Jefferson County PUD

Jefferson County PUD
Electric Cost of Service and Rate Study

January 2017

Prepared by:

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January 16, 2017

Mr. Jim Parker
Jefferson County PUD
310 Four Corners Road
Port Townsend, WA 98368-9368

SUBJECT: Electric Cost of Service and Rate Study

Dear Jim:

Please find attached the final report on the electric cost of service and rate study prepared by EES Consulting, Inc. (EES). This study has been developed through the assistance of Jefferson County PUD (PUD) staff and has been performed in a manner consistent with generally accepted ratemaking practices. Furthermore, it is based upon information and records provided by the PUD to EES.

Thank you for the opportunity to assist the PUD. Please contact me directly if there are any questions about the report.

Very truly yours,

Gary

Gary Saleba
President

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Executive Summary

Jefferson County PUD ("PUD") retained EES Consulting, Inc. ("EES") to perform an electric cost of service and rate study as part of its ongoing efforts to maintain fiscally prudent and fair rates for its electric utility customers. The purpose of this report is to discuss the data inputs, assumptions and results that were part of developing the rate study.

A comprehensive rate study generally consists of three separate, yet interrelated analyses. These three analyses are revenue requirement, cost of service, and rate design.

Revenue Requirement

A revenue requirement analysis compares the overall revenues of the utility to its expenses and helps determine the overall adjustment to rate levels that is required. For this analysis, a "cash basis" method was used for determining the PUD's revenue requirement. Annual operating expenses for calendar year (CY) 2015 were used to determine the revenue requirement by account as well as the 2017 budget forecast provided by the PUD.

A base case was defined to develop the COSA. This base case assumed the following:

- Historic year for costs is CY 2015.
- Historic year for loads is CY 2015.
- Test year for the revenue requirements is the budget for CY 2017.
- Allocation uses the load data projected for 2017.
- The total system load forecast for CY 2016 through CY 2020 was based on projections provided by Bonneville Power Administration (BPA).
- Expenses were taken directly from the PUD's 2015 actual operating expenses by account and the 2016 and 2017 budgets. Expenses for 2018-2020 were forecast assuming an average annual escalation rate of 2.5% per year for costs that were not fixed.
- Power supply costs are based on 100% purchases from BPA at forecasted rates.
- Revenues are calculated using current rates and billing determinants.
- Capital improvement projects are assumed to be fully-funded by retail rate revenues or reserve funds (no new debt).

Looking at the CY 2017 period, revenues are expected to be $31.6 million, while expenses are projected to be $34.9 million. This results in a 10.4% or $3.3 million deficit in retail rate revenues if all capital projects were funded from rates. As the PUD has the ability to fund a portion of its $3.7 capital budget from reserves, proposed rates would include a 6.6% increase allowing $2.4 million to be funded by rates and the remaining $1.4 million to be funded from reserves. This level of rate increase would result in a Debt Service Coverage Ratio of 1.4, which is a positive move towards financial stability.

In 2018 a 6.1% rate increase is proposed based on current projections. This would allow $3.6 million of CIP to be funded through rates and another $70,000 to be funded from reserves. Under this proposal the utility would meet a 1.6 Debt Service Coverage Ratio.

For 2019 and 2020, it is expected that much lower rate increases will be required to meet inflationary increases, including an expected BPA rate increase in October of 2019.

A summary of the draft cash basis revenue requirement is shown in Table 1.

Table 1
Summary of the Revenue Requirement
CY 2017-2020

Revenues	***2017***	***2018***	***2019***	***2020***
Present Rate Revenues	$31,577,158	$31,796,893	$31,878,911	$32,024,759
Other Income	$734,756	$753,125	$771,953	$791,252
Total Revenues	$32,311,914	$32,550,018	$32,650,864	$32,816,010
Expenses				
Generation	$15,733,023	$16,362,854	$16,678,667	$17,555,556
Transmission	$72,224	$74,030	$75,880	$77,777
Distribution	$4,665,767	$4,782,411	$4,901,971	$5,024,521
Customer Accounts and Services	$1,330,850	$1,364,121	$1,398,224	$1,433,180
Administration and General	$1,770,049	$1,814,300	$1,859,658	$1,906,149
Low Income Program	$500,000	$500,000	$500,000	$500,000
Capital Projects	$3,737,500	$4,447,500	$5,046,040	$5,046,040
Taxes	$1,918,186	$1,966,141	$2,015,294	$2,065,677
Interest and Debt Service	$5,986,760	$5,986,760	$5,986,760	$5,986,760
Total Expenses	$35,714,359	$37,298,117	$38,462,495	$39,595,659
Surplus (Deficiency) in Funds	-$3,402,445	-$4,748,099	-$5,811,631	-$6,779,649
Annual Required Increase (Decrease)	10.8%	4.2%	3.3%	2.9%
Proposed Increase (After Reserves)	6.6%	6.1%		

Note that using the reserve funds allows the overall rate increase to be lower as well as spreading the rate increase more equally between 2017 and 2018. The rate increase proposed for 2017 is expected to be implemented in two phases to lessen customer impacts over the winter months. In the first phase starting on January 1, 2017 the customer charges would be increased. On June 1, 2017 the demand and energy rates would be adjusted, including some simplification of the rates. Rates are proposed to increase again in June 2018 but any required changes will be reviewed in light of the financial circumstances at the time.

Cost of Service Study

A cost of service analysis (COSA) is concerned with the equitable allocation of the revenue requirement to the various customer classes of service. As is standard procedure for cost of service analyses, the revenue requirement for the PUD was functionalized, classified and allocated. Unlike most cost of service studies, costs were kept functionalized throughout the analysis which provides for greater transparency when reviewing results.

A COSA study can be performed using embedded costs or marginal costs. Embedded costs generally reflect the actual costs incurred by the utility and closely track the costs kept in its accounting records. Marginal costs reflect the cost associated with adding a new customer, and are based on costs of facilities and services if incurred at the present time. This study uses an embedded COSA as its standard methodology.

Generally, there are two methodologies that can be used to classify distribution costs: 100% demand and minimum system. The 100% demand methodology assumes that the distribution system is built to meet the non-coincident peak of customers. Therefore, distribution costs using this method are classified as 100% demand related.

Under the minimum system approach, specific distribution costs are split between demand and customer. This approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year. The concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers “demand” a delivery quantity greater than the minimum unit of electricity and that therefore, those costs should be treated as demand related. Because the residential class tends to have a higher share of the number of customers as compared to the share of non-coincident peak, the minimum system methodology tends to allocate more costs to the residential class and customer charges tend to be higher than with the 100% demand methodology. Demand-vs-customer allocations for the minimum system case were derived using data from the other Northwest public utilities.

Given a number of assumptions, the results show that using present rates, the PUD would be under-collecting revenues to meet allocation year costs. When examining the results, it is important to note that the inter-class cost allocation is based on load data estimates and usage pattern assumptions. Therefore, deviations of less than 10% from the cost of service typically do not warrant interclass rate modifications.

CY 2017 COSA results are summarized for the minimum system approach in Table 2 and for the 100% demand approach in Table 3.

Table 2
Summary of Cost of Service Analysis – Minimum System

	Present Rate Revenues	Net Revenue Requirement	Surplus/ (Deficiency) in Present Rates	Revenue to Cost Ratio	Adjusted Revenue to Cost Ratio
Residential 7	$20,318,884	$22,836,719	-$2,517,835	89.0%	98.3%
General Service 24	$4,226,868	$5,337,901	-$1,111,033	79.2%	87.5%
Small Demand 25	$2,019,432	$1,603,095	$416,337	126.0%	139.2%
Large Demand 26	$807,535	$629,624	$177,911	128.3%	141.7%
Primary 31	$912,375	$791,677	$120,698	115.2%	127.3%
Irrigation 29	$3,163	$6,596	-$3,433	47.9%	53.0%
Interruptible Schools 43	$447,287	$656,120	-$208,833	68.2%	75.3%
Street & Hwy Lighting	$155,712	$216,310	-$60,599	72.0%	79.5%
PTP	$2,733,002	$2,854,817	-$121,815	95.7%	105.7%
TOTAL	$31,624,257	$34,914,759	-$3,308,604	90.6%	100.0%

Table 3
Summary of Cost of Service Analysis – 100% Demand

	Present Rate Revenues	Net Revenue Requirement	Surplus/ (Deficiency) in Present Rates	Revenue to Cost Ratio	Adjusted Revenue to Cost Ratio
Residential 7	$20,318,884	$22,484,187	-$2,165,303	90.4%	99.8%
General Service 24	$4,226,868	$5,383,275	-$1,156,407	78.5%	86.7%
Small Demand 25	$2,019,432	$1,699,852	$319,579	118.8%	131.2%
Large Demand 26	$807,535	$670,192	$137,342	120.5%	133.0%
Primary 31	$912,375	$875,981	$36,394	104.2%	115.0%
Irrigation 29	$3,163	$7,168	-$4,005	44.1%	48.7%
Interruptible Schools 43	$447,287	$733,973	-$286,686	60.9%	67.3%
Street & Hwy Lighting	$155,712	$205,431	-$49,719	75.8%	83.7%
PTP	$2,733,002	$2,854,700	-$121,698	95.7%	105.7%
TOTAL	$31,624,257	$34,914,759	-$3,308,604	90.6%	100.0%

The revenue to cost ratios show how much each class is paying relative to its allocated costs. Because the 2017 revenues fall short of the budget, the *adjusted* revenue to cost ratios show the results as if the total system was collecting sufficient revenues. The adjusted revenue to cost ratios are a better indicator of whether or not each class is paying its fair share of the costs of the utility.

In both cases, the results show that the residential class is paying close to 100% of its costs. The small general service (Rate 24) is paying below 90% of its cost and should receive an above average increase at some point. The various large general service/commercial classes are all paying more than their cost of service and should at some point receive either a rate decrease or rate increases less than the average for the utility. There is some difference in the general service/commercial levels when comparing the results under the minimum system and 100% demand approach.

The irrigation and lighting classes are both well below their cost of service, however, these classes are more difficult to model within a COSA as their loads are not typical. The interruptible school class is paying 67 to 75% of its cost of service and should see a rate increase in the future. While the value of the interruptibility has not been incorporated in the COSA, there is little value to the PUD with BPA purchases for all of the PUD's power supply. This differs from the situation for PSE, where substantial costs could be avoided due to their resource mix.

