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

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE
BLACK HILLS INDUSTRIAL INTERVENORS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

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DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

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

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

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe your education.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the

State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. ("Ebasco"), as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost of service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity, I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing, as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of Electrical World. My article on "Standby Electric Rates" was published in the November 8, 1984, issue of Public Utilities Fortnightly. In February 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, before the

Federal Energy Regulatory Commission ("FERC"), and in the United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Exhibit___(SJB-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Black Hills Industrial Intervenors ("BHII"), a group of General Service, Large and Industrial Contract customers of Black Hills Power, Inc. ("BHP" or the "Company").

Q. What is the purpose of your Direct Testimony?

A. I am presenting testimony on issues pertaining to BHP's class cost of service study and its apportionment of the overall revenue increase to rate classes. The South Dakota Public Utilities Commission (the "Commission") has not had the opportunity to consider the proposed Settlement Stipulation between BHP and the Commission Staff ("Staff") of December 8, 2014 (the "Proposed Settlement"). Therefore, my testimony addresses the revenue increases to each rate class under both the Company's originally filed case, in which it requested an overall revenue increase of $14,634,238, and the Proposed Settlement, under which it would receive an overall revenue increase of $6,890,746.

With respect to these increases, I present testimony on the Company's originally filed class cost of service study and rate class revenue apportionment, as well as the reasonableness of the Proposed Settlement rate class revenue increases shown in Exhibit No. 2 of the Proposed Settlement.

As part of this testimony, I discuss a number of errors in the Company's study. I present an alternative analysis that corrects these errors and provides a reasonable basis to evaluate the reasonableness of BHP's rates relative to cost of service and the appropriate apportionment of any approved increase in the Company's overall revenues.

Q. Would you please summarize your recommendations in this case?

A. Yes, my summary is as follows:

- **The Company's class cost of service study should be rejected because it has a number of errors – both actual numerical errors and conceptual errors – that result in an inaccurate measure of the cost of providing service to each of the its rate classes. These errors, when corrected, show that the Company is earning a rate of return higher than the system average rate of return from the Combined General Service Large/Industrial Contract rate class. This is in contrast to the results shown in the Company's filed class cost of service study.**

- **Notwithstanding the problems with the Company's class cost of service study, the Company's proposed apportionment of the overall approved revenue increase to each rate class appears to be reasonable and should be accepted. The Company's originally-filed rate class revenue increases reflect a level of mitigation to each rate class that produces results that are reasonably consistent with the results of the BHII corrected class cost of service study that I present in this testimony. The Proposed Settlement rate class revenue increases that are designed to recover the overall increase of $6.89 million in**

the Proposed Settlement are also reasonable. Effectively, the Proposed Settlement rate class increases shown in Exhibit No. 2 are consistent with the results of my corrected class cost of service study. If the Commission approves the overall base rate increase of $6,890,746, in the Proposed Settlement, then the rate class increases shown in Exhibit No. 2 should be accepted. However, if the Commission approves an overall base rate increase that is lower than $6,890,746, as BHII witness Lane Kollen recommends, then the increases shown in Exhibit No. 2 should be reduced proportionately.

- **Going forward, the Commission should require the Company to file a class cost of service study in its next base rate case reflecting the corrections that I recommend in my testimony. At a minimum, the Company should file an alternative study that incorporates my corrections in its next case.**

II. CLASS COST OF SERVICE ISSUES

A. Overview of the Company's Results

Q. Please provide an overview of the purpose of a class cost of service study.

A. In general terms, a class cost of service study is an analysis used to determine each class's responsibility for a utility's total costs by separating the utility's total costs into amounts that are associated with each of the various customer classes. This analysis consists of the following three steps: (1) a *functionalization* of costs, (2) a *classification* of those costs' primary causative factors, and (3) an *allocation* of those costs among the various customer classes. A utility's investments and expenses are first functionalized into production, transmission, distribution, and other functions. The next step is to determine the primary factors that cause the costs to be incurred (*i.e.*, determination of whether the investments and expenses are demand/capacity-related, energy-related, or customer-related). An appropriate allocator is then used to allocate the various classified costs to customer classes. There are various types of methods that can be employed to perform a class cost of service analysis. The analyst is charged with identifying the economic theory that is most representative to measure cost-causation.

Q. What are the results of the Company's cost of service study?

A. Table 1 below summarizes the earned rate of return and relative rate of return at present rates for each customer class, based on the Company's study.

Table 1 Summary of Cost of Service Results		
Customer Class	Rate of Return As Filed	Relative ROR Index
Residential	5.11%	0.76
General Service	9.85%	1.46
Combined Gen Svc Lg - Ind Contract	5.70%	0.85
Lighting Service	12.14%	1.80
Water Pumping/Irrigation	7.78%	1.16
Total South Dakota Retail	6.73%	1.00

The analysis underlying the Company's results in Table 1 suggests that the Residential class and the Combined General Service Large/Industrial Contract class are earning below the system average return (relative rates of return below 1.0). However, the Company's analysis is flawed. As discussed below, the Combined General Service Large/Industrial Contract class is earning a rate of return higher than the system average rate of return.

Q. Have you identified specific problems with the Company's class cost of service study?

A. Yes. I have found a number of problems with the Company's study. As I will discuss, correcting these errors results in a significant revision to each rate class's earned rate of return and the corresponding rate increase for each class that can be justified based on its rate of return. I will present a revised cost of service study reflecting all of these corrections in a subsequent portion of my testimony.

Specifically, I have identified errors in three broad areas: (1) the allocation of production demand-related costs, (2) the classification and allocation of distribution-related costs and (3) the energy-related costs associated with voltage loss factors.

B. The Company Erroneously Allocates Production Demand-related Costs

Q. Have you reviewed the Company's class cost of service study filed in this case?

A. Yes. As discussed by Company witness Charles Gray, the Company utilized an Average and Excess Demand ("A&E") methodology to allocate fixed production demand-related costs to rate classes.

Q. What is the A&E Methodology?

A. According to the National Association of Regulatory Utility Commissions ("NARUC") Electric Utility Cost Allocation Manual (the "NARUC Cost Allocation Manual"), the A&E methodology is an energy-weighting method. Generally speaking, all production plant costs are classified as demand-related and the methodology allocates those production plant costs to rate classes using factors that incorporate the classes' average demands and non-coincident peak demands.

Q. Do you have any objections to the Company's use of the A&E Methodology?

A. No. It is a reasonable methodology that is consistent with traditional production demand allocation methodologies discussed in the NARUC Cost Allocation Manual. The A&E Methodology has also been adopted by a number of electric utilities and approved by state regulatory commissions throughout the country. For example, Public Service Company of Colorado has utilized the A&E method and it has been approved in a number of Colorado cases by the Public Utilities Commission of the State of Colorado. It has also been approved by the Virginia State Corporation Commission in a number of Virginia Electric Power Company rate cases, as well as the Texas Public Utility Commission in electric utility rate cases in that state.

Q. How does BHP apply the A&E Methodology?

A. Specifically, BHP used a 3 coincident peak ("CP") A&E method in which the A&E demand costs are allocated based on each class's contribution to the three BHP South Dakota summer coincident peaks, which are the average hourly demands during BHP's highest peaks in the months of July, August and September.

With respect to distribution costs, the Company assigned all costs in distribution account 362 through 368 on the basis of class non-coincident peak ("NCP") demands. For account 369, services, the Company used a weighted NCP demand allocation method.

Q. Would you please discuss the problems that you have identified with the Company's allocation of production demand-related costs?

A. Notwithstanding my support for the use of the A&E method in this case, I have identified two errors in the Company's method. First, there is an error in its A&E calculation for two rate classes (Residential – Total Electric Demand and General Service – Total Electric). While each of these two classes has "excess demand," no excess demand assignment was made to these classes.[1]

The second error is a conceptual error associated with the Company's calculation of the 3 CP A&E factor. The traditional A&E method separates demand-related costs into two categories, average demand-related and excess demand-related, based on the annual system load factor. This load factor is calculated as the ratio of average demand to the annual system peak (1 CP). Average demand costs are determined by multiplying the load factor times total demand costs; excess demand costs are determined by multiplying (1 minus the load factor) times total demand costs. In the Company's analysis in this case, it used a 3 CP load factor to perform this initial allocation. My experience has been that the initial separation of the demand-related costs into average and excess categories is based on a 1 CP annual system load factor, even if a multiple coincident peak is used to allocate the "excess" costs to classes. The annual system load factor is the correct measure of average demand and excess demand because the system is planned to meet the annual peak. While use of a 3 CP allocator to assign excess costs to rate classes is

[1] Excess demand is the rate class's 3 CP demand less its average demand.

reasonable and is consistent with the 4 CP A&E method used in Colorado, the 3 CP load factor is not consistent with the requirement that BHP has to meet its annual system peak.

Q. Are there any additional problems with the Company's allocation of production demand costs?

A. Yes. The Company has identified [redacted] of interruptible/curtailable load on its system. This includes [redacted] of curtailable load associated with the general service large rate class and [redacted] of interruptible load associated with the industrial contract rate class. Customers taking non-firm interruptible service receive a credit reflecting the lower quality of service they receive. Other customers benefit from this interruptible load because the Company does not need as much capacity as it otherwise would require – thus, saving all firm customers the cost of such additional generating capacity. In effect, interruptible load provides a demand response generation resource in a manner similar to supply-side capacity. In exchange for providing capacity to the system by curtailing their usage at the time of peak demand and in other critical periods, customers subscribing to non-firm interruptible service receive a rate credit on their power bills.

Q. Did the Company's cost of service study reflect this interruptible load arrangement in any manner?

A. No. Rate classes that have interruptible load receive a rate credit, or an implicit rate credit in the form of a lower overall demand charge, in the case of a contract rate. As such, rate classes that have customers with interruptible load produce lower test-year revenues than an equivalent firm power customer, all else being equal. The Company's cost of service analysis makes no adjustment to reflect the important distinction between equivalent customers that receive different service (*i.e.*, interruptible vs. firm), nor does it make any load adjustment to reflect the interruptible portion of rate class load.

