

Okanogan County Electric Cooperative

Okanogan County Electric Cooperative Electric Cost of Service and Rate Study Final January 3, 2012

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Executive Summary

Okanogan County Electric Cooperative (OCEC) retained EES Consulting, Inc. (EES Consulting) 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 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, an “accrual basis” method was used for determining OCEC’s revenue requirement. Annual operating expenses from a proposed budget for calendar year (CY) 2010 were used to determine the revenue requirement as well as the budget forecast provided by OCEC.

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

- Historic year is CY 2010 (January 2010 – December 2010).
- Test year/allocation year is CY 2012.
- Load forecast was based on load growth rates used in OCEC’s 2012 budget forecast. Actual customer loads from January 2010 through December 2010 are used.
- Expenses were taken directly from OCEC’s annual operating expenses and forecasted at an average rate of 2.9 percent.
- Power supply costs are calculated using the most recent pricing from the Bonneville Power Administration (July 2011) and the COSA load forecast.

Total CY 2012 revenues are expected to equal \$4.8 million, while expenses are projected to amount to \$5.1 million. This results in a 5.05 percent deficit in revenues relative to costs. A summary of the draft revenue requirement is shown in Table 1.

Table 1
Summary of the Revenue Requirement
CY: 2012

| Revenues | |
|---|--------------------|
| Present Rate Revenues | \$4,785,482 |
| Other Income | 111,231 |
| Total Revenues | \$4,896,713 |
| Expenses | |
| Generation | \$2,328,014 |
| Transmission | 0 |
| Distribution | 725,824 |
| Customer Accounts and Services | 267,100 |
| Administration and General | 598,036 |
| Depreciation | 325,290 |
| Taxes | 180,646 |
| Interest and Debt Service | 270,484 |
| Other Contributions (including Patronage Capital & Operating Margins) | 448,490 |
| Total Expenses | \$5,143,884 |
| Surplus (Deficiency) in Funds | (\$247,172) |
| Total Required Revenue Increase (Decrease) | 5.05% |
| Present Rate Revenues | \$4,785,482 |
| Rev Req (Expenses less Other Income) | \$5,032,653 |
| Surplus (Deficiency) in Funds | (\$247,172) |
| Required Retail Rate Increase (Decrease) | 5.17% |

Cost of Service Study

A cost of service (COSA) study 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 OCEC was functionalized, classified and allocated. Unlike most cost of service studies, costs were kept functionalized throughout the analysis.

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 percent demand and minimum system. The 100 percent demand methodology assumes that the distribution system is built to meet the non-coincident peak. Therefore, distribution costs using this method are classified as 100 percent 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 percent demand methodology. Demand-vs-customer allocations for the minimum system case were derived using data from OCEC and other Northwest public utilities.

Given a number of assumptions, the results show that using present rates, OCEC would be under-collecting revenues to meet test 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 percent from the cost of service typically do not warrant interclass rate modifications.

These results are summarized in Table 2 for minimum system and in Table 3 for 100 percent demand. More detail behind the results shown in Table 2 is presented in Schedules 1.1 and 1.2. Table 4 provides the average results used for rate design.

| 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 with Average Rate Increase |
| Residential | \$2,150,045 | \$2,147,282 | \$2,763 | 100.1% |
| Seasonal | 1,495,214 | 1,503,847 | (8,633) | 99.4% |
| Small Commercial | 602,847 | 717,756 | (114,909) | 84.0% |
| Large Commercial | 414,574 | 435,874 | (21,300) | 95.1% |
| Irrigation | 117,521 | 218,622 | (101,101) | 53.8% |
| Street Lighting | 5,280 | 9,272 | (3,992) | 56.9% |
| TOTAL | \$4,785,482 | \$5,032,653 | (\$247,172) | 95.1% |

| 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 with Average Rate Increase |
| Residential | \$2,150,045 | \$2,151,223 | (\$1,178) | 99.9% |
| Seasonal | 1,495,214 | 1,443,748 | 51,466 | 103.6% |
| Small Commercial | 602,847 | 745,821 | (142,974) | 80.8% |
| Large Commercial | 414,574 | 483,453 | (68,879) | 85.8% |
| Irrigation | 117,521 | 198,575 | (81,054) | 59.2% |
| Street Lighting | 5,280 | 9,832 | (4,552) | 53.7% |
| TOTAL | \$4,785,482 | \$5,032,653 | (\$247,172) | 95.1% |

