Annual Amortization Expense for Estimated 69 kV Surveying Costs	(0.137)	94.855% Acct 593	(0.130)
Remove Unamortized Regulatory Asset for Estimated 69 kV Surveying Costs	(0.548)	91.67% SALWAG	(0.502)

Note: There was no ADIT included in the test year related to the Reg Asset to remove. Company confirmed in response to BHII-20.

EXHIBIT___(LK-12)

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BHII Request No. 20: Reference Schedule H-20. The following questions relate to the costs for the 69kV LIDAR Surveying Project.

a. Please provide a schedule by month and by FERC account showing (1) the actual costs incurred for the surveying project through the most recent month for which actual information is available and (2) the projected costs thereafter.

b. Please provide copies of all source documentation pertaining to the actual costs incurred referenced in response to subpart (a) of this question. Include all electronic work papers with formulas intact.

c. Please provide the details of the plan to perform the surveying project, including the estimated timeframe that the project would start and conclude, the types of costs to be incurred, and the timing of such costs.

d. Please provide a copy of all internal planning documents describing the surveying project.

e. Please explain why there is no pro forma adjustment for the ADIT related to this deferred asset.

f. Please indicate whether the Company has requested an order from the Commission to defer these costs as a regulatory asset. If so, please cite all authorities or references to such authorization included in the Company's filing in this proceeding. If there are none, please explain why.

g. Reference the testimony of Mr. Fredrich at page 10, lines 15-17, pertaining to the 69kV LIDAR Surveying Project. Please describe "the past experience of BHC" and how the estimated cost of $800,000 for the 69kV system was determined. Please provide all supporting assumptions, data, and computations, including electronic spreadsheets with formulas intact.

Response to BHII Request No. 20:

a. Black Hills Power is still in the process of finalizing the scope of project to obtain final RFQ's from the vendors.

b. As noted above, the LiDar patrol work has not yet begun for 2014, so there are no actual costs to report to date.

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c. Details of the plan: Black Hills Power is still in the process of developing the final plans and specifications for the work to be completed in 2014. Attachment 20B is the RFQ specifications that were associated with the 2013 survey work for Black Hills /Colorado Electric and Black Hills Power. It is anticipated that the 2014 survey work will be similar in nature to the type of work outlined in the attached specifications.

Estimated timeframe: Black Hills Power anticipates getting the RFQ out to the vendors by the end of July 2014.

Type of costs to be incurred:
- New Lidar, Ortho & Oblique Imagery, Ground Control Survey and Weather Data
- Processing and Mapping all topographical DTM files and Plan and Profile data maps along the route
- Conductor Operating Temperature Assessments and report
- Delivery in a PLS CADD.bak file

Timing of such costs: Timing of the costs will be dependent on the availability of the vendor to meet proposed schedule. Targeted timeline would be by the end of 3Q 2014.

d. Please see Attachments 20A and 20B.

e. A pro forma adjustment for the ADIT related to this deferred asset should have been reflected on Schedule M-1 and inadvertently it was not. Such an adjustment is determined to be $191,688 ($547,680 * 35%).

f. The Company has requested to defer these costs as a regulatory asset as part of this rate filing. If the Commission does not issue its decision in this filing by the end of 2014, the Company will make a separate request to the Commission to defer the LiDar costs as a regulatory asset.

g. The $800,000 estimate for 2014 was based on the completion of 532 miles of 69kV line to be surveyed at $1,500/mile. See Attachment 20A.

Attachments:
20A - Lidar Workpaper
20B - BHCLidarSpec

EXHIBIT___(LK-13)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Alternative Adjustment to Extend Amortization of 69kV Surveying Project Costs to 10 Years
And to Reduce Rate Base for Related ADIT
($ Millions)

Source: Schedule H-20	Total Company	South Dakota Retail %	South Dakota Retail
Total Estimated BHP Portion of Costs	0.685		
Company's Proposed Amortization Period in Years	5		
Company's Proposed Annual Amortization Expense	0.137	94.855% Acct 593	0.130
Company's Proposed Unamortized Regulatory Asset	0.548	91.67% SALWAG	0.502
Amortizaton Expense over 10 Years	0.068	94.855% Acct 593	0.065
Reduction in Amortization Expense - 10 Years	(0.068)	94.855% Acct 593	(0.065)
Increase in Rate Base By Amortizing over 10 Years	0.068	91.67% SALWAG	0.063
ADIT on Remaining Regulatory Asset Balance			
Unamortized Regulatory Asset - 10 Years	0.616		
Federal Income Tax Rate	35.0%		
ADIT on Unamortized Regulatory Asset Balance	(0.216)	91.67% SALWAG	(0.198)
Total Reduction to Rate Base			(0.135)
As Filed Grossed Up ROR			11.43%
Reduction in Return on Rate Base			(0.015)
Reduction in Revenue Requirement			(0.080)

EXHIBIT___(LK-14)

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REQUESTING PARTY: Black Hills Industrial Intervenors

BHII Request No. 18: Reference Schedule H-1, line 5, identified as "Employee Additions\Eliminations."

a. Please provide a detailed description of these costs. In the description, please detail the costs included for each open vacancy and additional employee.

b. Please provide the calculation of this amount, including all assumptions, data, and electronic spreadsheets with formulas intact.

c. Please explain how these additional costs differ from the requested FutureTrack Workforce costs.

d. Please explain how these additional costs are incremental to the costs for those employees being transferred from the retired generating plants.

Response to BHII Request No. 18:

a. See Attachment 18, "Positions by Dept" tab. The position descriptions and detail of the costs are shown in rows 30 through 54.
b. See Attachment 18.
c. The FutureTrack WorkForce Development Program is a recruitment and training program to address pending retirements. The additional costs on Schedule H-1 are for current open positions to be filled as soon as possible. They do not include any positions related to FutureTrack.
d. The additional costs for Employee Additions are for current open positions. The only adjustment made for the employees being transferred from the retired generating plants is for labor costs associated with Neil Simpson I employees that will be charged to power plants not owned by Black Hills Power at the Neil Simpson Complex. These costs have been removed on line 3 of Schedule H-1.

Attachments: 18 – BHP SD Payroll Adjustment Workpaper

Position Summary by Dept

Department	Already filled before Jan 28th	Additions	Terminations	Transfers	Total	
5123		3			3	captured in GDPM adjustment
8600		1	-1	1	1	replacement/soon to retire
8606	0	3		-2	1	
8610				3	3	
8612		1			1	
8616			-1		-1	retirement 2014
8617		1			1	
8619		1			1	
8621		1			1	
8623		3			3	
8626				-1	-1	
8628		1			1	
8638	1	2		2	5	
8639		1			1	
8640		2			2	
8650	1			-1	0	
8652		5	-6	-2	-3	Customer Service Remodel adjustment
	2	25	-8	0	19	
less other adjustments		-6	6			
		19	-2	17		

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Salaries for Additions by Dept		BHP portion	Fully Loaded (65%)
8600	52,150	52,150	86,048
8606	105,200	39,976	65,960
	76,523	29,079	47,980
	76,523	29,079	47,980
8612	74,500	74,500	122,925
8617	41,800	41,800	68,970
8619	74,500	74,500	122,925
8621	48,450	48,450	79,943
8623	74,500	74,500	122,925
	62,850	62,850	103,703
	74,500	74,500	122,925
8628	85,634	85,634	141,295
8638	81,350	30,913	51,006
	81,350	30,913	51,006
8639	57,800	21,964	36,241
8640	52,150	19,817	32,698
	68,350	25,973	42,855
8652	41,800	41,800	68,970
	81,350	81,350	134,228
Total Additions	1,311,280	939,747	1,550,583

Salaries for Terminations by Dept		BHP portion	Fully Loaded (65%)
8600	32,635	32,635	53,848
8616	70,762	70,762	116,757
Total Terminations	103,397	103,397	170,605

Net Additions	**1,379,978**	
2015 wage increase (union)	6,575	
2015 wage increase (non-union)	23,987	
Adjusted Total	**1,410,540**	**BHP Fully Loaded**

Additions

8612 System Protection Engineer
8619 Reliability Engineer
8623 Energy Services Engineer
8623 Energy Services Rep
8638 Instrument Tech II
8638 Instrument Tech II
8639 Process Chemistry Tech
8600 Lead Customer Service Rep
8606 Generation Operations Trainer
8606 Plant Maintenance Operator
8606 Plant Maintenance Operator
8617 Mobile Communicatinos Tech
8621 Business Analyst
8623 Energy Services Key Acct Rep
8628 Lead Line Mechanic
8640 Drafting/Document Control Tech
8640 Electrical Control Engineer
8652 Admin Asst
8652 Construction Rep

Retirements pending

8600 Cashier/Switchboard Operator
8616 Electrician Thereafter

EXHIBIT___(LK-15)

Docket No. EL14-026

Black Hills Power, Inc.

BHII Adjustment to Extend Amortization Period for Remaining NBV on Retired Plants to 10 Years And to Include ADIT in Rate Base

($ Millions)

	Total Company	South Dakota Retail %	South Dakota Retail
Source: Schedule J-2			
Amount of Remaining Plant Costs to be Amortized			
Ben French	(0.535)		
Osage Units 1-3	(0.688)		
Neil Simpson	4.833		
Total Remaining Plant Costs (NBV) to be Amortized	3.610		
Total Obsolete Inventory From All Above Units	2.867		
Total Costs Set Up as Regulatory Asset	6.477		
Company's Proposed Amortization Period in Years	5		
Company's Proposed Annual Amortization Expense	1.295		
Company's Proposed Unamortized Regulatory Asset	5.181		
Adjusted Amortization Period in Years	10		
Adjusted Annual Amortization	0.648		
Adjusted Unamortized Regulatory Asset	5.829		
Decrease in Annual Amortization Expense	(0.648)	89.83% PRODPLT	(0.582)
Increase in Unamortized Regulatory Asset	0.648	89.83% PRODPLT	0.582
Increase in ADIT on Regulatory Asset Balance			
Increase in Unamortized Regulatory Asset			0.582
Federal Income Tax Rate			35.0%
ADIT on Regulatory Asset Balance			(0.204)
Net Increase in Rate Base			0.378
As Filed Grossed Up ROR			11.43%
Increase in Return on Rate Base			0.043
Reduction in Revenue Requirement			(0.539)

EXHIBIT___(LK-16)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Reduce Depreciation Expense by Extending Service Life Span of CPGS
And to Include ADIT in Rate Base
($ Millions)

	Total Company	South Dakota Retail %	South Dakota Retail
Source: Statements E and J			
As Filed CPGS Plant in Service	92.251		
As Filed CPGS Average Depreciation Rate	3.29%	Based on 35 Year Life Span	
As Filed CPGS Depreciation Expense	3.035		
As Adjusted CPGS Average Depreciation Rate	2.88%	Based on 40 Year Life Span	
As Adjusted CPGS Depreciation Expense	2.659		
Reduce Depreciation Expense to Extend Life Span of CPG	(0.376)	89.831% PRODPLT	(0.338)
Accumulated Depreciation			
One Half of Depreciation Expense Reduction (See Statement E Note 3)	(0.188)		
Decrease Accumulated Depreciation for Expense Reductic	0.188	89.831% PRODPLT	0.169
The Effect Increases Rate Base			
Accumulated Deferred Income Taxes (See Schedule M-2)			
Book Depreciation Expense Reduction	(0.376)	100% of Expense Reduction x Tax Rate	
Federal Income Tax Rate	0.35		
Increase ADIT for Expense Reduction	(0.132)	89.831% PRODPLT	(0.118)
The Effect Decreases Rate Base			

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Black Hills Power, Inc.
BHII Adjustment to Reduce Depreciation Expense by Extending Service Life Span of CPGS
And to Include ADIT in Rate Base
($ Millions)

Computation of Adjusted Depreciation Rate
See BHII 15 Attach b for Computed Rates

	Original Cost	Future Book Accruals	Rem Life at 35 Year Span	Rem Life at 40 Year Span	Annual Accrual	Rate
Acct 341	7,028,693	7,309,841	33.75	38.57	189,521	2.70%
Acct 342	10,543,040	10,964,761	31.5	36	304,577	2.89%
Acct 344	38,657,812	40,204,125	31.61	36.13	1,112,763	2.88%
Acct 345	10,543,040	10,964,761	31.78	36.32	301,893	2.86%
Acct 346	3,514,347	3,654,920	27.37	31.28	116,845	3.32%
	70,286,931				2,025,600	2.88%

EXHIBIT___(LK-17)

BLACK HILLS POWER, INC.
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RESPONSE DATE : July 7, 2014

REQUESTING PARTY: Black Hills Industrial Intervenors

BHII Request No. 11: If not previously provided in response to discovery, please provide a copy of all workpapers and source documents relied on by Mr. Spanos to perform the depreciation study for the depreciation rates proposed in this proceeding, including a copy of all notes, correspondence with the Company and/or its affiliates, and electronic spreadsheets with formulas intact.

Response to BHII Request No. 11:

Attachment 11 provides the workpapers and source documents relied on by Mr. Spanos to perform the depreciation study. These documents include notes and correspondence related to the depreciation study.

Attachments: 11 - Spanos Workpapers

Forecasted Plant Retirement Dates

Coal Plants - BHP				
	ORIGINAL		REVISED	
Osage	2014			ok
Ben French	2014			ok
NSI	2014			ok
Wyodak	2030			want to sync with Pacificorp's depr study (John to look at)
NS2	2045			ok
Wygen III (52% ownership)	2060			ok
CT's - BHP				
Diesel Generators	2020			ok
Frame 5 Gas turbines	2030			ok
CT 1	2050			John, we want to see what the rates would look like using both a 40 year and 45 year life
Lange	2050			John, we want to see what the rates would look like using both a 40 year and 45 year life
CC Unit 1 @ CPGS	2054			ok, 40 years
Coal Plants - CLFP				
Wygen I (76.5% ownership)	2053		2048	we want to use a 45 year life to match what was approved in rate cases
Wygen II	2058		2053	we want to use a 45 year life to match what was approved in rate cases
CT's - CLFP				
CC Unit 1 @ CPGS	2054		2049	we are more comfortable with a 35 year life instead of 40
SC Unit 2 @ CPGS	2054			ok, 40 years

EXHIBIT___(LK-18)

Exhibit JJS-2

(FULL)

BLACK HILLS POWER

Rapid City, South Dakota

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS

RELATED TO ELECTRIC PLANT

AS OF DECEMBER 31, 2012

GANNETT FLEMING, INC. - VALUATION AND RATE DIVISION

Harrisburg, Pennsylvania

BLACK HILLS POWER

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE
AND CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2012

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	STEAM PRODUCTION PLANT									
	BEN FRENCH STATION									
311.00	STRUCTURES AND IMPROVEMENTS	80-R1.5	*	(28)	2,251,067.03	2,470,217	411,149	225,045	10.00	1.8
312.01	BOILER PLANT EQUIPMENT	55-S0.5	*	(28)	6,842,535.53	6,971,855	1,786,590	985,304	14.40	1.8
314.00	TURBOGENERATOR UNITS	55-S0.5	*	(28)	3,956,115.75	3,267,891	1,795,937	987,811	24.97	1.8
315.00	ACCESSORY ELECTRIC EQUIPMENT	65-R2.5	*	(28)	756,487.01	817,196	151,107	83,050	10.98	1.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0	*	(28)	461,437.84	529,424	61,216	33,837	7.33	1.8
	TOTAL BEN FRENCH STATION				14,267,643.16	14,056,583	4,205,999	2,315,047	16.23	1.8
	NEIL SIMPSON I									
311.00	STRUCTURES AND IMPROVEMENTS	80-R1.5	*	(13)	2,263,790.00	2,055,490	502,593	275,250	12.16	1.8
312.01	BOILER PLANT EQUIPMENT	55-S0.5	*	(13)	14,327,824.99	10,348,851	5,841,591	3,210,557	22.41	1.8
314.00	TURBOGENERATOR UNITS	55-S0.5	*	(13)	3,916,967.11	2,797,900	1,628,273	896,130	22.88	1.8
315.00	ACCESSORY ELECTRIC EQUIPMENT	65-R2.5	*	(13)	1,334,432.06	622,246	885,662	484,612	36.32	1.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0	*	(13)	424,995.16	434,602	45,643	25,339	5.96	1.8
	TOTAL NEIL SIMPSON I				22,268,009.32	16,259,089	8,903,762	4,891,888	21.97	1.8
	NEIL SIMPSON II									
311.00	STRUCTURES AND IMPROVEMENTS	80-R1.5	*	(14)	15,863,029.45	5,523,394	12,560,460	412,027	2.60	30.5
312.01	BOILER PLANT EQUIPMENT	55-S0.5	*	(14)	76,897,107.11	26,330,450	61,332,252	2,211,622	2.88	27.7
314.00	TURBOGENERATOR UNITS	55-S0.5	*	(14)	41,534,097.95	11,029,471	36,319,401	1,278,221	3.08	28.4
315.00	ACCESSORY ELECTRIC EQUIPMENT	65-R2.5	*	(14)	8,429,093.00	2,511,631	7,097,535	230,583	2.74	30.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0	*	(14)	875,989.44	165,386	833,242	31,072	3.55	26.8
	TOTAL NEIL SIMPSON II				143,599,316.95	45,560,332	118,142,890	4,163,525	2.90	28.4
	OSAGE PLANT									
311.00	STRUCTURES AND IMPROVEMENTS	80-R1.5	*	(22)	4,233,377.67	4,422,755	741,966	406,009	9.59	1.8
312.01	BOILER PLANT EQUIPMENT	55-S0.5	*	(22)	7,454,702.13	7,272,558	1,822,179	1,005,395	13.49	1.8
314.00	TURBOGENERATOR UNITS	55-S0.5	*	(22)	4,780,167.64	4,641,657	1,190,148	656,960	13.74	1.8
315.00	ACCESSORY ELECTRIC EQUIPMENT	65-R2.5	*	(22)	1,054,887.74	1,198,790	88,173	48,528	4.60	1.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0	*	(22)	455,950.73	459,478	96,782	53,529	11.74	1.8
	TOTAL OSAGE PLANT				17,979,085.91	17,995,238	3,939,248	2,170,421	12.07	1.8
	WY GEN 3									
311.00	STRUCTURES AND IMPROVEMENTS	80-R1.5	*	(13)	6,799,493.56	417,254	7,266,174	166,503	2.45	43.6
312.01	BOILER PLANT EQUIPMENT	55-S0.5	*	(13)	57,567,754.14	4,343,796	60,707,766	1,517,622	2.64	40.0
314.00	TURBOGENERATOR UNITS	55-S0.5	*	(13)	58,398,596.28	3,202,879	62,787,535	1,569,482	2.69	40.0
315.00	ACCESSORY ELECTRIC EQUIPMENT	65-R2.5	*	(13)	6,737,220.28	377,879	7,235,180	163,953	2.43	44.1
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0	*	(13)	709,079.57	28,882	772,378	21,429	3.02	36.0
	TOTAL WY GEN 3				130,212,143.83	8,370,690	138,769,033	3,438,989	2.64	40.4

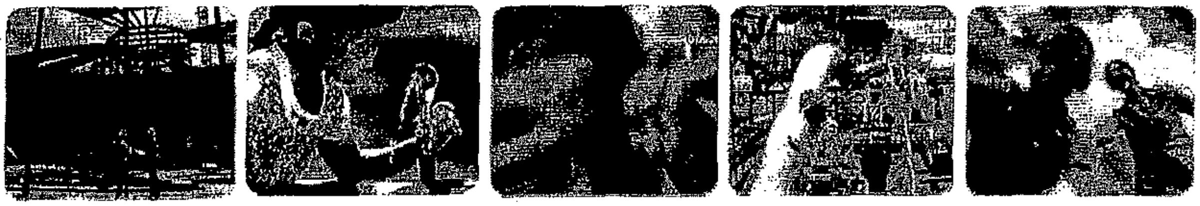
BLACK HILLS POWER

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2012

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	WYODAK PLANT									
311.00	STRUCTURES AND IMPROVEMENTS	80-R1.5	*	(13)	9,164,989.89	7,214,391	3,142,048	125,770	1.37	25.0
312.01	BOILER PLANT EQUIPMENT	55-S0.5	*	(13)	76,887,888.24	29,347,729	57,535,585	2,378,850	3.09	24.2
313.00	ENGINES AND GENERATORS	50-S1.5	*	(13)	341,748.14	216,828	169,347	6,793	1.99	24.9
314.00	TURBOGENERATOR UNITS	55-S0.5	*	(13)	15,192,790.87	5,557,047	11,610,807	482,632	3.18	24.1
315.00	ACCESSORY ELECTRIC EQUIPMENT	65-R2.5	*	(13)	6,616,782.96	5,008,048	2,468,917	99,004	1.50	24.9
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0	*	(13)	1,007,314.51	427,522	710,743	31,411	3.12	22.6
	TOTAL WYODAK PLANT				109,211,514.61	47,771,565	75,637,447	3,124,460	2.86	24.2
	TOTAL STEAM PRODUCTION PLANT				437,537,713.78	150,013,497	349,598,379	20,104,330	4.59	17.4
	OTHER PRODUCTION PLANT									
	BEN FRENCH CT									
341.00	STRUCTURES AND IMPROVEMENTS	55-R3	*	(13)	22,448.14	18,574	6,792	437	1.95	15.5
342.00	FUEL HOLDERS AND ACCESSORIES	50-S0.5	*	(13)	1,375,821.53	903,454	651,224	40,929	2.97	15.9
344.10	GENERATORS	45-R2	*	(13)	16,549,367.07	12,793,447	5,907,338	415,401	2.51	14.2
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2	*	(13)	672,968.54	427,262	333,192	29,853	4.44	11.2
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	30-S1.5	*	(13)	14,717.62	12,177	4,454	569	3.87	7.8
	TOTAL BEN FRENCH CT				18,635,322.90	14,154,914	6,903,000	487,189	2.61	14.2
	BEN FRENCH DIESEL									
342.00	FUEL HOLDERS AND ACCESSORIES	50-S0.5	*	(22)	51,864.25	47,265	16,009	2,215	4.27	7.2
344.10	GENERATORS	45-R2	*	(22)	828,868.97	774,635	236,585	36,709	4.43	6.4
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2	*	(22)	110,823.34	60,434	74,770	11,226	10.13	6.7
	TOTAL BEN FRENCH DIESEL				991,556.56	882,334	327,364	50,150	5.06	6.5
	LANGE CT									
341.00	STRUCTURES AND IMPROVEMENTS	55-R3	*	(5)	324,886.40	102,053	239,078	7,174	2.21	33.3
342.00	FUEL HOLDERS AND ACCESSORIES	50-S0.5	*	(5)	1,722,516.16	526,052	1,282,590	43,258	2.51	29.6
344.10	GENERATORS	45-R2	*	(5)	26,182,995.19	9,824,794	17,667,351	593,903	2.27	29.7
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2	*	(5)	2,095,868.47	792,608	1,408,054	50,943	2.43	27.6
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	30-S1.5	*	(5)	16,611.59	6,306	11,136	527	3.17	21.1
	TOTAL LANGE CT				30,342,877.81	11,251,813	20,608,209	695,805	2.29	29.6
	NEIL SIMPSON CT									
341.00	STRUCTURES AND IMPROVEMENTS	55-R3	*	(5)	176,358.69	78,850	106,327	3,405	1.93	31.2
342.00	FUEL HOLDERS AND ACCESSORIES	50-S0.5	*	(5)	2,116,073.40	616,956	1,604,921	56,038	2.65	28.6
344.10	GENERATORS	45-R2	*	(5)	25,644,954.15	8,133,641	18,793,561	660,704	2.58	28.4
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2	*	(5)	1,987,599.72	927,847	1,159,133	45,006	2.26	25.8
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	30-S1.5	*	(5)	51,538.76	24,278	29,838	1,316	2.55	22.7
	TOTAL NEIL SIMPSON CT				29,976,524.72	9,781,572	21,693,780	766,469	2.56	28.3
	TOTAL OTHER PRODUCTION PLANT				79,946,281.99	36,070,633	49,532,353	1,999,613	2.50	24.8

EXHIBIT___(LK-19)

BUILDING A WORLD OF DIFFERENCE®



BLACK HILLS POWER, INC.

