OPALCO's COST OF SERVICE ANALYSIS AND RATE DESIGN PROCESS

The following documents summarize the lengthy process OPALCO and the Board of Directors went through to do a Cost of Service Analysis (COSA) and to develop a rate structure that would recover OPALCO's cost of service. The goal of the resulting rate structure is to meet revenue requirements, fairly allocate expenses in relation to each member's use of and impact on the system, reduce the effect of weather, market and other volatility and promote stability in OPALCO's financial position.

EES Consulting

November 13, 2014

TO: Foster Hildreth

FROM: Anne Falcon

SUBJECT: Collection of Fixed Costs

Introduction

Utility customers are increasingly exploring options for using energy more efficiently and applying alternative energy sources to meet their needs. As a result, utilities are experiencing financial pressures due to reduced energy sales. In the short-term, utilities cannot reduce the fixed cost of delivering the power, as these services are still needed by the utility customers. Because traditional rate structures collect the majority of revenues from a volumetric energy charge, utilities are finding it more and more difficult to collect sufficient revenues to meet the fixed costs of operating the utility.

OPALCO is experiencing this phenomenon today. Successful energy efficiency programs, distributed generation pressures, and warmer weather has contributed to a significant shortfall in current revenues. In order to avoid this issue in the future, EES Consulting was asked to provide a description of rate options available to OPALCO to ensure collection of non-avoidable (fixed) costs as energy sales are reduced.

Considerations

There are several reasons why average energy use is declining. Some of these reasons are provided below:

1. **Homes have higher efficiency levels.** New homes are held to higher weatherization standards and older homes are more efficient on average thanks to large tax credits for weatherization upgrades.
2. **Increased energy efficiency investment**. Increased spending and state mandates have made energy efficiency investment available to more people.
3. **Technological advancements.** As technology has developed, we have switched to more efficient technologies including battery operated devices.

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4. **Market transformation.** Lighting and televisions are up to 80 percent more efficient due to changes in codes and standards. In addition, all of the new major appliances have increased efficiency grades.
5. **Cooling off.** Homeowners are exchanging their window air conditioning units for central air and consequently increasing cooling efficiency.
6. **Distributed generation has become more affordable.** Refurbished solar and wind resources, leasing programs, and falling capital costs have made distributed generation more affordable.
7. **Distributed generation has become more prevalent.** Sixty-eight percent of wind turbines installed in the U.S. between 2003 and 2012 were distributed generation.
8. **Climate Change.** Temperatures have been warmer than normal in the last 10 years.

Combined with the reduction in energy use, OPALCO has unique circumstances as it is a rural island utility with several expensive underwater cables. Compared to many urban utilities, OPALCO's cost of delivery is very high. Because OPALCO recovers the majority of these fixed delivery costs through their energy charge, the utility experiences significant losses when energy sales are down.

At the same time, OPALCO is a progressive utility that is actively pursuing energy efficiency and encourages distributed generation as a way to reach self-sufficiency of resources.

OPALCO's customer mix include 53 percent electric heating customers, a large percent of low/fixed income customers and also includes a large percentage of seasonal customers. When exploring rate design options, these characteristics and potential bill impacts must be considered.

It is also important to note that the 25 percent of OPALCO members are part-time/seasonal residents, with low electric usage occurring primarily in the warmer months. The recurring costs for members to remain connected to the grid on an annual basis is equivalent for all members within each rate class. Since the current rate structure has fix expenses collected in the variable component of the rate, the revenue collected to offset such expenses results in full-time residents subsidizing part-time residents.

Strategies

Navigating rate policies regarding distributed generation and energy efficiency can be a tricky exercise. The following strategies can help your utility thrive under changing electricity use profiles:

1. Implement High Fixed Charge

Under this strategy, the power supply related costs from the COSA would be collected based on variable charges, such as energy and demand charges, while the non-power supply costs would be collected based on a fixed monthly charge. Table 1 provides the calculated charges from the most recent COSA study.

Table 1

Calculation of High Fixed Charge

	Total	Residential	Residential TOU	Pump	Commercial / Industrial Small	Commercial Marina	Public Street/ Highway Lighting
Power Supply (Energy, Demand and BPA Transmission)	$7,838,396	$5,367,355	$68,850	$50,411	$2,260,781	$90,966	$33
Power Supply Unit Costs ($/Kwh)	$0.0377	$0.0370	$0.0370	$0.0353	$0.0396	$0.0395	$0.0353
Non-Power Supply	$14,267,077	$10,203,492	$107,318	$263,910	$3,458,082	$199,607	$34,668
Non-Power Supply Unit Costs ($/Customer/Month)	$86.21	$73.90	$120.38	$44.08	$189.15	$90.20	$959.81

Based on data in Table 1, this strategy would charge each residential customer $73.90 per month or $886.97 per year in fixed cost regardless of energy usage. This would have a high bill impact on households with distributed generation, seasonal customers and low energy users as the current fixed charge is $28.60 per month or $343.20 per year. The winners under this strategy would be the high energy users because they no longer pay for the delivery system in their energy charge. This strategy would not encourage energy efficiency and could potentially cause an increase in energy consumption.

Before implementing this charge, it is important to remember the recent experience at other utilities that increased the fixed monthly charge significantly. If OPALCO chooses this strategy, it is recommended to slowly implement this high charge over time and to invest in significant customer education prior to implementation.

2. Implement Minimum Bill

Another strategy would be to implement a minimum bill amount that must be paid by all customers. It is similar to the High Fixed Charge strategy, but customers would be able to include energy consumption in their minimum bill charge. This strategy would work by keeping the current rate structure, but for low users or seasonal customers, the minimum bill would be increased to $73.90 per month.

This strategy mitigated some of the impact of the high monthly charge strategy. However, if the minimum bill is set at the level of the High Charge ($78/month), low energy customers, seasonal customers and distributed generation customers will experience significant bill increases. This option also does not promote energy efficiency.

3. Implement Cost Recovery Charge

Another option to collect the shortfall in revenues would be to implement a Cost Recovery Charge. A Cost Recovery Charge (CRC) is designed to recoup lost revenues that are caused by fluctuations in energy consumption. The CRC gives utilities the ability to deal with ongoing revenue changes without having to make frequent changes to the base rate structure. The CRC is typically calculated once per month based on actual costs and revenues. However, the CRC can be designed to be calculated monthly, quarterly or annually. The CRC can be calculated to recover sufficient additional revenues for OPALCO to meet TIER requirements or some other financial target.

