BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

IN THE MATTER OF THE APPLICATION OF BLACK HILLS/KANSAS GAS UTILITY COMPANY, LLC, d/b/a BLACK HILLS ENERGY, FOR APPROVAL OF THE COMMISSION TO MAKE CERTAIN CHANGES IN ITS RATES FOR NATURAL GAS SERVICE	**)))))))**	**DOCKET NO. 25-BHCG-298-RTS**

DIRECT TESTIMONY AND SCHEDULES OF

GLENN A. WATKINS

RE: CLASS COST OF SERVICE,
CLASS REVENUE DISTRIBUTION,
AND
RESIDENTIAL RATE DESIGN

ON BEHALF OF

THE CITIZENS' UTILITY RATEPAYER BOARD

MAY 9, 2025

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Glenn A. Watkins. My business address is 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

Q. What is your professional and educational background?

A. I am President and Senior Economist with Technical Associates, Inc. ("TAI"), which is an economics and financial consulting firm with offices in the Richmond, Virginia area. Except for a six-month period during 1987 in which I was employed by Old Dominion Electric Cooperative as its forecasting and rate economist, I have been employed by TAI continuously since 1980.

During my career at TAI, I have conducted marginal and embedded cost of service; rate design; cost of capital; revenue requirement; and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities. I have provided expert testimony on more than 250 occasions in Alabama, Alaska, Arizona, Colorado, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia.

I hold an M.B.A. and B.S. in economics from Virginia Commonwealth University and am a Certified Rate of Return Analyst. A more complete description of my education and experience as well as a list of my prior testimonies is provided in my Schedule GAW-1.

Q. Have you previously provided testimony before this Commission?

A. Yes. I have provided testimony on several occasions including Black Hills Energy's ("Company" or "Black Hills") last rate case (Docket No. 21-BHCG-418-RTS), as well as the most recent rate cases for Atmos Energy (Docket No. 23-ATMG-359-RTS), Evergy Kansas Central (Docket No. 23-EKCE-755-RTS) and Kansas Gas Service (Docket No. 24-KGSG-610-RTS).

Q. What is the purpose of your testimony in this proceeding?

A. TAI has been engaged by the Citizens' Utility Ratepayer Board ("CURB") to investigate and evaluate Black Hills' class cost of service studies ("CCOSS"), class revenue allocations, and proposed Residential and Small Commercial rate designs. The purpose of my testimony is to present the findings of my investigation and offer my recommendations to the Commission in these areas.

Q. Please provide a summary of your recommendations.

A. I have concluded that Company witness Fritel's CCOSS significantly under-assigns costs to Irrigation and Large Volume customers, thereby, over-assigning costs to the Residential and Small Commercial classes. I have conducted my own CCOSS that is in accordance with accepted industry practices and more reasonably assigns Transmission and Distribution Mains costs across classes.

With regard to class revenue distributions, Mr. Fritel's proposals are based primarily on the results of his cost allocations; therefore, I recommend a significantly different distribution across classes of any authorized increase in this case.

With regard to Residential and Small Commercial rate designs, I recommend maintaining the current customer charges of $18.50 and $28.00 per month, respectively.

II. CLASS COST OF SERVICE

A. General Concepts

Q. Please briefly explain the concept of a CCOSS and its purpose in a rate proceeding.

A. Because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner, most costs cannot be specifically attributed to a particular customer or group of customers. Therefore, the costs jointly incurred to serve all or most customers must be allocated across specific customers or customer rate classes. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned in the CCOSS.

It is generally accepted that, to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs to which causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor (e.g., peak demand, energy or throughput usage, number of customers, etc.).

Q. In your opinion, how should the results of a CCOSS be utilized in the ratemaking process?

A. Although certain principles are used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements arise as a result of the quality of data and the level of detail available from financial records. There are also fundamental differences in opinions regarding what cost causation factors should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, as mentioned previously, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In these regards, two different cost studies conducted for the same utility and the same period of time often yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility.

Q. Have the higher courts opined on the usefulness of cost allocations for purposes of establishing revenue responsibility and rates?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to the Federal Energy Regulatory Commission ["FERC"]), the U.S. Supreme Court stated:

> But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]

[1]*Colorado Interstate Gas Co. v. Federal Power Commission,* 324 U.S. 581, 590 (1945).

Q. Does your opinion, and the findings of the U.S. Supreme Court, imply that cost allocations should play no role in the ratemaking process?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible, approaches may produce significantly different results. In this regard, when all cost allocation approaches consistently show that certain classes are over- or under-contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one cost allocation approach shows dramatically different results than another approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q. With regard to the practice of relying upon CCOSS in establishing class revenue responsibility, has this Commission provided guidance relating to the usefulness of individual CCOSS?

A. Yes. In a KCPL rate case (Docket No. 12-KCPE-764-RTS), the Commission found:

> Under the principle of cost causation adopted by the Kansas courts, one class of customers should not bear the costs created by another class. Absent a reasonable basis, the Commission may not order a discriminatory rate design. A [CCOSS] is designed to allocate the utility's total system cost of service to the various customer classes. There is no single, universally accepted method for allocating costs to customer classes.[2] [Footnotes omitted.]

[2] Order, page 23.

Q. Please explain the basic concepts of cost allocation for public utilities, particularly Natural Gas Distribution Companies ("NGDCs").

A. As I mentioned earlier, the majority of a NGDC's plant investment serves customers in a joint manner. In this regard, the NGDC's infrastructure is a system benefiting all customers. If all customers were the same size and had identical usage characteristics, cost allocation would be simple, bordering on superfluous. However, in reality, a utility's customer base is not so simplistic. Customers are categorized into groups based on comparable energy requirements and usage characteristics. However, the amount of service that each customer requires within these groups can vary greatly, depending on the time of year. Therefore, comparative usage characteristics should be considered. Because different groups of customers also utilize the system at varying degrees during the year, consideration should also be given to the particular demands placed on the system during peak usage periods.

Q. With regard to NGDCs, is there any controversial aspect of class cost allocations that tends to overshadow other issues?

A. Yes. For virtually every NGDC, the largest single rate base items are Mains (Distribution and/or Transmission). Furthermore, several other rate base and operating income accounts are typically allocated to classes based on the previous assignment of Mains. Therefore, the methods and approaches used to allocate Mains to classes are usually the most important (in terms of class rate of return ["ROR"] results) and tend to be the most controversial.

Q. What methods are commonly used to allocate natural gas Mains?

A. While a myriad of cost allocation methods and approaches have been developed, three methods predominate in the NGDC industry: "Peak Responsibility," "Peak and Average" ("P&A") (also known as "Demand/Commodity" or "Demand/Energy"), and "Customer/Demand," which I will address shortly in more detail. These methods differ in the criteria used to allocate Mains, as cost allocation analysts do not universally agree on the cost-causative factors or drivers influencing mains investments. There are three criteria generally considered when selecting a Mains cost allocation method: peak demand (whether coincident, non-coincident, or actual or design day); annual (average day) usage; and number of customers. Because a NGDC system must be capable of supplying gas to its firm customers during peak demand periods (i.e., on very cold days), relative class peak day demands are often considered a good proxy for measuring the cost causation of Mains investment.[3] Annual (or average day) throughput is also often used to allocate Mains since this factor reflects the utilization of a utility's Mains investment. Number of customers is also sometimes considered when allocating Mains. That is, customer counts by class serve as a basis for allocation of Mains. Even though annual levels of usage and peak load requirements vary greatly between customer classes (e.g., residential versus large industrial), some analysts are of the opinion that customer counts should be considered because at least some infrastructure investment in Mains is required simply to "connect" every customer to the system. With these three criteria identified, numerous methods weigh and utilize these criteria differently within the cost allocation process. In other

[3] Embedded cost allocations are directly only concerned with relative, not absolute, criteria. That is, because embedded cost allocations reflect nothing more than dividing total system costs between classes, it is the relative (percentage) contributors to total system amounts that is relevant.

words, some methods may only rely on one criterion while others consider two or more criteria with varying weight given to each factor utilized.

As mentioned previously, the three most common NGDC cost allocation methods are the "Peak Responsibility" method (whether coincident or class non-coincident), in which peak day demands are the only factor utilized to allocate Mains; the "P&A" or "Demand/Commodity" approach, in which both peak day and annual (average day) throughput is reflected within the allocation of Mains;[4] and the Customer/Demand method, which utilizes a combination of peak day demands and customer counts to assign Mains cost responsibility.

Under the Customer/Demand method, the weight given to class customer counts and peak day demands is determined from a separate analysis using one of two approaches: minimum-size and zero-intercept. The "minimum-size" approach prices the entire system footage of Mains at the cost per foot of the smallest diameter pipe installed. This "minimum-size" cost is then divided by the actual total investment in Mains to determine the weight given to customer counts. One (1) minus the customer percentage is then given to the peak day demand within the allocation process. Under the zero-intercept approach, statistical linear regression techniques are used to estimate the cost of a theoretical "zero size" Main. Similar to the minimum-size approach, the cost of this estimated zero size pipe per foot is multiplied by the total system footage and is then divided by total Mains investment to arrive at a customer weighting.

[4] Under the P&A or Demand/Commodity approach, peak use and annual throughput are either weighted equally or based on system load factor, where load factor is the ratio of average daily usage to peak day usage. When using a load factor approach to weight P&A usage, the weighting of average day usage is that of the system load factor, while the peak day weight is one minus the system load factor.

B. Black Hills CCOSS

Q. Please generally explain the approach Company witness Ethan Fritel used to allocate Mains-related costs.

A. Although Black Hills books Transmission Mains (Account 367) and Distribution Mains (Account 376) separately for financial reporting purposes, Mr. Fritel re-functionalized these two accounts based on the diameter (size) of pipes. Specifically, Mr. Fritel treats Mains that are 10-inches or larger as Transmission Mains and Mains less than 10-inches as Distribution Mains. The following is a comparison of the Company's booked Mains for financial reporting purposes and Mr. Fritel's re-functionalized definition of Mains:

TABLE 1
Transmission & Distribution Gross Plant[5]

	Per Books	Fritel Functionalization
Transmission	$61,180,956	$41,797,080
Distribution	$165,607,324	$184,991,200
Total	$226,788,280	$226,788,280

Q. Did Mr. Fritel re-functionalize Mains based on the booked cost of Mains by individual size of pipe?

A. No. Mr. Fritel ignored the Company's books and records as it relates to the booked (original) cost of individual size of pipes and instead used an unconventional approach to reassign costs based on what he refers to as the "relative capacity" of each size of pipe as well as calculating a "trended original cost" of each size of pipe.[6] Ultimately, Mr. Fritel's re-functionalization of Transmission and Distribution gross plant resulted in a difference

[5] Per Exhibit EJF-13.
[6] Per Exhibit EJF-10.

between the actual booked separation between Transmission and Distribution gross plant as shown in the Table 1 above.

Q. How did Mr. Fritel ultimately allocate his re-functionalized Mains across classes?

A. Mr. Fritel allocated his re-functionalized Transmission Mains (10-inches and larger) based on a combination of class peak day demands, winter throughput, and annual throughput. With respect to his re-functionalized Distribution Mains (less than 10-inches in diameter), Mr. Fritel allocated these costs based on a combination of class peak demands, winter volumes, and weighted customers. The following table provides the end result of Mr. Fritel's functionalization, classification, and allocation approach:

TABLE 2
Fritel Re-Functionalization, Classification & Allocation of Gross Mains Plant

	Peak Day	Winter Volume	Annual Volume	Weighted Customers[7]	Total
Transmission Function:					
Amount	$13,936,140	$13,936,140	$13,924,800	$0	$41,797,080
Percent	33.34%	33.34%	33.32%	0.00%	100.00%
Distribution Function:					
Amount	$24,050,897	$24,050,897	$0	$136,889,406	$184,991,201
Percent	13.00%	13.00%	0.00%	74.00%	100.00%

As can be observed in the table above, Mr. Fritel ultimately classified and allocated his re-functionalized "Transmission-related" Mains approximately equally between peak day demand, winter volumes and annual volumes. With regard to his re-functionalized "Distribution-related" Mains, Mr. Fritel classified and allocated these costs to classes

[7] Mr. Fritel's weighted customer allocation factor is based on his weighted service line cost.

based on 74% weighted customers, 13% on peak day demand, and 13% on winter volumes. The remaining 26% was allocated equally between peak day demand and winter volumes.

Q. Please provide a comparison of each of the various allocation factors Mr. Fritel used to assign Transmission and Distribution Mains costs.

A. The following table provides a listing and comparison of class allocation factors for each of the four categories used by Mr. Fritel to ultimately allocate Mains-related costs:

TABLE 3
Fritel Mains Allocation Factors

Class	Peak Demand	Winter Volume	Annual Volume	Weighted Customers
Residential	55.29%	46.74%	31.18%	83.06%
Small Commercial	11.81%	10.10%	6.44%	9.68%
Small Volume	14.22%	13.54%	9.70%	2.73%
Large Volume - Firm	18.67%	28.43%	34.11%	0.51%
Irrigation – Sales	0.00%	0.00%	14.10%	3.15%
Irrigation – Transportation	0.00%	0.00%	3.27%	0.81%
Large Volume Interruptible	0.00%	1.19%	1.19%	0.05%
Total Company	100.000%	100.000%	100.000%	100.000%

Q. Why are Mr. Fritel's peak day demands for Irrigation and Large Volume Interruptible equal to zero?

A. Mr. Fritel calculated peak day demands only for the firm classes. Presumably, his rationale is that Interruptible customers may be curtailed during peak demand periods such that he has not assigned any peak day cost responsibility to Interruptible customers. With regard to the Irrigation classes, the Black Hills system peaks in the winter months such that there is little to no contribution to Irrigation loads during the transmission peak.

Q. Why are Mr. Fritel's winter volumes for Irrigation also equal to zero?

A. Although Irrigation customers used 3.624 million therms during the test year winter months (2.992 million therms for Irrigation Sales and 0.632 million therms for Irrigation Transportation),[8] Mr. Fritel set these values to zero presumably on his rationale that Irrigation customers are predominately summer users of natural gas.

Q. Please provide Mr. Fritel's ultimate class allocation percentages associated with Transmission and Distribution Mains.

A. Mr. Fritel's Mains allocation approach results in the following class allocations:

TABLE 4
Fritel Class Allocation Percentages
(Transmission & Distribution Mains)

	Amount		Percent	
Class	Transmission Function	Distribution Function	Transmission Function	Distribution Function
Residential	$18,562,511	$138,243,536	44.41%	74.73%
Small Commercial	$3,950,195	$18,521,758	9.45%	10.01%
Small Volume	$5,219,590	$10,417,473	12.49%	5.63%
Large Volume - Firm	$11,314,342	$12,032,988	27.07%	6.50%
Irrigation – Sales	$1,963,873	$4,318,486	4.70%	2.33%
Irrigation – Transportation	$454,718	$1,106,251	1.09%	0.60%
Large Volume Interruptible	$331,851	$350,709	0.79%	0.19%
Total Company	$41,797,080	$184,991,201	100.00%	100.00%

Q. What are the results of Mr. Fritel's CCOSS?

A. Mr. Fritel's study produces the following class RORs and indexed RORs at current rates[9]:

[8] Per Mr. Fritel's workpaper entitled: "KSG Direct Exhibit EJF-6,7,8.xlsx," Tab: WP-12.

[9] Indexed RORs are also known as relative RORs and measure each class's absolute ROR as a percentage of the system average ROR. For example, the Residential class ROR is 1.75% and the system average ROR is 3.19% resulting in a Residential indexed ROR 55%.

TABLE 5
Fritel Calculated Class RORs & Indexed RORs
At Current Rates

Class	ROR	Indexed ROR
Residential	1.75%	55%
Small Commercial	2.69%	84%
Small Volume	6.05%	190%
Large Volume - Firm	15.80%	496%
Irrigation – Sales	4.47%	140%
Irrigation – Transportation	3.70%	116%
Large Volume Interruptible	20.71%	650%
Total Company	3.19%	100%

Q. Were you able to replicate Mr. Fritel's CCOSS results?

A. Yes. As a result of the way in which Mr. Fritel's model is structured, it is difficult to evaluate how individual rate base and operating income FERC accounts are actually allocated to classes. Therefore, I utilized my own CCOSS Excel model that specifically shows class allocations by FERC account. I was able to exactly replicate Mr. Fritel's results using my CCOSS model.

Q. Do you have any disagreements with the approach Mr. Fritel used to allocate Transmission and Distribution Mains?

A. Yes, I have two material disagreements with Mr. Fritel's approach to ultimately allocate Transmission and Distribution Mains to individual classes. First, as noted earlier, Mr. Fritel has allocated 74.00% of his functionalized Distribution Mains based on weighted customers. Second, Mr. Fritel has allocated very little Mains cost responsibility to the Irrigation and Large Volume Interruptible classes, despite their actual load and usage profiles.

Q. Please explain Mr. Fritel's rationale for allocating 74% of Mains less than 10-inches in diameter based on customers.

A. In his Exhibit EJF-9, page 6, Mr. Fritel claims that "the cost of these facilities [small Mains less than 10-inches] is driven by two principle factors." First, he opines that there is a cost of extending the system that is driven by number of customers. Second, he opines that there is a cost associated with the peak day requirements of the customers connected to the system.

Q. Why do you disagree with Mr. Fritel's classification of his re-functionalized Distribution Mains as 74% customer-related?

A. First, there is not a single customer that connects to a natural gas system simply to be connected. Rather, natural gas customers connect to a system in order to consume natural gas for their energy needs. While it is obvious that customers must be physically connected to a NGDC's system, natural gas consumption is the very purpose for the existence of Black Hills; i.e., an infrastructure system of pipes to distribute natural gas to its consumers to meet their energy needs. Second, NGDCs do not wantonly install Mains throughout their service territory if there is no anticipated natural gas to be distributed through those Mains. Importantly, the Company's current tariff concerning its extension of Mains requires that there be enough revenue (natural gas usage) to warrant the economic investment required to extend the Company's distribution system.[10] In other words, the Company has not and will not extend Mains simply to connect customers absent enough usage and resulting revenues to justify any Mains extensions.

[10] Black Hill Energy tariff, General Rules, Regulations, Terms and Conditions, Index No. 11, Section 8 (Line Extension Policy).

Q. How did Mr. Fritel develop a classification of his functionalized Distribution Mains as 74% customer-related?

A. While Mr. Fritel's calculations are provided in his Exhibit EJF-10, he used an unconventional method to classify his functionalized Distribution Mains as 74% customer-related and 26% capacity-related. Specifically, Mr. Fritel used the Handy Whitman Index to inflate actual vintage year original investments by size and type to calculate a trended cost per foot by size of pipe.[11] He then calculated a relative capacity amount for each size of pipe using an exponential factor of 2.5. With this, Mr. Fritel calculated a trended original cost per relative unit of capacity. Mr. Fritel's calculations then become complicated and, in my opinion, illogical.

He first calculated his relative capacity of all combined Mains with a diameter of less than 10-inches (379,981,235). He then calculated what he referred to as the trended original cost per unit of capacity for only an 8-inch diameter pipe ($0.3867). This results in a "capacity related" trended original cost of all pipes less than 10-inches ($146,938,371). The capacity related trended original cost of all pipes less than 10-inches is divided by the total trended original cost of all pipes less than 10-inches ($565,089,071), which results in a capacity component of 26% with the complement of the remaining trended original cost amount (one minus the capacity component) being equal to 74% customer-related.

Q. In your 40-plus year career, have you ever seen an approach to classify Distribution Mains between capacity-related and customer-related anywhere near the approach used by Black Hills.

[11] This aspect of Mr. Fritel's analysis of using trended original costs is not uncommon or unconventional.

A. No, and I will add nowhere close.

Q. Notwithstanding your disagreement that Distribution Mains should be classified and allocated based on customers, are the results of Mr. Fritel's 74% customer-related classification logical?