| Table 4 | | | | |
|--|------------------------------|--------------------------------|---|---|
| Summary of Cost of Service Analysis - Average | | | | |
| | Present Rate Revenues | Net Revenue Requirement | Surplus/ (Deficiency) in Present Rates | Revenue to Cost Ratio with Average Rate Increase |
| Residential | \$2,150,045 | \$2,149,253 | \$793 | 100.0% |
| Seasonal | 1,495,214 | 1,473,798 | 21,417 | 101.5% |
| Small Commercial | 602,847 | 731,789 | -128,942 | 82.4% |
| Large Commercial | 414,574 | 459,664 | -45,090 | 90.2% |
| Irrigation | 117,521 | 208,599 | -91,078 | 56.3% |
| Street Lighting | 5,280 | 9,552 | -4,272 | 55.3% |
| TOTAL | \$4,785,482 | \$5,032,653 | (\$247,172) | 95.1% |

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.

Output from the COSA analysis was designed to facilitate the development of rate designs. Unit cost determinations, by function, typically represent the starting point from which final rate

design determinations can be developed. Schedule 2.1 details the COSA's unit cost determinations, which are instrumental to the development of unit cost information that could be used in the modification of OCEC's current rate structure.

Alternative rate design features that could be considered include flat energy charges, incremental and decremental block energy charges, seasonal energy charges, time-of-use energy charges, customer charges (versus minimum charges) and demand charges for customer classes with new meters capable of providing hourly load data. Also to be considered in designing rates is the adjustment of rate components to more competitive levels.

The COSA results project OCEC needs an overall rate adjustment of 5.2 percent for CY 2012, 5.9 percent for CY 2013, or 7.8 percent for CY 2014. These adjustments are not cumulative; they are the rate change required over present rates in the given year.

Recommendation

Based on the projected revenue requirement and COSA analysis, the following recommendations for OCEC have been developed by EES Consulting:

- Using current rates, OCEC is running a deficit in revenues compared to CY 2012 costs.
- Based on the current COSA inter-class results, it appears that an adjustment in rate design may be needed at this time.
- Rate design recommendations will be discussed separate from this report.

Overview of Rate Setting Principles

EES Consulting, Inc. (EES Consulting) was retained by Okanogan County Electric Cooperative (OCEC) to perform a comprehensive electric cost of service and rate study. Performing an electric rate study is necessary to assure that OCEC'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 OCEC.

Overview and Organization of Report

In developing electric rates for OCEC, a major goal of the study is to develop cost-based rates that meet OCEC'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 OCEC'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 OCEC. 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 presented.

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 OCEC'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 OCEC.

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 OCEC'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 OCEC'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, OCEC is a public utility district regulated by a Board of Directors.

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. Pacific Power 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.

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.

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 5 compares the cash and utility accounting conventions.

Table 5
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 |
| $\Sigma =$ Revenue Requirement | $\Sigma =$ Revenue Requirement |

For this study, an accrual basis was used to determine the utility’s revenue requirement.

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 OCEC. 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 OCEC’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 OCEC must make is the method of accumulating costs. OCEC utilized the “accrual basis” approach for determining revenue requirement. In summary form, OCEC’s components to its revenue requirement include the elements shown in Table 6.

Table 6
Elements of an Accrual Basis Revenue Requirement

| | |
|---|--|
| + Operation and Maintenance Expenses (O&M) | |
| ✓ Power Supply Expense | |
| ✓ Transmission Expense | |
| ✓ Distribution Expense | |
| ✓ Customer Accounting Expenses | |
| ✓ Customer Service & Information Expense | |
| ✓ Administrative and General Expense | |
| + Interest Expense | |
| + Other Contributions (including Patronage Capital & Operating Margins) | |
| + Depreciation | |
| + 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 OCEC, a calendar year test period was utilized (January through December). CY 2012 was chosen as the test period for the cost of service study. OCEC provided budgeted cost projections for CY 2011. Revenues from retail rates and purchased power costs were forecast based on forecast CY 2011 loads. Projected CY 2011 costs are provided in Schedule 3.1. OCEC’s revenue requirement allocated to customer classes can be found in Schedule 3.4.

Development of the Projected Load Forecast and Forecast Revenues

The load forecast for CY 2011 through CY 2015 was calculated based on the growth rates from the load forecast provided by OCEC staff.

