BEFORE THE

KANSAS CITY BOARD OF PUBLIC UTILITES

Prepared Direct Testimony of

Craig E. Brown

Issue:

Electric Revenue Requirements
Electric Cost of Service
Electric Rate Design

June 2023

I. Introduction

Q. Please state your name and business address.

A. Craig E. Brown, 9400 Ward Parkway, Kansas City, MO 64114.

Q. What is your occupation?

A. I am employed by 1898 & Co., a division of Burns & McDonnell Engineering Company, Inc. (hereinafter called "1898 & Co."), as a Senior Project Manager in the Financial Analysis and Rate Design business line. 1898 & Co. is a business, technology and security solutions consulting firm serving multiple industries, including the electric power industry. As a part of Burns & McDonnell, 1898 & Co. draws on 125 years of experience.

Q. Please summarize your educational and professional experience.

A. For the past 19 years, I have worked as a consultant, project manager, expert witness, and analyst on utility financial, ratemaking, and regulatory projects. Since joining Burns & McDonnell in 2019 I have focused primarily on cost of service, ratemaking, and regulatory consulting for electric utilities. Prior to joining Burns & McDonnell, I worked for 15 years in the Rate and Regulatory practice at Black & Veatch Management Consulting, where I was a Principal Consultant and Rate and Regulatory Team Lead, consulting on projects for electric, gas, water, and wastewater utilities. Prior to joining Black & Veatch in 2004 I was employed as an accountant and small business consultant at independent firms in Overland Park, Kansas and Phoenix, Arizona. I graduated from the University of Missouri – Columbia in 1997, with a Bachelor of Science degree in Hotel and Restaurant Management. In 2004, I received a Master of

Business Administration degree with an emphasis in Finance from Rockhurst University.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Board of Public Utilities of the Unified Government of Kansas City, Kansas and Wyandotte County, Kansas (BPU).

Q. Have you previously testified before this Board?

A. Yes. I testified before this Board in the BPU's two prior electric rate cases in 2010 and 2017.

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

A. The purpose of my testimony is to support the 1898 & Co. study of electric revenue requirements, cost of service, and rate design recommendations, including detailed rate recommendations for rate changes effective July 1, 2023 and July 1, 2024.

Q. Do you sponsor any exhibits?

A. Yes, I sponsor one exhibit: Exhibit CEB-1 – 2023 Electric Revenue Requirements, Cost of Service and Rate Design report (Report). This exhibit was prepared by me or under my supervision and direction.

Q. Please describe the study presented in the Report.

A. The report presents a comprehensive rate study prepared for the electric utility of the BPU. A comprehensive rate study includes three distinct phases:

1. Revenue and revenue requirements,
2. Cost of service, and
3. Rate design.

The **revenue and revenue requirements** phase develops a five-year financial forecast of operations under existing rates. The forecast includes a plan for financing the BPU's capital improvement program (CIP) with a mix of debt financing and financing from annual operating revenues (cash financing). Rate adjustments are projected to meet key financial metrics including debt service coverage and minimum cash balances (measured in days cash on hand). The overall goal of the revenue and revenue requirements phase is to determine the overall revenue adjustment needed for the electric utility.

The goal of the **cost of service (COS)** phase is to determine each rate classes' allocated share of revenue requirements for a single test year. Typically for municipal utilities, the test year is based on the future year the rates will be implemented, also known as the rate effective period. For BPU, I used a 2023 test year. The cost of service study compares the allocated costs of each rate class to the revenues generated by existing rates to provide an indication of cost recovery of each rate class relative to the system average.

Rate design is the final stage of a rate study involves developing the specific rate structure that allows the utility to recover its costs for a given test year based on the overall system increase and potentially targeted adjustments by class based on the cost of service study.

Q. How is your testimony organized?

A. My testimony is organized in six sections as follows:

I. Introduction

II. Revenue and Revenue Requirements

III. Cost of Service

IV. Rate Design

V. Miscellaneous Rate Manual Changes

VI. Summary

Q. Please summarize your testimony.

A. I recommend that BPU increases its base rate charges by 2.5% in 2023 and 2.5% in 2024. I recommend the BPU begin to fund an operating reserve fund (ERC Reserve) linked to fuel and purchased power costs that are recovered in the Energy Rate Component (ERC). Based on the COS study results, I recommend the BPU make targeted revenue adjustments by class to improve equitable cost recovery by class.