This strategy would impact customers based on their energy usage as the charge is most often designed as an energy charge ($/kWh).

4. Combination of Options

The last strategy would be to implement a combination of the strategies listed above. This option could develop a minimum bill payment and/or increase the monthly fixed charge over time and implement a Cost Recovery Charge to collect any shortfalls. In addition, these strategies could be ramped up over time to mitigate the immediate impact on customers.

Conclusion

Regardless of the strategy that is implemented to ensure recovery of lost revenues due to low energy consumption and fixed costs, it is important to keep in mind the following:

- Take care of vulnerable customers (low and fixed income) by providing access to resources that will allow them to participate in energy efficiency programs.
- Consider the impact on energy efficiency participation.
- Consider the impact on local distributed generation cost effectiveness.
- Continue to monitor the fixed cost of the system and consider options for long term savings.
- Educate customers on rate components and why rates are changing.
- Consider the additional customer education needs and front office staffing needs as customers may object to bill increases.

ORCAS POWER AND LIGHT COOPERATIVE

POLICY 29

ENERGY SERVICES RATE DESIGN

29.1 PURPOSE

To set forth policy relating to the development and implementation of electric rates that follows the strategic objectives of the Cooperative.

29.2 POLICY

29.2.1 Commitment to Rate Design

It is the policy of the Board of Directors of the Cooperative to develop electric rates that allow the Cooperative to provide electricity that is reliable, cost-based, considerate of the environment and maintains the Cooperative's financial strength at the Cooperative's lowest cost. The Cooperative's Rate Structures shall meet revenue requirements, fairly allocate the Cooperative's expenses in relation to each members' use of and impact on the system, reduce the effects of weather, market and other volatility and promote stability in the Cooperative's ongoing financial position as indicated through equity and TIER.

29.2.2 Basic Fundamentals

29.2.2.1 The Cooperative will periodically perform cost of service studies to inform whether existing rate structures are meeting the goals of this policy.

29.2.2.2 Rates will be developed and implemented that:

29.2.2.2.1 Meet revenue requirements and are cost-based;

29.2.2.2.2 Are implemented over time when dramatic rate changes occur;

29.2.2.2.3 Generate margins which meet long-term financial objectives and lender requirements and as per the Cooperative's strategic directives;

29.2.2.2.4 Decrease revenue volatility to counter warming temperature trends and reduction in energy usage.

29.2.2.2.5 **Facility**: Utilize a fixed cost methodology whereby the facility charge collects the Cooperatives' fixed expenses;

29.2.2.2.6 **Demand**: Implement a demand element which reflects the costs associated with variable need for system capacity for all member classes as the phase out/replacement of existing meters progresses;

29.2.2.2.7 **Energy**: Implement a variable mechanism that passes energy costs to members based on their usage;

29.2.2.2.8 **<u>Cost Recovery Charge</u>**: Implement a Cost Recovery Charge (CRC) on member bills to recoup lost revenues that are caused by fluctuations in energy consumption.

29.2.2.3 Rates will incorporate a mechanism for ensuring any above the Cooperative's power provider's base load rates (BPA Tier 1) will be charged for those costs.

29.2.2.4 Rate increases necessary to meet budgetary revenue requirements are to be applied to the facility charge component of member bills until 29.2.2.2.5 is achieved.

29.2.2.5 Rates shall be independent of OPALCO approved member programs for energy conservation, energy assistance (PAL), member owned renewal energy (MORE), etc. The determination of the funding of these programs will be through Board action as laid out during the budgeting process.

29.2.3 Management Responsibility

29.2.3.1 Management will be held accountable for implementing rates as approved by the Board of Directors and routinely report to the Board of Directors as to the need to adjust rates to account for changes in cost or strategic initiatives.

J. Foster Hildreth, General Manager

Effective Date: <u>11/20/2014</u>

OPALCO Rate Summary

Facility Charge Analysis

November 2015

April Board Meeting: Rate Structure Objectives

✔ • Rates Should Meet Revenue Requirement

✔ • Rates Should be Cost Based

✔ • Rates Should be "Just, Reasonable and Not Unduly Discriminatory or Preferential" — "Fair and Equitable"

✔ • Rates Should be Easy to Understand and Administer

✔ • Rates and the Cost Allocation Process Should Conform to Generally Accepted Rate Setting Techniques

✔ • Rates Should Provide Revenue Stability to the Utility and Rate Stability to the Customer

Rate Structure Objectives

✔ • Rates Should Meet Revenue Requirement

✔ • Rates Should Provide Revenue Stability to the Utility and Rate Stability to the Customer

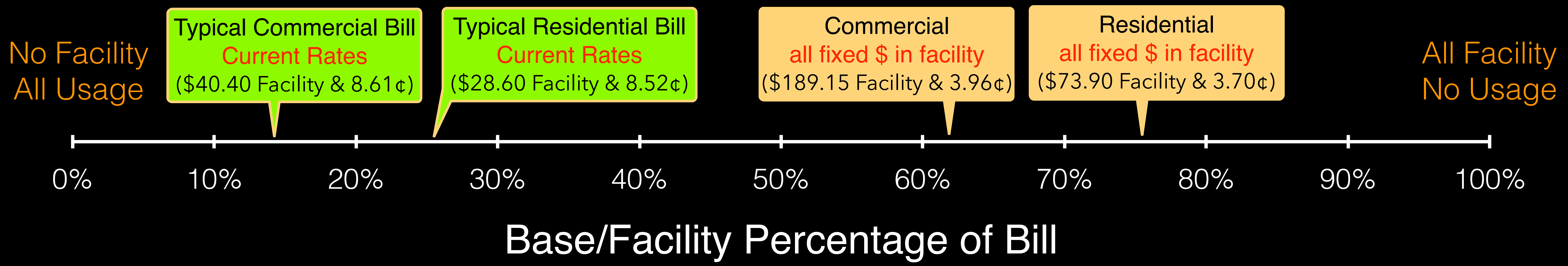
Meeting sustainable revenue requirements supports all other OPALCO objectives and initiatives, including:

- Maintain and operate our utility
- Reliable electricity
- Self funding strategic programs
  - Energy efficiency & conservation
  - Local renewable energy generation
  - Education programs
- Low income member support
- Supporting local economy
  - Employees, contractors, construction, broadband infrastructure