The load forecast is important as it is what is utilized to allocate costs within the cost of service and also they are the units of consumption used to design final rates. A summary of the loads for historic CY 2010 can be seen on Schedule 1.7. Line losses were calculated using total system purchases and total customer sales in CY 2010. Primary line losses were assumed to be 2.00 percent, secondary line losses were assumed to be 5.11 percent. 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 2012 using current retail rate schedules and forecasted CY 2012 loads.

Development of Power Supply Costs

OCEC purchases wholesale power as a slice customer from the Bonneville Power Administration (BPA). OCEC receives all of its wholesale power requirements from BPA. From October 2011 and forward, BPA power supply costs are based on OCEC's contract high water mark (CHWM) and BPA's tiered rate structure. OCEC has elected a share of BPA's power supply as a load following customer; therefore, OCEC will pay a fixed monthly charge, load shaping charges, and demand charges beginning in October 2011. Power supply costs also include BPA transmission costs under a Network Transmission (NT) contract. For purposes of this report, NT rates are assumed constant through the study period. Projected power supply costs were provided by OCEC.

As with most electric utilities, the major expense associated with operating the utility is power supply. Approximately \$2.3 million or 45 percent of the CY 2012 total revenue requirement of the utility are production costs.

The total power requirement for OCEC was projected to be approximately 55 million kWh in CY 2012. For the time period reviewed in this study, the peak demand was expected to occur in December. On a cost per kWh basis, power purchases would equal approximately 4.2 cents. Total power supply costs are forecast to be \$2.3 million in CY 2012, \$2.4 million in CY 2013 and \$2.4 million in CY 2014.

Other Operations and Maintenance Expenses

OCEC'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 CY 2012 O&M expenses are projected at \$3.9 million. Of this amount, \$2.3 million is related to power supply costs. Therefore, non-power supply operating expenses are expected to be approximately \$1.6 million in CY 2012.

Taxes

For CY 2012, taxes are projected at \$180,646.

Interest Expense

CY 2012 interest on long term debt and debt service is projected at \$270,484.

Depreciation

CY 2012 total depreciation for OCEC is projected at \$325,290.

Other Contributions (including Patronage Capital & Operating Margins)

For CY 2012, other contributions included additional cash of \$249,894 needed to meet the TIER requirement, \$100,000 in the rate stabilization account, patronage capital of \$17,900 and operating margins of \$80,696 for a total of \$448,490.

Miscellaneous Revenues

OCEC receives additional operating and non-operating revenues and contributions. These come in the form of interest and dividend revenues, idle service revenues, rents, and other revenue. The combined estimate of these revenue items for CY 2012 is approximately \$111,231.

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 OCEC uses an “accrual basis” approach for rate setting, the basic revenue requirement is presented in that format. A summary of OCEC’s revenue requirement for the forecasted period can be seen summarized in Table 7.

Table 7
Summary of the Revenue Requirement
Actual 2012

| Applications of Funds | CY: 2012 |
|---|------------------|
| Operation and Maintenance Exp. | |
| Power Generation | \$2,328,014 |
| Transmission | 0 |
| Distribution | 725,824 |
| Customer Service and Accounting | 267,100 |
| Administrative and General | 598,036 |
| Total O&M Expenses | 3,918,974 |
| Depreciation | 325,290 |
| Taxes | 180,646 |
| Interest and Debt Service | 270,484 |
| Other Contributions (including Patronage Capital & Operating Margins) | 448,490 |
| Total Revenue Requirement | 5,143,884 |
| Less: Other Revenues/Net | (111,231) |
| Net Revenue Requirement | 5,032,653 |
| Revenues at Current Rates | 4,785,482 |
| Needed Retail Rate Increase | 5.17% |
| Needed Overall Revenue Increase | 5.05% |

Table 8 shows projected rate increases through CY 2015. The rate increases in column *f* are based on a snapshot in time; the rate increase needed in each year (over current rates) is calculated to meet the revenue requirement in that year only. For example the 5.9 percent rate increase projected for 2013 would not use the surpluses from 2011 to 2012. Also, the rate increases should not be summed across years. For example, if rates were increased 5.2 percent in 2012, the 5.9 percent rate increase projected for 2013 would be decreased to a 0.7 percent rate increase.

Since power supply costs are projected to increase significantly, these are shown separately in column *b*.