II. Revenue and Revenue Requirements

Q. Please describe the process of determining the adequacy of existing electric rates of the BPU.

A. The adequacy of BPU's electric rates was reviewed over a five year period from 2023 through 2027 (the forecast period). The first step was to calculate the revenue that would be generated in the forecast period using the BPU's existing rates. This was accomplished by taking the BPU's forecast of energy sales in kilowatt-hours (kWh) (the Load Forecast) and projecting the billing determinants in the forecast period. The billing determinants include the number of customers, demand (in kilowatts (kW)), and energy (in kWh) for each rate class in the forecast period. The development of billing determinants is discussed in more detail in Section 3.1 of the Report. Next, we calculated the revenue that would be generated in each year of the forecast period using the BPU's existing rates.

Q. Why was a five year period chosen for the review?

A. 1898 & Co. uses a multiple year period to forecast the need for rate adequacy. We recommend rate adjustments, if needed, be adequate for utilities to operate and plan capital additions for at least two to five years.

Q. What is the next step after determining revenue under existing rates?

A. The next step is to determine the revenue requirements of the utility for each year of the forecast period. Each year is treated as a separate test year for the purpose of determining the rates applicable to customers in each year. Revenue requirements are defined as the annual cash operating requirements of the utility. The traditional revenue requirements for a municipal utility operating on a cash basis include operation and maintenance (O&M) expenses including administrative and general expenses (A&G), debt service payments, routine capital outlay, cash financed capital projects, transfers to other entities, and other expenses less other revenues.

Q. How were these components of revenue requirements developed for the BPU?

A. As discussed in Section 3.2 of the Report, the revenue requirements for the forecast period were primarily developed from the 2023 Budget. Following a review of historical data, we worked with BPU management to develop escalation factors to forecast O&M Expense, Other Revenues, and Other Expenses. BPU provided a forecast of fuel costs, purchased power expenses, and SPP Integrated

Market activity. For the Capital Improvement Plan (CIP) used in the Study, we used the 2023 Budget CIP, which includes a forecast of projects and costs for 2023 through 2027.

Q. How does the CIP relate to annual revenue requirements?

A. Two major components of revenue requirements are debt service and funding of capital projects with annual rate revenues, also referred to as "cash financed capital." The CIP, and the associated decisions on which projects are bond financed versus cash financed, directly impact the annual revenue requirements to be recovered in rates. While bond funding projects appropriately spreads the costs of major projects over many years, the utility will also incur interest expense in the process. In addition, base rates may need to be adjusted to meet debt service coverage requirements. It is the debt service payment that becomes the annual revenue requirement.

Alternatively, cash financed capital projects incur no interest expense, but the entire cost of the project is recovered in rate revenue in the year the project is completed. This places more pressure on a utility's cash reserves and operating cash balance.

Q. How were the bond financing versus cash financing decisions made in this study?

A. The size and timing of the bond financing plan was developed collaboratively between 1898 & Co. and BPU Staff. The Forecast Period includes one bond issue in 2023 as recommended by 1898 & Co. This bond issue will provide $50 million in proceeds for funding CIP projects. All other projects in the CIP are cash financed. The key driver for issuing a bond early in the study period is to improve the BPU's operating cash balances that have been eroded in recent years by cash financing all capital projects. By bond financing more capital projects, this allows the BPU's cash balances to recover to target ranges, while reducing the need for larger base rate increases.

Q. What assumptions did you use for proposed bond financing?

A. The BPU provided assumptions to 1898 & Co. for the proposed bond financing. The bonds are projected to have a 30-year term and net interest costs of 5.0%.

Q. What are the key drivers for determining the most efficient split between bond and cash financing?

A. There are two main drivers used when determining the most efficient capital financing plan: debt service coverage and maintaining a minimum operating reserve. As discussed in the testimony of Ms. Lori Austin, the target debt service coverage for the electric utility is 1.6 times the annual debt service payment without the inclusion of revenue from payments in lieu of taxes (PILOT). The target operating reserve is 120 days of O&M expenses. The goal is to adjust the mix between cash and bond financing to meet both targets while minimizing rate increases. Maintaining adequate bond coverage requires managing the total utility leverage with a combination of internally generated capital dollars and external debt financing. Stronger credit metrics reduce the cost of external financing and come from the use of additional internally generated capital dollars.

Q. How does revenue under existing rates compare to the annual cash revenue requirements in the forecast period?

A. As shown on Line 60 of Table 3-4 of the Report, revenue at existing rates is less than the revenue requirement beginning in 2024 resulting in annual deficits through the remainder of the study period.

Q. Please identify the annual deficits that make up this total.

A. As shown in this reproduction of Table 3-9 from the Report, annual forecast deficits range from $836,000 in 2024 and increase up to a $11.9 million deficit in 2027. This table also illustrates the impact of these deficits on days of O&M reserved and debt service coverage. Based on the forecast, BPU's coverage is below the 1.60 target beginning in 2024 and continuing throughout the rest of the study period. Days cash on hand is also below the target throughout the forecast and is reduced to 24 days by the end of the study period.