Q. What is the impact of this failure to recognize and distinguish between firm and interruptible load in the Company's cost of service study?

A. Because the BHP cost of service study simply reports the reduced revenues paid by interruptible load without any recognition (in the form of an adjustment) to reflect the interruptible nature of the load, the reported rates of return for rate classes that have interruptible load are biased and understate the Company's actual rate of return from those rate classes. This is a very significant problem for the combined general service large/industrial contract rate class – a class that has a significant amount of interruptible load. Thus, any decision based on the Company's analysis is incorrect; including relying on the class cost of service study to assign the proposed revenue increase to this class.

Q. How should the Company's class cost of service study be revised to correct this problem?

A. Based on my experience, the best way to properly reflect interruptible load in a class cost of service study is to use an imputed avoided capacity cost approach. This methodology assumes that the value of interruptible load (per kW) is equivalent to the avoided cost of a new combustion turbine generating unit. Each rate class that has interruptible load is credited with the avoided capacity cost on a $/kW basis and the total cost of the interruptible-load credit is then allocated on a demand allocation factor basis to all rate classes (including the classes that have interruptible load). The net impact on a total company basis is $0 and therefore the adjustment has no effect on the overall rate of return or revenue requirement for the Company. This is the methodology that I have used to adjust BHP's class cost of service study in this case.

Q. How did you develop the avoided capacity cost?

A. I relied on a levelized cost analysis from the U.S. Energy Information Administration ("EIA").[2] Baron Exhibit__(SJB-2) contains a copy of the EIA analysis, which reflects the levelized fixed costs of a new-build 2019 simple cycle combustion turbine, expressed in 2012 dollars. As shown on page 6 of the exhibit, the levelized capital cost is $40.20/MWh and the levelized fixed O&M expense is $2.80/MWh (both in $2012). Because the EIA values are on a $/MWh, I converted them to an equivalent $/kW-year basis using the 30% annual capacity factor assumed in EIA's analysis. Finally, I escalated the 2012 cost to 2013 by applying a 1.5% inflation factor. The resulting 2013 levelized avoided capacity cost is $114.70/kW-year. This avoided capacity cost is credited to the combined general service large/industrial contract rate class for each of the [redacted] of interruptible load. The total cost of this credit is then allocated to all rate classes (including the combined general service large/industrial contract class) to reflect the resource cost provided by interruptible load.

[2] Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014, Energy Information Administration, April 2014.

C. The Company Misclassifies and Inaccurately Allocates Distribution-Related Costs

Q. Would you discuss the next category of adjustments that you made to the Company's cost of service study?

A. The next category of adjustments is associated with the classification and allocation of BHP distribution system costs. The largest of these adjustments is designed to correct the Company's study by reflecting a minimum distribution system methodology, as described in the NARUC Cost Allocation Manual. The Company's analysis assumed 100% of distribution costs in FERC accounts 364 to 369 are demand-related, with no amounts classified as customer-related. As I discuss below, this is not a reasonable cost classification/allocation methodology and is inconsistent with the methodologies discussed in the NARUC Cost Allocation Manual. While the NARUC Cost Allocation Manual does not require any specific methodology, the methodologies discussed in the NARUC Cost Allocation Manual for cost allocation are deemed to be reasonable and generally accepted.

Q. Would you explain the minimum distribution system methodology?

A. Yes. As described in the NARUC Cost Allocation Manual, the underlying argument in support of a customer component for distribution costs is that there is a minimal level of distribution investment necessary to connect a customer to the distribution system (lines, poles, transformers) that is independent of the level of demand of the customer. An excerpt from the NARUC manual that discusses the classification of distribution costs is contained in Baron Exhibit__(SJB-3).

The amount of distribution cost that is a function of the requirement to interconnect the customer, regardless of the customer's size, is appropriately assigned to rate classes on the basis of the number of customers, rather than on the kW demand of the class. As stated on page 90 of the NARUC cost allocation manual:

> When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs...[T]he number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system.

Q. Has BHP offered evidence disputing that conclusion?

A. No. BHP witness Gray simply states on page 25 of his direct testimony that "Due to the potential misclassification or misallocation to customer classes from these shortcomings associated with employing these classification methods, the Company elected to classify these accounts as demand." Mr. Gray's testimony provides no justification for completely ignoring a customer component associated with poles, overhead conductors, underground conductors and transformers. Ironically, Mr. Gray relied completely on the analysis of distribution costs relied upon by BHP's affiliate in Colorado ("Black Hills Colorado" or "BHC") in 2012, for the purpose of developing the Company's primary/secondary distribution facility split, as I discuss below.[3] I say that Mr. Gray's reliance on the 2012 Black Hills Colorado case is ironic because the 2012 BHC case used distribution system analyses actually developed in a 2004 BHC case. Mr. Gray and I

[3] *See* Baron Exhibit__(SJB-4), which contains a copy of the Company's response BHII Request No. 36.

both participated in that case, a case in which the Company fully supported the use of the minimum distribution system methodology that I advocate here.[4]

Q. Would you briefly explain the conceptual basis for a minimum distribution cost methodology?

A. As discussed in the NARUC cost allocation manual, there are two approaches that are typically used to develop a customer component of distribution plant and expenses. Each of the two approaches ("zero-intercept" and "minimum size") is designed to measure a "zero load cost" associated with serving customers. Each methodology attempts to measure the customer component of various distribution plant accounts (e.g., poles, primary lines, secondary lines, line transformers). Each of the two methods is designed to estimate the component of distribution plant cost that is incurred by a utility to effectively interconnect a customer to the system, as opposed to providing a specific level of power (kW demand) to the customer. Though arithmetically the zero-intercept method does, for example, produce the cost of "line transformers" associated with "0" kW demand, the more appropriate interpretation of the zero-intercept is that it represents the portion of cost that does not vary with a change in size or kW demand and thus <u>should not</u> be allocated on NCP demand (as BHP has done). Essentially, the "zero-intercept" represents the cost that would be incurred, irrespective of differences in the kW demand of a distribution customer. It is this cost, which is not related to customer usage levels, that is used in the zero-intercept method to identify the portion of distribution costs that

[4] The 2004 case involved BHC's predecessor company, Aquila , Inc.

should be allocated to rate classes based on the number of primary and secondary distribution customers taking service in the class.

Conceptually, this analysis is designed to estimate the behavior of costs statistically, as the Company meets growth in both the number of distribution customers and the loads of these customers. For example, new distribution investment in poles or underground conductors for a new subdivision may be associated with unsold, or unoccupied homes that have "0" kW demand – yet the cost for these facilities is still incurred. Similarly, distribution facilities must be installed to meet the needs of part time residents that may have little or no demand during a portion of the year – yet the cost of such distribution facilities still must be incurred and does not vary as a result of the fact that such facilities serve part-time residents. The minimum distribution system methodology recognizes this circumstance by assigning a portion of the cost of these facilities based on the existence of a "customer," and not just the level of the customer's kW demand. BHP's analysis, on the other hand, assumes that all distribution costs (except meters) vary directly with kW demand, without any fixed component that should be allocated on the basis of the number of customers in each class.

Q. Do you believe that a minimum distribution system methodology is appropriate for BHP?

A. Yes. The conceptual basis for the minimum distribution system method is that it reflects a classification of the distribution facilities that would be required to simply interconnect a customer to the system, irrespective of the kW load of the customer. From a cost-causation standpoint, the argument supporting this approach is that all of these minimal facilities are needed to interconnect a customer to the BHP system.

Q. Did BHP provide the necessary information to develop a BHP-specific minimum distribution system methodology?

A. No. However, as I noted previously, BHP's affiliate Black Hills Colorado developed, presented, and supported a minimum distribution analysis for its 2012 rate case. While BHP relies on BHC's primary/secondary split analysis from that case, the Company selectively ignores BHC's minimum distribution system analysis. In the interest of consistency, just as BHP is relying on the BHC primary/secondary classification analysis, I am relying on the BHC minimum distribution system classification analysis.

Q. Are you familiar with the methodology used by Black Hills Colorado to develop its minimum distribution system demand/energy classification?

A. Yes. The Company, which was Aquila, Inc. in 2004 at that time of the original distribution system analysis (both the primary/secondary split analysis used by BHP in this case and the minimum distribution system analysis that I am using), separately analyzed each distribution plant account to determine the amount of cost that is driven by the addition of customers to the BHC distribution system and the remaining amount of cost that is related to the level of NCP kW demand associated with these customers. BHC classified all of its distribution substation costs as demand-related, since these facilities provide service at the upstream portion of the distribution system and are designed and sized to meet the maximum diversified loads of customers imposed on the system downstream from these facilities. For other distribution facilities, such as primary conductors, secondary conductors and line transformers, BHC classified the facilities as both customer and demand-related using a statistical regression analysis of actual installed costs. The approach used by BHC is generally referred to as the "zero-intercept method" and is specifically identified in the NARUC Cost Allocation Manual as one of the two methods used to classify and allocate distribution costs in a cost of service study. As stated on page 90 of the manual:

> When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

The manual goes on to state, also on page 90:

> Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

The manual clearly makes two important points on the issue of the classification of distribution costs into a customer component and a demand component. The manual states that (1) the utility must classify such costs, and (2) there are two methods to do so.

BHC performed a statistical analysis to identify the portion of a specific FERC distribution plant account (for example, Account No. 368, line transformers) that varies with changes in kW demand and the portion of the costs that do not. This latter portion, which has been statistically identified as invariant to the size of the facility and thus kW load changes, should reasonably be assigned to customer classes on the basis of the number of customers within the class.

Q. Does the Zero Intercept method provide a reasonable basis to classify distribution costs into both a customer and a demand component?

A. Yes. The methodology utilizes a statistical analysis to estimate the relationship between "size" and cost for each of the distribution plant accounts. As discussed in the NARUC Cost Allocation Manual, the purpose of the analysis is to identify the relationship between changes in the size of a particular distribution facility (such as line transformers, conductors, poles, etc.) and the cost of the facility. This statistical analysis then determines the portion of cost that varies with the level of customer load and the portion that is invariant with size or load. The cost-invariant portion is represented by the Y-intercept of the statistical regression equation.