A. No. First, remember that a key component of Mr. Fritel's calculations is the "trended original cost per unit of capacity" for 8-inch pipe. This amount is calculated based on the total trended original cost per foot of 8-inch pipe ($70.00) multiplied by the length (feet) of 8-inch pipe (435,143) and then divided by the "relative" capacity of an 8-inch pipe (78,769,297). However, Mr. Fritel arbitrarily adjusted his $70.00 trended original cost per foot of an 8-inch pipe as he states in the spreadsheet to his Exhibit EJF-10: "The actual TOC [trended original cost]/ft of 8-inch is too low relative to the 6-inch and should be somewhere in between the 8 and 10 inch. Use $70 per foot for the TOC of 8 inch."[12] This then questions the veracity of the data used within Mr. Fritel's analysis. Another example of the quality of data within Mr. Fritel's Mains study concerns his trended original cost per foot of a 6-inch pipe ($101.99) versus the trended original cost per foot of an 8-inch per foot ($70.00). Similarly, Mr. Fritel's calculated trended original cost per foot of 16-inch pipe is only $9.48 which is even lower than the trended original cost per foot of a 1-inch or 2-inch pipe ($20.49 and $25.75, respectively). This of course makes no sense as the cost of an extremely large 16-inch steel pipe is undoubtedly more expensive than plastic pipes of only one or two inches in diameter.

[12] This statement is factually incorrect in that Mr. Fritel's calculated TOC per foot of 6-inch pipe is $101.99. The calculated TOC per foot of 8-inch pipe is $94.09 such that Mr. Fritel's selected $70.00 per foot is even lower than the calculated TOC per foot of 8-inch pipe.

Finally, from a commonsense perspective, consider the lengths and original costs of various size pipes less than 10-inches in diameter shown in the table below:

TABLE 6
Fritel Analysis of Mains from Black Hills Property Records[13]

	Amount		Percent of Total	
Diameter	Original Cost	Miles of Pipe	Original Cost	Miles of Pipe
1	$3,150,019	66	1.8%	2.4%
2	$79,055,813	1,577	46.0%	57.0%
3	$1,786,268	124	1.0%	4.5%
4	$43,998,475	615	25.6%	22.2%
6	$27,260,823	300	15.9%	10.8%
8	$16,536,714	82	9.6%	3.0%
Total	$171,788,113	2,765	100.0%	100.0%

Almost 60% (59.44%) of the Company's Mains less than 10-inches in diameter are 2-inches or less which are relatively small Mains. However, these small Mains serve the maximum demands of all customers connected to these relatively small Mains. In other words, these relatively small Mains are not in place simply to connect these customers but actually serve the maximum loads of the customers served by these relatively small Mains. Next, consider Mains between 4-inches and 8-inches in diameter which comprise almost a thousand miles of pipe (997). These are relatively large gas Mains that serve not only larger customers directly but also distribute gas from city gates to smaller-sized Mains, yet implicitly, and accepting Mr. Fritel's approach, 74% of these relatively large Mains are utilized simply to connect customers to the system. Clearly, these two examples defy logic.

[13] Per Exhibit EJF-10.

Q. Please explain your disagreement with Mr. Fritel's assignment of Transmission and Distribution Mains cost to Irrigation and Large Volume Interruptible customers.

A. As a result of Mr. Fritel's approach to allocate Transmission and Distribution Mains based on a weighting of peak demands, winter volumes, annual volumes, and weighted customers, he has assigned very little cost responsibility to the Irrigation and Large Volume Interruptible classes. As an illustration, the Irrigation class (Sales plus Transportation) constitutes 17.37% of Black Hills total annual throughput while he only allocates 3.46% of the Company's total Transmission and Distribution Mains investment to this class. Similarly, the Large Volume Interruptible class accounts for 1.19% of the Company's total annual throughput while Mr. Fritel allocates only 0.30% of the Company's investment in Transmission and Distribution Mains to this class. Although peak demands should be considered in the assignment of Mains cost responsibility, annual throughput should also be considered.

C. CURB CCOSS

Q. Have you allocated the Company's Transmission and Distributions Mains that consider both peak demands and usage throughout the year?

A. Yes. I have allocated the Company's Transmission and Distribution Mains utilizing the Peak and Average ("P&A") methodology. This method recognizes each class's utilization of the Company's facilities throughout the year and also recognizes that some classes rely upon the Company's facilities (Mains) more than others do during peak periods.

Q. Please explain how you developed your P&A allocators for Transmission Mains.

A. Due to differences between Irrigation and Large Volume Interruptible customers, I have calculated the peak portion of my P&A allocators differently for Transmission Mains and Distribution Mains.

With regard to the Large Volume Interruptible class, these customers can be interrupted or curtailed during peak system demands and therefore are of a lesser quality of service than firm customers. As such, I have not assigned any of the "peak" portion to Interruptible customers but only the "average" portion within my P&A allocation factors.

With respect to the Irrigation class, these customers place very little demand on the system during the winter months when the transmission system will be peaking. Therefore, any Irrigation demands during the winter peak period are negligible such that I have also not assigned any "peak" portion to Irrigation customers for Transmission Mains. However, as will be discussed later, I have assigned a peak responsibility to Irrigation customers with regard to Distribution Mains. The following table provides the derivation of my Transmission Mains P&A allocator:

TABLE 7
CURB Transmission P&A Allocator
(50% Peak/50% Average Weighting)

Class	Peak Day		Avg. (Annual Throughput)		P&A
	Amount	Percent	Amount	Percent	Allocator
Residential	834,482	55.29%	172,571	31.18%	43.24%
Small Commercial	178,257	11.81%	35,651	6.44%	9.13%
Small Volume	214,653	14.22%	53,663	9.70%	11.96%
Large Volume - Firm	281,764	18.67%	188,782	34.11%	26.39%
Irrigation – Sales	0	0.00%	78,047	14.10%	7.05%
Irrigation – Transportation	0	0.00%	18,071	3.27%	1.63%
Large Volume Interruptible	0	0.00%	6,603	1.19%	0.60%
Total	1,509,156	100.000%	553,388	100.000%	100.000%

As can be seen in the table above, there is no peak day cost assigned to the Interruptible classes to reflect the lesser quality of service afforded to these customers as well as to recognize the off-peak nature of Irrigation service. Therefore, my approach to assign Transmission Mains reasonably reflects cost causation and is equitable across all customer classes in that both peak day demands and annual throughput are considered for the firm classes and that the Interruptible and Irrigation classes are assigned significantly less relative cost responsibility than the firm customer classes.

Q. Please explain how you developed your P&A allocators for Distribution Mains.

A. With regard to the P&A allocation factor utilized to assign Distribution Mains, I have also excluded a demand (peak) component for Interruptible customers but have included a demand component for Irrigation customers. In evaluating the Mains that ultimately serve Irrigation customers, most of the Distribution Mains serving these customers are either exclusively or largely devoted to serving Irrigation customers. That is, Black Hills has installed a significant number of Distribution Mains in order to serve only (or mostly) Irrigation customers. In response to Confidential Data Request CURB-21, the Company provided a Google Earth screenshot of the primary irrigation areas with an overlay of Black Hills' Distribution Mains. Upon careful evaluation of the areas serving Irrigation customers, it is apparent that Distribution Mains were installed and are in place to exclusively serve Irrigation customers.[14] Therefore, Irrigation customers should be assigned a demand component of Distribution Mains.

[14] My detailed examination of these areas in Google Earth determined there are a very few farmhouses also potentially served by the irrigation Distribution Mains.

In developing a peak demand component for Irrigation, I estimated the Irrigation average day demand during the highest month of usage in the test year (August 2024) as a surrogate for this class's non-coincident peak ("NCP") demand. The highest Irrigation average day usages in August 2024 are weather normalized per Mr. Fritel's normalization adjustment and are as follows:

TABLE 8
August 2024 Irrigation Throughput

	Sales	Transport
(1) Actual Aug. 2024	1,876,774	7,573,562
(2) Normalization Adj. Aug. 2024 [15]	(179,383)	(426,125)
(3) Total Weather-Normalized	1,697,391	7,147,437
(4) Avg. Use Per Day: (3) x 12 ÷ 365	55,805	234,984

The following table provides the derivation of my Distribution Mains P&A allocator:

TABLE 9
CURB Distribution P&A Allocator
(50% Peak/50% Average Weighting)

Class	Peak Day Amount	Peak Day Percent	Avg. (Annual Throughput) Amount	Avg. (Annual Throughput) Percent	P&A Allocator
Residential	834,482	46.36%	172,571	31.18%	38.77%
Small Commercial	178,257	9.90%	35,651	6.44%	8.17%
Small Volume	214,653	11.93%	53,663	9.70%	10.81%
Large Volume - Firm	281,764	15.65%	188,782	34.11%	24.88%
Irrigation – Sales	55,805	3.10%	78,047	14.10%	8.60%
Irrigation – Transportation	234,984	13.06%	18,071	3.27%	8.16%
Large Volume Interruptible	0	0.00%	6,603	1.19%	0.60%
Total	1,799,944	100.000%	553,388	100.000%	100.000%

With respect to Distribution Mains, there continues to be no peak day cost assigned to the Large Volume Interruptible class to reflect the lesser quality of service afforded to these customers. The Irrigation classes are assigned peak day responsibility to recognize the

[15] Calculated per Schedule GAW-2.

dedicated Distribution Mains required to serve these customers. Therefore, this approach reasonably reflects cost causation and is equitable across all customer classes.

Q. Earlier you explained that Mr. Fritel re-functionalized the Company's booked Transmission and Distribution Mains. Have you conducted your CCOSS analysis utilizing both Mr. Fritel's re-functionalization of Transmission and Distribution Mains as well as the Company's booked amounts of Transmission and Distribution Mains?

A. Yes. In order to avoid controversy relating to Mr. Fritel's re-functionalization of Mains, I conducted my CCOSS analysis using both approaches, i.e., accepting Mr. Fritel's re-functionalization and utilizing the Company's booked separation of Transmission and Distribution Mains. As can be seen below, there is virtually no difference in class RORs at current rates under Mr. Fritel's re-functionalization approach or the Company's booked separation between Transmission and Distribution Mains under the P&A method to allocate Mains.

Q. Please provide the results of your CCOSS analysis utilizing the P&A method to allocate Transmission and Distribution Mains.

A. The following tables provide a comparison of Mr. Fritel's CCOSS results at current rates as well as my CCOSS results utilizing the P&A method to allocate Mains (accepting Mr. Fritel's re-functionalization as well as using the booked separation between Transmission and Distribution Mains):

TABLE 10
Comparison of Class RORs at Current Rates

Class	Fritel CCOSS	CURB CCOSS: Fritel Re-Functionalized Dist. & Trans.	CURB CCOSS: Booked Dist. & Trans.
Residential	1.75%	4.74%	4.75%
Small Commercial	2.69%	3.69%	3.71%
Small Volume	6.05%	2.51%	2.53%
Large Volume - Firm	15.80%	2.05%	2.08%
Irrigation – Sales	4.47%	-1.39%	-1.48%
Irrigation – Transportation	3.70%	-5.93%	-6.88%
Large Volume Interruptible	20.71%	8.31%	8.31%
Total Company	3.19%	3.19%	3.19%

TABLE 11
Comparison of Indexed RORs at Current Rates

Class	Fritel CCOSS	CURB CCOSS: Fritel Re-Functionalized Trans. & Dist.	CURB CCOSS: Booked Trans. & Dist.
Residential	55%	149%	149%
Small Commercial	84%	116%	116%
Small Volume	190%	79%	80%
Large Volume - Firm	496%	64%	65%
Irrigation – Sales	140%	-43%	-46%
Irrigation – Transportation	116%	-186%	-216%
Large Volume Interruptible	650%	261%	261%
Total Company	100%	100%	100%

The details of my CCOSS analyses are provided in my Schedule GAW-3 (using Fritel re-functionalization of Transmission and Distribution Mains) and Schedule GAW-4 (using actual booked Transmission and Distribution Mains).

Q. What are your conclusions regarding class cost allocations in this case?

A. As can be observed in the tables above, there are significant differences in class RORs and indexed RORs at current rates between Mr. Fritel's study and my studies. The underlying reasons for these differences are:

(a) Mr. Fritel assigned 74% of Mains less than 10-inches based on customers; and,

(b) Mr. Fritel assigned no peak or winter volume demand responsibility to Irrigation customers even though there are a significant amount of Mains dedicated to serving just these customers.

As a result, I recommend that no weight be given to his CCOSS and that my CCOSS utilizing an industry-accepted approach to allocate Transmission and Distribution Mains should be used as a guide in establishing class revenue responsibility.

III. <u>CLASS REVENUE DISTRIBUTION</u>

Q. How does Black Hills propose to distribute its requested overall $17.2 million increase to individual classes and rate schedules?

A. The following reflects Mr. Fritel's recommended class revenue increases:

TABLE 12
Black Hills Proposed Class Revenue Increases
($000)

Class	Current Margin Revenue	Black Hills Proposed Increase	Black Hills Proposed Percent Increase
Residential	$39,244	$13,996	35.66%
Small Commercial	$6,407	$2,187	34.14%
Small Volume	$4,871	$430	8.83%
Large Volume Firm	$6,507	$18	0.27%
Irrigation Sales	$2,445	$485	19.84%
Irrigation Transportation	$589	$109	18.52%
Interruptible Large Volume	$286	-$18	-6.15%
Total Margin	$60,348	$17,207	28.51%

Q. How did Mr. Fritel develop his proposed class revenue increases?

A. On page 27 of his direct testimony, Mr. Fritel states that "No customer class should receive a decrease when other classes receive an increase in base rate revenues under the proposed rates." His testimony continues with his recommendation for "no change to the base rates for the Large Volume classes and to use the revenue decrease that would otherwise result from reducing their rates to be used instead to moderate the Residential customer class increase."

Q. Is Mr. Fritel's description within his testimony factually accurate?

A. No.

Q. Please explain how Mr. Fritel did assign revenues across rate classes.

A. In drilling through Mr. Fritel's calculations within his Exhibit EJF-15, it was determined that he used the following approach to class revenue increases.

<u>Residential and Small Commercial Revenues</u> – Mr. Fritel first developed the Residential and Small Commercial customer charge revenues based on his proposed customer charges. He then allocated his calculated cost of service revenue deficiencies (from his CCOSS) for the Residential and Small Commercial classes combined in order to develop his proposed volumetric charges. This then resulted in the combined Residential and Small Commercial class revenues at proposed rates equaling his calculated cost of service (revenue requirement) for these two classes on a combined basis.[16]

[16] There is a very small difference in the combined revenues at proposed rates and combined cost of service.

Firm Small Volume Revenues – This class was essentially priced at Mr. Fritel's allocated cost of service (revenue requirement).

Firm and Interruptible Large Volume Revenues – Mr. Fritel assigned no change in the combined revenues for the Large Volume rate schedules (Firm Sales, Transportation, and Interruptible).

Irrigation Sales and Transportation – Mr. Fritel used a similar approach as used for the Residential and Small Commercial classes. That is, Mr. Fritel first developed the Irrigation Sales and Transportation customer charge revenues based on his proposed customer charges. He then allocated his calculated cost of service revenue deficiencies (from his CCOSS) for the Irrigation Sales and Transportation rate schedules combined in order to develop his proposed volumetric charges. This then resulted in the combined Irrigation Sales and Transportation revenues at proposed rates equaling his calculated cost of service (revenue requirement) for these two rate schedules on a combined basis.[17]

Q. Is Mr. Fritel's proposed class revenue distribution reasonable?

A. No. Mr. Fritel's class revenue distribution is premised almost entirely upon his CCOSS wherein he has significantly over-assigned costs to the Residential class and significantly under-assigned costs to the Small and Large Volume Firm classes as well as the Irrigation classes. Indeed, and as shown in my Tables 10 and 11, while Mr. Fritel's study indicates that the Small and Large Volume Firm classes are currently contributing revenues well above the system average ROR and the Irrigation classes (Sales and Transportation) are also contributing revenues above the system average ROR, my analysis indicates that these

[17] *Id.*

classes and customers are actually achieving deficient and/or negative RORs at current rates.

Q. Do you recommend an alternative class revenue distribution?

A. Yes. In developing my recommended class revenue distribution, I have considered gradualism as well as the results of my CCOSS. As shown in my Schedule GAW-5, I evaluated each class's relative (indexed) ROR at current rates. For those classes whose indexed RORs are negative (a negative ROR at current rates), these classes were assigned 150% of the system average percentage increase (Irrigation Sales and Transportation). Those classes whose indexed RORs are below parity (Small and Large Volume Firm), I assigned a larger percentage increase than the system average percentage increase to these classes (115% of the system average for Small Volume and 130% of system average for Large Volume). The Small Commercial ROR is fairly close to parity such that I assigned 100% of the system average percentage increase to this class. The Interruptible Large Volume class ROR is significantly above parity such that I assigned only a modest increase (50%) of the system average percentage increase to this class. Finally, the Residential class was treated as the residual in order to collect the overall requested increase. The following table provides a summary of my recommended class increases at the Company's overall requested $17.2 million increase:

TABLE 13
CURB Recommended Class Revenue Increases
($000)

Class	Current Margin Revenue	Indexed ROR[18]	Percent Of System Pct. Increase	$ Increase	% Increase
Residential	$39,244	149%	Residual	$10,033	25.57%
Small Commercial	$6,407	116%	100%	$1,827	28.51%
Small Volume	$4,871	80%	115%	$1,597	32.79%
Large Volume Firm	$6,507	65%	130%	$2,412	37.07%
Irrigation Sales	$2,445	-45%	150%	$1,046	42.77%
Irrigation Transportation	$589	-201%	150%	$252	42.77%
Interruptible Large Volume	$286	261%	50%	$41	14.26%
Total Margin	$60,348	100%		$17,207	28.51%

Q. Do all classes move closer to their allocated cost of service under your recommended class revenue allocations?

A. Yes. As shown in the table below, all classes move closer to parity under my recommended class revenue allocations:

TABLE 14
Class Movements Towards Allocated Cost of Service
Under CURB Recommended Class Revenue Increases

	Fritel Re-Functionalized T&D Mains		Booked T&D Mains	
Class	Current Rates	CURB Proposed	Current Rates	CURB Proposed
Residential	149%	123%	149%	123%
Small Commercial	116%	113%	116%	113%
Small Volume	79%	91%	80%	91%
Large Volume Firm	64%	84%	65%	84%
Irrigation Sales	-43%	35%	-46%	34%
Irrigation Transportation	-186%	-58%	-216%	-69%
Interruptible Large Volume	261%	145%	261%	145%
Total Margin	100%	100%	100%	100%

[18] Average of CURB CCOSS utilizing Fritel's re-functionalization and actual booked functionalization of Transmission and Distribution Mains.

Q. Please provide a summary comparison of Black Hills' and your recommended class revenue increases utilizing the Company's proposed overall increase of $17.2 million.

A. The following table provides a comparison of the Company's and my recommended class revenue increases utilizing the Company's proposed overall revenue increase:

TABLE 15
Comparison of Black Hills & CURB
Recommended Class Revenue Increases
($000)

Class	Company Proposed	CURB Recommended
Residential	$13,996	$10,033
Small Commercial	$2,187	$1,827
Small Volume	$430	$1,597
Large Volume Firm	$18	$2,412
Irrigation Sales	$485	$1,046
Irrigation Transportation	$109	$252
Interruptible Large Volume	-$18	$41
Total Margin	$17,207	$17,207

Q. In the event the Commission authorizes less than the $17.2 million overall increase requested by the Company, how should the overall authorized increase be distributed to individual customer classes?

A. If the Commission authorizes less of an overall increase than that requested by Black Hills, my recommended class revenue distribution should be scaled back proportionately.

IV. RESIDENTIAL AND SMALL COMMERCIAL RATE DESIGN

Q. Please explain Black Hills' current and proposed Residential and Small Commercial rate structures.

A. The Company's Residential and Small Commercial base rates are structured with a fixed monthly customer (service) charge plus a flat delivery charge per therm. In addition, these customers are subject to several reconcilable riders including the Gas System Reliability Surcharge ("GSRS") rider, a Purchased Gas Adjustment ("PGA") rider, a Weather Normalization Adjustment ("WNA") rider and Ad Valorem Tax Surcharge rider.

