May 28, 2015

Mr. David Brownlee
City of Needles
817 Third Street
Needles, California 92363

Dear Mr. Brownlee:

It is with pleasure that we submit this Final Draft Electric Cost of Service and Rate Study for the Needles Public Utility Authority.

We appreciate all of the help you and your staff have provided in conjunction with this study. Please feel free to contact me directly with any questions or comments.

Very truly yours,

Kelly Tarp
Senior Project Manager

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A registered professional engineering corporation with offices in
Kirkland, WA and Portland, OR

Needles Public Utility Authority

Needles Public Utility Authority
Electric Cost of Service and Rate Study
Final Draft
May 28, 2015

Prepared by:

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Executive Summary

The Needles Public Utility Authority (NPUA) 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 customers. NPUA is a component unit of the City of Needles and operates the City's water, sewer and electric enterprises. The purpose of this report is to discuss the data inputs, assumptions and results that were part of developing the electric 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. A historic fiscal year (FY) 2014 (July 1, 2013 through June 30, 2014) test period provided by NPUA staff was used.

A base case was defined to develop the study results. This base case for the electric utility assumed the following:

- Load forecast was based on actual sales and purchases in FY 2014 and escalated 0 percent per year for FY 2015 and beyond.
- Revenue for FY 2014 was based on actual revenues collected. Revenues for FY 2015 and beyond was based on an average of FY 2013 and FY 2014 revenues as provided by NPUA and adjusted to exclude FY2014 uncollectable account write offs and credit refunding. Revenues were not obtained by customer class, but were estimated based on historic usage information.
- O&M expenses, the franchise fee, purchase payment and debt service expenses were taken from the FY 2014 Audited Financial Statements and the FY 2015 forecast was provided by NPUA.
- Expenses beyond FY 2015 were assumed to grow at a rate of 3.0 percent per year
- For this study, it has been assumed that rates shall support an amount equal to 4.44 percent of gross plant or $630,408/year asset replacement starting in FY 2015.

The revenue requirement analysis for the electric utility showed that the total FY 2014 revenues were $5.6 million for the electric system, excluding the utility users' tax. Expenses were $5.9 million for the same period. This results in a deficit in the revenues relative to costs of 4.4 percent. However, based on the forecast revenue requirement, NPUA may not require a system-wide increase in electric rate revenues in FY 2015. A summary of the revenue requirement is shown in Table 1.

Table 1 Summary of Revenue Requirement		
	FY 2014 (actual)	**FY 2015 (forecast)**
Revenues		
Present Revenues From Rates (incl. PPA)	$5,606,515	$6,425,124
Other Income [1]	16,567	221,757
Total Revenues	**$5,623,082**	**$6,646,881**
Operating Expenses		
Power Supply [2]	$1,819,101	$1,825,000
Operation & Maintenance	2,297,399	2,297,399
Direct Write Offs (Uncollectable Accts)	0	0
Franchise Fee	280,326	321,256
Purchase Payment	335,948	370,862
Conservation Programs	208,586	200,000
Debt Service (P+I)	924,271	947,928
Capital Projects / Asset Replacement[3]	0	630,403
Total Operating Expenses	**$5,865,631**	**$6,592,849**
Surplus (Deficiency) in Funds	($242,549)	$54,032
Required Rate Increase (Decrease)	4.3%	-0.8%

1. *Other income includes state excise tax collected through rates, pole rental, connection fees, establishment fees, customer contributions and other miscellaneous revenues.*
2. *Power costs include all costs related to obtaining power supply, including power purchase cost, transmission, ancillary services, scheduling, AB32, etc.*
3. *Asset Replacement funded at 4.44 percent of gross plant.*

Capital Improvement projects assumed to equal $630,403 (4.44 percent of gross plant) has increased the revenue requirement beginning in FY 2015. The importance of properly funding for capital improvements cannot be understated. In particular, failure to properly fund for renewals and replacement within retail rates will ultimate lead to long-term financial problems. In effect, the utility will either use cash reserves to finance these renewals and replacement projects in the short-run or worse yet, not make the necessary replacements at all. In general, annual depreciation is not sufficient and utilities tend to fund in the order of 5 to 10 percent of the gross plant for annual renewal and replacement CIP. Annual depreciation is approximated at 3.3 percent of gross plant.

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 utility was functionalized, classified and allocated. Unlike most cost of service studies, this analysis kept costs functionalized throughout the analysis so that the calculation of unbundled rates could be facilitated.

A COSA 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 costs 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.

A cost of service study begins by "functionalizing" a utility's revenue requirement as power supply, transmission, distribution and customer for the electric analysis. Next, the functionalized costs are "classified" to demand-, energy-, and customer-related component costs for electric.

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

Specific electric distribution costs are sometimes split between demand and customer according to a minimum system approach with the peak load carrying capability adjustment. This approach reflects the philosophy that the system is in place, in part, because there are customers to serve throughout the service territory, and that a minimally-sized electric 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 delivered quantity greater than the minimum unit of electricity and that, therefore, those costs should be treated as demand-related. Allocation factors for the minimum system case were based on NPUA's previous cost of service study.

The COSA results for the electric system based on the minimum system and 100% demand methods are summarized in Tables 2 and 3, respectively.

Table 2
Summary of Electric Cost of Service Analysis – Minimum System

	Present Rate Revenues	Net Revenue Requirement	Surplus/ (Deficiency) in Present Rates	Revenue to Cost Ratio
Residential	$2,903,663	$3,035,474	($131,812)	95.7%
Commercial	2,343,224	2,391,772	(48,549)	98.0%
Master Meter	61,557	64,821	(3,263)	95.0%
Municipal	237,759	244,428	(6,669)	97.3%
Lighting	58,218	110,154	(51,936)	52.9%
Native Village	2,095	2,415	(320)	86.8%
TOTAL	**$5,606,515**	**$5,849,064**	**($242,549)**	**95.9%**

Table 3 Summary of Electric Cost of Service Analysis – 100 Percent Demand				
	Present Rate Revenues	**Net Revenue Requirement**	**Surplus/ (Deficiency) in Present Rates**	**Revenue to Cost Ratio**
Residential	$2,903,663	$2,970,095	($66,433)	97.8%
Commercial	2,343,224	2,450,627	(107,403)	95.6%
Master Meter	61,557	67,613	(6,056)	91.0%
Municipal	237,759	251,372	(13,614)	94.6%
Lighting	58,218	106,950	(48,733)	54.4%
Native Village	2,095	2,406	(311)	87.1%
TOTAL	**$5,606,515**	**$5,849,064**	**($242,549)**	**95.9%**

It is important to note when examining the results, that the inter-class cost allocation is based on load data estimates and usage pattern assumptions. Therefore, deviations in the interclass revenue and cost ratios of less than +/- 10 percent from system averages do not typically warrant interclass rate modifications. Figures 1 and 2 show the results under both methodologies with only the lighting class under-collecting. In addition, usage data for some customer classes, for example street lighting, is estimated based on very limited information. This decreases the accuracy significantly in results for these classes.