The zero-intercept ("b" in the straight line equation "$Y = A*X + b$" used to estimate the customer component of each distribution account) represents the portion of cost that does not vary with a change in size or kW demand and thus <u>should not</u> be allocated on NCP demand as the Staff advocates. Essentially, the "zero-intercept" represents the cost that would be incurred, irrespective of differences in the kW demand of a distribution customer. It is this cost-invariant component that is used in the zero-intercept method to identify the portion of distribution costs that should be allocated to rate classes based on the number of primary and secondary distribution customers taking service in the class.

Q. Would you summarize the demand/customer classification for each FERC account that was developed by BHC and which you are relying on in this case?

A. Table 2 below shows the percentage demand/customer classification for each of the major distribution accounts. I used these classification percentages to classify BHP's distribution plant in the corresponding accounts in my corrected class cost of service study.

Table 2
Minimum Distribution Study Classification Factors*

Plant Account	Percent Demand	Percent Customer
364 - Poles, Towers & Fixtures	83.4%	16.6%
365 - Overhead Conductors & Devices	88.6%	11.4%
366 - Underground Conduit	19.3%	80.7%
367 - Underground Conductors & Devices	14.2%	85.8%
368 - Line Transformers	44.3%	55.8%

* Source: Black Hills Colorado Study

Q. Did you make any adjustments to the Company's allocation of FERC account 369 distribution services?

A. Yes. As stated in response to SDPUC Request No. 3-72, the Company allocated services on the following basis:

> Account 369 – Services were allocated on class NCP demand with additional customer weighting factors added to the NCPs of the residential class (2.41) and NCPs of the small general service class (1.53), consistent with the allocation method employed in Black Hills 2012 filing for Account 369.

Q. Is this a reasonable allocation method for Account 369-Services costs?

A. No. I do not recall ever seeing a utility classifying Account 369 costs as anything other than 100% customer-related and then allocated to rate classes on the basis of the number of customers. The NARUC Cost Allocation Manual, at page 96 [page 14 of 17, Exhibit__(SJB-3)] states that these costs are "generally classified as customer-related." While the NARUC manual notes that some utilities recognize size differences through a demand component, this does not mean that it is appropriate to allocate these costs on NCP demand, with a weighting factor for the residential and small general service classes, as the Company has done in this case. I believe that a customer classification of these costs appropriately reflects cost causation.

Q. Would you discuss the next correction that you made to the Company's class cost of service study?

A. The Company's analysis of distribution facilities did not recognize any distinction between customers served at 69,000 volt ("69 kV") and other primary voltage customers. Based on a review of BHP data, these 69 kV customers should not be allocated substation and primary line costs that are associated with lower voltage primary service that cannot be used to serve 69 kV loads. To correct this problem, I functionalized Accounts 360 to 362, which are associated with substation plant costs, into two sub-functions: 69 kV subtransmission and other. Because the 69 kV customers are not served by lower voltage facilities, they should only be allocated an NCP demand share of the 69 kV facilities and none of the other lower voltage costs. This adjustment removes the NCP demand allocator for the 69 kV classes for accounts 361-362 and develops a blended allocator for account 360 that 1) allocates the land for 69 kV lines to all classes and 2) the land for substations only to rate classes taking service below 69 kV.

A similar adjustment has been made to distribution costs in Accounts 364 to 367 associated with poles, overhead lines and underground lines and conduit. To the extent that these distribution accounts contain costs for facilities that can only serve customers taking service at voltages below 69 kV, the 69 kV customers should not be allocated such costs. To sub-functionalize these costs, investment in Accounts 364-367 associated with the 69 kV system were separated based on the ratio of 69 kV related investment at September 2013. These 69 kV costs were then assigned to all rate classes in the manner used in the Company's study. The remaining investment is assigned only to rate classes served below 69 kV. For purposes of this adjustment, I relied on the primary/secondary functionalization developed by the Company and assumed that the 69 kV investment is completely in the primary amount.

D. The Company Failed to Take Into Account Loss Factors

Q. Would you discuss the final adjustment that you made to the Company's class cost of service study?

A. Based on the Commission's decision in Docket EL12-061, all costs collected through the Energy Cost Adjustment ("ECA") have been removed from base rates in this case. All of these costs will be collected through the ECA. The current ECA does not differentiate by rate class service voltage (i.e, secondary, primary, 69 kV). As a result customers that take service at primary and 69 kV are subsidizing customers taking service at secondary voltage – this occurs because all kWh are billed the identical ECA charge per kWh. When the ECA was determined as simply the incremental cost over (or under) the base amount of fuel and purchased power expense, this voltage issue was not significant since the base amount of fuel and purchased power expenses were allocated to rate classes in each base rate cost of service study on a loss adjusted kWh energy basis. Thus only the incremental (negative or positive) ECA adjustment was misaligned with cost causation.

As a result of the change to 100% of fuel and purchased power costs now being recovered in the ECA, ignoring this loss issue becomes more significant. Absent a change in the ECA to reflect loss differences among rate classes, it is reasonable to make a loss adjustment in the base rate class cost of service study.

Q. Would you describe how you performed this analysis?

A. Yes. I developed an adjustment to each rate class's O&M expenses based on the difference between: (1) an allocation of the test year amount of fuel and purchased energy expense ($33,519,802) based on metered kWh and (2) an allocation of the same expense using loss-adjusted rate class kWh. The resulting amounts for each rate class sum to $0 on a total BHP basis and therefore this adjustment has no impact on BHP's overall expenses or revenue requirements. The adjustment simply provides a cost of service recognition for differences in energy losses incurred by BHP to actually serve each rate class.

E. Results from Corrected Class Cost of Service Study

Q. What are the overall results of your corrected class cost of service study?

A. Table 3 below summarizes the rates of return and relative rate of return indexes at present rates produced by the BHII corrected class cost of service study versus the Company's filed cost of service study. Baron Exhibit__(SJB-5) contains summary schedules from the corrected class cost of service study.

Table 3
Summary of Cost of Service Results
BHII Corrected Class Cost of Service Study

	BHII Corrected		BHP As-Filed	
Customer Class	Rate of Return	ROR Index	Rate of Return	ROR Index
Residential	4.23%	0.63	5.11%	0.76
General Service	9.98%	1.48	9.85%	1.46
Combined GSL-ICS	7.26%	1.08	5.70%	0.85
Lighting Service	12.37%	1.84	12.14%	1.80
Water Pumping/Irrigation	9.39%	1.40	7.78%	1.16
Total South Dakota Retail	6.73%	1.00	6.73%	1.00

III. APPORTIONMENT OF THE REVENUE INCREASE TO RATE CLASSES

Q. In its original filing in this case, how did the Company propose to apportion its requested $14,634,238 revenue increase to rate classes?

A. Table 4 below shows the increases proposed by BHP, assuming that it receives its originally filed requested overall revenue increase in this case. According to the testimony of Company witness Kyle White, the Company has utilized the results of its filed class cost of service study, subject to mitigation limits such that no rate class receives less than 75% of the average retail percentage increase of 9.3% and no class receives more than 120% of the average increase.[5] Also shown in Table 4 are the unmitigated increases that would otherwise be produced by the Company's as-filed class cost of service study.

Table 4
Summary of BHP Proposed Rate Increases

Customer Class	Increases Per BHP Cost of Service		BHP Proposed Increases	
	$	%	$	%
Residential	11,671,978	19.3%	6,536,767	10.8%
General Service	(3,259,960)	-6.4%	3,899,585	7.3%
Combined Gen Svc Lg - Ind Contract	6,465,811	15.4%	4,048,108	9.7%
Lighting Service	(319,005)	-15.7%	148,409	7.3%
Water Pumping/Irrigation	75,415	3.5%	7,290	6.1%
Total South Dakota Retail	14,634,238	9.3%	14,640,159	9.3%

Q. Have you developed the rate class increases that would be supported by your corrected class cost of service study?

[5] Direct Testimony of Kyle D. White at 9.

A. Yes. Table 5 shows these increases, again based on the Company's overall originally requested increase of $14.6 million. These increases are the increases that would be required at full cost of service rates, with no mitigation or limitations.

Table 5
Summary of BHII Corrected Cost of Service Results

Customer Class	Increases Per BHII Cost of Service $	Increases Per BHII Cost of Service %	BHP Proposed Increases $	BHP Proposed Increases %
Residential	16,070,797	26.5%	6,536,767	10.8%
General Service	(3,515,966)	-6.9%	3,899,585	7.3%
Combined Gen Svc Lg - Ind Contract	2,501,091	6.0%	4,048,108	9.7%
Lighting Service	(334,987)	-16.5%	148,409	7.3%
Water Pumping/Irrigation	(86,697)	-4.0%	7,290	6.1%
Total South Dakota Retail	14,634,238	9.3%	14,640,159	9.3%

As can be seen, based on the BHII corrected class cost of service study, the increase to the Combined General Service Large/Industrial Contract Class would be substantially less than the Company's proposed increase (6.0% versus 9.7%). However, the increases shown in Table 5 are based directly on the BHII class cost of service study and do not reflect any mitigation. As I will discuss below, I believe that it is appropriate to mitigate the increases to each rate class.

Q. What are the increases to each rate class proposed in the Proposed Settlement?

A. Table 6 below summarizes the increases to each rate class shown in Proposed Settlement Exhibit No. 2.

Table 6
Summary of BHP Proposed Rate Increases

Customer Class	Increases Per BHP Cost of Service	
	$	%
Residential	3,077,150	5.04%
General Service*	1,838,869	3.45%
Combined Gen Svc Lg - Ind Contract	1,904,657	4.55%
Lighting Service	69,858	3.45%
Total South Dakota Retail	6,890,534	4.35%

* Includes Water Pumping/Irrigation.

Q. Have you developed an analysis of the increases to each rate class using the BHII corrected class cost of service study, adjusted to reflect the Proposed Settlement revenue increases agreed to by the Company and the Commission Staff?