Finally, the revenues collected from PTP are recovering roughly 100% of the costs to serve the customer.

There is an inherent uncertainty associated with any COSA due to the uncertainty of peak loads by class and the differences in methods that can be used. Therefore the results should not be interpreted as providing a full and accurate detailed level of costs per customer class. The COSA should be used as an overall guideline to assist in designing rates, but rates do not necessarily need to exactly match the results of the COSA.

Rate Design

Rate design encompasses a multitude of considerations that often are somewhat removed from fundamental unit cost determinations. Issues such as appropriate price signals, potential impact of rate adjustments, ability to pay, intra-class subsidies etc., will ultimately influence the final approved rate structure.

Specific rate designs have been developed as part of this study and are included in the last section of this report. The rate proposal was reviewed and approved by the Board with minor adjustments. The approved rates and their impacts are discussed in that later section.

In general, the approved rates include increases to the basic charges in January of 2017. This is followed by increases in the demand and energy charges in June of 2017. Also in June, changes will be made to simplify the rates, including the elimination of seasonal differences, block demand charges and declining block energy charges. The inverted block rate for the Residential class is maintained and demand charges will apply to all kW, not just the amount over 50 kW.

For the utility as a whole, the rate increase will reflect a 6.6% increase in revenues for the entire year. Rate increases in January range from 0% to 7% by customer class while the June increases range from 0% to 10%. When the entire year is accounted for, the increase in revenues by class ranges from 5.5% to 10%.

Rate changes for 2018 were recommended to the utility but they have not yet been approved. They are included in this report for completeness and as a starting point for 2018. But a rate proposal for 2018 will need to reflect actual sales and revenues over the next year, budgets for 2018 and customer response to the 2017 rate changes. The combined 2-year rate increase is designed to be roughly 11% for most of the rate classes.

Overview of Rate Setting Principles

EES Consulting, Inc. ("EES") was retained by Jefferson County PUD ("PUD") to perform a comprehensive electric cost of service and rate study. Performing an electric rate study is necessary to assure that the PUD's rates continue to recover the cost of operations and are structured to be fair, equitable and competitive.

In conducting this study, three inter-related analyses were performed. The first analysis performed was a revenue requirement analysis. This analysis examines the various sources and applications of funds for the utility and determines the overall revenue (retail rate) adjustment required of the utility. The next analysis developed is a cost of service analysis. The cost of service analysis is used to determine the fair and equitable allocation of the total revenue requirement to the various customer classes of service. The report concludes with a discussion of the rate design options available to the PUD and the unit cost output from the cost of service analysis.

Overview and Organization of Report

In developing electric rates for the PUD, a major goal of the study is to develop cost-based rates that meet the PUD's revenue requirement needs. It is important to understand that revenue requirement consists of both operational expenses and capital costs. Failure to collect the full revenue requirement may lead to a system that is more expensive to operate in the long run, and more susceptible to periodic outages and failures.

This report is organized such that it follows the steps taken in analyzing and developing the PUD's cost of service. Contained in this section is a generic discussion of the theory and financial principles behind setting rates. This is followed by a section discussing the development of the revenue requirement analysis for the PUD. The following section discusses the cost of service study and the results of that process. This is followed by an update on recent events at BPA. Finally, rate design options are discussed.

A technical appendix is attached at the end of this report that details the various analyses using the minimum system and 100% demand methodologies to classify distribution costs. The schedules contained in the technical appendix are referenced throughout the report.

The setting of electric utility rates that are "fair and equitable" is a complex process. This process is directed, however, by "generally accepted methodologies" that can be used as a guide in developing the PUD's electric rates. At the same time, there are often a number of financial principles or guidelines that must be taken into consideration during this process. Therefore, the setting of electric rates that are "fair and equitable" is an integration of these generally accepted methodologies and any related financial policies or specific considerations from the PUD.

The purpose of this section of the report is to provide a brief overview of the basic fundamentals of cost identification and allocation for purposes of developing electric rates. From this base-level of knowledge, more insight and understanding can be obtained from the following sections of the report that discuss the specifics of the review of the PUD's allocated costs.

Overview of the Analyses

As discussed previously, there are a number of "generally accepted methodologies" for allocating costs for ratemaking purposes. However, all of these methodologies share the same basic framework. That is, in allocating electric costs two separate yet interrelated analyses are generally performed. It is within these two separate analyses that different methodologies exist. The two analyses contained within the basic framework for allocating electric costs are revenue requirement analysis and cost of service analysis.

The revenue requirement analysis reviews the various sources of funds and applications of funds for the utility. For purposes of this report, only the PUD's application of funds is reviewed.

Within the next step of the study, the cost of service analysis takes the results of the revenue requirement analysis and attempts to equitably allocate those costs to the various customer classes of service (e.g., residential, commercial, etc.). This analysis provides a determination of the level of revenue responsibility of each class of service and the adjustments required to meet the cost of service.

Types of Utilities

As noted above, there are different methodologies that exist for setting electric rates. The first distinction often made in developing a methodology is the type of utility that is attempting to set the rates. Utilities are generally divided into two types by ownership—public and private utilities.

Public utilities are generally owned by a municipality, cooperative, county, or special district and are operated on a not-for-profit basis. Public utilities are generally capitalized by issuing debt and soliciting funds from customers through direct capital contributions or user rates. Through statute and/or the lack of profit motive, public utilities do not pay state and federal income taxes. Finally, a public utility is usually regulated by a publicly elected or appointed City Council, Board of Commissioners, or Board of Trustees. As a point of reference, the PUD is a public utility regulated by a Board of Commissioners.

In contrast, private electric utilities are capitalized by issuing debt or equity (stock) to the general public. The owners of the private utility are its equity contributors, or shareholders. Private utilities are taxable entities, and finally, they are generally regulated by state public utility commissions. Puget Sound Energy (PSE) is an example of a private electric utility.

These differences in ownership and other characteristics often lead to two different methods for reviewing revenue requirement needs. A more detailed discussion of the different methodologies that may be used is provided below.

Overview of Revenue Requirement Methodologies

By virtue of differences noted above for a public versus a private utility, their revenue requirements are based upon different elements or methodologies. Most private utilities use what is known as a "utility" or "accrual" basis of determining revenue requirement or setting rate levels. This convention calculates a utility's annual revenue requirement by aggregating a period's operation and maintenance (O&M) expenses, taxes, depreciation expense, and a "fair" return on investment. Operating expenses include the labor, materials, supplies, etc., that are needed to keep the utility functioning. Private utilities must also pay state and federal income taxes, along with any applicable property, franchise, sales or other forms of taxes. Next, depreciation expense is a means of recouping the cost of capital facilities over the useful lives of those facilities and also a means of generating internal cash. Finally, a return on the capital invested pays for the utility's interest expense on indebtedness, provides funds for a return to the utility's equity holders in the form of dividends, and leaves a balance for retained earnings and cash flow purposes. Electric cooperatives often use the accrual method and substitute operating margins for a rate of return in the revenue requirement.

In contrast to the "utility" or "accrual" method of developing revenue requirement for private utilities, a different method of determining annual revenue requirement is often used for public utilities. The convention used by most public utilities is called the "cash basis" of cost accounting. As the name implies, a public utility aggregates its cash expenditures to determine its total revenue requirement for a specified period of time. This methodology conforms nicely to most public utility budgetary processes, and is a very straightforward and easily understood calculation. While this method is most often used by public/people's utility districts, this method does not always conform to electric cooperative budgetary processes.

Under the "cash basis" approach, there are four component costs. They are operation and maintenance expenses, taxes, debt service, and capital improvements funded from rates. The operating portion of the revenue requirement, i.e., O&M and taxes, are similar under either methodology. The major difference between the two methodologies is the way in which capital costs are viewed and handled. Capital costs under the cash basis approach are calculated by adding debt service to capital improvements financed with rate revenues. A utility's depreciation expense is often used as a measure of the reasonable level of funding required from rates for capital improvement activities. Depreciation expense represents the current investment of the utility and that portion that has become worn out or obsolete and must be renewed or replaced. It should further be noted that the two portions of the capital expense component are necessary under the cash basis approach because utilities often cannot finance all capital facilities with long-term debt.

Table 4 compares the cash and utility accounting conventions.

Table 4 Cash vs. Utility Basis Comparison			
	Cash Basis		**Utility (Accrual) Basis**
+	O&M Expense	+	O&M Expense
+	Taxes	+	Taxes
+	Capital Improvements Financed with Operating Revenues (Depreciation Expense)	+	Depreciation Expense
+	Debt Service (Principal & Interest)	+	Return on Investment (Interest + Margin)
Σ	= Revenue Requirement	Σ	= Revenue Requirement

For this study, a cash basis was used to determine the PUD's revenue requirement because this method conforms to the PUD's budgetary processes. The accrual basis is also included in the COSA model and was reviewed to provide assurance that the utility's financial health is satisfactory under both methodologies.

Overview of Cost Allocation Procedures

After the total revenue requirement has been determined, it is allocated to the various customer classes of service based upon a fair and equitable methodology that reflects the cost-causal relationships for the production and delivery of the services. This analytical exercise usually takes the form of a "cost-of-service" study. A cost of service study begins by "functionalizing" a utility's revenue requirement as power supply, transmission, distribution and customer. Next, the functionalized costs are "classified" to demand-, energy-, and customer-related component costs. Demand related costs are those that the utility incurs to meet a customer's maximum instantaneous usage requirement, and is usually measured in kilowatts (kW). Energy related costs are those that vary directly with longer periods of consumption and are usually measured in kilowatt-hours (kWh). Customer related costs are those that vary with the number and type of customers served. These three component costs are then "allocated" to each class of service based upon the most equitable method available for each specific cost. At that point, the revenue requirement has been allocated to each class of service and a determination of the necessary revenue adjustments between classes of service can be made.

Rate Design and Economic Theory

The final step in the rate study process is to design rates for each class of service taking into consideration the results of the revenue requirement and cost of service analysis. Rates can take many forms, but ultimately they should reflect the component costs that the utility incurs (demand, energy and customer related costs), and collect the desired level of revenues. Industry restructuring requires a greater level of detail to be provided in rates. This creates the need to rethink traditional methods of rate design, including unbundling of rates.