Figure 1
Minimum System Results

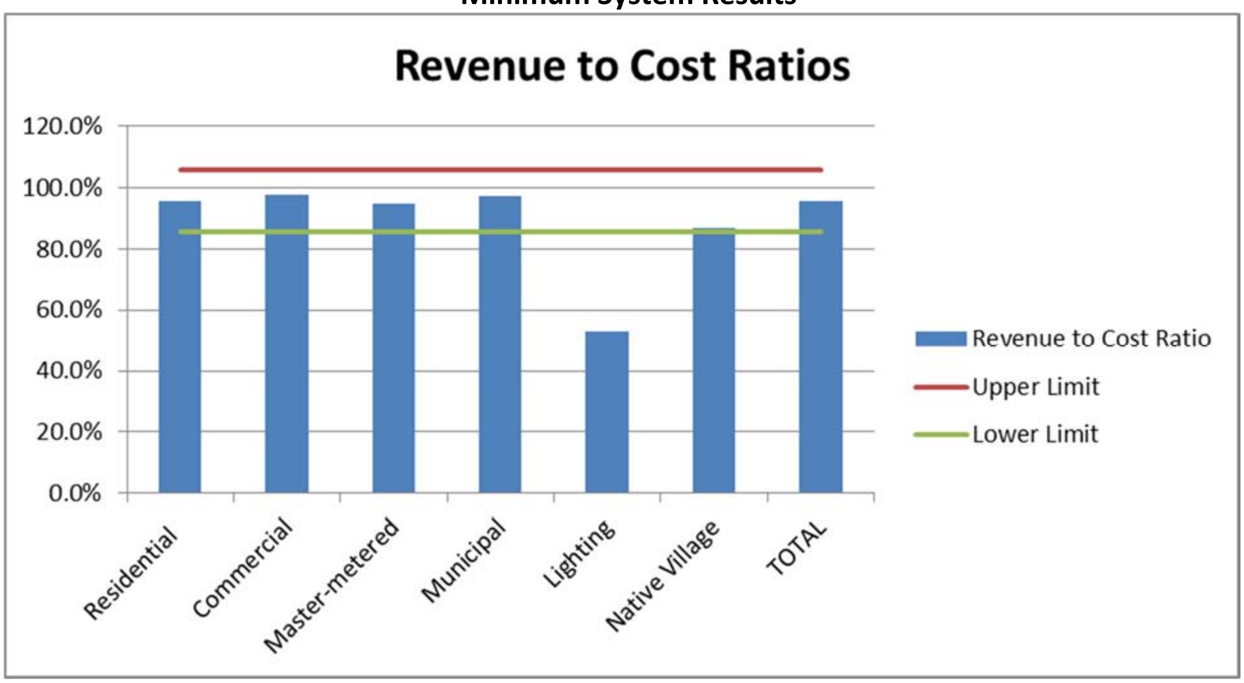


Figure 2
100 Percent Demand Results

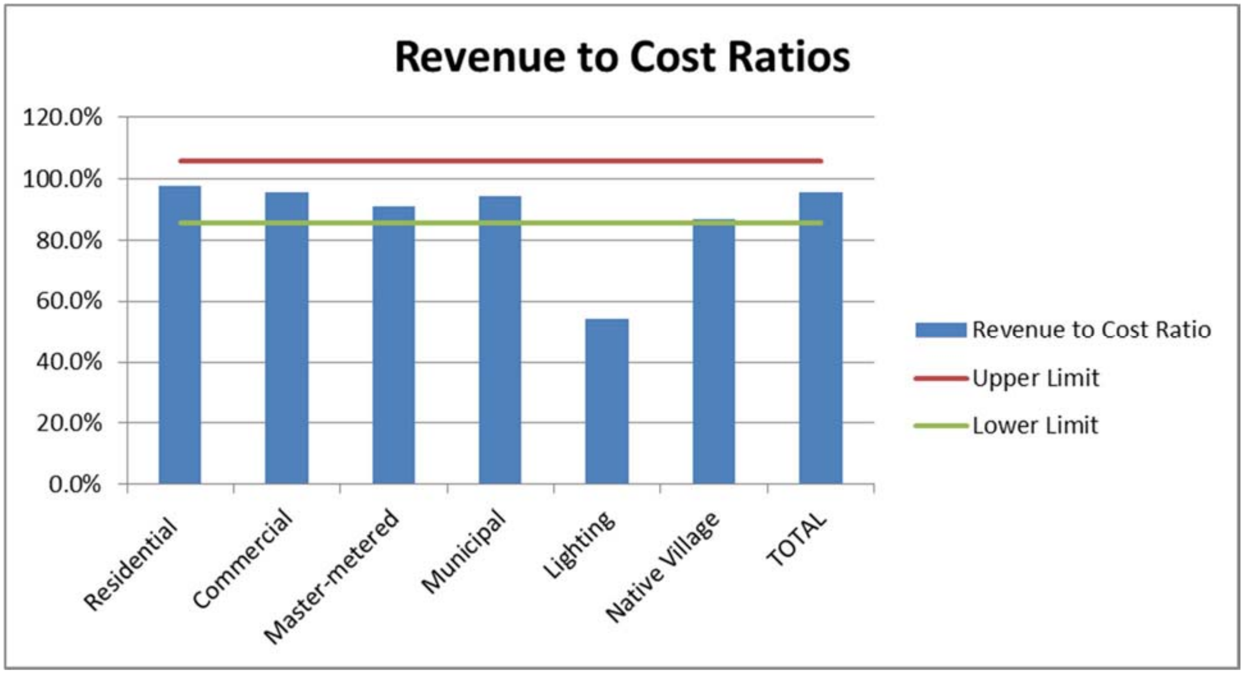


Table 4 shows projected rate adjustments through FY 2018. The rate changes in column *f* are based on a snapshot in time; the rate change needed in each year (over current rates) is calculated to meet the revenue requirement in that year only. Rate adjustments should not be summed across years.

Table 4
Projected Rate Adjustments

FY	Present Rate Revenues *a*	Power Supply Costs *B*	Non-Power Supply Costs, Net(1) *C*	Revenue Requiremen t *d = b + c*	Surplus (Deficiency) *e = a - d*	Rate Increase (Decrease) Over Current Rates *f =- e/a*
2014	5,606,515	1,819,101	4,029,963	5,849,064	(242,549)	4.3%
2015	6,425,124	1,825,000	4,546,092	6,371,092	54,032	-0.8%
2016	6,425,124	1,875,250	4,809,191	6,684,441	(259,317)	4.0%
2017	6,425,124	1,927,008	4,885,396	6,812,404	(387,280)	6.0%
2018	6,425,124	1,980,318	4,963,871	6,944,188	(519,064)	8.1%

1. Includes miscellaneous revenues.

As shown above in Table 4, the electric utility's projected retail revenues at current rates are insufficient to cover its projected cost obligations over the study period.