Mr. Fritel proposes to increase the Residential base rate fixed monthly service charge from $18.50 per month to $31.50 per month and increase the Small Commercial fixed monthly service charge from $28.00 to $49.50 per month. In this regard, the current Residential GSRS rider is $2.27 while the Small Commercial GSRS rider is $3.70, which are based on a statutorily required fixed charge basis, will be reset to zero with the conclusion of this case. The current Residential and Small Commercial base delivery (margin) charge is $0.20251 per therm for both rate schedules and, under the Company's proposal, this rate would be increased to $0.20947 per therm.

Q. Given the current base rate Residential customer charge of $18.50 per month and the current delivery charge of $0.20251 per therm, what percentage of Residential base rate revenues are collected from the fixed monthly customer charge?

A. As shown in Mr. Fritel's Exhibit EJF-6, $23.519 million is collected from Residential base rate fixed monthly customer charges, while $12.756 million is collected from the volumetric delivery charge. As such, 64.8% of total Residential base rate revenues are collected from the fixed monthly customer charge. However, in addition to the base rate fixed charges, the current Residential GSRS rider contributes an additional $2.969 million in fixed charge revenues. Therefore, under current rates, Residential customers' unavoidable fixed monthly charges represent 67.5% of a customer's bill associated with margin rates.

Q. Under Mr. Fritel's proposal, what percentage of Residential base rate revenues would be collected from fixed monthly customer charges?

A. Under Mr. Fritel's proposed rates, the GSRS will be set to zero and the base rate customer charge will be increased to $31.50. Under the Company's proposal, 75.2% of Residential base rate revenues would initially be collected from fixed monthly customer charges with GSRS rates and revenues increasing over time until the Company's next rate case.[19]

Q. Given the current base rate Small Commercial customer charge of $28.00 per month and the current delivery charge of $0.20251 per therm, what percentage of Small Commercial Sales base rate revenues are collected from the fixed monthly customer charge?

A. Also shown in Mr. Fritel's Exhibit EJF-6, $3.251 million is collected from Small Commercial Sales base rate fixed monthly customer charges, while $2.519 million is collected from the volumetric delivery charge. As such, 56.4% of total Small Commercial Sales base rate revenues are collected from the fixed monthly customer charge. However, in addition to the base rate fixed charges, the current Small Commercial GSRS rider contributes an additional $0.443 million in fixed charge revenues. Therefore, under current rates, Small Commercial Sales customers' unavoidable fixed monthly charges represent 59.5% of a customer's bill associated with margin rates.

[19] Per Exhibit EJF-15. Proposed customer charge revenue of $40.046 million divided by total proposed margin revenue of $53.240 million.

Q. Under Mr. Fritel's proposal, what percentage of Small Commercial Sales base rate revenues would be collected from fixed monthly customer charges?

A. Under Mr. Fritel's proposed rates, the GSRS will be set to zero and the base rate customer charge will be increased to $49.50. Under the Company's proposal, 68.9% of Small Commercial Sales base rate revenues would initially be collected from fixed monthly customer charges with GSRS rates and revenues increasing over time until the Company's next rate case.[20]

Q. Do these high percentages of revenues collected from unavoidable fixed charges concern you?

A. Yes. Under current rates, more than two-thirds (67.5%) of Residential margin revenues and almost 60% (59.5%) of Small Commercial Sales margin revenues are collected from unavoidable fixed monthly charges. These high percentages are even more concerning under the Company's proposed fixed charges wherein 75.2% of the Residential and 68.9% of the Small Commercial Sales margin revenues would be collected from unavoidable fixed monthly charges. These high percentages inhibit these customers' ability to control their natural gas bills and is contrary to conservation efforts since a large portion of the customer's bill is fixed in nature and does not vary with consumption. Furthermore, such a high percentage of margin revenue collected from fixed charges clearly reduces the Company's revenue risks in that customer charge revenue is guaranteed for as long as a customer is connected to the system.

[20] Per Exhibit EJF-15. Proposed customer charge revenue of $5.747 million divided by total proposed margin revenue of $8.346 million.

Q. Did Mr. Fritel explain how he developed his proposed monthly customer charges?

A. Yes. On page 28 of his direct testimony, Company witness Fritel indicates that his proposed customer charges are designed to recover all of his classified costs associated with services, meters and regulators, and customer accounting as well as 50% of what he refers to as "customer-related distribution costs." These calculations result in a Residential rate of $31.47 which was then rounded to $31.50. With regard to Small Commercial, Mr. Fritel's calculated customer charge was $49.81 which was rounded to $49.50.

Q. Are Mr. Fritel's calculated customer costs and proposed customer charges reasonable?

A. No. Mr. Fritel's "customer" costs are simply the result of placing all costs into one of three costing buckets: customer; demand; or commodity. However, a careful examination of his analysis reveals that the vast majority of these costs that he has placed in the "customer" bucket are simply overhead costs as well as costs associated with the investment in Transmission and Distribution Mains as well as the general operation of the Company's transmission and distribution system. The following table provides examples of the total Company amounts Mr. Fritel has classified and placed in his "customer" cost bucket for developing his proposed fixed monthly customer charges:

TABLE 16
Examples of Inappropriate Costs Included in Mr. Fritel's "Customer Costs"
($000)

		Fritel Customer Costs for Rate Design			
	Total Company	Services, Meters and Cust. Accts.	50% of Distribution	Total Customer Costs	Percent Fritel Customer Costs
Gross Plant					
Intangible Plant	$3,509	$2,125	$404	$2,529	72.1%
General Plant	$36,310	$21,989	$4,177	$26,167	72.1%
Other Utility Plant	$16,585	$10,154	$1,876	$12,030	72.5%
O&M Expenses					
Transmission O&M	$702	$0	$211	$211	30.1%
Dist. Super. & Eng.	$1,991	$1,043	$286	$1,329	66.7%
Mains & Services - Ops	$3,222	$1,261	$592	$1,853	57.5%
Maintenance of Mains	$779	$0	$235	$235	30.2%
Maint. of Compressor Station	$76	$0	$23	$23	30.2%
Meas. Reg. & Station Eqmt.	$703	$418	$204	$623	88.6%
Other Dist. Expenses	$1,817	$942	$264	$1,206	66.4%
Rent Expense	$17	$9	$2	$11	66.4%
A&G Expenses	$15,677	$9,136	$1,737	$10,873	69.4%

Q. In your opinion, what costs should be evaluated in determining fixed monthly customer charges?

A. In my opinion, only those direct costs required to connect and maintain a customer's account should be included in evaluating fixed monthly customer charges. These include the capital costs for meters and services and the O&M costs associated with operating and maintaining meters and services, meter reading, and customer records expenses. In this regard, overhead and non-customer distribution costs such as those included by Mr. Fritel and outlined above should not be included in the evaluation of customers for determining reasonable fixed monthly customer charges.

Q. Is there academic support for your opinion that fixed monthly customer charges should only reflect the direct costs required to connect and maintain a customer's account?

A. Yes. In his well-known treatise Principles of Public Utility Rates, Professor James C. Bonbright states:

> But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." **They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories**.[21]

Q. There are some regulatory analysts of the opinion that a utility's "fixed costs" should be collected in fixed charges. Do you agree with this premise?

A. No. First and foremost, there is not a single economic theory that supports the premise that fixed costs should be collected in fixed charges. Accepted economic theory indicates that efficient price signals result when prices are equal to marginal costs. The marginal cost of a particular product or service is equal to the incremental cost of providing an additional unit of service or the incremental cost of adding an additional customer. These marginal costs reflect the incremental costs of additional capital expenditures (sunk or fixed costs) along with the incremental operating and maintenance costs of an additional unit of output or customer. In no way does any economic theory even suggest that any company's sunk, or fixed costs, should be priced on a fixed charge basis.

Secondly, it is often said that regulation should serve as a surrogate for competition. In this regard, competitive market-based prices are generally structured on usage (i.e.,

[21] Second Edition, page 492 **[Emphasis Added]**.

volume-based pricing) rather than on fixed charges. These competitive pricing structures include those industries that were once regulated and are now competitive in nature including: railroads; airlines; trucking; and products pipelines.[22]

Finally, if one were to apply the philosophy that fixed costs should be collected from fixed charges to Black Hills, according to Mr. Fritel's analysis, 98% of the Residential class's margin revenues would be collected in fixed charges.[23]

Q. Is the natural gas distribution industry unique in its cost structures, which are comprised largely of fixed costs in the short-run?

A. No. Most manufacturing and transportation industries are comprised of cost structures predominated with "fixed" costs. These fixed costs, also known as "sunk" costs, are primarily comprised of investment in plant and equipment. Virtually every capital-intensive industry is faced with a high percentage of so-called fixed costs in the short-run, and as indicated earlier, prices for competitive products and services in these capital-intensive industries are invariably established on a volumetric basis.

Q. How should the level of fixed monthly customer charges be evaluated?

A. Although it is my opinion that fixed monthly customer charges should only reflect the direct costs required to connect and maintain a customer's account, I recognize that some Commissions prefer to also include some level of overhead or indirect costs. The direct

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[22] There are competitive services that are partially priced on a fixed charge per month basis, such as cable television and cellular phone service. However, even these services are somewhat volumetrically-priced in that prices will vary depending on the level of services subscribed to. Furthermore, it is not cost effective for these industries to meter and measure every unit of usage.

[23] Calculated per Mr. Fritel's Exhibit EJF-14, Table 5:
(Customer Costs of $48.558 million + Demand Costs of $5.992 million) ÷ Total Cost of Service of $55.533 million.

costs only reflect the cost of service lines, meters, meter reading, customer records, and billing. Additional overhead or indirect costs that may be considered include provisions for corporate computer billing systems, employee pensions and benefits, and employee wage taxes (FICA and Medicare).

Q. Have you conducted analyses of those costs that more reasonably should be considered in developing fair and reasonable Residential customer charges?

A. Yes. I have conducted both a direct customer cost analysis as well as an analysis that includes a provision for certain overhead or indirect costs.

Q. What are the results of the Residential and Small Commercial customer cost analyses you conducted for this case?

A. My Schedule GAW-6 provides the details of my Residential and Small Commercial customer cost analyses, which are conducted using both the Company's requested 10.50% ROE as well as a placeholder ROE of 9.50%. As indicated in this Schedule, my analysis produces a direct Residential customer cost range of $13.42 to $13.97 per month while the analysis that includes a provision for indirect costs produces a range of $14.15 per month to $14.69 per month. With regard to Small Commercial, my analysis produces a direct customer cost range of $22.26 to $23.11 per month while the analysis that includes a provision for indirect costs produces a range of $23.56 to $24.41 per month.

Q. What is your recommendation concerning Black Hills' Residential and Small Commercial customer charges?

A. Although my Residential customer cost analyses indicate that a customer charge in the range of $13.42 per month to $14.69 per month is warranted, in the interest of rate continuity, I recommend that the current Residential fixed monthly customer charge of $18.50 be maintained. Similarly, my Small Commercial customer analyses indicate that a customer charge in the range of $22.26 to $24.41 per month is warranted, I recommend that the Small Commercial fixed customer charge of $28.00 per month be maintained. In these regards, maintaining the current fixed monthly Residential and Small Commercial charges of $18.50 and $28.00, respectively, will allow for the recovery of a significant level of overhead costs.

Q. Do you have concluding comments regarding the establishment of reasonable fixed monthly customer charges?

A. Yes. It should be recognized that Residential customers utilize very little natural gas in the summer months, and at the same time, have much higher electric bills due to increased air conditioning and cooling. As a result, high natural gas fixed monthly customer charges place a significant burden on low-income Residential customers in the summer months, regardless of additional gas conservation efforts, while dealing with larger electricity bills. In other words, an unavoidable fixed natural gas charge of upwards of $31.50 per month will further prevent relief from high utility bills during low-usage periods. CURB believes that the customer charge is one aspect of rate design that can have positive impacts on reducing a household's utility bill.

Finally, even with a lower fixed Residential and Small Commercial customer charge, Black Hills will have every opportunity to recover its allowed overall Residential revenue requirement, particularly in light of the fact that margin rates are based on weather-normalized usage and, to the extent that weather is abnormal, customers are subjected to a WNA rider. Furthermore, Black Hills is entitled to reconcile and recover all of its incremental Ad Valorem Taxes, PGA costs and incremental capital costs associated with the replacement of various types of plant.

Q. Does this complete your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HANOVER) ss:

Glenn A. Watkins, being duly sworn upon his oath, deposes and states that he is a consultant for the Citizens' Utility Ratepayer Board, that he has read and is familiar with the foregoing *Direct Testimony*, and that the statements made herein are true and correct to the best of his knowledge, information, and belief.

Glenn A. Watkins

SUBSCRIBED AND SWORN to before me this 8th day of May, 2025.

Jennifer D. Polansky
Notary Public
I was commissioned a notary in the state of Virginia as Jennifer R. Dolen

My Commission expires: October 31, 2026
Reg. #7315146

JENNIFER R. DOLEN
NOTARY PUBLIC
REG # 7315146
MY COMMISSION EXPIRES 10/31/2026
COMMONWEALTH OF VIRGINIA

BACKGROUND & EXPERIENCE PROFILE
GLENN A. WATKINS
PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jan. 2017-Present	President/Senior Economist, Technical Associates, Inc.
Mar. 1993-Dec. 2016	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. <u>Public Utility Regulation</u>

A. <u>Costing Studies</u> -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. <u>Rate Design Studies</u> -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

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C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers' compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

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IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

BLACK HILLS ENERGY
Sales Irrigation

	Oct '14 thru Sep '15	Oct '15 thru Sep '16	Oct '16 thru Sep '17	Oct '17 thru Sep '18	Oct '18 thru Sep '19	Oct '19 thru Sep '20	Oct '20 thru Sep '21	Oct '21 thru Sep '22	Oct '22 thru Sep '23	Oct '23 thru Sep '24	10-Year Average
Oct	159,323	295,924	325,302	146,991	139,569	225,634	296,476	233,266	302,650	385,568	251,070
Nov	203,481	55,323	280,511	141,031	59,919	159,135	109,491	148,630	199,137	242,871	159,953
Dec	60,249	38,575	52,033	57,798	33,679	87,352	67,984	94,770	61,723	114,251	66,841
Jan	51,311	38,808	40,376	49,109	35,473	71,270	46,820	53,189	55,362	45,817	48,754
Feb	25,782	31,460	37,301	66,952	75,452	35,061	50,408	37,237	42,746	87,741	49,014
Mar	133,335	216,027	178,741	194,555	61,984	136,451	63,065	123,064	177,991	141,127	142,634
Apr	829,515	483,962	156,698	344,915	125,397	283,355	179,998	468,409	620,045	556,175	404,847
May	334,811	245,059	106,882	645,829	361,815	728,297	376,595	760,630	675,047	814,202	504,917
Jun	282,900	753,898	476,478	880,387	289,071	1,052,954	571,025	814,944	226,639	831,538	617,983
Jul	**1,961,221**	1,478,463	**1,570,268**	**1,440,942**	1,510,454	**1,817,497**	1,650,208	**1,835,319**	1,014,923	1,595,692	1,587,499
Aug	1,824,822	**1,864,207**	1,527,201	1,348,204	**1,827,716**	1,584,457	**1,974,150**	1,722,749	**1,423,628**	**1,876,774**	**1,697,391**
Sept	1,203,304	945,503	1,263,779	360,592	954,211	1,036,487	1,313,031	1,124,486	1,280,005	1,168,903	1,065,030

Max Month	1,876,774	1,697,391
Normalization Adjustment		(179,383)

BLACK HILLS ENERGY
Interruptible Irrigation Volumes

	Oct '14 thru Sep '15	**Oct '15 thru Sep '16**	**Oct '16 thru Sep '17**	**Oct '17 thru Sep '18**	**Oct '18 thru Sep '19**	**Oct '19 thru Sep '20**	**Oct '20 thru Sep '21**	**Oct '21 thru Sep '22**	**Oct '22 thru Sep '23**	**Oct '23 thru Sep '24**	**10-Year Average**
Oct	852,230	1,178,386	1,227,106	725,122	575,582	1,035,434	1,473,110	1,137,363	1,729,923	1,533,451	1,146,771
Nov	661,929	258,757	1,139,141	710,365	172,031	631,920	580,818	803,099	1,265,391	1,319,845	754,330
Dec	386,102	136,080	331,520	588,924	215,042	595,771	300,493	834,981	572,339	537,866	449,912
Jan	221,487	141,655	183,927	217,347	218,952	277,310	243,228	327,545	474,362	217,547	252,336
Feb	199,218	153,855	145,099	353,456	109,008	160,655	151,197	280,582	478,314	173,381	220,477
Mar	612,278	1,015,204	1,027,296	1,267,510	146,441	377,299	391,003	1,061,453	1,410,878	743,144	805,251
Apr	2,585,890	1,970,143	783,118	1,731,226	519,243	1,311,942	1,078,665	2,855,144	3,403,732	2,603,159	1,884,226
May	1,468,615	1,324,926	575,166	3,242,379	1,246,408	3,174,811	1,975,058	4,328,649	2,779,120	3,866,441	2,398,157
Jun	1,184,627	2,727,419	2,332,781	4,412,200	974,141	5,178,280	2,741,536	4,552,300	968,636	3,523,001	2,859,492
Jul	6,684,099	5,392,371	**7,079,808**	**6,653,439**	5,889,120	**7,729,250**	7,059,122	**8,636,380**	3,585,121	5,588,655	6,429,737
Aug	**6,826,220**	**7,343,981**	6,695,475	5,306,738	**7,654,743**	6,467,898	**8,350,184**	8,595,815	**6,659,758**	**7,573,562**	**7,147,437**
Sept	4,256,353	3,123,073	4,668,920	2,271,239	3,993,851	3,756,429	5,154,463	5,390,657	4,867,838	3,906,217	4,138,904

Max Month	7,573,562	7,147,437
Normalization Adjustment		(426,125)

BLACK HILLS ENERGY
Peak & Average CCOSS
Fritel Re-Functionalization of Transmission & Distribution Mains
(Summary)