A. Yes. Table 7 shows these increases, based on the Staff/BHP overall revenue increase of $6.89 million. Also shown in Table 7 are a set of corresponding increases with two levels of mitigation that I believe would be appropriate, if the BHII corrected class cost of service study were adopted by the Commission. The first level of mitigation would eliminate any revenue decreases (*i.e.*, a limitation that no rate class receives a rate decrease). The additional revenue produced by this "no rate decrease" limitation is spread as a <u>credit</u> to each of the other rate classes in proportion to the otherwise applicable increases. The second level of mitigation that I would recommend would limit the increase to each rate class to no more than 1.5 times the retail average increase (1.5 X 4.35 = 6.53%).

Table 7
Summary of BHII Class Cost of Service Results and Mitigated Increases
Using the Settlement Revenue Requirement

Customer Class	Increases Per BHII Cost of Service		Increases with Mitigation -1 (Eliminate decreases)		Increases With Additional Mitigation (Limit Increase to 1.5 X Avg,)		
	$	%	$	%	$ Mitigation	$	%
Residential	12,636,616	20.72%	6,633,869	10.88%	(2,650,215)	3,983,654	6.53%
General Service	(5,649,518)	-11.04%	-	0.00%	1,394,103	1,394,103	2.73%
Combined GS Lg - Ind Contr	489,315	1.17%	256,877	0.61%	1,141,373	1,398,249	3.34%
Lighting Service	(409,879)	-20.23%	-	0.00%	55,222	55,222	2.73%
Water Pumping/Irrigation	(175,787)	-8.05%	-	0.00%	59,517	59,517	2.73%
Total South Dakota Retail	6,890,746	4.35%	6,890,746	4.35%	(0)	6,890,746	4.35%

For this second mitigation adjustment, I have allocated the reduction to the residential class increase to each of the other rate classes based on a uniform percentage amount applied to present revenues.

Q. How do the mitigated increases shown in Table 7 compare to the increases shown in Exhibit No. 2 to the Proposed Settlement?

A. While the increases shown in Table 7 differ from the Proposed Settlement rate class increases, I am offering Table 7 as a means of reaching the Proposed Settlement increases. Thus, I am not advocating that the Commission accept the increases set forth in Table 7. I believe that the relative apportionment of the increases shown in Proposed Settlement Exhibit No. 2 (my Table 6) are reasonable, assuming the Commission approves the overall Proposed Settlement revenue increase of $6,890,746.

If, however, the Commission accepts the recommendation of BHII witness Kollen that the overall revenue increase in this case should be much lower than the Proposed Settlement amount, then I recommend that the overall approved BHP revenue increase be apportioned based on the increases shown in Proposed Settlement Exhibit No. 2, by scaling back the increases in Exhibit No. 2 proportionately. For example, if the Commission approves an overall BHP increase of $3.0 million, then the increases shown in Proposed Settlement Exhibit No. 2 should be reduced proportionately for each rate class by the ratio of [$3,000,000/$6,890,746] or 43.5367%. This would mean that the dollar increase to say, the residential class, would be $1,339,688 instead of the Proposed Settlement residential class increase of $3,077,150. Similar proportionate adjustments would be made to the increases for each rate class shown in Exhibit No. 2.

Q. Do you have any additional recommendations?

A. Yes. The Commission should require BHP to file a class cost of service study in its next base rate case reflecting the corrections that I have discussed in my testimony. At a minimum, the Company should be required to file an alternative class cost of service study (in addition to its preferred method) reflecting the corrections that I am recommending. The changes to the Company's study that I have presented provide a more appropriate basis to evaluate the reasonableness of the Company's rates.

Q. Does this conclude your Direct Testimony?

A. Yes.

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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

Docket No. EL14-026

EXHIBITS

OF

STEPHEN J. BARON

**ON BEHALF OF THE
BLACK HILLS INDUSTRIAL INTERVENORS**

**J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA**

December 2014

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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

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EXHIBIT__(SJB-1)

OF

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December 2014

Expert Testimony Appearances
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Stephen J. Baron
As of November 2014

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of	Chamber of	Santa Clara	Cost-of-service, rate design.

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Date	Case	Jurisdict.	Party	Utility	Subject
		Santa Clara	Commerce	Municipal	
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy	Indiana & Michigan	Interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
			Consumers	Power Co.	
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp.,	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

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Date	Case	Jurisdict.	Party	Utility	Subject
			Allegheny Ludlum Corp.		
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.

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Date	Case	Jurisdict.	Party	Utility	Subject
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.

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06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.
04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses, Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues

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Date	Case	Jurisdict.	Party	Utility	Subject
	P-00062214		Alliance		
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue alllocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to

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Date	Case	Jurisdict.	Party	Utility	Subject
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Rate Schedules Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
5/09	PUE-2009-00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis
6/09	PUE-2009-00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
6/09	PUE-2009-00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009-00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan

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Date	Case	Jurisdict.	Party	Utility	Subject
12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design
2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
3/10	E015/ GR-09-1151	MN	Large Power Intervenors	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales
4/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
4/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
7/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Cost of Service, Rate Design
09/10	2010-00167	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
09/10	10M-245E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Economic Impact of Clean Air Act
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design, Transmission Rider
11/10	Doc. No. 4220-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Northern States Power Co. Wisconsin	Cost of Service, rate design
12/10	10A-554EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Demand Side Management Issues
12/10	10-2586-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Provider of Last Resort Rate Plan Electric Security Plan
3/11	20000-384-ER-10	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power Wyoming	Electric Cost of Service, Revenue Apportionment, Rate Design

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Date	Case	Jurisdict.	Party	Utility	Subject
5/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
6/11	Docket No. 10-035-124	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/11	PUE-2011 -00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
07/11	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Entergy System Agreement - Successor Agreement, Revisions, RTO Day 2 Market Issues
07/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Provider of Last Resort Issues
08/11	PUE-2011-00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Rate Recovery of RPS Costs
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co. Kentucky Utilities Company	Environmental Cost Recovery
09/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Stipulation Support Testimony
10/11	11-0452 E-P-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Reduction Cost Recovery
11/11	11-1274 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Decoupling
12/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
3/12	Case No. 2011-00401	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Environmental Cost Recovery
4/12	2011-00036 Rehearing Case	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
5/12	2011-346 2011-348	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
6/12	PUE-2012 -00051	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider

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Date	Case	Jurisdict.	Party	Utility	Subject
6/12	12-00012 12-00026	TN	Eastman Chemical Co. Air Products and Chemicals, Inc.	Kingsport Power Company	Demand Response Programs
6/12	Docket No. 11-035-200	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/12	12-0275-E-GI-EE	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Rider
6/12	12-0399-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/12	120015-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/12	2011-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Environmental Cost Recovery
8/12	Case No. 2012-00226	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Real Time Pricing Tariff
9/12	ER12-1384	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement, Cancelled Plant Cost Treatment
9/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/12	12-1238 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost Recovery Issues
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana	Purchased Power Contracts
12/12	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales Damages Phase
12/12	E-01933A-12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Decoupling
1/13	12-1188 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Securitization of ENEC Costs
1/13	E-01933A-12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
4/13	12-1571 E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Generation Resource Transition Plan Issues

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4/13	PUE-2012 -00141	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Generation Asset Transfer Issues
6/13	12-1655 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Generation Asset Transfer Issues
06/13	U-32675	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	MISO Joint Implementation Plan Issues
7/13	130040-EI	FL	WCF Health Utility Alliance	Tampa Electric Company	Cost of Service, Rate Design
7/13	13-0467-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/13	13-0462-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
8/13	13-0557-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Ratemaking Policy Associated with Rural Economic Reserve Funds
10/13	13-0764-E-CN	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Clinch River Gas Conversion Project
11/13	R-2013-2372129	PA	United States Steel Corporation	Duquesne Light Company	Cost of Service, Rate Design
11/13	13A-0686EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Demand Side Management Issues
11/13	13-1064-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
4/14	ER-432-002	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Union Pacific Railroad Litigation Settlement
5/14	2013-2385 2013-2386	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
5/14	14-0344-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
5/14	14-0345-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
5/14	Docket No. 13-035-184	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service

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7/14	PUE-2014 -00007	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
7/14	ER13-2483	FERC	Bear Island Paper WB LLC	Old Dominion Electric Cooperative.	Cost of Service, Rate Design Issues
8/14	14-0546-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Mitchell Asset Transfer
8/14	PUE-2014 -00026	VA	Old Dominion Committee	Appalachian Power Company	Biennial Review Case - Cost of Service Issues
9/14	14-841-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Electric Security Rate Plan Standard Service Offer
10/14	14-0702-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/14	14-1550-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")

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**

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF THE
BLACK HILLS INDUSTRIAL INTERVENORS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

December 2014

Independent Statistics & Analysis
U.S. Energy Information Administration

April 2014

Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014

This paper presents average values of levelized costs for generating technologies that are brought online in 2019[1] as represented in the National Energy Modeling System (NEMS) for the *Annual Energy Outlook 2014* (AEO2014) Reference case.[2] Both national values and the minimum and maximum values across the 22 U.S. regions of the NEMS electricity market module are presented.

Levelized cost of electricity (LCOE) is often cited as a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kilowatthour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.[3] The importance of the factors varies among the technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small variable O&M costs, LCOE changes in rough proportion to the estimated capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect LCOE. The availability of various incentives, including state or federal tax credits, can also impact the calculation of LCOE. As with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change.

It is important to note that, while LCOE is a convenient summary measure of the overall competiveness of different generating technologies, actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other factors. The ***projected utilization rate***, which depends on the load shape and the existing resource mix in an area where additional capacity is needed, is one such factor. The ***existing resource mix*** in a region can directly impact the economic viability of a new investment through its effect on the economics surrounding the displacement of existing resources. For example, a wind resource that would primarily displace existing natural gas generation will usually have a different economic value than one that would displace existing coal generation.