Table 8
Projected Rate Increases

| CY | Present Rate Revenues <i>A</i> | Power Supply Costs <i>b</i> | Non-Power Supply Costs, Net* <i>c</i> | Revenue Requirement <i>d = b + c</i> | Surplus (Deficiency) <i>e = a - d</i> | Rate Increase (decrease) Over Current Rates <i>f = - e/a</i> |
|-------------|--|---|---|--|---|--|
| 2011 | 4,785,482 | 2,080,337 | 2,598,670 | 4,679,007 | 106,475 | -2.2% |
| 2012 | 4,785,482 | 2,328,014 | 2,704,639 | 5,032,653 | (247,171) | 5.2% |
| 2013 | 4,833,284 | 2,422,195 | 2,695,410 | 5,117,605 | (284,322) | 5.9% |
| 2014 | 4,881,564 | 2,442,415 | 2,821,561 | 5,263,976 | (382,412) | 7.8% |
| 2015 | 4,930,326 | 2,479,163 | 2,971,288 | 5,450,451 | (520,124) | 10.5% |

*Includes miscellaneous revenues.

Recommendation

OCEC's revenues are sufficient to cover its cost obligations beginning in 2012.

It is important to note that OCEC's current revenue to cost balance needs to be continually monitored. Both short and longer term supply and operating cost considerations will need to be evaluated and analyzed as the Board of Directors works with OCEC'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, OCEC'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 OCEC'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

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.

OCEC Functionalization Method

The specific functions used for OCEC'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 OCEC 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

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.”

OCEC Classification Method

The following are the specific classifiers used in OCEC’s COSA within each of the four functions:

- 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 OCEC’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.

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.

Tiered Rate Methodology

OCEC's power supply cost structure changes during CY 2011. For the first part of the year (January through September), OCEC will purchase energy and demand from BPA as a preference customer. This split of energy and demand for power supply expense reflects the BPA preference customer pricing provisions, OCEC's demand at time of BPA's total customer peak, and BPA's power supply resources available to OCEC. The demand portion of the expense relates to the fixed charges associated with the peak level of power purchased. The energy portion reflects the amounts paid for actual power taken.

Beginning in October 2011, OCEC will continue to purchase a share of BPA's power supply as a load following customer; however, the tiered rate structure will apply thereby changing the make-up of OCEC's power supply costs. OCEC's power supply costs from BPA are structured so that one large fixed customer charge includes the majority of the energy cost component. Demand charges will apply to only a portion of OCEC's demand at the time of OCEC's peak. The fixed monthly charge is functionalized into energy. The energy cost component is then allocated to customers based on annual kWh consumption. The demand costs are allocated based on monthly coincident peak for each class (12 CP).

Transmission

BPA provides OCEC with transmission services to transfer power from BPA's supply to OCEC's system. The transmission bill components are separated into energy and demand costs before they are allocated to customer classes. The energy cost component is allocated to customer classes based non-coincident peak demand. The demand related component is allocated based on each customer class' share of OCEC's system peak, or coincident peak (CP). Coincident peak and, conversely, non-coincident peak are discussed more below.

- *Coincident peak demand (CP)* 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.
- *Non-coincident peak demand (NCP)* 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 OCEC'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 own transmission assets associated with providing power to OCEC's distribution system. Transmission services that OCEC must incur to deliver the purchased power supply to OCEC's service area are included in purchased power 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. 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 percent 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.

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.

Standard Allocation

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

OCEC Allocation

The following are the specific allocation methods used in OCEC'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 OCEC'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, green-energy related costs and revenues, and surplus sales revenue.
- 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 customers 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 OCEC’s assets as of December 2010 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 total revenue.
- Miscellaneous Other Revenues
 - ✓ Miscellaneous other revenues are generally allocated to customers based on allocation of all other O&M expenses.

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 (rate schedule):

- Residential (A)
- Seasonal (A)
- Small Commercial (A)
- Large Commercial (L)
- Irrigation (C)
- Street Lighting

Major Assumptions of the Cost of Service Study

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

- Forecast calendar year 2012 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 rates for a slice customer effective through September 2011. BPA’s tiered rate methodology customer rate structure is applied to power supply beginning in October 2011.
- Distribution plant was classified based both on a “minimum system” approach and a “100% demand” approach.
- Load forecast was based on data provided by OCEC.
- No growth is assumed from 2011 through 2015 for the revenues of idle services in the other revenues section of the revenue requirement.
- PNGC Options Costs of \$11,000 for CY 2011 and \$20,000 for CY 2012 are assumed in the power supply expenses of the revenue requirement.
- A line item for Banks Pumping Error was added to the power supply expenses in the revenue requirement.