The process of developing competitive rate designs in a restructured environment will require greater consideration of fundamental economic and pricing theories. For example, economic theory dictates that, in a competitive market, the price of a commodity must roughly equal its cost, if equity among customers is to be maintained. The electric industry, however, has been a monopoly since its inception over 100 years ago and the concept of a competitive market was only in the minds of regulators who attempted to establish rates that were fair and equitable.

Competitive power markets have allowed some retail customers to investigate, as well as access, alternative power suppliers in direct competition with the utility for the business of supplying power to them. Traditional rate designs using time-of-day, seasonal or marginal cost-based utility rates were originally developed primarily to provide more accurate price signals for the cost of power supply. However, new rate designs for a competitive power supply need to be more detailed than in the past. The utility, in designing power supply rates, will need to take into consideration the characteristics of the power supply it acquires, as well as the characteristics of the customer to whom the utility will sell, as the utility will need to match the quality, quantity and price of the market alternative over some period of time.

While the power supply portion of the electric industry may be open to competition for retail customers, the transmission and distribution of that electricity is not. Thus, a customer may be faced with options for power supply but will still be required to purchase wires service from the local utility. The wires cost component is fixed and does not vary with usage, although distribution system investment does vary with the number of customers. These factors must be given consideration in designing rates if the utility is to recover its costs. Consumers will also need more accurate price signals that reflect the true cost of electricity production and delivery.

Providing greater detail in rate design will not come without cost or without some degree of effort. It will require greater refinement, not only of costing and pricing techniques, but of scheduling, billing, metering and other services as well. However, the result should be more accurate price signals that reflect the true cost of electricity production and delivery, greater efficiency in the marketplace, and overall savings to customers of power services.

These basic tenets have considerable foundation in economic literature and in today's competitive electric utility environment. They also serve as primary guidelines for rate design, and are used by most utility regulators and administrative agencies. This "price-equals-cost" concept will provide the basis for much of the subsequent analysis and comment.

Development of the Revenue Requirement

This section of the report presents the development of the electric revenue requirement for the PUD. Simply stated, a revenue requirement analysis compares the overall revenues of the utility to its expenses and determines the overall adjustment to rate levels that is required.

Overview of the PUD's Revenue Requirement Methodology

In developing the revenue requirement, a number of decisions must be made regarding the basic methodology to be used. As discussed in the previous section of the report, the first decision the PUD must make is the method of accumulating costs. The PUD utilized the "cash basis" approach for determining revenue requirement. In summary form, the PUD's components to its revenue requirement include the elements shown in Table 5.

Table 5
Elements of an Cash Basis Revenue Requirement

+	Operation and Maintenance Expenses (O&M)	
	✓	Power Supply Expense
	✓	Transmission Expense
	✓	Distribution Expense
	✓	Customer Accounting & Service Expenses
	✓	Administrative and General Expense
+	Capital Projects Funded From Rates	
+	Debt Service (Principal & Interest)	
+	Other Contributions	
+	Taxes	
	=	Total Revenue Requirement
	-	Miscellaneous Revenue Sources
Σ	=	Net Revenues Required From Rates

From this basic analytical framework, the next step in determining the revenue requirement methodology is to select a time period over which to review revenue and expenses. In the case of the PUD, a calendar year test period was utilized (January through December). CY 2017 was chosen as the test period for the cost of service study. The PUD provided actual costs for CY 2015 and budgeted cost projections for CY 2016 and CY 2017. Revenues from retail rates were calculated using present rates and projected loads. Purchased power costs were calculated based on BPA projected rates and the projected loads for the utility.

Development of the Projected Load Forecast and Forecast Revenues

Detailed load information is an underlying component of the COSA and is used for developing power supply costs, revenues and allocation factors. To develop detailed loads for the test year, actual loads for the CY 2015 period were used as the starting point. Loads were taken from the PUD's billing cycle information by customer class as well as the actual total system loads as measured on the BPA bills for the PUD. The load forecast for CY 2017 through CY 2020 was calculated based on total system loads as forecast for BPA. There was no growth expected for the lighting class and Port Townsend Paper (PTP).

The load forecast is a critical component to the COSA as it is the basis for cost allocation and design rates. A summary of the loads for the historic 2015 period can be seen on Schedule 1.7. Line losses were calculated using total system purchases and total customer sales for the 2015period. Primary line losses were assumed to be 2%, secondary line losses were assumed to be 3.9%. Load factors and coincident factors were determined using the calculated line losses and actual load data by customer class.

Forecast revenues at present rates were calculated for CY 2017 through CY 2020 using current retail rate schedules and forecast loads. Projected revenues from current rates are $31.6 million in CY 2017.

Development of Power Supply Costs

The PUD purchases wholesale power from the Bonneville Power Administration (BPA). More information on the contract with BPA can be found in a later section of this report. Currently, the PUD receives all of its wholesale power requirements from BPA. Total power supply costs are based on the PUD's forecast monthly energy consumption and peak demands multiplied by BPA's wholesale rates.

As with most electric utilities, the major expense associated with operating the utility is power supply. Approximately $15.7 million or 45% of the CY 2017 total utility revenue requirement are power supply costs.

The total purchased power requirements for the PUD are projected to be approximately 380.9 million kWh, or 43.5 average MW in CY 2017. For the time period reviewed in this study, the peak demand was expected to occur in December. Projected December peak demands are forecast at 98.6 MW in 2017. This results in an annual load factor of 44%. On a cost per kWh basis, power purchases would equal approximately 4.13 cents in CY 2017, 4.28 in CY 2018, 4.35 in CY 2019 and 4.56 in CY 2020. Total power supply costs are forecast to be $15.7 million in CY 2017, $16.4 million in CY 2018, $16.7 million in CY 2019 and $17.6 million in CY 2020.

Other Operations and Maintenance Expenses

The PUD's financial forecast was used for the development of non-purchased power related operations and maintenance (O&M) expenses. Budgeted operating costs were divided between transmission, distribution, customer service and accounting, administrative and general expenses categories through the revenue requirement development process.

Total O&M expenses are projected to be $23.6 million in CY 2017. Of this amount, non-power supply operating expenses are expected to be approximately $7.8 million in CY 2017, or 22% of total costs.

Taxes

Taxes are projected to be $1.9 million in CY 2017. This does not include the utility tax collected by the City of Port Townsend. That tax applies only to certain customers, and is added to the bill rather than included within the electric rate. Both the revenues and the expenses associated with that tax are excluded from the COSA as they balance to $0 and will not impact retail rates.

Debt Service Expense

The PUDs debt service obligation of $5.99 million in CY 2015 is included in the revenue requirement.

Capital Projects Funded From Rates

Capital Projects are projected to be $3.7 million in CY 2017. This entire amount was included in the revenue requirements for purposes of the COSA, however, it is expected that a portion of this will be paid from the PUD's reserve account. No new debt is planned to cover the CIP projections.

Miscellaneous Revenues

The PUD receives additional operating and non-operating revenues and contributions. These come in the form of rents, interest and dividend revenues, service revenues, and other revenues. The combined estimate of these revenue items is $735,000 in CY 2017. These other revenues are used to offset the revenue requirements as they are not part of the retail rate revenues developed within the COSA.

Summary of Revenue Requirement

Once all of the components of the cash basis revenue requirement have been forecast, the parts can be summed to equal the total revenue requirement. Since the PUD uses a "cash basis" approach for rate setting, the basic revenue requirement is presented in that format. A summary of the PUD's revenue requirement for the forecasted period can be seen summarized in Table 6.

Table 6
Summary of the Revenue Requirement
CY 2017-2020

Revenues	***2017***	***2018***	***2019***	***2020***
Present Rate Revenues	$31,577,158	$31,796,893	$31,878,911	$32,024,759
Expenses				
Generation	$15,733,023	$16,362,854	$16,678,667	$17,555,556
Transmission	$72,224	$74,030	$75,880	$77,777
Distribution	$4,665,767	$4,782,411	$4,901,971	$5,024,521
Customer Accounts and Services	$1,330,850	$1,364,121	$1,398,224	$1,433,180
Administration and General	$1,770,049	$1,814,300	$1,859,658	$1,906,149
Low Income Funding	$500,000	$500,000	$500,000	$500,000
Taxes	$1,918,186	$1,966,141	$2,015,294	$2,065,677
Interest and Debt Service	$5,986,760	$5,986,760	$5,986,760	$5,986,760
Capital Funded from Rates	$3,737,500	$4,447,500	$5,046,040	$5,046,040
Other Revenues	-$734,756	-$753,125	-$771,953	-$791,252
Total Expenses	$34,979,603	$36,544,992	$37,690,542	$38,804,407
Surplus (Deficiency) in Funds	-$3,402,445	-$4,748,099	-$5,811,631	-$6,779,649
Total Required Increase (Decrease)	10.8%	14.9%	18.2%	21.2%
Incremental Increase per Year	10.8%	4.2%	3.3%	2.9%

Projected CY 2017 costs are provided in Schedule 3.1. The PUD's revenue requirement allocated to customer classes can be found in Schedule 3.4.

Recommendation

The PUD has not had a rate increase since the time of its inception. This was an important step in meeting the expectations that rates would not increase significantly as a result of the acquisition. The PUD has a rate increase from BPA coming in October of 2017 and is planning on increasing staffing and spending capital to better maintain and improve the current system. These pressures have led to the need for a rate increase for the coming year. Not that PSE rates have increased over this time period and are expected to increase more over the next few years.

Looking at the CY 2017 period, revenues are expected to be $31.6 million, while expenses are projected to be $35.0 million. This results in a 10.8% or $3.4 million deficit in retail rate revenues if all capital projects were funded from rates. As the PUD has the ability to fund a portion of its $3.7 capital budget from reserves, it was determined that $ 2.37 million of CIP be funded from rates and $1.36 million be funded from reserves. This results in the need for a 6.6% rate increase for the year. Having a rate increase and funding a large share of the CIP from rates allows the utility to achieve a projected Debt Service Coverage (DSC) ratio of 1.4. This is necessary to meet borrowing requirements and provide financial stability.

Because the shortfall in revenues is partially offset by reserve funds, the rate increase in 2017 is lower than the required 10.8%. This means that in 2018 the shortfall in revenues will be greater than shown in Table 6. At the current time it is recommended that close to $100,000 of reserves should be used and that $4.45 million of CIP for 2018 should be funded from rates. This would result in a rate increase of 6.1% for the year and a DSC of 1.6. By spreading out the rate increases more evenly over 2017 and 2018, customers see a more moderate impact and the customer increases its financial stability over time.

