APPENDIX

To the Appellee's Brief
32CIV15-146

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	)))))	**JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION** **EL14-026**

Black Hills Power, Inc. and the Staff of the South Dakota Public Utilities Commission, jointly referred to as "Parties," hereby file the above-referenced Joint Motion for Approval of Settlement Stipulation. The Parties request that the South Dakota Public Utilities Commission adopt the attached Settlement Stipulation as the settlement and resolution of all of the issues between these Parties in this proceeding. In support of this Motion, the Parties submit as follows:

1. This Joint Motion is made pursuant to ARSD 20:10:01:19.
2. The Settlement Stipulation resolves all of the issues between these Parties in EL14-026.
3. The terms of the Settlement Stipulation represent a negotiated settlement of all of the issues between these Parties in Docket No. EL14-026.
4. The terms of the Settlement Stipulation agreed upon are just and reasonable and consistent with South Dakota law.

WHEREFORE, for the foregoing reasons, the undersigned Parties jointly request the Commission to: 1) grant the Joint Motion for Approval of Settlement Stipulation, 2) adopt the attached Settlement Stipulation without modification for the purpose of resolving all issues in this proceeding, and 3) enter an Order finding that the attached Settlement Stipulation results in just and reasonable rates for customers of Black Hills Power, Inc.

South Dakota Public Utilities Commission Staff	**Black Hills Power, Inc.**
By: KAREN E. CREMER (Print)	By: Todd Brink (Print)
Karen E. Cremer (Sign)	Todd Brink (Sign)
Title: staff attorney	Title: Sr. Managing Counsel
Date: 12/08/2014	Date: 12/8/2014

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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

It is hereby stipulated and agreed by and among Black Hills Power, Inc. ("Applicant" or "Black Hills Power") and the South Dakota Public Utilities Commission Staff ("Staff") (jointly "Party" or "Parties"), that the following Settlement Stipulation ("Stipulation") may be adopted by the South Dakota Public Utilities Commission ("Commission") in the above-captioned matter. In support of its Application for Authority to Increase Its Electric Rates ("Application"), Applicant does hereby offer this Stipulation, the Application and all supporting materials filed March 31, 2014, and thereafter. The Parties offer no answering testimony or exhibits, conditioned upon the Commission accepting the following Stipulation without any material condition or modification.

I. INTRODUCTION

On March 31, 2014, Black Hills Power filed with the Commission the aforementioned Application through which it requested authority to increase annual revenues by approximately $14.6 million.

On June 6, 2014, GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, and Wharf Resources (U.S.A.), Inc. (collectively "BHII") filed a Petition to Intervene. On the same date, Dakota Rural Action ("DRA") also filed a Petition to Intervene. The Commission issued its Order Granting Intervention to BHII and DRA on June 26, 2014.

On September 4, 2014, Black Hills Power filed a Motion for Approval of Settlement Agreement (SDSTA), requesting the approval of a contract with deviations with the South Dakota Science and Technology Authority ("SDSTA"). On September 18, 2014, the Commission entered an Order deferring until later in the process the approval of the contract with deviations between Black Hills Power and SDSTA. As an alternative to approving the contract with deviations at that time, the Commission conditionally authorized and approved implementation of the contract with deviations rates on an interim basis, commencing on October 1, 2014.

The Parties have been able to resolve all issues between them in this proceeding and have entered into this Stipulation, which, if accepted and ordered by the Commission, will determine the rates to result from Black Hills Power's Application. The Parties recognize that the Commission has granted intervention to BHII and DRA. The Intervenors are not parties to this Stipulation.

II. PURPOSE

This Stipulation has been prepared and executed by the Parties for the sole purpose of resolving the issues between them in Docket No. EL14-026. The Parties acknowledge that they may have differing views that justify the end result, which they deem to be just and reasonable, and, in light of such differences, the Parties agree that the resolution of any single issue, whether express or implied by the Stipulation, should not be viewed as precedent setting. In consideration of the mutual promises hereinafter set forth, the Parties agree as follows:

1) Upon execution of the Stipulation, the Parties shall file this Stipulation with the Commission together with a joint motion requesting that the Commission issue an order approving this Stipulation in its entirety without condition or modification.

2) This Stipulation includes all terms of settlement and is submitted with the condition that in the event the Commission imposes any material changes in or conditions to this Stipulation which are unacceptable to either Party, this Stipulation may, at the option of either Party, be withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding nor be used for any other purpose.

3) This Stipulation shall become binding upon execution by the Parties, provided however, that if this Stipulation does not become effective in accordance with Paragraph 2 above, it shall be null, void, and privileged. This Stipulation is intended to relate only to the specific matters referred to herein; neither Party waives any claim or right which it may otherwise have with respect to any matter not expressly provided for herein; neither Party shall be deemed to have approved, accepted, agreed, or consented to any ratemaking principle, or any method of cost of service determination, or any method of cost allocation underlying the provisions of this Stipulation, or be advantaged or prejudiced or bound thereby in any other current or future rate proceeding before the Commission. Neither Party nor a representative thereof shall directly or indirectly refer to this Stipulation or that part of any order of the Commission

relating to this Stipulation as precedent in any other current or future rate proceeding or any other proceeding before the Commission.

4) The Parties to this proceeding stipulate that all prefiled testimony, exhibits, and workpapers will be made a part of the record in this proceeding. The Parties understand that if this matter had not been settled, Commission Staff would have filed direct testimony and Black Hills Power would have filed rebuttal testimony responding to certain of the positions contained in the testimony of Commission Staff.

5) It is understood that Commission Staff enters into this Stipulation for the benefit of all of Black Hills Power's South Dakota customers affected by this docket.

III. ELEMENTS OF THE SETTLEMENT STIPULATION

1. Revenue Requirement

The Parties agree that the total revenue deficiency is $6,890,746. The Parties agree that Black Hills Power's tariffs will be designed to produce an increase in annual base rate levels of $6,890,746 or approximately 4.35% of total retail revenues at existing rates based on a South Dakota jurisdictional retail revenue requirement of $165,122,614. The Parties agree to a 7.76% rate of return on rate base.

2. Tariffs

The Parties have agreed to revised tariffs and those tariffs are attached as Exhibit 1 to this Stipulation for presentation to the Commission.

The Parties agree that the rate design to be set forth in the revisions to Black Hills Power's tariffs are just and reasonable and provide for the movement of each customer class toward its associated cost of service. The Parties agree that the increase in rates for electric service will be allocated to the affected rate classes resulting in increases as shown on attached Exhibit 2. The Parties agree that the rates agreed to by the Parties result in just and reasonable rates for all of Black Hills Power's South Dakota customers.

The Parties agree that the revised rate schedules shall be implemented for service rendered on and after March 1, 2015, with the bills prorated so that usage prior to October 1, 2014, is billed at the previous rates, and usage on and after October 1, 2014, is billed at the new rates.

3. Interim Rate Refund

Interim rates were implemented on October 1, 2014. Approval of this Stipulation will authorize a rate increase less than the interim rate level in effect. Black Hills Power agrees to refund customers a portion of the interim rates collected during the period October 1, 2014, through the effective date of new rates, plus interest. Attached hereto as Exhibit 3 is the Interim Rate Refund Plan. The form of the Customer Notice is attached hereto as Exhibit 4.

4. Depreciation Expense

The Parties agree that the depreciation lives and rates presented in this rate case will be the ones in effect with the approval of this Stipulation. The depreciable life of the Cheyenne Prairie Generating Station is 40 years with a depreciation rate of 2.98%.

5. Decommissioning Expense

The Parties agree that the total company decommissioning cost of $9,930,958 is included in the Decommissioning amortization identified in the 10th element of the Stipulation below and included in the revenue requirement. This amount includes the cost of decommissioning the Ben French, Neil Simpson I, and Osage coal-fired generation facilities, and does not include any contingency. The Parties agree that Black Hills Power may seek recovery, in a future Black Hills Power rate case, of all costs for decommissioning not otherwise recovered from customers.

6. Rate Case Expense

The Parties agree that a total of $212,861 in rate case expense associated with Docket EL14-026 is included in the Rate Case Expense amortization identified in the 10th element of the Stipulation below and included in the revenue requirement. Actual rate case expenses incurred in excess of this amount will be recoverable in the next Black Hills Power rate case to the extent those expenses are deemed necessary and reasonable.

7. Economic Development

The Parties agree that economic development expenses up to $100,000 shall be equally shared by shareholders ($50,000) and customers ($50,000). The economic development expenses shall include, but not be limited to, all South Dakota labor, expenses, and monetary contributions. This program will begin on October 1, 2014, and shall continue thereafter until revised by the Commission. Black Hills Power will submit, on an annual basis, no later than March 1st of each year beginning in 2015, for Commission approval a filing which describes the cost, design, and benefit of Black Hills Power's economic development programs. Program costs will be reported on a calendar year basis. Any portion of the annual customer contribution that remains unspent at the end of a program year shall be carried over into the next program year for Commission approval of expenditures or refund. No carry over shall occur for amounts spent annually in excess of $100,000. This agreement does not preclude Black Hills Power from spending more on economic development nor does it restrict Black

Hills Power from asking for modification of these economic development terms in its next general rate filing.

8. Cheyenne Prairie Generating Station Compliance Report

Black Hills Power agrees to file an informational report by February 28, 2015, on the remaining Cheyenne Prairie Generating Station capital projects, specifically the auxiliary boiler, testing, site finish work, and internal closeout labor.

9. Major Maintenance Accrual

The Parties agree to define major maintenance for steam plants as the expenses incurred during the period of time when a steam turbine generator is opened for maintenance.

10. Amortization

The Parties agree that amortizations being recovered in rates under the terms of the Stipulation include the following where the cost (SD Amount Amortized) will be deferred and amortized over the periods shown:

Item	SD Amount Amortized ($)	Amortization Period (years)	SD Annual Amount
Rate Case Expense	$625,657	3	$208,552
Decommissioning	$14,685,070	10	$1,468,507
Winter Storm Atlas	$3,157,426	10	$315,743
69 kV LIDAR Surveying	$320,533	5	$64,107

a. Rate Case Expense

The Parties agree that the unamortized actual rate case expenses from Dockets EL12-061 and EL12-062 will be combined with the current actual rate case expenses from Docket EL14-026 and will be deferred, amortized and recovered over three (3) years. The Parties agree that the average unamortized balance of $369,191 will be included as a component of rate base. As a result of the Parties' agreement on the treatment of rate case expenses in this Stipulation, the Commission's approval of the treatment of rate case expenses in Dockets EL12-061 and EL12-062 is superseded upon approval of this Stipulation.

b. Decommissioning

The Parties agree that the net book value, inventory, and decommissioning costs associated with the Ben French, Neil Simpson I, and Osage coal-fired generation facilities will be deferred, amortized and recovered over ten (10) years. The Parties agree that the unamortized balance of $12,482,309 will be included as a component of rate base.

c. Winter Storm Atlas

The Parties agree that the incremental costs associated with Winter Storm Atlas and the South Dakota System Line Inspection will be deferred, amortized, and recovered over ten (10) years. The Parties agree that the unamortized balance of $2,683,812 will be included as a component of rate base.

d. 69 kV LIDAR Surveying Project

The Parties agree that the 69 kV LIDAR surveying costs will be deferred, amortized and recovered over five (5) years. The Parties agree that the unamortized balance of $154,093 will be included as a component of rate base.

11. Pension Expense

The Parties agree that pension expense should be normalized. A five year normalization period was used in this case. The Parties agree this normalization period shall be used in future rate cases over the next five years unless there is an extraordinary event that makes a five-year normalization method unreasonable.

12. Final Approval of Contracts with Deviations

The Parties agree that the contract with deviations, as filed on September 4, 2014, between Black Hills Power and SDSTA that is the subject of the Commission's Order Conditionally Authorizing and Approving Implementation of Contracts with Deviations, should be finally approved by the Commission without condition, and agree to support their final approval without condition.

13. Moratorium

A. The Parties agree that Black Hills Power shall not file any rate application for an increase in base rates which would go into effect prior to October 1, 2016; provided, this restriction would not prevent Black Hills Power from filing for a base rate increase to take effect prior to October 1, 2016, if Black Hills Power's cost of service is expected to increase due to an "Extraordinary Event." The Parties agree that this rate moratorium does not apply to any rider or other adjustment mechanism, including, but not limited to, the Energy Cost Adjustments, Environmental Improvement Adjustment, Transmission Facility Adjustment, Energy Efficiency Solutions Adjustment, and Phase In Plan Rate.

B. As used in this Stipulation "Extraordinary Event" is any one of the following occurrences:

1) *Governmental Impositions* – Changes in federal, state or local governmental requirements or governmental charges including, but not limited to, income taxes, taxes, charges or regulations imposed on energy, emissions, environmental externalities, or reclamation requirements imposed after October 1, 2014, upon Black Hills Power that are projected to cause its South Dakota cost of service to increase by $1,000,000 or greater.

Increases in Black Hills Power's South Dakota cost of service that are less than $1,000,000 will be presumed not to be material for the purposes of this paragraph.

2) *Major Capital Additions* – New capital projects with individual budgets greater than $10,000,000.

3) *Loss of a Major Customer* – Black Hills Power is expected to lose $2,000,000 or more of annual revenue from a single customer's accounts.

4) *Loss of Power Supply* – Black Hills Power loses power available from its power generation or purchase power contracts in an amount of 10 megawatts or more for a period forecasted to be at least six (6) months in duration.

This Stipulation is entered into effective this 8th day of December, 2014.

BLACK HILLS POWER, INC.

By: Kyle White
Kyle White

Its: V.P. of Regulatory Affairs

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF

By: Karen E. Cremer
Karen E. Cremer

Its: Staff Attorney

<u>Exhibits to Settlement Stipulation</u>

Exhibit 1	Tariffs
Exhibit 2	Allocation of Rate Increase
Exhibit 3	Interim Rate Refund Plan
Exhibit 4	Form of Customer Notice

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	))))	**AMENDED SETTLEMENT STIPULATION** **EL14-026**

It is hereby stipulated and agreed by and among Black Hills Power, Inc. ("Applicant" or "Black Hills Power") and the South Dakota Public Utilities Commission Staff ("Staff") (jointly "Party" or "Parties"), that the following Amended Settlement Stipulation ("Amended Stipulation") may be adopted by the South Dakota Public Utilities Commission ("Commission") in the above-captioned matter. In support of its Application for Authority to Increase Its Electric Rates ("Application"), the Parties do hereby offer this Amended Stipulation, the Application and all supporting materials filed March 31, 2014, and thereafter.

I. INTRODUCTION

On March 31, 2014, Black Hills Power filed with the Commission the aforementioned Application through which it requested authority to increase annual revenues by approximately $14.6 million.

On June 6, 2014, GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, and Wharf Resources (U.S.A.), Inc. (collectively "BHII") filed a Petition to Intervene. On the same date, Dakota Rural Action ("DRA") also filed a Petition to Intervene. The Commission issued its Order Granting Intervention to BHII and DRA on June 26, 2014.

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Science and Technology Authority ("SDSTA"). On September 18, 2014, the Commission entered an Order deferring until later in the process the approval of the contract with deviations between Black Hills Power and SDSTA. As an alternative to approving the contract with deviations at that time, the Commission conditionally authorized and approved implementation of the contract with deviations rates on an interim basis, commencing on October 1, 2014.

The Parties have been able to resolve all issues between them in this proceeding and have entered into this Amended Stipulation, which, if accepted and ordered by the Commission, will determine the rates to result from Black Hills Power's Application. The Parties recognize that the Commission has granted intervention to BHII and DRA. The Intervenors are not parties to this Amended Stipulation.

II. PURPOSE

This Amended Stipulation has been prepared and executed by the Parties for the sole purpose of resolving the issues between them in Docket No. EL14-026. The Parties acknowledge that they may have differing views that justify the end result, which they deem to be just and reasonable, and, in light of such differences, the Parties agree that the resolution of any single issue, whether express or implied by the Amended Stipulation, should not be viewed as precedent setting. In consideration of the mutual promises hereinafter set forth, the Parties agree as follows:

1) Upon execution of the Amended Stipulation, the Parties shall file this Amended Stipulation with the Commission together with an amended joint motion requesting that the Commission issue an order approving this Amended Stipulation in its entirety without condition or modification.

2) This Amended Stipulation includes all terms of settlement and is submitted with the condition that in the event the Commission imposes any material changes in or conditions to this Amended Stipulation which are unacceptable to either Party, this Amended Stipulation may, at the option of either Party, be withdrawn and shall not constitute any part of the record in this proceeding or any other proceeding nor be used for any other purpose.