A related factor is the ***capacity value***, which depends on both the existing capacity mix and load characteristics in a region. Since load must be balanced on a continuous basis, units whose output can be varied to follow demand (dispatchable technologies) generally have more value to a system than less

[1] 2019 is shown because the long lead time needed for some technologies means that the plant could not be brought online prior to 2019 unless it was already under construction.
[2] The full report is available at http://www.eia.gov/forecasts/aeo/index.cfm.
[3] The specific assumptions for each of these factors are given in the *Assumptions to the Annual Energy Outlook*, available at http://www.eia.doe.gov/oiaf/aeo/index.html.

flexible units (non-dispatchable technologies), or those whose operation is tied to the availability of an intermittent resource. The LCOE values for dispatchable and nondispatchable technologies are listed separately in the tables, because caution should be used when comparing them to one another.

Since projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed, the direct comparison of LCOE across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives. Conceptually, a better assessment of economic competitiveness can be gained through consideration of avoided cost, a measure of what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project, as well as its levelized cost. Avoided cost, which provides a proxy measure for the annual economic value of a candidate project, may be summed over its financial life and converted to a stream of equal annual payments. The avoided cost is divided by average annual output of the project to develop the "levelized" avoided cost of electricity (LACE) for the project.[4] The LACE value may then be compared with the LCOE value for the candidate project to provide an indication of whether or not the project's value exceeds its cost. If multiple technologies are available to meet load, comparisons of each project's LACE to its LCOE may be used to determine which project provides the best net economic value. Estimating avoided costs is more complex than estimating levelized costs because it requires information about how the system would have operated without the option under evaluation. In this discussion, the calculation of avoided costs is based on the marginal value of energy and capacity that would result from adding a unit of a given technology and represents the potential revenue available to the project owner from the sale of energy and generating capacity. While the economic decisions for capacity additions in EIA's long-term projections use neither LACE nor LCOE concepts, the LACE and net value estimates presented in this report are generally more representative of the factors contributing to the projections than looking at LCOE alone. However, both the LACE and LCOE estimates are simplifications of modeled decisions, and may not fully capture all decision factors or match modeled results.

Policy-related factors, such as environmental regulations and investment or production tax credits for specified generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future policies may cause plant owners or investors who finance plants to place a value on ***portfolio diversification.*** While EIA considers many of these factors in its analysis of technology choice in the electricity sector, these concepts are not included in LCOE or LACE calculations.

The LCOE values shown for each utility-scale generation technology in Table 1 and Table 2 in this discussion are calculated based on a 30-year cost recovery period, using a real after tax weighted average cost of capital (WACC) of 6.5%. In reality, the cost recovery period and cost of capital can vary by technology and project type. In the AEO2014 reference case, 3 percentage points are added to the cost of capital when evaluating investments in greenhouse gas (GHG) intensive technologies like coal-

[4] Further discussion of the levelized avoided cost concept and its use in assessing economic competitiveness can be found in this article: http://www.eia.gov/renewable/workshop/gencosts/.

fired power and coal-to-liquids (CTL) plants without carbon control and sequestration (CCS). In LCOE terms, the impact of the cost of capital adder is similar to that of an emissions fee of $15 per metric ton of carbon dioxide (CO_2) when investing in a new coal plant without CCS, which is representative of the costs used by utilities and regulators in their resource planning.[5] The adjustment should not be seen as an increase in the actual cost of financing, but rather as representing the implicit hurdle being added to GHG-intensive projects to account for the possibility that they may eventually have to purchase allowances or invest in other GHG-emission-reducing projects to offset their emissions. As a result, the LCOE values for coal-fired plants without CCS are higher than would otherwise be expected.

The levelized capital component reflects costs calculated using tax depreciation schedules consistent with permanent tax law, which vary by technology. Although the capital and operating components do not incorporate the production or investment tax credits available to some technologies, a subsidy column is included in Table 1 to reflect the estimated value of these tax credits, where available, in 2019. In the reference case, tax credits are assumed to expire based on current laws and regulations.

Some technologies, notably solar photovoltaic (PV), are used in both utility-scale generating plants and distributed end-use residential and commercial applications. As noted above, the LCOE (and also subsequent LACE) calculations presented in the tables apply only to the utility-scale use of those technologies.

In Table 1 and Table 2, the LCOE for each technology is evaluated based on the capacity factor indicated, which generally corresponds to the high end of its likely utilization range. Simple combustion turbines (conventional or advanced technology) that are typically used for peak load duty cycles are evaluated at a 30% capacity factor. The duty cycle for intermittent renewable resources, wind and solar, is not operator controlled, but dependent on the weather or solar cycle (that is, sunrise/sunset) and so will not necessarily correspond to operator dispatched duty cycles. As a result, their LCOE values are not directly comparable to those for other technologies (even where the average annual capacity factor may be similar) and therefore are shown in separate sections within each of the tables. The capacity factors shown for solar, wind, and hydroelectric resources in Table 1 are simple averages of the capacity factor for the marginal site in each region. These capacity factors can vary significantly by region and can represent resources that may or may not get built in EIA capacity projections. They should not be interpreted as representing EIA's estimate or projection of the gross generating potential of resources actually projected to be built.

As mentioned above, the LCOE values shown in Table 1 are national averages. However, as shown in Table 2, there is significant regional variation in LCOE values based on local labor markets and the cost and availability of fuel or energy resources such as windy sites. For example, LCOE for incremental wind capacity coming online in 2019 ranges from $71.3/MWh in the region with the best available resources in 2019 to $90.3/MWh in regions where LCOE values are highest due to lower quality wind resources and/or higher capital costs for the best sites that can accommodate additional wind capacity. Costs shown for wind may include additional costs associated with transmission upgrades needed to access

[5] Morgan Stanley, "Leading Wall Street Banks Establish The Carbon Principles" (Press Release, February 4, 2008), www.morganstanley.com/about/press/articles/6017.html.

remote resources, as well as other factors that markets may or may not internalize into the market price for wind power.

As previously indicated, LACE provides an estimate of the cost of generation and capacity resources displaced by a marginal unit of new capacity of a particular type, thus providing an estimate of the value of building such new capacity. This is especially important to consider for intermittent resources, such as wind or solar, that have substantially different duty cycles than the baseload, intermediate and peaking duty cycles of conventional generators. Table 3 provides the range of LACE estimates for different capacity types. The LACE estimates in this table have been calculated assuming the same maximum capacity factor as in the LCOE. A subset of the full list of technologies in Table 1 is shown because the LACE value for similar technologies with the same capacity factor would have the same value (for example, conventional and advanced combined cycle plants will have the same avoided cost of electricity). Values are not shown for combustion turbines, because turbines are more often built for their capacity value to meet a reserve margin rather than to meet generation requirements and avoid energy costs.

When the LACE of a particular technology exceeds its LCOE at a given time and place, that technology would generally be economically attractive to build. While the build decisions in the real world, and as modeled in the AEO, are somewhat more complex than a simple LACE to LCOE comparison, including such factors as policy and non-economic drivers, the net economic value (LACE minus LCOE, including subsidy, for a given technology, region and year) shown in Table 4 provides a reasonable point of comparison of first-order economic competitiveness among a wider variety of technologies than is possible using either the LCOE or LACE tables individually. In Table 4, a negative difference indicates that the cost of the marginal new unit of capacity exceeds its value to the system, as measured by LACE; a positive difference indicates that the marginal new unit brings in value in excess of its cost by displacing more expensive generation and capacity options. The range of differences columns represent the variation in the calculation of the difference for each region. For example, in the region where the advanced combined cycle appears most economic in 2019, the LCOE is $61.5/MWh and the LACE is $62.3/MWh, resulting in a net difference of $0.8/MWh. This range of differences is not based on the difference between the minimum values shown in Table 2 and Table 3, but represents the lower and upper bound resulting from the LACE minus LCOE calculations for each of the 22 regions.

The average net differences shown in Table 4 are for plants coming online in 2019, consistent with Tables 1-3, as well as for plants that could come online in 2040, to show how the relative competitiveness changes over the projection period. Additional tables showing the LCOE cost components and regional variation in LCOE and LACE for 2040 can be found in the Appendix. In 2019, the average net differences are negative for all technologies except geothermal, reflecting the fact that on average, new capacity is not needed in 2019. However, the upper value for both combined cycle technologies is at or above zero, indicating competiveness in a particular region. Geothermal cost data is site-specific, and the relatively large positive value for that technology results because there may be individual sites that are very cost competitive, leading to new builds, but there is a limited amount of capacity available at that cost. By 2040, the LCOE values for most technologies are lower, typically reflecting declining capital costs over time. All technologies receive cost reductions from learning over time, with newer, advanced technologies receiving larger cost reductions, while conventional technologies will see smaller learning effects. Capital costs are also adjusted over time based on commodity prices, through a factor based on the metals and metal products index, which declines in real terms over the projection. However, the LCOE for natural gas-fired technologies rises over time, because rising fuel costs more than offset any decline in capital costs. The LACE values for all technologies increase by 2040 relative to 2019, reflecting higher energy costs and a greater value for new capacity. As a result, the difference between LACE and LCOE for almost all technologies gets closer to a net positive value in 2040, and there are several technologies (advanced combined cycle, wind, solar PV, hydro and geothermal) that have multiple regions with positive net differences.