Rate Design

Rate design encompasses a multitude of considerations that often are somewhat removed from the unit costs resulting from the cost of service analysis. 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 studies were 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 in the Appendix details the COSA's unbundled unit cost determinations for the electric system.

Recommendation

Based on the projected revenue requirement and COSA study, EES makes the following recommendations:

- Using current electric rates, NPUA is collecting sufficient revenues to meet costs in FY 2015.

- Based on the current inter-class results for the electric system COSA, a change in rate design may not be needed at this time. Beyond FY 2015 NPUA may consider a flat across-the-board rate increase to meet forecast expenses. This recommendation reflects the uncertainty inherent in the COSA study based on the uncertainty associated with the load data and other input assumptions. Therefore, before implementing any new rates, NPUA should obtain legal review and approval.

- It is important to remember that any rate increase above 10 percent is generally considered a rate shock and it is therefore the recommendation of EES that NPUA keep rate changes below 10 percent for any single customer class.

Overview of Rate Setting Principles

EES was retained by the Needles Public Utility Authority (NPUA) to perform a comprehensive electric cost of service and rate study.

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 utilities and determines the overall revenue (rate) adjustment required of the utilities. 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. Finally, based on the results of the cost of service analysis and other policy considerations, rate design options are developed.

Overview and Organization of Report

In developing electric rates for the electric utility, a major goal of the study is to develop cost-based unbundled rates that meet the utility's revenue requirement needs. It is important to understand that a 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 failures.

This report is organized such that it follows the steps taken in analyzing and developing the utility'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 for each utility, discussing the development of the revenue requirement analysis, the cost of service study, and the results of that process. This is followed by a discussion of the utility's power supply costs. Finally, rate design principles are presented.

Technical appendices are attached at the end of this report that detail the various analyses for the electric utility using the 100% demand methodologies to classify distribution costs. The schedules contained in the technical appendices are referenced throughout the report.

The setting of 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 utility'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 rates that are "fair and equitable" is an integration of these generally accepted methodologies and the financial policies or specific considerations for the NPUA utilities. For the purpose of developing the cost of service studies, EES assumed that each utility must be financially stable and "stand on its own".

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 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 utility'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 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 costs are the revenue requirement analysis and the 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 electric utility'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 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 City of Needles is a public entity regulated by the City Council.

In contrast, private 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 Gas and Electric Company 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 an "accrual" or "utility" 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 "accrual" or "utility" 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 may be helpful in comparing the cash and accrual accounting conventions.

Table 5 Cash vs. Accrual Basis Comparison			
	Cash Basis		Accrual (Utility) Basis
+	O&M Expense	+	O&M Expense
+	Taxes	+	Taxes
+	Capital Improvements Financed with Operating Revenues (Depreciation Expense)	+	Depreciation Expense
+	Debt Service	+	Return on Investment
Σ	= Revenue Requirement	Σ	= Revenue Requirement

For this study, cash basis accounting 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 costs. Next, the functionalized costs are "classified" to demand-, energy-, and customer-related component costs.

Electric 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 for electric systems are those that vary with the number and type of customers served.

These 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 utility's customer classes 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 and collect the desired level of revenues. The rate process utilizes the results of the revenue requirement and cost of service to develop rates which achieve the overall goals and objectives of the NPUA. These goals and objectives may include consideration of cost based rates, but may also consider items such as the customer's ability to pay, continuity of past rate philosophy, economic development, ease of administration, etc. It is important to understand that cost of service is only one goal or objective in designing final electric rates, however, it is an important one.

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. This statements implications on utility rate designs is significant. For example, capacity-related costs are usually incurred by an electric utility to meet peak demand. Thus, the customers causing maximum peak day demands should properly pay for the demand related facilities in proportion to their contribution to maximum demands. Traditional rate designs such as time-of-day, seasonal or marginal cost-based utility rates embrace this economic concept. Through refinement of costing and pricing techniques, consumers of a product are given a more accurate price signal of what a commodity costs to produce and deliver.

These basic tenets have considerable foundation in the economic literature and in today's competitive electric utility environment. They also serve as primary guidelines for 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.

Revenue Requirement and Cost of Service Analysis

This section of the report presents the introduction to the revenue requirements and the cost of service analysis (COSA) for NPUA's electric system.

Overview of NPUA'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 NPUA must make is the method of accumulating costs. For this analysis, a cash basis method is used in determining the utility's revenue requirement. In summary form, the utility's components to its revenue requirement include the elements shown in Table 6.

Table 6
Elements of Cash 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
+	Debt Service	
+	Other Contributions	
+	Franchise Fee	
+	Purchase Payment	
+	Capital Improvement Projects	
	=	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 NPUA, a fiscal year test period was utilized. A historic period, fiscal year (FY) 2014, was chosen as the test period for the cost of service study. NPUA also provided budgeted cost projections based on the proposed FY 2015 budget for the electric utility. Revenues were based on actual FY 2014 revenues. The revenue requirement allocated to customer classes of the electric system can be found in Schedule 3.4 of Appendix A.

COSA Definition and General Principles

A COSA 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 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 approach to cost allocation 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, NPUA'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 for the electric.

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 for electric systems.

The 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.

Capital Improvement Projects

Capital Improvement Projects (CIP) are related to the infrastructure of each utility. Capital improvement projects are of an ongoing basis and are generally divided into two types or categories. These two categories are capital improvement projects which are related to renewal and replacement, and growth related facilities. Renewal and replacements are, as the name suggests, the replacement of existing and worn out (depreciated) facilities. Growth related facilities are those related to system expansion, system upgrades and new customers.

The importance of properly funding for capital improvements cannot be understated. In particular, failure to properly fund for renewals and replacement within retail rates will ultimate lead to long term financial problems. In effect, the utility will either use cash reserves to finance these renewals and replacement projects in the short-run, or worse yet, not make the necessary replacements at all.

As a general "rule of thumb" NPUA should, at a minimum, be funding renewals and replacements from rates at an amount greater than or equal to the annual depreciation expense. Annual depreciation expense reflects the current investment in plant that is being depreciated or "losing" its useful life. Therefore, this portion of plant investment needs to be replaced to maintain the existing level of infrastructure and service to customers. In general, annual depreciation is not sufficient and utilities tend to fund in the order of 5 to 10 percent of the gross plant for annual renewal and replacement CIP.

It must be kept in mind that the minimum suggested assumes that funding for replacement and renewal has occurred over time. If replacement and renewal projects have not been done in the past, the minimum funding equal to annual depreciation expense is not sufficient to update the system. In such a case, consideration may be given to funding within rates some amount greater than annual depreciation expense for the funding of renewal and replacement programs.

For this study, it has been assumed that rates shall support an amount approximately equal to 4.44 percent of gross plant for asset replacement beginning in FY 2015.

General Ratemaking Principles

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.

Electric Cost of Service Analysis

This section includes the development of the revenue requirement and the cost of service analysis for NPUA's electric utility.