3) This Amended Stipulation shall become binding upon execution by the Parties, provided however, that if this Amended Stipulation does not become effective in accordance with Paragraph 2 above, it shall be null, void, and privileged. This Amended Stipulation is intended to relate only to the specific matters referred to herein; neither Party waives any claim or right which it may otherwise have with respect to any matter not expressly provided for herein; neither Party shall be deemed to have approved, accepted, agreed, or consented to any ratemaking principle, or any method of cost of service determination, or any method of cost allocation underlying the provisions of this Amended Stipulation, or be advantaged or prejudiced or bound thereby in any other current or future rate proceeding before the Commission. Neither Party nor a representative thereof shall directly or indirectly refer to this Amended Stipulation or that part of any order of the Commission relating to this Amended Stipulation as precedent in any other current or future rate proceeding or any other proceeding before the Commission.

4) The Parties to this proceeding stipulate that all prefiled testimony, testimony given at the hearing, exhibits, and workpapers will be made a part of the record

in this proceeding. The Parties understand that if this matter had not been settled, Commission Staff would have filed further direct testimony and Black Hills Power would have filed rebuttal testimony responding to certain positions contained in the direct testimony of Commission Staff.

5) It is understood that Commission Staff enters into this Amended Stipulation for the benefit of all of Black Hills Power's South Dakota customers affected by this docket.

III. ELEMENTS OF THE AMENDED SETTLEMENT STIPULATION

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2. Tariffs

The Parties agreed to revised tariffs and those tariffs are attached as Exhibit 1 to the original Stipulation, filed December 9, 2014, for presentation to the Commission. The Parties agree to file compliance tariffs with the Commission approved effective date.

The Parties agree that the rate design to be set forth in the revisions to Black Hills Power's tariffs are just and reasonable and provide for the movement of each customer class toward its associated cost of service. The Parties agree that the increase in rates for electric service will be allocated to the affected rate classes resulting in increases as shown in Exhibit 2, attached to the original Stipulation filed on December 9, 2014. The Parties agree that the rates agreed to by the Parties result in just and reasonable rates for all of Black Hills Power's South Dakota customers.

The Parties agree that the revised rate schedules shall be implemented for service rendered on and after the Commission approved effective date, with the bills prorated so that usage prior to October 1, 2014, is billed at the previous rates, and usage on and after October 1, 2014, is billed at the new rates.

3. Interim Rate Refund

Interim rates were implemented on October 1, 2014. Approval of this Amended Stipulation will authorize a rate increase less than the interim rate level in effect. Black Hills Power agrees to refund customers a portion of the interim rates collected during the period October 1, 2014, through the effective date of new rates, plus interest. The Parties agree to file revisions to the Interim Rate Refund Plan and the Customer Notice, attached as Exhibits 3 and 4 to the original Stipulation, filed December 9, 2014, to reflect the Commission's final decision.

4. Depreciation Expense

The Parties agree that the depreciation lives and rates presented in this rate case will be the ones in effect with the approval of this Amended Stipulation. The depreciable life of the Cheyenne Prairie Generating Station is 40 years with a depreciation rate of 2.98%.

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7. Economic Development

The Parties agree that economic development expenses up to $100,000 shall be equally shared by shareholders ($50,000) and customers ($50,000). The economic development expenses shall include, but not be limited to, all South Dakota labor, expenses, and monetary contributions. This program will begin on October 1, 2014, and shall continue thereafter until revised by the Commission. Black Hills Power will submit, on an annual basis, no later than April 1st, 2015, and March 1st of each year beginning in 2016, for Commission approval a filing which describes the cost, design, and benefit of Black Hills Power's economic development programs. Program costs will be reported on a calendar year basis. Any portion of the annual customer contribution that remains unspent at the end of a program year shall be carried over into the next program year for Commission approval of expenditures or refund. No carry over shall occur for amounts spent annually in excess of $100,000. This agreement does not preclude Black Hills Power from spending more on economic development nor does it restrict Black Hills Power from asking for modification of these economic development terms in its next general rate filing.

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Black Hills Power agrees to file an informational report by April 1, 2015, on the remaining Cheyenne Prairie Generating Station capital projects, specifically the auxiliary boiler, testing, site finish work, and internal closeout labor.

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The Parties agree to define major maintenance for steam plants as the expenses incurred during the period of time when a steam turbine generator is opened for maintenance.

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Item	SD Amount Amortized ($)	Amortization Period (years)	SD Annual Amount
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a. Rate Case Expense

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b. Decommissioning

The Parties agree that the net book value, inventory, and decommissioning costs associated with the Ben French, Neil Simpson I, and Osage coal-fired generation facilities will be deferred, amortized and recovered over ten (10) years. The Parties agree that the unamortized balance of $12,482,309 will be included as a component of rate base.

c. Winter Storm Atlas

The Parties agree that the incremental costs associated with Winter Storm Atlas and the South Dakota System Line Inspection will be deferred, amortized, and recovered over ten (10) years. The Parties agree that the unamortized balance of $2,683,812 will be included as a component of rate base.

d. 69 kV LIDAR Surveying Project

The Parties agree that the 69 kV LIDAR surveying costs will be deferred, amortized and recovered over five (5) years. The Parties agree that the unamortized balance of $154,093 will be included as a component of rate base.

11. Pension Expense

The Parties agree that pension expense should be normalized. A five year normalization period was used in this case. The Parties agree this normalization period shall be used in future rate cases over the next five years unless there is an extraordinary event that makes a five-year normalization method unreasonable.

12. Final Approval of Contracts with Deviations

The Parties agree that the contract with deviations, as filed on September 4, 2014, between Black Hills Power and SDSTA that is the subject of the Commission's Order Conditionally Authorizing and Approving Implementation of Contracts with Deviations, should be finally approved by the Commission without condition, and agree to support their final approval without condition.

13. Moratorium

A. The Parties agree that Black Hills Power shall not file any rate application for an increase in base rates which would go into effect prior to January 1, 2017; provided, this restriction would not prevent Black Hills Power from filing for a base rate increase to take effect prior to January 1, 2017, if Black Hills Power's cost of service is expected to increase due to an "Extraordinary Event." The Parties agree that this rate moratorium does not apply to any rider or other adjustment mechanism, including, but not limited to, the Energy Cost Adjustments, Environmental Improvement Adjustment, Transmission Facility Adjustment, Energy Efficiency Solutions Adjustment, and Phase In Plan Rate.

B. As used in this Amended Stipulation "Extraordinary Event" is any one of the following occurrences:

1) *Governmental Impositions* – Changes in federal, state or local governmental requirements or governmental charges including, but not limited to, income taxes, taxes, charges or regulations imposed on energy, emissions, environmental externalities, or reclamation requirements imposed after October 1, 2014, upon Black Hills Power that are projected to cause its South Dakota cost of service to increase by $1,000,000 or greater.

Increases in Black Hills Power's South Dakota cost of service that are less than $1,000,000 will be presumed not to be material for the purposes of this paragraph.

2) *Major Capital Additions* – New capital projects with individual budgets greater than $10,000,000.

3) *Loss of a Major Customer* – Black Hills Power is expected to lose $2,000,000 or more of annual revenue from a single customer's accounts.

4) *Loss of Power Supply* – Black Hills Power loses power available from its power generation or purchase power contracts in an amount of 10 megawatts or more for a period forecasted to be at least six (6) months in duration.

This Amended Stipulation is entered into effective this 10th day of February, 2015.

BLACK HILLS POWER, INC.

By: Kyle White jt
Kyle White

Its: V.P. Regulatory Affairs

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION STAFF

By: Karen E. Cremer
Karen E. Cremer

Its: Staff Attorney

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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

STAFF MEMORANDUM SUPPORTING
AMENDED SETTLEMENT STIPULATION

DOCKET EL14-026

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

BACKGROUND

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

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

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

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

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

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

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

OVERVIEW OF AMENDED SETTLEMENT

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

Utility Holdings Allocation Oversight Correction

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

Wyodak Operations and Maintenance Adjustment

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

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

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

No Change to Revenue Deficiency

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

Additional Moratorium

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

RECOMMENDATION

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

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

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

DOCKET NO. EL14-026

TESTIMONY OF DAVID E. PETERSON

ON BEHALF OF THE COMMISSION STAFF

JANUARY 15, 2015

EXHIBIT
STAFF 1

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I. INTRODUCTION

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

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

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

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

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

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

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

A. Yes. I have presented testimony in 146 other proceedings before the state regulatory commissions in Alabama, Arkansas, California, Colorado, Connecticut, Delaware, Indiana, Kansas, Maine, Maryland, Montana, Nevada, New Jersey, New Mexico, New York, Pennsylvania, South Dakota, West Virginia, and Wyoming, and before the Federal Energy Regulatory Commission. Collectively, my testimonies have addressed the following topics: the appropriate test year, rate base, revenues, expenses, depreciation, taxes, capital structure, capital costs, rate of return, cost allocation, rate design, life-cycle analyses, affiliate transactions, mergers, acquisitions, and cost-tracking procedures.

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

II. SUMMARY

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

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

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

A. Yes, I have. I testified in a number of electric and natural gas distribution rate proceedings when I was on the Commission Staff during the period 1977 through 1980. More recently, I have assisted the Commission Staff in several rate proceedings, including those involving Black Hills Power, Inc. ("BHP" or "the Company"), wherein the issues were resolved by settlements. However, I filed testimony on behalf of the Commission Staff in Docket No. EL12-046 involving a rate increase request filed by Northern States Power Company and in Docket No. NG12-008 involving a rate increase request filed by Montana-Dakota Utilities Co.

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

A. I was asked to present the Commission Staff's support for the Settlement Stipulation reached by the Commission Staff and BHP. The Settlement Stipulation is intended to resolve all of the issues in this proceeding. My testimony also addresses certain issues raised in the testimonies presented by witnesses for the Black Hills Industrial Intervenors[1] ("BHII").

[1] Members of the Black Hills Industrial Intervenors include 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.

Q. BEFORE YOU BEGIN DISCUSSING THE SETTLEMENT STIPULATION AND BHII'S ISSUES, PLEASE PROVIDE A BRIEF SUMMARY OF BHP'S RATE REQUEST IN THIS PROCEEDING.

A. BHP currently provides electric service to approximately 65,500 customers within Rapid City and other western South Dakota communities under rates approved by the South Dakota Public Utilities Commission ("the Commission"). BHP is a wholly-owned subsidiary of Black Hills Corporation ("BHC"). BHC also owns other regulated natural gas and electric utility companies operating in Colorado, Iowa, Kansas, Montana, Nebraska and Wyoming. BHC also owns non-regulated companies that generate wholesale electricity, that produce natural gas and crude oil and that mine coal.

BHP's base (i.e., non-fuel) electric rates that were in effect at the time that the Company initiated the instant proceeding were those that were approved by the Commission at the conclusion of BHP's last base rate proceeding in Docket No. EL12-061. BHP's 2012 rate proceeding was filed using an adjusted test year ended June 30, 2012. BHP had initially requested a $13.745 million annual revenue increase in that case. However, the Commission approved a settlement agreement that authorized BHP to increase annual revenues by approximately $8.831 million, effective October 1, 2013.

On March 31, 2014, BHP filed an application with the Commission seeking to increase base electric rates by approximately $14.634 million, or 9.27 percent, to be effective October 1, 2014. This effective date was chosen by the Company to coincide with the expected in-service date of the Cheyenne Prairie Generating Station ("CPGS"). BHP is a co-owner of the CPGS. BHP's current rate request was calculated from a Company-prepared revenue requirement study that relied on a test year ended September 30, 2013. On October 1, 2014, BHP placed its proposed rates into effect on an interim basis. BHP's interim rates will remain in effect until the conclusion of this proceeding.

III. SETTLEMENT STIPULATION

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

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

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

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

November and into the beginning of December. Ultimately, the Commission Staff and BHP reached a negotiated settlement that is intended to resolve all of the issues arising in this proceeding. A Settlement Stipulation, signed on December 8, 2014, by representatives of the Commission Staff and BHP, memorializes the terms of the settlement. BHII and DRA chose not to join the settlement. Concurrent with the filing of my testimony, the Commission Staff is also filing a Staff Memorandum Supporting Settlement Stipulation ("Staff Memorandum"). The Staff Memorandum carefully summarizes all of the Commission Staff's adjustments that are factored into the agreed-upon settlement revenue increase.

Q. WOULD IT BE FAIR TO CHARACTERIZE THE AGREEMENT REACHED BETWEEN BHP AND THE COMMISSION STAFF AS A "BLACK BOX" SETTLEMENT?

A. No. Any such characterization of the settlement would be wrong. A black box settlement typically is one where the specific resolution of issues cannot be identified. This is not what occurred in this proceeding, however. Rather, the Commission Staff prepared a detailed calculation of BHP's test year rate base, revenues and expenses, including known and measurable post-test year changes. The Commission Staff revenue requirement determination identified differences that it had with certain rate base, revenue and expense claims made by the Company and issues raised by the Commission Staff that were not mentioned in the Company's filing. The Commission Staff also carefully considered the issues and adjustments proposed by BHII in confidential settlement discussions. The end result of the Commission Staff's analyses is the Staff Memorandum, and the supporting schedules, which detail how the Commission Staff arrived at and can justify the $6,890,746 revenue deficiency reflected in the Settlement Stipulation. That document stands on its own and there is no need for me to explain in my testimony each Commission Staff adjustment. The points that I am trying to make in this discussion, however, are that the Commission Staff carefully considered all of the issues raised in this proceeding by BHP and the BHII and that the Staff Memorandum provides the Commission and the other parties a transparent roadmap showing how the Commission Staff determined that the agreed-upon annual revenue increase, $6,890,746, is consistent with South Dakota Law, prior Commission practices, and sound ratemaking principles and results in just and reasonable rates. It is for these reasons that I recommend the Commission approve the Settlement Stipulation and the terms contained therein.

In the following sections of my testimony I address certain claims made by witnesses for the BHII, who did not join in the Settlement Stipulation.

IV. BHII'S REVENUE REQUIREMENT TESTIMONY

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF LANE KOLLEN ON BEHALF OF THE BHII?

A. Yes, I have.

Q. WERE YOU AWARE OF THE ISSUES RAISED BY MR. KOLLEN PRIOR TO SEEING HIS TESTIMONY?

A. Generally, yes. I was not aware of the specific details of each adjustment that Mr. Kollen recommends prior to him filing testimony, but substantially all of the issues he raises were identified and discussed in settlement discussions held earlier in this proceeding and were considered by the Commission Staff.

Q. BEGINNING AT PAGE 7 OF HIS DIRECT TESTIMONY, MR. KOLLEN DISCUSSES GENERAL RATEMAKING PRINCIPLES WHICH HE

ACKNOWLEGES FORM THE BASIS FOR MANY OF HIS RECOMMENDED ADJUSTMENTS. PLEASE COMMENT ON THE GENERAL RATEMAKING PRINCIPLES THAT HE DISCUSSES.

A. Mr. Kollen identifies and recommends the following three principles:

1. The Commission should limit any post-test year adjustment to the twelve-month period immediately following the historical test year ended September 30, 2013.

2. The Commission should reject proposed post-test year increases in various expenses that are not justified and that the Company did not demonstrate were necessary and appropriate.

3. The Commission should 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.

Initially, while I am unable to discern a difference between Mr. Kollen's second and third principles, I can find no fault in either principle. In fact, I believe that the Commission Staff's revenue requirement, as described in detail in the Staff Memorandum, is faithful to both principles.

Ironically, Mr. Kollen's first principle is inconsistent with his third. It is my understanding that the Commission's long-standing policy has been to consider post-test year adjustments up to twenty-four months, not twelve months, beyond the end of the test year provided they are known with reasonable certainty and measureable with reasonable accuracy. Indeed such a treatment is, in effect, mandated to the Commission by South Dakota Administrative Rule 20:10:13:44. In addition to ignoring the twenty-four month look-out provision, Mr. Kollen apparently interprets this administrative rule to require that any costs that are beyond twelve months post-test year must be accompanied by projected changes in revenue for the same period. This is not how the Commission and the

Commission Staff have interpreted this rule, however. Rather, it is my understanding that both the Commission Staff and the Commission have previously interpreted this rule to mean that for any post-test year change in expense or investment that has an incremental revenue component (i.e., expenses or investments made to increase sales and/or to serve new customers) a corresponding revenue adjustment must also be recognized. It is for this reason that the Settlement Stipulation does not include any costs associated with post-test year plant additions that are designed to improve sales or to serve new customers. Similarly, there is no corresponding revenue offset for any of the post-test year expense adjustments that are reflected in the Settlement Stipulation. Therefore, the Settlement Stipulation is consistent with prior Commission policy in this regard and with the governing administrative rule. By the same token, the adjustments recommended by Mr. Kollen that do not reflect this principle as I have described it are inconsistent with long-standing Commission policy.