Financial Metrics Under Existing Rates						
Description	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Revenue Surplus / (Deficiency) Under Existing Rates	$ 12,930,453	$ 786,157	$ (835,770)	$ (1,075,671)	$ (12,937,820)	$ (11,855,808)
Operating Cash Balance						
Beg Balance	$ 25,619,100	$ 38,549,553	$ 39,335,710	$ 38,499,941	$ 37,424,270	$ 24,486,449
Annual Cash Flow	$ 12,930,453	$ 786,157	$ (835,770)	$ (1,075,671)	$ (12,937,820)	$ (11,855,808)
End Balance	$ 38,549,553	$ 39,335,710	$ 38,499,941	$ 37,424,270	$ 24,486,449	$ 12,630,642
Days of O&M Reserved	**82**	**74**	**76**	**72**	**47**	**24**
Target Minimum Days Cash	90	120	120	120	120	120
Annual Debt Service Coverage without PILOT Revenue						
Total System Achieved (Total Debt)	**1.85**	**1.61**	**1.48**	**1.47**	**1.54**	**1.53**
Target Minimum Coverage	1.60	1.60	1.60	1.60	1.60	1.60

Q. What does the study recommend to resolve the annual operating deficits?

A. There are three primary recommendations to resolve the annual operating deficits and allow the BPU to meet their target financial metrics in their stated financial policies:

1. Two consecutive base rate increases of 2.5% on July 1, 2023 and July 1, 2024,

2. Creation of an ERC Reserve Fund to fund share of BPU's target of 120 days of cash on hand that is related to fuel and purchased power costs through the ERC rider, and

3. Issue a revenue bond for $50 million to fund major capital projects planned for 2023 through 2025 to reduce the impact on BPU's cash balances.

Q. What is the purpose of the ERC Reserve Fund?

A. BPU has a financial policy to maintain a minimum of 120 days of cash on hand to manage seasonal fluctuations in cash flows. The metric is a measure of days of operating expenses including fuel and purchased power that are recovered in the ERC rider plus all O&M expenses that are recovered in base rates. Historically, if rates need to be adjusted to increase revenues to meet BPU's days cash on hand target, it has solely been through increasing base rates. We recommend that the portion of the 120 day target attributable to fuel and purchased power expenses be maintained through the ERC rider and the amount attributable to all other O&M expenses be maintained through base rate adjustments.

Q. How do you propose funding the ERC Reserve?

A. Based on current projections of costs recovered in the ERC of approximately $80 million, the ERC Reserve should be approximately $26 million. It would be inappropriate to build to this amount all in one year, so we have proposed a gradual build up of the reserve over a period of five years. This amounts to an additional $1.5 million per quarter ($6 million annually) recovered in the ERC rider.

Q. Are there any other changes to base rate and ERC cost recovery?

A. Yes, there is. While the ERC is designed to recover all fuel and purchased power costs in a rider separate from base rates, there are certain fixed capacity costs that are recovered in base rates due to the fixed nature of the costs. Currently the amount embedded in base rates is $2.6 million per year. Since the last rate hearing in 2017, the amount of fixed capacity contract costs have increased to $4,642,930 per year. We propose to increase the amount recovered in base rates to this amount and reduce the costs recovered in the ERC by approximately $2 million per year. This effectively has no impact on customer bills, as it is a transfer from one rate to another, but it does impact the magnitude of the base rate increases required.

Q. Please summarize the need for the rate adjustments you are proposing?

A. There are many interrelated issues that can lead to the need for rate increases. The most common include inflationary increases to operating costs, issuance of new debt, loss of customer load, maintaining adequate debt service coverage, and maintaining healthy operating reserves. Included in the BPU's financial policy is a requirement that net revenue for the electric utility should be equal to 160 percent of annual debt service payments, excluding PILOT revenue. With recommendations from 1898 & Co., the BPU has set a goal of increasing operating reserves to 120 days of cash on hand, which is a key driver in this rate case, along with increasing the amount of fixed purchased power capacity payments recovered in base rates from $2.6 million to $4.6 million. The latter has a net zero impact on customer's total bills as the amount of purchased power costs recovered in the Energy Rate Component (ERC) is reduced by $2.0 million.

Q. Do these proposed rate increases meet the BPU's financial goals?

A. As seen on Table 3-13 of the Report, the electric utility does meet its stated target for both debt service coverage and operating reserve by 2025. The operating reserve level is maintained at 120 days of O&M through the rate increases and bond issuance, while the debt service coverage remains comfortably above 1.60 throughout the study period.