Revenue Requirement

This section of the report outlines the development of the electric utility revenue requirement. 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.

Development of the Projected Loads and Revenues

System loads were assumed to stay the same as actual FY 2014 with an assumed zero percent load growth. A summary of the loads for FY 2015 for the electric system can be seen on Schedule 1.7 of Appendix A.

Forecast revenues at present rates were estimated by NPUA as the average of FY 2013 and FY 2014 revenues and adjusted to exclude FY2014 uncollectable account write offs and credit refunding.

Development of Power Supply Costs

As with most electric utilities, the major expense associated with operating the utility is power supply. NPUA purchases wholesale power from the Western Area Power Administration (WAPA). Because of the utility's heavy hydroelectric portfolio, NPUA joined Aggregated Energy Services (AES) January 1, 2014. All members of AES have allocations of Federal Hydro Resources, which are then aggregated and scheduled to result in greater efficiencies and more economical use and dispatch.

Approximately $1.8 million or 29 percent of the total revenue requirement of the utility is direct power supply costs, including the cost of wheeling this power to NPUA's electric system. The total energy requirement for NPUA was approximately 58.5 million kWh in FY 2014. For the time period reviewed in this study, the peak demand occurred in July 2013. On a unit cost basis, power costs would equal approximately 3.11 cents per kWh.

Power costs forecasts were provided by NPUA for FY 2015.

Other Operations and Maintenance Expenses

NPUA's audited FY 2014 expenses and proposed FY 2015 budget was used for the development of non-purchased power related operations and maintenance (O&M) expenses. Operating costs were divided between distribution, customer service and accounting, administrative and general expenses categories through the revenue requirement development process.

Total O&M expenses were $4.3 million. Of this amount, $1.8 million is related to power supply costs. Therefore, non-power supply operating expenses were approximately $2.5 million in FY 2014. This includes $208,586 for California mandated solar rebates and conservation.

Franchise Fee & Purchase Payment

This category includes a Franchise Fee transfer to the City of $280,326 (5 percent of revenues) and a Purchase Payment transfer of $335,948. For FY 2014, the expenses in this category totaled $616,274. The Utility Users Tax was excluded from this analysis.

Capital Improvement Projects

The FY 2014 audited financials did not include specific capital improvement project (CIP) expenses. For this draft report, the revenue requirement similarly does not include specific electric system CIP expenditures. However, an amount equal to $630,408 or 4.44 percent of the total gross plant is included as general CIP starting in FY 2015.

Debt Service

The final component of the revenue requirement is the debt service and bank service charges for FY 2014. This adds approximately $924,271 to the electric system's revenue requirement, net of the purchase payment.

Miscellaneous Revenues

NPUA's electric system receives additional operating and non-operating revenues. These come in the form of hook-up fees, rental and late charges, meter reading charges, and pole joint-use fees. The combined estimate of these revenue items for FY 2014 is $16,567.

Summary of Revenue Requirement

Once all of the components of the cash basis revenue requirement have been forecast, the total revenue requirement is determined. A summary of NPUA's electric system revenue requirement for the historic period can be seen in summary Table 7.

Table 7 Summary of the Electric Revenue Requirement Historic FY 2014	
Revenues	
Present Revenues From Rates (incl. PPA)	$5,606,515
Other Income [1]	16,567
Total Revenues	$5,623,082
Operating Expenses	
Power Supply [2]	$1,819,101
Operation & Maintenance	2,297,399
Direct Write Offs (Uncollectable Accounts)	0
Franchise Fee	280,326
Purchase Payment	335,948
Conservation Programs (net of loan repayment revenue)	208,586
Debt Service	924,271
Capital Projects Funded from Rates (Asset Replacement)[3]	0
Total Operating Expenses	$5,865,631
Surplus (Deficiency) in Funds	($242,549)
Required Rate Increase (Decrease)	4.3%

1. *Other income includes state excise tax collected through rates, pole rental, connection fees, establishment fees, customer contributions and other miscellaneous revenues.*
2. *Power costs include all costs related to obtaining power supply, including power purchase cost, transmission, ancillary services, scheduling, AB32, etc.*
3. *Asset replacement equal to 4.44 percent of gross plant.*

The capital program is assumed to fund equal to 4.44 percent of gross plant in service and has increased the revenue requirement beginning in FY 2015. The importance of properly funding for capital improvements cannot be understated. In particular, failure to properly fund for renewals and replacement within retail rates will ultimate lead to long-term financial problems. In effect, the utility will either use cash reserves to finance these renewals and replacement projects in the short-run or worse yet, not make the necessary replacements at all. In general, annual depreciation is not sufficient and utilities tend to fund in the order of 5 to 10 percent of the gross plant for annual renewal and replacement CIP. Annual depreciation is approximated at 3.3 percent of gross plant.

Table 8 shows projected rate adjustments through FY 2018. The rate changes in column *f* are based on a snapshot in time; the rate change needed in each year (over current rates) is calculated to meet the revenue requirement in that year only. Rate adjustments should not be summed across years.

Table 8 Projected Rate Adjustments						
FY	**Present Rate Revenues** *a*	**Power Supply Costs** *b*	**Non-Power Supply Costs, Net**[(1)] *C*	**Revenue Requiremen t** *d = b + c*	**Surplus (Deficiency)** *e = a - d*	**Rate Increase (Decrease) Over Current Rates** *f =- e/a*
2014	5,606,515	1,819,101	4,029,963	5,849,064	(242,549)	4.3%
2015	6,425,124	1,825,000	4,546,092	6,371,092	54,032	-0.8%
2016	6,425,124	1,875,250	4,809,191	6,684,441	(259,317)	4.0%
2017	6,425,124	1,927,008	4,885,396	6,812,404	(387,280)	6.0%
2018	6,425,124	1,980,318	4,963,871	6,944,188	(519,064)	8.1%

1. Includes miscellaneous revenues.

As shown above in Table 8, the electric utility's projected retail revenues at current rates are insufficient to cover its projected cost obligations over the study period. However, current rates are sufficient to cover FY 2015 cost obligations.

Once the overall rate change required has been determined for the electric utility, the next step is to determine the inter-class cost allocation. A cost of service study begins with a utility's revenue requirement and allocates expenses to each of the customer classes.

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 principle 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 electric system's cost of service, and provide a summary of the results.

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 City's system of accounts.

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.

NPUA's Electric System Functionalization Method

The specific functions used for NPUA's electric 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 function includes the utility's own transmission assets associated with providing power to NPUA's distribution system. Transmission services that NPUA 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 allocation factor that, when applied, will distribute those costs among the appropriate customer classes during the allocation phase of the analysis.

Functionalized power purchases 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 Electric 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. Demand 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 electric distribution costs are generally split between demand and customer.

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

Alternatively, 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. 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."

NPUA's Electric Classification Method

The following are the specific classifiers used in NPUA's electric 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). The specific classifiers used for the power supply function include:

  - Energy
  - Demand

  The split of energy and demand for power supply expense reflects the pricing provisions of the purchase contracts in place during 2013-2014, the supply customers' peak demand requirement, and the power supply resources available to NPUA to meet those requirements. 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.