Q. CONCERNING THE ADJUSTMENTS THAT MR. KOLLEN RECOMMENDS, ARE ANY OF THAT ARE ALREADY REFLECTED IN THE SETTLEMENT STIPULATION?

A. Yes. Many of Mr. Kollen's recommended adjustments already are addressed in the manner described in the Staff Memorandum and are part of the agreed-upon revenue requirement by the Commission Staff and BHP. These adjustments include the following:

1. Double-count of CPGS spare parts inventory (eliminated in settlement);
2. Decommissioning regulatory asset (contingency allowance in original cost estimate has been removed by settlement);
3. Decommissioning regulatory asset (ten-year amortization reflected in settlement).

4. Storm Atlas regulatory asset deferred income taxes (corrected in settlement);
5. Retired steam plants amortization (ten-year amortization period reflected in settlement);
6. Storm Atlas regulatory asset amortization (ten-year amortization period reflected in settlement);
7. CPGS depreciation (depreciation rate reflects 40-year life span);
8. FutureTrack Workforce Program (all costs were excluded in settlement and no deferrals will be made. Rather, only the cost of employees actually hired to date are reflected in settlement); and
9. Employee additions (only the cost of employees actually hired to date are reflected in the settlement).

Q. MR. KOLLEN TESTIFIES THAT IT IS IMPROPER TO INCLUDE THE NET OPERATING LOSS ("NOL") ASSET IN RATE BASE. DO YOU AGREE?

A. No, I do not. As explained in the Staff Memorandum, over the past several years, "bonus" depreciation previously authorized by Congress significantly increased BHP's annual tax deductions. The sum of BHP's tax deduction, including the new bonus depreciation deductions, however, exceeded its taxable revenues, which resulted in an NOL for tax purposes. Because of the tax loss position, BHP was not able to utilize all of its allowable tax deductions in the year they were earned. Consistent with accounting requirements, it had recorded deferred taxes relating to these tax deductions, nevertheless. The corresponding accumulated deferred tax liability is used as an offset or reduction to BHP's rate base. Without an adjustment, BHP's rate base would be reduced (via the deferred tax liability offset) by more than the tax benefit that the Company has realized to date because of the unused tax deductions. Therefore, it is necessary to adjust BHP's rate base to reflect the unused tax deductions. The specific adjustment reflected in BHP's rate base is a deferred tax asset, to which Mr. Kollen objects. Failure to provide for the deferred tax asset in rate base, as Mr. Kollen recommends, however, risks a violation of the IRS's normalization requirements.

The U.S. Tax Code Section 168 (i) (9) concerning the Accelerated Cost Recovery System that is now being used by BHP and other utilities to determine depreciation-related tax deductions provides as follows:

(9) Normalization rules

(A) In general

In order to use a normalization method of accounting with respect to any public utility property for purposes of subsection (f)(2)—

(i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes; and

(ii) if the amount allowable as a deduction under this section with respect to such property (respecting all elections made by the taxpayer under this section) differs from the amount that would be allowable as a deduction under section 167 using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

(B) Use of inconsistent estimates and projections, etc.

(i) In general: One way in which the requirements of subparagraph (A) are not met is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with the requirements of subparagraph (A).

(ii) Use of inconsistent estimates and projections: The procedures and adjustments which are to be treated as inconsistent for purposes of clause (i) shall include any procedure or adjustment for ratemaking purposes which uses an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under subparagraph (A)(ii) unless such estimate or projection is also used, for ratemaking purposes, with respect to the other 2 such items and with respect to the rate base.

In this instance, a violation identified in paragraph (B) (ii) above could result if Mr. Kollen's recommendation were to be adopted by the Commission because BHP's resulting reserve for deferred taxes for ratemaking purposes (i.e., excluding the deferred tax asset) would not match the tax benefits of the depreciation-related tax deductions that BHP has received to date because a portion of those benefits are yet unrealized due to the existence of the NOL.

Violating the IRS normalization requirements could result in the disallowance of BHP's accelerated tax depreciation deductions which will have an extremely adverse impact on South Dakota ratepayers, including members of the BHII.

Moreover, the treatment of BHP's NOL reflected in the Settlement Stipulation is the same as that approved by the Commission in BHP's last base rate case and in the base rate cases for other South Dakota utilities. For these reasons, I recommend the Commission reject Mr. Kollen's NOL rate base adjustment.

Q. WHAT WAS BHP INITIALLY REQUESTING CONCERNING ITS DECOMMISSIONING ASSETS ASSOCIATED WITH THE RETIREMENT OF THE NEIL SIMPSON I, BEN FRENCH, AND OSAGE COAL-FIRED GENERATING UNITS?

A. BHP initially proposed to amortize estimated costs, including contingency allowances, associated with the retirement and decommissioning of these three generating stations over <u>five</u> years and to include the unamortized balance in rate base.

Q. HOW IS THIS ISSUE TREATED IN THE SETTLEMENT?

A. The settlement removes all contingency allowances that had been included in BHP's cost estimates. It also provides for a ten-year amortization period and includes the average unamortized balance over the first three years in rate base.

Q. WHAT DOES MR. KOLLEN RECOMMEND ON THIS ISSUE?

A. Mr. Kollen objects to any rate recognition for this issue at this time. Instead, he recommends the Commission authorize BHP to defer the decommissioning costs as regulatory assets and to address recovery of the assets in the Company's next base rate case. In support of his recommendation, Mr. Kollen objects to the contingency allowance contained in BHP's cost estimate and to BHP's proposed five-year amortization period. Both of these concerns are addressed in the settlement, however. Mr. Kollen also objects to current rate recovery because he believes the decommissioning costs (1) are not known with reasonable certainty and measurable with reasonable accuracy, (2) will be incurred more than twelve months beyond the end of the test year, and (3) are not accompanied by revenue adjustments. I already discussed my issue with Mr. Kollen's interpretation of the administrative rule governing post-test year adjustments. ARSD 20:10:13:44 permits the Commission to look out twenty-four months beyond the end of the test year to recognize known and measurable revenue and cost changes; and not just the twelve months that Mr. Kollen advocates. Also, there is no revenue producing aspect to retiring the three coal-fired units. Thus, there is no merit to Mr. Kollen's second and third arguments. As for his first argument, that the decommissioning costs are not known with reasonable certainty and measurable with reasonable accuracy, again, there is no merit to Mr. Kollen's claim. The Commission Staff was comfortable with recognizing BHP's cost claims, excluding the contingency allowances, as a known change because approximately 70 percent of the estimated costs are capped by a fixed price contract for decommissioning activities. Since a majority of the costs are determined by a fixed price contract, I believe that this reasonably qualifies the adjustment as known and measurable. As for Mr. Kollen's recommendation to defer BHP's decommissioning costs until the next rate proceeding, by following that path, it is likely that BHP would not have agreed to the stay-out moratorium provision in the Settlement Stipulation. Deferring decommissioning costs also comes with a price. Unamortized decommissioning costs are included in rate base and earn a return such that future ratepayers will pay more the longer recovery is delayed. For these reasons, I support the treatment reflected in the Settlement Stipulation relating to BHP's decommissioning costs.

Q. MR. KOLLEN ALSO OBJECTS TO BHP'S PROPOSED TREATMENT OF THE 69 KV LIGHT DETECTION AND RANGING ("LIDAR") SURVEYING COSTS. HOW IS THIS ISSUE TREATED IN THE SETTLEMENT?

A. The settlement provides for an amortization of BHP's costs associated with this project over a five-year period.

Q. WHAT ARE MR. KOLLEN'S OBJECTIONS TO RECOGNIZING THESE COSTS?

A. Mr. Kollen objects to recognizing these costs in rates because they were not incurred within twelve months following the end of the test year. Moreover, to the extent that the costs are to be amortized, Mr. Kollen recommends a ten-year amortization rather than five years as provided for in the settlement.

Q. WHAT IS YOUR RESPONSE TO MR. KOLLEN'S CONCERNS?

A. BHP expected to have incurred its LIDAR surveying costs by the end of the third quarter in 2014. This is well within the twenty-four month period the

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

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

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

Q. HOW IS THIS ISSUE TREATED IN THE SETTLEMENT?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. WHY IS THAT IMPORTANT?

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

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

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

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

V. BHII'S COST ALLOCATION TESTIMONY

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF STEPHEN J. BARON ON BEHALF OF THE BHII CONCERNING CLASS COST ALLOCATION?

A. Yes, I have. In his testimony, Mr. Baron identified what he believes are several errors in BHP's class cost of service study ("CCOSS"). Based on his analyses, Mr. Baron recommended the Commission reject the Company's CCOSS. In spite of Mr. Baron's concerns with BHP's CCOSS, he nevertheless recommended the Commission approve the apportionment of the overall approved revenue increase to the rate classes as reflected in the Settlement Stipulation. Mr. Baron also recommended the Commission require BHP to file in its next base rate case a CCOSS reflecting the changes that he recommended in this case.

Q. BEFORE YOU DISCUSS MR. BARON'S RECOMMENDED CHANGES TO BHP'S CCOSS, DO YOU HAVE ANY INITIAL COMMENTS ON HIS TESTIMONY AND RECOMMENDATIONS?

A. Yes. Because the BHII accepts the apportionment of the overall approved revenue increase reflected in the Settlement Stipulation, there are no remaining issues to be decided by the Commission regarding the spread of the rate change among the rate classes. This is true irrespective of the issues that Mr. Baron raises with the CCOSS. In fact, Mr. Baron's testimony is unnecessary since the Company's CCOSS is not being adopted in the Settlement Stipulation and neither the Commission Staff nor BHP is asking the Commission to accept the Company's CCOSS. Only the spread of the revenue change among the rate classes is being resolved by the Settlement Stipulation and through Mr. Baron's testimony the BHII is accepting the settlement resolution concerning the spread of the revenue change. Under the Settlement Stipulation, BHP, the Commission Staff and the BHII are free to advocate whatever they choose concerning the CCOSS in BHP's next base rate proceeding. Therefore, it is not necessary for the Commission to rule on any CCOSS issue in this proceeding; nor is it necessary for the Commission to direct BHP to file a CCOSS in any particular manner in the next case. All parties' rights are preserved in the Settlement Stipulation to advocate different CCOSS allocation procedures in BHP's next base rate case, should they so choose.

Q. MR. BARON RECOMMENDED SEVERAL CHANGES TO BHP'S CCOSS. WHICH AMONG HIS RECOMMENDED CHANGES IS THE MOST SIGNIFICANT IN TERMS OF IMPACT ON CLASS RATES OF RETURN?

A. By far, the recommended change that has the most impact on class rates of return relative to those shown in BHP's CCOSS is the minimum distribution system ("MDS") approach. The impact is illustrated in the table below.

Table 2
Class Cost of Service Study Analysis
Comparison of Class Rates of Return

Rate Class	Column 1 BHC Results	Column 2 BHC with MDS	Column 3 BHII Adjustments
Residential	5.11%	4.47%	4.23%
General Service	9.85%	10.33%	9.98%
Combined GS Lg – Ind Contract	5.70%	6.50%	7.26%
Lighting	12.14%	12.19%	12.37%
Water pumping/irrigation	7.78%	9.10%	9.39%
Total SD retail	6.73%	6.73%	6.73%

Sources:
Columns 1,3: Baron Direct, page 26
Column 2: BHII's response to Staff DR-4

Column 1 on the table above presents class rates of return under BHP's CCOSS at existing base rates. Column 2 shows the resulting class rates of return if only the MDS change that Mr. Baron advocates is incorporated into BHP's CCOSS. Column 3 shows class rates of return if all of Mr. Baron's recommendations are adopted. Notice that the change in class rates of return between Columns 2 and 3 is not as significant as the change between Columns 1 and 2. The relative changes between the columns demonstrate the significance of the MDS approach to Mr. Baron's recommended results.

Q. WHAT IS THE MDS?

A. The MDS postulates that there are certain types of facilities that must be installed by the utility to provide customers access to the utility's electrical service, regardless of customer usage requirements. The MDS then classifies the cost of the minimum (or zero) size of these facilities as customer-related. For example, the MDS calculation relied on by Mr. Baron attempts to estimate the cost of a wooden pole that is essentially zero feet tall and then re-price the actual cost of all of the wooden poles presently in service to reflect the cost of the minimum size pole (zero feet). Using statistical techniques, the MDS study estimated that a wooden pole with zero height would cost $44.33. This amount was multiplied by the total number of wooden pole to determine the total cost of the minimum size system. The re-priced minimum size pole inventory divided by the total investment in poles produces the ratio or percentage of the Company's pole investment that Mr. Baron then classified as customer-related. The remainder of the pole investment was classified as a demand-related cost. A similar procedure was used to re-price BHP investments in underground conduit and conductors, overhead conductors, and line transformers.

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

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

Those who support classifying distribution facilities (other than services and meters) on a customer basis do so based on an assertion that some minimum investment is necessary to make electrical service available for each customer, regardless of the customer's peak or annual service requirements. Proponents then argue that this "customer-related" investment should be defined as either: a) the hypothetical cost of the current distribution system revalued using the cost of minimum-sized distribution facilities presently installed on the system (the MDS approach) or; b) the hypothetical cost of distribution plant having no load carrying capability (the so-called "zero-intercept" approach being advocated by Mr. Baron).

The minimum size distribution equipment that a utility will actually install, however, is based on expected customer loads and existing customer densities, not on the number of customers served by the utility or minimum service requirements. As for the zero-intercept approach, no utility installs distribution equipment incapable of carrying loads. Rather, the facilities that BHP installs are sized, designed, operated and maintained in order to meet the individual customers' peak and annual service and safety requirements. Neither the MDS nor the zero-intercept variant of the MDS gives appropriate consideration to actual system design, construction and operation. The MDS fails to reflect cost-causation and, therefore, is not a proper cost allocation method.

Q. APART FROM YOUR CONCEPTUAL ISSUES WITH THE ZERO-INTERCEPT APPROACH TO THE MDS THAT MR. BARON ADVOCATES, DO YOU HAVE ANY CONCERNS ABOUT THE MDS STUDY AND THE ZERO-INTERCEPT CALCULATIONS UPON WHICH MR. BARON RELIES?

A. Yes, I do. The concerns that I discuss below only begin to scratch the surface of the problems with the MDS calculations that may lie underneath. But, they are sufficient enough for the Commission to challenge and to reject Mr. Baron's blind reliance on the results of the MDS study.

Initially, it should be noted that neither Mr. Baron nor any one in his firm participated in preparing the MDS study upon which he relies. Nor does Mr. Baron have any knowledge of BHP's specific distribution design criteria.[5] Rather, Mr. Baron relies on a ten-year old study that BHP Colorado's former owner, Aquila, Inc., prepared for a 2004 rate case in Colorado. Mr. Baron never attempts to prove that the conditions in Colorado are similar to those in BHP's South Dakota service territory. Nor does Mr. Baron demonstrate the MDS study is equally valid today with the passage of so much time. The only support that Mr. Baron seems to offer for his use of Aquila's ten-year old MDS study is pointing to the fact that BHP itself used the same study in this case to develop the primary/secondary distribution facility split in its CCOSS.

Q. IS THAT A SUFFICIENT REASON FOR USING AQUILA'S 2004 MDS STUDY IN COLORADO IN THIS 2014 BHP SOUTH DAKOTA CASE?

A. No, it is not. While BHP used the same study to split the primary and secondary distribution facilities in its CCOSS, neither the MDS study nor BHP's CCOSS

[5] See BHII's response to Staff Data Request No. 7.

study and results are being adopted in this case. Mr. Baron's reliance on BHP using the same MDS study for a different purpose, therefore, is misplaced. Moreover, Mr. Baron does not have an independent basis for using that MDS study in this proceeding since it was not designed for nor does it attempt to explain the design and cost components of BHP's South Dakota service territory.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE MDS STUDY?

A. Yes. The statistics supporting the study are suspect as well. The author of the study back in 2004 used three modeled regression forms (i.e., linear, exponential, and polynomial) for each of Aquila's four distribution plant accounts that were studied. The author then chose the "best" regression form among the three. But, the only statistical parameter that he used to choose among the three modeled regression forms was R-squared. While the study employed the R-squared statistic in a consistent fashion throughout the study (i.e., always choosing the equation with the highest R-squared), in many cases the R-squared statistic was so high, and so close to the other R-squared statistics for the other regression forms, as to call into question whether meaningful statistical inferences could be obtained on the basis of R-squared alone. For example, for Account 365, Overhead Conductors, the linear model had an R-squared of 0.9984, and the polynomial model had an R-squared of 0.9994. But the intercepts (i.e., the MDS point) were quite different; the linear model had an intercept of $0.5905, and the polynomial model had an intercept that was nearly 60 percent greater at $0.9376. While the R-squared of the polynomial model was slightly higher than that of the linear model, it is possible that the difference in intercepts is not statistically significant. But we have no way of determining whether that is the case because the more relevant statistical parameters – the standard deviation of the intercepts or T-statistics – are not provided in the MDS study. This highlights a common fallacy in the use of regression models; that R-squared is a sufficient parameter for making statistical inferences. It is not. It is possible that the R-squared is low, but the regression coefficients are still statistically significant based on the standard deviations. The opposite also can be true, especially with respect to intercepts; the R-squared can be high and the intercept still not be significantly different than zero.