III. Cost of Service

Q. What is the purpose of the cost of service study you are sponsoring?

A. Many purposes exist for electric utility cost analysis ranging from designing appropriate price signals to determining the share of costs borne by various rate classes. Just as there are many uses for cost analysis, there are different types of cost studies. In general, cost of service studies may be based on the embedded cost, average cost, or marginal cost. Embedded cost of service studies analyze the costs for a test period based on either the book value of accounting costs (a historical period) or the estimated book value of costs for a forecast test year. For the BPU the costs are forecasted costs for a 2023 test year that matches costs and revenues for the "Rate Effective Period." The Rate Effective Period is the year the new rates will become effective. This results in matching costs and rates.

The purpose of the embedded cost of service study used in my testimony is to allocate the test year revenue requirements between customer classes to determine the cost to serve the class. In addition, the cost of service study determines the required increase in revenues needed to recover the cost of service from the customer class. It is the cost of service that forms the basis for allocating the required rate increase among the customer classes. In addition, the cost of service study has guided various elements of the rate design to provide for a closer matching of cost causation and revenues.

Q. Why is a cost of service study a useful tool for determining rates?

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost of service studies results from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs. In addition, utility costs may be fixed or variable costs. Finally, utility costs exhibit significant economies of scale. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of a cost of service study requires an understanding of the operating characteristics of the utility system. The application of a sound set of cost of service principles results in a set of target revenues for each class that reflects a reasonable share of system costs.

Q. Please explain the steps involved in developing the cost of service study.

A. The cost of service study follows a traditional three step process: functionalization, classification and allocation. This three step process underlies the determination of cost causation. By identifying the functions of utility service: generation, transmission, distribution and customer for electric service and the costs for each of these functions, the foundation is laid for the second step - classification. Classification is the process of separating costs for each of these functions, the functionalized costs into the utility services provided - demand (capacity), energy, customer, and direct assignment. The allocation process involves determining how each rate class uses the various cost classifications. The key element of the cost allocation process is to determine the cost causation within each individual function and classification.

Q. How are costs functionalized?

A. In general, utilities maintain their accounting records consistent with these functions. That is, there is separate accounting for generation such that we know both the capital costs and operation and maintenance expenses associated with the production and purchase of electric energy. Similarly, we know the same information for distribution based on the facilities that function as part of the distribution system. The availability of accounting records permits functionalization with little room for differences among cost analysts.

Q. How are costs classified?

A. Costs are classified based on the operational characteristics of the system: demand, energy, and customer. **Demand** costs are capacity related costs associated with plant that is designed, installed, and operated to meet maximum electric usage requirements such as larger transformers or more localized distribution facilities, which are designed to satisfy individual customer maximum demands. Measures of maximum demand can include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand.

Energy costs are those costs that vary directly with the production of energy such as fuel costs; other fuel related expenses or purchased power expense.

Customer costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer costs are largely a function of the number and density of customers served and continue to be incurred whether or not the customer uses any electricity. They may include capital costs associated with minimum size distribution systems, services, meters, and customer billing and accounting expenses.

Classification is an important step in the cost study since the classification determines the type of allocation factor used in the study for each function. Generally, production and transmission functions are classified as demand or energy, while distribution functions are classified as demand or customer. In the distribution plant, certain items such as meters and service lines are a function of customers, so we are able to separately functionalize cost to the customer function. Likewise assets and expenses related to substations are all demand related. Accounts related to poles, conductor, and line transformers have both a demand and a customer component, which has been estimated at 75% demand and 25% customer for the BPU COS study.

Q. How are costs allocated?

A. We develop allocation factors for each of the classification categories based on cost causation principles. For example, energy-related costs are allocated to the customer classes on the basis of their respective energy (kWh) requirements at the generation level of the BPU's system, which includes applicable system energy losses. Customer-related costs are allocated using factors based on customer count, sometimes weighted for various factors, such as meter costs. Demand allocation factors are based on a measure of peak demand, generally a form of coincident peak (CP) or non-coincident peak (NCP).

Q. Please expand on how demand costs are allocated.

A. There are many potential methods of demand cost allocation for electric utilities. The methods essentially fall into three fundamental categories as follows:

1. Coincident Peak (CP) Methods
2. Non-Coincident Peak (NCP) Methods
3. Energy-weighted methods such as Average and Excess Demand (AED).