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 NPUA'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.

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.

- Transmission

The transmission function includes the utility's own transmission assets associated with providing power to NPUA's electric distribution system. Transmission services that NPUA must incur to deliver the purchased power supply to the utility'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:

- NCP on Primary System
- NCP on Secondary System
- Actual Customer
- 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. NPUA's relatively uniform customer base and lack of large industrial customers lead to a greater portion of costs being 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 for NPUA's electric system can be found in Schedule 3.3.

Direct Assignment

Some costs can be directly assigned to certain customer classes without being classified to one of the functions previously described. These are generally costs associated with specific services, such as dedicated capital facilities, or with specific customer classes, such as lighting customers for electric systems. Schedule 3.5 of provides the background information for all direct assigned electric system 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.

NPUA's Electric Allocation

FY 2014 data related to total system purchases and total customer sales were used to determine line losses, load factors and coincident factors. The specific allocation methods used in the NPUA's electric COSA are discussed below. The specific method of cost allocation by electric system customer class can be found in Schedule 3.1 of Appendix A.

- 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.

- *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 NPUA's transmission system.

- *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.

- Energy Allocation Factors. Energy costs vary directly with consumption. Accordingly, energy allocation factors were based upon electricity sales for each class by month.

- 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. For this study, it is assumed that all customers require the same effort for meter reading, billing and customer service.

- Other Cost Allocation. Other costs are allocated based on specific rate base items, O&M function totals, revenues, labor ratios and other allocation factors.

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

  - 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 transmission, distribution, general and customer accounting costs.

- Franchise Fee and Purchase Payment. These transfers were allocated based on the allocation of revenue.

- Miscellaneous Other Revenues. These revenues are 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:

- Residential
- Commercial
- Master-Meter
- Municipal
- Lighting
- Native Village

Major Assumptions of the Cost of Service Study

Major assumptions used in conducting the cost of service study for NPUA's electric system are as follows:

- Historic FY 2014 was selected as the test period for the allocation of costs within the cost of service study.

- The revenue requirement as outlined in this section was used for the cost of service study.

- Purchased power was assigned to demand and energy based upon contract charges.

- Distribution plant was classified based on both the "Minimum System" and the "100% Demand" approach.

Given these key assumptions, the cost of service analysis could be completed. Schedules 3.4 and 4.3 show the functionalized and classified rate base and revenue requirement for the electric system, 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. As explained above, the allocated cost of service was kept separated by function to facilitate rate design that could be unbundled.

Tables 9 and 10 provide the COSA results for the electric system using the minimum system and 100 percent demand methodologies, respectively.

Table 9
Summary of Functionalized Cost of Service
Minimum System Approach – FY 2014

	Production Related	Transmission Related	Distribution Related	Customer Related	Direct Assignment	Net Revenue Requirement
Residential	1,463,745	101,174	698,624	771,931	0	3,035,474
Commercial	1,529,302	76,313	642,220	143,894	44	2,391,772
Master-Meter	42,348	2,674	19,457	342	0	64,821
Municipal	157,698	7,818	67,206	11,707	0	244,428
Lighting	7,473	0	7,262	35,022	60,396	110,154
Native Village	1,019	32	734	631	0	2,415
TOTAL	3,201,584	188,010	1,435,503	963,527	60,440	5,849,064

Table 10
Summary of Functionalized Cost of Service
100 Percent Demand Approach – FY 2014

	Production Related	Transmission Related	Distribution Related	Customer Related	Direct Assignment	Net Revenue Requirement
Residential	1,463,745	101,174	810,043	595,133	0	2,970,095
Commercial	1,529,302	76,313	733,354	111,615	44	2,450,627
Master-Meter	42,348	2,674	22,328	264	0	67,613
Municipal	157,698	7,818	76,831	9,025	0	251,372
Lighting	7,473	0	7,439	31,642	60,396	106,950
Native Village	1,019	32	869	487	0	2,406
TOTAL	3,201,584	188,010	1,650,864	748,165	60,440	5,849,064

The overall results are summarized in Table 11 for minimum system and Table 12 for 100 percent demand. More detail behind the results is presented in Schedules 1.1 and 1.2 of Appendix A.

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 Before Rate Increase**
Residential	$2,903,663	$3,035,474	($131,812)	95.7%
Commercial	2,343,224	2,391,772	(48,549)	98.0%
Master-Meter	61,557	64,821	(3,263)	95.0%
Municipal	237,759	244,428	(6,669)	97.3%
Lighting	58,218	110,154	(51,936)	52.9%
Native Village	2,095	2,415	(320)	86.8%
TOTAL	**$5,606,515**	**$5,849,064**	**($242,549)**	**95.9%**

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 Before Rate Increase**
Residential	$2,903,663	$2,970,095	($66,433)	97.8%
Commercial	2,343,224	2,450,627	(107,403)	95.6%
Master-Meter	61,557	67,613	(6,056)	91.0%
Municipal	237,759	251,372	(13,614)	94.6%
Lighting	58,218	106,950	(48,733)	54.4%
Native Village	2,095	2,406	(311)	87.1%
TOTAL	**$5,606,515**	**$5,849,064**	**($242,549)**	**95.9%**