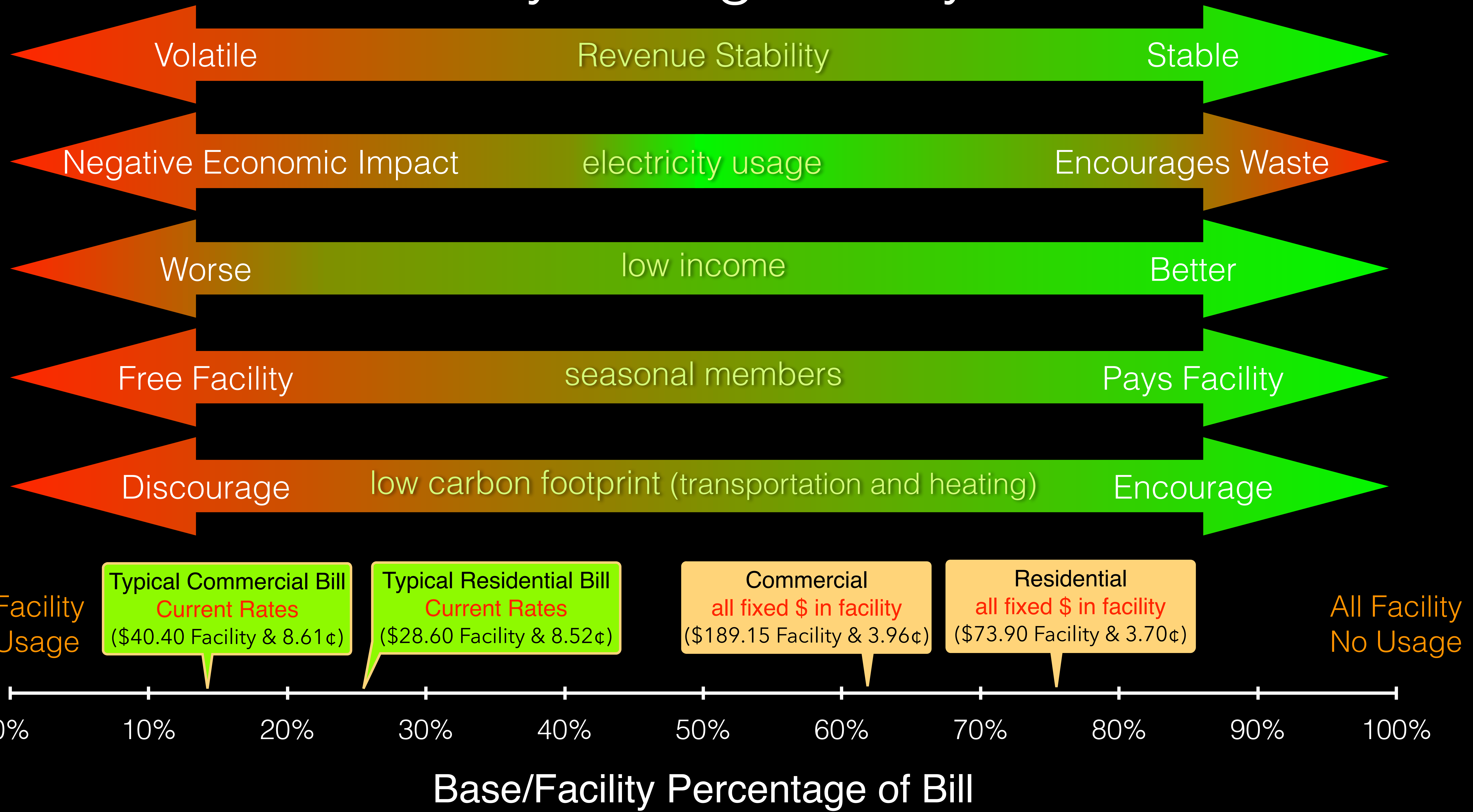
April Board Meeting: Rate Structure Objectives

✔ • Rates Should be "Just, Reasonable and Not Unduly Discriminatory or Preferential" — "Fair and Equitable"

Facility Charge Analysis



Facility Charge Analysis



Rate Scenario Analysis

Average Monthly Usage and Bill

Rate Scenarios	All Residential 12,600 members	Low Income 279 members	Commercial 1,655 members
Energy Usage (kWh)	925	1062	2730
Existing ($28.60 Facility & 8.52¢)	$114.20	$119.12	$295.10
Proposed ($28.60 Facility & 8.50¢)	$114.63	$118.64	$300.85
All fixed $ in facility ($73.90 Facility & 3.70¢)	$110.91	$113.94	$305.42
100% Usage ($0 Facility & 11.00¢)	$110.06	$116.82	$323.02

What problems are we trying to solve?

- Reliable
- Self sustainable
- Affordable
- Low Carbon

What do we want to Acheive, Cause, Create?

Low Carbon

Member programs:

- Energy Efficiency
- Renewables
- Low Income Assistance

Thank You!

MEMORANDUM

January 16, 2015

TO: Board of Directors

FROM: Foster Hildreth

RE: Rates and Tariffs

In an effort to confirm the effectiveness of the rate design proposed in December, staff revisited sales projections to align them with actual 2014 kWh sales. The resulting calculations predicted a 10.4% increase in revenue for 2015. To reach the targeted revenue increase of 12% (approved in the 2015 budget), kWh charges were adjusted for Residential, Pumps, Small Commercial, and Large Commercial tariffs.

Attached is an updated proposed tariff schedule as well as a memo from EES with supporting data.