Report on Depreciation Accrual Rates

Electric Utility Property Through December 31, 2008

September 18, 2009

BLACK & VEATCH
Building a world of difference®

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Osage Plant

Historical and Forecast Plant Additions & Balances
Account: 311 Structures & Improvements

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1953
Retirement Date	2013
Service Life, Yrs	60
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			EOY Plant Balance		
			Transaction Year			Vintage Year					Transfers and			
Line	Vintage Year	Vintage Age	Beg. Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1953	60					2,046,367		2,046,367	-		2,046,367		2,046,367
2	1954	59				107,853	26,060	6,246	26,060	6,246		2,066,181		2,066,181
3	1955	58					26,313	6,307	26,313	6,307		2,086,187		2,086,187
4	1956	57					26,568	6,368	26,568	6,368		2,106,387		2,106,387
5	1957	56					26,825	6,429	26,825	6,429		2,126,783		2,126,783
6	1958	55				1,823	27,085	6,492	27,085	6,492		2,147,375		2,147,375
7	1959	54					27,347	6,555	27,347	6,555		2,168,168		2,168,168
8	1960	53					27,612	6,618	27,612	6,618		2,189,161		2,189,161
9	1961	52					27,879	6,682	27,879	6,682		2,210,358		2,210,358
10	1962	51				432	28,149	6,747	28,149	6,747		2,231,760		2,231,760
11	1963	50					28,421	6,812	28,421	6,812		2,253,369		2,253,369
12	1964	49					28,697	6,878	28,697	6,878		2,275,188		2,275,188
13	1965	48					28,974	6,945	28,974	6,945		2,297,217		2,297,217
14	1966	47				1,657	29,255	7,012	29,255	7,012		2,319,461		2,319,461
15	1967	46					29,538	7,080	29,538	7,080		2,341,919		2,341,919
16	1968	45					29,824	7,148	29,824	7,148		2,364,595		2,364,595
17	1969	44					30,113	7,218	30,113	7,218		2,387,490		2,387,490
18	1970	43				2,521	30,405	7,287	30,405	7,287		2,410,608		2,410,608
19	1971	42					30,699	7,358	30,699	7,358		2,433,948		2,433,948
20	1972	41				5,973	30,996	7,429	30,996	7,429		2,457,515		2,457,515
21	1973	40					31,296	7,501	31,296	7,501		2,481,311		2,481,311
22	1974	39					31,599	7,574	31,599	7,574		2,505,336		2,505,336
23	1975	38					31,905	7,647	31,905	7,647		2,529,594		2,529,594
24	1976	37					32,214	7,721	32,214	7,721		2,554,088		2,554,088
25	1977	36					32,526	7,796	32,526	7,796		2,578,818		2,578,818
26	1978	35				1,313	32,841	7,871	32,841	7,871		2,603,787		2,603,787
27	1979	34					33,159	7,948	33,159	7,948		2,628,999		2,628,999
28	1980	33				459,599	33,480	8,025	33,480	8,025		2,654,455		2,654,455
29	1981	32					33,804	8,102	33,804	8,102		2,680,157		2,680,157
30	1982	31					34,132	8,181	34,132	8,181		2,706,107		2,706,107
31	1983	30				6,667	34,462	8,260	34,462	8,260		2,732,310		2,732,310
32	1984	29					34,796	8,340	34,796	8,340		2,758,766		2,758,766
33	1985	28				79,664	35,133	8,421	35,133	8,421		2,785,478		2,785,478
34	1986	27					35,473	8,502	35,473	8,502		2,812,448		2,812,448
35	1987	26					35,816	8,585	35,816	8,585		2,839,680		2,839,680
36	1988	25				87,422	36,163	8,668	36,163	8,668		2,867,176		2,867,176
37	1989	24	2,867,176	46,652									2,913,828	2,913,828
38	1990	23		103,313	2,194						(33,244)		2,981,703	2,981,703
39	1991	22		37,851	12,666	18,737							3,006,888	3,006,888
40	1992	21		147,740	39,067								3,115,561	3,115,561
41	1993	20		501,546	22,370				501,546	22,370			3,594,737	3,594,737
42	1994	19		1,337,983	29,747				1,337,983	29,747			4,902,973	4,902,973
43	1995	18		73,372					73,372	-			4,976,345	4,976,345
44	1996	17		7,898	9,057				7,898	9,057			4,975,185	4,975,185
45	1997	16			521,670				-	521,670			4,453,515	4,453,515
46	1998	15		4,369	136,832				4,369	136,832			4,321,052	4,321,052
47	1999	14							-	-			4,321,052	4,321,052
48	2000	13							-	-			4,321,052	4,321,052
49	2001	12							-	-			4,321,052	4,321,052
50	2002	11							-	-			4,321,052	4,321,052
51	2003	10							-	-			4,321,052	4,321,052
52	2004	9							-	-			4,321,052	4,321,052
53	2005	8							-	-			4,321,052	4,321,052
54	2006	7							-	-	(57,372)		4,263,680	4,263,680
55	2007	6		128,368					128,368	-	104		4,392,152	4,392,152
56	2008	5							-	-			4,392,152	4,392,152
57	Total		$ 2,867,176	$ 2,389,091	$ 773,603	$ 773,642	$ 3,125,928	$ 258,753	$ 5,179,464	$ 978,429	$ (90,512)	$ 87,638,547	$ 82,537,134	$ 170,175,681
	Major Additions/Retirements													
	1997				$ 521,670									
	1994			$ 1,337,983										
	Routine Activity			$ 1,051,108	$ 251,933									
58	Historical Interim Activity			1.27%	0.31%									
59	Forecast Interim Activity			0.50%	0.31%									
60	2009	4							21,961	13,406				4,400,706
61	2010	3							22,004	13,433				4,409,277
62	2011	2							22,046	13,459				4,417,865
63	2012	1							22,089	13,485				4,426,469
64	2013	0									(4,426,469)			-
									$ 5,267,564	$ 1,032,211				$ 187,829,999

Whole Life Depreciation Rate Calculation

Historical Additions	5,179,464
Forecast Additions	88,100
Total Additions	5,267,564
Gross Salvage Value	221,323
Less Cost of Removal	442,647
Net Salvage Value	(221,323)
Total to be Recovered	5,488,886
Forecast Plant Balances	187,829,999
Whole Life Accrual Rate	2.92%
Cost of Removal Accrual Rate	0.24%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.16%
Depreciable Service Life, years	34.2

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	4,392,152
Forecast Additions	88,100
Gross Salvage Value	221,323
Less Cost of Removal	442,647
Net Salvage Value	(221,323)
Forecast Plant Balances	17,654,318

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Osage Plant

Historical and Forecast Plant Additions & Balances
Account: 312 Boiler Plant Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1953
Retirement Date	2013
Service Life, Yrs	60
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			EOY Plant Balance		
				Transaction Year										
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Vintage Year Retirements	Additions	Retirements	Additions	Retirements	Transfers and Adjustments	Adjustments	Per Books	Simulated
1	1953	60					3,705,569		3,705,569	-		3,705,569		3,705,569
2	1954	59				71,775	40,796	9,692	40,796	9,692		3,736,673		3,736,673
3	1955	58					41,138	9,774	41,138	9,774		3,768,037		3,768,037
4	1956	57					41,483	9,856	41,483	9,856		3,799,665		3,799,665
5	1957	56					41,832	9,938	41,832	9,938		3,831,558		3,831,558
6	1958	55				762	42,183	10,022	42,183	10,022		3,863,719		3,863,719
7	1959	54					42,537	10,106	42,537	10,106		3,896,149		3,896,149
8	1960	53					42,894	10,191	42,894	10,191		3,928,852		3,928,852
9	1961	52					43,254	10,276	43,254	10,276		3,961,830		3,961,830
10	1962	51					43,617	10,363	43,617	10,363		3,995,084		3,995,084
11	1963	50					43,983	10,450	43,983	10,450		4,028,617		4,028,617
12	1964	49					44,352	10,537	44,352	10,537		4,062,432		4,062,432
13	1965	48					44,725	10,626	44,725	10,626		4,096,531		4,096,531
14	1966	47					45,100	10,715	45,100	10,715		4,130,916		4,130,916
15	1967	46					45,478	10,805	45,478	10,805		4,165,590		4,165,590
16	1968	45					45,860	10,896	45,860	10,896		4,200,554		4,200,554
17	1969	44					46,245	10,987	46,245	10,987		4,235,812		4,235,812
18	1970	43				12,642	46,633	11,079	46,633	11,079		4,271,366		4,271,366
19	1971	42					47,025	11,172	47,025	11,172		4,307,219		4,307,219
20	1972	41					47,419	11,266	47,419	11,266		4,343,372		4,343,372
21	1973	40					47,817	11,361	47,817	11,361		4,379,829		4,379,829
22	1974	39					48,219	11,456	48,219	11,456		4,416,592		4,416,592
23	1975	38					48,624	11,552	48,624	11,552		4,453,663		4,453,663
24	1976	37					49,032	11,649	49,032	11,649		4,491,045		4,491,045
25	1977	36				2,200	49,443	11,747	49,443	11,747		4,528,742		4,528,742
26	1978	35					49,858	11,845	49,858	11,845		4,566,755		4,566,755
27	1979	34				15,634	50,277	11,945	50,277	11,945		4,605,086		4,605,086
28	1980	33				2,000	50,699	12,045	50,699	12,045		4,643,740		4,643,740
29	1981	32				2,000	51,124	12,146	51,124	12,146		4,682,718		4,682,718
30	1982	31				105,538	51,553	12,248	51,553	12,248		4,722,023		4,722,023
31	1983	30					51,986	12,351	51,986	12,351		4,761,658		4,761,658
32	1984	29				20,365	52,422	12,455	52,422	12,455		4,801,626		4,801,626
33	1985	28					52,862	12,559	52,862	12,559		4,841,929		4,841,929
34	1986	27				2,304	53,306	12,665	53,306	12,665		4,882,571		4,882,571
35	1987	26					53,754	12,771	53,754	12,771	/	4,923,553		4,923,553
36	1988	25				35,014	54,205	12,878	54,205	12,878		4,964,880		4,964,880
37	1989	24	4,964,880	34,880									4,999,760	4,999,760
38	1990	23		156,910							(20,459)		5,136,211	5,136,211
39	1991	22		47,052	25,267	4,058							5,157,997	5,157,997
40	1992	21		841,359	53,757								5,945,599	5,945,599
41	1993	20		1,183,608	39,065	79,448			1,183,608	39,065			7,090,142	7,090,142
42	1994	19							-	-			7,090,142	7,090,142
43	1995	18		31,356	7,500				31,356	7,500			7,113,998	7,113,998
44	1996	17		26,378	106,337				26,378	106,337			7,034,040	7,034,040
45	1997	16		55,404	9,642				55,404	9,642	211		7,080,013	7,080,013
46	1998	15							-	-			7,080,013	7,080,013
47	1999	14		24,743	8,500				24,743	8,500			7,096,256	7,096,256
48	2000	13							-	-			7,096,256	7,096,256
49	2001	12							-	-			7,096,256	7,096,256
50	2002	11		31,181	56,248				31,181	56,248			7,071,189	7,071,189
51	2003	10							-	-			7,071,189	7,071,189
52	2004	9		71,202	4,784				71,202	4,784			7,137,607	7,137,607
53	2005	8		25,951	7,626				25,951	7,626			7,155,932	7,155,932
54	2006	7							-	-	35,344		7,191,275	7,191,275
55	2007	6		142,490	35,014				142,490	35,014	(234)		7,298,517	7,298,517
56	2008	5							-	-			7,298,517	7,298,517
57	Total		$ 4,964,880	$ 2,672,515	$ 353,740	$ 353,740	$ 5,357,305	$ 392,425	$ 6,949,619	$ 667,141	$ 14,862	$154,995,955	$ 135,240,911	$ 290,236,866
	Major Additions/Retirements													
	1993			$ 1,183,608										
	Routine Activity			$ 1,488,907	$ 353,740									
58	Historical Interim Activity			1.10%	0.26%									
59	Forecast Interim Activity			0.50%	0.26%									
60	2009	4							36,493	19,090				7,315,920
61	2010	3							36,580	19,136				7,333,364
62	2011	2							36,667	19,181				7,350,849
63	2012	1							36,754	19,227				7,368,376
64	2013	0									(7,368,376)			-
									$ 7,096,112	$ 743,775				$ 319,605,374

Whole Life Depreciation Rate Calculation

Historical Additions	6,949,619
Forecast Additions	146,493
Total Additions	7,096,112
Gross Salvage Value	368,419
Less Cost of Removal	736,838
Net Salvage Value	(368,419)
Total to be Recovered	7,464,531
Forecast Plant Balances	319,605,374
Whole Life Accrual Rate	2.34%
Cost of Removal Accrual Rate	0.23%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.57%
Depreciable Service Life, years	42.8

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	7,298,517
Forecast Additions	146,493
Gross Salvage Value	368,419
Less Cost of Removal	736,838
Net Salvage Value	(368,419)
Forecast Plant Balances	29,368,509

005942

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Osage Plant

Historical and Forecast Plant Additions & Balances
Account: 314 Turbogenerator Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1953
Retirement Date	2013
Service Life, Yrs	60
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			EOY Plant Balance		
			Transaction Year			Vintage Year					Transfers and			
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1953	60					[redacted]		2,661,025	-		2,661,025		2,661,025
2	1954	59				66,690	18,400	4,552	18,400	4,552		2,674,872		2,674,872
3	1955	58					18,495	4,576	18,495	4,576		2,688,791		2,688,791
4	1956	57					18,592	4,600	18,592	4,600		2,702,783		2,702,783
5	1957	56					18,688	4,624	18,688	4,624		2,716,848		2,716,848
6	1958	55					18,786	4,648	18,786	4,648		2,730,985		2,730,985
7	1959	54					18,883	4,672	18,883	4,672		2,745,197		2,745,197
8	1960	53					18,982	4,696	18,982	4,696		2,759,482		2,759,482
9	1961	52					19,080	4,721	19,080	4,721		2,773,841		2,773,841
10	1962	51					19,180	4,745	19,180	4,745		2,788,276		2,788,276
11	1963	50					19,280	4,770	19,280	4,770		2,802,785		2,802,785
12	1964	49					19,380	4,795	19,380	4,795		2,817,370		2,817,370
13	1965	48					19,481	4,820	19,481	4,820		2,832,031		2,832,031
14	1966	47					19,582	4,845	19,582	4,845		2,846,768		2,846,768
15	1967	46					19,684	4,870	19,684	4,870		2,861,582		2,861,582
16	1968	45					19,786	4,896	19,786	4,896		2,876,473		2,876,473
17	1969	44					19,889	4,921	19,889	4,921		2,891,441		2,891,441
18	1970	43					19,993	4,947	19,993	4,947		2,906,487		2,906,487
19	1971	42					20,097	4,972	20,097	4,972		2,921,612		2,921,612
20	1972	41					20,202	4,998	20,202	4,998		2,936,815		2,936,815
21	1973	40					20,307	5,024	20,307	5,024		2,952,098		2,952,098
22	1974	39					20,412	5,050	20,412	5,050		2,967,460		2,967,460
23	1975	38					20,519	5,077	20,519	5,077		2,982,901		2,982,901
24	1976	37					20,625	5,103	20,625	5,103		2,998,424		2,998,424
25	1977	36					20,733	5,130	20,733	5,130		3,014,027		3,014,027
26	1978	35					20,841	5,156	20,841	5,156		3,029,711		3,029,711
27	1979	34				43,235	20,949	5,183	20,949	5,183		3,045,477		3,045,477
28	1980	33					21,058	5,210	21,058	5,210		3,061,324		3,061,324
29	1981	32					21,168	5,237	21,168	5,237		3,077,255		3,077,255
30	1982	31					21,278	5,265	21,278	5,265		3,093,268		3,093,268
31	1983	30					21,388	5,292	21,388	5,292		3,109,364		3,109,364
32	1984	29				3,758	21,500	5,319	21,500	5,319		3,125,545		3,125,545
33	1985	28				4,843	21,612	5,347	21,612	5,347		3,141,809		3,141,809
34	1986	27				707	21,724	5,375	21,724	5,375		3,158,158		3,158,158
35	1987	26					21,837	5,403	21,837	5,403		3,174,593		3,174,593
36	1988	25					21,951	5,431	21,951	5,431		3,191,112		3,191,112
37	1989	24	3,191,112	112,899	21,617	500							3,282,394	3,282,394
38	1990	23		211,355	21,617						33,244		3,505,375	3,505,375
39	1991	22			26,799								3,478,576	3,478,576
40	1992	21		195,001	45,891	5,500							3,627,686	3,627,686
41	1993	20		747,773		1,701			747,773	-			4,375,458	4,375,458
42	1994	19							-	-			4,375,458	4,375,458
43	1995	18							-	-			4,375,458	4,375,458
44	1996	17							-	-			4,375,458	4,375,458
45	1997	16		32,618	7,929	17,285			32,618	7,929			4,400,147	4,400,147
46	1998	15							-	-			4,400,147	4,400,147
47	1999	14							-	-			4,400,147	4,400,147
48	2000	13							-	-			4,400,147	4,400,147
49	2001	12		11,637					11,637	-			4,411,785	4,411,785
50	2002	11							-	-			4,411,785	4,411,785
51	2003	10							-	-			4,411,785	4,411,785
52	2004	9							-	-			4,411,785	4,411,785
53	2005	8		8,524	3,081				8,524	3,081			4,417,227	4,417,227
54	2006	7		10,627					10,627	-	(107,873)		4,319,981	4,319,981
55	2007	6		237	17,285				237	17,285	20		4,302,953	4,302,953
56	2008	5		313,906					313,906	-			4,616,858	4,616,858
57	Total		$ 3,191,112	$ 1,644,575	$ 144,220	$ 144,219	$ 3,365,384	$ 174,272	$ 4,490,705	$ 202,567	$ (74,610)	$105,057,990	$ 84,300,612	$ 189,358,601
	Major Additions/Retirements													
	1993			$ 747,773										
	2008			$ 313,906										
	Routine Activity			$ 582,897	$ 144,220									
58	Historical Interim Activity			0.69%	0.17%									
59	Forecast Interim Activity			0.69%	0.17%									
60	2009	4							31,923	7,898				4,640,883
61	2010	3							32,089	7,940				4,665,033
62	2011	2							32,256	7,981				4,689,309
63	2012	1							32,424	8,022				4,713,711
64	2013	0									(4,713,711)			-
									$ 4,619,398	$ 234,408				$ 208,067,537

Whole Life Depreciation Rate Calculation

Historical Additions	4,490,705
Forecast Additions	128,693
Total Additions	4,619,398
Gross Salvage Value	235,686
Less Cost of Removal	471,371
Net Salvage Value	(235,686)
Total to be Recovered	4,855,084
Forecast Plant Balances	208,067,537
Whole Life Accrual Rate	2.33%
Cost of Removal Accrual Rate	0.23%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.56%
Depreciable Service Life, years	42.9

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	4,616,858
Forecast Additions	128,693
Gross Salvage Value	235,686
Less Cost of Removal	471,371
Net Salvage Value	(235,686)
Forecast Plant Balances	18,708,936

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Osage Plant

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1953
Retirement Date	2013
Service Life, Yrs	60
Initial Plant Balance	0

2008

Historical and Forecast Plant Additions & Balances
Account: 315 Accessory Electric Equipment