Within each of these categories, there are numerous specific types of methods. Further, to reflect the cost of an electric system, a complete cost of service study requires application of more than one demand category of allocation factors. For example, non-coincident peaks drive the allocation of distribution capacity while it is some combination of coincident peaks and demand and energy methods for generation. Within each classification category, there may be multiple specific methods. Under the CP allocation category options include a single CP, four CP, 12 CP, winter/summer CP and so forth. Under the AED allocation there are a number of methods that consider both demand and energy such as peak and average, peaker methods and so forth. In any event, the choice of methods relies on the concept of cost causation to choose the most appropriate method that reflects those costs. NCP methods may use a variety of peaks other than the actual system peak based on the peaks of individual service classifications or individual customers. Cost causation requires the determination of the cost to serve each class of customers in a way that recognizes apparent cost responsibility and reflects the engineering and operating characteristics of the utility system. The key drivers in determining appropriate demand allocators are shown in the table below.

Cost Allocation Method Summary

Allocation Method	Assumption about Cost	Allocation Factor
CP Methods	System peak loads drive costs	Class coincident demand
AED Methods	Peak and energy drive costs	Average demand, NCP and load factor
NCP Methods	Class or customer peaks drive costs	Class or customer NCP

Q. What method do you use for BPU's production and transmission systems?

A. In the case of production, the choice of an allocation factor depends on how costs are incurred for the capacity portion of production costs. It is a basic proposition of reliable utility service that the utility must have adequate capacity to meet the peak load requirements of its customers plus a level of reserves to maintain reliability. In the Southwest Power Pool (SPP), that level of reserves is determined on the SPP systemwide reserve requirements. This means that peak load causes capacity costs to be incurred. However, when a utility plans its system, it uses a combination of different technologies to meet both capacity and energy requirements by considering the system load duration curve as well as peak load. As such both peak demand and energy requirements are considered in investment and operational decisions. For BPU's COS Study, I used the energy-weighted method of Average and Excess Demand (AED).

Q. **Has the BPU board previously adopted this method for allocating production capacity costs?**

A. Yes. The BPU Board adopted this cost allocation methodology in 2010 and 2017. The Board correctly recognized that this method represents cost causation for production assets.

Q. Please summarize the allocation process for the production function.

A. The production function is classified as demand or energy. In the simplest form energy costs are allocated to customers based on energy consumption. Demand costs for production are allocated using the AED method discussed above. This method recognizes the planning and operational considerations for the system. The BPU does not plan capacity solely on the peak hour although that is a consideration. Rather, the BPU considers other factors such as system load factor, annual fuel costs, load duration and other relevant factors thus the assumptions related to AED are applicable and using that method of allocation reflects cost causation.

Q. Please summarize the allocation process for the transmission function.

A. Transmission is allocated in the same way as generation demand. The transmission system serves as the facilities required to move generation to loads. This method assures that off peak loads such as lighting are allocated a portion of transmission plant.

Q. Please summarize the allocation process for the distribution function.

A. Distribution plant is designed and sized to serve the non-coincident peak load of customers. At the customer premise, for assets such as meters and service connections, cost are allocated using a customer allocation factor. For common facilities such as lines and substations the facilities recognize the increasing diversity that exists as loads become more remote from the individual customer. For these loads the use of a class NCP represents the most appropriate allocation factor.

Q. Please summarize the allocation process for the customer function.

A, The costs related to the customer function represent costs that permit the customer to access the delivery system and the costs associated with meter reading, billing and customer service. The cost of service study recognizes that the cost of facilities on the customers' premise is not the same for each class. Residential meters, for example, have a lower installed cost than meters for other customer classes. To recognize differences, the cost of service study uses weighted customer accounts to reflect these differences in customer access facilities. The weighted customer allocators differ for different accounts based on underlying cost causation. The residential class has a weight of one and all other classes are weighted relative to residential costs. Weights range from 0.50 to a high of 20 for metering for the largest customers.

Q. Please provide a high level summary of classification and allocation by function.

A. 1) Production function:

a) Classified as demand and energy

b) Demand allocated using the AED method. Energy allocated on loss adjusted energy

2) Transmission function:

a) Classified as demand

b) Demand allocated on AED to match generation

3) Distribution Substation:

a) Classified as demand

b) Allocated on class substation NCP

4) Distribution Transformer:

a) Classified as demand

b) Allocated on class secondary NCP

5) Distribution Lines and Poles:

a) 75% classified as demand and 25% classified as customer

b) Demand allocated on class NCP and customer allocated on weighted customer

6) Distribution Services and Meters:

a) Classified as customer

b) Allocated on weighted Service and Meter costs

7) Customer function: (i.e. billing, meter reading and collections)

a) Classified to Customer

b) Allocated on number of customers or weighted customers

Q. Does the cost of service study follow sound procedures and produce usable results?

A. Yes. The methods used in the cost of service study are guided by the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners (NARUC). As with any COS Study, there are assumptions required relative to the choice of allocation methodology. As discussed above those assumptions are justified by the analysis of the system and its operation. In addition, certain assumptions were necessary in the development of allocation factors where measured data was not available. For example, for some customers the only measured data available was metered kWhs. In that case it was necessary to estimate demand factors for NCP values used in the cost study. Using both experience, regional benchmarking, and professional judgment, these estimates were reasonable. Thus, the COS study produces usable results as described above.