2015 Budget

Rate Detail: Revised with updated weather forecast and EES/Test Data Confirmation 1-15-15

Revenue Increase:		12% Increase	6% Increase	6% Increase	6% Increase	6% Increase
	2014 Existing	2015 Budget	2016 Projected	2017 Projected	2018 Projected *	2019 Projected *
Residential						
Facility Rate ($/Service/Month)	28.60	$38.90	$48.20	$58.10	$66.00	$74.70
Demand Rate ($/Service/Month)		0.00	1.00	3.00	3.00	3.00
Energy Rates ($/kWh)						
Block 1 (≤5,000 kWh)	$0.0852					
Block 2 (>5,000 kWh)	$0.1006					
Summer Block 1 (<1,500 kWh)		~~$0.0850~~ $0.0855	~~$0.0813~~ $0.0850	~~$0.0780~~ $0.0820	~~$0.0780~~ $0.0820	~~$0.0780~~ $0.0820
Summer Block 2 (1,500 to 3,000 kWh)		~~$0.0950~~ $0.0970	~~$0.1036~~ $0.1050	~~$0.1085~~ $0.1100	~~$0.1085~~ $0.1100	~~$0.1085~~ $0.1100
Summer Block 3 (>3000 kWh)		$0.1150	$0.1150	$0.1150	$0.1150	$0.1150
Winter Block 1 (<3,000 kWh)		~~$0.0850~~ $0.0855	~~$0813~~ $0.0850	~~$0.0780~~ $0.0820	~~$0.0780~~ $0.0820	~~$0.0780~~ $0.0820
Winter Block 2 (3,000 to 5,000 kWh)		~~$0.0950~~ $0.0970	~~$0.1036~~ $0.1050	$0.1100	$0.1100	$0.1100
Winter Block 3 (>5,000 kWh)		$0.1150	$0.1150	~~$0.1085~~ $0.1150	~~$0.1085~~ $0.1150	~~$0.1085~~ $0.1150
Residential TOU						
Facility Rate ($/Service/Month)	$32.20	$43.80	$54.20	$65.40	$74.30	$84.10
Demand Rate ($/Service/Month)			$0.50	$1.00	$1.00	$1.00
Energy Rates ($/kWh)						
TOU Period 1 (6 am – Noon)	$0.1294	$0.1450	$0.1450	$0.1450	$0.1450	$0.1450
TOU Period 2 (Noon – 10* pm) *To be*	$0.0590	$0.0900	$0.0900	$0.0900	$0.0900	$0.0900
phased in over 3 years		*Noon – 8 pm*	*Noon – 9 pm*	*Noon – 10 pm*	*Noon – 10 pm*	*Noon – 10 pm*
TOU Period 3 (10* pm – 6 am)	$0.0507	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400
Small Commercial (<20 kW)						
Facility Rate ($/Service/Month)	$40.40	$54.90	$67.90	$81.90	$93.00	$105.20
Energy Rates ($/kWh)						
Block 1 (<5,000 kWh)	$0.0866	~~$0.0861~~ $0.0870	~~$0.0861~~ $0.0870	~~$0.0861~~ $0.0870	~~$0.0861~~ $0.0870	~~$0.0861~~ $0.0870
Block 2 (>5,000 kWh)	$0.0781	~~$0.0861~~ $0.0970	~~$0.0944~~ $0.0980	~~$0.1059~~ $0.1060	~~$0.1059~~ $0.1060	~~$0.1059~~ $0.1060
Demand Rate ($/Service/Month)						
First 20 kW (Flat Rate)	$0.00	$5.00	$5.30	$6.00	$6.00	$6.00
Over 20 kW	$3.15					

2015 Budget

Rate Detail (continued): Revised with updated weather forecast and EES/Test Data Confirmation 1-15-15

Revenue Increase:		12% Increase	6% Increase	6% Increase	6% Increase	6% Increase
	2014 Existing	2015 Budget	2016 Projected	2017 Projected	2018 Projected *	2019 Projected *
Large Commercial (>20kW)						
Facility Rate ($/Service/Month)	$40.40	$54.90	$67.90	$81.90	$93.00	$105.20
Energy Rates ($/kWh)						
Block 1 (<5,000 kWh)	$0.0866	~~$0.0775~~ $0.0790	~~$0.0777~~ $0.0795	~~$0.0782~~ $0.0800	~~$0.0782~~ $0.0800	~~$0.0782~~ $0.0800
Block 2 (5,000 – 150,000 kWh)	$0.0781	~~$0.0775~~ $0.0873	~~$0.0777~~ $0.0880	~~$0.0782~~ $0.0885	~~$0.0782~~ $0.0885	~~$0.0782~~ $0.0885
Block 3 (>150,000 kWh)		$0.1162	$0.1166	$0.1173	$0.1173	$0.1173
Demand Rates ($/kW)						
First 20 kW	$0.00					
Over 20 kW	$3.15					
Block 1 (≤300 kW)		$3.15	~~$3.15~~ $3.90	~~$3.15~~ $4.65	~~$3.15~~ $5.40	~~$3.15~~ $6.15
Block 2 (>300 kW)		$4.73	~~$4.75~~ $5.48	~~$4.73~~ $6.23	~~$4.73~~ $6.89	~~$4.73~~ $7.73
Pumps						
Facility Rate ($/Service/Month)	$25.30	$34.40	$42.60	$51.40	$58.40	$66.10
Energy Rates ($/kWh)						
0-370 kWh	$0.0978	$0.0923	$0.0813	$0.0771	$0.0771	$0.0771
371-5,000 kWh	$0.0752	$0.0802	$0.0813	$0.0771	$0.0771	$0.0771
Over 5,000 kWh	$0.0900	~~$0.0878~~ $0.0900	$0.0830	$0.0771	$0.0771	$0.0771
Demand Rate ($/Service/Month)						
First 20 kW (Flat Rate)	$0.00	$0.00	$1.00	$2.50	$2.50	$2.50
Over 20 kW	$3.15	$3.15	$3.15	$3.15	$3.15	$3.15

Note: * Same Rate Structure as 2017; requires new Cost of Service Study

EES Consulting

January 15, 2015

TO: Foster Hildreth, OPALCO

FROM: Anne Falcon AHF

SUBJECT: Rate Impact of Proposed Rate Design

Introduction

As part of a comprehensive process, OPALCO's Staff and Board have been reviewing electric rate design option and utility objectives over the last several months. Based on Board and customer input, a design which increases the fixed monthly charge and reduces the energy block sizes was developed. This design will allow OPALCO to address the utility's fixed costs by collecting more revenue in a fixed monthly charge, while providing a price signal to encourage energy efficiency.

Due to budgetary issues, the new rates will need to collect an additional 12% in revenues. This memo explores the impact of the new rates and provides options for proceeding.

Impact of New Rates

In order to evaluate the new rates, monthly customer billing data for 2013 was obtained and used to develop consumption by rate block. It is important to note that the actual impact is highly dependent on the timing and volume of electricity used by OPALCO's members. The estimates in this memo and the rate models rely on assumptions based on prior consumption behaviors by OPALCO members.

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The current and initially proposed new residential rates are shown in Table 1. In addition, the shares of total annual energy consumption are shown in the last column.