Given current projections, the rate increases for 2019 and 2020 would be in the range of 3% per year which tracks more closely with inflation.

It is important to note that the PUD's current revenue to cost balance needs to be continually monitored. Both short and long term supply and operating cost considerations need to be evaluated and analyzed as the Board of Commissioners works with the PUD's management to reach its operating objectives.

Cost of Service Analysis

The objective of the cost of service analysis (COSA) is to analyze costs and equitably assign those costs to customers commensurate with the cost of serving those customers. The founding principal of cost allocation is the concept of cost-causation. Cost-causation evaluates which customer or group of customers causes the utility to incur certain costs by linking system facility investments and operating costs to serve certain facilities to the services used by different customers. This section of the report will discuss the general approach used to apportion the utility's cost of service, and provide a summary of the results.

COSA Definition and General Principles

A COSA study allocates the costs of providing utility service to the various customer classes served by the utility based upon the cost-causal relationship associated with specific expense items. This approach is taken to develop a fair and equitable designation of costs to each customer class, where customers pay for the costs that they incur. Because the majority of costs are not incurred by any one type of customer, the COSA becomes an exercise in spreading joint and common costs among the various classes using factors appropriate to each type of expense. The COSA is the second step in a traditional three-step process for developing service rates. The first step is the development of the test period revenue requirement for the utility, which is the starting input for the COSA. The COSA spreads the revenue requirement across the various customer classes, creating per unit costs by class. In the third step, rates are designed for each customer class, with per unit costs being one consideration in setting the appropriate rate levels.

A COSA study can be performed using embedded costs or marginal costs. Embedded costs generally reflect the actual costs incurred by the utility and closely track the costs kept in its accounting records. Marginal costs reflect the cost associated with adding a new customer, and are based on costs of facilities and services if incurred at the present time. While marginal costs can be valuable for designing rates in certain instances, marginal costs are generally higher than embedded costs. Therefore, the use of a marginal COSA study usually requires that all costs be scaled back to a level equal to the embedded cost revenue requirement established using actual or projected costs from an "accounting" perspective.

This study uses an embedded COSA as its standard methodology. Therefore, the PUD's embedded cost revenue requirement and existing rate base investment are used in developing the COSA results.

There are three basic steps to follow in developing a COSA, namely:

- Functionalization
- Classification
- Allocation

Functionalization separates costs into major categories that reflect the utility's plant investment and different services provided to customers. The primary functional categories are production, transmission, distribution, and general.

Classification determines the portion of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related, or customer-related. Production costs are related to supplying and transporting power to customers on the system. Transmission costs are related to the bulk transfer of power throughout the system, which is designed to meet the peak demand requirement. The distribution system is designed to extend service to all customers attached to the system and to meet the peak load capacity requirement of each customer. Additionally, costs can be classified based on system revenues or directly assigned to a customer or group of customers.

Allocation of costs to specific customer classes is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the particular measurement of system demand, whether coincident peak, non-coincident peak or some variation determined to be appropriate for the particular cost item. An analysis of customer requirement, loads, and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records, customer load data, and special studies.

General Ratemaking Principles

While this section does not address the design of rates, it is important to note that the COSA results will be one of the considerations when the process of designing rates for various customer classes begins. The basic goals of rate design include:

- The utility's ability to collect the appropriate revenue requirement
- Utility revenues and customer rates are stable and predictable
- Proper price signals are sent to create efficiency of resources
- Rates are fair and equitable among customers and avoid undue discrimination
- Rates are simple, easy to understand and feasible for the utility to implement

The COSA is generally used to assist in meeting the second and fourth goals of rate design. Price signals are best if they reflect the specific costs incurred. Rates are generally considered fair and equitable if customers are deemed to pay their share of the costs incurred by the utility. Additionally the first goal is met as long as the COSA is based on the appropriate revenue requirement, and the use of a consistent COSA methodology contributes towards the second goal. Rates are more stable through time if the COSA methodology is not significantly changed every time a rate application is made.

Functionalization of Costs

The first step in the COSA process following finalization of the revenue requirement is to functionalize the revenue requirement. Functionalization is the separation of cost data into the functional activities performed in the operation of a utility system (i.e., power supply, transmission, distribution and customer service). Functionalization was accomplished using the PUD's system of accounts, which largely segregates costs in this manner.

In addition to the functionalized costs, certain joint costs are spread to each functional category based on the relationship of the joint cost to the business function. These joint costs include such items as administrative and general costs.

Standard Functionalization Method

Plant investment costs or rate base are generally functionalized into production, transmission, distribution and general cost categories. The functionalization of rate base typically is very straightforward as costs for the different functions are readily identifiable and rate base accounts are maintained by functional categories.

Expense accounts are also typically kept according to these basic functional categories, with expense items associated with certain types of plant being treated in the same manner as the corresponding plant account.

The two areas where there generally are differences in functionalization among utilities are in the treatment of general plant and A&G expenses. Typically, general plant is considered a separate functional category. Some utilities, when their internal accounting systems can support such an assignment process, will record general plant investment by loading the costs into the other functional categories, much like an overhead assignment or a form of activity based accounting.

On the expense side, A&G costs can be treated in much the same way. Generally, they are treated as a separate expense category that can be spread to functions based upon all other O&M expenses. However, they can also be spread to functions on the basis of total net plant, labor ratios, or, in some cases, directly assigned as part of the activity based accounting approach.

Jefferson County PUD Functionalization Method

The specific functions used for the PUD's COSA are defined below. The functions generally follow standard cost of service approaches.

- ***Power Supply*.** The power supply function category includes all power-related services that are obtained by the utility through direct purchase. Where a utility does not produce power, the purchase activity represents a form of supply acquisition activity.
- ***Transmission*.** The transmission services that the PUD must acquire to deliver the purchased power supply to the service area are included in purchased power costs. The costs associated with the distribution system's transmission service include only those

costs for operating and maintaining the transmission lines, poles, towers, substations, etc., used to deliver power to the distribution network.

- ***Distribution*.** Distribution services include all services required to move the electricity from the point of interconnection between the transmission system and the distribution system to the end user of the power. These include substations, primary and secondary poles and conductors, line transformers, services and meters as well as customer costs and any direct assignment items.
- ***Customer.*** Customer related services include all services related to the presence of customers on the system, not to customer usage. These services include meter reading, billing, collections, advertising, etc.

Classification of Costs

The second step in performing a cost of service study is to classify the functionalized expenses to traditional cost causation categories. These cost causation categories can be directly related to specific consumption behavior or system configuration measurements such as coincident peak (CP) or non-coincident peak (NCP) demand, energy, or number of customers. Each classification category will have a specific allocator that, when applied, will distribute those costs among the appropriate customer classes during the allocation phase of the analysis.

Functionalized power purchases, storage and transmission system costs are classified as demand-related and/or energy-related and in some instances directly assigned, while distribution costs are classified as demand or customer-related, or directly assigned to specific customer classes of service.

Standard Classification Method

The three most general classification categories are demand-related, energy/commodity-related and customer-related. Within these three categories there are multiple ways of defining each option as well as varying ways to split costs between two or more classifiers. For example, demand and energy-related costs can be separated by seasonal distinctions as well as to reflect peak/off peak consumption periods. Customer related costs could be separated by demand and customer categories, while customer categories can distinguish between actual customer and weighted customer characteristics. Other classifiers sometimes used in the process include revenue-related and direct assignment. In addition, there are many instances where costs are not specifically classified to a particular category but rather in the same manner as an individual cost account or subtotal of specific cost accounts.

Generally, power production and purchased power costs are classified by a combination of demand and energy. Transmission costs are generally classified as peak demand, while distribution costs are generally split between demand and customer.

Generally there are two methodologies that can be used to classify distribution costs: 100% demand and minimum system. The 100% demand methodology assumes that the distribution system is built to meet the non-coincident peak. Therefore, distribution costs are classified as 100% demand related. Specific distribution costs are sometimes split between demand and customer according to a minimum system approach. This approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year. The concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers "demand" a delivery quantity greater than the minimum unit of electricity and that therefore, those costs should be treated as demand related. Because the residential class tends to have a higher share of the number of customers as compared to the share of non-coincident peak, the minimum system methodology tends to allocate more costs to the residential customer class and customer charges tend to be higher than with the 100% demand methodology.

The process of cost classification is the area within the COSA that can create considerable cost variability between customer classes due to differences in system configurations, demand measurements and assignment philosophy. The complexity of the entire COSA process is further compounded since, in some cases, the classification category is clear but the specific allocator is not. For example, a particular cost item may clearly be peak demand-related but that demand can be measured as either a single coincident peak for the year, a 2 CP approach to reflect seasonal considerations, the sum of 12 monthly coincident peaks, or through some other approach such as "Average & Excess."

Jefferson County PUD Classification Method

The following are the specific classifiers used in the PUD's COSA within each of the four functions (power supply, transmission, distribution and customer):

- Power Supply

  Classifying power supply costs to demand and energy (commodity) components requires the evaluation of a number of complex, interrelated factors. Consideration must be given to what or who caused the power supply purchase to be made, and to the uses to which it will be put (i.e., meeting demand and energy requirement). Within this study, power supply costs are classified to demand and energy based on the PUD's power cost forecast for the test period. The specific classifiers used for the power supply function include:

  - Energy
  - Demand

  Energy related costs are those that vary with the total amount of electricity consumed by a customer. Electricity usage measured in kWh is used in this portion of the analysis as well. Energy costs are the costs of consumption over a specified period of time, such as a month or year. The PUD purchases power requirements from BPA via a load following contract. As a load following customer of BPA, the PUD pays a fixed monthly charge for their share of energy and demand, load following charges/credits to account for the difference between utility monthly load shape and power supply, and demand charges on a portion of the PUD's peak demand. For this study, the fixed monthly charge is allocated to customer classes based on energy.

Demand related costs are those that vary with the maximum demand or the maximum rates of power supply to customer classes. Customer and system demands for this analysis were measured in kW. Demand costs are generally related to the size of facilities needed to meet a customer's maximum demand at any point in time.

Within this study, demand costs were further classified as either:

- Coincident peak demand (CP)
- Non-coincident peak demand (NCP)

Coincident peak demand refers to the demand placed upon the system by each customer at the time of the system maximum peak and is generally related to meeting power supply or transmission peak requirements. The non-coincident peak demand refers to the sum of the individual customer peak demands regardless of the time of occurrence. The sizing and corresponding expenses associated with distribution lines, which are sized to meet the specific individual customer demands for a limited geographic area within the utility's service territory, are examples of non-coincident demand costs.