Q. Please summarize the results of the cost of service study.

A. The cost of service study provides the required revenue increase to produce the proposed class revenue requirement for the test year 2023. The following table summarizes the revenue deficiency by class as well as the indicated percentage adjustments to each to reach cost of service.

Cost of Service Summary

	Total System	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	USD 500	Private Area Lighting	KCK	BPU Interdepartmental
Cost of Service Summary										
Revenue Requirement	$ 151,326,326	$ 57,714,955	$ 15,766,386	$ 30,367,094	$ 10,718,146	$ 26,614,713	$ 4,285,166	$ 1,616,531	$ 2,686,724	$ 1,556,611
Revenue from Current Rates	$ 147,635,440	$ 53,092,238	$ 17,308,307	$ 31,960,311	$ 11,559,431	$ 27,320,996	$ 4,295,902	$ 1,596,942	$ -	$ 501,312
Class Deficiency	$ 3,690,886	$ 4,622,717	$ (1,541,922)	$ (1,593,218)	$ (841,285)	$ (706,283)	$ (10,736)	$ 19,590	$ 2,686,724	$ 1,055,299
Adjustment for KCK and BPU Deficiency	$ -	$ 1,468,359	$ 401,122	$ 772,587	$ 272,687	$ 677,120	$ 109,021	$ 41,127	$ (2,686,724)	$ (1,055,299)
Adjusted Class Cost of Service	$ 151,326,326	$ 59,183,315	$ 16,167,507	$ 31,139,680	$ 10,990,832	$ 27,291,833	$ 4,394,188	$ 1,657,658	$ -	$ 501,312
Indicated % Adjustment	**2.50%**	**11.47%**	**-6.59%**	**-2.57%**	**-4.92%**	**-0.11%**	**2.29%**	**3.80%**		

The indicated adjustments in the table above show the required increase (or decrease) to bring all classes to their exact cost of service. A general interpretation of these results show that the residential class is under-recovering its allocated cost of service more than any other class and the commercial and industrial classes are all over-recovering their allocated cost of service.

III. Rate Design

Q. What is the first step in the rate design process?

A. The rate design process begins with a review of the class cost of service results. For classes with indicated increases larger than the system average, a larger percentage increase has been proposed. This mainly lies with the residential class, which shows the need for the highest adjustment. For classes recovering more than the indicated cost of service or are near their cost of service, a lower increase has been proposed.

Q. What is the proposed overall revenue increase in base rates for each of the two years?

A. The overall base rate revenue increase is 2.50% per year for both 2023 and 2024.

Q. How did you determine the rate adjustments for each class?

A. We capped the maximum increase for any class at 150% of the system average, which results in a 3.75% increase cap for the residential class each year. The commercial and industrial classes receive less than the system average based on the lowest percentage that still allows the system to recover an overall increase of 2.50%. The recommended base rate adjustments by class are shown in the table below:

Base Rate Summary		
Class	**2023**	**2024**
Residential	3.75%	3.75%
Small General Service	1.75%	1.73%
Medium General Service	1.75%	1.73%
Large General Service	1.75%	1.73%
Large Power Service	1.75%	1.73%
USD 500	2.50%	2.50%
Private Area Lighting	2.50%	2.50%
BPU Interdepartmental	2.50%	2.50%

Q. How did you apply these class revenue targets to each class?

A. The details for each class are presented in Section 5.2 of the Report. In general, there was an intentional effort to apply more of the rate increases to rate components that recover fixed costs over those that recover variable costs. Specifically, the majority of the rate adjustments were applied to the Customer Charge, Facilities Charge, and Demand Charges, with more minimal changes to Energy Charges.

Q. What rate increase is proposed for the residential rate for the test year?

A. The proposed increase is 3.75% on base rates. The increase for residential service is set at 150% of the system average increase and is designed to gradually move residential customers closer to the cost of service.

Q. Are you proposing any structural changes to the residential rate class?

A. Yes, we are proposing to eliminate the Residential Electric Heating rate (rate code 101) and have one consolidated residential class that structurally looks more like the current electric heating rate. So instead of one flat energy charge for the entire year, the proposed residential rate will have a seasonal factor with a flat energy charge in the summer and a declining block structure during the 8 non-summer months (October - May). The new structure will continue to benefit customers that have increased usage in the winter from electric heating.