Figure 3
Minimum System Results

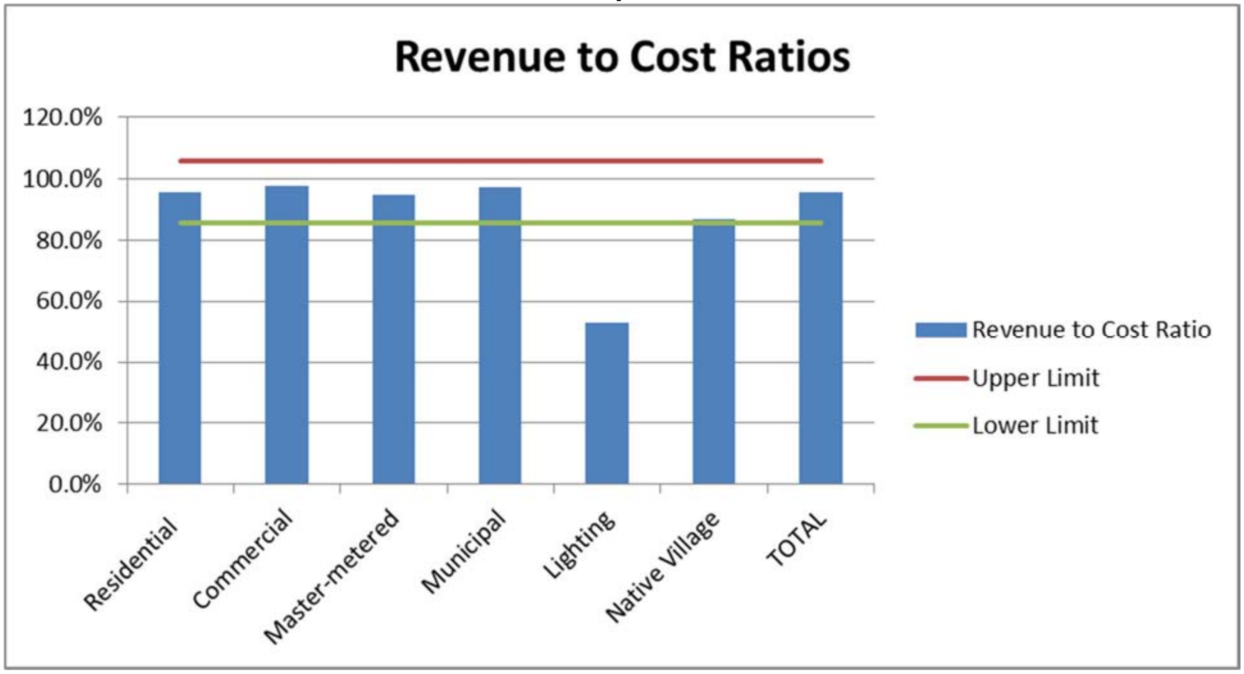
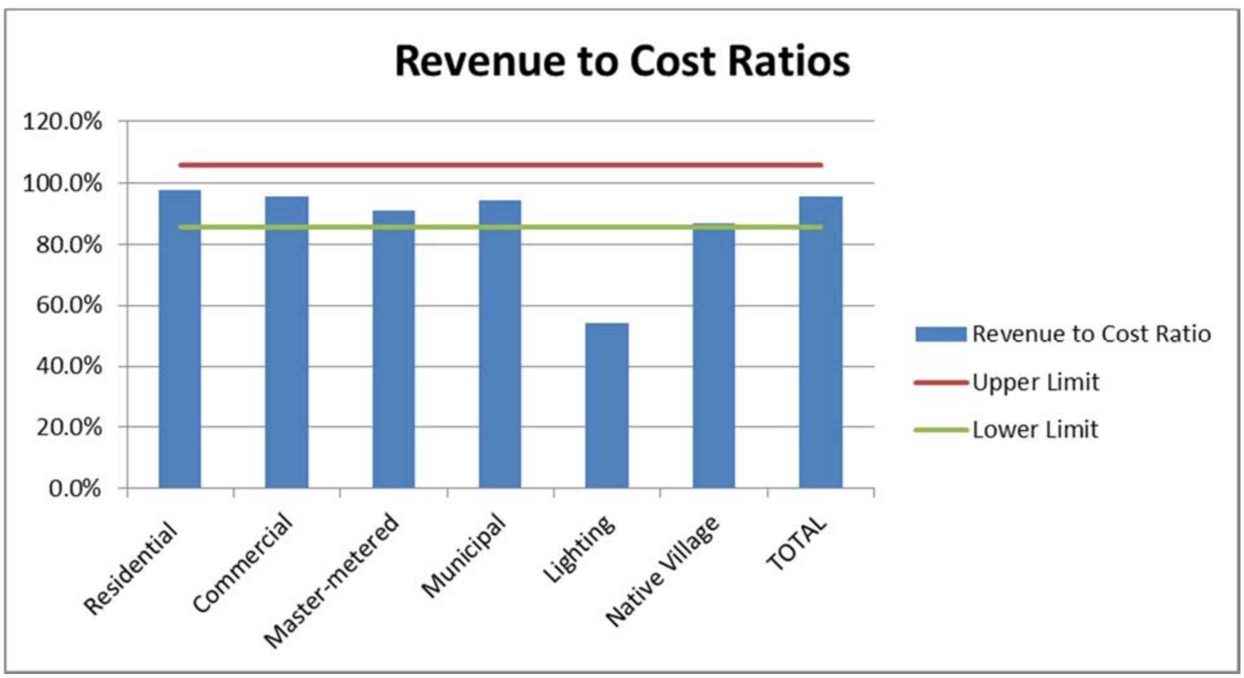


Figure 4
100 Percent Demand Results



Given a number of assumptions, the results show that using present rates, NPUA's electric system is under-collecting from the Lighting class, while the remaining classes are within 10 percent of cost of service (see Figures 3 and 4). It is important to note when examining the results, 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 estimated cost of service typically do not warrant interclass rate modifications.

Rate Design Principles

Rates need to be designed to recover the utility's cost of service. In the current environment, NPUA will have to be increasingly diligent in reviewing certain key components of its revenue requirement to ensure revenue sufficiency. Rate designs that track volatile costs and that acknowledge the effects of price elasticity will become more prominent and important in the coming years.

This section of the report will identify rate setting principles as well as provide a framework for evaluation of the various rate design options. The section then reviews rate design options followed by a review of NPUA's present rate structures.

Rate Setting Principles

Prudent rate administration requires that several viewpoints be considered in setting rates to the extent that the consumer remains a captive customer of the utility. These views balance the needs of the consumer, the utility, and society as a whole. All three need to be considered when designing rates.

Consumer

From a consumer's perspective, several issues predominate.

- Rates should foster fairness and equity. Customers should pay the cost incurred to provide them with service. This means that one customer class should not subsidize another customer class.

- Rates should be comparable. Customers that place similar demands on the utility's system should be served under the same rate. Alternatively, consumers that receive materially different types and/or levels of service should be charged differently. Discrimination should be avoided.

- Rates should be "affordable." Since utility services are seen as a necessity, service from the utility should be affordable to all customers within its service area or provisions should be made to ensure that this would be the case.

- The consumers should easily understand rates. Unless consumers can reasonably ascertain how their consumption patterns affect the price they pay, they will not be able to make rational decisions pertaining to usage. Clear price signals will drive a more competitive market for generated power.

- Rates should be designed so that they are stable, predictable and do not unnecessarily create adverse impacts on the consumer. Unstable rates can hinder planning, particularly for larger customers. For example, unstable rates have the effect of putting industrial customers at a competitive disadvantage versus similar companies with more stable rates.

Utility

Utilities have their own set of issues and concerns.

- Rates must fully recover the utility's revenue requirement.
- Rates for publicly owned utilities should allow for sufficient funds to cover needed capital improvements.
- Rates should be fair and equitable and send proper price signals. Rates that are fair and equitable promote good customer service.
- The rate structure should promote economic efficiency. The rate structure should facilitate good decision-making and foster efficient expansion of the system, and encourage efficient use of the existing system.
- The rate structure should provide for revenue stability and predictability.
- Just as the rate structure should be simple and easy to understand by the consumer, it should also be easy to administer by the utility.

Society

From a societal perspective, a number of further issues should be examined when designing rates. Rates should foster economic efficiency. The rate structure should ensure the optimal use of society's scarce energy resources. Efficiency not only leads to optimal use, it also should lead to optimal non-use, or conservation. With achievement of this level of efficiency as a goal, rates should closely reflect the cost of service. This will also ensure that rates are both fair and equitable among users. As another means of assuring equity in ratemaking, there should be continuity in ratemaking philosophy.