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year					EOY Plant Balance		
			Transaction Year			Vintage Year			Adjusted Transaction Year		Transfers and			
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1953	60					[redacted]		348,629	-		348,629		348,629
2	1954	59					1,215	453	1,215	453		349,391		349,391
3	1955	58					1,218	454	1,218	454		350,155		350,155
4	1956	57					1,221	455	1,221	455		350,920		350,920
5	1957	56					1,223	456	1,223	456		351,687		351,687
6	1958	55					1,226	457	1,226	457		352,456		352,456
7	1959	54					1,229	458	1,229	458		353,226		353,226
8	1960	53					1,232	459	1,232	459		353,998		353,998
9	1961	52					1,234	460	1,234	460		354,772		354,772
10	1962	51					1,237	461	1,237	461		355,548		355,548
11	1963	50					1,240	462	1,240	462		356,325		356,325
12	1964	49					1,242	463	1,242	463		357,104		357,104
13	1965	48					1,245	464	1,245	464		357,884		357,884
14	1966	47					1,248	465	1,248	465		358,667		358,667
15	1967	46					1,250	466	1,250	466		359,450		359,450
16	1968	45					1,253	468	1,253	468		360,236		360,236
17	1969	44					1,256	469	1,256	469		361,024		361,024
18	1970	43					1,259	470	1,259	470		361,813		361,813
19	1971	42					1,261	471	1,261	471		362,604		362,604
20	1972	41					1,264	472	1,264	472		363,396		363,396
21	1973	40					1,267	473	1,267	473		364,191		364,191
22	1974	39					1,270	474	1,270	474		364,987		364,987
23	1975	38					1,273	475	1,273	475		365,784		365,784
24	1976	37					1,275	476	1,275	476		366,584		366,584
25	1977	36					1,278	477	1,278	477		367,385		367,385
26	1978	35					1,281	478	1,281	478		368,188		368,188
27	1979	34					1,284	479	1,284	479		368,993		368,993
28	1980	33					1,286	480	1,286	480		369,800		369,800
29	1981	32					1,289	481	1,289	481		370,608		370,608
30	1982	31					1,292	482	1,292	482		371,418		371,418
31	1983	30					1,295	483	1,295	483		372,230		372,230
32	1984	29					1,298	484	1,298	484		373,044		373,044
33	1985	28					1,301	485	1,301	485		373,859		373,859
34	1986	27					1,303	486	1,303	486		374,676		374,676
35	1987	26					1,306	487	1,306	487		375,495		375,495
36	1988	25					1,309	488	1,309	488		376,316		376,316
37	1989	24	376,316						-	-			376,316	376,316
38	1990	23							-	-			376,316	376,316
39	1991	22							-	-			376,316	376,316
40	1992	21		5,676					5,676	-			381,992	381,992
41	1993	20		108,772					108,772	-			490,763	490,763
42	1994	19							-	-			490,763	490,763
43	1995	18							-	-			490,763	490,763
44	1996	17		10,760					10,760	-			501,524	501,524
45	1997	16							-	-			501,524	501,524
46	1998	15		20,127		19,982			20,127	-	359,680		881,330	881,330
47	1999	14							-	-	162,486		1,043,817	1,043,817
48	2000	13							-	-			1,043,817	1,043,817
49	2001	12							-	-			1,043,817	1,043,817
50	2002	11		6,817					6,817	-	1,649		1,052,282	1,052,282
51	2003	10							-	-			1,052,282	1,052,282
52	2004	9							-	-	167		1,052,450	1,052,450
53	2005	8		10,184	19,982				10,184	19,982			1,042,652	1,042,652
54	2006	7							-	-	12,236		1,054,888	1,054,888
55	2007	6							-	-			1,054,888	1,054,888
56	2008	5							-	-			1,054,888	1,054,888
57	Total		$ 376,316	$ 162,336	$ 19,982	$ 19,982	$ 392,790	$ 16,474	$ 555,126	$ 36,456	$ 536,218	$ 13,042,841	$ 15,363,388	$ 28,406,230
	Major Additions/Retirements													
	1993			$ 108,772										
	Routine Activity			$ 53,564	$ 19,982									
58	Historical Interim Activity			0.35%	0.13%									
59	Forecast Interim Activity			0.35%	0.13%									
60	2009	4							3,678	1,372				1,057,194
61	2010	3							3,686	1,375				1,059,504
62	2011	2							3,694	1,378				1,061,820
63	2012	1							3,702	1,381				1,064,141
64	2013	0									(1,064,141)			-
									$ 569,886	$ 41,962				$ 32,646,890

Whole Life Depreciation Rate Calculation

Historical Additions	555,126
Forecast Additions	14,760
Total Additions	569,886
Gross Salvage Value	53,207
Less Cost of Removal	106,414
Net Salvage Value	(53,207)
Total to be Recovered	623,093
Forecast Plant Balances	32,648,890
Whole Life Accrual Rate	1.91%
Cost of Removal Accrual Rate	0.33%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.23%
Depreciable Service Life, years	52.4

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	1,054,888
Forecast Additions	14,760
Gross Salvage Value	53,207
Less Cost of Removal	106,414
Net Salvage Value	(53,207)
Forecast Plant Balances	4,242,660

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Osage Plant

Historical and Forecast Plant Additions & Balances
Account: 316 Miscellaneous Power Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1953
Retirement Date	2013
Service Life, Yrs	60
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			EOY Plant Balance		
			Transaction Year											
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Vintage Year Retirements	Additions	Retirements	Additions	Retirements	Transfers and Adjustments	Adjustments	Per Books	Simulated
1	1953	60					[redacted]		132,992	-		132,992		132,992
2	1954	59				39,710	2,462	308	2,462	308		135,146		135,146
3	1955	58					2,502	313	2,502	313		137,335		137,335
4	1956	57					2,542	318	2,542	318		139,559		139,559
5	1957	56					2,583	323	2,583	323		141,819		141,819
6	1958	55					2,625	328	2,625	328		144,116		144,116
7	1959	54					2,668	334	2,668	334		146,449		146,449
8	1960	53					2,711	339	2,711	339		148,821		148,821
9	1961	52					2,755	345	2,755	345		151,231		151,231
10	1962	51					2,799	350	2,799	350		153,680		153,680
11	1963	50					2,845	356	2,845	356		156,169		156,169
12	1964	49					2,891	362	2,891	362		158,698		158,698
13	1965	48					2,937	367	2,937	367		161,268		161,268
14	1966	47					2,985	373	2,985	373		163,880		163,880
15	1967	46					3,033	379	3,033	379		166,534		166,534
16	1968	45					3,083	386	3,083	386		169,231		169,231
17	1969	44					3,132	392	3,132	392		171,972		171,972
18	1970	43					3,183	398	3,183	398		174,757		174,757
19	1971	42				438	3,235	405	3,235	405		177,587		177,587
20	1972	41					3,287	411	3,287	411		180,463		180,463
21	1973	40				300	3,340	418	3,340	418		183,385		183,385
22	1974	39					3,394	425	3,394	425		186,355		186,355
23	1975	38					3,449	431	3,449	431		189,373		189,373
24	1976	37					3,505	438	3,505	438		192,440		192,440
25	1977	36				133	3,562	446	3,562	446		195,556		195,556
26	1978	35				950	3,620	453	3,620	453		198,723		198,723
27	1979	34				1,850	3,678	460	3,678	460		201,942		201,942
28	1980	33				3,043	3,738	468	3,738	468		205,212		205,212
29	1981	32					3,798	475	3,798	475		208,535		208,535
30	1982	31					3,860	483	3,860	483		211,912		211,912
31	1983	30					3,922	491	3,922	491		215,344		215,344
32	1984	29					3,986	499	3,986	499		218,832		218,832
33	1985	28				511	4,051	507	4,051	507		222,376		222,376
34	1986	27					4,116	515	4,116	515		225,977		225,977
35	1987	26					4,183	523	4,183	523		229,637		229,637
36	1988	25				6,495	4,251	532	4,251	532		233,355		233,355
37	1989	24	233,355	16,456									249,811	249,811
38	1990	23		22,924	36,023								236,712	236,712
39	1991	22		10,097	3,058						96,488		340,239	340,239
40	1992	21		12,911									353,150	353,150
41	1993	20		14,373					14,373	-			367,523	367,523
42	1994	19		5,898					5,898	-			373,421	373,421
43	1995	18		4,964					4,964	-			378,386	378,386
44	1996	17							-	-	101,391		479,777	479,777
45	1997	16			7,352				-	7,352			472,425	472,425
46	1998	15		7,941		3,033			7,941	-			480,366	480,366
47	1999	14		947					947	-			481,313	481,313
48	2000	13		1,825					1,825	-	5,729		488,868	488,868
49	2001	12		3,738					3,738	-			492,605	492,605
50	2002	11		22,539					22,539	-			515,144	515,144
51	2003	10							-	-			515,144	515,144
52	2004	9		6,297	6,495				6,297	6,495			514,946	514,946
53	2005	8		2,502					2,502	-			517,449	517,449
54	2006	7		21,870					21,870	-	(88,392)		450,927	450,927
55	2007	6		4,128	3,033				4,128	3,033			452,022	452,022
56	2008	5							-	-			452,022	452,022
57	Total		$ 233,355	$ 159,411	$ 55,961	$ 55,961	$ 247,703	$ 14,347	$ 344,726	$ 31,227	$ 115,217	$ 6,430,662	$ 8,612,253	$ 15,042,915

Line		Additions	Retirements
	Major Additions/Retirements		
	1990		$ 36,023
	Routine Activity	$ 159,411	$ 19,938
58	Historical Interim Activity	1.85%	0.23%
59	Forecast Interim Activity	1.00%	0.23%

Line	Vintage Year	Vintage Age	[I] Additions	[J] Retirements	[K] Transfers and Adjustments	[N] Simulated
60	2009	4	4,520	1,046		455,496
61	2010	3	4,555	1,055		458,996
62	2011	2	4,590	1,063		462,524
63	2012	1	4,625	1,071		466,078
64	2013	0			(466,078)	-
			$ 363,016	$ 35,462		$ 16,886,009

Whole Life Depreciation Rate Calculation

Historical Additions	344,726
Forecast Additions	18,290
Total Additions	363,016
Gross Salvage Value	23,304
Less Cost of Removal	46,608
Net Salvage Value	(23,304)
Total to be Recovered	386,320
Forecast Plant Balances	16,886,009
Whole Life Accrual Rate	2.29%
Cost of Removal Accrual Rate	0.28%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.56%
Depreciable Service Life, years	43.7

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	452,022
Forecast Additions	18,290
Gross Salvage Value	23,304
Less Cost of Removal	46,608
Net Salvage Value	(23,304)
Forecast Plant Balances	1,843,094

005945

Summary by Plant
Black Hills Power
Ben French Facility

Account	Description	Direct Investment 2008$	Depreciation Rate
310	Land		
311	Structure & Improvements	2,119,670	2.68%
312	Boiler Plant Equipment	6,403,948	3.90%
313	Engines & Engine Driven Generators	0	0.00%
314	Turbo Generator Equipment	3,105,937	3.46%
315	Accessory Electric Equipment	747,759	2.24%
316	Misc Power Equipment	459,835	3.78%
	Total	12,837,149	$\boxed{3.49\%}$ whole life weighted average rate

Remaining Life Depreciation Rate Calculation

Per Books Balance 12/31/08	13,360,210
Forecast Interim Additions	7,221,185
Forecast Gross Salvage Value	966,460
Forecast Less Cost of Removal	1,932,919
Forecast Net Salvage Value	(966,460)
Forecast Total to be Recovered with COR	21,547,854
Forecast Total to be Recovered w/o COR	19,614,935
Accumulated Depreciation (2008 EOY)	(13,050,958)
Forecast Remaining Life Balance with COR	8,496,897
Forecast Remaining Life Balance w/o COR	6,563,977
Forecast Plant Balances	234,568,689
Remaining Life Rate with COR	3.62%
Remaining Life Rate w/o COR	2.80%

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Ben French Plant

Historical and Forecast Plant Additions & Balances
Account: 311 Structures & Improvements

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1960
Retirement Date	2023
Service Life, Yrs	63
Initial Plant Balance	0

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance		
			Transaction Year			Vintage Year								
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1960	63					[redacted]		1,645,152	-		1,645,152		1,645,152
2	1961	62					18,125	7,282	18,125	7,282		1,655,995		1,655,995
3	1962	61				110,466	18,245	7,330	18,245	7,330		1,666,911		1,666,911
4	1963	60					18,365	7,378	18,365	7,378		1,677,898		1,677,898
5	1964	59					18,486	7,426	18,486	7,426		1,688,957		1,688,957
6	1965	58					18,608	7,475	18,608	7,475		1,700,090		1,700,090
7	1966	57					18,731	7,525	18,731	7,525		1,711,296		1,711,296
8	1967	56					18,854	7,574	18,854	7,574		1,722,576		1,722,576
9	1968	55					18,978	7,624	18,978	7,624		1,733,930		1,733,930
10	1969	54					19,103	7,674	19,103	7,674		1,745,359		1,745,359
11	1970	53					19,229	7,725	19,229	7,725		1,756,863		1,756,863
12	1971	52				567	19,356	7,776	19,356	7,776		1,768,443		1,768,443
13	1972	51					19,484	7,827	19,484	7,827		1,780,099		1,780,099
14	1973	50					19,612	7,879	19,612	7,879		1,791,832		1,791,832
15	1974	49					19,741	7,931	19,741	7,931		1,803,643		1,803,643
16	1975	48					19,871	7,983	19,871	7,983		1,815,531		1,815,531
17	1976	47					20,002	8,036	20,002	8,036		1,827,498		1,827,498
18	1977	46					20,134	8,089	20,134	8,089		1,839,544		1,839,544
19	1978	45					20,267	8,142	20,267	8,142		1,851,669		1,851,669
20	1979	44					20,401	8,196	20,401	8,196		1,863,874		1,863,874
21	1980	43				16,059	20,535	8,250	20,535	8,250		1,876,159		1,876,159
22	1981	42				7,135	20,670	8,304	20,670	8,304		1,888,526		1,888,526
23	1982	41				3,853	20,807	8,359	20,807	8,359		1,900,974		1,900,974
24	1983	40					20,944	8,414	20,944	8,414		1,913,504		1,913,504
25	1984	39					21,082	8,469	21,082	8,469		1,926,116		1,926,116
26	1985	38					21,221	8,525	21,221	8,525		1,938,812		1,938,812
27	1986	37				3,566	21,361	8,581	21,361	8,581		1,951,591		1,951,591
28	1987	36					21,501	8,638	21,501	8,638		1,964,455		1,964,455
29	1988	35				39,280	21,643	8,695	21,643	8,695		1,977,403		1,977,403
30	1989	34	1,977,403	9,156	567				9,156	567			1,985,992	1,985,992
31	1990	33		3,453	34,000				3,453	34,000			1,955,445	1,955,445
32	1991	32		57,884	18,022				57,884	18,022			1,995,307	1,995,307
33	1992	31		32,045	3,018				32,045	3,018			2,024,334	2,024,334
34	1993	30		42,529	64,172				42,529	64,172			2,002,691	2,002,691
35	1994	29		60,359					60,359	-			2,063,050	2,063,050
36	1995	28		4,810					4,810	-			2,067,860	2,067,860
37	1996	27		78,597	1,265				78,597	1,265			2,145,193	2,145,193
38	1997	26							-	-	(135,790)		2,009,403	2,009,403
39	1998	25							-	-			2,009,403	2,009,403
40	1999	24							-	-			2,009,403	2,009,403
41	2000	23							-	-			2,009,403	2,009,403
42	2001	22							-	-			2,009,403	2,009,403
43	2002	21		25,330	16,750				25,330	16,750			2,017,982	2,017,982
44	2003	20		12,030					12,030	-			2,030,013	2,030,013
45	2004	19		100,652	43,133				100,652	43,133			2,087,532	2,087,532
46	2005	18		8,946					8,946	-			2,096,478	2,096,478
47	2006	17		14,576					14,576	-	8,617		2,119,670	2,119,670
48	2007	16							-	-			2,119,670	2,119,670
49	2008	15							-	-			2,119,670	2,119,670
50	Total		$ 1,977,403	$ 450,368	$ 180,927	$ 180,926	$ 2,200,508	$ 223,105	$ 2,650,876	$ 404,032	$ (127,173)	$ 52,384,699	$ 40,871,900	$ 93,262,599
	Major Additions/Retirements													
	Routine Activity			$ 450,368										
51	Historical Interim Activity			1.10%	0.44%									
52	Forecast Interim Activity			1.10%	0.44%									
53	2009	14							23,353	9,382				2,133,642
54	2010	13							23,507	9,444				2,147,705
55	2011	12							23,662	9,506				2,161,862
56	2012	11							23,818	9,568				2,176,111
57	2013	10							23,975	9,632				2,190,455
58	2014	9							24,133	9,695				2,204,893
59	2015	8							24,292	9,759				2,219,426
60	2016	7							24,452	9,823				2,234,055
61	2017	6							24,613	9,888				2,248,780
62	2018	5							24,776	9,953				2,263,603
63	2019	4							24,939	10,019				2,278,523
64	2020	3							25,103	10,085				2,293,541
65	2021	2							25,269	10,151				2,308,659
66	2022	1							25,435	10,218				2,323,876
67	2023	0									(2,323,876)			-
			$ 1,977,403	$ 450,368	$ 180,927	$ 180,926	$ 2,200,508	$ 223,105	$ 2,992,205	$ 341,155	$ (2,451,049)		$	124,447,729

Whole Life Depreciation Rate Calculation

Historical Additions	2,650,876
Forecast Additions	341,329
Total Additions	2,992,205
Gross Salvage Value	116,194
Less Cost of Removal	232,388
Net Salvage Value	(116,194)
Total to be Recovered	3,108,398
Forecast Plant Balances	124,447,729
Whole Life Accrual Rate	2.50%
Cost of Removal Accrual Rate	0.19%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.68%
Depreciable Service Life, years	40.0

Remaining Life Depreciation Rate Calculation

Account Balance - 12/31/08	2,119,670
Forecast Additions	341,329
Gross Salvage Value	116,194
Less Cost of Removal	232,388
Net Salvage Value	(116,194)
Forecast Plant Balances	31,185,130

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Ben French Plant

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1960
Retirement Date	2023
Service Life, Yrs	63
Initial Plant Balance	0

2008

Historical and Forecast Plant Additions & Balances
Account: 312 Boiler Plant Equipment

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year					EOY Plant Balance		
			Transaction Year						Adjusted Transaction Year		Transfers and			
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Vintage Year Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1960	63				2,500	3,820,187		3,820,187	-		3,820,187		3,820,187
2	1961	62					52,984	12,641	52,984	12,641		3,860,530		3,860,530
3	1962	61				39,889	53,544	12,774	53,544	12,774		3,901,299		3,901,299
4	1963	60					54,109	12,909	54,109	12,909		3,942,499		3,942,499
5	1964	59					54,681	13,046	54,681	13,046		3,984,134		3,984,134
6	1965	58					55,258	13,183	55,258	13,183		4,026,209		4,026,209
7	1966	57					55,842	13,323	55,842	13,323		4,068,728		4,068,728
8	1967	56					56,431	13,463	56,431	13,463		4,111,696		4,111,696
9	1968	55					57,027	13,605	57,027	13,605		4,155,118		4,155,118
10	1969	54					57,630	13,749	57,630	13,749		4,198,999		4,198,999
11	1970	53					58,238	13,894	58,238	13,894		4,243,343		4,243,343
12	1971	52					58,853	14,041	58,853	14,041		4,288,155		4,288,155
13	1972	51					59,475	14,189	59,475	14,189		4,333,440		4,333,440
14	1973	50					60,103	14,339	60,103	14,339		4,379,204		4,379,204
15	1974	49					60,738	14,491	60,738	14,491		4,425,451		4,425,451
16	1975	48					61,379	14,644	61,379	14,644		4,472,186		4,472,186
17	1976	47					62,027	14,798	62,027	14,798		4,519,415		4,519,415
18	1977	46					62,682	14,955	62,682	14,955		4,567,142		4,567,142
19	1978	45					63,344	15,113	63,344	15,113		4,615,374		4,615,374
20	1979	44				6,000	64,013	15,272	64,013	15,272		4,664,115		4,664,115
21	1980	43				98,487	64,689	15,433	64,689	15,433		4,713,371		4,713,371
22	1981	42				32,549	65,372	15,596	65,372	15,596		4,763,147		4,763,147
23	1982	41				12,941	66,063	15,761	66,063	15,761		4,813,448		4,813,448
24	1983	40					66,760	15,928	66,760	15,928		4,864,281		4,864,281
25	1984	39					67,465	16,096	67,465	16,096		4,915,651		4,915,651
26	1985	38					68,178	16,266	68,178	16,266		4,967,563		4,967,563
27	1986	37					68,898	16,437	68,898	16,437		5,020,023		5,020,023
28	1987	36					69,625	16,611	69,625	16,611		5,073,037		5,073,037
29	1988	35				72,919	70,361	16,787	70,361	16,787		5,126,612		5,126,612
30	1989	34	5,126,612	37,022		29,189			37,022	-			5,163,634	5,163,634
31	1990	33		52,835	9,353				52,835	9,353			5,207,115	5,207,115
32	1991	32		15,092					15,092	-			5,222,208	5,222,208
33	1992	31		148,634	133,732	41,778			148,634	133,732	4,701		5,241,811	5,241,811
34	1993	30		21,689					21,689	-			5,263,500	5,263,500
35	1994	29		35,582	2,092				35,582	2,092			5,296,989	5,296,989
36	1995	28		129,310	7,100	35,265			129,310	7,100			5,419,199	5,419,199
37	1996	27							-	-			5,419,199	5,419,199
38	1997	26		11,134					11,134	-	74,036		5,504,369	5,504,369
39	1998	25		57,570					57,570	-			5,561,939	5,561,939
40	1999	24		26,381	8,000				26,381	8,000			5,580,320	5,580,320
41	2000	23		271,830	28,500				271,830	28,500	(79,802)		5,743,848	5,743,848
42	2001	22							-	-			5,743,848	5,743,848
43	2002	21		19,484					19,484	-			5,763,332	5,763,332
44	2003	20							-	-			5,763,332	5,763,332
45	2004	19		89,039	41,778				89,039	41,778			5,810,593	5,810,593
46	2005	18		22,792	3,588				22,792	3,588			5,829,796	5,829,796
47	2006	17		230,602	72,919				230,602	72,919	92,704		6,080,183	6,080,183
48	2007	16		205,698	29,189				205,698	29,189			6,256,691	6,256,691
49	2008	15		182,522	35,265				182,522	35,265			6,403,948	6,403,948
50	Total		$ 5,126,612	$ 1,557,214	$ 371,517	$ 371,517	$ 5,535,956	$ 409,345	$ 7,093,171	$ 780,861	$ 91,639	$128,834,355	$ 112,275,853	$ 241,110,208

Major Additions/Retirements

	Routine Activity	$ 1,557,214	
51	Historical Interim Activity	1.39%	0.33%
52	Forecast Interim Activity	1.39%	0.33%

Line	Vintage Year	Vintage Age	Adjusted Additions	Adjusted Retirements	Transfers and Adjustments	Simulated
53	2009	14	88,820	21,190		6,471,577
54	2010	13	89,758	21,414		6,539,921
55	2011	12	1,990,706	21,640		8,508,986
56	2012	11	118,036	28,156		8,598,846
57	2013	10	119,262	28,453		8,689,655
58	2014	9	120,522	28,754		8,781,422
59	2015	8	121,794	29,057		8,874,159
60	2016	7	2,272,757	29,364		11,117,552
61	2017	6	154,195	36,788		11,234,959
62	2018	5	155,824	37,176		11,353,607
63	2019	4	157,469	37,569		11,473,508
64	2020	3	159,132	37,965		11,594,674
65	2021	2	160,813	38,366		11,717,121
66	2022	1	162,511	38,772		11,840,860
67	2023	0			(11,840,860)	-
			$ 12,964,749	$ 1,315,527		$ 377,907,055