Description	Total Gas Utility Adjusted	Residential Service	Firm and Transportation: Small Commercial	Firm and Transportation: Small Volume	Firm and Transportation: Large Volume	Irrigation: Sales	Irrigation: Transportation	Interruptible Large Volume
Current Margin Rate Revenues	$60,347,609	$39,244,269	$6,406,588	$4,870,538	$6,506,797	$2,444,623	$588,871	$285,924
Other Operating Revenues	$3,379,475	$1,680,778	$268,579	$317,088	$672,850	$236,071	$187,668	$16,442
Total Non-Gas Revenues	$63,727,084	$40,925,046	$6,675,167	$5,187,626	$7,179,647	$2,680,694	$776,538	$302,367
O&M Expenses	$32,351,842	$19,653,466	$3,406,049	$2,636,219	$3,634,516	$1,865,862	$1,043,149	$112,580
Depreciation & Amort.	$12,746,995	$7,546,364	$1,301,993	$1,085,457	$1,539,527	$761,452	$468,010	$44,191
Taxes Other Than Income	$8,963,372	$5,031,121	$861,899	$814,519	$1,250,146	$593,156	$378,826	$33,705
Federal Income Tax	($84,781)	$652,691	$31,018	($59,052)	($144,108)	($255,224)	($325,583)	$15,477
Total Expenses	$53,977,428	$32,883,643	$5,600,959	$4,477,143	$6,280,081	$2,965,245	$1,564,402	$205,954
Net Operating Income	$9,749,657	$8,041,403	$1,074,208	$710,482	$899,566	($284,551)	($787,864)	$96,413
Rate base	$305,947,330	$169,739,119	$29,095,551	$28,339,195	$43,807,509	$20,528,327	$13,277,216	$1,160,412
ROR at Current Rates	3.19%	4.74%	3.69%	2.51%	2.05%	-1.39%	-5.93%	8.31%
Indexed ROR	100%	149%	116%	79%	64%	-43%	-186%	261%
Rate Base:								
Gross Plant	$495,300,471	$275,378,710	$47,067,104	$45,537,716	$70,642,062	$33,328,738	$21,464,328	$1,881,814
Accum. Depreciation	($138,756,353)	($77,741,458)	($13,247,657)	($12,677,424)	($19,396,559)	($9,262,809)	($5,910,489)	($519,956)
Other Rate Base Items	($50,596,788)	($27,898,132)	($4,723,896)	($4,521,096)	($7,437,995)	($3,537,602)	($2,276,624)	($201,445)
Total Rate Base	$305,947,330	$169,739,119	$29,095,551	$28,339,195	$43,807,509	$20,528,327	$13,277,216	$1,160,412
Cost of Service @ Requested 7.63% ROR								
Required Return	$23,343,781	$12,951,095	$2,219,991	$2,162,281	$3,342,513	$1,566,311	$1,013,052	$88,539
O&M	$32,351,842	$19,653,466	$3,406,049	$2,636,219	$3,634,516	$1,865,862	$1,043,149	$112,580
Depreciation	$12,746,995	$7,546,364	$1,301,993	$1,085,457	$1,539,527	$761,452	$468,010	$44,191
Taxes Other Than Income	$8,963,372	$5,031,121	$861,899	$814,519	$1,250,146	$593,156	$378,826	$33,705
Income Taxes	$3,528,847	$1,957,799	$335,593	$326,869	$505,283	$236,777	$153,142	$13,384
Other Operating Revenue	($3,379,475)	($1,680,778)	($268,579)	($317,088)	($672,850)	($236,071)	($187,668)	($16,442)
Net Base Rate Cost of Service	$77,555,361	$45,459,068	$7,856,946	$6,708,257	$9,599,135	$4,787,486	$2,868,511	$275,958
Base Rate Revenue Deficiency	$17,207,752	$6,214,800	$1,450,358	$1,837,719	$3,092,338	$2,342,864	$2,279,640	($9,966)
Curb Proposed Revenue Increase	$17,207,273	$10,033,325	$1,826,749	$1,597,080	$2,411,918	$1,045,575	$251,862	$40,764
Revenue Conversion Factor	1.2658	1.2658	1.2658	1.2658	1.2658	1.2658	1.2658	1.2658
Increase to Operating Income	$13,594,124	$7,926,548	$1,443,172	$1,261,729	$1,905,469	$826,027	$198,977	$32,204
Operating Income at CURB Increase	$23,343,781	$15,967,951	$2,517,379	$1,972,211	$2,805,035	$541,476	-$588,887	$128,617
ROR @ CURB Increase	7.63%	9.41%	8.65%	6.96%	6.40%	2.64%	-4.44%	11.08%
Indexed ROR @ CURB Increase	100%	123%	113%	91%	84%	35%	-58%	145%

BLACK HILLS ENERGY
Peak & Average CCOSS
Fritel Re-Functionalization of Transmission & Distribution Mains
(Rate Base)

Acct. No.	Description			Total Gas Utility Adjusted	TAI Allocator Name	TAI Allocator No.	Residential Service	Firm and Transportation Small Commercial	Firm and Transportation Small Volume	Firm and Transportation Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
	Gas Plant in Service												
	Intangible Plant												
301	Organization			$186,932	Supervised O & M before General	28	$113,818	$19,636	$15,342	$20,653	$10,687	$6,169	$627
302	Franchises & Consents			$74,990	Supervised O & M before General	28	$45,659	$7,877	$6,155	$8,285	$4,287	$2,475	$252
303	Miscellaneous Intangible Plant			$3,246,838	Supervised O & M before General	28	$1,976,914	$341,058	$266,485	$358,723	$185,618	$107,143	$10,898
	Total Intangible Plant			$3,508,760			$2,136,391	$368,571	$287,982	$387,661	$200,592	$115,786	$11,777
	Production & Gathering Plant												
336	Purification Equipment			$0	Trans. + Dist. Mains	14	$0	$0	$0	$0	$0	$0	$0
	Total Product. & Gather. Plant			$0			$0	$0	$0	$0	$0	$0	$0
	Transmission Plant												
365	Land & Land Rights			$737,239	Trans. + Dist. Mains	14	$291,918	$61,550	$81,267	$185,503	$61,310	$51,292	$4,398
366	Structures & Improvements			$261,735	Trans. + Dist. Mains	14	$103,637	$21,852	$28,851	$65,857	$21,766	$18,210	$1,562
367	Mains	61,180,956											
	Large Mains	11,275,650											
	Demand		50.000%	$5,637,825	Transmission P&A	32	$2,437,769	$514,566	$674,302	$1,487,937	$397,563	$92,052	$33,636
	Commodity		50.000%	$5,637,825	Transmission P&A	32	$2,437,769	$514,566	$674,302	$1,487,937	$397,563	$92,052	$33,636
	Small Mains	49,905,306											
	Demand		50.000%	$24,952,653	Distribution P&A	33	$9,674,887	$2,039,358	$2,697,731	$6,209,193	$2,146,399	$2,036,213	$148,871
	Customer		50.000%	$24,952,653	Distribution P&A	33	$9,674,887	$2,039,358	$2,697,731	$6,209,193	$2,146,399	$2,036,213	$148,871
368	Compressor Station Equipment			$2,475	Trans. + Dist. Mains	14	$980	$207	$273	$623	$206	$172	$15
369	Measuring & Reg. Station Eq.			$5,388,010	Trans. + Dist. Mains	14	$2,133,445	$449,832	$593,928	$1,355,723	$448,077	$374,859	$32,146
371	Other Equipment			$106,238	Trans. + Dist. Mains	14	$42,066	$8,870	$11,711	$26,732	$8,835	$7,391	$634
	Total Transmission Plant			$67,676,653			$26,797,359	$5,650,157	$7,460,097	$17,028,697	$5,628,119	$4,708,455	$403,769
	Distribution Plant												
374	Land & Land Rights			$979,307	Trans. + Dist. Mains	14	$387,768	$81,760	$107,950	$246,412	$81,441	$68,133	$5,843
375	Structures & Improvements			$1,188,888	Trans. + Dist. Mains	14	$470,754	$99,257	$131,053	$299,146	$98,870	$82,714	$7,093
376	Mains	165,607,324											
	Large Mains	30,521,430											
	Demand		50.000%	$15,260,715	Transmission P&A	32	$6,598,661	$1,392,849	$1,825,231	$4,027,613	$1,076,142	$249,172	$91,048
	Commodity		50.000%	$15,260,715	Transmission P&A	32	$6,598,661	$1,392,849	$1,825,231	$4,027,613	$1,076,142	$249,172	$91,048
	Small Mains	135,085,895											
	Demand		50.000%	$67,542,947	Distribution P&A	33	$26,188,414	$5,520,225	$7,302,338	$16,807,320	$5,809,969	$5,511,711	$402,971
	Customer		50.000%	$67,542,947	Distribution P&A	33	$26,188,414	$5,520,225	$7,302,338	$16,807,320	$5,809,969	$5,511,711	$402,971
377	Compressor Station Equipment			$175,304	Trans. + Dist. Mains	14	$69,414	$14,636	$19,324	$44,110	$14,579	$12,196	$1,046
378	Meas. & Reg. Sta. Equip.			$10,654,248	Trans. + Dist. Mains	14	$4,218,673	$889,497	$1,174,433	$2,680,806	$886,028	$741,246	$63,565
379	Meas. & Reg. Sta. Equip. - CG			$61,111	Trans. + Dist. Mains	14	$24,197	$5,102	$6,736	$15,377	$5,082	$4,252	$365
380	Services			$106,525,531	Services (Wgtd. Customers)	10	$88,481,793	$10,313,096	$2,910,353	$548,440	$3,360,589	$860,870	$50,390
381	Meters			$24,534,672	Meters (Wgtd. Customers)	11	$15,685,172	$2,925,125	$3,095,510	$534,721	$1,787,195	$457,820	$49,129
382	Meter Installations			$4,871,135	Meters (Wgtd. Customers)	11	$3,114,148	$580,757	$614,585	$106,164	$354,831	$90,896	$9,754
383	House Regulators			$53,543,483	Meters (Wgtd. Customers)	11	$34,230,689	$6,383,675	$6,755,517	$1,166,954	$3,900,303	$999,127	$107,218
385	Indust. Meas. & Reg. Sta. Equip.			$2,962,366	Meters (Wgtd. Customers)	11	$1,893,859	$353,185	$373,758	$64,563	$215,790	$55,278	$5,932
387	Other Equipment			$115,909	Trans. + Dist. Mains	14	$45,895	$9,677	$12,777	$29,165	$9,639	$8,064	$692
	Total Distribution Plant			$371,219,276			$214,196,511	$35,481,915	$33,457,136	$47,405,723	$24,486,567	$14,902,362	$1,289,063

BLACK HILLS ENERGY
Peak & Average CCOSS
Fritel Re-Functionalization of Transmission & Distribution Mains
(Rate Base)

Acct. No.	Description	Total Gas Utility Adjusted	TAI Allocator Name	TAI Allocator No.	Residential Service	Firm and Transportation Small Commercial	Small Volume	Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
	General Plant										
389	Land & Land Rights	$856,543	Supervised O & M before General	28	$521,526	$89,974	$70,301	$94,634	$48,968	$28,265	$2,875
390	Structures and Improvements	$13,423,778	Supervised O & M before General	28	$8,173,383	$1,410,076	$1,101,758	$1,483,108	$767,423	$442,974	$45,055
391	Office Furniture & Equipment	$1,784,950	Supervised O & M before General	28	$1,086,809	$187,497	$146,500	$197,208	$102,044	$58,902	$5,991
392	Transportation Equipment	$12,927,430	Supervised O & M before General	28	$7,871,170	$1,357,938	$1,061,020	$1,428,270	$739,047	$426,595	$43,389
393	Stores Equipment	$55,274	Supervised O & M before General	28	$33,655	$5,806	$4,537	$6,107	$3,160	$1,824	$186
394	Tools & Work Equipment	$4,896,920	Supervised O & M before General	28	$2,981,605	$514,388	$401,915	$541,030	$279,952	$161,594	$16,436
395	Laboratory Equipment	$11,714	Supervised O & M before General	28	$7,132	$1,230	$961	$1,294	$670	$387	$39
396	Power Operated Equipment	$1,099,514	Supervised O & M before General	28	$669,465	$115,496	$90,243	$121,478	$62,858	$36,283	$3,690
397	Communication Equipment	$1,221,839	Supervised O & M before General	28	$743,945	$128,346	$100,283	$134,993	$69,851	$40,320	$4,101
398	Misc. Equipment	$32,417	Supervised O & M before General	28	$19,738	$3,405	$2,661	$3,582	$1,853	$1,070	$109
	General Plant	$36,310,377			$22,108,429	$3,814,157	$2,980,178	$4,011,704	$2,075,825	$1,198,213	$121,871
118	Other Utility Plant (Allocated on Customer Count)	$277,554	Cust. Accounting (Wgtd. Customers)	12	$210,600	$39,275	$13,854	$6,527	$5,332	$1,366	$600
118	Other Utility Plant (Allocated on Blended Ratio)	$16,307,851	Supervised O & M before General	28	$9,929,419	$1,713,028	$1,338,469	$1,801,751	$932,302	$538,146	$54,735
	Total Other Utility Plant	$16,585,405			$10,140,020	$1,752,303	$1,352,323	$1,808,278	$937,635	$539,512	$55,335
	Total Plant in Service	$495,300,471			$275,378,710	$47,067,104	$45,537,716	$70,642,062	$33,328,738	$21,464,328	$1,881,814
	Accumulated Depreciation										
	Intangible	($2,856,240)	Intangible Plant	15	($1,739,089)	($300,029)	($234,426)	($315,568)	($163,288)	($94,254)	($9,587)
	Production & Gathering	$0	Prod. & Gathering Plant	16							
	Transmission	($16,209,075)	Transmission Plant	17	($6,418,172)	($1,353,256)	($1,786,750)	($4,078,503)	($1,347,977)	($1,127,711)	($96,706)
	Distribution	($103,784,334)	Distribution Plant	18	($59,884,396)	($9,919,924)	($9,353,842)	($13,253,545)	($6,845,878)	($4,166,356)	($360,392)
	General	($9,276,564)	General Plant	19	($5,648,254)	($974,440)	($761,375)	($1,024,909)	($530,331)	($306,119)	($31,135)
	Other Utility Plant (Allocated on Customer Count)	($97,596)	Cust. Accounting (Wgtd. Customers)	12	($74,053)	($13,810)	($4,872)	($2,295)	($1,875)	($480)	($211)
	Other Utility Plant (Allocated on Blended Ratio)	($6,532,545)	Supervised O & M before General	28	($3,977,494)	($686,199)	($536,159)	($721,739)	($373,459)	($215,569)	($21,926)
	Total Accumulated Depreciation	($138,756,353)			($77,741,458)	($13,247,657)	($12,677,424)	($19,396,559)	($9,262,809)	($5,910,489)	($519,956)
	Net Plant	$356,544,118			$197,637,251	$33,819,447	$32,860,291	$51,245,503	$24,065,929	$15,553,839	$1,361,857
	Other Rate Base Items										
	Materials & Supplies	$2,899,107	Plant In Service	20	$1,611,855	$275,495	$266,543	$413,484	$195,081	$125,636	$11,015
	Gas Storage	$2,662,837	50% winter Sales/50% peak- Sales	30	$1,870,245	$383,512	$336,938	$72,142	$0	$0	$0
	Prepayments	$52,303	Net Plant	22	$28,992	$4,961	$4,820	$7,517	$3,530	$2,282	$200
	Customer Advances	($506,945)	Supervised O & M before General	28	($308,665)	($53,251)	($41,608)	($56,009)	($28,981)	($16,729)	($1,701)
	Customer Deposits	($1,090,806)	Cust. Accounting (Wgtd. Customers)	12	($827,673)	($154,352)	($54,448)	($25,651)	($20,957)	($5,368)	($2,357)
	Accum. Deferred Income Taxes	($54,613,284)	Net Plant	22	($30,272,886)	($5,180,260)	($5,033,342)	($7,849,478)	($3,686,274)	($2,382,444)	($208,601)
	Total Other Rate Base Items	($50,596,788)			($27,898,132)	($4,723,896)	($4,521,096)	($7,437,995)	($3,537,602)	($2,276,624)	($201,445)
	Total Rate Base	$305,947,330			$169,739,119	$29,095,551	$28,339,195	$43,807,509	$20,528,327	$13,277,216	$1,160,412

BLACK HILLS ENERGY
Peak & Average CCOSS
Fritel Re-Functionalization of Transmission & Distribution Mains
(Expenses)

Acct. No.	Description	Total Gas Utility Adjusted	TAI Allocator Name	TAI Allocator No.	Residential Service	Firm and Transportation Small Commercial	Firm and Transportation Small Volume	Firm and Transportation Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
		$									
	O & M Expenses										
	Transmission Expenses										
	Operation										
850	Supervision & Engineering	$181,374	Trans. + Dist. Mains	14	$71,817	$15,142	$19,993	$45,637	$15,083	$12,619	$1,082
851	Sys. Control & Load Dispatch.	$1,550	Annual Throughput	5	$483	$100	$150	$529	$219	$51	$18
852	Communication System Expenses	$1,239	Trans. + Dist. Mains	14	$491	$103	$137	$312	$103	$86	$7
856	Mains Expenses	$215,672	Trans. + Dist. Mains	14	$85,398	$18,006	$23,774	$54,267	$17,936	$15,005	$1,287
857	Meas. & Reg. Sta. Expenses	$8,010	Trans. + Dist. Mains	14	$3,172	$669	$883	$2,015	$666	$557	$48
859	Other Expenses	$232,030	Trans. + Dist. Mains	14	$91,875	$19,372	$25,577	$58,383	$19,296	$16,143	$1,384
860	Rents	$19,709	Trans. + Dist. Mains	14	$7,804	$1,645	$2,173	$4,959	$1,639	$1,371	$118
	Total Operation	$659,584			$261,040	$55,038	$72,686	$166,102	$54,942	$45,832	$3,944
	Maintenance										
861	Supervision & Engineering	$24,448	Trans. + Dist. Mains	14	$9,681	$2,041	$2,695	$6,152	$2,033	$1,701	$146
862	Structures & Improvements	$4,244	Trans. + Dist. Mains	14	$1,680	$354	$468	$1,068	$353	$295	$25
863	Mains	$6,246	Trans. + Dist. Mains	14	$2,473	$521	$688	$1,572	$519	$435	$37
864	Compressor Station Equipment	$0	Trans. + Dist. Mains	14	$0	$0	$0	$0	$0	$0	$0
865	Meas. & Reg. Sta. Equip.	$1,628	Trans. + Dist. Mains	14	$645	$136	$180	$410	$135	$113	$10
866	Communication Equipment	$5,366	Trans. + Dist. Mains	14	$2,125	$448	$591	$1,350	$446	$373	$32
867	Other Equipment	$0	Trans. + Dist. Mains	14	$0	$0	$0	$0	$0	$0	$0
	Total Maintenance	$41,932			$16,604	$3,501	$4,622	$10,551	$3,487	$2,917	$250
	Total Transmission Expenses	$701,517			$277,643	$58,538	$77,309	$176,653	$58,429	$48,749	$4,195
	Distribution Expenses										
	Operation										
870	Supervision & Engineering	$1,907,147	Accts. 871-880	23	$1,119,060	$180,451	$163,025	$240,809	$122,019	$75,319	$6,464
871	Load Dispatching	$1,330	Annual Throughput	5	$415	$86	$129	$454	$188	$43	$16
872	Compressor Station Expenses	($559)	Annual Throughput	5	($174)	($36)	($54)	($191)	($79)	($18)	($7)
874	Mains & Services	$3,221,989	Accts. 376 + 380	24	$1,823,986	$285,803	$250,594	$499,855	$202,848	$146,607	$12,295
875	Measuring & Regulating Sta. Equip, - General	$411,639	Acct. 378	25	$162,993	$34,367	$45,376	$103,576	$34,233	$28,639	$2,456
876	Measuring & Regulating Sta. Equip, - Ind.	$25,985	Meters (Wgtd. Customers)	11	$16,613	$3,098	$3,279	$566	$1,893	$485	$52
877	Measuring & Regulating Sta. Equp. - CG	$138,853	Trans. + Dist. Mains	14	$54,980	$11,592	$15,306	$34,938	$11,547	$9,660	$828
878	Meters & House Regulators	$878,442	Meters (Wgtd. Customers)	11	$561,594	$104,732	$110,832	$19,145	$63,989	$16,392	$1,759
879	Customer Installation Expenses	$579,715	Services (Wgtd. Customers)	10	$481,521	$56,124	$15,838	$2,985	$18,288	$4,685	$274
880	Other Expenses	$1,744,926	Distribution Plant	18	$1,006,836	$166,784	$157,266	$222,832	$115,100	$70,049	$6,059
881	Rents	$16,633	Distribution Plant	18	$9,598	$1,590	$1,499	$2,124	$1,097	$668	$58
	Total Operation	$8,926,103			$5,237,422	$844,591	$763,090	$1,127,093	$571,123	$352,529	$30,254
	Maintenance										
885	Supervision & Engineering	$84,013	Accts. 886 - 894	26	$47,368	$8,485	$8,861	$9,769	$5,995	$3,244	$290
886	Structures & Improvements	$0	Trans. + Dist. Mains	14	$0	$0	$0	$0	$0	$0	$0
887	Mains	$779,470	Acct. 376	27	$308,640	$65,076	$85,922	$196,129	$64,822	$54,230	$4,650
888	Main. Of Compressor Sta. Eq.	$76,313	Trans. + Dist. Mains	14	$30,217	$6,371	$8,412	$19,202	$6,346	$5,309	$455
889	Meas. & Reg. Sta. Eq. - Gen.	$126,214	Trans. + Dist. Mains	14	$49,976	$10,537	$13,913	$31,758	$10,496	$8,781	$753
890	Meas. & Reg. Sta. Eq. - Ind.	$85,702	Meters (Wgtd. Customers)	11	$54,790	$10,218	$10,813	$1,868	$6,243	$1,599	$172
891	Meas. & Reg. Sta. Eq. - City Gate	$306,644	Meters (Wgtd. Customers)	11	$196,039	$36,559	$38,689	$6,683	$22,337	$5,722	$614
892	Services	$320,489	Services (Wgtd. Customers)	10	$266,204	$31,028	$8,756	$1,650	$10,111	$2,590	$152