For this analysis, consumption statistics are reported as either demand (kW) or energy (kWh). Reported energy consumption reflects monthly-metered customer consumption by class. For classes that are not billed or metered on measured demand, demand information was derived based on an association between energy consumption, days within the particular month and class load factor assumptions that convert each class's consumption profile into NCP demand estimates. From those NCP determinations, customer class CP demand values were derived such that when the peak month CP values of all the various classes are summed, they match the PUD's maximum system peak metered at its interconnection with the regional transmission system. The CP and related NCP values developed within the COSA are later used to allocate demand related costs to the customer classes examined within the analysis.

- Transmission

  The transmission function includes the utility's owned transmission assets associated with providing power to the PUD's distribution system. BPA transmission costs are included in power supply costs. The costs associated with the local utility's transmission service include only those costs for operating and maintaining the transmission lines, poles, towers, substations, etc. used to deliver power to the distribution network. The cost of providing transmission service to a customer is considered to be directly proportional to the demand that customer imposes on the system.

- Distribution

  Distribution services include all services required to get energy supply from the point of interconnection between the transmission system and the utility's service area to the end user of the power. Classifying distribution costs requires a special analysis of the nature of the costs. Most distribution costs are split between demand and customer components. The demand component is the cost of facilities built to serve a particular load, such as distribution substations. The customer component is the cost of facilities that varies with the number of customers, such as meters. The following are the specific classifiers used for the distribution function:

- Non-coincident peak demand (NCP) on Primary System
- NCP on Secondary System
- Actual Customer
- Customers Weighted for Acct/Meter Reading
- Direct Assignment

The minimum system analysis is used to determine the lowest level of plant investment required to serve a utility's customers compared to the actual facilities in place to meet varying customer demands. A standard split of 40% customer and 60% demand was used for the PUD. With a relatively uniform customer base and a low percentage of industrial customers, a greater portion of costs are classified as customer related relative to demand under a minimum system approach to allocating costs. Using a "100% demand" classification approach assumes that distribution investment is based entirely on meeting the non-coincident peak demand.

- Customer

Customer related services include all services related to the presence of customers on the system, not to customer usage. These services include meter reading, billing, collections, advertising, etc. Customer related costs vary with the number and type of customers. They do not vary with system supply levels. These costs are sometimes referred to as "readiness to serve" or "availability" charges. Customer costs are incurred by the utility to have electricity supply readily available for a customer whether it is utilized or not.

There are two types of customer related cost classification categories—actual and weighted. Actual customer costs vary proportionally with the addition or deletion of a customer, regardless of the size or usage characteristics of the customer. An example of an actual customer related cost is postage on customer bills. The cost of postage does not vary regardless of the type or size of customer or usage levels. In contrast, a weighted customer cost reflects a disproportionate cost attributable to the addition or deletion of a customer. An example of weighted customer costs is meter-reading expenses. In some cases, it takes less time and effort to read a residential energy meter than it does to serve a large commercial customer that also has a demand meter. This type of difference is accounted for in the weighted customer allocation factors.

The specific classification of costs by account can be found in Schedule 3.3.

- Direct Assignment

  Some costs can be directly assigned to certain customer classes without being classified as demand, energy, or customer related. These are generally costs associated with specific services, such as dedicated capital facilities, or with specific customer classes, such as lighting customers. Schedule 3.5 provides the background information for all direct assigned costs. Approximately $67,000 in annual distribution operation and maintenance costs are directly assigned to the street lighting and security lights customer classes.

Allocation of Costs

The third step in performing a cost of service study is the allocation of the utility's total functionalized and classified revenue requirement to the customer classes of service. This is performed through the application of an appropriate allocation methodology.

In general, the allocation of costs is straightforward once the costs have been classified to a specific category.

The following are the specific allocation methods, some of which are used in the PUD's COSA. The specific method of cost allocation by customer can be found in Schedule 3.1.

- Demand Allocation Factors. For purposes of this study, five types of demand allocation factors were developed.

  - *Non-coincident peak demand allocation factor (NCP).* First, a non-coincident peak demand allocation factor was developed for each customer class. Expenses classified and allocated by the non-coincident peak demand allocation factor included those predicated on maximum demands such as distribution substations, and a portion of poles and lines, mains, meters and services. The NCP demand method allocates costs to each class of service based upon their highest individual non-coincident peak demand regardless of the time of occurrence. The NCP allocation factor is used to allocate distribution.

  - *1 Coincident peak (1 CP).* For each class of service, a contribution to a single annual system coincident peak was derived from the non-coincident peak by use of a coincidence factor. This coincident peak demand allocation method is referred to as the single coincident peak (1 CP) method. The 1 CP method allocates demand costs on the basis of a single demand value at the time of the system peak demand by each class. Expenses allocated on the 1 CP allocation factor include those related to the PUD's transmission system. The 1 CP allocation method is not used in this study.

  - *Sum of the two months coincident peaks (2 CP).* For each class of service, a contribution to a seasonal system coincident peak was also derived from the non-coincident peak by use of a coincidence factor. The coincident peak demand allocation method used was the sum of the summer and winter coincident peaks (2

CP) method. The 2 CP method allocates demand costs on the basis of the sum of the contributions to seasonal system peak demands by each class. The 2 CP method was not used in this study.

- *Sum of monthly coincident peak (12 CP).* As with the 1 CP calculation, a contribution to monthly system coincident peaks was derived from the non-coincident peak by use of a coincidence factor. This coincident peak demand allocation method is referred to as the sum of the monthly coincident peak (12 CP) method. The 12 CP method allocates demand costs on the basis of demand value at the time of the system peak demand in each month by each class. As discussed previously, the 12 CP method is used for power supply costs and transmission costs.
- *Average and excess method (A&E).* The average and excess method represents an alternative approach to CP related cost allocation. The A&E method compares a customer class's average demand against its maximum NCP demand in order to reflect, the classes *potential* peak demand volatility, and therefore its inherent ability to increase system peak requirement, that exists within each customer class. The A&E method was not used in this study.

- Energy Allocation Factors. Energy costs vary directly with consumption. Accordingly, energy allocation factors were based upon electricity sales for each class. Energy allocation factors were used to allocate power supply costs.
- Customer Allocation Factors. Two basic types of customer costs were identified—actual and weighted. The allocation factor for actual customers was derived from the actual number of customer served in each class of service. Two weighted customer allocation factors were also developed. The first weighted customer allocation factor considered the relative differences among the various customer classes of meter costs. The second weighted customer allocation factor considered the cost of customer accounting and meter reading by each rate class. Customer allocation factors were used to allocate some distribution costs such as meters and meter installations and costs associated with customer service, accounts, and sales.
- Rate Base Allocation. The value of the PUD's assets as of December 2015 is functionalized, classified and then allocated to customer classes. The resulting functionalized, classified and allocated rate base is then used to develop rate base allocation factors. These allocation factors (i.e., general plant, net plant, distribution rate base, etc.) are then used to allocate revenue requirement expenses. For example, maintenance of station equipment can be allocated using station equipment rate base, or property taxes might be allocated using net plant.
- Other Cost Allocation. Other costs are allocated based on specific rate base items, O&M function totals, revenues, labor ratios and other allocation factors. These other allocation factors were used to allocate administrative and general expense items, some other revenues such as dividend income or non-operating rental income.

The allocation factors shown in Schedule 3.1 are used to allocate costs by customer or by function using the percentages developed in Schedules 6.1 and 6.2.

- Administrative and General (A&G). All costs that are related to general overhead are classified to this area. Costs are allocated to customers based on their percentage of operation and maintenance expenses without power supply and A&G.

- Miscellaneous Other Revenues

  - ✓ Miscellaneous other revenues are generally allocated to customers based on allocation of all other O&M expenses without power supply and A&G.

Review of Customer Classes of Service

Customer classes of service refer to the arrangement of customers into groups that reflect common usage characteristics or facility requirement. The classes of service used within this study were as follows:

- Residential (Schedule 7 and 8)
- General Service (Schedule 24)
- Small Demand (Schedule 25)
- Large Demand (Schedule 26)
- Primary Service (Schedule 31)
- Irrigation (Schedule 29)
- Interruptible Schools (Schedule 43)
- Street Lighting
- Port Townsend Paper (PTP)

Major Assumptions of the Cost of Service Study

Major assumptions used in conducting the cost of service study for the PUD are as follows:

- Forecast calendar year 2017 was selected as the period for the allocation of costs within the cost of service study.
- The revenue requirement as outlined in Section 2 was used for the cost of service study.
- Purchased power was assigned to energy and demand based on BPA's rate structure.
- Distribution plant was classified based both on a "minimum system" approach (40% customer/60% demand) and a "100% demand" approach.
- Revenues are based on forecast loads and the PUD's current retail rates.
- Capital improvement projects are fully funded by retail rate revenues or reserves (no new debt).

Given these key assumptions, the cost of service analysis could be completed. Schedules 3.4 and 4.3 in the appendix show the functionalized and classified rate base and revenue requirement, allocated to each class of service.

Cost of Service Results

Given the above assumptions regarding the cost of service analysis, the various costs were classified and allocated to the customer classes of service. Table 7 shows the results of this analysis by function for the minimum system approach for allocation year 2017.

Table 7
Summary of Functionalized Cost of Service
Minimum System Approach

	Production Related	Transmission Related	Distribution Related	Customer Related	Direct Assignment	Net Revenue Requirement
Residential 7	$8,742,625	$534,254	$6,696,715	$6,863,125	$0	$22,836,719
General Service 24	$1,818,453	$107,700	$1,266,219	$2,145,530	$0	$5,337,901
Small Demand 25	$908,621	$42,060	$549,930	$102,484	$0	$1,603,095
Large Demand 26	$393,377	$15,380	$216,682	$4,185	$0	$629,624
Primary 31	$414,527	$31,516	$311,139	$34,496	$0	$791,677
Irrigation 29	$2,186	$171	$3,021	$1,217	$0	$6,596
Interruptible Schools 43	$270,509	$29,888	$348,232	$7,491	$0	$656,120
Street & Hwy Lighting	$50,221	$2,473	$64,326	$60,868	$38,423	$216,310
PTP	$2,567,806	$119,331	$165,752	$1,928	$0	$2,854,817
TOTAL	$15,168,325	$882,772	$9,622,015	$9,221,325	$66,972	$34,961,410

Table 8 provides the COSA results using a 100% demand methodology.