Whole Life Depreciation Rate Calculation

Historical Additions	7,093,171
Forecast Additions	5,871,578
Total Additions	12,964,749
Gross Salvage Value	592,043
Less Cost of Removal	1,184,086
Net Salvage Value	(592,043)
Total to be Recovered	13,556,792
Forecast Plant Balances	377,907,055
Whole Life Accrual Rate	3.59%
Cost of Removal Accrual Rate	0.31%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.90%
Depreciable Service Life, years	27.9

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	6,403,948
Forecast Additions	5,871,578
Gross Salvage Value	592,043
Less Cost of Removal	1,184,086
Net Salvage Value	(592,043)
Forecast Plant Balances	136,796,847

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Ben French Plant

Historical and Forecast Plant Additions & Balances
Account: 314 Turbogenerator Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1960
Retirement Date	2023
Service Life, Yrs	63
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			EOY Plant Balance		
			Transaction Year			Vintage Year					Transfers and			
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1960	63					[redacted]		1,247,946	-		1,247,946		1,247,946
2	1961	62					19,893	2,399	19,893	2,399		1,265,440		1,265,440
3	1962	61				43,500	20,172	2,432	20,172	2,432		1,283,180		1,283,180
4	1963	60					20,455	2,466	20,455	2,466		1,301,168		1,301,168
5	1964	59					20,741	2,501	20,741	2,501		1,319,409		1,319,409
6	1965	58					21,032	2,536	21,032	2,536		1,337,905		1,337,905
7	1966	57					21,327	2,572	21,327	2,572		1,356,660		1,356,660
8	1967	56					21,626	2,608	21,626	2,608		1,375,679		1,375,679
9	1968	55					21,929	2,644	21,929	2,644		1,394,964		1,394,964
10	1969	54					22,237	2,681	22,237	2,681		1,414,519		1,414,519
11	1970	53					22,548	2,719	22,548	2,719		1,434,348		1,434,348
12	1971	52					22,864	2,757	22,864	2,757		1,454,456		1,454,456
13	1972	51					23,185	2,796	23,185	2,796		1,474,845		1,474,845
14	1973	50					23,510	2,835	23,510	2,835		1,495,520		1,495,520
15	1974	49					23,840	2,875	23,840	2,875		1,516,485		1,516,485
16	1975	48					24,174	2,915	24,174	2,915		1,537,744		1,537,744
17	1976	47					24,513	2,956	24,513	2,956		1,559,301		1,559,301
18	1977	46					24,856	2,997	24,856	2,997		1,581,160		1,581,160
19	1978	45					25,205	3,039	25,205	3,039		1,603,325		1,603,325
20	1979	44					25,558	3,082	25,558	3,082		1,625,802		1,625,802
21	1980	43					25,916	3,125	25,916	3,125		1,648,593		1,648,593
22	1981	42					26,280	3,169	26,280	3,169		1,671,704		1,671,704
23	1982	41					26,648	3,213	26,648	3,213		1,695,139		1,695,139
24	1983	40					27,022	3,258	27,022	3,258		1,718,902		1,718,902
25	1984	39					27,400	3,304	27,400	3,304		1,742,998		1,742,998
26	1985	38					27,784	3,350	27,784	3,350		1,767,433		1,767,433
27	1986	37					28,174	3,397	28,174	3,397		1,792,209		1,792,209
28	1987	36					28,569	3,445	28,569	3,445		1,817,334		1,817,334
29	1988	35					28,969	3,493	28,969	3,493		1,842,810		1,842,810
30	1989	34	1,842,810			131,971			-	-			1,842,810	1,842,810
31	1990	33		3,255					3,255	-			1,846,064	1,846,064
32	1991	32		32,399	5,000				32,399	5,000			1,873,463	1,873,463
33	1992	31		124,888	20,000				124,888	20,000			1,978,351	1,978,351
34	1993	30		98,838	17,500				98,838	17,500			2,059,689	2,059,689
35	1994	29		47,259	1,000				47,259	1,000			2,105,948	2,105,948
36	1995	28		8,910					8,910	-			2,114,858	2,114,858
37	1996	27							-	-			2,114,858	2,114,858
38	1997	26							-	-			2,114,858	2,114,858
39	1998	25							-	-			2,114,858	2,114,858
40	1999	24							-	-			2,114,858	2,114,858
41	2000	23							-	-			2,114,858	2,114,858
42	2001	22							-	-			2,114,858	2,114,858
43	2002	21		269,232					269,232	-			2,384,090	2,384,090
44	2003	20							-	-			2,384,090	2,384,090
45	2004	19							-	-			2,384,090	2,384,090
46	2005	18							-	-			2,384,090	2,384,090
47	2006	17							-	-			2,384,090	2,384,090
48	2007	16		116,549	41,066	41,066			116,549	41,066			2,459,572	2,459,572
49	2008	15		778,336	131,971				778,336	131,971			3,105,937	3,105,937
50	Total		$ 1,842,810	$ 1,479,664	$ 216,537	$ 216,537	$ 1,924,374	$ 81,564	$ 3,404,038	$ 298,101	$ -	$ 44,276,978	$ 43,996,286	$ 88,273,263
	Major Additions/Retirements													
	2008			$ 778,336	$ 131,971									
	Routine Activity			$ 701,329	$ 84,566									
51	Historical Interim Activity			1.59%	0.19%									
52	Forecast Interim Activity			1.59%	0.19%									
53	2009	14							49,511	5,970				3,149,477
54	2010	13							50,205	6,054				3,193,628
55	2011	12							50,908	6,139				3,238,398
56	2012	11							51,622	6,225				3,283,796
57	2013	10							52,346	6,312				3,329,830
58	2014	9							53,080	6,400				3,376,509
59	2015	8							53,824	6,490				3,423,843
60	2016	7							54,578	6,581				3,471,840
61	2017	6							55,343	6,673				3,520,510
62	2018	5							56,119	6,767				3,569,862
63	2019	4							56,906	6,862				3,619,906
64	2020	3							57,704	6,958				3,670,652
65	2021	2							58,513	7,055				3,722,109
66	2022	1							59,333	7,154				3,774,287
67	2023	0								-	(3,774,287)			-
									$ 4,164,028	$ 389,741				$ 136,617,911

Whole Life Depreciation Rate Calculation

Historical Additions	3,404,038
Forecast Additions	759,990
Total Additions	4,164,028
Gross Salvage Value	188,714
Less Cost of Removal	377,429
Net Salvage Value	(188,714)
Total to be Recovered	4,352,743
Forecast Plant Balances	136,617,911
Whole Life Accrual Rate	3.19%
Cost of Removal Accrual Rate	0.28%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.46%
Depreciable Service Life, years	28.9

Remaining Life Depreciation Rate Calculation

Account Balance - 12/31/08	3,105,937
Forecast Additions	759,990
Gross Salvage Value	188,714
Less Cost of Removal	377,429
Net Salvage Value	(188,714)
Forecast Plant Balances	48,344,648

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Ben French Plant

Historical and Forecast Plant Additions & Balances
Account: 315 Accessory Electric Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1960
Retirement Date	2023
Service Life, Yrs	63
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			EOY Plant Balance		
			Transaction Year			Vintage Year					Transfers and			
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1960	63				899	423,745		423,745	-		423,745		423,745
2	1961	62					4,111	1,054	4,111	1,054		426,802		426,802
3	1962	61				1,750	4,141	1,061	4,141	1,061		429,882		429,882
4	1963	60					4,171	1,069	4,171	1,069		432,983		432,983
5	1964	59					4,201	1,077	4,201	1,077		436,107		436,107
6	1965	58					4,231	1,085	4,231	1,085		439,254		439,254
7	1966	57				21,673	4,262	1,092	4,262	1,092		442,423		442,423
8	1967	56					4,292	1,100	4,292	1,100		445,615		445,615
9	1968	55					4,323	1,108	4,323	1,108		448,831		448,831
10	1969	54					4,355	1,116	4,355	1,116		452,069		452,069
11	1970	53					4,386	1,124	4,386	1,124		455,331		455,331
12	1971	52					4,418	1,132	4,418	1,132		458,616		458,616
13	1972	51					4,449	1,141	4,449	1,141		461,925		461,925
14	1973	50					4,482	1,149	4,482	1,149		465,258		465,258
15	1974	49					4,514	1,157	4,514	1,157		468,615		468,615
16	1975	48					4,547	1,165	4,547	1,165		471,996		471,996
17	1976	47					4,579	1,174	4,579	1,174		475,401		475,401
18	1977	46					4,612	1,182	4,612	1,182		478,831		478,831
19	1978	45					4,646	1,191	4,646	1,191		482,286		482,286
20	1979	44					4,679	1,199	4,679	1,199		485,766		485,766
21	1980	43					4,713	1,208	4,713	1,208		489,271		489,271
22	1981	42					4,747	1,217	4,747	1,217		492,801		492,801
23	1982	41					4,781	1,226	4,781	1,226		496,356		496,356
24	1983	40					4,816	1,234	4,816	1,234		499,937		499,937
25	1984	39				20,735	4,850	1,243	4,850	1,243		503,545		503,545
26	1985	38					4,885	1,252	4,885	1,252		507,178		507,178
27	1986	37					4,921	1,261	4,921	1,261		510,837		510,837
28	1987	36					4,956	1,270	4,956	1,270		514,523		514,523
29	1988	35					4,992	1,280	4,992	1,280		518,235		518,235
30	1989	34	518,235	28,699					28,699	-			546,934	546,934
31	1990	33							-	-			546,934	546,934
32	1991	32		5,697					5,697	-			552,632	552,632
33	1992	31		13,820	607				13,820	607			565,846	565,846
34	1993	30		22,436	1,143				22,436	1,143			587,139	587,139
35	1994	29							-	-			587,139	587,139
36	1995	28							-	-			587,139	587,139
37	1996	27			899				-	899			586,240	586,240
38	1997	26		1,230					1,230	-			587,470	587,470
39	1998	25							-	-	743,409		1,330,879	1,330,879
40	1999	24							-	-			1,330,879	1,330,879
41	2000	23							-	-			1,330,879	1,330,879
42	2001	22							-	-			1,330,879	1,330,879
43	2002	21							-	-			1,330,879	1,330,879
44	2003	20							-	-			1,330,879	1,330,879
45	2004	19		71,417	20,735				71,417	20,735			1,381,561	1,381,561
46	2005	18							-	-			1,381,561	1,381,561
47	2006	17							-	-	(644,605)		736,956	736,956
48	2007	16							-	-			736,956	736,956
49	2008	15		32,476	21,673				32,476	21,673			747,759	747,759
50	Total		$ 518,235	$ 175,777	$ 45,057	$ 45,057	$ 550,804	$ 32,569	$ 726,581	$ 77,626	$ 98,804	$ 13,614,418	$ 18,117,538	$ 31,731,956

Major Additions/Retirements

Line			Additions	Retirements
	Routine Activity		$ 175,777	$ 45,057
51	Historical Interim Activity		0.97%	0.25%
52	Forecast Interim Activity		0.97%	0.25%

Line	Vintage Year	Vintage Age	Additions	Retirements	Transfers and Adjustments	Simulated
53	2009	14	7,255	1,860		753,154
54	2010	13	7,307	1,873		758,588
55	2011	12	7,360	1,887		764,061
56	2012	11	7,413	1,900		769,574
57	2013	10	7,466	1,914		775,127
58	2014	9	7,520	1,928		780,719
59	2015	8	7,575	1,942		786,352
60	2016	7	7,629	1,956		792,026
61	2017	6	7,684	1,970		797,740
62	2018	5	7,740	1,984		803,496
63	2019	4	7,796	1,998		809,293
64	2020	3	7,852	2,013		815,133
65	2021	2	7,908	2,027		821,014
66	2022	1	7,965	2,042		826,937
67	2023	0			(826,937)	-
			$ 833,051	$ 104,918		$ 42,785,171

Whole Life Depreciation Rate Calculation

Historical Additions	726,581
Forecast Additions	106,470
Total Additions	833,051
Gross Salvage Value	41,347
Less Cost of Removal	82,694
Net Salvage Value	(41,347)
Total to be Recovered	874,398
Forecast Plant Balances	42,785,171
Whole Life Accrual Rate	2.04%
Cost of Removal Accrual Rate	0.19%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.24%
Depreciable Service Life, years	44.7

Remaining Life Depreciation Rate Calculation

Account Balance - 12/31/08	747,759
Forecast Additions	106,470
Gross Salvage Value	41,347
Less Cost of Removal	82,694
Net Salvage Value	(41,347)
Forecast Plant Balances	11,053,215

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Unit Property: Steam Production, Ben French Plant

Historical and Forecast Plant Additions & Balances
Account: 316 Miscellaneous Plant Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1960
Retirement Date	2023
Service Life, Yrs	63
Initial Plant Balance	0

2008

Line	[A] Vintage Year	[B] Vintage Age	[C] Reported Per Books – Transaction Year – Beg. Balance	[D] Reported Per Books – Transaction Year – Additions	[E] Reported Per Books – Transaction Year – Retirements	[F] Reported Per Books – Vintage Year Retirements	[G] Adjustments to Transaction Year – Additions	[H] Adjustments to Transaction Year – Retirements	[I] Adjusted Transaction Year – Additions	[J] Adjusted Transaction Year – Retirements	[K] Transfers and Adjustments	[L] EOY Plant Balance – Adjustments	[M] EOY Plant Balance – Per Books	[N] EOY Plant Balance – Simulated
1	1960	63				59	213,392		213,392	-		213,392		213,392
2	1961	62					4,271	1,157	4,271	1,157		216,506		216,506
3	1962	61				31,846	4,333	1,174	4,333	1,174		219,666		219,666
4	1963	60					4,397	1,191	4,397	1,191		222,871		222,871
5	1964	59					4,461	1,208	4,461	1,208		226,123		226,123
6	1965	58					4,526	1,226	4,526	1,226		229,423		229,423
7	1966	57				30,000	4,592	1,244	4,592	1,244		232,771		232,771
8	1967	56					4,659	1,262	4,659	1,262		236,168		236,168
9	1968	55					4,727	1,281	4,727	1,281		239,614		239,614
10	1969	54					4,796	1,299	4,796	1,299		243,111		243,111
11	1970	53					4,866	1,318	4,866	1,318		246,659		246,659
12	1971	52					4,937	1,337	4,937	1,337		250,258		250,258
13	1972	51					5,009	1,357	5,009	1,357		253,910		253,910
14	1973	50				938	5,082	1,377	5,082	1,377		257,616		257,616
15	1974	49					5,156	1,397	5,156	1,397		261,375		261,375
16	1975	48					5,231	1,417	5,231	1,417		265,189		265,189
17	1976	47					5,308	1,438	5,308	1,438		269,059		269,059
18	1977	46				151,200	5,385	1,459	5,385	1,459		272,986		272,986
19	1978	45				76,500	5,464	1,480	5,464	1,480		276,969		276,969
20	1979	44				76,500	5,544	1,502	5,544	1,502		281,011		281,011
21	1980	43					5,625	1,524	5,625	1,524		285,112		285,112
22	1981	42				4,612	5,707	1,546	5,707	1,546		289,273		289,273
23	1982	41					5,790	1,569	5,790	1,569		293,494		293,494
24	1983	40					5,874	1,591	5,874	1,591		297,777		297,777
25	1984	39					5,960	1,615	5,960	1,615		302,122		302,122
26	1985	38					6,047	1,638	6,047	1,638		306,531		306,531
27	1986	37				1,834	6,135	1,662	6,135	1,662		311,004		311,004
28	1987	36				1,833	6,225	1,686	6,225	1,686		315,543		315,543
29	1988	35				1,382	6,316	1,711	6,316	1,711		320,148		320,148
30	1989	34	320,148	26,516	6,360	6,826			26,516	6,360			340,304	340,304
31	1990	33		6,715	338,812				6,715	338,812			8,207	8,207
32	1991	32		10,455	1,834				10,155	1,834	334,200		351,028	351,028
33	1992	31		126,790					126,790	-			477,818	477,818
34	1993	30		7,732					7,732	-			485,550	485,550
35	1994	29		28,290		1,696			28,290	-			513,840	513,840
36	1995	28		3,987	1,652				3,987	1,652			516,174	516,174
37	1996	27		3,905	997				3,905	997	(101,391)		417,691	417,691
38	1997	26		8,305					8,305	-			425,997	425,997
39	1998	25		599					599	-			426,595	426,595
40	1999	24		2,617					2,617	-			429,212	429,212
41	2000	23		2,078					2,078	-	13,145		444,435	444,435
42	2001	22		9,155					9,155	-			453,590	453,590
43	2002	21		32,468	27,363				32,468	27,363			458,695	458,695
44	2003	20		9,665					9,665	-			468,360	468,360
45	2004	19		6,287					6,287	-			474,647	474,647
46	2005	18							-	-			474,647	474,647
47	2006	17		12,556	1,382				12,556	1,382	(19,159)		466,661	466,661
48	2007	16							-	-			466,661	466,661
49	2008	15			6,826				-	6,826			459,835	459,835
50	Total		$ 320,148	$ 298,120	$ 385,226	$ 385,226	$ 359,815	$ 39,667	$ 657,934	$ 424,893	$ 226,794	$ 7,635,683	$ 8,559,947	$ 16,195,631

Line		[D]	[E]
	Major Additions/Retirements		
	1990		$ 338,812
	1992	$ 126,790	
	Routine Activity	$ 171,330	$ 46,414
51	Historical Interim Activity	2.00%	0.54%
52	Forecast Interim Activity	2.00%	0.54%

Line	[A] Vintage Year	[B] Vintage Age	[I] Additions	[J] Retirements	[K] Transfers and Adjustments	[N] Simulated
53	2009	14	9,204	2,493		466,545
54	2010	13	9,338	2,530		473,354
55	2011	12	9,474	2,567		480,261
56	2012	11	9,613	2,604		487,270
57	2013	10	9,753	2,642		494,380
58	2014	9	9,895	2,681		501,593
59	2015	8	10,040	2,720		508,915
60	2016	7	10,186	2,759		516,341
61	2017	6	10,335	2,800		523,876
62	2018	5	10,486	2,841		531,521
63	2019	4	10,639	2,882		539,278
64	2020	3	10,794	2,924		547,147
65	2021	2	10,951	2,967		555,132
66	2022	1	11,111	3,010		563,233
67	2023	0			(563,233)	-
			$ 799,751	$ 463,313		$ 23,384,480

Whole Life Depreciation Rate Calculation

Historical Additions	657,934
Forecast Additions	141,817
Total Additions	799,751
Gross Salvage Value	28,162
Less Cost of Removal	56,323
Net Salvage Value	(28,162)
Total to be Recovered	827,913
Forecast Plant Balances	23,384,480
Whole Life Accrual Rate	3.54%
Cost of Removal Accrual Rate	0.24%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.78%
Depreciable Service Life, years	28.2

Remaining Life Depreciation Rate Calculation

Account Balance - 12/31/08	459,835
Forecast Additions	141,817
Gross Salvage Value	28,162
Less Cost of Removal	56,323
Net Salvage Value	(28,162)
Forecast Plant Balances	7,188,849

Summary by Plant
Black Hills Power
Wyodak Facility

Account	Description	Direct Investment 2008$	Depreciation Rate
310	Land		
311	Structure & Improvements	9,039,917	3.58%
312	Boiler Plant Equipment	51,154,925	3.22%
313	Engines & Engine Driven Generators	249,991	4.79%
314	Turbo Generator Equipment	11,199,149	3.42%
315	Accessory Electric Equipment	6,213,171	3.35%
316	Misc Power Equipment	892,134	7.21%
	Total	78,749,286	3.35% whole life weighted average rate

Remaining Life Depreciation Rate Calculation

Per Books Balance 12/31/08	79,050,217
Forecast Interim Additions	23,744,384
Forecast Gross Salvage Value	4,987,227
Forecast Less Cost of Removal	10,469,954
Forecast Net Salvage Value	(5,482,728)
Forecast Total to be Recovered with COR	108,277,328
Forecast Total to be Recovered w/o COR	97,807,374
Accumulated Depreciation (2008 EOY)	(50,672,287)
Forecast Remaining Life Balance with COR	57,605,041
Forecast Remaining Life Balance w/o COR	47,135,087
Forecast Plant Balances	1,896,224,299
Remaining Life Rate with COR	3.04%
Remaining Life Rate w/o COR	2.49%

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Wyodak Plant

Gross Salvage	5%
Cost of Removal	15%
Net Salvage	-10%
Install Date	1978
Retirement Date	2030
Service Life, Yrs	52

2008

Historical and Forecast Plant Additions & Balances
Account: 311 Structures & Improvements

Initial Plant Balance 9,057

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year					EOY Plant Balance		
	Vintage	Vintage	Transaction Year			Vintage Year			Adjusted Transaction Year		Transfers and			
Line	Year	Age	Beg. Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1978	52					[redacted]		8,669	-		8,669		8,669
2	1979	51					48	10	48	10		8,707		8,707
3	1980	50					48	10	48	10		8,745		8,745
4	1981	49					48	10	48	10		8,783		8,783
5	1982	48					48	10	48	10		8,822		8,822
6	1983	47					49	10	49	10		8,861		8,861
7	1984	46					49	10	49	10		8,899		8,899
8	1985	45					49	10	49	10		8,938		8,938
9	1986	44					49	10	49	10		8,978		8,978
10	1987	43					50	10	50	10		9,017		9,017
11	1988	42					50	10	50	10		9,057		9,057
12	1989	41	9,057						-	-			9,057	9,057
13	1990	40							-	-			9,057	9,057
14	1991	39		8,346,974		156,948			8,346,974	-			8,356,031	8,356,031
15	1992	38		135,082		22,339			135,082	-			8,491,113	8,491,113
16	1993	37							-	-			8,491,113	8,491,113
17	1994	36		111,144					111,144	-			8,602,257	8,602,257
18	1995	35							-	-			8,602,257	8,602,257
19	1996	34		178,075	22,339				178,075	22,339			8,757,992	8,757,992
20	1997	33							-	-			8,757,992	8,757,992
21	1998	32							-	-			8,757,992	8,757,992
22	1999	31		211,509	74,467				211,509	74,467			8,895,035	8,895,035
23	2000	30							-	-			8,895,035	8,895,035
24	2001	29							-	-			8,895,035	8,895,035
25	2002	28							-	-			8,895,035	8,895,035
26	2003	27		31,636					31,636	-			8,926,670	8,926,670
27	2004	26		41,920					41,920	-			8,968,590	8,968,590
28	2005	25		26,267					26,267	-			8,994,857	8,994,857
29	2006	24		138,834					138,834	-	(5,922)		9,127,769	9,127,769
30	2007	23			82,482				-	82,482	(5,370)		9,039,917	9,039,917
31	2008	22							-	-			9,039,917	9,039,917
32	Total		$ 9,057	$ 9,221,440	$ 179,288	$ 179,287	$ -	$ -	$ 9,221,440	$ 179,288	$ (11,292)	$ -	$ 158,512,720	$ 158,512,720