BLACK HILLS ENERGY
Peak & Average CCOSS
Fritel Re-Functionalization of Transmission & Distribution Mains
(Expenses)

Acct. No.	Description	Total Gas Utility Adjusted	TAI Allocator Name	TAI Allocator No.	Residential Service	Firm and Transportation Small Commercial	Firm and Transportation Small Volume	Firm and Transportation Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
		$									
893	Meters & House Regulators	$645,990	Meters (Wgtd. Customers)	11	$412,985	$77,018	$81,504	$14,079	$47,056	$12,054	$1,294
894	Other Equipment	$71,953	Distribution Plant	18	$41,518	$6,877	$6,485	$9,189	$4,746	$2,889	$250
	Total Maintenance	$2,496,788			$1,407,737	$252,169	$263,355	$290,326	$178,152	$96,418	$8,630
	Total Distribution	$11,422,890			$6,645,158	$1,096,760	$1,026,445	$1,417,419	$749,276	$448,948	$38,884
	Customer Accounts Expenses										
901	Supervision	$206,719	Cust. Accounting (Wgtd. Customers)	12	$156,852	$29,251	$10,318	$4,861	$3,972	$1,017	$447
902	Meter Reading Expenses	$390,348	Cust. Accounting (Wgtd. Customers)	12	$296,185	$55,235	$19,484	$9,179	$7,500	$1,921	$843
903	Customer Records & Collection	$2,610,115	Cust. Accounting (Wgtd. Customers)	12	$1,980,481	$369,339	$130,284	$61,378	$50,147	$12,846	$5,639
904	Uncollectible Accounts	$874,790	Cust. Accounting (Wgtd. Customers)	12	$663,766	$123,786	$43,665	$20,571	$16,807	$4,305	$1,890
905	Miscellaneous	$56,307	Cust. Accounting (Wgtd. Customers)	12	$42,724	$7,968	$2,811	$1,324	$1,082	$277	$122
	Total Customer Accounts Expenses	$4,138,279			$3,140,008	$585,580	$206,563	$97,314	$79,506	$20,367	$8,941
	Customer Service & Inform. Exp.										
907	Supervision	$53,612	50% Thruput/50% Cust accts	29	$28,699	$5,520	$3,937	$9,775	$4,296	$1,007	$378
908	Customer Assistance Expenses	$129,645	50% Thruput/50% Cust accts	29	$69,400	$13,349	$9,522	$23,638	$10,388	$2,436	$914
909	Information & Instruction Exp.	$19,596	50% Thruput/50% Cust accts	29	$10,490	$2,018	$1,439	$3,573	$1,570	$368	$138
910	Miscellaneous	$377	50% Thruput/50% Cust accts	29	$202	$39	$28	$69	$30	$7	$3
	Total Cust. Service & Inf. Exp.	$203,229			$108,790	$20,925	$14,926	$37,054	$16,283	$3,818	$1,432
	Sales Expenses										
911	Supervision	$0	50% Thruput/50% Cust accts	29	$0	$0	$0	$0	$0	$0	$0
912	Demonstrating & Selling Exp.	$202,029	50% Thruput/50% Cust accts	29	$108,147	$20,802	$14,838	$36,835	$16,187	$3,796	$1,424
913	Advertising Expenses	$6,498	50% Thruput/50% Cust accts	29	$3,479	$669	$477	$1,185	$521	$122	$46
916	Miscellaneous	$0	50% Thruput/50% Cust accts	29	$0	$0	$0	$0	$0	$0	$0
	Total Sales Expenses	$208,527			$111,626	$21,471	$15,315	$38,020	$16,708	$3,918	$1,469
	Administrative & General Expenses										
	Operation										
920	A & G Salaries	$7,290,949	Supervised O & M before General	28	$4,439,266	$765,864	$598,405	$805,531	$416,816	$240,595	$24,471
921	Office Supplies & Expenses	$1,686,722	Supervised O & M before General	28	$1,027,000	$177,179	$138,438	$186,355	$96,428	$55,660	$5,661
922	Transfers	($1,488,431)	Supervised O & M before General	28	($906,266)	($156,349)	($122,163)	($164,447)	($85,092)	($49,117)	($4,996)
923	Outside Services Employed	$843,059	Supervised O & M before General	28	$513,317	$88,558	$69,194	$93,144	$48,197	$27,820	$2,830
924	Property Insurance	$19,713	Net Plant	22	$10,927	$1,870	$1,817	$2,833	$1,331	$860	$75
925	Injuries & Damages	$1,137,339	Supervised O & M before General	28	$692,496	$119,470	$93,347	$125,657	$65,020	$37,531	$3,817
926	Employee Pensions & Benefits	$2,647,511	Supervised O & M before General	28	$1,612,000	$278,103	$217,295	$292,507	$151,355	$87,366	$8,886
928	Regulatory Commission Expense	$586,604	Annual Throughput	5	$182,929	$37,791	$56,884	$200,113	$82,731	$19,156	$7,000
929	Duplicate Charges - Credit	$0	Supervised O & M before General	28	$0	$0	$0	$0	$0	$0	$0
930	Miscellaneous	$458,027	Supervised O & M before General	28	$278,881	$48,113	$37,593	$50,605	$26,185	$15,115	$1,537
931	Rents	$804,552	Supervised O & M before General	28	$489,871	$84,513	$66,034	$88,890	$45,995	$26,550	$2,700
932	Maintenance of General Plant	$1,691,353	Supervised O & M before General	28	$1,029,820	$177,665	$138,818	$186,867	$96,693	$55,813	$5,677
	Total A & G Expenses	$15,677,400			$9,370,240	$1,622,775	$1,295,662	$1,868,055	$945,659	$517,349	$57,659
	Total Operation & Maintenance	$32,351,842			$19,653,466	$3,406,049	$2,636,219	$3,634,516	$1,865,862	$1,043,149	$112,580
	Supervised O & M before General	$15,783,018			$9,609,863	$1,657,898	$1,295,393	$1,743,766	$902,298	$520,827	$52,973

BLACK HILLS ENERGY
Peak & Average CCOSS
Fritel Re-Functionalization of Transmission & Distribution Mains
(Expenses)

Acct. No.	Description	Total Gas Utility Adjusted	TAI Allocator Name	TAI Allocator No.	Residential Service	Firm and Transportation: Small Commercial	Firm and Transportation: Small Volume	Firm and Transportation: Large Volume	Irrigation: Sales	Irrigation: Transportation	Interruptible Large Volume
		$									
	Depreciation Expense										
	Intangible	$106,944	Intangible Plant	15	$65,115	$11,234	$8,777	$11,816	$6,114	$3,529	$359
	Production & Gathering	$0	Prod. & Gathering Plant	16							
	Transmission	$1,007,900	Transmission Plant	17	$399,090	$84,147	$111,102	$253,606	$83,819	$70,122	$6,013
	Distribution	$8,875,446	Distribution Plant	18	$5,121,204	$848,334	$799,923	$1,133,419	$585,447	$356,299	$30,820
	General	$872,286	General Plant	19	$531,112	$91,628	$71,593	$96,373	$49,868	$28,785	$2,928
	Other Utility Plant (Allocated on Customer Count)	$1,884,420	Cust. Accounting (Wgtd. Customers)	12	$1,429,844	$266,651	$94,061	$44,313	$36,204	$9,274	$4,071
	Other Utility Plant (Allocated on Blended Ratio)	$0	Supervised O & M before General	28	$0	$0	$0	$0	$0	$0	$0
	Total Depreciation Expense	$12,746,995			$7,546,364	$1,301,993	$1,085,457	$1,539,527	$761,452	$468,010	$44,191
	Taxes Other Than Income Taxes										
	Property Taxes	$7,815,966	Net Plant	22	$4,332,496	$741,371	$720,345	$1,123,376	$527,560	$340,963	$29,854
	Payroll Taxes	$969,408	Supervised O & M before General	28	$590,247	$101,830	$79,564	$107,104	$55,420	$31,990	$3,254
	Miscellaneous	$177,999	Supervised O & M before General	28	$108,379	$18,698	$14,609	$19,666	$10,176	$5,874	$597
	Total Taxes Other than Income Taxes	$8,963,372			$5,031,121	$861,899	$814,519	$1,250,146	$593,156	$378,826	$33,705
	Calculation of Income Taxes at Current Rates										
	Deferred Tax	$6,539,311	Rate Base	31	$3,628,000	$621,888	$605,721	$936,341	$438,772	$283,787	$24,803
	R&D Credit	($108,882)	Rate Base	31	($60,408)	($10,355)	($10,085)	($15,590)	($7,306)	($4,725)	($413)
	EDIT Amort	($521,416)	Rate Base	31	($289,281)	($49,587)	($48,298)	($74,660)	($34,986)	($22,628)	($1,978)
	Income Before Tax	$9,664,876			$8,694,094	$1,105,225	$651,430	$755,458	($539,775)	($1,113,447)	$111,890
	Interest	($7,128,573)	Rate Base	31	($3,954,921)	($677,926)	($660,303)	($1,020,715)	($478,310)	($309,359)	($27,038)
	Pre-Tax Income	$2,536,303			$4,739,172	$427,299	($8,873)	($265,257)	($1,018,085)	($1,422,806)	$84,852
	Meals	$61,393	Rate Base	31	$34,061	$5,838	$5,687	$8,791	$4,119	$2,664	$233
	Temp Differences	($31,139,574)	Rate Base	31	($17,276,189)	($2,961,369)	($2,884,387)	($4,458,765)	($2,089,390)	($1,351,366)	($118,108)
	Taxable Income	($28,541,878)			($12,502,956)	($2,528,232)	($2,887,573)	($4,715,231)	($3,103,356)	($2,771,508)	($33,022)
	Tax Rate	21%			21%	21%	21%	21%	21%	21%	21%
	Current Income tax	($5,993,794)			($2,625,621)	($530,929)	($606,390)	($990,198)	($651,705)	($582,017)	($6,935)
	Total Income Tax Expense at Current Rates	($84,781)			$652,691	$31,018	($59,052)	($144,108)	($255,224)	($325,583)	$15,477

BLACK HILLS ENERGY
Peak & Average CCOSS
Fritel Re-Functionalization of Transmission & Distribution Mains
(Revenues)

Acct. No.	Description	Total Gas Utility Adjusted	TAI Allocator Name	TAI Allocator No.	Residential Service	Firm and Transportation Small Commercial	Firm and Transportation Small Volume	Firm and Transportation Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
Margin Rate Revenues		$60,347,609			$39,244,269	$6,406,588	$4,870,538	$6,506,797	$2,444,623	$588,871	$285,924
Other Operating Revenues											
487	Forfeited Discounts	$333,613	DIR	DIR	$333,613	$0	$0	$0	$0	$0	$0
488	Misc. Service Revenues	$662,809	Supervised O & M before General	28	$403,567	$69,624	$54,400	$73,230	$37,892	$21,872	$2,225
489	Negotiated Margin Revenues	$2,383,053	Trans. + Dist. Mains	14	$943,598	$198,955	$262,687	$599,620	$198,179	$165,796	$14,218
	Total Other Operating Revenues	$3,379,475			$1,680,778	$268,579	$317,088	$672,850	$236,071	$187,668	$16,442
Total Non-Gas Operating Revenues		$63,727,084			$40,925,046	$6,675,167	$5,187,626	$7,179,647	$2,680,694	$776,538	$302,367

BLACK HILLS ENERGY
Peak & Average CCOSS
Fritel Re-Functionalization of Transmission & Distribution Mains
(Allocation Amounts)

TAI Allocator Name	TAI Allocator No.	Total Gas Utility Adjusted	Residential Service	Firm and Transportation Small Commercial	Firm and Transportation Small Volume	Firm and Transportation Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
Firm Winter Peak Day	1	1,509,156	834,482	178,257	214,653	281,764	0	0	0
Firm Winter Peak Day - Sales	2	1,162,833	834,482	169,981	142,316	16,055	0	0	0
Winter Throughput	3	100,777,221	47,106,556	10,174,634	13,646,104	28,651,723	0	0	1,198,205
Firm Winter Sales	4	68,561,217	47,106,556	9,726,753	8,959,570	2,768,338	0	0	0
Annual Throughput	5	201,986,634	62,988,365	13,012,730	19,587,128	68,905,286	28,487,029	6,595,933	2,410,164
Firm Throughput - Sales	6	92,309,495	62,988,365	12,408,578	12,986,334	3,926,218	0	0	0
Total Throughput - Sales	7	123,206,687	62,988,365	12,408,578	12,986,334	3,926,218	28,487,029	0	2,410,164
Average Customers	8	119,427	105,942	9,879	1,742	164	1,341	344	15
Weighted Customers - Distribution	9	127,547	105,942	12,348	3,485	657	4,024	1,031	60
Services (Wgtd. Customers)	10	127,547	105,942	12,348	3,485	657	4,024	1,031	60
Meters (Wgtd. Customers)	11	165,715	105,942	19,757	20,908	3,612	12,071	3,092	332
Cust. Accounting (Wgtd. Customers)	12	139,624	105,942	19,757	6,969	3,283	2,683	687	302
50% Peak/50% Winter Throughput	13	100.00000%	51.01894%	10.95392%	13.88214%	23.55052%	0.00000%	0.00000%	0.59448%
Trans. + Dist. Mains	14	$226,788,281	$89,799,461	$18,933,995	$24,999,206	$57,064,125	$18,860,145	$15,778,297	$1,353,052
Intangible Plant	15	$3,508,760	$2,136,391	$368,571	$287,982	$387,661	$200,592	$115,786	$11,777
Prod. & Gathering Plant	16	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Plant	17	$67,676,653	$26,797,359	$5,650,157	$7,460,097	$17,028,697	$5,628,119	$4,708,455	$403,769
Distribution Plant	18	$371,219,276	$214,196,511	$35,481,915	$33,457,136	$47,405,723	$24,486,567	$14,902,362	$1,289,063
General Plant	19	$36,310,377	$22,108,429	$3,814,157	$2,980,178	$4,011,704	$2,075,825	$1,198,213	$121,871
Plant In Service	20	$495,300,471	$275,378,710	$47,067,104	$45,537,716	$70,642,062	$33,328,738	$21,464,328	$1,881,814
Gas Supply - Demand	21								
Net Plant	22	$356,544,118	$197,637,251	$33,819,447	$32,860,291	$51,245,503	$24,065,929	$15,553,839	$1,361,857
Accts. 871-880	23	$7,002,322	$4,108,764	$662,549	$598,566	$884,160	$448,007	$276,543	$23,733
Accts. 376 + 380	24	$272,132,855	$154,055,942	$24,139,244	$21,165,492	$42,218,306	$17,132,809	$12,382,636	$1,038,427
Acct. 378	25	$10,654,248	$4,218,673	$889,497	$1,174,433	$2,680,806	$886,028	$741,246	$63,565
Accts. 886 - 894	26	$2,412,775	$1,360,369	$243,684	$254,493	$280,557	$172,158	$93,174	$8,339
Acct. 376	27	$165,607,324	$65,574,149	$13,826,148	$18,255,139	$41,669,865	$13,772,220	$11,521,766	$988,038
Supervised O & M before General	28	$15,783,018	$9,609,863	$1,657,898	$1,295,393	$1,743,766	$902,298	$520,827	$52,973
50% Thruput/50% Cust accts	29	100.00000%	53.53079%	10.29634%	7.34438%	18.23267%	8.01233%	1.87884%	0.70464%
50% winter Sales/50% peak- Sales	30	100.00000%	70.23505%	14.40238%	12.65336%	2.70921%	0.00000%	0.00000%	0.00000%
Rate Base	31	$305,947,330	$169,739,119	$29,095,551	$28,339,195	$43,807,509	$20,528,327	$13,277,216	$1,160,412
Transmission P&A	32	100.00000%	43.23952%	9.12702%	11.96033%	26.39203%	7.05171%	1.63276%	0.59661%
Distribution P&A	33	100.00000%	38.77298%	8.17291%	10.81140%	24.88390%	8.60189%	8.16031%	0.59661%

BLACK HILLS ENERGY
Peak & Average CCOSS
Fritel Re-Functionalization of Transmission & Distribution Mains
(Allocation Amounts)

TAI Allocator Name	TAI Allocator No.	Total Gas Utility Adjusted	Residential Service	Firm and Transportation			Irrigation		Interruptible
				Small Commercial	Small Volume	Large Volume	Sales	Transportation	Large Volume
Calculation of Trans. P&A									
	Peak Amount	1,509,156	834,482	178,257	214,653	281,764	0	0	0
	Peak Percent	100.00000%	55.29463%	11.81168%	14.22341%	18.67028%	0.00000%	0.00000%	0.00000%
	Avg. Amount	553,388	172,571	35,651	53,663	188,782	78,047	18,071	6,603
	Avg. Percent	100.00000%	31.18442%	6.44237%	9.69724%	34.11378%	14.10342%	3.26553%	1.19323%
	Total Trans. P&A	100.00000%	43.23952%	9.12702%	11.96033%	26.39203%	7.05171%	1.63276%	0.59661%
Calculation of Dist. P&A									
	Peak Amount	1,799,944	834,482	178,257	214,653	281,764	55,805	234,984	0
	Peak Percent	100.0000%	46.36154%	9.90345%	11.92556%	15.65402%	3.10035%	13.05508%	0.00000%
	Avg. Amount	553,388	172,571	35,651	53,663	188,782	78,047	18,071	6,603
	Avg. Percent	100.0000%	31.18442%	6.44237%	9.69724%	34.11378%	14.10342%	3.26553%	1.19323%
	Total Dist. P&A	100.0000%	38.77298%	8.17291%	10.81140%	24.88390%	8.60189%	8.16031%	0.59661%

BLACK HILLS ENERGY
Peak & Average CCOSS
Fritel Re-Functionalization of Transmission & Distribution Mains
(Allocation Percentages)