Table 8 Summary of Functionalized Cost of Service 100% Demand Approach						
	Production Related	**Transmission Related**	**Distribution Related**	**Customer Related**	**Direct Assignment**	**Net Revenue Requirement**
Residential 7	$8,742,625	$534,254	$8,632,100	$4,575,208	$0	$22,484,187
General Service 24	$1,818,453	$107,700	$1,584,279	$1,872,843	$0	$5,383,275
Small Demand 25	$908,621	$42,060	$656,762	$92,409	$0	$1,699,852
Large Demand 26	$393,377	$15,380	$257,661	$3,774	$0	$670,192
Primary 31	$414,527	$31,516	$396,814	$33,125	$0	$875,981
Irrigation 29	$2,186	$171	$3,753	$1,057	$0	$7,168
Interruptible Schools 43	$270,509	$29,888	$426,635	$6,941	$0	$733,973
Street & Hwy Lighting	$50,221	$2,473	$86,394	$27,919	$38,423	$205,431
PTP	$2,567,806	$119,331	$165,772	$1,791	$0	$2,854,700
TOTAL	$15,168,325	$882,772	$12,210,170	$6,615,069	$66,972	$34,943,309

The results are split between the various functions of the utility. For the residential class, costs are split 38% for power supply, 31% for transmission and distribution and 30% for customer-related costs in the minimum system case. With the 100% demand approach the power supply component remains at 38% but the transmission and distribution portion changes to 40% and the customer-related portion changes to 20%. For larger customers, a larger percent is related to power supply while less is related to the other functions. For PTP, 90% of the costs are related to power supply.

The overall results comparing revenues to the costs allocated within the COSA are summarized in Table 9 for minimum system and in Table 10 for 100% demand. More detail behind the results shown is presented in Schedules 1.1 and 1.2.

Table 9 Summary of Cost of Service Analysis – Minimum System					
	Present Rate Revenues	**Net Revenue Requirement**	**Surplus/ (Deficiency) in Present Rates**	**Revenue to Cost Ratio**	**Adjusted Revenue to Cost Ratio**
Residential 7	$20,318,884	$22,836,719	-$2,517,835	89.0%	98.3%
General Service 24	$4,226,868	$5,337,901	-$1,111,033	79.2%	87.5%
Small Demand 25	$2,019,432	$1,603,095	$416,337	126.0%	139.2%
Large Demand 26	$807,535	$629,624	$177,911	128.3%	141.7%
Primary 31	$912,375	$791,677	$120,698	115.2%	127.3%
Irrigation 29	$3,163	$6,596	-$3,433	47.9%	53.0%
Interruptible Schools 43	$447,287	$656,120	-$208,833	68.2%	75.3%
Street & Hwy Lighting	$155,712	$216,310	-$60,599	72.0%	79.5%
PTP	$2,733,002	$2,854,817	-$121,815	95.7%	105.7%
TOTAL	$31,624,257	$34,914,759	-$3,308,604	90.6%	100.0%

Table 10 Summary of Cost of Service Analysis – 100% Demand					
	Present Rate Revenues	**Net Revenue Requirement**	**Surplus/ (Deficiency) in Present Rates**	**Revenue to Cost Ratio**	**Adjusted Revenue to Cost Ratio**
Residential 7	$20,318,884	$22,484,187	-$2,165,303	90.4%	99.8%
General Service 24	$4,226,868	$5,383,275	-$1,156,407	78.5%	86.7%
Small Demand 25	$2,019,432	$1,699,852	$319,579	118.8%	131.2%
Large Demand 26	$807,535	$670,192	$137,342	120.5%	133.0%
Primary 31	$912,375	$875,981	$36,394	104.2%	115.0%
Irrigation 29	$3,163	$7,168	-$4,005	44.1%	48.7%
Interruptible Schools 43	$447,287	$733,973	-$286,686	60.9%	67.3%
Street & Hwy Lighting	$155,712	$205,431	-$49,719	75.8%	83.7%
PTP	$2,733,002	$2,854,700	-$121,698	95.7%	105.7%
TOTAL	$31,624,257	$34,914,759	-$3,308,604	90.6%	100.0%

The revenue to cost ratios show how much each class is paying relative to its allocated costs. Because the 2017 revenues fall short of the budget, the adjusted revenue to cost ratios show the results as if the total system was collecting sufficient revenues. The adjusted revenue to cost ratios are a better indicator of whether or not each class is paying its fair share of the costs of the utility.

When examining the results, it is important to note that the inter-class cost allocation is based on load data estimates and usage pattern assumptions. Therefore, deviations of less than 10% from the cost of service typically do not warrant interclass rate modifications.

In both cases, the results show that the residential class is paying close to 100% of its costs. The small general service (Rate 24) is paying below 90% of its cost and should receive an above average increase at some point. The various large general service/commercial classes are all paying more than their cost of service and should at some point receive either a rate decrease or rate increases less than the average for the utility. There is some difference in the general service/commercial levels when comparing the results under the minimum system and 100% demand approach.

The irrigation and lighting classes are both well below their cost of service, however, these classes are more difficult to model within a COSA as their loads are not typical. The interruptible school class is paying 67 to 75% of its cost of service and should see a rate increase in the future. While the value of the interruptibility has not been incorporated in the COSA, there is little value to the PUD with BPA purchases for all of the PUD's power supply. This differs from the situation for PSE, where substantial costs could be avoided due to their resource mix.

Finally, the revenues collected from PTP are recovering roughly 100% of the costs to serve the customer.

Bonneville Power Administration

Power supply makes up 45% of the PUD's annual revenue requirement. The PUD currently receives, and is expected to continue to receive, 100% of its wholesale power requirements from the Bonneville Power Administration (BPA). The PUD also purchases transmission service from BPA. Since the PUD purchases its power and transmission requirements from BPA, an overview of recent events related to BPA and the pricing of its services is instructive.

Introduction

BPA presently markets electric energy from 29 federal hydroelectric projects in the Pacific Northwest, certain nuclear projects, and contractual purchases and exchanges to meet approximately 50% of the Pacific Northwest's energy requirement. BPA also owns and operates approximately 75% of the Pacific Northwest's high-voltage transmission system. BPA's transmission facilities interconnect with utilities in the Canadian province of British Columbia and with utilities in California.

Power Business Line

In October 2001, BPA began providing power to its customers under 10-year power sales contracts. These contracts were negotiated at a time when power costs had risen to unprecedented levels, making BPA's low-cost products all the more attractive. The 2001 power contracts expired on September 30, 2011.

Bonneville's rate structure changed dramatically in October 2011. The rate structure was developed through a formal proceeding known as the Tiered Rate Methodology ("TRM"). Beginning in October 2011 Bonneville's rates were tiered with market-based rates serving load growth above 2010 actual loads (the high water mark or "HWM"). Under TRM total Tier 1 allocations roughly equal the capability of the FBS under critical water conditions. Under this approach, each Bonneville customer effectively receives a share of output from the FBS for a 20-year contract period. Power requirements above Tier 1 allocations may be purchased from Bonneville at Tier 2 rates or from alternative suppliers.

Tier 2 rates will be market based while Tier 1 rates will, for the most part, be cost based and be determined in formal rate proceedings.

Jefferson PUD's Contract with BPA

The PUD currently purchases power from BPA at PF-12 load following rates under TRM. Utilities can choose to shape their own power requirements (block or slice contracts with BPA), or they may choose BPA's load shaping product. Utilities that choose BPA's load shaping product (such as the PUD) are subject to load shaping rates. These rates apply when the utility's load shape is significantly different than the energy available from the FBS. During months where the utility's share of the FBS is less than power requirements, load shaping charges apply. In months where a utility's power requirements are less than the utility's share of the FBS load shaping credits apply. Load shaping charges and credits are based on actual market purchases or sales.

According to BPA's forecast, the PUD will not need to purchase any above-HWM resources during the study period of 2017-2020. As such, no above-HWM purchases are included in the power supply costs.

The BPA rates used to determine power purchase costs are based on current rate for the first 9 months of 2017. A proposed rate increase of roughly 3% for power supply and 1% for transmission rates was used beginning in October 2017. It is expected that another comparable rate increase will occur in October of 2019.

Transmission Business Line

The PUD purchases transmission from TBL under a Network Transmission ("NT") contract. Bonneville's TBL sets rates for a number of different transmission and ancillary services. The rates for each service are based on forecast sales and the costs of providing the services. The previous NT rate structure billed customers based on their system peak at the time of the total transmission system peak. Starting in 2015 the PUD is billed for transmission services based on the utility's non-coincident peak.

Rate Design

This section of the report will review the present rate structures for the PUD and will provide the proposed rates for 2017. A comparison with the unit costs developed in the cost of service study is also provided as it was used as one factor in designing the rates.

Based on the revenue deficiency for 2017, after the planned use of reserves to fund a portion of the CIP budget, the overall rate increase for the year is 6.6%. Proposed changes include increases in the basic charge as well as simplification of the rates in many cases. Because the rates in place reflected the rates for PSE at the time of the acquisition, the rates reflect the underlying costs of PSE and were more complex than needed for the PUD.

It was determined that the increases should be made in two steps. The first step would be on January 1, 2017 with changes to the basic charge. The changes to demand and energy charges would be made on June 1, 2017. This second step was delayed until June as the winter months typically have higher usage levels and the bill impacts would be larger in the winter. This also spreads out the rate increase over time so customers are not hit with all of the increase at one time.

While there are some differences in the COSA results showing that some classes are paying more or less than their cost, it was decided that the various customer classes should see similar rate increase levels at this time due to magnitude of the rate increase and the amount of restructuring of rates. The utility should consider making interclass adjustments in the future when the rates have stabilized to better reflect the COSA results.

The Board adopted the rates for 2017 based on the recommendations made with some adjustments. Rate changes for 2018 were recommended to the utility but they have not yet been approved. They are included in this report for completeness and as a starting point for 2018. But a rate proposal for 2018 will need to reflect actual sales and revenues over the next year, budgets for 2018 and customer response to the 2017 rate changes.