Major Additions/Retirements

	1991	$ 8,346,974	
	Routine Activity	$ 874,466	
33	Historical Interim Activity	0.55%	0.11%
34	Forecast Interim Activity	0.55%	0.11%

Line	[A]	[B]	[I] Additions	[J] Retirements	[K] Transfers and Adjustments	[N] Simulated
35	2009	21	49,870	10,225		9,079,563
36	2010	20	50,089	10,270		9,119,382
37	2011	19	50,309	10,315		9,159,377
38	2012	18	50,529	10,360		9,199,546
39	2013	17	50,751	10,405		9,239,892
40	2014	16	50,974	10,451		9,280,415
41	2015	15	51,197	10,497		9,321,115
42	2016	14	51,422	10,543		9,361,994
43	2017	13	51,647	10,589		9,403,052
44	2018	12	51,874	10,635		9,444,291
45	2019	11	52,101	10,682		9,485,710
46	2020	10	52,330	10,729		9,527,311
47	2021	9	52,559	10,776		9,569,094
48	2022	8	52,790	10,823		9,611,061
49	2023	7	53,021	10,871		9,653,211
50	2024	6	53,254	10,918		9,695,547
51	2025	5	53,487	10,966		9,738,068
52	2026	4	53,722	11,014		9,780,775
53	2027	3	53,958	11,063		9,823,670
54	2028	2	54,194	11,111		9,866,753
55	2029	1	54,432	11,160		9,910,025
56	2030	0			(9,910,025)	-
			$ 10,315,950	$ 403,690		$ 357,782,571

Whole Life Depreciation Rate Calculation

Historical Additions	9,221,440
Forecast Additions	1,094,510
Total Additions	10,315,950
Gross Salvage Value	495,501
Less Cost of Removal	1,486,504
Net Salvage Value	(991,003)
Total to be Recovered	11,306,953
Forecast Plant Balances	357,782,571
Whole Life Accrual Rate	3.16%
Cost of Removal Accrual Rate	0.42%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.58%
Depreciable Service Life, years	31.6

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	9,039,917
Forecast Additions	1,094,510
Gross Salvage Value	495,501
Less Cost of Removal	1,486,504
Net Salvage Value	(991,003)
Forecast Plant Balances	199,269,851

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Wyodak Plant

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1978
Retirement Date	2030
Service Life, Yrs	52

2008

Historical and Forecast Plant Additions & Balances
Account: 312 Boiler Plant Equipment

Initial Plant Balance 16,022,256

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year		Transfers and	EOY Plant Balance		
	Vintage	Vintage	Transaction Year			Vintage Year								
Line	Year	Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1978	52					[redacted]		15,548,879	-		15,548,879		15,548,879
2	1979	51					71,751	25,050	71,751	25,050		15,595,581		15,595,581
3	1980	50					71,967	25,125	71,967	25,125		15,642,422		15,642,422
4	1981	49					72,183	25,201	72,183	25,201		15,689,405		15,689,405
5	1982	48					72,400	25,276	72,400	25,276		15,736,528		15,736,528
6	1983	47					72,617	25,352	72,617	25,352		15,783,793		15,783,793
7	1984	46					72,835	25,429	72,835	25,429		15,831,200		15,831,200
8	1985	45					73,054	25,505	73,054	25,505		15,878,750		15,878,750
9	1986	44					73,274	25,581	73,274	25,581		15,926,442		15,926,442
10	1987	43					73,494	25,658	73,494	25,658		15,974,277		15,974,277
11	1988	42					73,714	25,735	73,714	25,735		16,022,256		16,022,256
12	1989	41	16,022,256	12,327,586		2,667,481			12,327,586	-			28,349,842	28,349,842
13	1990	40							-	-			28,349,842	28,349,842
14	1991	39		29,761,701		239,460			29,761,701	-			58,111,543	58,111,543
15	1992	38		636,467		35,917			636,467	-			58,748,010	58,748,010
16	1993	37							-	-			58,748,010	58,748,010
17	1994	36		124,541		67,236			124,541	-			58,872,551	58,872,551
18	1995	35		170,532	30,000				170,532	30,000			59,013,082	59,013,082
19	1996	34		1,258,258	626,066	8,901			1,258,258	626,066			59,645,274	59,645,274
20	1997	33							-	-			59,645,274	59,645,274
21	1998	32							-	-			59,645,274	59,645,274
22	1999	31		236,168	890,477				236,168	890,477			58,990,965	58,990,965
23	2000	30							-	-			58,990,965	58,990,965
24	2001	29			227,562				-	227,562			58,763,403	58,763,403
25	2002	28							-	-			58,763,403	58,763,403
26	2003	27		1,281,183					1,281,183	-			60,044,586	60,044,586
27	2004	26		358,678					358,678	-			60,403,263	60,403,263
28	2005	25		215,319					215,319	-			60,618,582	60,618,582
29	2006	24		178,430					178,430	-	(7,601,244)		53,195,768	53,195,768
30	2007	23		622,039	2,654,859				622,039	2,654,859	(8,024)		51,154,925	51,154,925
31	2008	22							-	-			51,154,925	51,154,925
32	Total		$ 16,022,256	$ 47,170,900	$ 4,428,964	$ 3,018,994	$ -	$ -	$ 47,170,900	$ 4,428,964	$ (7,609,268)	$ -	$ 1,101,209,488	$ 1,101,209,488
	Major Additions/Retirements													
	1989			$ 12,327,586										
	1991			$ 29,761,701										
	2007				$ 2,654,859									
	Routine Activity			$ 5,081,613	$ 1,774,105									
33	Historical Interim Activity			0.46%	0.16%									
34	Forecast Interim Activity			0.46%	0.16%									
35	2009	21							236,058	82,413				51,308,570
36	2010	20							236,767	82,661				51,462,676
37	2011	19							5,037,478	82,909				56,417,246
38	2012	18							260,342	90,891				56,586,696
39	2013	17							261,124	91,164				56,756,655
40	2014	16							261,908	91,438				56,927,125
41	2015	15							262,694	91,713				57,098,107
42	2016	14							2,807,483	91,988				59,813,603
43	2017	13							276,014	96,363				59,993,254
44	2018	12							276,843	96,652				60,173,446
45	2019	11							277,675	96,943				60,354,178
46	2020	10							278,509	97,234				60,535,453
47	2021	9							3,157,647	97,526				63,595,575
48	2022	8							293,467	102,456				63,786,585
49	2023	7							294,348	102,763				63,978,170
50	2024	6							295,232	103,072				64,170,330
51	2025	5							296,119	103,382				64,363,067
52	2026	4							3,553,543	103,692				67,812,918
53	2027	3							312,928	109,250				68,016,596
54	2028	2							313,868	109,578				68,220,885
55	2029	1							314,810	109,907				68,425,788
56	2030	0									(68,425,788)			-
									$ 66,475,758	$ 6,462,958				$ 2,381,006,411

Whole Life Depreciation Rate Calculation

Historical Additions	47,170,900
Forecast Additions	19,304,858
Total Additions	66,475,758
Gross Salvage Value	3,421,289
Less Cost of Removal	6,842,579
Net Salvage Value	(3,421,289)
Total to be Recovered	69,897,047
Forecast Plant Balances	2,381,006,411
Whole Life Accrual Rate	2.94%
Cost of Removal Accrual Rate	0.29%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.22%
Depreciable Service Life, years	34.1

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	51,154,925
Forecast Additions	19,304,858
Gross Salvage Value	3,421,289
Less Cost of Removal	6,842,579
Net Salvage Value	(3,421,289)
Forecast Plant Balances	1,279,796,923

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Wyodak Plant

Historical and Forecast Plant Additions & Balances
Account: 313 Engine and Engine Driven Generators

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1978
Retirement Date	2030
Service Life, Yrs	52
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			EOY Plant Balance		
			Transaction Year			Vintage Year					Transfers and			
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1978	52					[redacted]		-	-		-		-
2	1979	51					-	-	-	-		-		-
3	1980	50					-	-	-	-		-		-
4	1981	49					-	-	-	-		-		-
5	1982	48					-	-	-	-		-		-
6	1983	47					-	-	-	-		-		-
7	1984	46					-	-	-	-		-		-
8	1985	45					-	-	-	-		-		-
9	1986	44					-	-	-	-		-		-
10	1987	43					-	-	-	-		-		-
11	1988	42					-	-	-	-		-		-
12	1989	41	0						-	-			-	-
13	1990	40							-	-			-	-
14	1991	39							-	-			-	-
15	1992	38							-	-			-	-
16	1993	37							-	-			-	-
17	1994	36							-	-			-	-
18	1995	35							-	-			-	-
19	1996	34							-	-			-	-
20	1997	33							-	-			-	-
21	1998	32							-	-			-	-
22	1999	31							-	-			-	-
23	2000	30							-	-			-	-
24	2001	29							-	-			-	-
25	2002	28		232,960					232,960	-			232,960	232,960
26	2003	27		7,427					7,427	-			240,387	240,387
27	2004	26		19,645					19,645	-			260,032	260,032
28	2005	25							-	-	(10,041)		249,991	249,991
29	2006	24							-	-			249,991	249,991
30	2007	23							-	-			249,991	249,991
31	2008	22							-	-			249,991	249,991
32	Total		$ -	$ 260,032	$ -	$ -	$ -	$ -	$ 260,032	$ -	$ (10,041)	$ -	$ 1,733,340	$ 1,733,340

Major Additions/Retirements

Line								
	2002		$ 232,960					
	Routine Activity		$ 27,072					
33	Historical Interim Activity		1.56%	0.00%				
34	Forecast Interim Activity		1.00%	0.00%				
35	2009	21			2,500	-		252,490
36	2010	20			2,525	-		255,015
37	2011	19			2,550	-		257,565
38	2012	18			2,576	-		260,141
39	2013	17			2,601	-		262,743
40	2014	16			2,627	-		265,370
41	2015	15			2,654	-		268,024
42	2016	14			2,680	-		270,704
43	2017	13			2,707	-		273,411
44	2018	12			2,734	-		276,145
45	2019	11			2,761	-		278,906
46	2020	10			2,789	-		281,696
47	2021	9			2,817	-		284,513
48	2022	8			2,845	-		287,358
49	2023	7			2,874	-		290,231
50	2024	6			2,902	-		293,134
51	2025	5			2,931	-		296,065
52	2026	4			2,961	-		299,026
53	2027	3			2,990	-		302,016
54	2028	2			3,020	-		305,036
55	2029	1			3,050	-		308,086
56	2030	0					(308,086)	-
					$ 318,127	$ -		$ 7,601,014

Whole Life Depreciation Rate Calculation

Historical Additions	260,032
Forecast Additions	58,096
Total Additions	318,127
Gross Salvage Value	15,404
Less Cost of Removal	30,809
Net Salvage Value	(15,404)
Total to be Recovered	333,532
Forecast Plant Balances	7,601,014
Whole Life Accrual Rate	4.39%
Cost of Removal Accrual Rate	0.41%
Whole Life Accrual Rate (Excluding Cost of Removal)	4.79%
Depreciable Service Life, years	22.8

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	249,991
Forecast Additions	58,096
Gross Salvage Value	15,404
Less Cost of Removal	30,809
Net Salvage Value	(15,404)
Forecast Plant Balances	5,867,674

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Wyodak Plant

Historical and Forecast Plant Additions & Balances
Account: 314 Turbogenerator Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1978
Retirement Date	2030
Service Life, Yrs	52
Initial Plant Balance	7,179

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year					EOY Plant Balance		
			Transaction Year			Vintage Year			Adjusted Transaction Year		Transfers and			
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
	1971					1,828								
1	1978	52					[illegible]		7,061	-		7,061		7,061
2	1979	51					15	3	15	3		7,073		7,073
3	1980	50					15	3	15	3		7,084		7,084
4	1981	49					15	3	15	3		7,096		7,096
5	1982	48					15	3	15	3		7,108		7,108
6	1983	47					15	3	15	3		7,120		7,120
7	1984	46					15	3	15	3		7,132		7,132
8	1985	45					15	3	15	3		7,143		7,143
9	1986	44					15	3	15	3		7,155		7,155
10	1987	43					15	3	15	3		7,167		7,167
11	1988	42					15	3	15	3		7,179		7,179
12	1989	41	7,179	7,179					7,179	-			14,358	14,358
13	1990	40							-	-			14,358	14,358
14	1991	39		9,214,295		713,034			9,214,295	-			9,228,654	9,228,654
15	1992	38		299,654					299,654	-			9,528,308	9,528,308
16	1993	37							-	-			9,528,308	9,528,308
17	1994	36			2,103	2,103			-	2,103			9,526,205	9,526,205
18	1995	35		6,610	1,828	2,963			6,610	1,828			9,530,987	9,530,987
19	1996	34		543,893	204,140				543,893	204,140			9,870,739	9,870,739
20	1997	33							-	-			9,870,739	9,870,739
21	1998	32							-	-			9,870,739	9,870,739
22	1999	31			73,635				-	73,635	(10,906)		9,786,199	9,786,199
23	2000	30							-	-			9,786,199	9,786,199
24	2001	29							-	-			9,786,199	9,786,199
25	2002	28							-	-			9,786,199	9,786,199
26	2003	27		56,390					56,390	-			9,842,588	9,842,588
27	2004	26		5,883					5,883	-			9,848,472	9,848,472
28	2005	25		1,127					1,127	-			9,849,598	9,849,598
29	2006	24		1,975,529					1,975,529	-	(98,843)		11,728,285	11,728,285
30	2007	23			436,222				-	436,222	(92,914)		11,199,149	11,199,149
31	2008	22							-	-			11,199,149	11,199,149
32	Total		$ 7,179	$ 12,110,560	$ 717,928	$ 717,928	$ -	$ -	$ 12,110,560	$ 717,928	$ (200,663)	$ -	$ 179,795,433	$ 179,795,433

Line		Additions	Retirements
	Major Additions/Retirements		
	1991	$ 9,214,295	
	1996	$ 543,893	$ 204,140
	2006	$ 1,975,529	$ 436,222
	Routine Activity	$ 376,843	$ 77,566
33	Historical Interim Activity	0.21%	0.04%
34	Forecast Interim Activity	0.21%	0.04%

Line	Vintage Year	Vintage Age	Additions [I]	Retirements [J]	Transfers and Adjustments [K]	Simulated [N]
35	2009	21	23,473	4,831		11,217,790
36	2010	20	23,512	4,839		11,236,463
37	2011	19	23,551	4,848		11,255,166
38	2012	18	23,590	4,856		11,273,901
39	2013	17	23,630	4,864		11,292,667
40	2014	16	23,669	4,872		11,311,464
41	2015	15	23,708	4,880		11,330,292
42	2016	14	23,748	4,888		11,349,152
43	2017	13	23,787	4,896		11,368,043
44	2018	12	23,827	4,904		11,386,966
45	2019	11	23,867	4,912		11,405,920
46	2020	10	23,906	4,921		11,424,905
47	2021	9	23,946	4,929		11,443,923
48	2022	8	23,986	4,937		11,462,972
49	2023	7	24,026	4,945		11,482,052
50	2024	6	24,066	4,953		11,501,164
51	2025	5	24,106	4,962		11,520,309
52	2026	4	24,146	4,970		11,539,485
53	2027	3	24,186	4,978		11,558,693
54	2028	2	24,226	4,987		11,577,933
55	2029	1	24,267	4,995		11,597,205
56	2030	0			(11,597,205)	-
			$ 12,611,783	$ 821,095		$ 419,331,895

Whole Life Depreciation Rate Calculation

Historical Additions	12,110,560
Forecast Additions	501,223
Total Additions	12,611,783
Gross Salvage Value	579,860
Less Cost of Removal	1,159,720
Net Salvage Value	(579,860)
Total to be Recovered	13,191,643
Forecast Plant Balances	419,331,895
Whole Life Accrual Rate	3.15%
Cost of Removal Accrual Rate	0.28%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.42%
Depreciable Service Life, years	31.8

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	11,199,149
Forecast Additions	501,223
Gross Salvage Value	579,860
Less Cost of Removal	1,159,720
Net Salvage Value	(579,860)
Forecast Plant Balances	239,536,462

005956

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Wyodak Plant

Historical and Forecast Plant Additions & Balances
Account: 315 Accessorry Electric Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1978
Retirement Date	2030
Service Life, Yrs	52
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year					EOY Plant Balance		
			Transaction Year			Vintage Year			Adjusted Transaction Year		Transfers and			
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1978	52							-	-		-		-
2	1979	51					-	-	-	-		-		-
3	1980	50					-	-	-	-		-		-
4	1981	49					-	-	-	-		-		-
5	1982	48					-	-	-	-		-		-
6	1983	47					-	-	-	-		-		-
7	1984	46					-	-	-	-		-		-
8	1985	45					-	-	-	-		-		-
9	1986	44					-	-	-	-		-		-
10	1987	43					-	-	-	-		-		-
11	1988	42					-	-	-	-		-		-
12	1989	41	0						-	-			-	-
13	1990	40							-	-			-	-
14	1991	39		5,733,052		249,639			5,733,052	-			5,733,052	5,733,052
15	1992	38							-	-			5,733,052	5,733,052
16	1993	37							-	-			5,733,052	5,733,052
17	1994	36		8,595		5,988			8,595	-			5,741,647	5,741,647
18	1995	35							-	-			5,741,647	5,741,647
19	1996	34		296,346	208,756				296,346	208,756			5,829,237	5,829,237
20	1997	33							-	-			5,829,237	5,829,237
21	1998	32							-	-	99,024		5,928,261	5,928,261
22	1999	31		288,579	1,649				288,579	1,649			6,215,192	6,215,192
23	2000	30							-	-			6,215,192	6,215,192
24	2001	29							-	-			6,215,192	6,215,192
25	2002	28							-	-			6,215,192	6,215,192
26	2003	27		6,803					6,803	-			6,221,995	6,221,995
27	2004	26							-	-			6,221,995	6,221,995
28	2005	25							-	-			6,221,995	6,221,995
29	2006	24							-	-			6,221,995	6,221,995
30	2007	23		36,398	45,222				36,398	45,222			6,213,171	6,213,171
31	2008	22							-	-			6,213,171	6,213,171
32	Total		$ -	$ 6,369,774	$ 255,627	$ 255,627	$ -	$ -	$ 6,369,774	$ 255,627	$ 99,024	$ -	$ 108,444,277	$ 108,444,277
	Major Additions/Retirements													
	1991			$ 5,733,052										
	Routine Activity			$ 636,722	$ 255,627									
33	Historical Interim Activity			0.59%	0.24%									
34	Forecast Interim Activity			0.59%	0.24%									
35	2009	21							36,480	14,646				6,235,006
36	2010	20							36,608	14,697				6,256,917
37	2011	19							36,737	14,749				6,278,905
38	2012	18							36,866	14,801				6,300,970
39	2013	17							36,996	14,853				6,323,113
40	2014	16							37,126	14,905				6,345,334
41	2015	15							37,256	14,957				6,367,632
42	2016	14							37,387	15,010				6,390,010
43	2017	13							37,518	15,063				6,412,465
44	2018	12							37,650	15,116				6,435,000
45	2019	11							37,783	15,169				6,457,614
46	2020	10							37,915	15,222				6,480,307
47	2021	9							38,049	15,275				6,503,080
48	2022	8							38,182	15,329				6,525,933
49	2023	7							38,316	15,383				6,548,867
50	2024	6							38,451	15,437				6,571,881
51	2025	5							38,586	15,491				6,594,976
52	2026	4							38,722	15,546				6,618,152
53	2027	3							38,858	15,600				6,641,409
54	2028	2							38,994	15,655				6,664,749
55	2029	1							39,132	15,710				6,688,170
56	2030	0									(6,688,170)			-
									$ 7,163,387	$ 574,241				$ 244,084,766

Whole Life Depreciation Rate Calculation

Historical Additions	6,369,774
Forecast Additions	793,613
Total Additions	7,163,387
Gross Salvage Value	334,408
Less Cost of Removal	668,817
Net Salvage Value	(334,408)
Total to be Recovered	7,497,795
Forecast Plant Balances	244,084,766
Whole Life Accrual Rate	3.07%
Cost of Removal Accrual Rate	0.27%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.35%
Depreciable Service Life, years	32.6

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	6,213,171
Forecast Additions	793,613
Gross Salvage Value	334,408
Less Cost of Removal	668,817
Net Salvage Value	(334,408)
Forecast Plant Balances	135,640,489

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Wyodak Plant

Historical and Forecast Plant Additions & Balances
Account: 316 Miscellaneous Plant Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1978
Retirement Date	2030
Service Life, Yrs	52
Initial Plant Balance	21,473