TAI Allocator Name	TAI Allocator No.	Total Gas Utility Adjusted	Residential Service	Firm and Transportation Small Commercial	Firm and Transportation Small Volume	Firm and Transportation Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
Firm Winter Peak Day	1	100.00000%	55.29463%	11.81168%	14.22341%	18.67028%	0.00000%	0.00000%	0.00000%
Firm Winter Peak Day - Sales	2	100.00000%	71.76282%	14.61779%	12.23873%	1.38067%	0.00000%	0.00000%	0.00000%
Winter Throughput	3	100.00000%	46.74326%	10.09616%	13.54086%	28.43075%	0.00000%	0.00000%	1.18896%
Firm Winter Sales	4	100.00000%	68.70729%	14.18696%	13.06799%	4.03776%	0.00000%	0.00000%	0.00000%
Annual Throughput	5	100.00000%	31.18442%	6.44237%	9.69724%	34.11378%	14.10342%	3.26553%	1.19323%
Firm Throughput - Sales	6	100.00000%	68.23606%	13.44236%	14.06825%	4.25332%	0.00000%	0.00000%	0.00000%
Total Throughput - Sales	7	100.00000%	51.12414%	10.07135%	10.54028%	3.18669%	23.12133%	0.00000%	1.95620%
Average Customers	8	100.00000%	88.70862%	8.27163%	1.45891%	0.13746%	1.12307%	0.28769%	0.01263%
Weighted Customers - Distribution	9	100.00000%	83.06158%	9.68134%	2.73207%	0.51484%	3.15473%	0.80814%	0.04730%
Services (Wgtd. Customers)	10	100.00000%	83.06158%	9.68134%	2.73207%	0.51484%	3.15473%	0.80814%	0.04730%
Meters (Wgtd. Customers)	11	100.00000%	63.93064%	11.92241%	12.61688%	2.17945%	7.28437%	1.86601%	0.20024%
Cust. Accounting (Wgtd. Customers)	12	100.00000%	75.87715%	14.15032%	4.99152%	2.35156%	1.92124%	0.49216%	0.21606%
50% Peak/50% Winter Throughput	13	100.00000%	51.01894%	10.95392%	13.88214%	23.55052%	0.00000%	0.00000%	0.59448%
Trans. + Dist. Mains	14	100.00000%	39.59616%	8.34875%	11.02315%	25.16185%	8.31619%	6.95728%	0.59661%
Intangible Plant	15	100.00000%	60.88736%	10.50432%	8.20751%	11.04837%	5.71689%	3.29992%	0.33564%
Transmission Plant	17	100.00000%	39.59616%	8.34875%	11.02315%	25.16185%	8.31619%	6.95728%	0.59661%
Distribution Plant	18	100.00000%	57.70081%	9.55821%	9.01277%	12.77028%	6.59625%	4.01444%	0.34725%
General Plant	19	100.00000%	60.88736%	10.50432%	8.20751%	11.04837%	5.71689%	3.29992%	0.33564%
Plant In Service	20	100.00000%	55.59831%	9.50274%	9.19396%	14.26247%	6.72899%	4.33360%	0.37993%
Net Plant	22	100.00000%	55.43136%	9.48535%	9.21633%	14.37284%	6.74978%	4.36239%	0.38196%
Accts. 871-880	23	100.00000%	58.67717%	9.46185%	8.54810%	12.62667%	6.39798%	3.94930%	0.33893%
Accts. 376 + 380	24	100.00000%	56.61056%	8.87039%	7.77763%	15.51386%	6.29575%	4.55022%	0.38159%
Acct. 378	25	100.00000%	39.59616%	8.34875%	11.02315%	25.16185%	8.31619%	6.95728%	0.59661%
Accts. 886 - 894	26	100.00000%	56.38192%	10.09975%	10.54775%	11.62798%	7.13526%	3.86170%	0.34564%
Acct. 376	27	100.00000%	39.59616%	8.34875%	11.02315%	25.16185%	8.31619%	6.95728%	0.59661%
Supervised O & M before General	28	100.00000%	60.88736%	10.50432%	8.20751%	11.04837%	5.71689%	3.29992%	0.33564%
50% Thruput/50% Cust accts	29	100.00000%	53.53079%	10.29634%	7.34438%	18.23267%	8.01233%	1.87884%	0.70464%
50% winter Sales/50% peak- Sales	30	100.00000%	70.23505%	14.40238%	12.65336%	2.70921%	0.00000%	0.00000%	0.00000%
Rate Base	31	100.00000%	55.47985%	9.50999%	9.26277%	14.31864%	6.70976%	4.33971%	0.37929%
Transmission P&A	32	100.00000%	43.23952%	9.12702%	11.96033%	26.39203%	7.05171%	1.63276%	0.59661%
Distribution P&A	33	100.00000%	38.77298%	8.17291%	10.81140%	24.88390%	8.60189%	8.16031%	0.59661%

BLACK HILLS ENERGY
Peak & Average CCOSS
Actual Booked Transmission & Distribution Mains
(Summary)

Description	Total Gas Utility Adjusted	Residential Service	Firm and Transportation: Small Commercial	Firm and Transportation: Small Volume	Firm and Transportation: Large Volume	Irrigation: Sales	Irrigation: Transportation	Interruptible Large Volume
Current Margin Rate Revenues	$60,347,609	$39,244,269	$6,406,588	$4,870,538	$6,506,797	$2,444,623	$588,871	$285,924
Other Operating Revenues	$3,379,475	$1,688,651	$270,261	$319,113	$675,508	$233,339	$176,161	$16,442
Total Non-Gas Revenues	$63,727,084	$40,932,920	$6,676,849	$5,189,651	$7,182,305	$2,677,961	$765,032	$302,367
O&M Expenses	$32,351,842	$19,596,469	$3,393,874	$2,621,558	$3,615,270	$1,885,643	$1,126,448	$112,580
Depreciation & Amort.	$12,746,995	$7,546,731	$1,302,072	$1,085,552	$1,539,651	$761,324	$467,474	$44,191
Taxes Other Than Income	$8,963,372	$5,044,325	$864,719	$817,915	$1,254,604	$588,574	$359,530	$33,705
Federal Income Tax	($84,781)	$659,333	$32,436	($57,344)	($141,865)	($257,529)	($335,289)	$15,477
Total Expenses	$53,977,428	$32,846,857	$5,593,101	$4,467,681	$6,267,660	$2,978,012	$1,618,163	$205,954
Net Operating Income	$9,749,657	$8,086,063	$1,083,748	$721,970	$914,645	($300,051)	($853,131)	$96,413
Rate base	$305,947,330	$170,336,960	$29,223,258	$28,492,978	$44,009,370	$20,320,838	$12,403,514	$1,160,412
ROR at Current Rates	3.19%	4.75%	3.71%	2.53%	2.08%	-1.48%	-6.88%	8.31%
Indexed ROR	100%	149%	116%	80%	65%	-46%	-216%	261%
Rate Base:								
Gross Plant	$495,300,471	$276,215,945	$47,245,948	$45,753,077	$70,924,756	$33,038,163	$20,240,768	$1,881,814
Accum. Depreciation	($138,756,353)	($77,879,729)	($13,277,193)	($12,712,992)	($19,443,246)	($9,214,820)	($5,708,416)	($519,956)
Other Rate Base Items	($50,596,788)	($27,999,256)	($4,745,497)	($4,547,108)	($7,472,139)	($3,502,505)	($2,128,838)	($201,445)
Total Rate Base	$305,947,330	$170,336,960	$29,223,258	$28,492,978	$44,009,370	$20,320,838	$12,403,514	$1,160,412
Cost of Service @ Requested 7.63% ROR								
Required Return	$23,343,781	$12,996,710	$2,229,735	$2,174,014	$3,357,915	$1,550,480	$946,388	$88,539
O&M	$32,351,842	$19,596,469	$3,393,874	$2,621,558	$3,615,270	$1,885,643	$1,126,448	$112,580
Depreciation	$12,746,995	$7,546,731	$1,302,072	$1,085,552	$1,539,651	$761,324	$467,474	$44,191
Taxes Other Than Income	$8,963,372	$5,044,325	$864,719	$817,915	$1,254,604	$588,574	$359,530	$33,705
Income Taxes	$3,528,847	$1,964,694	$337,066	$328,643	$507,611	$234,384	$143,064	$13,384
Other Operating Revenue	($3,379,475)	($1,688,651)	($270,261)	($319,113)	($675,508)	($233,339)	($176,161)	($16,442)
Net Base Rate Cost of Service	$77,555,361	$45,460,278	$7,857,204	$6,708,569	$9,599,543	$4,787,067	$2,866,743	$275,958
Base Rate Revenue Deficiency	$17,207,752	$6,216,009	$1,450,616	$1,838,031	$3,092,746	$2,342,444	$2,277,872	($9,966)
Curb Proposed Revenue Increase	$17,207,273	$10,033,325	$1,826,749	$1,597,080	$2,411,918	$1,045,575	$251,862	$40,764
Revenue Conversion Factor	1.2658	1.2658	1.2658	1.2658	1.2658	1.2658	1.2658	1.2658
Increase to Operating Income	$13,594,124	$7,926,548	$1,443,172	$1,261,729	$1,905,469	$826,027	$198,977	$32,204
Operating Income at CURB Increase	$23,343,781	$16,012,611	$2,526,919	$1,983,699	$2,820,114	$525,976	-$654,154	$128,617
ROR @ CURB Increase	7.63%	9.40%	8.65%	6.96%	6.41%	2.59%	-5.27%	11.08%
Indexed ROR @ CURB Increase	100%	123%	113%	91%	84%	34%	-69%	145%

BLACK HILLS ENERGY
Peak & Average CCOSS
Actual Booked Transmission & Distribution Mains
(Rate Base)

Acct. No.	Description			Total Gas Utility Adjusted	TAI Allocator Name	TAI Allocator No.	Residential Service	Firm and Transportation Small Commercial	Firm and Transportation Small Volume	Firm and Transportation Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
	Gas Plant in Service												
	Intangible Plant												
301	Organization			$186,932	Supervised O & M before General	28	$113,473	$19,562	$15,254	$20,536	$10,806	$6,673	$627
302	Franchises & Consents			$74,990	Supervised O & M before General	28	$45,521	$7,848	$6,119	$8,238	$4,335	$2,677	$252
303	Miscellaneous Intangible Plant			$3,246,838	Supervised O & M before General	28	$1,970,918	$339,777	$264,942	$356,698	$187,699	$115,906	$10,898
	Total Intangible Plant			$3,508,760			$2,129,912	$367,187	$286,315	$385,473	$202,841	$125,256	$11,777
	Production & Gathering Plant												
336	Purification Equipment			$0	Trans. + Dist. Mains	14	$0	$0	$0	$0	$0	$0	$0
	Total Product. & Gather. Plant			$0			$0	$0	$0	$0	$0	$0	$0
	Transmission Plant												
365	Land & Land Rights			$737,239	Trans. + Dist. Mains	14	$294,733	$62,151	$81,991	$186,453	$60,333	$47,179	$4,398
366	Structures & Improvements			$261,735	Trans. + Dist. Mains	14	$104,636	$22,065	$29,108	$66,195	$21,420	$16,749	$1,562
367	Mains	61,180,956											
	Large Mains	11,275,650											
	Demand		50.000%	$5,637,825	Transmission P&A	32	$2,437,769	$514,566	$674,302	$1,487,937	$397,563	$92,052	$33,636
	Commodity		50.000%	$5,637,825	Transmission P&A	32	$2,437,769	$514,566	$674,302	$1,487,937	$397,563	$92,052	$33,636
	Small Mains	49,905,306											
	Demand		50.000%	$24,952,653	Transmission P&A	32	$10,789,409	$2,277,435	$2,984,419	$6,585,512	$1,759,589	$407,418	$148,871
	Customer		50.000%	$24,952,653	Transmission P&A	32	$10,789,409	$2,277,435	$2,984,419	$6,585,512	$1,759,589	$407,418	$148,871
368	Compressor Station Equipment			$2,475	Trans. + Dist. Mains	14	$989	$209	$275	$626	$203	$158	$15
369	Measuring & Reg. Station Eq.			$5,388,010	Trans. + Dist. Mains	14	$2,154,015	$454,226	$599,219	$1,362,668	$440,938	$344,798	$32,146
371	Other Equipment			$106,238	Trans. + Dist. Mains	14	$42,472	$8,956	$11,815	$26,868	$8,694	$6,799	$634
	Total Transmission Plant			$67,676,653			$29,051,200	$6,131,608	$8,039,852	$17,789,709	$4,845,892	$1,414,624	$403,769
	Distribution Plant												
374	Land & Land Rights			$979,307	Trans. + Dist. Mains	14	$391,507	$82,559	$108,912	$247,674	$80,143	$62,669	$5,843
375	Structures & Improvements			$1,188,888	Trans. + Dist. Mains	14	$475,293	$100,227	$132,220	$300,679	$97,295	$76,081	$7,093
376	Mains	165,607,324											
	Large Mains	30,521,430											
	Demand		50.000%	$15,260,715	Distribution P&A	33	$5,917,034	$1,247,245	$1,649,897	$3,797,461	$1,312,710	$1,245,321	$91,048
	Commodity		50.000%	$15,260,715	Distribution P&A	33	$5,917,034	$1,247,245	$1,649,897	$3,797,461	$1,312,710	$1,245,321	$91,048
	Small Mains	135,085,895											
	Demand		50.000%	$67,542,947	Distribution P&A	33	$26,188,414	$5,520,225	$7,302,338	$16,807,320	$5,809,969	$5,511,711	$402,971
	Customer		50.000%	$67,542,947	Distribution P&A	33	$26,188,414	$5,520,225	$7,302,338	$16,807,320	$5,809,969	$5,511,711	$402,971
377	Compressor Station Equipment			$175,304	Trans. + Dist. Mains	14	$70,083	$14,779	$19,496	$44,336	$14,346	$11,218	$1,046
378	Meas. & Reg. Sta. Equip.			$10,654,248	Trans. + Dist. Mains	14	$4,259,347	$898,185	$1,184,896	$2,694,539	$871,911	$681,804	$63,565
379	Meas. & Reg. Sta. Equip. - CG			$61,111	Trans. + Dist. Mains	14	$24,431	$5,152	$6,796	$15,455	$5,001	$3,911	$365
380	Services			$106,525,531	Services (Wgtd. Customers)	10	$88,481,793	$10,313,096	$2,910,353	$548,440	$3,360,589	$860,870	$50,390
381	Meters			$24,534,672	Meters (Wgtd. Customers)	11	$15,685,172	$2,925,125	$3,095,510	$534,721	$1,787,195	$457,820	$49,129
382	Meter Installations			$4,871,135	Meters (Wgtd. Customers)	11	$3,114,148	$580,757	$614,585	$106,164	$354,831	$90,896	$9,754
383	House Regulators			$53,543,483	Meters (Wgtd. Customers)	11	$34,230,689	$6,383,675	$6,755,517	$1,166,954	$3,900,303	$999,127	$107,218
385	Indust. Meas. & Reg. Sta. Equip.			$2,962,366	Meters (Wgtd. Customers)	11	$1,893,859	$353,185	$373,758	$64,563	$215,790	$55,278	$5,932
387	Other Equipment			$115,909	Trans. + Dist. Mains	14	$46,338	$9,771	$12,891	$29,314	$9,486	$7,417	$692
	Total Distribution Plant			$371,219,276			$212,883,554	$35,201,449	$33,119,405	$46,962,402	$24,942,247	$16,821,157	$1,289,063

BLACK HILLS ENERGY
Peak & Average CCOSS
Actual Booked Transmission & Distribution Mains
(Rate Base)

Acct. No.	Description	Total Gas Utility Adjusted	TAI Allocator Name	TAI Allocator No.	Residential Service	Firm and Transportation: Small Commercial	Firm and Transportation: Small Volume	Firm and Transportation: Large Volume	Irrigation: Sales	Irrigation: Transportation	Interruptible Large Volume
	General Plant										
389	Land & Land Rights	$856,543	Supervised O & M before General	28	$519,945	$89,636	$69,894	$94,100	$49,517	$30,577	$2,875
390	Structures and Improvements	$13,423,778	Supervised O & M before General	28	$8,148,594	$1,404,781	$1,095,381	$1,474,738	$776,026	$479,202	$45,055
391	Office Furniture & Equipment	$1,784,950	Supervised O & M before General	28	$1,083,512	$186,793	$145,652	$196,095	$103,188	$63,719	$5,991
392	Transportation Equipment	$12,927,430	Supervised O & M before General	28	$7,847,298	$1,352,839	$1,054,879	$1,420,209	$747,333	$461,483	$43,389
393	Stores Equipment	$55,274	Supervised O & M before General	28	$33,553	$5,784	$4,510	$6,072	$3,195	$1,973	$186
394	Tools & Work Equipment	$4,896,920	Supervised O & M before General	28	$2,972,562	$512,456	$399,589	$537,976	$283,090	$174,810	$16,436
395	Laboratory Equipment	$11,714	Supervised O & M before General	28	$7,111	$1,226	$956	$1,287	$677	$418	$39
396	Power Operated Equipment	$1,099,514	Supervised O & M before General	28	$667,434	$115,063	$89,720	$120,793	$63,563	$39,250	$3,690
397	Communication Equipment	$1,221,839	Supervised O & M before General	28	$741,689	$127,864	$99,702	$134,231	$70,634	$43,617	$4,101
398	Misc. Equipment	$32,417	Supervised O & M before General	28	$19,678	$3,392	$2,645	$3,561	$1,874	$1,157	$109
	General Plant	$36,310,377			$22,041,375	$3,799,834	$2,962,930	$3,989,063	$2,099,097	$1,296,207	$121,871
118	Other Utility Plant (Allocated on Customer Count)	$277,554	Cust. Accounting (Wgtd. Customers)	12	$210,600	$39,275	$13,854	$6,527	$5,332	$1,366	$600
118	Other Utility Plant (Allocated on Blended Ratio)	$16,307,851	Supervised O & M before General	28	$9,899,304	$1,706,595	$1,330,722	$1,791,583	$942,754	$582,157	$54,735
		$16,585,405			$10,109,904	$1,745,870	$1,344,576	$1,798,110	$948,087	$583,523	$55,335
	Total Plant in Service	$495,300,471			$276,215,945	$47,245,948	$45,753,077	$70,924,756	$33,038,163	$20,240,768	$1,881,814
	Accumulated Depreciation										
	Intangible	($2,856,240)	Intangible Plant	15	($1,733,815)	($298,902)	($233,069)	($313,787)	($165,119)	($101,962)	($9,587)
	Production & Gathering	$0	Prod. & Gathering Plant	16							
	Transmission	($16,209,075)	Transmission Plant	17	($6,957,984)	($1,468,567)	($1,925,606)	($4,260,771)	($1,160,628)	($338,813)	($96,706)
	Distribution	($103,784,334)	Distribution Plant	18	($59,517,324)	($9,841,512)	($9,259,420)	($13,129,603)	($6,973,276)	($4,702,807)	($360,392)
	General	($9,276,564)	General Plant	19	($5,631,124)	($970,780)	($756,968)	($1,019,125)	($536,277)	($331,155)	($31,135)
	Other Utility Plant (Allocated on Customer Count)	($97,596)	Cust. Accounting (Wgtd. Customers)	12	($74,053)	($13,810)	($4,872)	($2,295)	($1,875)	($480)	($211)
	Other Utility Plant (Allocated on Blended Ratio)	($6,532,545)	Supervised O & M before General	28	($3,965,430)	($683,622)	($533,056)	($717,666)	($377,645)	($233,199)	($21,926)
	Total Accumulated Depreciation	($138,756,353)			($77,879,729)	($13,277,193)	($12,712,992)	($19,443,246)	($9,214,820)	($5,708,416)	($519,956)
	Net Plant	$356,544,118			$198,336,216	$33,968,755	$33,040,086	$51,481,509	$23,823,344	$14,532,352	$1,361,857
	Other Rate Base Items										
	Materials & Supplies	$2,899,107	Plant In Service	20	$1,616,755	$276,541	$267,803	$415,139	$193,380	$118,474	$11,015
	Gas Storage	$2,662,837	50% winter Sales/50% peak- Sales	30	$1,870,245	$383,512	$336,938	$72,142	$0	$0	$0
	Prepayments	$52,303	Net Plant	22	$29,095	$4,983	$4,847	$7,552	$3,495	$2,132	$200
	Customer Advances	($506,945)	Supervised O & M before General	28	($307,729)	($53,051)	($41,367)	($55,693)	($29,306)	($18,097)	($1,701)
	Customer Deposits	($1,090,806)	Cust. Accounting (Wgtd. Customers)	12	($827,673)	($154,352)	($54,448)	($25,651)	($20,957)	($5,368)	($2,357)
	Accum. Deferred Income Taxes	($54,613,284)	Net Plant	22	($30,379,949)	($5,203,130)	($5,060,882)	($7,885,628)	($3,649,117)	($2,225,978)	($208,601)
	Total Other Rate Base Items	($50,596,788)			($27,999,256)	($4,745,497)	($4,547,108)	($7,472,139)	($3,502,505)	($2,128,838)	($201,445)
	Total Rate Base	$305,947,330			$170,336,960	$29,223,258	$28,492,978	$44,009,370	$20,320,838	$12,403,514	$1,160,412

BLACK HILLS ENERGY
Peak & Average CCOSS
Actual Booked Transmission & Distribution Mains
(Expenses)