Table 1
Current and Proposed Rates

	Current Rate	Proposed Rate	% Usage in Block
Facility Rate	$28.60	$38.90	
Block 1 (<5,000 kWh)	$0.0852		98%
Block 2 (>5,000 kWh)	$0.1006		2%
Summer Block 1 (<1,500 kWh)		$0.0850	25%
Summer Block 2 (>1,500 kWh)		$0.0950	4%
Winter Block 1 (<3,000 kWh)		$0.0850	64%
Winter Block 2 (3,000 – 5,000 kWh)		$0.0950	4%
Winter Block 3 (>5,000 kWh)		$0.1050	2%

Table 2 provides the estimated revenue impact from the new rates (as presented in December).

Table 2
Projected Revenue Increase Based on original 2015 kWh projections

	kWh Sales	Revenue	Percent Increase
January	23,509,511	$2,473,363	7.1%
February	20,783,661	$2,402,971	8.2%
March	20,183,135	$2,338,883	1.2%
April	16,244,087	$2,003,470	14.4%
May	13,692,838	$1,786,141	17.3%
June	12,352,015	$1,667,241	22.5%
July	12,878,744	$1,706,134	13.9%
August	12,783,429	$1,698,135	12.2%
September	12,503,555	$1,676,057	17.8%
October	15,661,318	$1,946,756	27.8%
November	19,377,116	$2,272,626	15.0%
December	24,536,539	$2,725,366	4.3%
Total	204,505,948	$24,697,143	12.1%

Table 2 demonstrates that the proposed rates are expected to collect approximately 12.1 percent more revenues compared to existing rates. However, the kWh originally projected during the rate design phase was higher than actual results for 2014. It should also be noted that the winter increase is in the order of 8.2 to 27.8 percent, while the revenue increase during the summer months are in the order of 12.2 to 22.5 percent.

Considerations

Because 2015 loads are expected to be similar to actual 2014 loads, the data was updated to reflect kWh closer to 2014 actual kWh sales.

Table 3
Current and Updated Rates

	Current Rate	Updated Rate
Facility Rate	$28.60	$38.90
Block 1 (<5,000 kWh)	$0.0852	
Block 2 (>5,000 kWh)	$0.1006	
Summer Block 1 (<1,500 kWh)		$0.0850
Summer Block 2 (1,500 – 3,000 kWh)		$0.0950
Summer Block 3 (> 3,000 kWh)		$0.1050
Winter Block 1 (<3,000 kWh)		$0.0850
Winter Block 2 (3,000 – 5,000 kWh)		$0.0950
Winter Block 3 (>5,000 kWh)		$0.1050

Based on the rates above the updated projected revenues can be found in Table 4.

Table 4
Projected Revenue Increase Based on 2014 kWh Sales

	kWh Sales	Revenue	Percent Increase
January	22,992,304	$2,429,770	5.2%
February	20,346,973	$2,364,660	6.5%
March	19,758,868	$2,301,961	-0.4%
April	15,886,718	$1,973,776	12.7%
May	13,405,000	$1,761,205	15.6%
June	12,092,362	$1,644,818	20.9%
July	12,608,018	$1,682,776	12.4%
August	12,527,248	$1,674,974	10.6%
September	12,240,720	$1,653,383	16.2%
October	15,332,104	$1,918,349	25.9%
November	18,950,821	$2,237,094	13.2%
December	23,996,735	$2,680,061	2.5%
Total	200,137,871	$24,322,827	10.4%

After the adjustments for actual 2014 kWh sales are considered, the projected revenue increase is 10.4%. To reach a 2015 target of 12%, changes were made to the kWh charges for Residential and Commercial tariffs as shown in Table 5.

Table 5 Current and Updated Rates		
	Current Residential Rate	**Updated Residential Rate**
Facility Rate	$28.60	$38.90
Block 1 (<5,000 kWh)	$0.0852	
Block 2 (>5,000 kWh)	$0.1006	
Summer Block 1 (<1,500 kWh)		$0.0855
Summer Block 2 (1,500 – 3,000 kWh)		$0.0970
Summer Block 3 (>3,000 kWh)		$0.1150
Winter Block 1 (<3,000 kWh)		$0.0855
Winter Block 2 (3,000 – 5,000 kWh)		$0.0970
Winter Block 3 (>5,000 kWh)		$0.1150
	Current Small Commercial Rate	**Updated Small Comm. Rate**
Facility Rate	$40.40	$54.90
Block 1 (<5,000 kWh)	$0.0866	$0.0870
Block 2 (>5,000 kWh)	$0.0781	$0.0970
	Current Large Commercial Rate	**Updated Large Comm. Rate**
Facility Rate	$40.40	$54.90
Block 1 (<5,000 kWh)	$0.0866	
Block 2 (>5,000 kWh)	$0.0781	
Block 1 (<5,000 kWh)		$0.0790
Block 2 (5,000 – 150,000 kWh)		$0.0873
Block 3 (>150,000 kWh)		$0.1162

Based on the rates above the updated projected revenues can be found in Table 6.

Table 6 Projected Revenue Increase Based on 2014 kWh/adjusted kWh charges			
	kWh Sales	**Revenue**	**Percent Increase**
January	22,992,304	$2,429,742	5.2%
February	20,346,973	$2,408,701	8.5%
March	19,758,868	$2,339,079	1.2%
April	15,886,718	$2,005,423	14.5%
May	13,405,000	$1,788,333	17.4%
June	12,092,362	$1,671,006	22.8%
July	12,608,018	$1,711,609	14.3%
August	12,527,248	$1,704,221	12.6%
September	12,240,720	$1,681,014	18.1%
October	15,332,104	$1,950,632	28.0%
November	18,950,821	$2,275,294	15.1%
December	23,996,735	$2,732,087	4.5%
Total	200,137,871	$24,697,141	12.1%

The complete recommended rate design for all tariffs is attached.

CC: Russell Guerry
Amy Saxe

Orcas Power and Light Cooperative
Electric Cost of Service and Rate Study
Final
February 12, 2015

Prepared by:

EES Consulting

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Contents

Executive Summary

Orcas Power and Light ("OPALCO") 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 utility customers. The purpose of this report is to discuss the data inputs, assumptions and results that were part of developing the rate study.

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

Revenue Requirement

A revenue requirement analysis compares the overall revenues of the utility to its expenses and helps determine the overall adjustment to rate levels that is required. For this analysis, a "cash basis" method was used for determining OPALCO's revenue requirement. Annual operating expenses for calendar year (CY) 2012 were used to determine the revenue requirement as well as the 2013 budget forecast provided by OPALCO.