Q. Please describe the changes to the rate code 100 general purpose Residential Rate to recover this percentage increase.

A. The proposed rate continues to have a Customer Charge that is designed to recognize that the local facilities such as meter and service provide access to the system. The current charge is increased from $22.00 per month to $24.00 per month in 2023 and then increased to $26.00 per month in 2024. The remainder of the assigned revenue is collected in the energy charge. The energy charge is flat in the summer months with a declining block rate in the winter months that recognizes increased winter usage. The use of a lower winter block matches costs and provides for more efficient operation of the BPU system. This also recognizes the higher load factor of heating customers and the lower per unit costs for delivery facilities resulting from economies of scale in the distribution system.

Q. Have you provided bill comparisons for the Residential Rates?

A. Yes. I have provided residential bill comparisons in Table 5-4 of the Report.

Q. What rate increase is proposed for the Small General Service (SGS) rate for the test year?

A. The proposed increase is 1.75% on base rates. Current revenues in this class exceed the cost of service; therefore a rate adjustment below the system average is justified.

Q. Please describe the changes to the rate code 200 Small General Service rate.

A. The proposed rates, as shown in Table 5-5 of Exhibit CEB-1, continue to be structured with a Customer Charge, Facilities Charge, Demand Charge, and an Energy Charge. The Customer Charge is proposed to increase from $40.00 per month to $42.00 in 2023 and $44.00 in 2024. The 2023 Facilities Charge of $3.38 per kW for secondary service or $2.74 for primary service has been set using the cost of service results as a guide. The rate continues to have a Demand Charge for demand over 10 kW and the proposed rate is increased from $5.57 to $5.75 for 2023. The proposed Energy Charge consists of a flat energy charge per kWh for the standard SGS class and a declining block structure during the winter months for the SGS Electric Heating class.

Q. What rate increase is proposed for the Medium General Service (MGS) rate for the test year?

A. The proposed increase is 1.75% on base rates. Current revenues in this class exceed the cost of service; therefore a rate adjustment below the system average is justified.

Q. Please describe the changes to the rate code 250 Medium General Service rate.

A. The proposed rates, as shown in Table 5-6 of Exhibit CEB-1, continue to be structured with a Customer Charge, Facilities Charge, Demand Charge, and an Energy Charge. The Customer Charge is proposed to increase from $85.00 per month to $90.00 in 2023 and $95.00 in 2024. The 2023 Facilities Charge of $4.22 per kW for secondary service or $3.65 for primary service has been set using the cost of service results as a guide. The rate continues to have a Demand Charge. The Energy Charge continues to have an hour's use of demand structure with two blocks to recognize high load factor use. For qualified electric heating customers (Rate

251) there is a winter block of the rate that is priced at a lower per kWh rate above 300 kWh per kW.

Q. Please explain the hour's use of demand charge structure used for the Energy Charge for Rates 250, 300, And 400.

A. The hour's use of demand charge (Wright rate) was developed by Mr. Arthur Wright in the 19th century to recognize both demand and load factor. The load factor component recognizes the intensity of the use of demand. Among other benefits, it serves as a proxy for off peak energy use. For example, for the typical month about 230 hours are on peak while the remainder is off peak. By charging more for the first 300 hours of use and less for over 300 hours, recognition is given to both the lower unit fixed costs for higher load factor and the off peak nature of the extra use of demand and energy on nights and weekends.

Q. What rate increase is proposed for the Large General Service (LGS) rate for the test year?

A. The proposed increase is 1.75% on base rates. Current revenues in this class exceed the cost of service; therefore a rate adjustment below the system average is justified.

Q. Please describe the changes to the rate code 300 Large General Service rate.

A. The proposed rates, as shown in Table 5-7 of Exhibit CEB-1, continue to be structured with a Customer Charge, Facilities Charge, Demand Charge, and an Energy Charge. The Customer Charge is proposed to increase from $170.00 per month to $180.00 in 2023 and $190.00 in 2024. The 2023 Facilities Charge of $4.26 per kW for secondary service or $3.68 for primary service has been set using the cost of service results as a guide. The rate continues to have a Demand Charge. The

Energy Charge continues to have an hour's use of demand structure with two blocks to recognize high load factor use. For qualified electric heating customers (Rate 301) there is a winter block of the rate that is priced at a lower per kWh rate.

Q. What rate increase is proposed for the Large Power Service rate for the test year?

A. The proposed increase is 1.75% on base rates. Current revenues in this class exceed the cost of service; therefore a rate adjustment below the system average is justified.