While the option was discussed to have a lesser base rate increase and show the state utility taxes as a separate line item on the bill, this option was not adopted for 2017. At some point in the future, this may be required of the utility. The City tax for those customers within the City of Port Townsend is already shown as a separate line item on the bill.

Residential Rates

Schedule 7 is the primary residential class, however, Schedule 8 contains residential and farm general service customers. For the COSA and for 2017 rates, the Schedule 8 has been combined into Schedule 7. There are 16,683 customers on Schedule 7 and average use is 12,000 kWh per customer per year, or 1,000 kWh per month.

The present Schedule 7 rate design is comprised of a monthly customer charge and an inverted block energy charge. An inverted block rate means that as usage increases, the customer pays more for each unit of energy. Schedule 8 contains a higher customer charge and a flat energy charge. Rates are presented in Table 11. The unit costs developed from the COSA using both the minimum system approach and the 100% demand approach are also included in the table.

Because the basic charge was well below the unit costs associated with customer-related costs, the basic charge was proposed to increase significantly. It was also recommended by EES that the rates be changed from an inverted block rate to a flat rate to better reflect how rates are changed by BPA. The Board decided to retain the inverted block rates to continue to send conservation price signals to customers.

The customer-related costs differ significantly between the minimum system and 100% demand approach. The minimum system approach is the more common approach used and reflects the fact that the poles, wires and transformers are required to be installed for every customer even if they use a minimum amount of electricity. Even with the 100% demand approach, the customer charge would need to increase to reflect the per unit customer costs.

Note that the COSA shows that the residential class is paying nearly 100% of its cost of service overall.

Table 11
Comparison of Rates to Current and Approved Rates and Unit Costs
Residential Class

		Unit Costs from COSA		Approved Rates	
	Current Rates	Minimum System	100 % Demand	January 2017	June 1, 2017
Schedule 7 – Residential					
Customer Charge ($/month)	$7.49	$34.28	$22.85	$14.50	$14.50
Energy Charge (cents/kWh)	8.5011 (1st 600 kWh) 10.3589 (> 600 kWh)	7.98	8.95	8.5011 10.3589	8.60 10.48
Schedule 8 – Residential & Farm					
Customer Charge ($/month)	$9.66	Same as Schedule 7			
Energy Charge (cents/kWh)	9.5072				

The approved rates result in a 7% increase in January and an additional 1% increase in June. Because the increase is spread out during the year, the revenues from the June increase do not occur for the entire year. Based on revenues for the entire year, the rate increase for the class is 7.4%

For 2018 it is recommended that the basic charge be increased to $17.00 in January and the energy rates remain the same as in 2017. This would result in a rate increase of 3.3% for the year when compared to 2017. The two year combined increase in revenues would be 10.9% when compared to current revenues.

The customer charge is place for PSE may have reflected their costs but does not reflect the costs facing the PUD. The customer charge for PSE may also have been kept low due to pressure from various customer advocacy groups in the regulated environment. Table 12 provides a further breakdown to show the costs that are included in the customer charge to provide a better understanding of why customer charges should be increased.

Table 12
Detailed Components of Customer-Related Costs

Cost Category	Minimum System	100% Demand
Meter/Distribution O&M	$7.44	$8.55
Customer Service/Accounts	$7.77	$7.77
A&G Expenses	$3.98	$4.06
Taxes	$0.00	$0.00
Debt Service	$0.05	$1.64
Capital Funded from Rates	$6.32	$1.14
Credit from Other Revenues	-$0.27	-$0.21
Total Customer-Related Costs	$34.28	$22.85

It can also be seen that the majority of utilities in the region have higher basic charges than the PUD. This further supports the appropriateness of increasing the basis charge. Table 13 shows the rates in place for various utilities as well as the monthly bill for a customer using 1,000 kWh per month.

Table 13 Comparison of Rates to Other Utilities Residential Class					
	Base Charge	**Energy (Block 1 or Flat)**	**Energy (Block 2)**	**Energy (Block 3)**	**Monthly Bill at 1,000 kWh**
Grays	$39.00	$0.054	$0.082		$117.59
Mason 1	$31.66	$0.075			$113.07
Mason 3	$31.42	$0.070			$112.14
Clallam	$27.68	$0.072			$99.70
Lewis	$22.81	$0.055			$77.81
Peninsula	$20.50	$0.072	$0.077	$0.079	$95.50
Cowlitz	$18.50	$0.071			$89.50
Snohomish	$15.51	$0.099			$98.79
Pacific	$13.00	$0.065			$77.90
Clark	$12.00	$0.082			$94.00
Jefferson	$7.49	$0.085	$0.104		$108.22
PSE	$7.87	$0.091	$0.109		$106.22
Seattle City Light	$4.51	$0.059	$0.126		$116.12

Finally, a bill comparison for customers at various usage levels was provided to show the impact of the changes in rate design for 2017. In January, the increase in the basic charge has a much larger bill impact on a percent basis for small electric users compared to those that use more power. But the impact is an added $7.00 per month increase regardless of usage level. In June, the small users would see a lower bill impact than those with higher usage levels.

Table 14 Bill Impacts at Different Usage Levels Residential Class					
		Average Bill per Month		**% Impact**	
	Current Rates	**January 2017**	**June 1, 2017**	**January 2017**	**June 1, 2017**
100	$15.99	$23.00	$23.10	43.8%	0.4%
500	$50.00	$57.01	$57.50	14.0%	0.9%
1,000	**$99.93**	**$106.94**	**$108.02**	**7.0%**	**1.0%**
1,500	$151.73	$158.74	$160.42	4.6%	1.1%
2,000	$203.52	$210.53	$212.82	3.4%	1.1%

General Service Rates

There are four general service rates in place to reflect different sizes and voltage levels of customers. Schedule 24 (General Service) is for customers below 50 KW and does not have a demand charge in the rate. Schedule 24 has 1,988 customers with average use of 21,000 kWh. Schedule 25 (Small Demand) is for customers over 50 kW and under 350 kW. There are 73 customers with average use of 298,000 kWh. Schedule 26 (Large Demand) is for customers over 350 kW and has 3 customers with average use of 3.24 million kWh. There is a discount on this rate for any customers served at primary voltage. Schedule 31 is for customers served at the primary distribution level, with no specific size limitations. There are 10 customers with average use of 897,000 kWh.

In addition to having four separate rate schedules for general service customers, the rate design varies significantly between the four classes. Schedule 24 has a no demand charge and flat seasonal energy rates. Schedule 25 has energy rates that are both declining block rates and seasonal. Demand rates are also seasonal. Schedule 26 and Schedule 31 both have a flat energy rate with no seasonal difference but demand rates are seasonal.

Current and approved 2017 rates are presented in Table 15. The unit costs developed from the COSA using both the minimum system approach and the 100% demand approach are also included in the table.

Note that the COSA shows that the general service classes are paying more than their cost of service, therefore, the unit costs shown in the table are lower than present rates overall. The exception is Rate 24, where the class is paying less than 90% of its costs.

Table 15 Comparison of Rates to Other Utilities and Unit Costs General Service Classes					
		Unit Costs from COSA		Approved Rates	
	Current Rates	Minimum System	100% Demand	January 2017	June 1, 2017
Schedule 24 – General Service					
Customer Charge ($/month)	$9.66	$89.92	$54.39	$17.00	$17.00
Energy Charge (cents/kWh)	9.5072 (Oct-Mar) 9.1974 (Apr-Sep)	7.61	8.37	9.5072 9.1974	9.85
Schedule 25 – Medium General Service					
Customer Charge ($/month)	$51.77	$116.26	$78.49	$60.00	$60.00
Energy Charge (cents/kWh)	(Oct-Mar) 9.4791 (1st 20,000 kWh) 6.9280 (>20,000 kWh) (Apr-Sep) 8.6638 (1st 20,000 kWh) 6.9280 (>20,000 kWh)	3.57	3.57	9.4791 6.9280 8.6638 6.9280	8.10
Demand Charge ($/kW/month)	$9.01 (> 50 kW Oct-Mar) $6.01 (> 50 kW Apr-Sep)	$9.99	$11.07	$9.01 $6.01	$5.00 All kW
Schedule 26 – Large Demand General Service					
Customer Charge ($/month)	$104.46	$116.26	$104.83	$110.00	$110.00
Energy Charge (cents/kWh)	6.7061	3.57	3.57	6.7061	7.20
Demand Charge ($/kW/month)	$8.94 (> 50 kW Oct-Mar) $5.96 (> 50 kW Apr-Sep)	$14.00	$11.47	$8.94 $5.96	$9.00 All kW
Schedule 31 – Primary General Service					
Customer Charge ($/month)	$339.51	$287.47	$276.04	$339.51	$300.00
Energy Charge (cents/kWh)	6.4918	3.57	3.57	6.4918	7.00
Demand Charge ($/kW/month)	$8.64 (> 50 kW Oct-Mar) $5.76 (> 50 kW Apr-Sep)	$10.94	$13.08	$8.64 $5.76	$8.25 All kW

It was proposed that the basic charges be increased to better reflect the COSA results. It was also proposed that the rates be simplified to be easier to understand, easier to administer, more reflective of the underlying costs and be more consistent with one another. This simplification included eliminating all of the seasonal and block charges and applying the demand charge to all kW rather than the amount over 50 kW.

For Rate 24, there would be no demand charge. The basic charge would increase in January and the energy rate would change in June. For Rates 25 and 25 the basic charge would increase in

January and the demand and energy charges would change in June. For Rate 31, the basic charge will decrease and all changes will be made in June.

Based on the approved rates, the rate increase for Rate 24 is 3.9% in January and 5.0% in June. Revenues for 2017 would be 7.1% higher than under current rates. The bill impacts under the approved rates are shown in Table 16. Customer with low consumption would have a high percent impact in January but a lower than average impact in June.

Schedule 24 rates for 2018 are proposed to include a $19.00 basic charge in January and the energy rate would remain at the June 2017 level. This results in a 3.4% overall increase in revenues for 2018 and a total impact of 10.8% for the two-year period.

Table 16
Bill Impacts at Different Usage Levels
Rate 24 General Service Class

		Average Bill per Month		% Impact	
	Current Rates	**January 2017**	**June 1, 2017**	**January 2017**	**June 1, 2017**
300	$38	$45	$47	19.4%	3.2%
800	$85	$92	$96	8.7%	4.2%
1,757	**$174**	**$182**	**$190**	**4.2%**	**4.7%**
5,000	$478	$485	$510	1.5%	5.0%
10,000	$946	$953	$1,002	0.8%	5.1%

Based on the approved rates, the rate increase for Rate 25 is 0.3% in January and 9.2% in June. Revenues for 2017 would be 5.4% higher than under current rates. The bill impacts under the approved rates are shown in Table 17. Rate impacts for January are minimal. In June, customers with low consumption would have a higher than average percent impact in their bill.