There is yet further indication of problems with Aquila's MDS study. Take Account 365 – Wood Poles, for example. Each of Aquila's R-squared values for this account are high, ranging between 0.9451 and 0.9981. The intercepts vary from -\$569.89 (linear model) to +\$801.43 (polynomial model). But is the intercept not statistically different from zero? We cannot answer that question because the relevant statistical parameters to evaluate this are not included in the MDS study.

The Wood Pole regression analysis points out yet another problem with this type of analysis. If you look at the graph provided in the MDS study for Wood Poles, there are no data points below a pole height of 30 feet. That is of course because pole heights of say five feet are unheard of. But the regression model assumes that such a thing really exists. The issue here is that of extrapolating out of the observed range. The NARUC Electric Cost Allocation Manual referenced by Mr. Baron in support of the MDS approach recognizes this shortcoming in the MDS approach.[6] Statistically, extrapolating out of an observed range is always questionable, and standard deviations are absolutely essential to make any kind of a meaningful inference about estimates outside the range of observations. But, this is precisely what the MDS approach requires; hypothesizing about costs that never have been, or ever will be, observed in the real world because real world

[6] See Baron Exhibit ___(SJB-3), page 13 of 17.

electrical distribution engineers do not design for minimum or zero-load conditions.

It is my understanding that the Commission has never before adopted the MDS approach for any utility in South Dakota. I am loathe to recommend the Commission adopt such a significant change in its long-standing practice based on a ten-year old study prepared by another utility in another state where the analyses are incomplete. Moreover, the author of the original study upon which Mr. Baron relies is not even a participant in this proceeding. Thus, it is not possible for the Commission Staff to ask questions about the study. In sum, the MDS study relied on by Mr. Baron raises more questions than it answers and should not be deemed reliable by the Commission for rate setting purposes.

Q. MR. BARON ALSO RAISES AN ISSUE CONCERNING ENERGY LOSS FACTORS NOT BEING REFLECTED IN BHP'S CURRENT ENERGY COST ADJUSTMENT ("ECA") FACTOR. DO YOU HAVE ANY COMMENT ON THIS?

A. I am not aware if the Commission Staff has taken a position on loss factors in connection with the ECA. Regardless, however, to the extent that the BHII feels it has a legitimate concern with this issue, it is being raised in the wrong forum. Mr. Baron acknowledges that ECA revenues and expenses are excluded in BHP's base rates. Therefore, if the BHII wishes to pursue this issue it should do so in connection with a review of BHP's ECA.

VI. CONCLUSION

Q. ON PAGE 4 OF HIS DIRECT TESTIMONY, MR. KOLLEN STATES: "AS DEMONSTRATED BELOW, THE PROPOSED SETTLEMENT BETWEEN THE COMPANY AND THE STAFF IS WOEFULLY INADEQUATE." DO YOU CARE TO COMMENT ON MR. KOLLEN'S STATEMENT?

A. Mr. Kollen's disparaging characterization of the settlement marginalizes the hundreds of hours that were devoted to the rate investigation by the Commission Staff in analyzing BHP's rate request and in crafting a resolution of all issues through a negotiated settlement. As is evident by the Staff Memorandum, the Commission Staff arrived at its settlement position based on a thorough analysis of all issues while relying on long-standing Commission practices and requirements imposed by South Dakota Administrative Rules governing ratemaking practices in the State. Obviously, there was give-and-take between the Commission Staff and BHP in settlement negotiations. Staff did not receive all that it hoped for; neither did BHP. In fact, BHP agreed to accept less than one-half (47 percent) of its original requested revenue increase. Moreover, the settling parties agreed to a stay-out provision that restricts BHP's ability to seek another base rate increase prior to October 1, 2016. The two-year rate moratorium has real value to BHP customers, including the members of the BHII.

As shown in my testimony above, the Settlement Stipulation addresses many of the revenue requirement issues that Mr. Kollen raised. Other issues raised by Mr. Kollen are inconsistent with long-standing Commission practices and the requirements of South Dakota Administrative Rules governing public utility ratemaking. And while Mr. Kollen raised some legitimate concerns with a few of his issues, those issues were addressed in confidential settlement negotiations and were part of the give-and-take therein. As for Mr. Baron's testimony, it seems unnecessary given that no party is asking the Commission to accept the Company's CCOSS and that the BHII supports the apportionment of the revenue increase to the rate classes that is reflected in the settlement. Whatever issue the BHII has with cost allocation can be addressed in BHP's next rate proceeding given that any resolution at this time will not have any impact on the outcome of this proceeding.

Q. DOES THIS COMPLETE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

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

REQUEST DATE : April 29, 2014

RESPONSE DATE : May 20, 2014

REQUESTING PARTY: SDPUC Staff

SDPUC Request No. 2-5:

Provide copies of all union contracts in effect during the test year and to date.

Response to SDPUC Request No. 2-5:

Please see Confidential Attachment 2-5.

Attachments: 2-5 – Confidential BHP Union Contract (4.1.12 to 3.31.17)

EXHIBIT
STAFF 2

BHP-SDPUC-000786

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

REQUEST DATE : April 29, 2014

RESPONSE DATE : May 20, 2014

REQUESTING PARTY: SDPUC Staff

SDPUC Request No. 2-6:

Provide copies of all salary studies utilized by BHP mentioned in Company witness Laura A. Patterson's direct testimony, including: Towers Watson, Aon Hewitt, Mercer, the Edison Electric Institute (EEI), ECI, the EAPDIS, LLC, Ed Powell, and other surveys, including several specific to wages by state. Also, provide any other surveys not mentioned that BHP used to determine compensation levels for each labor group (union, non-union, executive, etc.) during the test year and to date.

Response to SDPUC Request No. 2-6:

CONFIDENTIAL RESPONSE:

Please see Confidential Attachments 2-6A through 2-6AAX.

Attachments:
2-6A Confidential 2012 IEHRA 2012 Energy Industry Compensation Survey Results
2-6B Confidential 2012 Variable Compensation Measurement Report
2-6C Confidential ERCCS_2013 (Ed Powell)
2-6D Confidential 2012 Aon Hewitt US TCM Executive Compensation Policies and Programs
2-6E Confidential Exec Asst Ad Hoc Survey
2-6F Confidential 2012 ETCCS (Ed Powell)
2-6G Confidential ETCCS_2011
2-6H Confidential SOS Summary
2-6I Confidential 2013 ECI National Trend_13_14
2-6J Confidential 2012 ECI National Trend_12_13
2-6K Confidential SOS Results-SOS-LR-27-12-Bargaining Unit Contracts and Base Salary Percentage Increases
2-6L Confidential TW Union Wage Study Participant Report 3.7.12
2-6M Confidential ECI National Trend_10_11
2-6N Confidential EAPDIS 2010-2011 MERITBUDGET
2-6O Confidential 2011 Pearl Meyer & Partners Comp Planning Survey
2-6P Confidential 2012-2013 US Compensation Planning Report
2-6Q Confidential Mercer-compensation-planning
2-6R Confidential 2011-2012 Compensation Policies and Practices
2-6S Confidential 2011 US Compensation Planning Report Update
2-6T Confidential May 2013 TW Integrys Energy Gen Wage Increase v. Meritl
2-6U Confidential TW 2013 merit budget preview
2-6V Confidential 2012 Avista Incentive Design Study

BHP-SDPUC-000787

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

REQUEST DATE : April 29, 2014

RESPONSE DATE : May 20, 2014

REQUESTING PARTY: SDPUC Staff

2-6W Confidential SHRM Employee Recognition Programs, Fall 2012
2-6X Confidential 2011 Colo Dept of Labor Report on Green Jobs
2-6Y Confidential 2012-2012 Kenexa Pay for Performance Survey
2-6Z Confidential 2013 Kenexa Compensation Outlook Report
2-6AA Confidential Buck's Compensation Planning for 2014
2-6AB Confidential Ed Powell 2013 Engineer Levels
2-6AC Confidential 2013-compensation-best-practices-report
2-6AD Confidential Career Progression Survey Results
2-6AE Confidential Ed Powell 2013 MERITBUDGET
2-6AF Confidential Ed Powell 2014 MERITBUDGET
2-6AG General Industry Salary Budget Survey Results Preview
2-6AH Confidential 2012_Variable_Comp AON
2-6AI Confidential 2013-2014_US_Salary_Increase_Survey_Results_Participant_List
2-6AJ Confidential AonHewitt 2011 Performance Bonus Review
2-6AK Confidential 2013_Variable_Compensation_Measurement_Survey_Results
2-6AL Confidential Preli_Hewitt_2013-2014_US_Salary_Increase_Survey_Results (1)
2-6AM Confidential World at Work Metrics Survey 2012
2-6AN Confidential 2011-2012 World at Work Salary Budget Survey Results
2-6AO Confidential 2012-2013 Salary Budget Survey Executive Report & Analysis
2-6AP Confidential World at Work Utilities COLA Report
2-6AQ Confidential 2012 Work at Work Salary Structure Policies and Practices
2-6AR Confidential 2013 Salary Budget Survey Insights and Analysis
2-6AS Confidential 2013-2014 World at Work Job Evaluation and Market Pricing Policies
2-6AT Confidential 2013-2014 World at Work Salary Budget Survey
2-6AU Confidential World at Work 2012 Salary Budget Survey
2-6AV Confidential 2013-2014 World at Work Salary Budget Survey Top Level Results
2-6AW Confidential World at Work 2012 Compensation Program and Practices
2-6AX Confidential 2014_US_Compensation Policies and Practices_National
2-6AY 2013-2014 US Compensation Planning Survey
2-6AZ Confidential Mercer IT Workforce Practices Survey
2-6AAA Confidential 2014_US_Compensation Policies and Practices_Detailed
2-6AAB Confidential 130924_WB_Compensation_planning_2014_US_forecast_and_trends
2-6AAC Confidential 2012 Mercer Rewards and Career Communication Survey
2-6AAD Confidential 2012-2013 US Incentive Plan Design - Overview
2-6AAE Confidential Mercer 2012 US Incentive Plan Design – Overview
2-6AAF Confidential Mercer 2012-2013 US Comp Planning Report
2-6AAG Confidential 2013-2014 US Compensation Planning Preliminary Report
2-6AAH Confidential Mercer 2012 US National Short-term Incentive Plan Design
2-6AAI Confidential Mercer 2012-2013 US National Short-term Incentive Plan Design

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

REQUEST DATE : April 29, 2014

RESPONSE DATE : May 20, 2014

REQUESTING PARTY: SDPUC Staff

2-6AAJ Confidential MERCER_CompPlanning2012_SEC[1]
2-6AAK Confidential Mercer 2012 employee attraction retention engagement
2-6AAL Confidential Mercer 2012 GlobalLeveling
2-6AAM Confidential Mercer 2011 Exec Comp Perf
2-6AAN Confidential Mercer 2012 exec comp talent mgmt.
2-6AAO Confidential Mercer 2012 hr_mobility_challenges
2-6AAP Confidential Mercer 2012 us car policies
2-6AAQ Confidential Summary of SOS-LR-9-14-Bargaining Unit Contracts and Base Salary
2-6AAR Confidential Participant Report-State of South Dakota 2013
2-6AAS Confidential Electric Utility FLSA & Good PracticesSURVEY 01-24-14
2-6AAT Confidential Participant_letter_Gill
2-6AAU Confidential 2013 SD Benefits Markets Prevalence Participant Report
2-6AAV Confidential Comp Survey Contact List
2-6AAW Confidential Critical Infrastructure Protection Pay Policies
2-6AAX Confidential 2014 Incentive Pay Practices Survey Publicly Traded Companies

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

REQUEST DATE : April 29, 2014

RESPONSE DATE : May 20, 2014

REQUESTING PARTY: SDPUC Staff

SDPUC Request No. 2-7:

Provide wage studies comparing BHP employee wages to employees of other utilities in the area such as Rushmore Electric Power Cooperative, Black Hills Electric Power Cooperative, Butte Electric Cooperative, and Basin Electric Power Cooperative.

Response to SDPUC Request No. 2-7:

CONFIDENTIAL RESPONSE

Please see Confidential Attachment 2-7.

Attachments: 2-7 – Confidential Exhibit 1250 Div B and Div A contract union comparisons that are not just and reasonable or other otherwise justified and that should be rejected or modified or failed to make adjustments that are necessary to ensure that costs are adjusted reasonable.

In the first category are adjustments, one, to reflect a five-year average of pension expense rather than using the expense that, in fact, was known and measurable at the time of the filing for the period 12 months after the end of the historic test year. And that's what I recommend.

Number two, to increase the depreciation rates expense for net negative salvage on production plant that isn't justified at this time.

And, three, using unduly short amortization periods for regulatory assets.

In my testimony I provide this table that we looked at previously that summarizes our recommendations in that first column. In the second column similar quantifications on those issues in the Proposed Settlement. And the third column would be the adjustments that would be necessary if you start with the Proposed Settlement.

And I'd like to briefly review the largest of the issues reflected on this table and to respond to the company and Staff rebuttal testimony on some of the and yet it shows up in the Proposed Settlement.

And the same thing then with the Black Hills Utility Holding Company. The company said, well, our actual costs from the two service companies through September 30, 2014, were X and Y, and then that's what appeared in the Proposed Settlement, including the $286,000 error. And we don't think any of that complies with South Dakota Law.

And then also incentive compensation. Basically, the Settlement does have some incentive compensation excluded. We believe that there are additional amounts tied to financial performance of the company that should be excluded. And we'll go through all of that but --

And then pension expense, the company proposes a new methodology where it takes a five-year average of the years 2008 through -- I'm sorry. 2010 through 2014, even though it knew what 2014 pension expense was because that comes out of actuarial reports. So that not only was known and measurable, it was actual at the time of the company's filing.

Instead it just came up with a new method. I described it as opportunistic simply because it was lower in 2014. And I don't believe the Commission should adopt the five-year average.

And then, finally, I'd like to talk about

Excepting the current rate increase, do you know what those other three totalled?

A. Quite frankly, not sitting here. Somebody else has my opening statement where I had that information.

THE WITNESS: Oh, thanks.

A. It's about 30 percent, just for the three.

Q. And so the rate increase that's at issue would be on top of that?

A. That's right. Bring it up to about 40 percent.

Q. I believe that -- I wanted to ask you a clarification question from your testimony regarding the incentive compensation. And you, if I understood it correctly, referred to BHP -- I believe it was Black Hills Power coming up with a new methodology for expenses in that area; is that correct?

A. That would be pension expense. And the company proposed a five-year average rather than the 2014 actual known and measurable at the time of its filing. It's a new methodology.

Q. So when you say it's a "new methodology" is it one that's simply new to you or new to, I guess, the field in which we're talking about?

A. New to Black Hills Power. And in prior cases my understanding is that the company has used the test year amount rather than a five-year average. There may have last issue that Ms. Collier was visiting with you about.

It's my understanding in your written testimony that you referred to a normalization adjustment as "opportunistic."

Is that correct?

THE WITNESS: That had to do with the pension expense. And the fact is that in the 2014 actuarial report, which is the basis for the pension expense, it was significantly less than in prior years. And that's not surprising, given the returns in the market. And you would expect to see that reflected in pension expense.

And that was clearly known and measurable at the time of the company's filing because it used that in the five-year average. And it was one of those situations where the expenses went down.

And normally the customers would get the value of that. Instead, the company came up with a new methodology by using a five-year average.

CHAIRMAN NELSON: Were you present this morning for my discussion, I think with Mr. White, where instead of using the word "opportunistic" I used the word "cherry picked"?

THE WITNESS: No, I wasn't here.

CHAIRMAN NELSON: You weren't here. We had a good discussion about that. And I was trying to figure out, you know, in what circumstances do they attempt to use the normalization adjustment as opposed to strictly use a number from the test year. And he talked about the fact if there were material swings in the dollar figures from year to year.

And so my question for you is in what circumstances would you find a normalization adjustment appropriate? Because, obviously, you don't in this case. But where would it be appropriate?