Table 1. Estimated levelized cost of electricity (LCOE) for new generation resources, 2019

	U.S. Average LCOE (2012 $/MWh) for Plants Entering Service in 2019							
Plant Type	**Capacity Factor (%)**	**Levelized Capital Cost**	**Fixed O&M**	**Variable O&M (including fuel)**	**Transmission Investment**	**Total System LCOE**	**Subsidy[1]**	**Total LCOE including Subsidy**
Dispatchable Technologies								
Conventional Coal	85	60.0	4.2	30.3	1.2	95.6		
Integrated Coal-Gasification Combined Cycle (IGCC)	85	76.1	6.9	31.7	1.2	115.9		
IGCC with CCS	85	97.8	9.8	38.6	1.2	147.4		
Natural Gas-fired								
Conventional combined Cycle	87	14.3	1.7	49.1	1.2	66.3		
Advanced Combined Cycle	87	15.7	2.0	45.5	1.2	64.4		
Advanced CC with CCS	87	30.3	4.2	55.6	1.2	91.3		
Conventional Combustion Turbine	30	40.2	2.8	82.0	3.4	128.4		
Advanced Combustion Turbine	30	27.3	2.7	70.3	3.4	103.8		
Advanced Nuclear	90	71.4	11.8	11.8	1.1	96.1	-10.0	86.1
Geothermal	92	34.2	12.2	0.0	1.4	47.9	-3.4	44.5
Biomass	83	47.4	14.5	39.5	1.2	102.6		
Non-Dispatchable Technologies								
Wind	35	64.1	13.0	0.0	3.2	80.3		
Wind – Offshore	37	175.4	22.8	0.0	5.8	204.1		
Solar PV[2]	25	114.5	11.4	0.0	4.1	130.0	-11.5	118.6
Solar Thermal	20	195.0	42.1	0.0	6.0	243.1	-19.5	223.6
Hydroelectric[3]	53	72.0	4.1	6.4	2.0	84.5		

[1]The subsidy component is based on targeted tax credits such as the production or investment tax credit available for some technologies. It only reflects subsidies available in 2019, which include a permanent 10% investment tax credit for geothermal and solar technologies, and the $18.0/MWh production tax credit for up to 6 GW of advanced nuclear plants, based on the Energy Policy Acts of 1992 and 2005. EIA models tax credit expiration as in current laws and regulations: new solar thermal and PV plants are eligible to receive a 30% investment tax credit on capital expenditures if placed in service before the end of 2016, and 10% thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $21.5/MWh ($10.7/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30% investment tax credit, if they are under construction before the end of 2013.

[2]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

Table 2. Regional variation in levelized cost of electricity (LCOE) for new generation resources, 2019

	Range for Total System LCOE (2012 $/MWh)			Range for Total LCOE with Subsidies[1] (2012 $/MWh)		
Plant Type	**Minimum**	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**
Dispatchable Technologies						
Conventional Coal	87.0	95.6	114.4			
IGCC	106.4	115.9	131.5			
IGCC with CCS	137.3	147.4	163.3			
Natural Gas-fired						
Conventional Combined Cycle	61.1	66.3	75.8			
Advanced Combined Cycle	59.6	64.4	73.6			
Advanced CC with CCS	85.5	91.3	105.0			
Conventional Combustion Turbine	106.0	128.4	149.4			
Advanced Combustion Turbine	96.9	103.8	119.8			
Advanced Nuclear	92.6	96.1	102.0	82.6	86.1	92.0
Geothermal	46.2	47.9	50.3	43.1	44.5	46.4
Biomass	92.3	102.6	122.9			
Non-Dispatchable Technologies						
Wind	71.3	80.3	90.3			
Wind – Offshore	168.7	204.1	271.0			
Solar PV[2]	101.4	130.0	200.9	92.6	118.6	182.6
Solar Thermal	176.8	243.1	388.0	162.6	223.6	356.7
Hydroelectric[3]	61.6	84.5	137.7			

[1]Levelized cost with subsidies reflects subsidies available in 2019, which include a permanent 10% investment tax credit for geothermal and solar technologies, and the $18.0/MWh production tax credit for up to 6 GW of advanced nuclear plants, based on the Energy Policy Acts of 1992 and 2005.

[2]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Note: The levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are as follows: Wind – 31% to 45%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydroelectric – 30% to 65%. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

Table 3: Regional variation in levelized avoided costs of electricity (LACE) for new generation resources, 2019

	Range for LACE (2012 $/MWh)		
Plant Type	**Minimum**	**Average**	**Maximum**
Dispatchable Technologies			
Coal-fired plant types without CCS	54.6	62.2	70.6
IGCC with CCS[1]	54.6	62.0	70.6
Natural Gas-fired Combined Cycle	54.5	62.9	74.2
Advanced Nuclear	54.6	61.7	70.5
Geothermal	58.3	60.9	62.4
Biomass	54.5	63.3	74.5
Non-Dispatchable Technologies			
Wind	51.7	55.7	66.4
Wind – Offshore	55.1	62.3	73.7
Solar PV	50.8	73.4	89.6
Solar Thermal	48.2	73.3	82.3
Hydroelectric	54.1	59.9	69.5

[1]Coal without CCS cannot be built in California, therefore the average LACE for coal technologies without CCS is computed over fewer regions than the LACE for IGCC with CCS. Otherwise, the LACE for any given region is the same across coal technologies, with or without CCS.

Table 4: Difference between levelized avoided costs of electricity (LACE) and levelized costs of electricity (LCOE), 2019 and 2040

	Comparison of LACE - LCOE (2012 $/MWh)				
Plant Type	**Average LCOE**	**Average LACE**	**Average Difference**	**Range of Differences**	
2019					
Dispatchable Technologies					
Conventional Coal	95.6	62.2	-33.5	-48.9	-25.1
IGCC	115.9	62.2	-53.7	-66.1	-43.9
IGCC with CCS	147.4	62.0	-85.4	-104.7	-74.8
Natural Gas-fired					
Conventional Combined Cycle	66.3	62.9	-3.4	-13.7	0.0
Advanced Combined Cycle	64.4	62.9	-1.5	-11.2	0.8
Advanced CC with CCS	91.3	62.9	-28.4	-34.6	-23.7
Advanced Nuclear	86.1	61.7	-24.4	-33.0	-13.0
Geothermal	44.5	60.9	16.4	15.2	18.1
Biomass	102.6	63.3	-39.3	-57.2	-28.5
Non-Dispatchable Technologies					
Wind	80.3	55.7	-24.5	-37.6	-6.3
Wind – Offshore	204.1	62.3	-141.8	-210.1	-107.1
Solar PV	118.6	73.4	-45.2	-96.5	-21.2
Solar Thermal	223.6	73.3	-150.3	-279.3	-83.4
Hydro	84.5	59.9	-24.6	-54.7	-1.0
2040					
Dispatchable Technologies					
Conventional Coal	87.0	76.4	-10.7	-26.3	-5.3
IGCC	99.7	76.4	-23.3	-34.3	-18.2
IGCC with CCS	121.2	77.0	-44.3	-51.8	-38.8
Natural Gas-fired					
Conventional Combined Cycle	81.2	77.7	-3.5	-7.7	-0.4
Advanced Combined Cycle	77.8	77.7	-0.1	-3.9	2.0
Advanced CC with CCS	103.0	77.7	-25.3	-30.0	-15.5
Advanced Nuclear	83.0	76.1	-6.8	-10.1	-0.2
Geothermal	63.5	78.7	47.0	0.5	75.2
Biomass	97.0	78.0	-19.0	-38.4	-9.4
Non-Dispatchable Technologies					
Wind	73.1	70.8	-2.3	-11.8	13.0
Wind – Offshore	170.3	77.4	-92.9	-150.7	-59.3
Solar PV	101.3	89.4	-11.9	-58.4	10.6
Solar Thermal	188.7	96.5	-92.2	-205.1	-36.0
Hydro	84.6	75.3	-9.3	-27.8	11.0

Appendix: Tables for 2040

Table A5. Estimated levelized cost of electricity (LCOE) for new generation resources, 2040

	U.S. Average LCOE (2012 $/MWh) for Plants Entering Service in 2040							
Plant Type	Capacity Factor (%)	Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System LCOE	Subsidy[1]	Total LCOE including Subsidy
Dispatchable Technologies								
Conventional Coal	85	52.0	4.2	29.7	1.1	87.0		
Integrated Coal-Gasification Combined Cycle (IGCC)	85	62.8	6.9	28.9	1.1	99.7		
IGCC with CCS	85	77.2	9.8	33.1	1.2	121.2		
Natural Gas-fired								
Conventional Combined Cycle	87	12.5	1.7	65.8	1.2	81.2		
Advanced Combined Cycle	87	13.0	2.0	61.7	1.2	77.8		
Advanced CC with CCS	87	23.4	4.2	74.3	1.2	103.0		
Conventional Combustion Turbine	30	35.2	2.8	107.1	3.4	148.5		
Advanced Combustion Turbine	30	21.8	2.7	87.9	3.4	115.8		
Advanced Nuclear	90	56.7	11.8	13.3	1.1	83.0		
Geothermal	94	43.6	22.9	0.0	1.4	67.8	-4.4	63.5
Biomass	83	39.8	14.5	41.4	1.2	97.0		
Non-Dispatchable Technologies								
Wind	34	56.6	13.3	0.0	3.2	73.1		
Wind – Offshore	37	141.7	22.8	0.0	5.7	170.3		
Solar PV[2]	25	95.3	11.4	0.0	4.0	110.8	-9.5	101.3
Solar Thermal	20	156.2	42.1	0.0	5.9	204.3	-15.6	188.7
Hydroelectric[3]	51	71.2	4.5	7.0	2.1	84.6		

[1]The subsidy component is based on targeted tax credits such as the production or investment tax credit available for some technologies. It only reflects subsidies available in 2040, which includes a permanent 10% investment tax credit for geothermal and solar technologies, based on the Energy Policy Act of 1992. EIA models tax credit expiration as in current laws and regulations: new solar thermal and PV plants are eligible to receive a 30% investment tax credit on capital expenditures if placed in service before the end of 2016, and 10% thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $21.5/MWh ($10.7/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30% investment tax credit, if they are under construction before the end of 2013.

[2]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

Table A6. Regional variation in levelized cost of electricity (LCOE) for new generation resources, 2040

	Range for Total System LCOE (2012 $/MWh)			Range for Total LCOE with Subsidies[1] (2012 $/MWh)		
Plant Type	**Minimum**	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**
Dispatchable Technologies						
Conventional Coal	78.9	87.0	106.7			
IGCC	90.8	99.7	114.7			
IGCC with CCS	113.0	121.2	135.7			
Natural Gas-fired						
Conventional Combined Cycle	75.8	81.2	94.0			
Advanced Combined Cycle	73.4	77.8	89.4			
Advanced CC with CCS	97.8	103.0	114.8			
Conventional Combustion Turbine	118.8	148.5	172.3			
Advanced Combustion Turbine	108.9	115.8	132.3			
Advanced Nuclear	80.2	83.0	87.6			
Geothermal	54.4	67.8	81.3	50.7	63.5	76.3
Biomass	85.3	97.0	118.8			
Non-Dispatchable Technologies						
Wind	63.4	73.1	82.9			
Wind – Offshore	140.9	170.3	225.3			
Solar PV[2]	86.5	110.8	170.2	79.2	101.3	155.0
Solar Thermal	148.6	204.3	325.6	137.2	188.7	300.5
Hydroelectric[3]	63.6	84.6	122.4			

[1]Levelized cost with subsidies reflects subsidies available in 2040, which includes a permanent 10% investment tax credit for geothermal and solar technologies, based on the Energy Policy Act of 1992.