Acct. No.	Description	Total Gas Utility Adjusted	TAI Allocator Name	TAI Allocator No.	Residential Service	Firm and Transportation Small Commercial	Firm and Transportation Small Volume	Firm and Transportation Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
		$									
	O & M Expenses										
	Transmission Expenses										
	Operation										
850	Supervision & Engineering	$181,374	Trans. + Dist. Mains	14	$72,510	$15,290	$20,171	$45,871	$14,843	$11,607	$1,082
851	Sys. Control & Load Dispatch.	$1,550	Annual Throughput	5	$483	$100	$150	$529	$219	$51	$18
852	Communication System Expenses	$1,239	Trans. + Dist. Mains	14	$495	$104	$138	$313	$101	$79	$7
856	Mains Expenses	$215,672	Trans. + Dist. Mains	14	$86,221	$18,182	$23,986	$54,545	$17,650	$13,802	$1,287
857	Meas. & Reg. Sta. Expenses	$8,010	Trans. + Dist. Mains	14	$3,202	$675	$891	$2,026	$655	$513	$48
859	Other Expenses	$232,030	Trans. + Dist. Mains	14	$92,761	$19,561	$25,805	$58,682	$18,989	$14,848	$1,384
860	Rents	$19,709	Trans. + Dist. Mains	14	$7,879	$1,662	$2,192	$4,985	$1,613	$1,261	$118
	Total Operation	$659,584			$263,552	$55,574	$73,333	$166,951	$54,070	$42,161	$3,944
	Maintenance										
861	Supervision & Engineering	$24,448	Trans. + Dist. Mains	14	$9,774	$2,061	$2,719	$6,183	$2,001	$1,565	$146
862	Structures & Improvements	$4,244	Trans. + Dist. Mains	14	$1,697	$358	$472	$1,073	$347	$272	$25
863	Mains	$6,246	Trans. + Dist. Mains	14	$2,497	$527	$695	$1,580	$511	$400	$37
864	Compressor Station Equipment	$0	Trans. + Dist. Mains	14	$0	$0	$0	$0	$0	$0	$0
865	Meas. & Reg. Sta. Equip.	$1,628	Trans. + Dist. Mains	14	$651	$137	$181	$412	$133	$104	$10
866	Communication Equipment	$5,366	Trans. + Dist. Mains	14	$2,145	$452	$597	$1,357	$439	$343	$32
867	Other Equipment	$0	Trans. + Dist. Mains	14	$0	$0	$0	$0	$0	$0	$0
	Total Maintenance	$41,932			$16,764	$3,535	$4,663	$10,605	$3,432	$2,683	$250
	Total Transmission Expenses	$701,517			$280,316	$59,109	$77,996	$177,556	$57,502	$44,844	$4,195
	Distribution Expenses										
	Operation										
870	Supervision & Engineering	$1,907,147	Accts. 871-880	23	$1,113,556	$179,276	$161,609	$238,951	$123,929	$83,363	$6,464
871	Load Dispatching	$1,330	Annual Throughput	5	$415	$86	$129	$454	$188	$43	$16
872	Compressor Station Expenses	($559)	Annual Throughput	5	($174)	($36)	($54)	($191)	($79)	($18)	($7)
874	Mains & Services	$3,221,989	Accts. 376 + 380	24	$1,807,845	$282,355	$246,443	$494,405	$208,450	$170,196	$12,295
875	Measuring & Regulating Sta. Equip, - General	$411,639	Acct. 378	25	$164,565	$34,702	$45,780	$104,107	$33,687	$26,342	$2,456
876	Measuring & Regulating Sta. Equip, - Ind.	$25,985	Meters (Wgtd. Customers)	11	$16,613	$3,098	$3,279	$566	$1,893	$485	$52
877	Measuring & Regulating Sta. Equp. - CG	$138,853	Trans. + Dist. Mains	14	$55,511	$11,706	$15,442	$35,117	$11,363	$8,886	$828
878	Meters & House Regulators	$878,442	Meters (Wgtd. Customers)	11	$561,594	$104,732	$110,832	$19,145	$63,989	$16,392	$1,759
879	Customer Installation Expenses	$579,715	Services (Wgtd. Customers)	10	$481,521	$56,124	$15,838	$2,985	$18,288	$4,685	$274
880	Other Expenses	$1,744,926	Distribution Plant	18	$1,000,665	$165,465	$155,679	$220,748	$117,242	$79,068	$6,059
881	Rents	$16,633	Distribution Plant	18	$9,539	$1,577	$1,484	$2,104	$1,118	$754	$58
	Total Operation	$8,926,103			$5,211,648	$839,085	$756,460	$1,118,391	$580,069	$390,196	$30,254
	Maintenance										
885	Supervision & Engineering	$84,013	Accts. 886 - 894	26	$47,163	$8,441	$8,809	$9,700	$6,066	$3,544	$290
886	Structures & Improvements	$0	Trans. + Dist. Mains	14	$0	$0	$0	$0	$0	$0	$0
887	Mains	$779,470	Acct. 376	27	$302,224	$63,705	$84,272	$193,962	$67,049	$63,607	$4,650
888	Main. Of Compressor Sta. Eq.	$76,313	Trans. + Dist. Mains	14	$30,508	$6,433	$8,487	$19,300	$6,245	$4,884	$455
889	Meas. & Reg. Sta. Eq. - Gen.	$126,214	Trans. + Dist. Mains	14	$50,458	$10,640	$14,037	$31,920	$10,329	$8,077	$753
890	Meas. & Reg. Sta. Eq. - Ind.	$85,702	Meters (Wgtd. Customers)	11	$54,790	$10,218	$10,813	$1,868	$6,243	$1,599	$172

BLACK HILLS ENERGY
Peak & Average CCOSS
Actual Booked Transmission & Distribution Mains
(Expenses)

Acct. No.	Description	Total Gas Utility Adjusted	TAI Allocator Name	TAI Allocator No.	Residential Service	Firm and Transportation Small Commercial	Small Volume	Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
		$									
891	Meas. & Reg. Sta. Eq. - City Gate	$306,644	Meters (Wgtd. Customers)	11	$196,039	$36,559	$38,689	$6,683	$22,337	$5,722	$614
892	Services	$320,489	Services (Wgtd. Customers)	10	$266,204	$31,028	$8,756	$1,650	$10,111	$2,590	$152
893	Meters & House Regulators	$645,990	Meters (Wgtd. Customers)	11	$412,985	$77,018	$81,504	$14,079	$47,056	$12,054	$1,294
894	Other Equipment	$71,953	Distribution Plant	18	$41,263	$6,823	$6,420	$9,103	$4,835	$3,260	$250
	Total Maintenance	$2,496,788			$1,401,634	$250,866	$261,785	$288,265	$180,270	$105,338	$8,630
	Total Distribution	$11,422,890			$6,613,281	$1,089,951	$1,018,245	$1,406,656	$760,339	$495,534	$38,884
	Customer Accounts Expenses										
901	Supervision	$206,719	Cust. Accounting (Wgtd. Customers)	12	$156,852	$29,251	$10,318	$4,861	$3,972	$1,017	$447
902	Meter Reading Expenses	$390,348	Cust. Accounting (Wgtd. Customers)	12	$296,185	$55,235	$19,484	$9,179	$7,500	$1,921	$843
903	Customer Records & Collection	$2,610,115	Cust. Accounting (Wgtd. Customers)	12	$1,980,481	$369,339	$130,284	$61,378	$50,147	$12,846	$5,639
904	Uncollectible Accounts	$874,790	Cust. Accounting (Wgtd. Customers)	12	$663,766	$123,786	$43,665	$20,571	$16,807	$4,305	$1,890
905	Miscellaneous	$56,307	Cust. Accounting (Wgtd. Customers)	12	$42,724	$7,968	$2,811	$1,324	$1,082	$277	$122
	Total Customer Accounts Expenses	$4,138,279			$3,140,008	$585,580	$206,563	$97,314	$79,506	$20,367	$8,941
	Customer Service & Inform. Exp.										
907	Supervision	$53,612	50% Thruput/50% Cust accts	29	$28,699	$5,520	$3,937	$9,775	$4,296	$1,007	$378
908	Customer Assistance Expenses	$129,645	50% Thruput/50% Cust accts	29	$69,400	$13,349	$9,522	$23,638	$10,388	$2,436	$914
909	Information & Instruction Exp.	$19,596	50% Thruput/50% Cust accts	29	$10,490	$2,018	$1,439	$3,573	$1,570	$368	$138
910	Miscellaneous	$377	50% Thruput/50% Cust accts	29	$202	$39	$28	$69	$30	$7	$3
	Total Cust. Service & Inf. Exp.	$203,229			$108,790	$20,925	$14,926	$37,054	$16,283	$3,818	$1,432
	Sales Expenses										
911	Supervision	$0	50% Thruput/50% Cust accts	29	$0	$0	$0	$0	$0	$0	$0
912	Demonstrating & Selling Exp.	$202,029	50% Thruput/50% Cust accts	29	$108,147	$20,802	$14,838	$36,835	$16,187	$3,796	$1,424
913	Advertising Expenses	$6,498	50% Thruput/50% Cust accts	29	$3,479	$669	$477	$1,185	$521	$122	$46
916	Miscellaneous	$0	50% Thruput/50% Cust accts	29	$0	$0	$0	$0	$0	$0	$0
	Total Sales Expenses	$208,527			$111,626	$21,471	$15,315	$38,020	$16,708	$3,918	$1,469
	Administrative & General Expenses										
	Operation										
920	A & G Salaries	$7,290,949	Supervised O & M before General	28	$4,425,802	$762,988	$594,942	$800,985	$421,489	$260,272	$24,471
921	Office Supplies & Expenses	$1,686,722	Supervised O & M before General	28	$1,023,885	$176,513	$137,637	$185,303	$97,509	$60,213	$5,661
922	Transfers	($1,488,431)	Supervised O & M before General	28	($903,517)	($155,762)	($121,456)	($163,519)	($86,046)	($53,134)	($4,996)
923	Outside Services Employed	$843,059	Supervised O & M before General	28	$511,760	$88,225	$68,794	$92,619	$48,737	$30,096	$2,830
924	Property Insurance	$19,713	Net Plant	22	$10,966	$1,878	$1,827	$2,846	$1,317	$803	$75
925	Injuries & Damages	$1,137,339	Supervised O & M before General	28	$690,395	$119,021	$92,807	$124,948	$65,749	$40,601	$3,817
926	Employee Pensions & Benefits	$2,647,511	Supervised O & M before General	28	$1,607,111	$277,059	$216,037	$290,856	$153,052	$94,511	$8,886
928	Regulatory Commission Expense	$586,604	Annual Throughput	5	$182,929	$37,791	$56,884	$200,113	$82,731	$19,156	$7,000
929	Duplicate Charges - Credit	$0	Supervised O & M before General	28	$0	$0	$0	$0	$0	$0	$0
930	Miscellaneous	$458,027	Supervised O & M before General	28	$278,035	$47,932	$37,375	$50,319	$26,478	$16,351	$1,537
931	Rents	$804,552	Supervised O & M before General	28	$488,385	$84,195	$65,652	$88,388	$46,511	$28,721	$2,700
932	Maintenance of General Plant	$1,691,353	Supervised O & M before General	28	$1,026,697	$176,998	$138,015	$185,812	$97,777	$60,378	$5,677
	Total A & G Expenses	$15,677,400			$9,342,447	$1,616,839	$1,288,513	$1,858,670	$955,305	$557,967	$57,659

BLACK HILLS ENERGY
Peak & Average CCOSS
Actual Booked Transmission & Distribution Mains
(Expenses)

		Total	TAI	TAI		Firm and Transportation					Interruptible
Acct.		Gas Utility	Allocator	Allocator	Residential	Small	Small	Large	Irrigation		Large
No.	Description	Adjusted	Name	No.	Service	Commercial	Volume	Volume	Sales	Transportation	Volume
		$									
	Total Operation & Maintenance	$32,351,842			$19,596,469	$3,393,874	$2,621,558	$3,615,270	$1,885,643	$1,126,448	$112,580
	Supervised O & M before General	$15,783,018			$9,580,716	$1,651,672	$1,287,896	$1,733,924	$912,414	$563,422	$52,973
	Depreciation Expense										
	Intangible	$106,944	Intangible Plant	15	$64,918	$11,192	$8,727	$11,749	$6,182	$3,818	$359
	Production & Gathering	$0	Prod. & Gathering Plant	16							
	Transmission	$1,007,900	Transmission Plant	17	$432,656	$91,317	$119,737	$264,940	$72,169	$21,068	$6,013
	Distribution	$8,875,446	Distribution Plant	18	$5,089,812	$841,628	$791,849	$1,122,820	$596,342	$402,175	$30,820
	General	$872,286	General Plant	19	$529,501	$91,284	$71,179	$95,829	$50,427	$31,139	$2,928
	Other Utility Plant (Allocated on Customer Count)	$1,884,420	Cust. Accounting (Wgtd. Customers)	12	$1,429,844	$266,651	$94,061	$44,313	$36,204	$9,274	$4,071
	Other Utility Plant (Allocated on Blended Ratio)	$0	Supervised O & M before General	28	$0	$0	$0	$0	$0	$0	$0
	Total Depreciation Expense	$12,746,995			$7,546,731	$1,302,072	$1,085,552	$1,539,651	$761,324	$467,474	$44,191
	Taxes Other Than Income Taxes										
	Property Taxes	$7,815,966	Net Plant	22	$4,347,818	$744,645	$724,287	$1,128,550	$522,242	$318,570	$29,854
	Payroll Taxes	$969,408	Supervised O & M before General	28	$588,457	$101,447	$79,104	$106,499	$56,041	$34,606	$3,254
	Miscellaneous	$177,999	Supervised O & M before General	28	$108,050	$18,627	$14,525	$19,555	$10,290	$6,354	$597
	Total Taxes Other than Income Taxes	$8,963,372			$5,044,325	$864,719	$817,915	$1,254,604	$588,574	$359,530	$33,705
	Calculation of Income Taxes at Current Rates										
	Deferred Tax	$6,539,311	Rate Base	31	$3,640,778	$624,617	$609,008	$940,655	$434,337	$265,112	$24,803
	R&D Credit	($108,882)	Rate Base	31	($60,620)	($10,400)	($10,140)	($15,662)	($7,232)	($4,414)	($413)
	EDIT Amort	($521,416)	Rate Base	31	($290,299)	($49,804)	($48,560)	($75,004)	($34,632)	($21,139)	($1,978)
	Income Before Tax	$9,664,876			$8,745,395	$1,116,184	$664,626	$772,780	($557,580)	($1,188,420)	$111,890
	Interest	($7,128,573)	Rate Base	31	($3,968,851)	($680,902)	($663,886)	($1,025,418)	($473,476)	($289,002)	($27,038)
	Pre-Tax Income	$2,536,303			$4,776,544	$435,282	$740	($252,638)	($1,031,056)	($1,477,422)	$84,852
	Meals	$61,393	Rate Base	31	$34,181	$5,864	$5,718	$8,831	$4,078	$2,489	$233
	Temp Differences	($31,139,574)	Rate Base	31	($17,337,038)	($2,974,368)	($2,900,039)	($4,479,310)	($2,068,272)	($1,262,440)	($118,108)
	Taxable Income	($28,541,878)			($12,526,313)	($2,533,221)	($2,893,581)	($4,723,117)	($3,095,250)	($2,737,373)	($33,022)
	Tax Rate	21%			21%	21%	21%	21%	21%	21%	21%
	Current Income tax	($5,993,794)			($2,630,526)	($531,976)	($607,652)	($991,855)	($650,002)	($574,848)	($6,935)
	Total Income Tax Expense at Current Rates	($84,781)			$659,333	$32,436	($57,344)	($141,865)	($257,529)	($335,289)	$15,477

BLACK HILLS ENERGY
Peak & Average CCOSS
Actual Booked Transmission & Distribution Mains
(Revenues)

Acct. No.	Description	Total Gas Utility Adjusted	TAI Allocator Name	TAI Allocator No.	Residential Service	Firm and Transportation Small Commercial	Firm and Transportation Small Volume	Firm and Transportation Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
Margin Rate Revenues		$60,347,609			$39,244,269	$6,406,588	$4,870,538	$6,506,797	$2,444,623	$588,871	$285,924
Other Operating Revenues											
487	Forfeited Discounts	$333,613	DIR	DIR	$333,613	$0	$0	$0	$0	$0	$0
488	Misc. Service Revenues	$662,809	Supervised O & M before General	28	$402,343	$69,362	$54,085	$72,816	$38,317	$23,661	$2,225
489	Negotiated Margin Revenues	$2,383,053	Trans. + Dist. Mains	14	$952,695	$200,899	$265,028	$602,692	$195,022	$152,500	$14,218
	Total Other Operating Revenues	$3,379,475			$1,688,651	$270,261	$319,113	$675,508	$233,339	$176,161	$16,442
Total Non-Gas Operating Revenues		$63,727,084			$40,932,920	$6,676,849	$5,189,651	$7,182,305	$2,677,961	$765,032	$302,367

BLACK HILLS ENERGY
Peak & Average CCOSS
Actual Booked Transmission & Distribution Mains
(Allocation Amounts)

TAI Allocator Name	TAI Allocator No.	Total Gas Utility Adjusted	Residential Service	Firm and Transportation Small Commercial	Firm and Transportation Small Volume	Firm and Transportation Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
Firm Winter Peak Day	1	1,509,156	834,482	178,257	214,653	281,764	0	0	0
Firm Winter Peak Day - Sales	2	1,162,833	834,482	169,981	142,316	16,055	0	0	0
Winter Throughput	3	100,777,221	47,106,556	10,174,634	13,646,104	28,651,723	0	0	1,198,205
Firm Winter Sales	4	68,561,217	47,106,556	9,726,753	8,959,570	2,768,338	0	0	0
Annual Throughput	5	201,986,634	62,988,365	13,012,730	19,587,128	68,905,286	28,487,029	6,595,933	2,410,164
Firm Throughput - Sales	6	92,309,495	62,988,365	12,408,578	12,986,334	3,926,218	0	0	0
Total Throughput - Sales	7	$123,206,687	$62,988,365	$12,408,578	$12,986,334	$3,926,218	$28,487,029	$0	$2,410,164
Average Customers	8	119,427	105,942	9,879	1,742	164	1,341	344	15
Weighted Customers - Distribution	9	127,547	105,942	12,348	3,485	657	4,024	1,031	60
Services (Wgtd. Customers)	10	127,547	105,942	12,348	3,485	657	4,024	1,031	60
Meters (Wgtd. Customers)	11	165,715	105,942	19,757	20,908	3,612	12,071	3,092	332
Cust. Accounting (Wgtd. Customers)	12	139,624	105,942	19,757	6,969	3,283	2,683	687	302
50% Peak/50% Winter Throughput	13	100.00000%	51.01894%	10.95392%	13.88214%	23.55052%	0.00000%	0.00000%	0.59448%
Trans. + Dist. Mains	14	$226,788,281	$90,665,250	$19,118,939	$25,221,912	$57,356,460	$18,559,661	$14,513,006	$1,353,052
Intangible Plant	15	$3,508,760	$2,129,912	$367,187	$286,315	$385,473	$202,841	$125,256	$11,777
Prod. & Gathering Plant	16	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Plant	17	$67,676,653	$29,051,200	$6,131,608	$8,039,852	$17,789,709	$4,845,892	$1,414,624	$403,769
Distribution Plant	18	$371,219,276	$212,883,554	$35,201,449	$33,119,405	$46,962,402	$24,942,247	$16,821,157	$1,289,063
General Plant	19	$36,310,377	$22,041,375	$3,799,834	$2,962,930	$3,989,063	$2,099,097	$1,296,207	$121,871
Plant In Service	20	$495,300,471	$276,215,945	$47,245,948	$45,753,077	$70,924,756	$33,038,163	$20,240,768	$1,881,814
Gas Supply - Demand	21								
Net Plant	22	$356,544,118	$198,336,216	$33,968,755	$33,040,086	$51,481,509	$23,823,344	$14,532,352	$1,361,857
Accts. 871-880	23	$7,002,322	$4,088,553	$658,232	$593,367	$877,336	$455,022	$306,079	$23,733
Accts. 376 + 380	24	$272,132,855	$152,692,689	$23,848,035	$20,814,823	$41,758,002	$17,605,945	$14,374,935	$1,038,427
Acct. 378	25	$10,654,248	$4,259,347	$898,185	$1,184,896	$2,694,539	$871,911	$681,804	$63,565
Accts. 886 - 894	26	$2,412,775	$1,354,471	$242,424	$252,976	$278,566	$174,205	$101,793	$8,339
Acct. 376	27	$165,607,324	$64,210,896	$13,534,938	$17,904,470	$41,209,562	$14,245,356	$13,514,065	$988,038
Supervised O & M before General	28	$15,783,018	$9,580,716	$1,651,672	$1,287,896	$1,733,924	$912,414	$563,422	$52,973
50% Thruput/50% Cust accts	29	100.00000%	53.53079%	10.29634%	7.34438%	18.23267%	8.01233%	1.87884%	0.70464%
50% winter Sales/50% peak- Sales	30	100.00000%	70.23505%	14.40238%	12.65336%	2.70921%	0.00000%	0.00000%	0.00000%
Rate Base	31	$305,947,330	$170,336,960	$29,223,258	$28,492,978	$44,009,370	$20,320,838	$12,403,514	$1,160,412
Transmission P&A	32	100.00000%	43.23952%	9.12702%	11.96033%	26.39203%	7.05171%	1.63276%	0.59661%
Distribution P&A	33	100.00000%	38.77298%	8.17291%	10.81140%	24.88390%	8.60189%	8.16031%	0.59661%