THE WITNESS: Well, the reason I don't in this case is because, you know, the market continues to go up and because that's a component of the pension expense, the return on those fund assets, then I would anticipate going forward that it would continue at lower levels, perhaps, than what we saw in 2009 and 2010 when the market was crashing.

But in some other cases, for example, normalization adjustments might be appropriate if there are pay raises at the end of a historic test year that weren't fully reflected in that test year. That certainly would be a known and measurable change. You would want to normalize that.

If there was some anomaly, for example, storm costs -- maybe a utility incurred 20 million dollars worth of storm costs -- you would take that out and probably treat that separately.

There may be some other examples too, but normally what you look for are abnormal and nonrecurring types of expenses, and then you either take them out entirely or you normalize them.

But pension expense is a recurring expense. And the question is what is the appropriate level. And they knew what it was for 2014 based upon the actuarial report so it was certainly known and measurable.

CHAIRMAN NELSON: Thank you.

MR. SMITH: Commissioner questions.

COMMISSIONER HANSON: I just have one.

In Interveners' Exhibit No. 9 that was handed out during your presentation did you address each one of those items either in your prefiled or in your discussion here today?

THE WITNESS: I did.

COMMISSIONER HANSON: Each one of them?

THE WITNESS: Yes. The only thing that I -- yes. I did. Including the quantification.

I did not address the capital structure as such or the rate of return, but I quantified the effects of it.

In other words, I did not -- I was agnostic on it. In other words, I didn't say yes I support it or

And I think that's the end of the inquiry as far as cost of service goes.

Mr. Baron pointed out a number of what he called errors in the study. In my opinion, the Commission probably doesn't need to issue a finding on any of those so-called errors in this case because they will not impact the apportionment of revenues. And Mr. Baron just acknowledged that.

But we did want to point out disagreement with Mr. Baron on the largest single what he called error in this study, and that's the use of the minimum distribution system. And I discussed that at length in my testimony.

MR. SMITH: Is he loud enough for you?

THE WITNESS: That concludes my summary.

Q. Based on your education and experience, do you have an opinion as to whether the Settlement Stipulation results in just and reasonable rates?

A. Yes, I do. And not only my education and experience but the -- my involvement in this rate case.

I was involved with the Commission's in-house staff since the beginning of this rate case, since it was filed. And I watched and oversaw, in some instances, the Staff's review of, as you said, over 500 discovery requests and the hundreds of hours that the Staff devoted to this case in identifying the issues and recommending alternative rate making treatments for some of the items claimed in the company's cost of service and revenue requirement.

Those issues are all identified specifically in the Staff memorandum in support of the Settlement, and I believe there's a high level of transparency. The Commission can see for itself. The extent of the review and the resolution of what the Staff considers each issue, important issue in the case.

And, yes, based on the -- based on the resolution that we've reached with the company, we believe that the resulting rates will be just and reasonable.

MS. CREMER: Thank you.

Mr. Peterson is available for cross-examination.

MR. SMITH: Mr. Magnuson, please proceed.

MR. MAGNUSON: Thank you, Mr. Smith.

We have no questions of this witness.

MR. SMITH: Okay. We'll go to Mr. Moratzka then.

MR. MORATZKA: Just a few brief questions.

CROSS-EXAMINATION

BY MR. MORATZKA:

Q. Good morning, Mr. Peterson.

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

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

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

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

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

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

But as far as are there other opportunities for -- for normalization that may cut in the opposite direction? Yeah. There's always that possibility in any at existing rates, therefore, a lower revenue deficiency.

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

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

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

CHAIRMAN NELSON: Thank you.

No further questions.

MR. SMITH: Commissioner Fiegen.

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

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

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

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

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

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

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

COMMISSIONER FIEGEN: Hello.

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

I still don't understand your testimony, though, on your concerns that you have with incentive pay. And you've agreed with the Staff Settlement, yet you still and executive retirement programs that grant additional incentive compensation to a very few people that are -- that are -- by definition, exceed the plans that abide to the general body of eligible employees. I'm critical of those types of plans.

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

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

Thank you.

MR. SMITH: Additional Commissioner questions.

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

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

recovery of our incentive compensation as a recognized necessary cost to attract, motivate, and retain employees.

We also have compromised somewhat in the rate design. The company would prefer to have higher costs associated with customer charges. And so there are customer benefits that are provided in the way Staff has negotiated this case.

We've also compromised on certain known and measurable adjustments. We have amortizations that, you know, with the time value money don't have an impact financially in the company, but there were numerous changes and compromises that were made to reach that Settlement.

And the Settlement recognizes that the company had certain expectations in the amount that we filed for at 14.6 million dollars. We're actually compromised now down to 6.89 million dollars. Plus we've agreed to live with these rates for a two-year period of time.

In addition, the energy cost adjustments was modified from what the company's initial application was to ensure that customers still had a utility interested in power marketing its profitability through that guarantee of a million dollars each year.

Q. Is there anything else that you would like to

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	))))	**FINAL DECISION AND ORDER; NOTICE OF ENTRY** **EL14-026**

PROCEDURAL HISTORY

On March 31, 2014, Black Hills Power, Inc. (BHP) filed with the South Dakota Public Utilities Commission (Commission) an Application for Authority to Increase Electric Rates (Application) and supporting exhibits requesting approval to increase rates for electric service to customers in its South Dakota service territory by approximately $14.6 million annually or approximately 9.27% based on BHP's test year ending September 30, 2013.[1] The Application included an extensive, detailed set of schedules and pre-filed testimony in support of the proposed rates. The Application stated that a typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month. The proposed changes would affect approximately 65,500 customers in BHP's South Dakota service territory. The Application requested an effective date of October 1, 2014, for the proposed rate increase which was the anticipated start-up date for BHP's Cheyenne Prairie Generating Station, then under construction, and coincides with the 180 day limitation on suspension of a requested rate increase pursuant to SDCL 49-34A-14.

On April 11, 2014, BHP filed revised Exhibits A, B, C, and D. On April 16, 2014, the Commission issued an Order Assessing Filing Fee assessing a filing fee of up to the $250,000 maximum allowed by SDCL 49-1-8 to reimburse the actual expenses incurred by the Commission in processing this docket. On June 6, 2014, GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively Black Hills Industrial Intervenors or BHII) filed a Petition to Intervene, and Dakota Rural Action, Inc. (DRA) filed a Petition to Intervene. On June 18, 2014, BHP filed Black Hills Power, Inc.'s, Objection to the Intervention Petition of Dakota Rural Action and Black Hills Power, Inc.'s Response to Intervention Petition of Black Hills Industrial Intervenors.

On June 20, 2014, DRA filed Dakota Rural Action's Response to Black Hills Power, Inc.'s Objection to Dakota Rural Action's Petition to Intervene and Dakota Rural Action, Inc.'s Attachment to Paragraph 4 of Response to Black Hills Power, Inc.'s Objection to Dakota Rural Action's Petition to Intervene. On June 26, 2014, the Commission issued an Order Granting Intervention, granting intervention to BHII and DRA, subject to the condition that DRA file an affidavit attesting to the members of DRA who were then current customers of BHP. On June 27, 2014, DRA filed a Supplemental Affidavit to Intervenor Dakota Rural Action, Inc.'s Petition to Intervene and Response to Black Hill Power, Inc.'s Objection.

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[1] The Application, Commission Orders in the case, and all other filings and documents in the record are available on the Commission's web page for Docket EL14-026 at: http://www.puc.sd.gov/Dockets/Electric/2014/EL14-026.aspx

On September 3, 2014, BHP filed a Notice of Intent to Implement Interim Rates advising the Commission and the public of BHP's intent to implement its requested rate increase as of October 1, 2014. On September 4, 2014, BHP filed a Motion for Approval of Settlement Agreement and Settlement Agreement to settle outstanding issues between BHP and the South Dakota Science and Technology Authority (SDSTA Settlement Agreement). The SDSTA Settlement Agreement includes a Third Amendment to Electric Power Service Agreement Between Black Hills Power, Inc. and South Dakota Science and Technology Authority (Third Amendment). On September 10, 2014, the Commission's staff (Staff) filed a Staff Memorandum regarding the Third Amendment. On September 12, 2014, BHP filed its responses to Staff's ninth set of data requests. On September 18, 2014, the Commission issued an Order Conditionally Authorizing and Approving Implementation of Contract with Deviations Rates on an Interim Basis, authorizing BHP to implement the rates set forth in the SDSTA Settlement Agreement subject to the conditions set forth in the Staff Memorandum. On September 24, 2014, BHP filed a revised tariff page Section No. 3A, Sheet No. 1.

On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits (Settlement Stipulation). On December 12, 2014, the Commission issued a Scheduling Order. On December 30, 2014, the Commission issued an Order for and Notice of Hearing setting this matter for hearing on January 27-29, 2015, at the Matthew Training Center in Pierre. On December 30, 2014, BHII filed the pre-filed testimony of its witnesses Lane Kollen and Stephan J. Baron and associated exhibits. On January 15, 2015, Staff filed the pre-filed testimony of its witness David E. Peterson and a Staff Memorandum Supporting Settlement Stipulation and associated exhibits. On January 15, 2015, BHP filed the pre-filed rebuttal testimony of Kyle D. White, John J. Spanos, Jon Thurber, Christopher Kilpatrick, and Robert J. Hollibaugh. On January 20, 2015, BHP, BHII, and Staff filed exhibit and witness lists.

On January 23, 2015, BHII filed a Motion for Briefing of GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, and Wharf Resources (U.S.A.), Inc. (Motion) requesting that the Commission issue an order establishing a post-hearing briefing schedule and recommending a schedule to be established by such order. The hearing was held as scheduled on January 27 and 28, 2015. Following the evidentiary hearing, the Commission considered the Motion and after discussion decided upon a schedule that would permit a decision to be rendered prior to the expiration of the one-year period commencing with the date the Application was filed. On January 29, 2015, the Commission issued a Post-Hearing Scheduling Order requiring all parties' post-hearing briefs to be filed and served on or before February 17, 2015, and setting the matter for Commission action on March 2, 2015.

On February 10, 2015, BHP and Staff filed an Amended Settlement Stipulation between BHP and Staff (Amended Stipulation) reflecting two changes to the factual bases supporting the agreed revenue requirement due to new information contained in pre-filed testimony filed after the Settlement Stipulation was entered into and filed and evidence introduced at the hearing. The first change corrects an error in the South Dakota jurisdictional allocation of transmission load dispatch expense, FERC Account 561, for the Black Hills Utility Holdings (BHUH) intercompany charges adjustment, reducing the revenue requirement by $286,041. The second change reflected in the Amended Stipulation accepts the $412,988 Wyodak operations and maintenance (O&M) adjustment as provided by BHP in Exhibit BHP 71. This adjustment updates production O&M costs at the Wyodak power plant from $3,045,652 incurred during the test year to $3,458,640 incurred from October 2013 through September 2014. This represents a known and measurable increase to test year expense. On February 10, 2014, Staff filed a Staff Memorandum Supporting Amended Settlement Stipulation.

On February 17, 2015, BHP, BHII, and DRA filed Post-Hearing Briefs, and Staff filed a letter concurring with BHP's Post-Hearing Brief. On February 23, 2015, BHP and Staff filed a Joint Motion for Approval of Amended Settlement Stipulation. At its regular meeting on March 2, 2015, after questions by Commissioners of the parties, the Commission voted unanimously to Grant the Joint Motion for approval of Amended Settlement Stipulation between BHP and Staff and approve the terms and conditions stipulated therein as the decision of the Commission on the rate increase requested by BHP with an effective date of April 1, 2015, to approve the Settlement Agreement and contract with deviations between BHP and SDSTA, to approve the interim rate refund plan set forth as Exhibit 3 to the original Settlement Stipulation between BHP and Staff but a with refund period beginning in May 2015, and with carrying charges on refunds of 7% as stipulated between BHP and Staff in the original Settlement Stipulation. On March 5, 2015, BHP filed a Customer Notice, revised tariff sheets, and an Interim Refund Plan conforming to the Commission's action at the March 2, 2015, meeting.

FINDINGS OF FACT

Procedural Findings

1. The Procedural History set forth above is hereby incorporated by reference in its entirety in these Procedural Findings. The procedural findings set forth in the Procedural History are a substantially complete and accurate description of the material documents filed in this docket and the proceedings conducted and decisions rendered by the Commission in this matter.

Parties

2. The Applicant is Black Hills Power, Inc., a corporation organized under the laws of South Dakota. Ex BHP 1, p. 4.[2] BHP is a wholly-owned subsidiary of Black Hills Corporation. Ex BHP 9, pp. 2-3. BHP is an investor owned "public utility" as defined in SDCL 49-34A-1(12) that provides retail electric service in South Dakota. Ex BHP 1, pp. 1 and 5; Ex BHP 9, pp. 2-3.

3. On June 26, 2014, the Commission issued an Order Granting Intervention to GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively, Black Hills Industrial Intervenors or BHII) and Dakota Rural Action (DRA).

4. The BHII companies are a group of General Service, Large and Industrial Contract customers of BHP. Ex BHII 3, p. 4.

5. DRA is a member-based organization with an office located in Rapid City. Dakota Rural Action's Petition to Intervene. A number of DRA's members are customers of BHP.

[2] References to the January 27-28, 2015, Hearing Transcript are in the format "TR" followed by the Hearing Transcript page number(s) referenced, and references to Hearing Exhibits are in the format Ex followed by "BHP" for BHP exhibits, "BHII" for BHII exhibits, "Staff" for Staff exhibits, and "JT" for BHP/Staff joint exhibits followed by the exhibit number and, where applicable, the page number(s) referenced or other identifying reference and, where applicable, the attachment or sub-exhibit identifier and page number(s) referenced.

Supplemental Affidavit to Intervenor Dakota Rural Action, Inc.'s Petition to Intervene and Response to Black Hill Power, Inc.'s Objection.

6. Staff also participated in the docket as a full party.

Amended Settlement Stipulation

7. BHP's Application as filed requested approval from the Commission to increase its rates for retail electric service to customers in its South Dakota service territory by approximately $14.6 million annually or approximately 9.27%. A typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month. The proposed changes would affect approximately 65,500 customers in South Dakota. The Application requested an effective date of October 1, 2014, for the proposed rate increase, which was the anticipated start-up date for BHP's Cheyenne Prairie Generating Station (CPGS), then under construction, and coincides with the 180 day limitation on suspension of a requested rate increase pursuant to SDCL 49-34A-14. Ex BHP 1, p. 3; Ex Staff 1, p. 4. The Application included an extensive, detailed set of schedules and pre-filed testimony in support of the proposed rates. Ex BHP 1, pp. 1-2; Exs BHP 4 through 58.

8. BHP's proposed increase was based on a historical test year ended September 30, 2013, adjusted for what BHP believed to be known and measurable changes, a 10.25% return on common equity, and an 8.48% overall rate of return on rate base. Ex BHP 5, Exhibit G, Statement G, p. 1; Ex BHP 23, p. 3; Ex BHP 46, pp. 7-8, 11-12; Ex BHP 48; TR 269.

9. The Application also requested approval of: an accounting order allowing BHP to use deferred accounting for the costs associated with the FutureTrack Workforce Development Program that deviate from the costs included in base rates; an accounting order for the Company's Winter Storm Atlas regulatory asset if the decision in the docket was not issued by December 31, 2014; revisions to the Energy Cost Adjustment tariff; and a modification to the major maintenance account to expense a portion of the plant overhaul cost each year based on a plant's planned maintenance cycle. Ex BHP 1, p. 3; Ex BHP 8, pp. 6-7; Ex BHP 15, pp. 14-15; Ex BHP 24, pp. 5-11, 14-17; Exs BHP 25-28.

10. Beginning immediately following BHP's filing of the Application on March 31, 2014, Staff and its outside consultants conducted an extensive review of the Application and the statements, exhibits, testimony, and working papers filed with the Application. In addition, Staff served at least 330 discovery requests for additional data and information on BHP and conducted a thorough analysis of BHP's responses thereto and also its responses to approximately 60 additional discovery requests served on BHP by BHII. Exhibit Staff 1, p. 5; TR pp. 263, 267-268.

11. Staff based its determination of an appropriate revenue requirement on a comprehensive analysis of the as-filed September 30, 2013, total BHP test year costs, and the additional information obtained through discovery that supported further post-test year adjustments. In particular, Staff first allocated total company amounts to the South Dakota retail jurisdiction. Staff then adjusted the September 30, 2013, test year results for appropriate post-test year changes. The Amended Settlement Stipulation incorporates numerous income adjustments and rate base adjustments. Ex Staff 1; Staff Memorandum Supporting Settlement Stipulation (Staff Memorandum); Staff Memorandum Supporting Amended Settlement Stipulation (Amended Staff Memorandum).