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			EOY Plant Balance		
			Transaction Year			Vintage Year					Transfers and			
Line	Vintage Year	Vintage Age	Beg. Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1978	52					[redacted]		12,423	-		12,423		12,423
2	1979	51					724	25	724	25		13,122		13,122
3	1980	50					765	26	765	26		13,860		13,860
4	1981	49					808	28	808	28		14,639		14,639
5	1982	48					853	30	853	30		15,463		15,463
6	1983	47					901	31	901	31		16,333		16,333
7	1984	46					952	33	952	33		17,251		17,251
8	1985	45					1,005	35	1,005	35		18,222		18,222
9	1986	44					1,062	37	1,062	37		19,247		19,247
10	1987	43					1,121	39	1,121	39		20,329		20,329
11	1988	42					1,184	41	1,184	41		21,473		21,473
12	1989	41	21,473						-	-			21,473	21,473
13	1990	40							-	-			21,473	21,473
14	1991	39		344,033		118,037			344,033	-			365,506	365,506
15	1992	38		29,448					29,448	-			394,954	394,954
16	1993	37							-	-			394,954	394,954
17	1994	36		120,135					120,135	-			515,089	515,089
18	1995	35		9,686					9,686	-			524,776	524,776
19	1996	34		136,897	22,551				136,897	22,551			639,121	639,121
20	1997	33							-	-			639,121	639,121
21	1998	32							-	-			639,121	639,121
22	1999	31		1,231					1,231	-	(16,820)		623,532	623,532
23	2000	30							-	-			623,532	623,532
24	2001	29							-	-			623,532	623,532
25	2002	28							-	-			623,532	623,532
26	2003	27		12,656					12,656	-			636,188	636,188
27	2004	26		2,079					2,079	-			638,267	638,267
28	2005	25		16,471					16,471	-	10,041		664,779	664,779
29	2006	24		142,622					142,622	-			807,402	807,402
30	2007	23		180,218	95,486				180,218	95,486			892,134	892,134
31	2008	22							-	-			892,134	892,134
32	Total		$ 21,473	$ 995,477	$ 118,037	$ 118,037	$ -	$ -	$ 995,477	$ 118,037	$ (6,779)	$ -	$ 11,180,620	$ 11,180,620

Major Additions/Retirements

Line			
	2007		$ 95,486
	1991	$ 344,033	
	Routine Activity	$ 651,444	$ 22,551
33	Historical Interim Activity	5.83%	0.20%
34	Forecast Interim Activity	5.83%	0.20%

Line	[A]	[B]	[I]	[J]	[K]	[N]
35	2009	21	51,981	1,799		942,315
36	2010	20	54,904	1,901		995,319
37	2011	19	57,993	2,008		1,051,304
38	2012	18	61,255	2,120		1,110,438
39	2013	17	64,700	2,240		1,172,898
40	2014	16	68,339	2,366		1,238,872
41	2015	15	72,183	2,499		1,308,557
42	2016	14	76,244	2,639		1,382,161
43	2017	13	80,532	2,788		1,459,906
44	2018	12	85,062	2,945		1,542,023
45	2019	11	89,847	3,110		1,628,760
46	2020	10	94,900	3,285		1,720,375
47	2021	9	100,238	3,470		1,817,144
48	2022	8	105,877	3,665		1,919,355
49	2023	7	111,832	3,871		2,027,316
50	2024	6	118,123	4,089		2,141,349
51	2025	5	124,767	4,319		2,261,797
52	2026	4	131,785	4,562		2,389,020
53	2027	3	139,197	4,819		2,523,399
54	2028	2	147,027	5,090		2,665,336
55	2029	1	155,297	5,376		2,815,257
56	2030	0			(2,815,257)	-
			$ 2,987,561	$ 186,998		$ 47,293,520

Whole Life Depreciation Rate Calculation

Historical Additions	995,477
Forecast Additions	1,992,084
Total Additions	2,987,561
Gross Salvage Value	140,763
Less Cost of Removal	281,526
Net Salvage Value	(140,763)
Total to be Recovered	3,128,324
Forecast Plant Balances	47,293,520
Whole Life Accrual Rate	6.61%
Cost of Removal Accrual Rate	0.60%
Whole Life Accrual Rate (Excluding Cost of Removal)	7.21%
Depreciable Service Life, years	15.1

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	892,134
Forecast Additions	1,992,084
Gross Salvage Value	140,763
Less Cost of Removal	281,526
Net Salvage Value	(140,763)
Forecast Plant Balances	36,112,900

Summary by Plant
Black Hills Power
Neil Simpson I Facility

Account	Description	Direct Investment 2008$	Depreciation Rate
310	Land	0	0.00%
311	Structure & Improvements	2,139,727	3.23%
312	Boiler Plant Equipment	12,718,813	3.92%
313	Engines & Engine Driven Generators		
314	Turbo Generator Equipment	2,866,457	2.42%
315	Accessory Electric Equipment	744,885	2.87%
316	Misc Power Equipment	429,468	2.83%
	Total	18,899,349	3.55% whole life weighted average rate

Remaining Life Depreciation Rate Calculation

Per Books Balance 12/31/08	18,913,575
Forecast Interim Additions	7,260,936
Forecast Gross Salvage Value	1,278,309
Forecast Less Cost of Removal	2,556,618
Forecast Net Salvage Value	(1,278,309)
Forecast Total to be Recovered with COR	27,452,820
Forecast Total to be Recovered w/o COR	24,896,202
Accumulated Depreciation (2008 EOY)	(16,151,840)
Forecast Remaining Life Balance with COR	11,300,980
Forecast Remaining Life Balance w/o COR	8,744,362
Forecast Plant Balances	323,756,007
Remaining Life Rate with COR	3.49%
Remaining Life Rate w/o COR	2.70%

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Neil Simpson 1 Plant

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1969
Retirement Date	2023
Service Life, Yrs	54

Historical and Forecast Plant Additions & Balances
Account: 311 Structures & Improvements

Initial Plant Balance 0

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			EOY Plant Balance		
			Transaction Year			Vintage Year					Transfers and			
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1954	69				16,928								
2	1955	68												
3	1956	67												
4	1957	66												
5	1958	65				10,142								
6	1959	64												
7	1960	63												
8	1961	62												
9	1962	61												
10	1963	60												
11	1964	59												
12	1965	58												
13	1966	57				2,050								
14	1967	56												
15	1968	55												
16	1969	54					[redacted]		1,311,253	-		1,311,253		1,311,253
17	1970	53				19,214	17,943	3,616	17,943	3,616		1,325,580		1,325,580
18	1971	52					18,139	3,655	18,139	3,655		1,340,063		1,340,063
19	1972	51				14,872	18,337	3,695	18,337	3,695		1,354,705		1,354,705
20	1973	50				373	18,537	3,736	18,537	3,736		1,369,507		1,369,507
21	1974	49					18,740	3,776	18,740	3,776		1,384,470		1,384,470
22	1975	48					18,944	3,818	18,944	3,818		1,399,597		1,399,597
23	1976	47					19,151	3,859	19,151	3,859		1,414,889		1,414,889
24	1977	46				1,259	19,351	3,901	19,361	3,901		1,430,348		1,430,348
25	1978	45				691	19,572	3,944	19,572	3,944		1,445,976		1,445,976
26	1979	44				6,709	19,786	3,987	19,786	3,987		1,461,775		1,461,775
27	1980	43					20,002	4,031	20,002	4,031		1,477,747		1,477,747
28	1981	42				5,801	20,221	4,075	20,221	4,075		1,493,893		1,493,893
29	1982	41				23,127	20,442	4,119	20,442	4,119		1,510,215		1,510,215
30	1983	40					20,665	4,164	20,665	4,164		1,526,716		1,526,716
31	1984	39					20,891	4,210	20,891	4,210		1,543,397		1,543,397
32	1985	38					21,119	4,256	21,119	4,256		1,560,260		1,560,260
33	1986	37					21,350	4,302	21,350	4,302		1,577,308		1,577,308
34	1987	36					21,583	4,349	21,583	4,349		1,594,542		1,594,542
35	1988	35					21,819	4,397	21,819	4,397		1,611,964		1,611,964
36	1989	34	1,611,964	6,594		9,028			6,594	-			1,618,558	1,618,558
37	1990	33		91,834					91,834	-			1,710,393	1,710,393
38	1991	32			3,146				-	3,146			1,707,247	1,707,247
39	1992	31		55,001					55,001	-			1,762,248	1,762,248
40	1993	30		27,973	3,057				27,973	3,057			1,787,163	1,787,163
41	1994	29		31,830	8,401				31,830	8,401			1,810,593	1,810,593
42	1995	28		41,913	29,836				41,913	29,836			1,822,669	1,822,669
43	1996	27		236,456					236,456	-			2,059,126	2,059,126
44	1997	26							-	-			2,059,126	2,059,126
45	1998	25		11,112					11,112	-			2,070,238	2,070,238
46	1999	24		136,167					136,167	-			2,206,405	2,206,405
47	2000	23			56,726				-	56,726	29,316		2,178,995	2,178,995
48	2001	22							-	-			2,178,995	2,178,995
49	2002	21							-	-			2,178,995	2,178,995
50	2003	20							-	-			2,178,995	2,178,995
51	2004	19							-	-			2,178,995	2,178,995
52	2005	18							-	-			2,178,995	2,178,995
53	2006	17			9,028				-	9,028	(174,827)		1,995,140	1,995,140
54	2007	16		144,402					144,402	-	185		2,139,727	2,139,727
55	2008	15							-	-			2,139,727	2,139,727
56	Total		$ 1,611,964	$ 783,282	$ 110,193	$ 110,193	$ 1,687,855	$ 75,891	$ 2,471,137	$ 186,084	$ (145,326)	$ 29,134,208	$ 39,962,331	$ 69,096,539
	Major Additions/Retirements													
	1996			$ 236,456										
	Routine Activity			$ 546,876										
57	Historical Interim Activity			1.37%	0.28%									
58	Forecast Interim Activity			1.37%	0.28%									
59	2009	14							29,270	5,900				2,163,106
60	2010	13							29,599	5,965				2,186,740
61	2011	12							29,922	6,030				2,210,613
62	2012	11							30,249	6,096				2,234,786
63	2013	10							30,580	6,162				2,259,204
64	2014	9							30,914	6,230				2,283,888
65	2015	8							31,252	6,298				2,308,842
66	2016	7							31,593	6,366				2,334,069
67	2017	6							31,938	6,436				2,359,571
68	2018	5							32,287	6,506				2,385,352
69	2019	4							32,640	6,577				2,411,415
70	2020	3							32,997	6,649				2,437,762
71	2021	2							33,357	6,722				2,464,397
72	2022	1							33,722	6,795				2,491,323
73	2023	0									(2,491,323)			-
									$ 2,911,466	$ 274,817				$ 101,627,627

Whole Life Depreciation Rate Calculation

Historical Additions	2,471,137
Forecast Additions	440,329
Total Additions	2,911,466
Gross Salvage Value	124,566
Less Cost of Removal	249,132
Net Salvage Value	(124,566)
Total to be Recovered	3,036,032
Forecast Plant Balances	101,627,627
Whole Life Accrual Rate	2.99%
Cost of Removal Accrual Rate	0.25%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.23%
Depreciable Service Life, years	33.5

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	2,139,727
Forecast Additions	440,329
Gross Salvage Value	124,566
Less Cost of Removal	249,132
Net Salvage Value	(124,566)
Forecast Plant Balances	32,531,088

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Neil Simpson 1 Plant

Historical and Forecast Plant Additions & Balances
Account: 312 Boiler Plant Equipment

Gross Salvage 5%
Cost of Removal 10%
Net Salvage -5%
Install Date 1969
Retirement Date 2023
Service Life, Yrs 54

Initial Plant Balance 0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year		Transfers and	EOY Plant Balance		
	Vintage	Vintage	Transaction Year			Vintage Year								
Line	Year	Age	Beg. Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1954	69												
2	1955	68												
3	1956	67												
4	1957	66												
5	1958	65												
6	1959	64												
7	1960	63												
8	1961	62												
9	1962	61												
10	1963	60												
11	1964	59												
12	1965	58												
13	1966	57												
14	1967	56												
15	1968	55												
16	1969	54					[illegible]		6,188,859	-		6,188,859		6,188,859
17	1970	53				361,655	49,227	12,069	49,227	12,069		6,226,018		6,226,018
18	1971	52				39,933	49,523	12,142	49,523	12,142		6,263,399		6,263,399
19	1972	51					49,820	12,214	49,820	12,214		6,301,005		6,301,005
20	1973	50					50,119	12,288	50,119	12,288		6,338,837		6,338,837
21	1974	49				10,678	50,420	12,362	50,420	12,362		6,376,895		6,376,895
22	1975	48					50,723	12,436	50,723	12,436		6,415,183		6,415,183
23	1976	47					51,028	12,510	51,028	12,510		6,453,700		6,453,700
24	1977	46					51,334	12,586	51,334	12,586		6,492,448		6,492,448
25	1978	45					51,642	12,661	51,642	12,661		6,531,420		6,531,429
26	1979	44					51,952	12,737	51,952	12,737		6,570,644		6,570,644
27	1980	43					52,264	12,814	52,264	12,814		6,610,095		6,610,095
28	1981	42				50,000	52,578	12,891	52,578	12,891		6,649,782		6,649,782
29	1982	41				3,000	52,894	12,968	52,894	12,968		6,689,708		6,689,708
30	1983	40					53,211	13,046	53,211	13,046		6,729,873		6,729,873
31	1984	39				8,307	53,531	13,124	53,531	13,124		6,770,280		6,770,280
32	1985	38				23,675	53,852	13,203	53,852	13,203		6,810,929		6,810,929
33	1986	37				5,610	54,175	13,282	54,175	13,282		6,851,822		6,851,822
34	1987	36				31,963	54,501	13,362	54,501	13,362		6,892,961		6,892,961
35	1988	35				59,541	54,828	13,442	54,828	13,442		6,934,347		6,934,347
36	1989	34	6,934,347	289,654	10,000	192,406			289,654	10,000			7,214,000	7,214,000
37	1990	33		36,670					36,670	-			7,250,671	7,250,671
38	1991	32		11,235	40,260				11,235	40,260			7,221,646	7,221,646
39	1992	31		5,042,694	357,921	13,700			5,042,694	357,921	(4,701)		11,901,718	11,901,718
40	1993	30		50,000	28,548				50,000	28,548			11,923,171	11,923,171
41	1994	29							-	-			11,923,171	11,923,171
42	1995	28		6,691	2,500				6,691	7,500			11,927,362	11,927,362
43	1996	27		7,142					7,142	-			11,934,504	11,934,504
44	1997	26							-	-			11,934,504	11,934,504
45	1998	25		327,253	48,781				327,253	48,781			12,212,977	12,212,977
46	1999	24		28,250	20,000				28,250	20,000			12,221,227	12,221,227
47	2000	23		296,577	46,139	7,499			296,577	46,139			12,471,665	12,471,665
48	2001	22		11,755					11,755	-			12,483,420	12,483,420
49	2002	21		11,477	8,824				11,477	8,824			12,486,074	12,486,074
50	2003	20		60,439	16,789				60,439	16,789			12,529,723	12,529,723
51	2004	19		177,055	56,758				177,055	56,758			12,650,020	12,650,020
52	2005	18		7,608					7,608	-			12,657,628	12,657,628
53	2006	17		104,038	83,697				104,038	83,697	(282,577)		12,395,393	12,395,393
54	2007	16		409,796	87,750				409,796	87,750	1,375		12,718,813	12,718,813
55	2008	15							-	-			12,718,813	12,718,813
56	Total		$ 6,934,347	$ 6,878,335	$ 807,965	$ 807,965	$ 7,176,483	$ 242,136	$ 14,054,817	$ 1,050,101	$ (285,903)	$ 131,098,213	$ 230,776,500	$ 361,874,713
	Major Additions/Retirements													
	1992			$ 5,042,694	$ 357,921									
	Routine Activity			$ 1,835,640	$ 450,044									
57	Historical Interim Activity			0.80%	0.20%									
58	Forecast Interim Activity			0.80%	0.20%									
59	2009	14							2,201,168	24,803				14,895,178
60	2010	13							118,479	29,048				14,984,609
61	2011	12							119,190	29,222				15,074,578
62	2012	11							119,906	29,397				15,165,086
63	2013	10							120,626	29,574				15,256,139
64	2014	9							121,350	29,751				15,347,737
65	2015	8							122,079	29,930				15,439,886
66	2016	7							122,812	30,110				15,532,588
67	2017	6							2,682,195	30,291				18,184,493
68	2018	5							144,643	35,462				18,293,673
69	2019	4							145,511	35,675				18,403,510
70	2020	3							146,385	35,889				18,514,006
71	2021	2							147,264	36,105				18,625,165
72	2022	1							148,148	36,322				18,736,991
73	2023	0									(18,736,991)			-
									$ 20,514,574	$ 1,491,680				$ 594,328,352

Whole Life Depreciation Rate Calculation

- Historical Additions: 14,054,817
- Forecast Additions: 6,459,757
- Total Additions: 20,514,574
- Gross Salvage Value: 936,850
- Less Cost of Removal: 1,873,699
- Net Salvage Value: (936,850)
- Total to be Recovered: 21,451,424

- Forecast Plant Balances: 594,328,352

- Whole Life Accrual Rate: 3.61%
- Cost of Removal Accrual Rate: 0.32%
- Whole Life Accrual Rate (Excluding Cost of Removal): 3.92%

- Depreciable Service Life, years: 27.7

Remaining Life Depreciation Rate Calculation

- Account Balance 12/31/08: 12,718,813
- Forecast Additions: 6,459,757
- Gross Salvage Value: 936,850
- Less Cost of Removal: 1,873,699
- Net Salvage Value: (936,850)

- Forecast Plant Balances: 232,453,639

005961

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Neil Simpson 1 Plant

Historical and Forecast Plant Additions & Balances
Account: 314 Turbogenerator Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1969
Retirement Date	2023
Service Life, Yrs	54
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			EOY Plant Balance		
			Transaction Year			Vintage Year					Transfers and			
Line	Vintage Year	Vintage Age	Beg. Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
1	1954	69												
2	1955	68												
3	1956	67												
4	1957	66												
5	1958	65												
6	1959	64												
7	1960	63												
8	1961	62												
9	1962	61												
10	1963	60												
11	1964	59												
12	1965	58												
13	1966	57												
14	1967	56												
15	1968	55												
16	1969	54					[redacted]		2,516,254	-		2,516,254		2,516,254
17	1970	53				16,262	11,272	861	11,272	861		2,526,665		2,526,665
18	1971	52				3,000	11,319	864	11,319	864		2,537,120		2,537,120
19	1972	51					11,366	868	11,366	868		2,547,618		2,547,618
20	1973	50					11,413	871	11,413	871		2,558,159		2,558,159
21	1974	49					11,460	875	11,460	875		2,568,744		2,568,744
22	1975	48					11,507	879	11,507	879		2,579,373		2,579,373
23	1976	47					11,555	882	11,555	882		2,590,046		2,590,046
24	1977	46					11,603	886	11,603	886		2,600,762		2,600,762
25	1978	45					11,651	889	11,651	889		2,611,524		2,611,524
26	1979	44					11,699	893	11,699	893		2,622,329		2,622,329
27	1980	43					11,747	897	11,747	897		2,633,180		2,633,180
28	1981	42					11,796	901	11,796	901		2,644,075		2,644,075
29	1982	41					11,845	904	11,845	904		2,655,015		2,655,015
30	1983	40					11,894	908	11,894	908		2,666,001		2,666,001
31	1984	39					11,943	912	11,943	912		2,677,032		2,677,032
32	1985	38					11,992	916	11,992	916		2,688,109		2,688,109
33	1986	37					12,042	919	12,042	919		2,699,232		2,699,232
34	1987	36					12,092	923	12,092	923		2,710,400		2,710,400
35	1988	35				159,525	12,142	927	12,142	927		2,721,615		2,721,615
36	1989	34	2,721,615	19,946					19,946	-			2,741,561	2,741,561
37	1990	33							-	-			2,741,561	2,741,561
38	1991	32		86,929	14,289				86,929	14,289			2,814,201	2,814,201
39	1992	31							-	-			2,814,201	2,814,201
40	1993	30		21,734	3,000				21,734	3,000			2,832,935	2,832,935
41	1994	29							-	-			2,832,935	2,832,935
42	1995	28							-	-			2,832,935	2,832,935
43	1996	27							-	-			2,832,935	2,832,935
44	1997	26							-	-			2,832,935	2,832,935
45	1998	25							-	-			2,832,935	2,832,935
46	1999	24							-	-			2,832,935	2,832,935
47	2000	23							-	-			2,832,935	2,832,935
48	2001	22		4,100					4,100	-			2,837,035	2,837,035
49	2002	21		81,398	159,525				81,398	159,525			2,758,908	2,758,908
50	2003	20							-	-			2,758,908	2,758,908
51	2004	19		38,189	1,973				38,189	1,973			2,795,124	2,795,124
52	2005	18							-	-			2,795,124	2,795,124
53	2006	17							-	-	71,333		2,866,457	2,866,457
54	2007	16							-	-			2,866,457	2,866,457
55	2008	15							-	-			2,866,457	2,866,457
56	Total		$ 2,721,615	$ 252,295	$ 178,787	$ 178,787	$ 2,738,590	$ 16,975	$ 2,990,885	$ 195,761	$ 71,333	$ 52,353,254	$ 56,319,477	$ 108,672,731
	Major Additions/Retirements													
	2002				$ 159,525									
	Routine Activity			$ 252,295	$ 19,262									
57	Historical Interim Activity			0.45%	0.03%									
58	Forecast Interim Activity			0.45%	0.03%									
59	2009	14							12,841	980				2,878,317
60	2010	13							12,894	984				2,890,227
61	2011	12							12,947	988				2,902,186
62	2012	11							13,001	993				2,914,194
63	2013	10							13,055	997				2,926,252
64	2014	9							13,109	1,001				2,938,360
65	2015	8							13,163	1,005				2,950,518
66	2016	7							13,217	1,009				2,962,727
67	2017	6							13,272	1,013				2,974,986
68	2018	5							13,327	1,017				2,987,295
69	2019	4							13,382	1,022				2,999,656
70	2020	3							13,438	1,026				3,012,067
71	2021	2							13,493	1,030				3,024,531
72	2022	1							13,549	1,034				3,037,045
73	2023	0									(3,037,045)			-
									$ 3,175,574	$ 209,862				$ 150,071,092

Whole Life Depreciation Rate Calculation

Historical Additions	2,990,885
Forecast Additions	184,689
Total Additions	3,175,574
Gross Salvage Value	151,852
Less Cost of Removal	303,705
Net Salvage Value	(151,852)
Total to be Recovered	3,327,426
Forecast Plant Balances	150,071,092
Whole Life Accrual Rate	2.22%
Cost of Removal Accrual Rate	0.20%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.42%
Depreciable Service Life, years	41.3

Remaining Life Depreciation Rate Calculatio

Account Balance - 12/31/08	2,866,457
Forecast Additions	184,689
Gross Salvage Value	151,852
Less Cost of Removal	303,705
Net Salvage Value	(151,852)
Forecast Plant Balances	41,398,361