BLACK HILLS ENERGY
Peak & Average CCOSS
Actual Booked Transmission & Distribution Mains
(Allocation Amounts)

TAI Allocator Name	TAI Allocator No.	Total Gas Utility Adjusted	Residential Service	Firm and Transportation Small Commercial	Firm and Transportation Small Volume	Firm and Transportation Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
Calculation of Trans. P&A									
	Peak Amount	1,509,156	834,482	178,257	214,653	281,764	0	0	0
	Peak Percent	100.00000%	55.29463%	11.81168%	14.22341%	18.67028%	0.00000%	0.00000%	0.00000%
	Avg. Amount	553,388	172,571	35,651	53,663	188,782	78,047	18,071	6,603
	Avg. Percent	100.00000%	31.18442%	6.44237%	9.69724%	34.11378%	14.10342%	3.26553%	1.19323%
	Total Trans. P&A	100.00000%	43.23952%	9.12702%	11.96033%	26.39203%	7.05171%	1.63276%	0.59661%
Calculation of Dist. P&A									
	Peak Amount	1,799,944	834,482	178,257	214,653	281,764	55,805	234,984	0
	Peak Percent	100.0000%	46.36154%	9.90345%	11.92556%	15.65402%	3.10035%	13.05508%	0.00000%
	Avg. Amount	553,388	172,571	35,651	53,663	188,782	78,047	18,071	6,603
	Avg. Percent	100.0000%	31.18442%	6.44237%	9.69724%	34.11378%	14.10342%	3.26553%	1.19323%
	Total Dist. P&A	100.0000%	38.77298%	8.17291%	10.81140%	24.88390%	8.60189%	8.16031%	0.59661%

BLACK HILLS ENERGY
Peak & Average CCOSS
Actual Booked Transmission & Distribution Mains
(Allocation Percentages)

TAI Allocator Name	TAI Allocator No.	Total Gas Utility Adjusted	Residential Service	Firm and Transportation Small Commercial	Firm and Transportation Small Volume	Firm and Transportation Large Volume	Irrigation Sales	Irrigation Transportation	Interruptible Large Volume
Firm Winter Peak Day	1	100.00000%	55.29463%	11.81168%	14.22341%	18.67028%	0.00000%	0.00000%	0.00000%
Firm Winter Peak Day - Sales	2	100.00000%	71.76282%	14.61779%	12.23873%	1.38067%	0.00000%	0.00000%	0.00000%
Winter Throughput	3	100.00000%	46.74326%	10.09616%	13.54086%	28.43075%	0.00000%	0.00000%	1.18896%
Firm Winter Sales	4	100.00000%	68.70729%	14.18696%	13.06799%	4.03776%	0.00000%	0.00000%	0.00000%
Annual Throughput	5	100.00000%	31.18442%	6.44237%	9.69724%	34.11378%	14.10342%	3.26553%	1.19323%
Firm Throughput - Sales	6	100.00000%	68.23606%	13.44236%	14.06825%	4.25332%	0.00000%	0.00000%	0.00000%
Total Throughput - Sales	7	100.00000%	51.12414%	10.07135%	10.54028%	3.18669%	23.12133%	0.00000%	1.95620%
Average Customers	8	100.00000%	88.70862%	8.27163%	1.45891%	0.13746%	1.12307%	0.28769%	0.01263%
Weighted Customers - Distribution	9	100.00000%	83.06158%	9.68134%	2.73207%	0.51484%	3.15473%	0.80814%	0.04730%
Services (Wgtd. Customers)	10	100.00000%	83.06158%	9.68134%	2.73207%	0.51484%	3.15473%	0.80814%	0.04730%
Meters (Wgtd. Customers)	11	100.00000%	63.93064%	11.92241%	12.61688%	2.17945%	7.28437%	1.86601%	0.20024%
Cust. Accounting (Wgtd. Customers)	12	100.00000%	75.87715%	14.15032%	4.99152%	2.35156%	1.92124%	0.49216%	0.21606%
50% Peak/50% Winter Throughput	13	100.00000%	51.01894%	10.95392%	13.88214%	23.55052%	0.00000%	0.00000%	0.59448%
Trans. + Dist. Mains	14	100.00000%	39.97793%	8.43030%	11.12135%	25.29075%	8.18369%	6.39936%	0.59661%
Intangible Plant	15	100.00000%	60.70269%	10.46487%	8.16001%	10.98601%	5.78098%	3.56980%	0.33564%
Transmission Plant	17	100.00000%	42.92647%	9.06015%	11.87980%	26.28633%	7.16036%	2.09027%	0.59661%
Distribution Plant	18	100.00000%	57.34712%	9.48266%	8.92179%	12.65085%	6.71901%	4.53133%	0.34725%
General Plant	19	100.00000%	60.70269%	10.46487%	8.16001%	10.98601%	5.78098%	3.56980%	0.33564%
Plant In Service	20	100.00000%	55.76735%	9.53885%	9.23744%	14.31954%	6.67033%	4.08656%	0.37993%
Gas Supply - Demand	21								
Net Plant	22	100.00000%	55.62740%	9.52722%	9.26676%	14.43903%	6.68174%	4.07589%	0.38196%
Accts. 871-880	23	100.00000%	58.38854%	9.40020%	8.47386%	12.52921%	6.49815%	4.37111%	0.33893%
Accts. 376 + 380	24	100.00000%	56.10961%	8.76338%	7.64877%	15.34471%	6.46961%	5.28232%	0.38159%
Acct. 378	25	100.00000%	39.97793%	8.43030%	11.12135%	25.29075%	8.18369%	6.39936%	0.59661%
Accts. 886 - 894	26	100.00000%	56.13748%	10.04754%	10.48487%	11.54545%	7.22009%	4.21893%	0.34564%
Acct. 376	27	100.00000%	38.77298%	8.17291%	10.81140%	24.88390%	8.60189%	8.16031%	0.59661%
Supervised O & M before General	28	100.00000%	60.70269%	10.46487%	8.16001%	10.98601%	5.78098%	3.56980%	0.33564%
50% Thruput/50% Cust accts	29	100.00000%	53.53079%	10.29634%	7.34438%	18.23267%	8.01233%	1.87884%	0.70464%
50% winter Sales/50% peak- Sales	30	100.00000%	70.23505%	14.40238%	12.65336%	2.70921%	0.00000%	0.00000%	0.00000%
Rate Base	31	100.00000%	55.67526%	9.55173%	9.31303%	14.38462%	6.64194%	4.05413%	0.37929%
Transmission P&A	32	100.00000%	43.23952%	9.12702%	11.96033%	26.39203%	7.05171%	1.63276%	0.59661%
Distribution P&A	33	100.00000%	38.77298%	8.17291%	10.81140%	24.88390%	8.60189%	8.16031%	0.59661%

BLACK HILLS ENERGY
CURB Recommended Revenue Distribution

	Black Hills Proposed					Indexed ROR CURB CCOSS at Current Rates Functionalization		CURB Recommended		
	Current Rate Revenues	Proposed Revenue	Proposed Change	Percent Change	Percent of System Average	Frital Approach	Booked Approach	Percent of System Average Increase	Percent Increase	Increase
Residential	$39,244,269	$53,240,375	$13,996,106	35.66%	125%	149%	149%		25.57%	$10,033,325
Small Commercial	$6,406,588	$8,593,655	$2,187,067	34.14%	120%	116%	116%	100%	28.51%	$1,826,749
Small Volume	$4,870,538	$5,300,678	$430,140	8.83%	31%	79%	80%	115%	32.79%	$1,597,080
Large Volume	$6,506,797	$6,524,383	$17,586	0.27%	1%	64%	65%	130%	37.07%	$2,411,918
Irrigation Sales	$2,444,623	$2,929,526	$484,903	19.84%	70%	-43%	-46%	150%	42.77%	$1,045,575
Irrigation Transportation	$588,871	$697,926	$109,055	18.52%	65%	-186%	-216%	150%	42.77%	$251,862
Interruptible Large Volume	$285,924	$268,339	($17,585)	-6.15%	-22%	261%	261%	50%	14.26%	$40,764
Total	$60,347,609	$77,554,882	$17,207,273	28.51%	100%	100%	100%		28.51%	$17,207,273

BLACK HILLS ENERGY
Residential Customer Cost Analysis

		Direct Costs		Direct + Indirect	
		ROE @ 9.50%	**ROE @ 10.50%**	**ROE @ 9.50%**	**ROE @ 10.50%**
Gross Plant					
380	Services	$88,481,793	$88,481,793	$88,481,793	$88,481,793
381	Meters	$15,685,172	$15,685,172	$15,685,172	$15,685,172
382	Meter Installations	$3,114,148	$3,114,148	$3,114,148	$3,114,148
383	House Regulators	$34,230,689	$34,230,689	$34,230,689	$34,230,689
118	Shared Services Billing System 1/			$200,256	$200,256
	Total Gross Plant	**$141,511,802**	**$141,511,802**	**$141,712,058**	**$141,712,058**
Depreciation Reserve 2/					
	Services	$27,121,593	$27,121,593	$27,121,593	$27,121,593
	Meters	$5,792,661	$5,792,661	$5,792,661	$5,792,661
	Meter Installations	$1,643,464	$1,643,464	$1,643,464	$1,643,464
	House Regulators	$4,811,499	$4,811,499	$4,811,499	$4,811,499
	Shared Services Billing System 1/			$70,416	$70,416
	Total Depreciation Reserve	**$39,369,217**	**$39,369,217**	**$39,439,633**	**$39,439,633**
Total Net Plant		**$102,142,585**	**$102,142,585**	**$102,272,425**	**$102,272,425**
Operation & Maintenance Expenses					
878	Meters & House Regulators	$561,594	$561,594	$561,594	$561,594
879	Customer Installation	$481,521	$481,521	$481,521	$481,521
892	Maintenance-Services	$266,204	$266,204	$266,204	$266,204
893	Maint. - Meters & House Regulators	$412,985	$412,985	$412,985	$412,985
902	Meter Reading	$296,185	$296,185	$296,185	$296,185
903	Records & Collections	$1,980,481	$1,980,481	$1,980,481	$1,980,481
926	Employee Pensions & Benefits 3/			$486,100	$486,100
	FICA 3/			$129,317	$129,317
	Total O & M Expenses	**$3,998,970**	**$3,998,970**	**$4,614,387**	**$4,614,387**
Depreciation Expense 4/					
	Services	$1,849,269	$1,849,269	$1,849,269	$1,849,269
	Meters	$1,304,811	$1,304,811	$1,304,811	$1,304,811
	Meter Installations	$28,027	$28,027	$28,027	$28,027
	House Regulators	$1,054,305	$1,054,305	$1,293,920	$1,293,920
	Shared Services Billing System 1/			$35,325	$35,325
	Total Depreciation Expense	$4,236,413	$4,236,413	$4,511,353	$4,511,353
Revenue Requirement					
	Interest	$2,405,458	$2,384,290	$2,408,516	$2,387,321
	Equity return	$4,851,773	$5,409,676	$4,857,940	$5,416,552
	Federal Income Tax @21.00%	$1,289,712	$1,438,015	$1,291,351	$1,439,843
	Revenue For Return	$8,546,942	$9,231,980	$8,557,807	$9,243,716
	O & M Expenses	$3,998,970	$3,998,970	$4,614,387	$4,614,387
	Depreciation Expense	$4,236,413	$4,236,413	$4,511,353	$4,511,353
	Subtotal Customer Revenue Requirement	$16,782,326	$17,467,364	$17,683,548	$18,369,456
	Uncollectibles @ 1.69% 5/	$283,851	$295,438	$299,094	$310,696
	Total Revenue Requirement	**$17,066,177**	**$17,762,802**	**$17,982,642**	**$18,680,152**
	Number of Customers	105,942	105,942	105,942	105,942
	Number of Bills	1,271,304	1,271,304	1,271,304	1,271,304
	TOTAL MONTHLY CUSTOMER COST	$13.42	$13.97	$14.15	$14.69

1/ Total Company shared services associated with CIS and Billing System, Per Schedule D multiplied by allocated Supervised O&M Before General per the Company's CCOSS.
2/ Accumulated Depreciation percent of Gross Plant per Statement E.
3/ Per page 2.
4/ Depreciation accrual rate per Statement J-1 times Gross Plant.
5/ Residential Uncollectible amount divided by Margin Revenue.

BLACK HILLS ENERGY
Small Commercial Customer Cost Analysis

		Direct Costs		Direct + Indirect	
		ROE @ 9.50%	**ROE @ 10.50%**	**ROE @ 9.50%**	**ROE @ 10.50%**
Gross Plant					
380	Services	$10,313,096	$10,313,096	$10,313,096	$10,313,096
381	Meters	$2,925,125	$2,925,125	$2,925,125	$2,925,125
382	Meter Installations	$580,757	$580,757	$580,757	$580,757
383	House Regulators	$6,383,675	$6,383,675	$6,383,675	$6,383,675
118	Shared Services Billing System 1/			$30,806	$30,806
	Total Gross Plant	**$20,202,653**	**$20,202,653**	**$20,233,459**	**$20,233,459**
Depreciation Reserve 2/					
	Services	$3,161,188	$3,161,188	$3,161,188	$3,161,188
	Meters	$1,080,272	$1,080,272	$1,080,272	$1,080,272
	Meter Installations	$306,489	$306,489	$306,489	$306,489
	House Regulators	$897,296	$897,296	$897,296	$897,296
	Shared Services Billing System 1/			$10,832	$10,832
	Total Depreciation Reserve	**$5,445,245**	**$5,445,245**	**$5,456,078**	**$5,456,078**
Total Net Plant		**$14,757,408**	**$14,757,408**	**$14,777,381**	**$14,777,381**
Operation & Maintenance Expenses					
878	Meters & House Regulators	$104,732	$104,732	$104,732	$104,732
879	Customer Installation	$56,124	$56,124	$56,124	$56,124
892	Maintenance-Services	$31,028	$31,028	$31,028	$31,028
893	Maint. - Meters & House Regulators	$77,018	$77,018	$77,018	$77,018
902	Meter Reading	$55,235	$55,235	$55,235	$55,235
903	Records & Collections	$369,339	$369,339	$369,339	$369,339
926	Employee Pensions & Benefits 3/			$78,482	$78,482
	FICA 3/			$20,879	$20,879
	Total O & M Expenses	**$693,476**	**$693,476**	**$792,837**	**$792,837**
Depreciation Expense 4/					
	Services	$215,544	$215,544	$215,544	$215,544
	Meters	$243,334	$243,334	$243,334	$243,334
	Meter Installations	$5,227	$5,227	$5,227	$5,227
	House Regulators	$196,617	$196,617	$241,303	$241,303
	Shared Services Billing System 1/			$5,434	$5,434
	Total Depreciation Expense	$660,722	$660,722	$710,842	$710,842
Revenue Requirement					
	Interest	$347,537	$344,479	$348,007	$344,945
	Equity return	$700,977	$781,582	$701,926	$782,640
	Federal Income Tax @21.00%	$186,336	$207,762	$186,588	$208,043
	Revenue For Return	$1,234,849	$1,333,823	$1,236,521	$1,335,628
	O & M Expenses	$693,476	$693,476	$792,837	$792,837
	Depreciation Expense	$660,722	$660,722	$710,842	$710,842
	Subtotal Customer Revenue Requirement	$2,589,047	$2,688,020	$2,740,199	$2,839,306
	Uncollectibles @ 1.93% 5/	$50,025	$51,937	$52,945	$54,860
	Total Revenue Requirement	**$2,639,072**	**$2,739,958**	**$2,793,144**	**$2,894,166**
	Number of Customers	9,879	9,879	9,879	9,879
	Number of Bills	118,548	118,548	118,548	118,548
	TOTAL MONTHLY CUSTOMER COST	$22.26	$23.11	$23.56	$24.41

1/ Total Company shared services associated with CIS and Billing System, Per Schedule D multiplied by allocated Supervised O&M Before General per the Company's CCOSS.
2/ Accumulated Depreciation percent of Gross Plant per Statement E.
3/ Per page 2.
4/ Depreciation accrual rate per Statement J-1 times Gross Plant.
5/ Small Commercial Uncollectible amount divided by Margin Revenue.

BLACK HILLS ENERGY
Pensions & Benefits Costs

Acct. No.			
926	Total Company Pension & Benefits	$2,125,565	Per Sch H-5
	Total Company Salaries & Wages	$7,391,708	Per Sch H-5
	Benefits Percent of Wages	28.76%	

		Total Company Salaries & Wages 1/	Total O&M Expense	Labor Percent of Total Exp.	Residential Account Expense	Residential Benefits Expense	FICA Expense	Sm. Comm. Account Expense	Sm. Comm. Benefits Expense	FICA Expense
878	Dist. Meter & House Regulator Expense	$630,186	$878,442	71.7391%	$561,594	$115,853	$30,820	$104,732	$21,606	$5,748
879	Dist. Customer Installation Expense	$501,431	$579,715	86.4961%	$481,521	$119,768	$31,862	$56,124	$13,960	$3,714
892	Dist. Maint. of Services	$227,190	$320,489	70.8885%	$266,204	$54,265	$14,436	$31,028	$6,325	$1,683
893	Dist. Maint. of Meters & House Regulators	$471,749	$645,990	73.0273%	$412,985	$86,726	$23,072	$77,018	$16,174	$4,303
902	Meter Reading Expenses	$298,093	$390,348	76.3660%	$296,185	$65,042	$17,303	$55,235	$12,130	$3,227
903	Customer Record & Collection Expenses	$203,699	$2,610,115	7.8042%	$1,980,481	$44,446	$11,824	$369,339	$8,289	$2,205
Total						$486,100	$129,317		$78,482	$20,879

Black Hills Cost of Capital

Debt	49.56%	4.71%	2.33%
Equity	50.44%	10.50%	5.30%
Total			7.63%

CURB Cost of Capital

Debt	50.00%	4.71%	2.36%
Equity	50.00%	9.50%	4.75%
Total	100.00%		7.11%

BLACK HILLS ENERGY
Depreciation Reserve Costs

	Total Company		
	Depreciation Reserve	Gross Plant	Percent Gross Plant
Services	$32,652,391	$106,525,531	30.65%
Meters	$9,060,853	$24,534,672	36.93%
Meter Installations	$2,570,699	$4,871,135	52.77%
House Regulators	$7,526,124	$53,543,483	14.06%
Shared Services Billing System	$97,596	$277,554	35.16%

CERTIFICATE OF SERVICE

25-BHCG-298-RTS

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing document was served by electronic service on this 9th day of May, 2025, to the following:

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