12. Settlement discussions between Staff, BHP, BHII, and DRA commenced in late October, 2014. Thereafter, Staff and BHP held several settlement discussions in an effort to arrive at a mutually acceptable resolution of the issues presented in BHP's filing. According to Staff's expert witness Peterson, substantially all of the issues raised by BHII's witness, Lane Kollen, were identified and discussed in such settlement discussions and were considered by Staff in its analysis and its negotiation of the Settlement Stipulation. Ex Staff 1, p. 8. Ultimately, Staff and BHP reached a comprehensive agreement on BHP's overall revenue deficiency and other issues presented in this case including, but not limited to, class revenue responsibilities, rate design, and tariff concerns. BHII and DRA did not elect to become parties to the Settlement Stipulation reached between BHP and Staff. Ex Staff 1, pp. 5-6. On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits. Exs JT 1-6.

13. In the Settlement Stipulation, BHP and Staff agreed that BHP's total revenue deficiency is $6,890,746 and that BHP's tariffs will be designed to produce an increase in annual base revenue levels of $6,890,746 or approximately 4.35% over total retail revenues at existing rates based on a South Dakota jurisdictional retail revenue requirement of $165,122,614. In the Settlement Stipulation, BHP and Staff agreed to a 7.76% rate of return on rate base. Ex JT 2, p. 4. A detailed explanation of the adjustments, data, analyses, and computations underlying the Settlement Stipulation's provisions to resolve the numerous matters at issue in this case between BHP and Staff is set forth in Staff's Memorandum in Support of Settlement Stipulation filed on January 15, 2015, together with the pre-filed testimony of Staff's expert witness, David E. Peterson, set forth in Ex Staff 1.

14. On February 10, 2015, following the filing of BHII's pre-filed testimony, Staff's pre-filed testimony, and BHP's pre-filed rebuttal testimony and the evidentiary hearing held on January 27-28, 2015, BHP and Staff jointly filed an Amended Settlement Stipulation, and Staff filed a Staff Memorandum Supporting Amended Settlement Stipulation. On February 23, 2015, BHP and Staff jointly filed a Joint Motion for Approval of Amended Settlement Stipulation. The Amended Stipulation seeks to correct an error in the South Dakota allocation of transmission load dispatch expense, FERC Account 561, for the Black Hills Corporation/Black Hills Utility Holdings intercompany charges adjustment, reducing the revenue requirement by $286,041. This error was brought to light in the pre-filed and hearing testimony of BHII witness Kollen and was acknowledged to be correct by Staff witness Peterson in his pre-filed testimony and in his hearing testimony. TR 163-164, 184; Ex BHII 1, p. 39-40; Ex BHP 70, p. 16; Ex Staff 1, p. 19.

15. A second change reflected in the Amended Stipulation involves the acceptance and inclusion of an expense adjustment of $412,988 for the South Dakota jurisdictional share of Wyodak generating plant O&M expenses as provided by BHP in its pre-filed testimony after the Settlement Stipulation was executed and filed. This adjustment updates production O&M costs at the Wyodak power plant from $3,045,652 incurred during the test year to $3,458,640 incurred from October 2013 through September 2014. Ex BHP 70, pp. 17-19; Ex BHP 71. This represents an increase to test year expense that was not known and measurable at the time the Settlement Stipulation was executed and filed but had become known and measurable at the time BHP's pre-filed rebuttal testimony exhibits were filed and became known and measurable prior to twenty-four months after the Application filing date. Ex BHP 70, pp. 17-19.

16. The Amended Stipulation uses the same calculation for cash working capital, net operating loss, interest synchronization, and bad debt adjustments as the Settlement

Stipulation. The revenue requirement value of each adjustment changes, however, based on the resolution of various issues in the case. These adjustments are dependent on the pro forma rate base, expenses, and revenues, and were recalculated as a result of the BHUH allocation correction and the Wyodak O&M expense adjustment. Staff Memorandum in Support of Amended Settlement Stipulation, p. 3.

17. Although the Staff Memorandum in Support of Amended Settlement Stipulation Exhibit___(BAM-4) Schedule 1 – Amended Settlement SD Electric Revenue Requirement cost of service calculations show a revenue deficiency of $7,010,894, the revenue deficiency in the Amended Stipulation, Section III, ¶1 retains the $6,890,746 level provided in the original Settlement Stipulation. With the inclusion of the Wyodak O&M costs, the amended cost of service in the Amended Stipulation supports a revenue requirement greater than that agreed upon in the Amended Stipulation, and ratepayers will not incur the added rate case expense required to prepare revised rates and tariff sheets. Staff Memorandum in Support of Amended Settlement Stipulation, p. 3.

18. In addition to the inclusion of only a portion of the Wyodak O&M expense adjustment in rates agreed to in the Amended Stipulation and the maintenance of the total rate increase at the same amount as in the Settlement Stipulation, Section III, ¶13 extends the rate case filing moratorium provision an additional three months from what was agreed to in the Settlement Stipulation. Under this provision, BHP will not be allowed to file any rate application for an increase in base rates which would go into effect prior to January 1, 2017.

19. The Commission finds that the agreements, adjustments, and rates proposed in the Amended Stipulation, considered together with the rate case moratorium, are just and reasonable, and the Amended Stipulation is approved by the Commission.

SDSTA Settlement Agreement

20. The Amended Stipulation in Section III, ¶12 accepts and recommends Commission approval of the SDSTA Settlement Agreement and the Third Amendment incorporated therein. The Amended Stipulation and Third Amendment are contracts with deviations, which are agreements between a public utility and one or more customers that provide for the provision of service under rates, terms, and/or conditions that deviate from the utility's rates, terms, and conditions specified in the utility's tariffs filed with, and approved by, the Commission. Contracts with deviations are generally approved for very large loads or other special business development circumstances under the authority of SDCL 49-34A-8.3. On September 18, 2014, the Commission issued an Order Conditionally Authorizing and Approving Implementation of Contract with Deviations Rates on an Interim Basis, authorizing BHP to implement the rates set forth in the SDSTA Settlement Agreement for SDSTA subject to the following conditions:

> 1. If the contract with deviations is not subsequently approved by the Commission, the rates to be paid by SDSTA for the period on and after October 1, 2014, shall be the rates ultimately approved in the rate case for the applicable class of service, with the difference between the interim rates paid by SDSTA and the rates ultimately approved in the rate case for the applicable class of service to be subject to true-up and refund or repayment, as the case may be, with interest at the rate approved in a refund order of the Commission after final decision in the general rate case; or

2. If the contract with deviations is subsequently approved by the Commission with modification of the settlement rates to be paid by SDSTA, the rates to be paid by SDSTA for the period on and after October 1, 2014, shall be such contract with deviation rates as are ultimately approved by the Commission, with the difference between the conditionally approved interim rates and the contract with deviation rates ultimately approved by the Commission to be subject to true-up and refund or repayment, as the case may be, with interest at the rate approved in the refund provisions of the Commission's order approving the contract with deviations with modified rates or, if refund is not ordered in such order, in the refund order of the Commission at the time of the general rate decision.

3. This approval does not pre-determine a Commission decision in the current or future rate case proceedings regarding rate treatment of revenue requirement shortfalls resulting from rates approved as contracts with deviations.

21. The SDSTA Settlement Agreement and Third Amendment were filed as confidential documents, as is generally, if not always, the case with contracts with deviations. The Commission finds that the SDSTA Settlement is just and reasonable and is approved by the Commission.

Black Hills Industrial Intervenors' Contested Issues

22. The issues addressed in Findings of Fact 23 through 55 were contested by BHII in its pre-filed and hearing testimony and/or its legal arguments at hearing, in its post-hearing brief, and in argument before the Commission at the Commission's decision hearing on March 2, 2015. Each of these issues is addressed separately below in the above-referenced Findings of Fact.

Allowable Test Year Adjustments under ARSD 20:10:13:44 and Applicable Statutes

23. A number of BHII's contested issues with the Settlement Stipulation and Amended Settlement Stipulation are primarily based on statutory interpretation and to such extent are issues of law, and the details of the Commission's legal rulings on such issues are set forth below in this decision's Conclusions of Law. The primary issue raised by BHII concerns the scope of what may be presented by an applicant for a rate increase within the twenty-four month cost of service adjustment period set forth in ARSD 20:10:13:44 and what may be considered by the Commission in rendering its decision, including the extent to which the Commission may consider capital cost additions and/or reductions, expense increases and/or reductions, and other relevant cost of service facts which become known and measurable during the pendency and processing of the case prior to the expiration of the twenty-four month period after the application is filed and which will be incurred during the period of 24 months after the filing of the application. ARSD 20:10:13:44 is set forth in Conclusion of Law 8.

24. In this case, the date 24 months after the end of the test year is September 30, 2015. TR 269.

25. BHII argues that ARSD 20:10:13:44 only allows the consideration of post-test year adjustments which were known and measurable at the time the rate increase application was filed. This position is based upon BHII's interpretation of the phrase "which are known with reasonable certainty and measurable with reasonable accuracy at the time of the filing." Ex BHII 1, p. 8.

26. Staff expert witness Peterson testified that during the four plus decades that he has worked with Staff on rate cases, the consistent interpretation of ARSD 20:10:13:44, read together with SDCL 49-34A-19, has been that because a historic test year is used to set rates for a future period, the analysis and substance of a proposed change in utility rates should include both known expenses during the test year and also adjustments to reflect any changes that occurred after the test year that become known and measurable within the 24-month period provided for in ARSD 20:10:13:44 and SDCL 49-34A-19. Staff has interpreted these provisions to mean that the adjustments have to be sufficiently known and measurable at the time of its review of the hundreds of responses to discovery requests and filings in the case. TR 279. This has been Staff's consistent policy and is therefore what is reflected in the Settlement Stipulation. It is also Staff's responsibility to closely examine the evidence that such changes are known and measurable expenses. This is the standard that Staff has relied on for years, and the Commission has approved numerous rate case settlements based on that standard. TR 275-276.

27. As is set forth in Conclusions of Law 8 through 10, the Commission concluded that adjustments in the Amended Settlement Stipulation are within the allowable adjustment periods set forth in SDCL 49-34A-19 and ARSD 20:10:13:44. The Commission accordingly finds that substantial and sufficient evidence was produced, introduced, and received in evidence in this proceeding to demonstrate that the rates agreed to in the Amended Settlement Agreement are just and reasonable and will adequately meet BHP's need for revenues sufficient to enable it to meet its current cost of furnishing adequate, efficient, economical, and reasonable service.

Inclusion of Revenue Changes for Period Covered by Post-Test Year Adjustments

28. BHII argues that all post-test year adjustments must be accompanied by changes in revenue during the same period. Ex BHII 1, p. 8.

29. Staff's witness Peterson testified that post-test year adjustments that are revenue producing or income producing must reflect either the additional revenue or the additional income that results from that change in operation before they may be recognized as a known and measurable adjustment. BHP points out that those types of changes are not included in the Settlement Stipulation and Amended Stipulation between BHP and Staff. TR 273; Ex BHP 70, p. 4.

30. Staff and the Commission have previously interpreted this rule to mean that for any post-test year change in expense or investment that has an incremental revenue component (i.e., expenses or investments made to increase sales and/or to serve new customers), a corresponding revenue adjustment must also be recognized. It is for this reason that the Amended Stipulation does not include any costs associated with post-test year plant additions that are designed to improve sales or to serve new customers. Similarly, there is no corresponding revenue offset for any of the post-test year expense adjustments that are reflected in the Amended Stipulation. Therefore, the Amended Stipulation is consistent with prior Commission policy in this regard and with the governing administrative rule. Ex Staff 1, p. 9.

31. Staff's analysis has been that if ARSD 20:10:13:44 intended that all revenues, not just those associated with plant additions, are intended or are supposed to be recognized within the 24-month post-test year period, the rule would require a forecast test year. The Commission has never recognized that to be the intent of the rule, nor has the Commission ever adopted or accepted a forecast test year in an electric utility rate increase filing. Therefore, the

only logical conclusion is that the revenue effect of specific post-test year changes has to be acknowledged or recognized in an adjustment before the adjustment itself can be reflected in the revenue requirement. That is the standard that Staff has relied on since the inception of the rule. TR 275-276.

32. In his pre-hearing testimony, BHII's witness Kollen testified that the Commission should limit any post-test year adjustment to the twelve month period immediately following the historical test year ended September 30, 2013. Ex BHII 1, p. 7. This opinion was also asserted by BHII's witness Baron. TR 252. The Commission finds that this would contravene the express language of ARSD 20:10:13:44 and that the Commission's discretion under SDCL 49-34A-19 has historically employed the full two-year adjustment period set forth in the statute. The Commission concludes that the appropriate test year adjustment period is 24 months.

FutureTrack and Associated O&M Costs

33. In its Application, BHP proposed to increase its expenses for its FutureTrack Workforce Development program. The primary purpose of this program was to recruit talent within critical areas to complete the advanced training necessary to fill highly skilled positions upon the retirement of existing employees. Ex BHP 19, p. 6. The Settlement Stipulation and Amended Stipulation both limit the inclusion of such costs to positions actually hired at the time of settlement negotiations without deferral of subsequently hired employee expenses, and did not include recovery for FutureTrack program additional hirings in the future. Ex Staff 1, p. 10; Staff Memorandum, p. 9. BHII's expert witness Kollen expressed the opinion that no recovery should be allowed at all for FutureTrack hirings because they were not known and measurable at the time the Application was filed. Ex BHII 1, pp. 25-30. The Commission finds that BHII's objection is not warranted.

Employee Additions and Eliminations

34. BHII objected to BHP's request for an adjustment to fund employee additions to those employee positions included in the test year. TR 182-183; Ex BHII 1, pp. 30-33. The Amended Stipulation limits recovery for employee additions to those actually hired and in service as of the date of the Settlement Stipulation. Ex Staff 1, p. 10. As with the previous FutureTrack issue, BHII's primary issues were that such additional hirings were not known and measurable as of the date the Application was filed and were speculative on a forward looking basis. The Amended Stipulation's limitation of this adjustment to actual hirings renders the future hiring issue moot. As to the post-test year filing issue, for the reasons set forth in Findings of Fact 23 through 27 and Conclusions of Law 6 through 10, the Commission finds that BHII's objection is not warranted.

NOL ADIT

35. BHII argued and presented both pre-filed and evidentiary hearing expert witness testimony that the Amended Stipulation's proposed inclusion of a tax-related net operating loss (NOL) accumulated deferred income taxes (ADIT) adjustment to the revenue requirement was inappropriate. Ex BHII 1, pp. 10-15; TR 178 et seq. BHP's expert witness Hollibaugh presented both pre-filed and evidentiary hearing testimony regarding the history leading to, the current status of, and the justification for continued maintenance of BHP's NOL ADIT. TR 148 et seq.; Ex BHP 73. Staff's expert witness Peterson testified that "Failure to provide for the deferred tax asset in rate base, as Mr. Kollen recommends, however, risks a violation of the IRS's normalization requirements." Ex Staff 1, p. 11. Based on its consideration of the testimony and

supporting documentary evidence presented by both BHP and BHII, the Commission finds that the issue of the NOL ADIT is very complex and that measures to address the underlying tax cost consequences for both BHP and ratepayers can be addressed in more than one justifiable manner.

36. The Commission finds that the NOL ADIT methodology utilized in the past few years and proposed by BHP for approval in this docket has resulted, and will result, in a just and reasonable method of accounting for and reporting BHP's taxable income/loss status and liability/credit, was developed and put into use as a consequence of the unique circumstances presented by the financial challenges and resulting Congressional tax law responses thereto arising from the severe negative economic consequences stemming from the early 2000s and 2008 and ensuing years' recessions, and will result in just and reasonable rate impacts to BHP customers.

Incentive Compensation

37. BHP's proposed revenue requirement included approximately $3.8 million for incentive compensation, including amounts billed from BHP's affiliates BHUH and BHSC. Ex BHII 6. In the Amended Stipulation, $666,000 of the Company's test year incentive compensation expenses is excluded. This is the amount that BHP identified as being tied to the Company's financial results. Ex Staff 1, p. 17. The Amended Stipulation did not change and includes this provision.

38. BHP provided evidence that employee incentive compensation plans are widely employed by utilities throughout the country and that it is necessary for BHP to provide employee incentive opportunities that are competitive with other companies in the industry. Another goal of the program is to focus employees on important objectives to improve the performance of utility operations by focusing on improvements to operational excellence, safety, reliability, and customer satisfaction. TR , 300; Ex BHP 22, pp. 8, 10.