Alternative Rate Designs

Utilities have a variety of rate design alternatives at their disposal. Use of any particular alternative has its advantages and disadvantages. Circumstances can dictate the use of different alternatives. Samples of the types of rate designs that are available to NPUA's electric systems follow.

- Flat Rates
- Tiered Rates
- Time of Use Rates
- Index Rates

- Marginal Cost-Based Rates
- Non-firm or Interruptible Rates
- Economic Development Rates

Flat Rates

Flat rates are the most basic and commonly used rate structure. This basic rate design is composed of two parts, a customer component and a usage charge. The customer charge applies to all the costs associated with being ready to serve the customer. Thus, this component includes costs associated with meter reading, billing, etc. The usage component is composed of costs associated with energy quantity.

Flat rates have the advantage of being simple to understand and administer. However, this rate design has difficulty reflecting the true cost of bundled service. For the electric system, this design does little to influence the power purchasing decisions of the utility's customers, since it provides little information on how consumption patterns affect costs. It can also lead to cash flow volatility if the utility purchases power at a cost that reflects time of day or seasonal prices and receives revenue from customers that reflects average costs.

Although flat rates are inappropriate for reflecting bundled costs, different flat rates may be appropriate for the various components of unbundled service.

Tiered Rates

Tiered (or block) rates are generally of two types, declining and inverted tiers. A tiered rate separates a consumer's energy usage into "tiers" or "blocks" and applies a different rate to each tier. Tiered rates were developed principally to reflect the cost of power supply for electric utilities. If power supply was a surplus commodity, declining tiered rates were deemed appropriate to encourage consumption. If power supply was a scarce commodity, inverted (or increasing) tiered rates were appropriate to discourage consumption. If rates are unbundled, tiered rates would not be appropriate for wires charges as these costs are fixed and do not vary with consumption.

Finally, if the utility wishes to alter its customers' consumption habits it should be aware of the price elasticity effects mentioned above. Inability to properly gauge the response of customers' consumption patterns to the effects of rate design and rate levels can have deleterious effects on the utility's revenues.

Examples of declining tiered rates and inverted tiered rates are shown below for the electric utility.

Declining Tiered Rates

For a declining tiered rate, additional usage will result in lower average and marginal rates. For example, assume that a utility charges 4.0 cents per kWh for the first 500 kWh of usage, 3.5 cents per kWh for the next 500 kWh and 3.0 cents per kWh for any additional energy consumption. If a utility customer consumed 1,200 kWh of energy, then its bill would be the 4.0 cents multiplied by the first 500 kWh plus 3.5 cents multiplied by the second 500 kWh plus 3.0 cent multiplied by the remaining 200 kWh of energy consumption. In this example the average price of power would be the total bill, $43.50, divided by the total usage, 1,200 kWh, or 3.625 cents per kWh. The marginal price of power would be 3.0 cents per kWh.

If the customer had only used 750 kWh, then its total bill would have been $28.75. The resulting average rate would have been 3.833 cents per kWh with a marginal rate of 4.0 cents per kWh. Therefore, as usage increases, the average and marginal price decreased.

Declining-tier rates provide incentive to consume more electricity. This would be an appropriate rate design if the marginal cost of providing such energy was also declining or below the average embedded cost of power. Increased usage would thus drive the average cost of power down. In the 1950's and 1960's, this was especially true. Building larger and more efficient power plants created greater efficiency in production and thus, caused average costs to decline.

Inverted Tiered Rates

An inverted tiered rate is based on the same principle, except that instead of lower average and marginal rates for increased usage, the rates increase with usage. Assume that the usage level and tiers are the same but rates of 3.0, 3.5 and 4.0 cents per kWh are charged for each tier. The power bill becomes $40.50, the average rate becomes 3.375 cents per kWh and the marginal rate is 4.0 cents per kWh. Had the customer consumed 750 kWh, its total bill would have been $23.75. This would have implied an average rate of 3.17 cents per kWh and a marginal rate of 3.5 cents. Therefore, as usage increased, the average and marginal costs increased.

Inverted-tier rates provide the exact opposite incentive as declining tier rates. These rates encourage conservation of energy resources, since greater consumption levels lead to higher prices. This is an appropriate rate design when the cost of energy production is increasing with increased load. This form of rate design was especially popular in the late 1970's and early 1980's when the economies of scale in energy production were diminishing and conservation became a primary objective.

Time of Use Rates

Temporal rate designs can be used to differentiate energy usage by time of use. These types of rates can differentiate on a "time-of-day," "seasonal" or "real-time" basis and are particularly appropriate for the power supply component of unbundled rates.

Time-of-Day Rates

Time-of-day rates typically split the day into two periods, a “heavy-load” or “peak” period and a “light-load” or “off-peak” period. Higher rates are generally associated with the peak period to pay for the increased capacity necessary to meet peak loads. This rate structure can also be intended to influence consumption patterns by encouraging usage in times where excess capacity is available on the system and away from peak-periods of the day when the most usage occurs. One downside to this rate design is the need for special meters to measure usage in the different time periods, as well as more complex billing and accounting. This rate typically only applies to electric systems.

Seasonal Rates

Seasonal rates typically split the year into 2 to 12 periods. Each period has its own rate, based on estimated usage and resource availability in the time period. Like time-of-day rates, this rate structure is intended to more accurately reflect the true costs of service by the utility. Traditionally, seasonal variation is particularly volatile in the Pacific Northwest due to the abundance of hydroelectric power in the region and the diversity in market demand on the west coast. During the late spring and early summer months, increased water flows tend to produce the opportunity for much more power generation than is typically consumed in the same period. Unlike time-of day rates, current billing and metering systems easily accommodate seasonal rates.

Real-Time Rates

Real-time rate structures are the ultimate in temporal pricing. This rate design allows for instantaneous changes in prices given the current loads and resources available. This rate structure allows utilities to charge an amount equal to the costs associated with providing power to its customers at the time of consumption. At the present time, this type of rate design is too complex and expensive to be cost-effectively implemented on a broad basis at the retail level. As the electric market matures and technologies advance, this rate design will become a viable option. This rate applies to electric systems only.

Index Rates

Index rates are another method of pricing unbundled power supply. This rate structure allows the power seller to shift the entire amount of power price risk to its customers, while ensuring that its costs will be covered. With index pricing, the rate or a portion of the rate increases or decreases based on a published price index. The published rate typically changes on a daily basis. This pricing option is predicated on the assumption that the utility will purchase a portion of its power requirement on the spot market. As the utility looks to diversify its power resources, index pricing can be an effective alternative.

More and more trading centers are being used to establish market-clearing prices for power in areas near these centers. One of the more influential trading centers in the emerging market is at the California-Oregon Border (COB). Prices for firm power traded at this trading center are quoted daily in the Wall Street Journal. Another popular West Coast hub is in Arizona at Palo Verde. Prices at this center are also quoted in the Wall Street Journal. In addition, a trading center located in central Washington is referred to as "Mid-Columbia." This is an area of several large hydroelectric projects that serve the electrical needs of a large number of customers in the region.