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Neil Simpson 1 Plant

Historical and Forecast Plant Additions & Balances
Account: 315 Accessory Electric Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1969
Retirement Date	2023
Service Life, Yrs	54
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			BOY Plant Balance		
			Transaction Year											
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Vintage Year Retirements	Additions	Retirements	Additions	Retirements	Transfers and Adjustments	Adjustments	Per Books	Simulated
1	1954	69				710								
2	1955	68												
3	1956	67												
4	1957	66												
5	1958	65												
6	1959	64												
7	1960	63												
8	1961	62												
9	1962	61												
10	1963	60												
11	1964	59												
12	1965	58												
13	1966	57				858								
14	1967	56												
15	1968	55												
16	1969	54					533,278		533,278	-		533,278		533,278
17	1970	53				39,960	5,402	2,451	5,402	2,451		536,229		536,229
18	1971	52					5,431	2,465	5,431	2,465		539,196		539,196
19	1972	51					5,462	2,478	5,462	2,478		542,179		542,179
20	1973	50					5,492	2,492	5,492	2,492		545,179		545,179
21	1974	49					5,522	2,506	5,522	2,506		548,195		548,195
22	1975	48					5,553	2,520	5,553	2,520		551,228		551,228
23	1976	47					5,583	2,534	5,583	2,534		554,278		554,278
24	1977	46					5,614	2,548	5,614	2,548		557,345		557,345
25	1978	45					5,645	2,562	5,645	2,562		560,428		560,428
26	1979	44					5,677	2,576	5,677	2,576		563,529		563,529
27	1980	43					5,708	2,590	5,708	2,590		566,647		566,647
28	1981	42					5,740	2,604	5,740	2,604		569,782		569,782
29	1982	41					5,771	2,619	5,771	2,619		572,935		572,935
30	1983	40				16,950	5,803	2,633	5,803	2,633		576,105		576,105
31	1984	39					5,835	2,648	5,835	2,648		579,292		579,292
32	1985	38					5,868	2,663	5,868	2,663		582,497		582,497
33	1986	37					5,900	2,677	5,900	2,677		585,720		585,720
34	1987	36					5,933	2,692	5,933	2,692		588,961		588,961
35	1988	35					5,966	2,707	5,966	2,707		592,219		592,219
36	1989	34	592,219	9,579					9,579	-			601,798	601,798
37	1990	33							-	-			601,798	601,798
38	1991	32		5,696	8,916				5,696	8,916			598,578	598,578
39	1992	31		1,892					1,892	-	(9,579)		590,891	590,891
40	1993	30							-	-			590,891	590,891
41	1994	29							-	-			590,891	590,891
42	1995	28							-	-			590,891	590,891
43	1996	27							-	-			590,891	590,891
44	1997	26							-	-			590,891	590,891
45	1998	25		72,341	31,044				72,341	31,044			632,188	632,188
46	1999	24							-	-			632,188	632,188
47	2000	23							-	-			632,188	632,188
48	2001	22							-	-			632,188	632,188
49	2002	21		39,365	18,518				39,365	18,518			653,035	653,035
50	2003	20							-	-			653,035	653,035
51	2004	19							-	-			653,035	653,035
52	2005	18							-	-			653,035	653,035
53	2006	17							-	-	91,849		744,885	744,885
54	2007	16							-	-			744,885	744,885
55	2008	15							-	-			744,885	744,885
56	Total		$ 592,219	$ 128,873	$ 58,478	$ 58,478	$ 641,183	$ 48,964	$ 770,056	$ 107,442	$ 82,270	$ 11,245,221	$ 12,723,066	$ 23,968,287
	Major Additions/Retirements													
	Routine Activity			$ 128,873										
57	Historical Interim Activity			1.01%	0.46%									
58	Forecast Interim Activity			1.01%	0.46%									
59	2009	14							7,545	3,424				749,006
60	2010	13							7,587	3,443				753,150
61	2011	12							7,629	3,462				757,317
62	2012	11							7,671	3,481				761,507
63	2013	10							7,713	3,500				765,720
64	2014	9							7,756	3,519				769,957
65	2015	8							7,799	3,539				774,217
66	2016	7							7,842	3,558				778,501
67	2017	6							7,885	3,578				782,808
68	2018	5							7,929	3,598				787,139
69	2019	4							7,973	3,618				791,494
70	2020	3							8,017	3,638				795,873
71	2021	2							8,061	3,658				800,277
72	2022	1							8,106	3,678				804,705
73	2023	0									(804,705)			-
									$ 879,570	$ 157,135				$ 34,839,958

Whole Life Depreciation Rate Calculation

Historical Additions	770,056
Forecast Additions	109,514
Total Additions	879,570
Gross Salvage Value	40,235
Less Cost of Removal	80,470
Net Salvage Value	(40,235)
Total to be Recovered	919,805
Forecast Plant Balances	34,839,958
Whole Life Accrual Rate	2.64%
Cost of Removal Accrual Rate	0.23%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.87%
Depreciable Service Life, years	24.8

Remaining Life Depreciation Rate Calculation

Accrual Balance - 12/31/08	744,885
Forecast Additions	109,514
Gross Salvage Value	40,235
Less Cost of Removal	80,470
Net Salvage Value	(40,235)
Forecast Plant Balances	10,871,672

Black Hills Power

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Neil Simpson 1 Plant

Historical and Forecast Plant Additions & Balances
Account: 316 Miscellaneous Plant Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1969
Retirement Date	2023
Service Life, Yrs	54
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			EOY Plant Balance		
			Transaction Year			Vintage Year								
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Transfers and Adjustments	Adjustments	Per Books	Simulated
1	1954	69												
2	1955	68												
3	1956	67												
4	1957	66												
5	1958	65												
6	1959	64												
7	1960	63												
8	1961	62												
9	1962	61												
10	1963	60												
11	1964	59												
12	1965	58												
13	1966	57												
14	1967	56												
15	1968	55												
16	1969	54					300,112		300,112	-		300,112		300,112
17	1970	53				64,347	3,108	-	3,108	-		303,220		303,220
18	1971	52					3,141	-	3,141	-		306,361		306,361
19	1972	51					3,173	-	3,173	-		309,534		309,534
20	1973	50					3,206	-	3,206	-		312,740		312,740
21	1974	49					3,239	-	3,239	-		315,979		315,979
22	1975	48					3,273	-	3,273	-		319,252		319,252
23	1976	47					3,307	-	3,307	-		322,559		322,559
24	1977	46					3,341	-	3,341	-		325,900		325,900
25	1978	45					3,376	-	3,376	-		329,275		329,275
26	1979	44					3,411	-	3,411	-		332,686		332,686
27	1980	43					3,446	-	3,446	-		336,132		336,132
28	1981	42					3,482	-	3,482	-		339,613		339,613
29	1982	41					3,518	-	3,518	-		343,131		343,131
30	1983	40					3,554	-	3,554	-		346,685		346,685
31	1984	39					3,591	-	3,591	-		350,276		350,276
32	1985	38					3,628	-	3,628	-		353,904		353,904
33	1986	37					3,666	-	3,666	-		357,569		357,569
34	1987	36					3,704	-	3,704	-		361,273		361,273
35	1988	35					3,742	-	3,742	-		365,015		365,015
36	1989	34	365,015	17,009					17,009	-			382,024	382,024
37	1990	33		6,448	64,347				6,448	64,347			324,125	324,125
38	1991	32		4,170					4,170	-			328,295	328,295
39	1992	31		12,917					12,917	-			341,211	341,211
40	1993	30							-	-			341,211	341,211
41	1994	29		25,487					25,487	-			366,699	366,699
42	1995	28							-	-			366,699	366,699
43	1996	27		5,371					5,371	-			372,070	372,070
44	1997	26		399					399	-			372,469	372,469
45	1998	25		2,297					2,297	-			374,765	374,765
46	1999	24							-	-			374,765	374,765
47	2000	23							-	-			374,765	374,765
48	2001	22							-	-			374,765	374,765
49	2002	21							-	-			374,765	374,765
50	2003	20		2,729					2,729	-			377,494	377,494
51	2004	19		763					763	-			378,257	378,257
52	2005	18							-	-			378,257	378,257
53	2006	17							-	-	51,210		429,468	429,468
54	2007	16							-	-			429,468	429,468
55	2008	15							-	-			429,468	429,468
56	Total		$ 365,015	$ 77,590	$ 64,347	$ 64,347	$ 365,015	$ -	$ 442,604	$ 64,347	$ 51,210	$ 6,631,213	$ 7,491,039	$ 14,122,252
	Major Additions/Retirements													
	1990				$ 64,347									
	Routine Activity			$ 77,590	$ -									
57	Historical Interim Activity			1.04%	0.00%									
58	Forecast Interim Activity			1.04%	0.00%									
59	2009	14							4,448	-				433,916
60	2010	13							4,494	-				438,410
61	2011	12							4,541	-				442,951
62	2012	11							4,588	-				447,539
63	2013	10							4,635	-				452,175
64	2014	9							4,683	-				456,858
65	2015	8							4,732	-				461,590
66	2016	7							4,781	-				466,371
67	2017	6							4,831	-				471,202
68	2018	5							4,881	-				476,082
69	2019	4							4,931	-				481,013
70	2020	3							4,982	-				485,995
71	2021	2							5,034	-				491,029
72	2022	1							5,086	-				496,115
73	2023	0									(496,115)			-
									$ 509,252	$ 64,347				$ 20,623,499

Whole Life Depreciation Rate Calculation

Historical Additions	442,604
Forecast Additions	66,647
Total Additions	509,252
Gross Salvage Value	24,806
Less Cost of Removal	49,612
Net Salvage Value	(24,806)
Total to be Recovered	534,058
Forecast Plant Balances	20,623,499
Whole Life Accrual Rate	2.59%
Cost of Removal Accrual Rate	0.24%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.83%
Depreciable Service Life, years	38.6

Remaining Life Depreciation Rate Calculation

Account Balance - 12/31/08	429,468
Forecast Additions	66,647
Gross Salvage Value	24,806
Less Cost of Removal	49,612
Net Salvage Value	(24,806)
Forecast Plant Balances	6,501,247

Summary by Plant
Black Hills Power
Neil Simpson 2 Facility

Account	Description	Direct Investment 2008$	Depreciation Rate
310	Land		
311	Structure & Improvements	13,248,871	2.73%
312	Boiler Plant Equipment	75,551,337	2.87%
313	Engines & Engine Driven Generators		
314	Turbo Generator Equipment	29,102,926	2.59%
315	Accessory Electric Equipment	6,272,379	2.58%
316	Misc Power Equipment	479,676	7.23%
	Total	124,655,189	2.79% whole life weighted average rate

Remaining Life Depreciation Rate Calculation

Per Books Balance 12/31/08	125,534,971
Forecast Interim Additions	29,159,701
Forecast Gross Salvage Value	7,637,352
Forecast Less Cost of Removal	15,274,704
Forecast Net Salvage Value	(7,637,352)
Forecast Total to be Recovered with COR	162,332,024
Forecast Total to be Recovered w/o COR	147,057,320
Accumulated Depreciation (2008 EOY)	(38,724,257)
Forecast Remaining Life Balance with COR	123,607,767
Forecast Remaining Life Balance w/o COR	108,333,063
Forecast Plant Balances	4,957,526,249
Remaining Life Rate with COR	2.49%
Remaining Life Rate w/o COR	2.19%

Black Hills Power Company

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Neil Simpson 2 Plant

Historical and Forecast Plant Additions & Balances
Account: 311 Structures & Improvements

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1998
Retirement Date	2045
Service Life, Yrs	47
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year				EOY Plant Balance	
			Transaction Year			Vintage Year								
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Transfers and Adjustments	Adjustments	Per Books	Simulated
41	1998	47		11,540,435		17,822			11,540,435	-			11,540,435	11,540,435
42	1999	46		322,184					322,184	-	624,511		12,487,130	12,487,130
43	2000	45		87,340					87,340	-			12,574,470	12,574,470
44	2001	44							-	-			12,574,470	12,574,470
45	2002	43		5,484					5,484	-			12,579,954	12,579,954
46	2003	42		22,835					22,835	-			12,602,789	12,602,789
47	2004	41		338,036					338,036	-			12,940,825	12,940,825
48	2005	40							-	-			12,940,825	12,940,825
49	2006	39		84,446					84,446	-	165,739		13,191,009	13,191,009
50	2007	38		76,060	17,822				76,060	17,822	(376)		13,248,871	13,248,871
51	2008	37							-	-			13,248,871	13,248,871
52	Total		$ -	$ 12,476,819	$ 17,822	$ 17,822	$ -	$ -	$ 12,476,819	$ 17,822	$ 789,874	$ -	$ 139,929,647	$ 139,929,647

Major Additions/Retirements
1998 $ 11,540,435

Routine Activity $ 936,183

Line			
53	Historical Interim Activity	0.67%	0.01%
54	Forecast Interim Activity	0.67%	0.01%

Line	[A] Vintage Year	[B] Vintage Age	[I] Additions	[J] Retirements	[K] Transfers and Adjustments	[N] Simulated
55	2009	36	88,659	1,687		13,335,842
56	2010	35	89,241	1,699		13,423,385
57	2011	34	89,827	1,710		13,511,502
58	2012	33	90,416	1,721		13,600,197
59	2013	32	91,010	1,732		13,689,475
60	2014	31	91,607	1,744		13,779,339
61	2015	30	92,209	1,755		13,869,793
62	2016	29	92,814	1,767		13,960,840
63	2017	28	93,423	1,778		14,052,486
64	2018	27	94,037	1,790		14,144,732
65	2019	26	94,654	1,802		14,237,585
66	2020	25	95,275	1,813		14,331,047
67	2021	24	95,901	1,825		14,425,122
68	2022	23	96,530	1,837		14,519,815
69	2023	22	97,164	1,849		14,615,130
70	2024	21	97,802	1,861		14,711,070
71	2025	20	98,444	1,874		14,807,640
72	2026	19	99,090	1,886		14,904,844
73	2027	18	99,740	1,898		15,002,686
74	2028	17	100,395	1,911		15,101,171
75	2029	16	101,054	1,923		15,200,302
76	2030	15	101,718	1,936		15,300,083
77	2031	14	102,385	1,949		15,400,520
78	2032	13	103,057	1,962		15,501,616
79	2033	12	103,734	1,974		15,603,375
80	2034	11	104,415	1,987		15,705,803
81	2035	10	105,100	2,000		15,808,903
82	2036	9	105,790	2,014		15,912,680
83	2037	8	106,485	2,027		16,017,137
84	2038	7	107,184	2,040		16,122,281
85	2039	6	107,887	2,053		16,228,115
86	2040	5	108,596	2,067		16,334,644
87	2041	4	109,308	2,080		16,441,872
88	2042	3	110,026	2,094		16,549,803
89	2043	2	110,748	2,108		16,658,444
90	2044	1	111,475	2,122		16,767,797
91	2045	0			(16,767,797)	-
			$ 16,064,021	$ 86,098		$ 679,506,724

Whole Life Depreciation Rate Calculation

Historical Additions	12,476,819
Forecast Additions	3,587,202
Total Additions	16,064,021
Gross Salvage Value	838,390
Less Cost of Removal	1,676,780
Net Salvage Value	(838,390)
Total to be Recovered	16,902,411
Forecast Plant Balances	679,506,724
Whole Life Accrual Rate	2.49%
Cost of Removal Accrual Rate	0.25%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.73%
Depreciable Service Life, years	40.2

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	13,248,871
Forecast Additions	3,587,202
Gross Salvage Value	838,390
Less Cost of Removal	1,676,780
Net Salvage Value	(838,390)
Forecast Plant Balances	539,577,076

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Black Hills Power Company

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Neil Simpson 2 Plant

Historical and Forecast Plant Additions & Balances
Account: 312 Boiler Plant Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1998
Retirement Date	2045
Service Life, Yrs	47
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year			EOY Plant Balance		
			Transaction Year											
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Vintage Year Retirement	Additions	Retirements	Additions	Retirements	Transfers and Adjustments	Adjustments	Per Books	Simulated
13	1970	75				6,013	-	-	-	-		-		-
14	1971	74					-	-	-	-		-		-
15	1972	73					-	-	-	-		-		-
16	1973	72					-	-	-	-		-		-
17	1974	71					-	-	-	-		-		-
18	1975	70					-	-	-	-		-		-
19	1976	69					-	-	-	-		-		-
20	1977	68					-	-	-	-		-		-
21	1978	67					-	-	-	-		-		-
22	1979	66					-	-	-	-		-		-
23	1980	65					-	-	-	-		-		-
24	1981	64					-	-	-	-		-		-
25	1982	63					-	-	-	-		-		-
26	1983	62					-	-	-	-		-		-
27	1984	61					-	-	-	-		-		-
28	1985	60					-	-	-	-		-		-
29	1986	59					-	-	-	-		-		-
30	1987	58					-	-	-	-		-		-
31	1988	57				6,533	-	-	-	-		-		-
32	1989	56											-	-
33	1990	55											-	-
34	1991	54											-	-
35	1992	53											-	-
36	1993	52							-	-			-	-
37	1994	51							-	-			-	-
38	1995	50							-	-			-	-
39	1996	49							-	-			-	-
40	1997	48		28,341					28,341	-			28,341	28,341
41	1998	47		74,009,175	6,533	1,658,776			74,009,175	6,533			74,030,983	74,030,983
42	1999	46		869,214	30,316				869,214	30,316	(467,515)		74,402,366	74,402,366
43	2000	45		587,861	31,013				587,861	31,013			74,959,214	74,959,214
44	2001	44		105,595	112,000				105,595	112,000			74,952,809	74,952,809
45	2002	43		135,029	3,344				135,029	3,344			75,084,494	75,084,494
46	2003	42		77,435					77,435	-			75,161,928	75,161,928
47	2004	41		380,167	50,000				380,167	50,000			75,492,095	75,492,095
48	2005	40		16,469	8,484				16,469	8,484			75,500,080	75,500,080
49	2006	39							-	-	183,186		75,683,266	75,683,266
50	2007	38		1,293,706	1,429,632				1,293,706	1,429,632	3,997		75,551,337	75,551,337
51	2008	37							-	-			75,551,337	75,551,337
52	Total		$ -	$ 77,502,991	$ 1,671,322	$ 1,671,332	$ -	$ -	$ 77,502,991	$ 1,671,322	$ (280,332)	$ -	$ 826,398,249	$ 826,398,249

Line		[D]	[E]
	Major Additions/Retirements		
	1998	$ 74,037,516	
	2007	$ 1,293,706	$ 1,429,632
	Routine Activity	$ 2,171,769	$ 241,690
53	Historical Interim Activity	0.26%	0.03%
54	Forecast Interim Activity	0.26%	0.03%

Line	Vintage Year	Vintage Age	Adjusted Additions [I]	Adjusted Retirements [J]	Transfers and Adjustments [K]	Simulated [N]
55	2009	36	198,548	22,096		75,727,789
56	2010	35	199,012	22,148		75,904,654
57	2011	34	199,477	22,199		76,081,931
58	2012	33	1,775,881	22,252		77,835,561
59	2013	32	204,553	22,764		78,017,348
60	2014	31	205,029	22,817		78,199,560
61	2015	30	205,508	22,870		78,382,198
62	2016	29	205,988	22,924		78,565,262
63	2017	28	206,469	22,977		78,748,753
64	2018	27	206,951	23,031		78,932,673
65	2019	26	2,080,730	23,085		80,990,318
66	2020	25	212,842	23,687		81,179,473
67	2021	24	213,339	23,742		81,369,071
68	2022	23	213,837	23,797		81,559,111
69	2023	22	214,337	23,851		81,749,594
70	2024	21	214,837	23,909		81,940,523
71	2025	20	215,339	23,965		82,131,898
72	2026	19	2,442,601	24,020		84,550,478
73	2027	18	222,198	24,728		84,747,948
74	2028	17	222,717	24,786		84,945,880
75	2029	16	223,237	24,843		85,144,274
76	2030	15	223,759	24,901		85,343,131
77	2031	14	224,281	24,960		85,542,452
78	2032	13	224,805	25,018		85,742,239
79	2033	12	2,872,247	25,076		88,589,410
80	2034	11	232,312	25,909		88,796,313
81	2035	10	233,356	25,970		89,003,700
82	2036	9	233,901	26,030		89,211,570
83	2037	8	234,447	26,091		89,419,927
84	2038	7	234,995	26,152		89,628,770
85	2039	6	235,544	26,213		89,838,101
86	2040	5	3,382,446	26,274		93,194,272
87	2041	4	244,914	27,236		93,411,930
88	2042	3	245,486	27,319		93,630,097
89	2043	2	246,059	27,383		93,848,773
90	2044	1	246,634	27,447		94,067,959
91	2045	0			(94,067,959)	-
			$ 96,902,106	$ 2,553,814		$ 3,862,371,189

Whole Life Depreciation Rate Calculation

Historical Additions	77,502,991
Forecast Additions	19,399,115
Total Additions	96,902,106
Gross Salvage Value	4,703,398
Less Cost of Removal	9,406,796
Net Salvage Value	(4,703,398)
Total to be Recovered	101,605,504
Forecast Plant Balances	3,862,371,189
Whole Life Accrual Rate	2.63%
Cost of Removal Accrual Rate	0.24%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.87%
Depreciable Service Life, years	38.0

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	75,551,337
Forecast Additions	19,399,115
Gross Salvage Value	4,703,398
Less Cost of Removal	9,406,796
Net Salvage Value	(4,703,398)
Forecast Plant Balances	3,035,972,939

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Black Hills Power Company

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Neil Simpson 2 Plant

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1998
Retirement Date	2045
Service Life, Yrs	47
Initial Plant Balance	0

2008

Historical and Forecast Plant Additions & Balances
Account: 314 Turbogenerator Equipment