39. BHII's expert witness Kollen offered opinion evidence that in addition to the amount excluded in the Settlement Stipulation, $149,000 in performance plan expenses and $739,000 in incentive restricted stock expenses should be excluded because these additional amounts represent incentive awards that are similar in nature to those excluded in the Settlement Stipulation. BHII witness Kollen also offered the opinion that by embedding such incentives in rates, BHP itself is not incentivized to manage toward operational performance. TR 184; Ex BHII 1, pp. 35-37; Ex BHII 6, p. 2.

40. In settlement discussions, Staff raised issues with the incentive compensation plan and the payments made under the plan. Staff's expert witness Peterson testified he did not necessarily disagree with Mr. Kollen's characterization of the incentive awards and in fact, had initially pursued the same issues on behalf of the Commission Staff earlier in this proceeding. In the end, however, the Commission Staff conceded this issue and agreed to exclude the $666,000 related specifically to financial performance, recognizing that the incentive compensation exclusion embodied in the settlement is essentially the same type of exclusion the Commission has approved for BHP in prior base rate case settlements and for other South Dakota utilities. Therefore, Mr. Peterson supported the exclusion that is contained in the Settlement Stipulation and recommended that the Commission reject Mr. Kollen's recommendation to expand the exclusion at this time. TR 285-287; Ex Staff 1, pp. 17-18. The Commission finds that the incentive compensation plan included in the Amended Stipulation does not render the Amended Stipulation unjust and unreasonable.

Pension Expense Normalization

41. As documented in the evidence presented in the case , BHP's pension expense varies significantly year-by-year. Ex Staff 1, p. 16. For example, the Company's test year pension expense was $2,844,759. For 2014, however, the expense dipped down to $976,122. To remedy the problem caused by the fluctuating expense for ratemaking purposes, BHP proposed, and the Staff accepted for settlement purposes, a normalization adjustment based on the average annual expense during the five-year period 2010-2014. These years included a year in which the pension expense was high at $3.25 million (2012) and a year in which the expense was low -- $976,122 (2014). The five-year average expense used for rate setting purposes was $2,336,305. As pointed out in Staff witness Peterson's testimony at hearing, the five-year average that was agreed upon by BHP and the Staff represented over a $500,000 reduction in the test year expense. TR 282.

42. BHII objected to the treatment of the pension expense in the Stipulation characterizing it as "opportunistic" in that it does not reduce the test year expense far enough and it prevents BHP ratepayers from receiving the benefit from the lower pension expense in 2014 that the Company enjoyed. Rather, BHII witness Mr. Kollen recommended that BHP's 2014 pension expense be recognized for ratemaking purposes. Ex BHII 1, pp. 33-34.

43. The Commission finds that it is BHII's position, not that of BHP and the Staff, which is opportunistic in this instance with respect to the pension expense. BHII's recommendation would set rates based on the lowest pension expense experienced in the last five years. BHII's recommendation is particularly egregious in this instance given that BHP's witness Thurber testified that the Company's most recent estimate of its 2015 pension expense is $2,056,581 – which is considerably higher than its 2014 expense that Mr. Kollen recommends and similar to the five-year average reflected in the Settlement Agreement. Ex BHP 70, pp. 22-23. The Commission also finds that the normalization treatment of a widely varying expense is consistent with sound regulatory principles and that the Commission has routinely relied on the normalization treatment in prior cases before the Commission, e.g. storm damage expense and uncollectible expenses. The facts and circumstances surrounding the pension expense make it appropriate to apply normalization treatment in this instance. Finally, the Commission further finds that Mr. Kollen's recommended adjustment is internally inconsistent with BHII's position regarding post-test year adjustments in that BHII's witness did not include a revenue adjustment to correspond to its proposed expense adjustment even though BHII incorrectly contends that a revenue adjustment is required for each post-test year adjustment.

Retired Steam Plants Decommissioning Expense

44. In 2014, BHP began to decommission its Neil Simpson 1, Ben French, and Osage coal-fired power plants. The Company expects the decommissioning to be completed by September 2015. BHP proposed to amortize the estimated costs associated with the retirement and decommissioning activities over five years and to include the unamortized balance in rate base. The Settlement Stipulation removes all of the contingency allowances that were included in BHP's original cost estimate. The Settlement Stipulation also revises the amount included for obsolete inventories and reflects a ten-year rather than a five-year amortization period for final retirement and decommissioning costs.

45. BHII objects to the treatment of final retirement and decommission costs associated with these three steam generating stations because it contends "[t]he 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." Ex BHII 1, p. 16.

46. As discussed elsewhere in this Order, the Commission finds no legitimate basis for Mr. Kollen's artificial twelve-month post-test year cut-off. ARSD 20:10:13:44 clearly allows that the Commission look up to 24-months post-test year when evaluating expense adjustments such as this. Therefore, the Commission rejects BHII's recommendation and adopts as just and reasonable the adjusted ten-year amortization expense reflected in the Settlement Stipulation.

Affiliate Allocations

47. The Amended Stipulation includes actual billings by BHP's affiliates – Black Hills Corp. and Black Hills Utility Holdings – to the Company for the twelve months ended August 31, 2014. Thus, the Settlement Stipulation reflects known costs experienced by BHP well within the twenty-four month post-test year period provided for in ARSD 20:10:13:44.

48. BHII objects to any increase in affiliate charges. BHII witness Mr. Kollen contends that there is no justification for the increases in affiliate charges and, further, that the magnitude of the increase is unreasonable on its face. Therefore, Mr. Kollen recommended that the post-test year expense be excluded from BHP's revenue requirement. Ex BHII 1, pp. 37-40.

49. The Commission finds that the affiliate expenses included in the Amended Stipulation are, in fact, the actual expenses that were billed to BHP by its affiliates – Black Hills Corp. and Black Hills Utilities Holdings. Therefore, the affiliate expense adjustments reflected in the Amended Stipulation are known and measurable and just and reasonable for inclusion in BHP's revenue requirement. BHII's contention of these costs being unreasonable on their face is without merit and is hereby rejected.

Steam and Other Production Plant Net Salvage

50. The proposed adjustment to net negative salvage reflects an estimated negative increase to the net of estimated salvage income and cost of removal, or an increase in the shortfall from projected salvage income less than the projected cost of removal. BHII Witness Kollen listed several reasons why he rejected BHP's proposed adjustment as well as the revised Settlement adjustment as set forth in Finding 51.

51. 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 present rates. The Commission's current policy appears to be to 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. Ex BHII 1, pp. 47-48.

52. Staff Witness Peterson disagreed, stating that "however desirable it might be to have all elements of the revenue requirement based on absolutely known and measurable

costs, depreciation allowances must reflect estimates because neither the service life of the asset nor the cost of the act of retirement are known until the asset has been retired. Depreciation allowances represent allocations of capital costs of an asset to the time periods as the asset provides service to customers over a long period of time. In the absence of making such estimates, ratepayers benefitting from the service provided by the asset will avoid these costs and cost recovery would be shifted to future ratepayers not benefitting from that service. I know of nothing that even suggests an existing Commission policy of refusing to recognize these retirement-related costs until after the plant is retired." Ex Staff 1, p. 20. The Commission finds that the Amended Stipulation reasonably addresses the net salvage cost issue.

LIDAR

53. As with BHP's decommissioning costs, BHP's LIDAR costs are governed and capped by a fixed rate contract. In the opinion of Staff witness Peterson, these costs are sufficiently known and measurable to be appropriately recognized in rates. The five-year amortization period reflected in the Amended Stipulation was determined to be appropriate because five years is the expected frequency for LIDAR surveying activities. It would be inappropriate to employ a ten-year amortization period as BHII witness Kollen recommends because to do so would unjustifiably burden BHP ratepayers, including BHII members, in years six through ten with costs for two different LIDAR surveys. A five-year amortization matches with the planned survey interval and is therefore more appropriate for these costs. Ex Staff 1, p. 15.

Class Cost of Service Study

54. Because BHII accepts the apportionment of the overall approved revenue increase reflected in the Settlement Stipulation, there are no remaining issues to be decided by the Commission regarding the spread of the rate change among the rate classes. Ex. Staff 1, p. 21.

55. Only the spread of the revenue change among the rate classes is being resolved by the Settlement Stipulation, and through Mr. Baron's testimony, BHII is accepting the settlement resolution concerning the spread of the revenue change. Under the Settlement Stipulation, BHP, the Commission Staff and the BHII are free to advocate whatever they choose concerning the CCOSS in BHP's next base rate proceeding. Therefore, it is not necessary for the Commission to rule on any CCOSS issue in this proceeding; nor is it necessary for the Commission to direct BHP to file a CCOSS in any particular manner in the next case. Ex Staff 1, pp. 21-22.

Refund of Overcharges

56. Interim rates were implemented on October 1, 2014. Approval of the Amended Settlement Stipulation will authorize a rate increase less than the interim rate level. BHP will refund to customers the difference between interim rates and new rates established by the settlement for usage during the period October 1, 2014, through the effective date of new rates, plus interest. Ex JT 2, p. 5.

57. Refunds with carrying charges of seven percent (7%) annual interest will occur in May 2015, in accordance with BHP's proposed Interim Refund Plan. March 2nd transcript, pp. 29-30.

Tariff Sheets

58. The revised tariff sheets proposed by BHP are as follows:

South Dakota Electric Rate Book

Section No. 1

Twenty-fifth Revised Sheet No. 3	Replaces Twenty-fourth Revised Sheet No. 3

Section No. 3

Fifteenth Revised Sheet No. 1	Replaces Fourteenth Revised Sheet No. 1
Thirteenth Revised Sheet No. 2	Replaces Twelfth Revised Sheet No. 2
Fifteenth Revised Sheet No. 3	Replaces Fourteenth Revised Sheet No. 3
Thirteenth Revised Sheet No. 4	Replaces Twelfth Revised Sheet No. 4
Fifteenth Revised Sheet No. 7	Replaces Fourteenth Revised Sheet No. 7
Fourteenth Revised Sheet No. 8	Replaces Thirteenth Revised Sheet No. 8
Fifteenth Revised Sheet No. 9	Replaces Fourteenth Revised Sheet No. 9
Thirteenth Revised Sheet No. 10	Replaces Twelfth Revised Sheet No. 10
Fifteenth Revised Sheet No. 11	Replaces Fourteenth Revised Sheet No. 11
Fourteenth Revised Sheet No. 12	Replaces Thirteenth Revised Sheet No. 12
Fourteenth Revised Sheet No. 13	Replaces Thirteenth Revised Sheet No. 13
Fifteenth Revised Sheet No. 14	Replaces Fourteenth Revised Sheet No. 14
Thirteenth Revised Sheet No. 15	Replaces Twelfth Revised Sheet No. 15
Seventeenth Revised Sheet No. 16	Replaces Sixteenth Revised Sheet No. 16
Eighteenth Revised Sheet No. 17	Replaces Seventeenth Revised Sheet No. 17
Fourteenth Revised Sheet No. 18	Replaces Thirteenth Revised Sheet No. 18
Fifteenth Revised Sheet No. 19	Replaces Fourteenth Revised Sheet No. 19
Fourteenth Revised Sheet No. 20	Replaces Thirteenth Revised Sheet No. 20
Sixteenth Revised Sheet No. 22	Replaces Fifteenth Revised Sheet No. 22
Fourteenth Revised Sheet No. 23	Replaces Thirteenth Revised Sheet No. 23
Fifteenth Revised Sheet No. 24	Replaces Fourteenth Revised Sheet No. 24
Thirteenth Revised Sheet No. 25	Replaces Twelfth Revised Sheet No. 25
Fifteenth Revised Sheet No. 26	Replaces Fourteenth Revised Sheet No. 26
Thirteenth Revised Sheet No. 27	Replaces Twelfth Revised Sheet No. 27
Ninth Revised Sheet No. 31	Replaces Eighth Revised Sheet No. 31
Eighth Revised Sheet No. 32	Replaces Seventh Revised Sheet No. 32
Original Sheet No. 32A	
Sixth Revised Sheet No. 33	Replaces Fifth Revised Sheet No. 33
Fifth Revised Sheet No. 34	Replaces Fourth Revised Sheet No. 34
Fourth Revised Sheet No. 35	Replaces Third Revised Sheet No. 35
Fifth Revised Sheet No. 36	Replaces Fourth Revised Sheet No. 36
Fourth Revised Sheet No. 37	Replaces Third Revised Sheet No. 37
Third Revised Sheet No. 38	Replaces Second Revised Sheet No. 38

Section 3A

Ninth Revised Sheet No. 1	Replaces Eighth Revised Sheet No. 1
Eighth Revised Sheet No. 2	Replaces Seventh Revised Sheet No. 2
Fifth Revised Sheet No. 3	Replaces Fourth Revised Sheet No. 3
Eighth Revised Sheet No. 4	Replaces Seventh Revised Sheet No. 4

Sixth Revised Sheet No. 5	Replaces Fifth Revised Sheet No. 5
Tenth Revised Sheet No. 6	Replaces Ninth Revised Sheet No. 6
Eighth Revised Sheet No. 7	Replaces Seventh Revised Sheet No. 7
Eighth Revised Sheet No. 8	Replaces Seventh Revised Sheet No. 8
Sixth Revised Sheet No. 9	Replaces Fifth Revised Sheet No. 9
Sixth Revised Sheet No. 10	Replaces Fifth Revised Sheet No. 10
Eighth Revised Sheet No. 11	Replaces Seventh Revised Sheet No. 11
Seventh Revised Sheet No. 12	Replaces Sixth Revised Sheet No. 12
Ninth Revised Sheet No. 13	Replaces Eighth Revised Sheet No. 13
Sixth Revised Sheet No. 14	Replaces Fifth Revised Sheet No. 14
Sixth Revised Sheet No. 15	Replaces Fifth Revised Sheet No. 15
Seventh Revised Sheet No. 16	Replaces Sixth Revised Sheet No. 16
Third Revised Sheet No. 17	Replaces Second Revised Sheet No. 17
Sixth Revised Sheet No. 18	Replaces Fifth Revised Sheet No. 18
Fourth Revised Sheet No. 19	Replaces Third Revised Sheet No. 19
Third Revised Sheet No. 20	Replaces Second Revised Sheet No. 20

Section 3B

Sixth Revised Sheet No. 1	Replaces Fifth Revised Sheet No. 1
Fifth Revised Sheet No. 2	Replaces Fourth Revised Sheet No. 2
Fifth Revised Sheet No. 3	Replaces Fourth Revised Sheet No. 3
Fifth Revised Sheet No. 4	Replaces Fourth Revised Sheet No. 4
Sixth Revised Sheet No. 5	Replaces Fifth Revised Sheet No. 5
Sixth Revised Sheet No. 8	Replaces Fifth Revised Sheet No. 8
Fifth Revised Sheet No. 9	Replaces Fourth Revised Sheet No. 9
Fifth Revised Sheet No. 10	Replaces Fourth Revised Sheet No. 10

Section 3C

Twelfth Revised Sheet No. 5	Replaces Eleventh Revised Sheet No. 5
Fourteenth Revised Sheet No. 11	Replaces Thirteenth Revised Sheet No. 11
Sixth Revised Sheet No. 12	Replaces Fifth Revised Sheet No. 12
First Revised Sheet No. 13	Replaces Original Sheet No. 13
Second Revised Sheet No. 14	Replaces First Revised Sheet No. 14
Second Revised Sheet No. 15	Replaces First Revised Sheet No. 15

Section 4

Fourth Revised Sheet No. 4	Replaces Third Revised Sheet No. 4
Eighth Revised Sheet No. 5	Replaces Seventh Revised Sheet No. 5
Sixth Revised Sheet No. 6	Replaces Fifth Revised Sheet No. 6

Section 5

Third Revised Sheet No. 4	Replaces Second Revised Sheet No. 4
Fifth Revised Sheet No. 21	Replaces Fourth Revised Sheet No. 21
Fourth Revised Sheet No. 22	Replaces Third Revised Sheet No. 22

Section 6

Third Revised Sheet No. 22	Replaces Second Revised Sheet No. 22

General

59. As stated in the Staff Memorandum, with respect to a Settlement Stipulation, petty criticisms can be levied against individual elements of the Settlement Stipulation. Because it is an agreed resolution of the case, however, a settlement stipulation is more appropriately judged on the basis of its overall resolution of the case because it involves trade-offs between the parties to it. The Commission believes that this is the appropriate way of assessing the justness and reasonableness of this Amended Stipulation as well. BHII focuses on the minute details of the Settlement Stipulation in isolation.