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

- Historic year is CY 2013 (January 2013 – December 2013).
- Test year is CY 2014.
- Load forecast for CY 2014 through CY 2018 was based on a 1.0 percent per year load growth forecast for residential and 0.5% load forecast for commercial from OPALCO. Actual customer loads from January 2013 through December 2013 are used.
- Expenses were taken directly from OPALCO's annual operating expenses, 2013 actual operating expenses, 2014, 2015 and 2016 operating budgets and forecasted at an average annual escalation rate of 3 percent per year beginning in 2017.
- Power supply costs are based on information provided by OPALCO and BPA's RIM model.
- Revenues are calculated using current rates and billing determinants.
- Margins based on OPALCO's annual budget included in Revenue Requirement.

Looking at the one year allocation period, the total CY 2014 revenues are expected to be $23.1 million, while expenses are projected to be $23.0 million. This results in a 0.4 percent surplus in retail rate revenues. A summary of the draft accrual basis revenue requirement is shown in Table 1.

Table 1 Summary of the Cash Basis Revenue Requirement CY: 2014	
Revenues	***CY 2014***
Present Rate Revenues	$23,056,883
Other Income	503,013
Total Revenues	$23,559,896
Expenses	
Power Supply	$7,962,823
Transmission	77,112
Distribution	5,142,615
Customer Accounts and Services	1,641,580
Administration and General	2,931,201
Depreciation	2,889,271
Taxes	948,050
Interest	915,599
Margin	1,003,540
Other Contributions	(47,280)
Total Expenses	$23,464,511
Surplus (Deficiency) in Funds	$95,385
Required Revenue Increase (Decrease)	-0.4%
Present Rate Revenues[1]	$23,056,883
Rev Req (Expenses less Other Income)	$22,961,498
Surplus (Deficiency) in Funds	$95,385
Required Retail Rate Increase (Decrease)	**-0.4%**

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 OPALCO was functionalized, classified and allocated. Unlike most cost of service studies, costs were kept functionalized throughout the analysis which provides for greater transparency when reviewing results.

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

Generally there are two methodologies that can be used to classify distribution costs: 100 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.

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

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

CY 2014 results are summarized for the minimum system approach in Table 2 and for the 100 percent demand approach in Table 3.

Table 2
Summary of CY 2014
Cost of Service Analysis - Minimum System

	Present Rate Revenues	Net Revenue Requirement	Surplus/ (Deficiency) in Present Rates	Revenue to Cost Ratio
Residential	$16,580,285	$16,183,057	$397,229	102.5%
Residential TOU	162,769	182,607	(19,839)	89.1%
Pump	276,720	330,155	(53,435)	83.8%
Commercial / Industrial	5,688,548	5,926,348	(237,800)	96.0%
Marina	317,453	302,550	14,903	104.9%
Public Street/ Highway Lighting	31,108	36,781	(5,673)	84.6%
TOTAL	**$23,056,883**	**$22,961,498**	**$95,385**	**100.4%**

Table 3 Summary of CY 2014 Cost of Service Analysis – 100 Percent Demand				
	Present Rate Revenues	**Net Revenue Requirement**	**Surplus/ (Deficiency) in Present Rates**	**Revenue to Cost Ratio**
Residential	$16,580,285	$15,651,679	$928,606	105.9%
Residential TOU	162,769	192,008	(29,240)	84.8%
Pump	276,720	248,743	27,977	111.2%
Commercial / Industrial	5,688,548	6,528,482	(839,934)	87.1%
Marina	317,453	304,533	12,920	104.2%
Public Street/ Highway Lighting	31,108	36,052	(4,944)	86.3%
TOTAL	**$23,056,883**	**$22,961,498**	**$95,385**	**100.4%**

Table 4 shows projected rate increases through CY 2018. 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. Rate increases should not be summed across years. For example, if rates were increased 6.4 percent in 2015, the 12.7 percent rate increase projected for 2016 would be adjusted to a 5.9 percent rate increase.

Power supply costs are shown separately in column *b*.

Table 4 Projected Rate Increases						
CY	**Present Rate Revenues**[1] *a*	**Power Supply Costs** *b*	**Non-Power Supply Costs, Net**[2] *C*	**Revenue Requirement** *d = b + c*	**Surplus (Deficiency)** *e = a - d*	**Rate Increase (Decrease) Over Current Rates** *f =- e/a*
2014	23,056,883	7,962,823	14,998,675	22,961,498	95,385	-0.4%
2015	23,256,301	8,201,127	16,551,432	24,752,559	(1,496,258)	6.4%
2016	23,456,387	8,181,202	18,261,702	26,442,904	(2,986,516)	12.7%
2017	23,660,674	8,303,318	17,966,501	26,269,818	(2,609,145)	11.0%
2018	23,865,664	8,676,675	18,960,403	27,637,077	(3,771,413)	15.8%

1. Calculated based on 2014 rates – includes no proposed rate increases
2. Includes miscellaneous revenues.

As shown above in Table 4, OPALCO's projected CY 2014 retail revenues meet its projected CY 2014 cost obligations. However, based on these projections, OPALCO's projected retail revenues at current rates are not sufficient to cover its projected cost obligations in 2015 through 2018.

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 OPALCO'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.

Recommendation

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

- Using current rates, OPALCO is collecting sufficient revenues compared to projected CY 2014 costs. However, starting in 2015, OPALCO may need a rate increase.
- Based on the current COSA inter-class results, it appears that a minor adjustment in rate design may be needed at this time.

Overview of Rate Setting Principles

EES Consulting, Inc. ("EES Consulting") was retained by Orcas Power and Light ("OPALCO") to perform a comprehensive electric cost of service and rate study. Performing an electric rate study is necessary to assure that OPALCO'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 OPALCO and the unit cost output from the cost of service analysis.

Overview and Organization of Report

In developing electric rates for OPALCO, a major goal of the study is to develop cost-based rates that meet OPALCO'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 OPALCO'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 OPALCO. The following section discusses the cost of service study and the results of that process. This is followed by an update on recent events at BPA. Finally, rate design options are discussed.

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

The setting of electric utility rates that are "fair and equitable" is a complex process. This process is directed, however, by "generally accepted methodologies" that can be used as a guide in developing OPALCO'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 OPALCO.