Marginal Cost-Based Rates

Marginal cost-based rates for retail bundled service in a fully regulated environment are controversial and relatively complex in application. This rate structure relies on more detailed cost estimations that delineate marginal costs of operations. Effectively, this rate design attempts to mimic a competitive market environment by estimating the producer's short-run supply curve, which shows the change in costs with each incremental or decremental unit of energy production, and charging rates that reflect the true cost of producing each additional unit of energy. This rate design is intended to promote the most efficient energy consumption decisions on the part of the consumer.

Marginal cost pricing when developed for retail bundled rates will over- or under-collect a utility's revenue requirement depending on the utility's "supply curve." In cases where marginal costs are declining, the utilities often over collect revenues, and when marginal costs are increasing, the opposite often occurs. Thus, adjustments are made to the overall level of rates while retaining the shape of the marginal cost curve so that the utility does not over- or under-collect revenue and so that the price signal is maintained.

Non-Firm or Interruptible Rates

Non-firm rates have been in use for some time. These rates are most applicable to power supply only, as wires costs do not vary with consumption. These rates are charged for energy that is provided on an as-available basis only, i.e., this energy is not guaranteed for delivery given certain conditions that may prevail between the time of the contract and the date of expected delivery. Due to the added risk to the customer and added flexibility to the utility, these rates are lower than "firm" rates, usually by an amount equal to the cost of providing firm capacity. This rate structure was historically attractive to large industrial customers that use a great deal of power and are willing to take on the added risk of having their power supply curtailed for a short period of time. However, given the current west coast power shortage, it is unlikely that many large industrial users would opt for this type of service in the near future.

Economic Development Rates

Economic development rates are designed to attract, retain or encourage expansion of existing commercial and industrial customers within the utility's service area. Although these types of rates do not promote efficiency, they can promote other external effects that may be beneficial to consumers in the utility's service area in the long run. For example, if a major employer within the region was planning to relocate to another area or shut down entirely due to the energy price, some special rates for their retention may be beneficial to the area's customer and job base. The rate must cover the variable cost of serving this customer and, at a minimum, contribute to recovery of fixed costs as well. Although an economic development rate would not recover the entire customer revenue requirement, only that portion of the fixed cost revenue requirement not covered in the rate would have to be made up by other customer groups rather than the entire fixed cost revenue requirement. However, if the utility collects the marginal cost of serving new customers from each of the new customers, the remaining utility customers are no worse off.

In summary, a number of the above mentioned rate design and pricing alternatives may be employed by NPUA. These alternatives may be used jointly or separately for different customer groups. In the end, the utility will have to balance the risk associated with matching loads and associated revenues with the power supply and its associated costs in addition to the rate design goals and objectives established by the utility.

NPUA's Present Electric Rates and Unit Costs

This section of the report will review the present rate structures with the current PPA for NPUA's electric utility and will provide a comparison with the unit costs developed in the cost of service study.

The electric COSA suggests an overall rate increase of 4.4 percent in order for NPUA's electric utility to pay for O&M expenses, transfers, power supply costs and capital expenditures. Based on the results of the study, it is recommended that NPUA implement a flat rate increase. Rates assume the current PPA is included in the base energy charge.

Residential

NPUA's present residential rate design is composed of a monthly service charge and a tiered energy charge. Presented below in Table 13 are the present rates for the residential customers and the COSA unit costs as flat rates.

Table 13
Comparative Rate Schedule for Residential Customers

	Present Rates incl. PPA	Minimum System	100 Percent Demand
Customer Charge: $/Month	$27.01	$26.31	$20.28
Energy Rate: $/kWh	$0.0846 (avg)	$0.0908	$0.0952
Increase over Present Rates	-	*4.5%*	*2.3%*

Commercial

The present rate design for Commercial customers includes a basic customer charge and a flat energy rate. Presented below in Table 14 are the present rates and the COSA unit costs.

Table 14 Comparative Rate Schedule for Commercial Customers			
	Present Rates incl. PPA	**Minimum System**	**100 Percent Demand**
Customer Charge: $/Month	$27.01	$26.87	$20.84
Energy Rate: $/kWh	$0.0846 (avg)	$0.0865	$0.0901
Increase over Present Rates	-	*2.1%*	*4.6%*

Master-Meter

NPUA's present master-meter rate design is composed of a monthly service charge and a tiered energy charge. Presented below in Table 16 are the present rates for the master-meter customers and the COSA unit costs as flat rates.

Table 16 Comparative Rate Schedule for Master-Meter Customers			
	Present Rates incl. PPA	**Minimum System**	**100 Percent Demand**
Customer Charge: $/Month	$27.01	$26.31	$20.28
Energy Rate: $/kWh	$0.0846 (avg)	$0.0892	$0.0931
Increase over Present Rates	-	5.3%	9.8%

Municipal

The present rate design for municipal customers includes a basic customer charge and a flat energy rate. Presented in Table 17 are the present rates for the municipal customers and the COSA unit costs for this customer class.

Table 17 Comparative Rate Schedule for Municipal Customers			
	Present Rates incl. PPA	**Minimum System**	**100 Percent Demand**
Customer Charge: $/Month	$27.01	$26.31	$20.28
Energy Rate: $/kWh	$0.0846 (avg)	$0.0873	$0.0909
Increase over Present Rates	-	*2.8%*	*5.7%*

Native Village

The present rate design for Native Village customers includes a basic customer charge and a flat energy rate. Presented in Table 18 are the present rates for the Native Village customers and the COSA unit costs for this customer class.

Table 18
Comparative Rate Schedule for Native Village Customers

	Present Rates incl. PPA	Minimum System	100 Percent Demand
Customer Charge: $/Month	$27.01	$26.31	$20.28
Energy Rate: $/kWh	$0.0846 (avg)	$0.1043	$0.1123
Increase over Present Rates	-	*15.3%*	*14.8%*

Lighting

The present rate design for lighting customers includes a fixed fee under approximately 20 different rate schedules based on wattage. The COSA recommends an 89 to 84 percent rate increase for this customer class for FY 2014.

Recommendation for the Electric Utility

Based on the projected revenue requirement and COSA study, EES makes the following recommendations:

- Using current electric rates, NPUA is collecting sufficient revenues to meet costs in FY 2015.

- Based on the current inter-class results for the electric system COSA, a change in rate design may not be needed at this time. Beyond FY 2015 NPUA may consider a flat across-the-board rate increase to meet forecast expenses. This recommendation reflects the uncertainty inherent in the COSA study based on the uncertainty associated with the load data and other input assumptions. Therefore, before implementing any new rates, NPUA should obtain legal review and approval.

- It is important to remember that any rate increase above 10 percent is generally considered a rate shock and it is therefore the recommendation of EES that NPUA keep rate changes below 10 percent for any single customer class.

Appendix A – Electric