[2]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Note: The levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are as follows: Wind – 32% to 41%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydroelectric – 35% to 65%. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release, December 2013, DOE/EIA-0383ER(2014).

Table A7: Regional variation in levelized avoided costs of electricity (LACE) for new generation resources, 2040

Plant Type	Range for LACE (2012 $/MWh) Minimum	Average	Maximum
Dispatchable Technologies			
Coal-fired plant types without CCS	72.3	76.4	80.7
IGCC with CCS[1]	72.3	77.0	88.6
Natural Gas-fired Combined Cycle	72.2	77.7	88.4
Advanced Nuclear	72.2	76.1	80.6
Geothermal	75.0	78.7	88.0
Biomass	72.3	78.0	88.7
Non-Dispatchable Technologies			
Wind	65.8	70.8	84.1
Wind – Offshore	71.9	77.4	88.1
Solar PV	83.2	89.4	96.5
Solar Thermal	87.7	96.5	104.4
Hydroelectric	71.0	75.3	88.0

[1]Coal without CCS cannot be built in California, therefore the average LACE for coal technologies without CCS is computed over fewer regions than the LACE for IGCC with CCS. Otherwise, the LACE for any given region is the same across coal technologies, with or without CCS.

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

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

**ON BEHALF OF THE
BLACK HILLS INDUSTRIAL INTERVENORS**

**J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA**

December 2014

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

PREFACE

This project was jointly assigned to the NARUC Staff Subcommittees on Electricity and Economics in February, 1985. Jack Doran, at the California PUC had led a task force in 1969 that wrote the original **Cost Allocation Manual**; the famous "Green Book". I was asked to put together a task force to revise it and include a Marginal Cost section.

I knew little about the subject and was not sure what I was getting into so I asked Jack how he had gone about drafting the first book. "Oh" he said, "There wasn't much to it. We each wrote a chapter and then exchanged them and rewrote them." What Jack did not tell me was that like most NARUC projects, the work was done after five o'clock and on weekends because the regular work always takes precedence. It is a good thing we did not realize how big a task we were tackling or we might never have started.

There was great interest in the project so when I asked for volunteers, I got plenty. We split into two working groups; embedded cost and marginal cost. Joe Jenkins from the Florida PSC headed up the Embedded Cost Working Group and Sarah Voll from the New Hampshire PUC took the Marginal Cost Working Group. We followed Jack's suggestions but, right from the beginning, we realized that once the chapters were technically correct, we would need a single editor to cast them all "into one hand" as Joe Jenkins put it. Steven Mintz from the Department of Energy volunteered for this task and has devoted tremendous effort to polishing the book into the final product you hold in your hands. Victoria Jow at the California PUC took Steven's final draft and desktop published the entire document using Ventura Publisher.

We set the following objectives for the manual:

- It should be simple enough to be used as a primer on the subject for new employees yet offer enough substance for experienced witnesses.
- It must be comprehensive yet fit in one volume.
- The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

It is with extreme gratitude that I acknowledge the energy and dedication contributed by the following task force members over the last five years.

Steven Mintz, Department of Energy, Editor; Joe Jenkins, Florida PSC, Leader, Embedded Cost Working Group; Sarah Voll, New Hampshire PUC, Leader, Marginal Cost Working Group; Victoria Jow, California PUC; John A. Anderson, ELCON; Jess Galura, Sacramento MUD; Chris Danforth, California PUC; Alfred Escamilla, Southern California Edison; Byron Harris, West Virginia CAD; Steve Houle, Texas Utility Electric Co.; Kevin Kelly, formally NRRI; Larry Klapow California PUC; Jim Ketter P.E., Missouri PSC; Ed Lucero, Price Waterhouse; J. Robert Malko, Utah State University; George McCluskey, New Hampshire PUC; Marge Meeter, Florida PSC; Gordon Murdock, The FERC; Dennis Nightingale, North Carolina UC; John Orecchio, The FERC; Carl Silsbee, Southern California Edison; Ben Turner, North Carolina UC; Dr. George Parkins, Colorado PUC; Warren Wendling, Colorado PUC; Schef Wright, formally Florida PSC; **IN MEMORIAL** Bob Kennedy Jr., Arkansas PSC.

Julian Ajello
California PUC

CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation [2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses [1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance [2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems [1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

[1]Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:	Demand
Distribution:	Overhead Primary
	Demand
	Customer
	Overhead Secondary
	Demand
	Customer
	Underground Primary
	Demand
	Customer
	Underground Secondary
	Demand
	Customer
	Line Transformers
	Demand
	Customer
Services:	Overhead
	Demand
	Customer
	Underground
	Demand
	Customer
Meters:	Customer
Street Lighting:	Customer
Customer Accounting:	Customer
Sales:	Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS OF DISTRIBUTION PLANT ACCOUNTS

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

A. The Minimum-Size Method

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. **Account 364 - Poles, Towers, and Fixtures**

   - Determine the average installed book cost of the minimum height pole currently being installed.
   - Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. **Account 365 - Overhead Conductors and Devices**

   - Determine minimum size conductor currently being installed.
   - Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. **Accounts 366 and 367 - Underground Conduits, Conductors, and Devices**

   - Determine minimum size cable currently being installed.
   - Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.
   - Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

4. **Account 368 - Line Transformers**

   - Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. Account 369 - Services

- Determine minimum size and average length of services currently being installed.
- Estimate cost of minimum size service and multiply by number of services to get customer component.
- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. Account 364 - Poles, Towers, and Fixtures

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.
- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.
- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.
  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.
  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.
  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)
  - Balance of conductor investment is assigned to demand.
  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (l/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to l/c cable. Since there are generally many types and sizes of l/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.
  - Determine the feet, investment, and average installed book cost per foot for l/c cables by size and type of cable.
  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.
  - Multiply minimum intercept cost by the total number of circuit feet (l/c cable with sheath is considered a circuit) to get customer component.
  - Balance of cable investment is assigned to demand.
  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

4. Account 368 - Line Transformers

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.
  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).
  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.
  - Multiply zero intercept cost by total number of line transformers to get customer component.
  - Balance of transformer investment is assigned to demand component.
  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step, it is not as controversial as the classification of substations, poles, transformers, and conductors.

1. Account 369 - Services

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

2. Account 370 - Meters

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

3. Account 371 - Installations on Customer Premises

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

4. Account 373 - Street Lighting and Signal Systems

This account is generally customer-related and is directly assigned to the street customer class.

III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

The load diversity differences for some utilities at the transmission and distribution substation levels may not be large. Consequently, some large distribution substations may be allocated using the same method as the transmission system. Before the cost analyst selects a method to allocate the different levels of distribution facilities, he must know the design and operational characteristics of the distribution system, as well as the demand losses at each level of the distribution system.

As previously indicated, the distribution system consists of several levels. The first level starts at the distribution substation, and the last level ends at the customer's meters. Power losses occur at each level and should be included in the demand allocators. Power losses are incorporated into the demand allocators by showing different demand loss factors at each predominant voltage level. The demand loss factor used to develop the primary-distribution demand allocator will be slightly larger than the demand loss factor used to develop the secondary demand allocator. When developing the distribution demand allocator, be aware that some customers take service at different voltage levels.

Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who benefit from these facilities are included in the allocator. For example, the loads of customers who take service at transmission level should not be reflected in the distribution substation or primary demand allocator. Similarly, when analysts develop the allocator for secondary demand facilities, the loads for customers served by the primary distribution system should not be included.

Utilities can gather load data to develop demand allocators, either through their load research program or their transformer load management program. In most cases, the load research program gathers data from meters on the customers' premises. A more complex procedure is to use the transformer load management program.

This procedure involves simulating load profiles for the various classes of equipment on the distribution system. This provides information on the nature of the load diversity between the customer and the substation, and its effect on equipment cost. Determining demand allocators through simulation provides a first-order load approximation, which represents the peak load for each type of distribution equipment.

The concept of peak load or "equipment peak" for each piece of distribution equipment can be understood by considering line transformers. If a given transformer's loading for each hour of a month can be calculated, a transformer load curve can be developed. By knowing the types of customers connected to each load management transformer, a simulated transformer load profile curve can be developed for the system. This can provide each customer's class demand at the time of the transformer's peak load. Similarly, an equipment peak can be defined for equipment at each level of the distribution system. Although the equipment peak obtained by this method may not be ideal, it will closely approximate the actual peak. Thus, this method should reflect the different load diversities among customers at each level of the distribution system. An illustration of the simulation procedure is provided in Appendix 6-A.

B. Allocation of Customer-Related Costs

When the demand-customer classification has been completed, most of the assumptions will have been made that affect the results of the completed cost of service study.

The allocation of the customer-related portion of the various plant accounts is based on the number of customers by classes of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications.

Expense allocations generally are based on the comparable plant allocator of the various classes. For instance, maintenance of overhead lines is generally assumed to be directly related to plant in overhead conductors and devices. Exceptions to this rule will occur in some accounts. Meter expenses, for example, are often a function of maintenance and testing schedules related more to revenue per customer than to the cost of the meters themselves.

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**

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF THE
BLACK HILLS INDUSTRIAL INTERVENORS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

December 2014

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

REQUEST DATE : June 30, 2014

RESPONSE DATE : July 28, 2014

REQUESTING PARTY: Black Hills Industrial Intervenors

BHII Request No. 36: Please provide all work papers (including all electronic work papers with formulas intact) supporting the development of the factors used to classify distribution accounts 364, 365, 366, and 367 between Primary and Secondary.