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 9 shows the results of this analysis by function for the minimum system approach.

| Table 9 | | | | | | |
|--|---------------------------|-----------------------------|-----------------------------|-------------------------|--------------------------|--------------------------------|
| Summary of Functionalized Cost of Service | | | | | | |
| Minimum System Approach | | | | | | |
| | Production Related | Transmission Related | Distribution Related | Customer Related | Direct Assignment | Net Revenue Requirement |
| Residential | 1,008,750 | 0 | 520,308 | 618,224 | 0 | 2,147,282 |
| Seasonal | 564,443 | 0 | 365,516 | 573,888 | 0 | 1,503,847 |
| Small Commercial | 364,903 | 0 | 150,164 | 202,690 | 0 | 717,756 |
| Large Commercial | 335,409 | 0 | 91,960 | 8,505 | 0 | 435,874 |
| Irrigation | 52,596 | 0 | 29,791 | 136,235 | 0 | 218,622 |
| Street Lighting | 1,914 | 0 | 1,359 | 342 | 5,658 | 9,272 |
| TOTAL | 2,328,014 | 0 | 1,159,098 | 1,539,883 | 5,658 | 5,032,653 |

A summary comparison of the allocated cost of service and anticipated revenue from present rates can be found in Table 11. Unit cost estimates have been developed in Schedule 2.1.

Table 10 provides the COSA results using a 100 percent demand methodology.

| Table 10 | | | | | | |
|--|---------------------------|-----------------------------|-----------------------------|-------------------------|--------------------------|--------------------------------|
| Summary of Functionalized Cost of Service | | | | | | |
| 100 Percent Demand Approach | | | | | | |
| | Production Related | Transmission Related | Distribution Related | Customer Related | Direct Assignment | Net Revenue Requirement |
| Residential | 1,008,750 | 0 | 803,998 | 338,474 | 0 | 2,151,223 |
| Seasonal | 564,443 | 0 | 565,105 | 314,201 | 0 | 1,443,748 |
| Small Commercial | 364,903 | 0 | 232,383 | 148,536 | 0 | 745,821 |
| Large Commercial | 335,409 | 0 | 141,425 | 6,619 | 0 | 483,453 |
| Irrigation | 52,596 | 0 | 46,143 | 99,836 | 0 | 198,575 |
| Street Lighting | 1,914 | 0 | 2,106 | 155 | 5,658 | 9,832 |
| TOTAL | 2,328,014 | 0 | 1,791,161 | 907,820 | 5,658 | 5,032,653 |

The overall results are summarized in Table 11 for minimum system and in Table 12 for 100 percent demand and table 13 for the average result. More detail behind the results shown is presented in Schedules 1.1 and 1.2.

Table 11
Summary of Cost of Service Analysis - Minimum System

| | Present Rate Revenues | Net Revenue Requirement | Surplus/ (Deficiency) in Present Rates | Revenue to Cost Ratio |
|------------------|----------------------------------|------------------------------------|---|----------------------------------|
| Residential | \$2,150,045 | \$2,147,282 | \$2,763 | 100.1% |
| Seasonal | 1,495,214 | 1,503,847 | (8,633) | 99.4% |
| Small Commercial | 602,847 | 717,756 | (114,909) | 84.0% |
| Large Commercial | 414,574 | 435,874 | (21,300) | 95.1% |
| Irrigation | 117,521 | 218,622 | (101,101) | 53.8% |
| Street Lighting | 5,280 | 9,272 | (3,992) | 56.9% |
| TOTAL | \$4,785,482 | \$5,032,653 | (\$247,172) | 95.1% |