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 OPALCO'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.

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, OPALCO is a cooperative 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. Puget Sound Energy is an example of a private electric utility.

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

Overview of Revenue Requirement Methodologies

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

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

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

Table 6 compares the cash and utility accounting conventions.

Table 6 Cash vs. Utility Basis Comparison			
	Cash Basis		**Utility (Accrual) Basis**
+	O&M Expense	+	O&M Expense
+	Taxes	+	Taxes
+	Capital Improvements Financed with Operating Revenues (Depreciation Expense)	+	Depreciation Expense
+	Debt Service (Principal & Interest)	+	Return on Investment (Interest + Margin)
Σ	= Revenue Requirement	Σ	= Revenue Requirement

For this study, an accrual basis was used to determine OPALCO's revenue requirement because this method conforms to OPALCO's budgetary processes.

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 OPALCO. 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 OPALCO'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 OPALCO must make is the method of accumulating costs. OPALCO utilized the "accrual basis" approach for determining revenue requirement. In summary form, OPALCO's components to its revenue requirement include the elements shown in Table 7.

Table 7
Elements of an Cash Basis Revenue Requirement

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

From this basic analytical framework, the next step in determining the revenue requirement methodology is to select a time period over which to review revenue and expenses. In the case of OPALCO, a calendar year test period was utilized (January through December). CY 2014 was chosen as the test period for the cost of service study. OPALCO provided actual costs for CY 2013 and budgeted cost projections for CY 2014 through CY 2016. Revenues from retail rates were calculated using present rates and projected loads. Purchased power costs were provided by OPALCO and BPA. Projected CY 2014 costs are provided in Schedule 3.1. OPALCO'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 2014 through CY 2017 was calculated based on 1.0 percent growth rates for the residential customer classes and 0.5 percent growth rates for the commercial classes as provided by OPALCO.

The load forecast is a critical component to the COSA as it is the basis for cost allocation and design rates. A summary of the loads for historic CY 2013 can be seen on Schedule 1.7. Line losses were calculated using total system purchases and total customer sales in CY 2013. Primary line losses were assumed to be 2 percent, secondary line losses were assumed to be 3.28 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 2014 through CY 2018 using current retail rate schedules and forecast loads. Projected revenues from current rates are $23.1 million in CY 2014.

Development of Power Supply Costs

OPALCO purchases wholesale power from the Bonneville Power Administration (BPA). OPALCO receives all of its wholesale power requirements from BPA. Projected power costs are based on information provided by OPALCO and BPA. Power supply costs also include BPA transmission costs under a Network Transmission (NT) contract. Beginning in October 2013, projected BPA power and transmission costs are based on final BPA rates (released July 2013) for the two-year rate period October 2013 through September 2015. Additional 6 percent rate increases are assumed to be effective October 2015 and October 2017.

As with most electric utilities, the major expense associated with operating the utility is power supply. Approximately $7.96 million or 33.9 percent of the CY 2014 total utility revenue requirement are power supply costs.

The total purchased power requirements for OPALCO are projected to be approximately 219 million kWh in CY 2014. For the time period reviewed in this study, the peak demand was expected to occur in December. Projected December peak demands are 63.8 MW in 2014. On a cost per kWh basis, power purchases would equal approximately 3.67 cents in CY 2014, 3.74 cents in CY 2015, 3.78 in CY 2016, and 3.80 in CY 2017. Total power supply costs are forecast to be $7.9 million in CY 2014, $7.5 million in CY 2015, $8.1 million in CY 2016 and $8.3 million in CY 2017.

Other Operations and Maintenance Expenses

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

Total O&M expenses are projected to be $17.8 million in CY 2014. Of this amount, non-power supply operating expenses are expected to be approximately $9.8 million in CY 2014.

Taxes

Taxes are projected to be $948,050 in CY 2014.

Depreciation Expense

OPALCOs depreciation in CY 2014 is projected at 2.9 million.

Interest

Interest is projected to be $915,599 in CY 2014.

Other Contributions

Other contributions of $956,260 in CY 2014 are included. This includes $1.0 million in Margin, income of $50,000 in capital credits and $3,000 in donations.

Miscellaneous Revenues

OPALCO receives additional operating and non-operating revenues and contributions. These come in the form of rents, interest, service revenues, and other revenues. The combined estimate of these revenue items is $503,013 in CY 2014.

Summary of Revenue Requirement

Once all of the components of the accrual basis revenue requirement have been forecast, the parts can be summed to equal the total revenue requirement. Since OPALCO uses an "accrual basis" approach for rate setting, the basic revenue requirement is presented in that format. A summary of OPALCO's revenue requirement for the forecasted period can be seen summarized in Table 8.

Table 8
Revenue Requirement Summary

Applications of Funds	**CY: 2014**
Operation and Maintenance Expenses	
Power Supply	$7,962,823
Transmission	77,112
Distribution	5,142,615
Customer Service and Accounting	1,641,580
Administrative and General	2,931,201
Total O&M Expenses	$17,755,331
Depreciation	2,889,271
Taxes	948,050
Interest	915,599
Margin	1,003,540
Other Contributions	(47,280)
Total Revenue Requirement	$23,464,511
Less: Other Revenues/Net	(503,013)
Net Revenue Requirement	$22,961,498
Revenues at Current Rates	$23,056,883
Required Retail Rate Increase/(Decrease)	**-0.4%**

Table 9 shows projected rate increases through CY 2018 under an accrual basis. 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. Rate increases should not be summed across years. For example, if rates were increased 6.4 percent in 2015, the 12.7 percent rate increase projected for 2016 would be adjusted to a 5.9 percent rate increase.