Response to BHII Request No. 36:

The factors used to classify distribution account 364, 365, 366 and 367 between Primary and Secondary were from a borrowed study from Black Hills Power's sister utility, Black Hills/Colorado Electric Utility Company, LP. The same factors used were previously used in the 2012 Black Hills Power rate case.

Black Hills Power was unable to locate all electronic work papers with formulas intact. Copies of the available work papers are attached as Attachment 36.

Attachments: 36 - Distribution Plant Account 364_367 Allocation Factors.pdf

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**

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

ON BEHALF OF THE
BLACK HILLS INDUSTRIAL INTERVENORS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

December 2014

BLACK HILLS INDUSTRIAL INTERVENORS
CORRECTED PRO FORMA CLASS COST OF SERVICE STUDY
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2013

LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL SOUTH DAKOTA	RESIDENTIAL SERVICE	GENERAL SERVICE	GS LARGE/ INDUSTRIAL CONTRACT	LIGHTING SERVICE	WATER PUMP IRRIGATION
	(a)	(b)	(c)	(d)	(e)	(h)	(i)	(j)
1	SUMMARY AT PRESENT RATES							
2								
3	DEVELOPMENT OF RETURN							
4								
5	OPERATING REVENUE	Sched O-1 Reference						
6	Base Sales of Electricity		124,169,353	49,009,989	41,997,396	29,828,727	1,702,416	1,630,824
7	Contract Revenues		19,288,845	7,350,394	5,857,566	5,751,361	106,151	223,374
8	Other Operating Revenue		5,800,779	3,478,253	1,209,889	928,155	131,091	53,392
9	TOTAL OPERATING REVENUE		149,258,977	59,838,635	49,064,851	36,508,243	1,939,658	1,907,590
10								
11	OPERATING EXPENSES							
12	Operation and Maintenance Expense		67,628,526	32,165,655	18,601,295	15,552,318	587,592	721,667
13	Depreciation Expense		26,137,533	11,979,102	7,295,360	6,275,606	291,762	295,703
14	Amortization Expense		4,031,631	1,980,627	1,085,427	888,252	35,436	41,889
15	Taxes Other Than Income Taxes		4,199,038	1,923,263	1,172,479	1,007,551	47,845	47,902
16	State Income Tax		0	0	0	0	0	0
17	Federal Income Tax		10,753,377	1,415,317	5,723,640	3,113,140	285,057	216,223
18	TOTAL OPERATING EXPENSES		112,750,105	49,463,963	33,878,201	26,836,866	1,247,691	1,323,385
19								
20	OPERATING INCOME (RETURN)		36,508,872	10,374,672	15,186,649	9,671,377	691,968	584,205
21								
22								
23	DEVELOPMENT OF RATE BASE							
24	Electric Plant in Service		901,099,320	412,869,069	251,496,019	216,167,196	10,294,636	10,272,399
25	Less: Accumulated Depreciation		251,710,991	117,394,415	69,368,736	58,651,647	3,415,356	2,880,837
26	Less: Amortization		2,835,303	1,080,448	861,014	845,403	15,603	32,834
27	Plus: Working Capital		13,863,167	5,602,535	3,841,110	4,071,969	155,094	192,459
28	Less: Other Rate Base Deductions		117,714,228	54,469,729	32,969,748	27,521,751	1,426,478	1,326,522
29								
30	TOTAL RATE BASE		542,701,964	245,527,012	152,137,631	133,220,364	5,592,293	6,224,664
31								
32								
33	RATE OF RETURN (PRESENT)		6.73%	4.23%	9.98%	7.26%	12.37%	9.39%
34								
35	INDEX RATE OF RETURN (PRESENT)		1.00	0.63	1.48	1.08	1.84	1.40
36								
37								
38								
39								
40								
41								
42								
43								

BLACK HILLS INDUSTRIAL INTERVENORS
CORRECTED PRO FORMA CLASS COST OF SERVICE STUDY
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2013

LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL SOUTH DAKOTA	RESIDENTIAL SERVICE	GENERAL SERVICE	GS LARGE/ INDUSTRIAL CONTRACT	LIGHTING SERVICE	WATER PUMP IRRIGATION
	(a)	(b)	(c)	(d)	(e)	(h)	(i)	(j)
44								
45								
46								
47	EQUALIZED RETURN AT PROPOSED ROR							
48								
49	DEVELOPMENT OF RETURN (EQUALIZED RATE LEVELS)							
50								
51	RATE BASE		542,701,964	245,527,012	152,137,631	133,220,364	5,592,293	6,224,664
52								
53	RATE OF RETURN		8.48%	8.48%	8.48%	8.48%	8.48%	8.48%
54								
55	RETURN (RATE BASE * ROR)		46,021,127	20,820,691	12,901,271	11,297,087	474,226	527,852
56								
57	LESS:							
58	OPERATING EXPENSES	Sched O-1 Reference						
59	Operation and Maintenance Expense		67,628,526	32,165,655	18,601,295	15,552,318	587,592	721,667
60	Depreciation Expense		26,137,533	11,979,102	7,295,360	6,275,606	291,762	295,703
61	Amortization Expense		4,031,631	1,980,627	1,085,427	888,252	35,436	41,889
62	Taxes Other Than Income Taxes		4,199,038	1,923,263	1,172,479	1,007,551	47,845	47,902
63	State Income Tax	CALCULATED	0	0	0	0	0	0
64	Federal Income Tax	CALCULATED	15,875,361	7,040,096	4,493,052	3,988,522	167,811	185,879
65	TOTAL OPERATING EXPENSES		117,872,089	55,088,742	32,647,613	27,712,248	1,130,445	1,293,041
66								
67	EQUALS TOTAL COST OF SERVICE		163,893,215	75,909,432	45,548,884	39,009,335	1,604,672	1,820,892
68								
69	LESS:							
70	OTHER OPERATING REVENUES		25,089,624	10,828,647	7,067,454	6,679,516	237,242	276,765
71								
72	EQUALS:							
73	PROPOSED BASE RATE SALES @ EQUALIZED ROR		138,803,591	65,080,786	38,481,430	32,329,819	1,367,430	1,544,127
74								
75								
76	TOTAL COST OF SERVICE INCREASE/DECREASE		14,634,238	16,070,797	(3,515,966)	2,501,091	(334,987)	(86,697)
77								
78	BASE SALES OF ELECTRICITY		124,169,353	49,009,989	41,997,396	29,828,727	1,702,416	1,630,824
79	SALES OF ELECTRICITY FOR BASE ENERGY COSTS	ENERGY2	33,682,213	11,594,018	9,158,128	12,053,051	323,929	553,088
80	TOTAL CURRENT RETAIL REVENUES		157,851,566	60,604,006	51,155,524	41,881,778	2,026,346	2,183,912
81								
82	REVENUE INCREASE TO RETAIL REVENUES (%)		9.27%	26.52%	-6.87%	5.97%	-16.53%	-3.97%
83								
84								
85								
86								
87								
88								
89								
90								
91								

BLACK HILLS INDUSTRIAL INTERVENORS
CORRECTED PRO FORMA CLASS COST OF SERVICE STUDY
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2013

LINE NO.	DESCRIPTION	ALLOCATION BASIS	TOTAL SOUTH DAKOTA	RESIDENTIAL SERVICE	GENERAL SERVICE	GS LARGE/ INDUSTRIAL CONTRACT	LIGHTING SERVICE	WATER PUMP IRRIGATION
	(a)	(b)	(c)	(d)	(e)	(h)	(i)	(j)
92								
93	RETURN AT PROPOSED RATES							
94								
95	DEVELOPMENT OF RETURN AT PROPOSED RATE LEVELS							
96								
97	OPERATING REVENUE							
98	Sales of Electricity		138,803,636	55,546,653	45,733,753	33,896,966	1,851,073	1,775,191
99	Contract Revenues		19,288,845	7,350,394	5,857,566	5,751,361	106,151	223,374
100	Other Operating Revenue		5,800,779	3,478,253	1,209,889	928,155	131,091	53,392
101	TOTAL OPERATING REVENUE		163,893,260	66,375,300	52,801,207	40,576,482	2,088,315	2,051,956
102								
103	OPERATING EXPENSES							
104	Operation and Maintenance Expense		67,628,526	32,165,655	18,601,295	15,552,318	587,592	721,667
105	Depreciation Expense		26,137,533	11,979,102	7,295,360	6,275,606	291,762	295,703
106	Amortization Expense		4,031,631	1,980,627	1,085,427	888,252	35,436	41,889
107	Taxes Other Than Income Taxes		4,199,038	1,923,263	1,172,479	1,007,551	47,845	47,902
108	State Income Tax	CALCULATED	0	0	0	0	0	0
109	Federal Income Tax	CALCULATED	15,875,376	3,703,150	7,031,365	4,537,023	337,087	266,752
110	TOTAL OPERATING EXPENSES		117,872,104	51,751,795	35,185,926	28,260,749	1,299,720	1,373,913
111								
112	OPERATING INCOME (RETURN) AT PROPOSED RATES		46,021,156	14,623,504	17,615,281	12,315,733	788,595	678,043
113								
114								
115	RATE BASE		542,701,964	245,527,012	152,137,631	133,220,364	5,592,293	6,224,664
116								
117								
118	RATE OF RETURN		8.48%	5.96%	11.58%	9.24%	14.10%	10.89%
119								
120	INDEX RATE OF RETURN		1.00	0.70	1.37	1.09	1.66	1.28
121								
122								
123	PROPOSED TOTAL REVENUE INCREASE ($)		14,634,283	6,536,664	3,736,357	4,068,239	148,657	144,367
124								
125	BASE SALES OF ELECTRICITY		124,169,353	49,009,989	41,997,396	29,828,727	1,702,416	1,630,824
126	SALES OF ELECTRICITY FOR BASE ENERGY COSTS	ENERGY2	33,682,213	11,594,018	9,158,128	12,053,051	323,929	553,088
127	TOTAL CURRENT RETAIL REVENUES		157,851,566	60,604,006	51,155,524	41,881,778	2,026,346	2,183,912
128								
129	PROPOSED TOTAL REVENUE INCREASE (%)		9.27%	10.79%	7.30%	9.71%	7.34%	6.61%