60. Staff witness Peterson testified that Staff believes that the end result of the Settlement Stipulation results in just and reasonable rates, and it reasonably reflects the cost that BHP will incur going forward. There were a number of issues which the Staff and the company disagreed on. The Staff's resolution of those issues is stated in the Staff Memorandum, but BHP had its own basis for settling certain issues which were either advantageous or adverse to the company. Staff does not see the company's analysis of that. But the end result, Staff believes, was just and reasonable rates and reasonably reflects the cost that the company expects to incur going forward. TR 280.

61. The Commission finds that the rates, terms and conditions in the Amended Stipulation demonstrate a thorough, penetrating, and credible analysis by Staff and its expert witnesses of the data and assumptions underlying the Application and the Amended Settlement Stipulation; balance fairly the interests of BHP and its customers; recover no more than BHP's current revenue requirements, including a reasonable return to its stockholders commensurate with its cost of equity capital; are supported by substantial evidence; and meet the just and reasonable standard set forth in SDCL 49-34A-6, as more specifically delineated in SDCL 49-34A-8, the unreasonable preference or advantage and unreasonable prejudice or disadvantage prohibitory standards of SDCL 49-34A-3, the fair and reasonable return standard of SDCL 49-34A-8, and are prudent, efficient, and economical and are reasonable and necessary to provide service to the public utility's customers as provided in SDCL 49-34A-8.4. These settlement rates allow BHP a reasonable opportunity to earn a return that is adequate to enable it to continue providing safe, adequate, and reliable service to its South Dakota retail customers.

62. The Commission finds that neither the SDSTA Settlement Agreement nor the Commission's approval of the SDSTA Settlement Agreement has affected the costs to be recovered from BHP's other customers under the Amended Settlement Stipulation.

63. To the extent that any Conclusion of Law set forth below is more appropriately a finding of fact, that Conclusion of Law is incorporated by reference as a Finding of Fact.

CONCLUSIONS OF LAW

1. The following statutes and rules are applicable to this proceeding and vest the Commission with jurisdiction over this matter: SDCL Chapters 1-26 and 49-34A, including 1-26-20, 49-34A-3, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-8.4, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-21, and 49-34A-22, and ARSD Chapters 20:10:01 and 20:10:13.

2. The primary issue raised by BHII concerns the scope of what adjustments may be presented by an applicant for a rate increase within the twenty-four month cost of service

adjustment period set forth in ARSD 20:10:13:44 and what may be considered by the Commission in rendering its decision, including the extent to which the Commission may consider capital cost additions and/or reductions, expense increases and/or reductions, and other relevant cost of service facts which become known and measurable during the pendency and processing of the case prior to the expiration of the twenty-four month period after the application is filed and which will be incurred during the period of 24 months after the filing of the application.

3. SDCL 49-34A-6 provides:

Every rate made, demanded or received by any public utility shall be just and reasonable. Every unjust or unreasonable rate shall be prohibited. The Public Utilities Commission is hereby authorized, empowered and directed to regulate all rates, fees and charges for the public utility service of all public utilities, including penalty for late payments, to the end that the public shall pay only just and reasonable rates for service rendered.

4. SDCL 49-34A-8 provides:

The commission, in the exercise of its power under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, economical, and reasonable service and to the need of the public utility for revenues sufficient to enable it to meet its total current cost of furnishing such service, including taxes and interest, and including adequate provision for depreciation of its utility property used and necessary in rendering service to the public, and to earn a fair and reasonable return upon the value of its property.

5. SDCL 49-34A-8.4 provides:

The burden is on the public utility to establish that the underlying costs of any rates, charges, or automatic adjustment charges filed under this chapter are prudent, efficient, and economical and are reasonable and necessary to provide service to the public utility's customers in this state.

6. SDCL 49-34A-19 provides in relevant part:

In determining the revenue requirement the commission shall consider revenue, expenses, cost of capital and any other factors or evidence material and relevant thereto. The commission may take into consideration the reasonable income and expenses that will be forthcoming in a period of twenty-four months in advance of the test year.

7. ARSD 20:10:13:01(11) provides as follows:

"Test period," the test period outlined in § 20:10:13:44, except that if additional material is filed by the utility, a test period is any 12 consecutive months beginning no later than the proposed effective date of the rate application.

8. ARSD 20:10:13:44 provides as follows:

> The statement of the cost of service shall contain an analysis of system costs as reflected on the filing utility's books for a test period consisting of 12 months of actual experience ending no earlier than 6 months before the date of filing of the data required by §§ 20:10:13:40 and 20:10:13:43 unless good cause for extension is shown. The analysis shall include the return, taxes, depreciation, and operating expenses and an allocation of such costs to the services rendered. The information submitted with the statement shall show the data itemized in this section for the test period, as reflected on the books of the filing public utility. Proposed adjustments to book costs shall be shown separately and shall be fully supported, including schedules showing their derivation, where appropriate. However, no adjustments shall be permitted 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 the filing and which will become effective within 24 months of the last month of the test period used for this section and unless expected changes in revenue are also shown for the same period.

9. As set forth in Findings of Fact 24, these provisions have for decades been interpreted together as providing for a historic test year as the cost of service basis period, but also, in part because such cost of service data are used to set rates for a future period, the analysis and substance of a proposed change in utility rates should include both known and measurable expenses during the test year and adjustments to reflect any changes that occurred after the test year that become known and measurable within the 24-month period for case processing provided for in ARSD 20:10:13:44 and SDCL 49-34A-19. Staff has interpreted these provisions to mean that the adjustments have to be sufficiently known and measurable at the time of their submission for Staff review of the responses to hundreds of discovery requests and filings in the case. Although the phrase "in advance of" is anomalous when read together with the word "forthcoming," the Commission concludes that the intent of SDCL 49-34A-19 is to permit the consideration of cost of service evidence that becomes known and measurable during the twenty-four month period following the end of the test year, that such interpretation is not inconsistent with the phrase "at the time of the filing" due to the voluminous "filings" in a rate case over a two year period in most rate cases, and that such interpretation results in the most accurate real-time basis for the utility's rates, thus minimizing the need for an immediate or near term filing by the utility of a follow-on rate case to recover such costs.

10. As to the issue of revenue during the twenty-four month rate case processing period, BHII argues that BHP and Staff neglected to provide and/or consider evidence of BHP's revenue during such period. BHII argues that this violates the matching principle and also runs contrary to SDCL 49-34A-19. BHP and Staff in contrast argue that the matching principle is not violated because the only adjustments accepted by Staff are adjustments that have no revenue generating component to them. The Commission concludes that none of the cost adjustments included in the Amended Settlement Stipulation result in additional revenue for BHP, and, in the context of a settlement stipulation that very significantly reduces the revenue requirement from what was requested by BHP in its Application and supported by its experts in its pre-filed and hearing testimony, such adjustments are just and reasonable.

11. With respect to BHII's argument at the March 2, 2015, decision hearing that BHII was not afforded due process to contest the Amended Settlement Stipulation's correction of the error in the BHUH allocation, the Commission concludes that this substantive amendment to the original Settlement Stipulation occurred precisely as a result of evidence introduced and

considered at the evidentiary hearing and the pre-filed testimony filed prior to the hearing and received in evidence at the hearing. The error in the calculation of the BHUH allocation was pointed out in BHII's expert witness Kollen's pre-filed testimony and acknowledged by BHP witness Thurber and Staff witness Peterson to be accurate in their pre-filed testimony and at hearing. The Commission has already heard the evidence and arguments regarding this amendment to the Settlement Stipulation, and nothing would be gained by another hearing on a matter that has already been heard.

12. No statute or rule precludes the inclusion of employee incentive compensation in the utility's cost of service and revenue requirement. The Commission's decision whether to allow incentive compensation and, if so, subject to what limitations are judgment calls concerning what meets the just and reasonable standard.

It is therefore

ORDERED, that the Amended Settlement Stipulation between Black Hills Power, Inc. and Staff is approved as the substance of the decision of the Commission in this docket with an effective date of April 1, 2015, and with refunds of interim rate billings in excess of the approved rates plus carrying charges of seven percent (7%) annual interest to occur in May, 2015, in accordance with BHP's proposed Interim Refund Plan. It is further

ORDERED, that the Settlement Agreement between Black Hills Power, Inc. and the South Dakota Science and Technology Authority and the Third Amendment to Electric Power Service Agreement between Black Hills Power, Inc. and South Dakota Science and Technology Authority are approved and refunds to SDSTA shall not therefore be necessary.

NOTICE OF ENTRY AND OF RIGHT TO APPEAL

PLEASE TAKE NOTICE that this Final Decision and Order; Notice of Entry was duly issued and entered on the 17th day of April, 2015. Pursuant to SDCL 1-26-32, this Final Decision and Order will take effect 10 days after the date of receipt or failure to accept delivery of the decision by the parties. Pursuant to ARSD 20:10:01:30.01, an application for a rehearing or reconsideration may be made by filing a written petition with the Commission within 30 days after the date of issuance of this Final Decision and Order; Notice of Entry. Pursuant to SDCL 1-26-31, the parties have the right to appeal this Final Decision and Order to the appropriate Circuit Court by serving notice of appeal of this decision to the circuit court within thirty (30) days after the date of service of this Notice of Decision.

Dated at Pierre, South Dakota, this 17th day of April, 2015.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, electronically ~~or~~ by mail.

By: [signature]

Date: 4/17/15

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

[signature]
CHRIS NELSON, ~~Chairman~~

[signature]
KRISTIE FIEGEN, Commissioner

[signature]
GARY HANSON, Commissioner

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	**ORDER FOR AND NOTICE OF HEARING ON PETITION FOR RECONSIDERATION** **EL14-026**

On March 31, 2014, Black Hills Power, Inc. (BHP) filed with the South Dakota Public Utilities Commission (Commission) an Application for Authority to Increase Electric Rates (Application) and supporting exhibits requesting approval to increase rates for electric service to customers in its South Dakota service territory by approximately $14.6 million annually or approximately 9.27% based on BHP's test year ending September 30, 2013. The Application included an extensive, detailed set of schedules and pre-filed testimony in support of the proposed rates. The Application stated that a typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month. The proposed changes would affect approximately 65,500 customers in BHP's South Dakota service territory. The Application requested an effective date of October 1, 2014, for the proposed rate increase which was the anticipated start-up date for BHP's Cheyenne Prairie Generating Station, then under construction, and coincides with the 180 day limitation on suspension of a requested rate increase pursuant to SDCL 49-34A-14.

On June 6, 2014, GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively Black Hills Industrial Intervenors or BHII) filed a Petition to Intervene, and Dakota Rural Action, Inc. (DRA) filed a Petition to Intervene. On June 26, 2014, the Commission issued an Order Granting Intervention to BHII and DRA.

On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits (Settlement Stipulation). On December 30, 2014, the Commission issued an Order for and Notice of Hearing setting the matter for hearing on January 27-29, 2015. The hearing was held as scheduled on January 27 and 28, 2015. On February 10, 2015, BHP and Staff filed an Amended Settlement Stipulation between BHP and Staff (Amended Stipulation) reflecting two changes to the factual bases supporting the agreed revenue requirement due to new information contained in pre-filed testimony filed after the Settlement Stipulation was entered into and filed and evidence introduced at the hearing. On February 23, 2015, BHP and Staff filed a Joint Motion for Approval of Amended Stipulation. Following post-hearing briefing and questioning from the Commission at a hearing on March 2, 2015, the Commission issued its Final Decision and Order; Notice of Entry on April 17, 2015 (Decision).

On April 1, 2015, BHII filed Black Hills Industrial Intervenors' Petition for Rehearing and Reconsideration (Petition) requesting Commission reconsideration of the following issues:

1. The Commission's interpretation of ARSD 20:10:13:44;
2. The Commission's interpretation of SDCL 49-34A-19;
3. The Commission's interpretation of SDCL 49-34A-24;

4. The Commission's decision to accept BHP's and Staff's exclusion of only $666,068 in incentive compensation related to financial goals in BHP's cost of service; and

5. The Commission's decision to accept BHP and Staff's normalization of pension expenses using a five-year average instead of BHP's actual 2014 pension expense as recommended by BHII.

In the Petition, BHII also requested rehearing on the following grounds: (1) that the Commission's approval of the Amended Stipulation violated principles of equity and due process; and (2) that the Commission's approval of the Amended Settlement, over BHII's timeliness objection, contravened Rule 6 of the South Dakota Rules of Civil Procedure. In the Petition, BHII reserved the right to supplement the Petition following the Commission's issuance of its written Decision. On April 17, 2015, BHP filed Black Hills Power, Inc.'s Answer to BHII's Petition for Rehearing and Reconsideration (BHP's Answer). On April 23, 2015, BHII filed a proposed schedule for party filings and Commission consideration of the Petition. On April 30, 2015, the Commission issued a Procedural Order on Petition for Reconsideration scheduling the Petition for hearing on May 26, 2015. It is therefore

ORDERED, that a hearing shall be held on the Petition and the issues raised therein and in responses thereto by other parties in connection with the Commission's regular meeting on Tuesday, May 26, 2015, beginning at 9:30 A.M. CDT in Room 413 of the State Capitol Building in Pierre, SD. After hearing from the parties, the Commission shall consider the following questions:

Shall the Commission grant the Petition for Rehearing and schedule the matter for an additional evidentiary hearing?

If not, shall the Commission grant the Petition for Reconsideration and reconsider its Decision?

If so, how shall the Commission rule on the issues on reconsideration?

Dated at Pierre, South Dakota, this 11th day of May, 2015.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, electronically or by mail.

By: [signature]

Date: 5/11/15

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

[signature]
CHRIS NELSON, Chairman

[signature]
KRISTIE FIEGEN, Commissioner

[signature]
GARY HANSON, Commissioner

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	))))	**ORDER DENYING REHEARING AND RECONSIDERATION** **EL14-026**

On March 31, 2014, Black Hills Power, Inc. (BHP) filed with the South Dakota Public Utilities Commission (Commission) an Application for Authority to Increase Electric Rates (Application) and supporting exhibits requesting approval to increase rates for electric service to customers in its South Dakota service territory by approximately $14.6 million annually or approximately 9.27% based on BHP's test year ending September 30, 2013. The Application included an extensive, detailed set of schedules and pre-filed testimony in support of the proposed rates. The Application stated that a typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month. The proposed changes would affect approximately 65,500 customers in BHP's South Dakota service territory. The Application requested an effective date of October 1, 2014, for the proposed rate increase which was the anticipated start-up date for BHP's Cheyenne Prairie Generating Station, then under construction, and coincides with the 180 day limitation on suspension of a requested rate increase pursuant to SDCL 49-34A-14.

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On December 9, 2014, BHP and the Commission's staff (Staff) jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits (Settlement Stipulation). On December 30, 2014, the Commission issued an Order for and Notice of Hearing setting the matter for hearing on January 27-29, 2015. The hearing was held as scheduled on January 27 and 28, 2015. On February 10, 2015, BHP and Staff filed an Amended Settlement Stipulation between BHP and Staff (Amended Stipulation) reflecting two changes to the factual bases supporting the agreed revenue requirement due to new information contained in pre-filed testimony filed after the Settlement Stipulation was entered into and filed and evidence introduced at the hearing. On February 23, 2015, BHP and Staff filed a Joint Motion for Approval of Amended Stipulation. Following post-hearing briefing and questioning from the Commission at a hearing on March 2, 2015, the Commission issued its Final Decision and Order; Notice of Entry on April 17, 2015 (Decision).

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4. The Commission's decision to accept BHP's and Staff's exclusion of only $666,068 in incentive compensation related to financial goals in BHP's cost of service; and

5. The Commission's decision to accept BHP and Staff's normalization of pension expenses using a five-year average instead of BHP's actual 2014 pension expense as recommended by BHII.

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At its regular meeting on May 26, 2015, the Commission considered the Amended Petition for Rehearing and Reconsideration. Finding that the Decision and its Findings of Fact are supported by substantial evidence, that the rulings on issues of statute and rule interpretation are consistent with decades of Staff and its experts' interpretation, which have never before been challenged by another party and which have been incorporated in numerous settlement stipulations approved by the Commission, that such interpretation rationally reconciles provisions such as SDCL 49-34A-19 and ARSD 20:10:13:44, and that the Commission did not violate principles of equity and due process or contravene SDCL 15-6-6 because the Amended Stipulation merely amended the Settlement Stipulation to reflect evidence introduced at hearing with full rights of evidence presentation, cross-examination, and advocacy having been afforded all parties, the Commission voted unanimously to deny the Petition for Rehearing and Reconsideration. It is therefore

ORDERED, that the Petition for Rehearing and Reconsideration is denied.

Dated at Pierre, South Dakota, this 29th day of May, 2015.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, electronically.

By: [signature]

Date: 5/29/15

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

[signature]

CHRIS NELSON, Chairman

[signature]

KRISTIE FIEGEN, Commissioner

[signature]

GARY HANSON, Commissioner