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year					EOY Plant Balance		
			Transaction Year			Vintage Year			Adjusted Transaction Year		Transfers and			
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
41	1998	47		27,051,645		192,000			27,051,645	-			27,051,645	27,051,645
42	1999	46							-	-	(77,928)		26,973,718	26,973,718
43	2000	45		37,085					37,085	-			27,010,803	27,010,803
44	2001	44		3,265					3,265	-			27,014,068	27,014,068
45	2002	43		1,713,883					1,713,883	-			28,727,951	28,727,951
46	2003	42		121,566					121,566	-			28,849,517	28,849,517
47	2004	41		76,317					76,317	-			28,925,834	28,925,834
48	2005	40							-	-			28,925,834	28,925,834
49	2006	39		285,377	192,000				285,377	192,000	7,967		29,027,178	29,027,178
50	2007	38		75,749					75,749	-			29,102,926	29,102,926
51	2008	37							-	-			29,102,926	29,102,926
52	Total		$ -	$ 29,364,887	$ 192,000	$ 192,000	$ -	$ -	$ 29,364,887	$ 192,000	$ (69,961)	$ -	$ 310,712,400	$ 310,712,400
	Major Additions/Retirements													
	1998			$ 27,051,645										
	2002			$ 1,713,883										
	Routine Activity			$ 599,359	$ 192,000									
53	Historical Interim Activity			0.19%	0.06%									
54	Forecast Interim Activity			0.19%	0.00%									
55	2009	36							56,139	-				29,159,066
56	2010	35							56,247	-				29,215,313
57	2011	34							56,356	-				29,271,669
58	2012	33							56,465	-				29,328,133
59	2013	32							56,574	-				29,384,707
60	2014	31							56,683	-				29,441,390
61	2015	30							56,792	-				29,498,181
62	2016	29							56,902	-				29,555,083
63	2017	28							57,011	-				29,612,094
64	2018	27							57,121	-				29,669,216
65	2019	26							57,231	-				29,726,447
66	2020	25							57,342	-				29,783,789
67	2021	24							57,452	-				29,841,241
68	2022	23							57,563	-				29,898,805
69	2023	22							57,674	-				29,956,479
70	2024	21							57,786	-				30,014,264
71	2025	20							57,897	-				30,072,162
72	2026	19							58,009	-				30,130,170
73	2027	18							58,121	-				30,188,291
74	2028	17							58,233	-				30,246,524
75	2029	16							58,345	-				30,304,869
76	2030	15							58,458	-				30,363,326
77	2031	14							58,570	-				30,421,897
78	2032	13							58,683	-				30,480,580
79	2033	12							58,797	-				30,539,377
80	2034	11							58,910	-				30,598,286
81	2035	10							59,024	-				30,657,310
82	2036	9							59,137	-				30,716,448
83	2037	8							59,252	-				30,775,699
84	2038	7							59,366	-				30,835,065
85	2039	6							59,480	-				30,894,545
86	2040	5							59,595	-				30,954,140
87	2041	4							59,710	-				31,013,850
88	2042	3							59,825	-				31,073,676
89	2043	2							59,941	-				31,133,616
90	2044	1							60,056	-				31,193,672
91	2045	0									(31,193,672)			-
									$ 31,455,633	$ 192,000				$ 1,396,661,779

Whole Life Depreciation Rate Calculation

Historical Additions	29,364,887
Forecast Additions	2,090,746
Total Additions	31,455,633
Gross Salvage Value	1,559,684
Less Cost of Removal	3,119,367
Net Salvage Value	(1,559,684)
Total to be Recovered	33,015,317
Forecast Plant Balances	1,396,661,779
Whole Life Accrual Rate	2.36%
Cost of Removal Accrual Rate	0.22%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.59%
Depreciable Service Life, years	42.3

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	29,102,926
Forecast Additions	2,090,746
Gross Salvage Value	1,559,684
Less Cost of Removal	3,119,367
Net Salvage Value	(1,559,684)
Forecast Plant Balances	1,085,949,379

Black Hills Power Company

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Neil Simpson 2 Plant

Historical and Forecast Plant Additions & Balances
Account: 315 Accessory Electric Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1998
Retirement Date	2045
Service Life, Yrs	47
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year					EOY Plant Balance		
			Transaction Year			Vintage Year			Adjusted Transaction Year		Transfers and			
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
41	1998	47		6,135,296					6,135,296	-			6,135,296	6,135,296
42	1999	46		11,151					11,151	-			6,146,447	6,146,447
43	2000	45							-	-			6,146,447	6,146,447
44	2001	44							-	-			6,146,447	6,146,447
45	2002	43							-	-			6,146,447	6,146,447
46	2003	42							-	-			6,146,447	6,146,447
47	2004	41		139,183					139,183	-			6,285,630	6,285,630
48	2005	40							-	-			6,285,630	6,285,630
49	2006	39							-	-	(13,251)		6,272,379	6,272,379
50	2007	38							-	-			6,272,379	6,272,379
51	2008	37							-	-			6,272,379	6,272,379
52	Total		$ -	$ 6,285,630	$ -	$ -	$ -	$ -	$ 6,285,630	$ -	$ (13,251)	$ -	$ 68,255,930	$ 68,255,930
	Major Additions/Retirements													
	1998			$ 6,135,296										
	Routine Activity			$ 130,334										
53	Historical Interim Activity			0.22%	0.00%									
54	Forecast Interim Activity			0.22%	0.00%									
55	2009	36							13,815	-				6,286,194
56	2010	35							13,845	-				6,300,039
57	2011	34							13,876	-				6,313,915
58	2012	33							13,906	-				6,327,822
59	2013	32							13,937	-				6,341,759
60	2014	31							13,968	-				6,355,727
61	2015	30							13,999	-				6,369,725
62	2016	29							14,029	-				6,383,755
63	2017	28							14,060	-				6,397,815
64	2018	27							14,091	-				6,411,906
65	2019	26							14,122	-				6,426,028
66	2020	25							14,153	-				6,440,182
67	2021	24							14,185	-				6,454,366
68	2022	23							14,216	-				6,468,582
69	2023	22							14,247	-				6,482,829
70	2024	21							14,278	-				6,497,108
71	2025	20							14,310	-				6,511,418
72	2026	19							14,341	-				6,525,759
73	2027	18							14,373	-				6,540,132
74	2028	17							14,405	-				6,554,537
75	2029	16							14,436	-				6,568,973
76	2030	15							14,468	-				6,583,441
77	2031	14							14,500	-				6,597,941
78	2032	13							14,532	-				6,612,473
79	2033	12							14,564	-				6,627,037
80	2034	11							14,596	-				6,641,634
81	2035	10							14,628	-				6,656,262
82	2036	9							14,660	-				6,670,922
83	2037	8							14,693	-				6,685,615
84	2038	7							14,725	-				6,700,340
85	2039	6							14,758	-				6,715,098
86	2040	5							14,790	-				6,729,888
87	2041	4							14,823	-				6,744,710
88	2042	3							14,855	-				6,759,566
89	2043	2							14,888	-				6,774,454
90	2044	1							14,921	-				6,789,374
91	2045	0									(6,789,374)			-
									$ 6,802,626	$ -				$ 303,503,255

Whole Life Depreciation Rate Calculation

Historical Additions	6,285,630
Forecast Additions	516,995
Total Additions	6,802,626
Gross Salvage Value	339,469
Less Cost of Removal	678,937
Net Salvage Value	(339,469)
Total to be Recovered	7,142,094
Forecast Plant Balances	303,503,255
Whole Life Accrual Rate	2.35%
Cost of Removal Accrual Rate	0.22%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.58%
Depreciable Service Life, years	42.5

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	6,272,379
Forecast Additions	516,995
Gross Salvage Value	339,469
Less Cost of Removal	678,937
Net Salvage Value	(339,469)
Forecast Plant Balances	235,247,325

Black Hills Power Company

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Neil Simpson 2 Plant

Historical and Forecast Plant Additions & Balances
Account: 316 Miscellaneous Power Equipment

Gross Salvage	5%
Cost of Removal	10%
Net Salvage	-5%
Install Date	1998
Retirement Date	2045
Service Life, Yrs	47
Initial Plant Balance	0

2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
			Reported Per Books				Adjustments to Transaction Year					EOY Plant Balance		
			Transaction Year			Vintage Year			Adjusted Transaction Year		Transfers and			
Line	Vintage Year	Vintage Age	Beg Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements	Adjustments	Adjustments	Per Books	Simulated
41	1998	47		279,045					279,045	-			279,045	279,045
42	1999	46		6,941					6,941	-	(79,068)		206,917	206,917
43	2000	45		13,614					13,614	-	38,764		259,296	259,296
44	2001	44		43,205					43,205	-			302,500	302,500
45	2002	43		7,852					7,852	-			310,352	310,352
46	2003	42		35,386					35,386	-			345,739	345,739
47	2004	41		21,531					21,531	-			367,270	367,270
48	2005	40		69,107					69,107	-			436,377	436,377
49	2006	39		25,198	7,978	7,978			25,198	7,978	5,965		459,562	459,562
50	2007	38							-	-			459,562	459,562
51	2008	37		20,114					20,114	-			479,676	479,676
52	Total		$ -	$ 521,993	$ 7,978	$ 7,978	$ -	$ -	$ 521,993	$ 7,978	$ (34,340)	$ -	$ 3,906,296	$ 3,906,296

	Major Additions/Retirements		
	1998	$ 279,045	
	Routine Activity	$ 242,948	
53	Historical Interim Activity	6.22%	0.20%
54	Forecast Interim Activity	6.22%	0.20%

Line	[A] Vintage Year	[B] Vintage Age	[I] Additions	[J] Retirements	[K] Transfers and Adjustments	[N] Simulated
55	2009	36	29,833	980		508,529
56	2010	35	31,627	1,039		539,118
57	2011	34	33,530	1,101		571,547
58	2012	33	35,547	1,167		605,927
59	2013	32	37,685	1,237		642,374
60	2014	31	39,952	1,312		681,014
61	2015	30	42,355	1,391		721,978
62	2016	29	44,903	1,474		765,407
63	2017	28	47,604	1,563		811,447
64	2018	27	50,467	1,657		860,257
65	2019	26	53,503	1,757		912,003
66	2020	25	56,721	1,863		966,862
67	2021	24	60,133	1,975		1,025,020
68	2022	23	63,750	2,093		1,086,677
69	2023	22	67,585	2,219		1,152,043
70	2024	21	71,650	2,353		1,221,340
71	2025	20	75,960	2,494		1,294,806
72	2026	19	80,529	2,644		1,372,691
73	2027	18	85,373	2,803		1,455,261
74	2028	17	90,508	2,972		1,542,797
75	2029	16	95,953	3,151		1,635,599
76	2030	15	101,724	3,340		1,733,983
77	2031	14	107,843	3,541		1,838,285
78	2032	13	114,330	3,754		1,948,862
79	2033	12	121,207	3,980		2,066,089
80	2034	11	128,498	4,219		2,190,368
81	2035	10	136,228	4,473		2,322,122
82	2036	9	144,422	4,742		2,461,802
83	2037	8	153,109	5,028		2,609,884
84	2038	7	162,319	5,330		2,766,873
85	2039	6	172,083	5,651		2,933,306
86	2040	5	182,434	5,990		3,109,749
87	2041	4	193,408	6,351		3,296,806
88	2042	3	205,042	6,733		3,495,115
89	2043	2	217,375	7,138		3,705,352
90	2044	1	230,451	7,567		3,928,236
91	2045	0			(3,928,236)	-
			$ 4,087,636	$ 125,060		$ 64,685,826

Whole Life Depreciation Rate Calculation

Historical Additions	521,993
Forecast Additions	3,565,643
Total Additions	4,087,636
Gross Salvage Value	196,412
Less Cost of Removal	392,824
Net Salvage Value	(196,412)
Total to be Recovered	4,284,047
Forecast Plant Balances	64,685,826
Whole Life Accrual Rate	6.62%
Cost of Removal Accrual Rate	0.61%
Whole Life Accrual Rate (Excluding Cost of Removal)	7.23%
Depreciable Service Life, years	15.1

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	479,676
Forecast Additions	3,565,643
Gross Salvage Value	196,412
Less Cost of Removal	392,824
Net Salvage Value	(196,412)
Forecast Plant Balances	60,779,529

EXHIBIT___(LK-20)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Depreciation Expense - Production
($ Millions)

Description	As Filed Depreciable Plant In Service	As Filed Depreciation Rate	As Filed Depreciation Expense	BHII Adjusted Depreciation Rate	BHII Adjusted Depreciation Expense	BHII Adjustment Total Company	South Dakota Retail %	BHII Adjustment South Dakota
Steam Production- by Plant								
Ben French	-		-		-	-	89.831%	-
Neil Simpson	-		-		-	-	89.831%	-
Neil Simpson II	153,367,574	2.90%	4,447,660	2.58%	3,956,883	(490,776)	89.831%	(440,869)
Osage	-		-		-	-	89.831%	-
Wygen III	134,929,287	2.64%	3,562,133	2.44%	3,292,275	(269,859)	89.831%	(242,417)
Wyodak	111,009,656	2.86%	3,174,876	2.53%	2,808,544	(366,332)	89.831%	(329,080)
CPGS	92,250,624	3.29%	3,035,046	2.88%	Adjusted in Separate Adjustment		89.831%	-
Other Production	83,199,162	2.50%	2,079,979	2.34%	1,946,860	(133,119)	89.831%	(119,582)
Total Production Plant Sum	574,756,303		16,299,694		12,004,563	(1,260,085)		(1,131,947)
Transmission	109,287,969	2.26%	2,469,908	2.26%	2,469,908	-		-
Distribution	331,966,699	2.70%	8,963,101	2.70%	8,963,101	-		-
General	50,440,557	4.62%	1,635,464	4.62%	1,635,464	-		-
Other Utility Plant	27,796,131	7.65%	2,126,404	7.65%	2,126,404	-		-
Subtotal Plant in Service Sum	1,094,247,659		31,494,570		27,199,439	(1,260,085)		(1,131,947)
Plant Acquisition Adjustment	4,870,308	2.00%	97,406	2.00%	97,406	-		-
Total Depreciable Plant In Service	1,099,117,967		31,591,976		27,296,846	(1,260,085)		(1,131,947)
Accumulated Depreciation One Half of Depreciation Expense Reduction (See Statement E Note 3)						(630,043)		
Decrease Accumulated Depreciation for Expense Reduction The Effect Increases Rate Base						630,043	89.831%	565,974
Accumulated Deferred Income Taxes (See Schedule M-2) Book Depreciation Expense Reduction						(1,260,085)		
Federal Income Tax Rate						0.35		
Increase ADIT for Expense Reduction The Effect Decreases Rate Base	(100% of Expense Reduction x tax rate)					(441,030)	89.831%	(396,182)

BLACK HILLS POWER, INC.
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2012

ACCT. (I)	TITLE (II)	NET SALVAGE PERCENT	ORIGINAL COST (III)	BOOK RESERVE	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT (X)	ANNUAL ACCRUAL PERCENT (XI)	COMPOSITE REMAIN LIFE (IX)
STEAM PRODUCTION PLANT								
	BEN FRENCH STATION							
311.00	Structures & Improvements	(28)	2,251,067	2,470,217	411,149	225,045	10.00%	1.8
312.01	Boiler Plant Equipment	(28)	6,842,536	6,971,855	1,786,590	985,304	14.40%	1.8
314.00	Turbogenerator Units	(28)	3,956,116	3,267,891	1,795,937	987,811	24.97%	1.8
315.00	Accessory Electrical Equipment	(28)	756,487	817,196	151,107	83,050	10.98%	1.8
316.00	Misc. Power Plant Equip.	(28)	461,438	529,424	61,216	33,837	7.33%	1.8
	Total		14,267,643	14,056,583	4,205,999	2,315,047	16.23%	1.8
	NEIL SIMPSON I							
311.00	Structures & Improvements	(13)	2,263,790	2,055,490	502,593	275,250	12.16%	1.8
312.01	Boiler Plant Equipment	(13)	14,327,825	10,348,851	5,841,591	3,210,557	22.41%	1.8
314.00	Turbogenerator Units	(13)	3,916,967	2,797,900	1,628,273	896,130	22.88%	1.8
315.00	Accessory Electrical Equipment	(13)	1,334,432	622,246	885,662	484,612	36.32%	1.8
316.00	Misc. Power Plant Equip.	(13)	424,995	434,602	45,643	25,339	5.96%	1.8
	Total		22,268,009	16,259,089	8,903,762	4,891,888	21.97%	1.8
	NEIL SIMPSON II							
311.00	Structures & Improvements	(5)	15,863,029	5,523,394	11,132,787	365,194	2.30%	30.5
312.01	Boiler Plant Equipment	(5)	76,897,107	26,330,450	54,411,512	1,962,062	2.55%	27.7
314.00	Turbogenerator Units	(5)	41,534,098	11,029,471	32,581,332	1,146,664	2.76%	28.4
315.00	Accessory Electrical Equipment	(5)	8,429,093	2,511,631	6,338,917	205,937	2.44%	30.8
316.00	Misc. Power Plant Equip.	(5)	875,989	165,386	754,403	28,132	3.21%	26.8
	Total		143,599,317	45,560,332	105,218,951	3,707,989	2.58%	28.4
	OSAGE							
311.00	Structures & Improvements	(22)	4,233,378	4,422,755	741,966	406,009	9.59%	1.8
312.01	Boiler Plant Equipment	(22)	7,454,702	7,272,558	1,822,179	1,005,395	13.49%	1.8
314.00	Turbogenerator Units	(22)	4,780,168	4,641,657	1,190,148	656,960	13.74%	1.8
315.00	Accessory Electrical Equipment	(22)	1,054,888	1,198,790	88,173	48,528	4.60%	1.8
316.00	Misc. Power Plant Equip.	(22)	455,951	459,478	96,782	53,529	11.74%	1.8
	Total		17,979,086	17,995,238	3,939,248	2,170,421	12.07%	1.8
	WY GEN 3							
311.00	Structures & Improvements	(5)	6,799,494	417,254	6,722,214	154,038	2.27%	43.6
312.01	Boiler Plant Equipment	(5)	57,567,754	4,343,796	56,102,346	1,402,492	2.44%	40.0
314.00	Turbogenerator Units	(5)	58,398,596	3,202,879	58,115,647	1,452,700	2.49%	40.0
315.00	Accessory Electrical Equipment	(5)	6,737,220	377,879	6,696,202	151,739	2.25%	44.1
316.00	Misc. Power Plant Equip.	(5)	709,080	28,882	715,652	19,855	2.80%	36.0
	Total		130,212,144	8,370,690	128,352,061	3,180,824	2.44%	40.4
	WYODAK							
311.00	Structures & Improvements	(5)	9,164,990	7,214,391	2,408,848	96,421	1.05%	25.0

BLACK HILLS POWER, INC.
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2012

ACCT. (I)	TITLE (II)	NET SALVAGE PERCENT	ORIGINAL COST (III)	BOOK RESERVE	FUTURE ACCRUALS	ANNUAL ACCRUAL AMOUNT (X)	ANNUAL ACCRUAL PERCENT (XI)	COMPOSITE REMAIN LIFE (IX)
312.01	Boiler Plant Equipment	(5)	76,887,888	29,347,729	51,384,554	2,124,531	2.76%	24.2
313.00	Engines and Generators	(5)	341,748	216,828	142,008	5,696	1.67%	24.9
314.00	Turbogenerator Units	(5)	15,192,791	5,557,047	10,395,383	432,110	2.84%	24.1
315.00	Accessory Electrical Equipment	(5)	6,616,783	5,008,048	1,939,574	77,777	1.18%	24.9
316.00	Misc. Power Plant Equip.	(5)	1,007,315	427,522	630,158	27,850	2.76%	22.6
	Total		109,211,515	47,771,565	66,900,525	2,764,385	2.53%	24.2
	Total Steam Production		437,537,714	150,013,497	317,520,546	19,030,554	4.35%	16.7
	Other Production Plant							
	BEN FRENCH CT							
341.00	Structures & Improvements	(5)	22,448	18,574	4,997	322	1.43%	15.5
342.00	Fuel Holders and Accessories	(5)	1,375,822	903,454	541,159	34,011	2.47%	15.9
344.10	Generators	(5)	16,549,367	12,793,447	4,583,388	322,302	1.95%	14.2
345.00	Accessory Electrical Equip.	(5)	672,969	427,262	279,355	25,029	3.72%	11.2
346.00	Misc. Power Plant Equip.	(5)	14,718	12,177	3,277	419	2.85%	7.8
	Total		18,635,323	14,154,914	5,412,176	382,083	2.05%	14.2
	BEN FRENCH DIESEL							
342.00	Fuel Holders and Accessories	(5)	51,864	47,265	7,192	995	1.92%	7.2
344.10	Generators	(5)	828,869	774,635	95,677	14,845	1.79%	6.4
345.00	Accessory Electrical Equip.	(5)	110,823	60,434	55,931	8,398	7.58%	6.7
	Total		991,557	882,334	158,800	24,238	2.44%	6.6
	LANGE CT							
341.00	Structures & Improvements	(5)	324,886	102,053	239,078	7,174	2.21%	33.3
342.00	Fuel Holders and Accessories	(5)	1,722,516	526,052	1,282,590	43,258	2.51%	29.6
344.10	Generators	(5)	26,182,995	9,824,794	17,667,351	593,903	2.27%	29.7
345.00	Accessory Electrical Equip.	(5)	2,095,868	792,608	1,408,054	50,943	2.43%	27.6
346.00	Misc. Power Plant Equip.	(5)	16,612	6,306	11,136	527	3.17%	21.1
	Total		30,342,878	11,251,813	20,608,209	695,805	2.29%	29.6
	NEIL SIMPSON CT							
341.00	Structures & Improvements	(5)	176,359	78,850	106,327	3,405	1.93%	31.2
342.00	Fuel Holders and Accessories	(5)	2,116,073	616,956	1,604,921	56,038	2.65%	28.6
344.10	Generators	(5)	25,644,954	8,133,641	18,793,561	660,704	2.58%	28.4
345.00	Accessory Electrical Equip.	(5)	1,987,600	927,847	1,159,133	45,006	2.26%	25.8
346.00	Misc. Power Plant Equip.	(5)	51,539	24,278	29,838	1,316	2.55%	22.7
	Total		29,976,525	9,781,572	21,693,780	766,469	2.56%	28.3
	Total Other Production Plant		79,946,282	36,070,633	47,872,965	1,868,595	2.34%	25.6

EXHIBIT___(LK-21)

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL-14-026
RATE CASE

REQUEST DATE	:	April 25, 2014
RESPONSE DATE	:	July 7, 2014
REQUESTING PARTY:		Black Hills Industrial Intervenors

BHII Request No. 5: Refer to Statement G, page 3 of 5. Please provide a copy of the source for the 5.79% interest rate assumed on the projected October 1, 2014 debt issuance.

Response to BHII Request No. 5:

The interest cost of 5.79% assumed on Statement G, page 3 of 5 was determined by using an estimate of the 30 year treasury rate plus a spread over the treasury rate applicable to Black Hills Power. These estimates were made just prior to the time the case was filed. On June 30, 2014, Black Hills Power entered into an agreement to issue $85 million of 30 year First Mortgage Bonds with a coupon rate of 4.43. The bond offering will be closed and funded on October 1, 2014.

Attachments: None