Table 12
Summary of Cost of Service Analysis – 100% Demand

| | Present Rate Revenues | Net Revenue Requirement | Surplus/ (Deficiency) in Present Rates | Revenue to Cost Ratio |
|------------------|----------------------------------|------------------------------------|---|----------------------------------|
| Residential | \$2,150,045 | \$2,151,223 | (\$1,178) | 99.9% |
| Seasonal | 1,495,214 | 1,443,748 | 51,466 | 103.6% |
| Small Commercial | 602,847 | 745,821 | (142,974) | 80.8% |
| Large Commercial | 414,574 | 483,453 | (68,879) | 85.8% |
| Irrigation | 117,521 | 198,575 | (81,054) | 59.2% |
| Street Lighting | 5,280 | 9,832 | (4,552) | 53.7% |
| TOTAL | \$4,785,482 | \$5,032,653 | (\$247,172) | 95.1% |

Table 13
Summary of Cost of Service Analysis - Average

| | Present Rate Revenues | Net Revenue Requirement | Surplus/ (Deficiency) in Present Rates | Revenue to Cost Ratio with Average Rate Increase |
|------------------|----------------------------------|------------------------------------|---|---|
| Residential | \$2,150,045 | \$2,149,253 | \$793 | 100.0% |
| Seasonal | 1,495,214 | 1,473,798 | 21,417 | 101.5% |
| Small Commercial | 602,847 | 731,789 | -128,942 | 82.4% |
| Large Commercial | 414,574 | 459,664 | -45,090 | 90.2% |
| Irrigation | 117,521 | 208,599 | -91,078 | 56.3% |
| Street Lighting | 5,280 | 9,552 | -4,272 | 55.3% |
| TOTAL | \$4,785,482 | \$5,032,653 | (\$247,172) | 95.1% |

Given a number of assumptions, the results show that using present rates, OCEC is not collecting sufficient revenues to meet current 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 percent from the cost of service typically do not warrant interclass rate modifications.

Bonneville Power Administration

Traditionally, power supply has made up close to 45.3 percent of OCEC's annual revenue requirement. OCEC currently receives, and is expected to continue to receive, 100 percent of its wholesale power requirements from the Bonneville Power Administration (BPA). OCEC also purchases transmission service from BPA. Since OCEC 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 percent of the Pacific Northwest's energy requirement. BPA also owns and operates approximately 75 percent 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.

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

Bonneville's rate structure will change dramatically beginning 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 will be tiered with market-based rates serving load growth above 2010 actual loads (the high water mark or "HWM"). Under TRM total Tier 1 allocations will roughly equal the capability of the FBS under critical water conditions. Under this approach, each Bonneville customer will effectively receive 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.

Bonneville is proposing to offer a number of alternatives for Tier 2 power products and associated pricing. Tier 2 rates will be designed to recover the full costs of the generating resources, or market purchases, or Bonneville's marginal resource cost in the event that power is provided from the existing system.

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

Power Business Line

On May 15, 2000, the Bonneville Administrator issued the Final Record of Decision (the “ROD”) for the Power Business Line (the “PBL”) rate case. The Priority Firm (PF) 2001 rates are effective October 2001 through September 2006. The decisions made in the ROD and subsequently approved at the Federal Energy Regulatory Commission (FERC), resulted in over a 200 percent increase in its demand charge and slightly lower energy charges over PF-96 rates (effective in 1996 through 2001). The rates provided in this ROD also included a seasonal shape that is differentiated monthly and is considerably more pronounced in the summer months. This seasonal shape, which applies to the demand and energy charges, was driven by the west coast power market, which is driven largely by cooling loads located in California.

OCEC currently purchases power from BPA as a slice customer. However, beginning in October 2011 OCEC’s contract with BPA changes such that power costs will be tiered. Tier 1 power costs will be based on the current Federal Base System (FBS) costs; however, the quantity of power OCEC will be able to purchase at these rates will be limited. BPA will use weather and conservation adjusted loads from historic years to set OCEC’s high water mark (HWM), or the maximum amount of energy OCEC may purchase at the lower Tier 1 rate.

Energy requirements in excess of OCEC’s HWM may be either purchased at Tier 2 rates (based on forecasted market prices) or from non-federal resources. Tier 2 rates apply to flat blocks of power. Utilities can choose to shape their own power requirements, or they may choose BPA’s load shaping product. Utilities that choose BPA’s load shaping product (such as OCEC) are subject to load shaping rates. These rates apply when the utilities 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.

Transmission Business Line

OCEC 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. Bonneville and its customers reached agreement for the 2009 transmission rate case which set rates for federal fiscal years 2010 and 2011. The agreement resulted in no rate increase on a net basis. For purposes of this report, NT rates are assumed constant through the study period.

Technical Appendix