The Schedule 25 rates would not change again until June of 2018 when the demand rate would increase to $5.50 and the energy rate would increase to 8.3 cents per kWh. This results in a 3.7% overall increase in revenues for 2018 and a total impact of 10.95% for the two-year period.

Table 17 Bill Impacts at Different Usage Levels Rate 25 Small Demand General Service Class					
		Average Bill per Month		% Impact	
	Current Rates	January 2017	June 1, 2017	January 2017	June 1, 2017
15,000	$1,305	$1,314	$1,521	0.6%	15.8%
24,840	**$2,224**	**$2,232**	**$2,480**	**0.4%**	**11.1%**
50,000	$4,583	$4,592	$4,930	0.2%	7.4%
100,000	$9,275	$9,284	$9,799	0.1%	5.6%

Based on the approved rates, the rate increase for Rate 26 is less than 0% in January and 10% in June. Revenues for 2017 would be 5.5% higher than under current rates. The bill impacts under the approved rates are shown in Table 18. All customers would see a comparable percent rate increase, regardless of energy consumption level. Because the demand charge is increasing more than the energy rate, customers with lower load factors would see an above average rate increase.

The Schedule 26 rates would not change again until June of 2018 when the energy rate would increase to 7.35 cents per kWh. This results in a 5.1% overall increase in revenues for 2018 and a total impact of 10.9% for the two-year period.

Table 18 Bill Impacts at Different Usage Levels Rate 26 Large Demand General Service Class					
		Average Bill per Month		% Impact	
	Current Rates	January 2017	June 1, 2017	January 2017	June 1, 2017
180,000	$14,912	$14,918	$16,376	0.0%	9.8%
270,405	**$22,349**	**$22,355**	**$24,546**	**0.0%**	**9.8%**
500,000	$41,237	$41,242	$45,293	0.0%	9.8%

Based on the approved rates, the rate increase for Rate 31 is less than 0% in January and 9.9% in June. Revenues for 2017 would be 5.5% higher than under current rates. The bill impacts under the approved rates are shown in Table 19. Customers with lower than average usage would receive lower than average bill impacts on a percent basis. Because the demand charge is increasing more than the energy rate, customers with lower load factors would see an above average rate increase.

The Schedule 31 rates would not change again until June of 2018 when the demand charge would increase to $8.50 energy rate would increase to 7.25 cents per kWh. This results in a 5.1% overall increase in revenues for 2018 and a total impact of 10.9% for the two-year period.

Table 19
Bill Impacts at Different Usage Levels
Rate 31 Primary General Service Class

		Average Bill per Month		% Impact	
	Current Rates	January 2017	June 1, 2017	January 2017	June 1, 2017
25,000	$2,764	$2,764	$2,968	0.0%	7.4%
74,779	$7,591	$7,591	$8,281	0.0%	9.1%
150,000	$14,886	$14,886	$16,310	0.0%	9.6%

Seasonal Irrigation Rates

There are only 3 customers on the PUD's irrigation rate (Schedule 29). Their average use is 15,600 kWh. Schedule 29 has the same customer charge as Schedule 24 but the same rate design as Schedule 25. However, both the demand and energy charges are lower than under Schedule 25, especially in the summer months. The COSA shows these customers are paying far less than their cost of service. Under the PUD's power supply costs from BPA, there are no significant cost differences between an irrigation and general service customer. It is likely that the lower rates for these customers have been maintained due to political pressure as opposed to actual cost differences.

Current rates approved rates for 2017 are presented in Table 20. The unit costs developed from the COSA using both the minimum system approach and the 100% demand approach are also included in the table.

The approved rates include an increase in the basic charge in January to better match costs. The energy rate is also changing from a seasonal declining block rate to a flat energy rate in June to reflect cost causation. As the current demand charge that is included in the Rate Schedule has not been applied in the past, it is not included in the new Rate Schedule.

Table 20 Comparison of Rates to Other Utilities and Unit Costs Seasonal Irrigation (Schedule 29)					
		Unit Costs from COSA		Approved Rates	
	Current Rates	Minimum System	100% Demand	January 2017	June 1, 2017
Customer Charge ($/month)	$24.28	$86.96	$75.53	$30.00	$30.00
Energy Charge (cents/kWh)	(Oct-Mar) 9.1225 (1st 20,000 kWh) 6.9678 (>20,000 kWh) (Apr-Sep) 6.3718 (1st 20,000 kWh) 5.4831 (>20,000 kWh)	11.46	13.02	9.1225 6.9678 6.3718 5.4831	6.50
Demand Charge ($/kW/month)	$8.83 (> 50 kW Oct-Mar) $4.35 (> 50 kW Apr-Sep)				

Based on the approved rates, the rate increase for Rate 29 is a 24% increase in the basic charge January, however, the customers generally do not take service in this month and therefore see no bill impacts. In June the energy rate would increase. Revenues for 2017 would be 9.7% higher than under current rates. The bill impacts under the approved rates are shown in Table 21. Customers with lower than average usage would receive higher than average bill impacts on a percent basis due to the increase in the basic charge.

The Schedule 29 rates would not change again until June of 2018 when the energy rate would increase to 6.65 cents per kWh. This results in a 2.0% overall increase in revenues for 2018 and a total impact of 11.9% for the two-year period.

Table 21 Bill Impacts at Different Usage Levels Rate 29 Seasonal Irrigation Class					
		Average Bill per Month		% Impact	
	Current Rates	January 2017	June 1, 2017	January 2017	June 1, 2017
100	$30.65	$36.37	$36.50	18.7%	0.4%
5,850	$397.03	$402.75	$410.25	1.4%	1.9%
9,340	$619.41	$625.13	$637.10	0.9%	1.9%

Interruptible School Rates

The PUD has a special rate for schools that can take interruptions in service. There are 4 schools on this rate with an average use of 1.3 million kWh. This is an unusual rate for a PUD. It was likely put in place as PSE could avoid large costs if they could control the peak demand of certain customers. The PUD would not incur large savings from interruption under purchases from BPA.

Current rates and approved 2017 rates are presented in Table 22. The unit costs developed from the COSA using both the minimum system approach and the 100% demand approach are also included in the table.

While this class is paying far less than its costs based on the COSA results, the Board decided that they should receive an average rate increase at this time due to the cost pressures facing the schools.

Table 22
Comparison of Rates to Other Utilities and Unit Costs
Interruptible Schools (Schedule 43)

		Unit Costs from COSA		Approved Rates	
	Current Rates	Minimum System	100% Demand	January 2017	June 1, 2017
Customer Charge ($/month)	$339.51	$155.77	$144.34	$339.51	$300.00
Energy Charge (cents/kWh)	6.066	3.57	3.57	6.066	6.80
Demand Charge ($/kW/month)	$4.60 plus $3.89 for critical demand	$17.46	$20.39	$4.60 plus $3.89 for critical demand	$5.00 All kW

Based on the approved rates, the rate increase for Rate 43 is 0% in January and 10% in June. Revenues for 2017 would be 4.7% higher than under current rates. The bill impacts under the approved rates are shown in Table 23. Customers would all receive a similar percent increase in their bills.

The Schedule 43 rates would not change again until June of 2018 when the demand charge would increase to $5.50 per kW-month. This results in a 7.3% overall increase in revenues for 2018 and a total impact of 12.3% for the two-year period.

Table 23 Bill Impacts at Different Usage Levels Rate 43 Interruptible Schools Class					
		Average Bill per Month		% Impact	
	Current Rates	January 2017	June 1, 2017	January 2017	June 1, 2017
50,000	$4,587	$4,587	$5,020	0.0%	9.4%
105,504	**$9,301**	**$9,301**	**$10,259**	**0.0%**	**10.3%**
200,000	$17,328	$17,328	$19,178	0.0%	10.7%

This class is only paying about 67% to 75% of its costs. The COSA shows that costs for these customers are comparable to other general service customers. It is recommended that the Board consider phasing out the discount for this class over time.

Lighting Services

The PUD has lighting rates that vary considerably and reflect the assumed usage for each different customer. Lighting rates were simplified in 2016. For 2017 the rates are approved to increase at roughly the average level for the utility. Table 24 shows the proposed lighting rates for 2017.

Table 24 Bill Impacts at Different Usage Levels Rate 43 Interruptible Schools Class			
	Current Rates	January 2017 Rates	% Impact January 1, 2017
Less than 100 Watts	$12.00	$13.00	8.3%
100>=200 Watts	$14.00	$15.00	7.1%
More than 200 Watts	$16.00	$17.00	6.3%

Port Townsend Paper

Because PTP is such a large customer and is served off of the transmission line, the PUD can calculate its share of BPA purchases each month and pass through the cost. An amount is currently added to reflect the PUD's administrative fees and taxes. The COSA shows that the monthly payment for administrative fees should be $2,120 per month.

Summary

The PUD has approved rates for 2017 that will be implemented in a two-step process. Basic charges will increase in January and demand and energy rate will increase in June. In addition to the overall rate increases, the rates will be simplified.

Table 25 summarizes the rate increases that will be applied to the various customer classes.

Table 25
Summary of Rate increases for 2017 and 2018

	Revenues at Current Rates	% Increase January 2017	% Increase June 2017	% Increase 2017 Total Revenues	% Increase 2017-2018
Rate 7 –Residential	$20,318,884	5.7%	1.0%	6.7%	10.9%
Rate 24 -General Service	$4,155,812	3.9%	5.0%	8.9%	10.8%
Rate 25 -Small Demand	$2,019,432	0.3%	9.2%	9.5%	11.0%
Rate 26 -Large Demand	$807,535	0.0%	10.0%	10.0%	10.9%
Rate 31 -Large Primary	$912,375	0.0%	9.9%	9.9%	10.9%
Rate 29 –Irrigation	$3,163	0.0%	6.1%	6.1%	11.9%
Rate 43 –Int. Schools	$447,287	0.0%	10.0%	5.5%	12.3%
Street & Hwy Lighting	$187,204	7.1%	0.0%	7.1%	14.3%

Technical Appendix