Q. Please describe the changes to the rate code 400 Large Power Service rate.

A. The proposed rates, as shown in Table 5-8 of Exhibit CEB-1, continue to be structured with a Customer Charge, Facilities Charge, Demand Charge, and an Energy Charge. The Customer Charge is proposed to increase from $400.00 per month to $420.00 in 2023 and $440.00 in 2024. The 2023 Facilities Charge of $3.50 per kW for secondary service, $2.95 per kW for primary service, or $1.03 per kW for substation service has been set using the cost of service results as a guide. The rate continues to have a Demand Charge. The Energy Charge continues to have an hour's use of demand structure with two blocks to recognize high load factor use. For qualified electric heating customers (Rate 401) there is a winter block of the rate that is priced at a lower per kWh rate.

Q. What rate increase is proposed for the rate for Unified School District #500 (USD 500) for the test year?

A. The proposed increase is 2.50% on base rates, which is in line with the system average increase.

Q. Please describe the changes to USD 500's rate.

A. The USD 500 rate is an energy only rate structure. The proposed rate is a 2.50% increase on the existing rate.

Q. Is this rate applicable to all school districts in the BPU's service territory?

A. No, this rate is specific to USD 500. All USD 500 schools use electricity for space heating. All other school districts are currently charged using the applicable Small, Medium, or Large General Service rate.

Q. What rate increase is proposed for the Lighting Rate for the test year?

A. The proposed increase is 2.50% on base rates, which is in line with the system average increase.

Q. Please describe the proposed Rate 700 Private Area Lighting and Traffic Signal rates.

A. All rate components of Rate 700 rates have been increased by 2.50%. Additionally, we have recommended four new rates for LED lights that are not currently in the rate manual.

IV. Miscellaneous Rate Manual Changes

Q. Please identify any additional changes recommended for the BPU rate manual.

A. There are a number of recommended changes for the Rate Manual in addition to the recommended rate increases. In general, the changes fall into the several categories such as administrative, clerical, policy or application. The following list provides the proposed Rate Manual changes:

- Merging of the standard Residential and Residential Electric Heat classes into one residential class that reflects the rate design of the current residential electric heating rate.
- Modifying the ERC rider to allow for additional recovery over costs to build and maintain an ERC Reserve fund.

- Creation of a Green Rider for customers that want to procure energy with renewable attributes.
- Other language changes within the Rate Manual to align the language with current BPU practice.

Q. Please explain the new Green Rider Program.

A. The Green Rider is a new program targeted at large commercial and industrial customers (generally the LGS and LPS rate classes), that allows customers to purchase energy with Environmental Attributes (EA) to meet renewable energy goals. Customers will be eligible to participate in the process to purchase EAs for amounts of not less than 10,000 MWh annually and not more than the customer's annual expected energy usage. The rider applies to customers who wish to achieve environmental sustainability goals by purchasing from BPU exclusive EAs associated with renewable energy that is either from facilities owned by BPU or procured by BPU through a Purchased Power Agreement (PPA).

Q. Please explain the changes made to Energy Rate Component Rider (ERC).

A. The BPU's current rate manual includes an Energy Rate Component (ERC) rider. The purpose of this rider is to provide for recovery of the Utility's power supply costs not recovered in the base monthly charges, with a reconciliation adjustment that provides for the treatment of over/under recoveries for each quarter period. Due to the volatile nature of power supply costs, which often puts pressure on a utility's cash balances, 1898 & Co. recommended creating a reserve fund tied directly to variable fuel and purchased power costs recovered in the ERC. In prior rate cases, if cash balances are declining due to the timing of cost recovery through ERC Rider, increasing operating cash funded through base rate increases was the only option for making up the temporary differences. Creation of an ERC Reserve eliminates that need. The overall level of rate increases will remain the same – the difference is if the ERC Reserve did not exist, base rate increases would need to be higher to make up the difference.

Q. Have you provided a copy of the proposed rates?

A. Yes. The proposed rates are provided as Appendix B to the Report (Exhibit CEB-1).

Q. Please provide a list of other Rate Manual changes.

A. The BPU Rate Manual consists of more than rates and includes items such as definitions of terms used in the Rate Manual and various adjustment factors as well as provisions applicable for rate schedules. The proposed changes include added definitions to ease administration of the Rate Manual.

V. Summary

Q. Please summarize your testimony.

A. Based on an overall base rate increase of 2.50% for the test period, the cost of service study indicates that the residential class requires an increase above the system average. The commercial classes – small, medium, large general, and large power service require lower than system average increases. The new rates are designed to track the cost of service study more closely as the charges move toward the unit costs from the cost of service study.

Q. Does this conclude your prepared direct testimony in this matter?

A. Yes, it does.