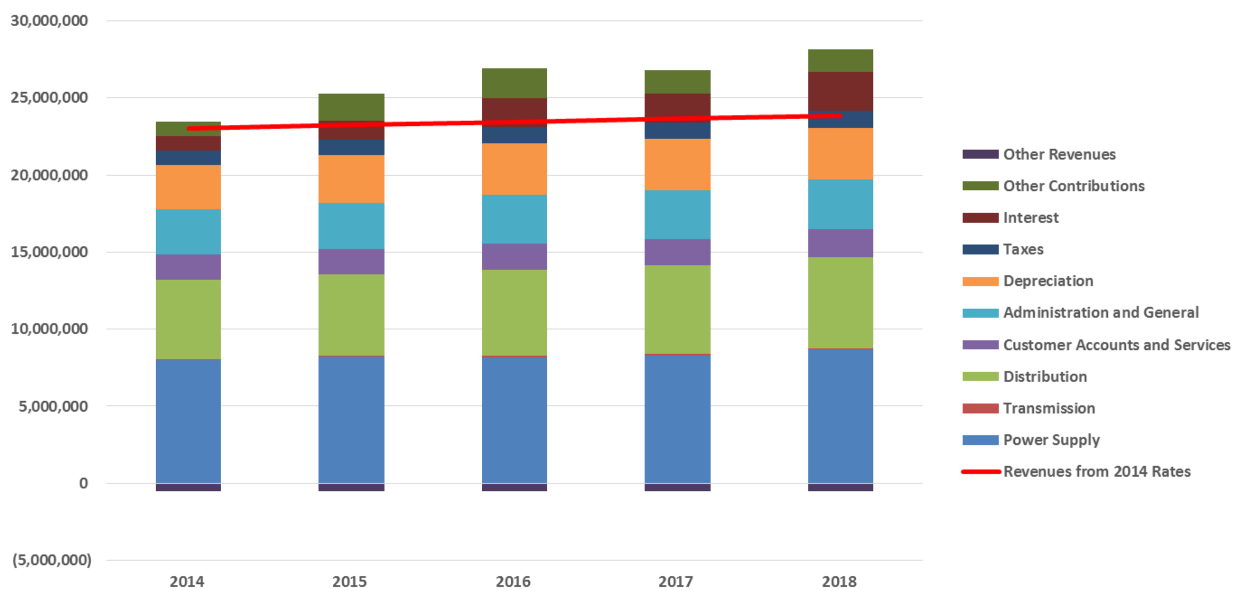
Since power supply costs are a significant portion of total revenue requirements and projected to increase when BPA's rates increase every two years, these are shown separately in column *b*.

Table 9 Projected Rate Increases						
CY	Present Rate Revenues[1] *a*	Power Supply Costs *b*	Non-Power Supply Costs, Net[2] *C*	Revenue Requirement *d = b + c*	Surplus (Deficiency) *e = a - d*	Rate Increase (Decrease) Over Current Rates *f =- e/a*
2014	23,056,883	7,962,823	14,998,675	22,961,498	95,385	-0.4%
2015	23,256,301	8,201,127	16,551,432	24,752,559	(1,496,258)	6.4%
2016	23,456,387	8,181,202	18,261,702	26,442,904	(2,986,516)	12.7%
2017	23,660,674	8,303,318	17,966,501	26,269,818	(2,609,145)	11.0%
2018	23,865,664	8,676,675	18,960,403	27,637,077	(3,771,413)	15.8%

1. Calculated based on 2014 rates – include no proposed rate increases
2. Includes miscellaneous revenues.

OPALCO's projected costs and revenues are also shown in Figure 1.

Figure 1
5 Year Revenue Requirement



Recommendation

OPALCO's projected retail revenues at current rates are not sufficient to cover its projected cost obligations in 2015 through 2017.

It is important to note that OPALCO's current revenue to cost balance needs to be continually monitored. Both short and long term supply and operating cost considerations need to be evaluated and analyzed as the Board of Directors works with OPALCO'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, OPALCO'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 OPALCO's system of accounts, which largely segregates costs in this manner.

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

Standard Functionalization Method

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

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

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

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

Orcas Power and Light Functionalization Method

The specific functions used for OPALCO'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 OPALCO must acquire to deliver the purchased power supply to the service area are included in purchased power costs. The costs associated with the distribution system's transmission service include only those

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

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

Classification of Costs

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

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

Standard Classification Method

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

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

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

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

Orcas Power and Light Classification Method

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

- Power Supply

  Classifying power supply costs to demand and energy (commodity) components requires the evaluation of a number of complex, interrelated factors. Consideration must be given to what or who caused the power supply purchase to be made, and to the uses to which it will be put (i.e., meeting demand and energy requirement). Within this study, power supply costs are classified to demand and energy based on OPALCO'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.

BPA Power

OPALCO's power supply cost structure changed in October 2011 when the utility began purchasing a share of BPA's generating resources, known as the federal-based system or FBS, under a new 17-year contract as a load following customer. Under the new power contracts BPA's rates are tiered such that power supply requirements in excess of the utility's 2010 load requirements must be purchased at market-based rates. Cost-based rates apply to the utility's purchases up to its 2010 load requirements. MEC's cost-based power supply costs from BPA are structured such that one large fixed customer charge includes the majority of the energy cost component. The new demand charges apply only to a portion of MEC's monthly system peak demands, however, the monthly demand rates are 4 to 5 times greater than the previous demand rates. The fixed monthly charge is functionalized to energy in the COSA. The energy cost component, which includes the BPA customer and load shaping charges, is allocated to customer classes based on projected kWh consumption. The demand costs are allocated based on monthly coincident peak for each customer class (12 CP).

BPA Transmission

BPA provides OPALCO with transmission services to transfer power from BPA's supply to OPALCO's system. The transmission bill components are separated into energy and demand costs within the COSA 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 OPALCO'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 OPALCO's maximum system peak metered at its interconnection with the regional transmission system. The CP and related NCP values developed within the COSA are later used to allocate demand related costs to the customer classes examined within the analysis.

- Transmission

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

- Distribution

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

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

  The minimum system analysis is used to determine the lowest level of plant investment required to serve a utility's customers compared to the actual facilities in place to meet varying customer demands. 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. Approximately $35,000 in annual distribution operation and maintenance costs are directly assigned to the street lighting and security lights customer classes.

Allocation of Costs

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

Standard Allocation

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

Orcas Power and Light Allocation

The following are the specific allocation methods used in OPALCO'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 OPALCO'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 customer served in each class of service. Two weighted customer allocation factors were also developed. The first weighted customer allocation factor considered the relative differences among the various customer classes of meter costs. The second weighted customer allocation factor considered the cost of customer accounting and meter reading by each rate class. Customer allocation factors were used to allocate some distribution costs such as meters and meter installations and costs associated with customer service, accounts, and sales.

- Rate Base Allocation. The value of OPALCO's assets as of December 2012 is functionalized, classified and then allocated to customer classes. The resulting functionalized, classified and allocated rate base is then used to develop rate base allocation factors. These allocation factors (i.e., general plant, net plant, distribution rate base, etc.) are then used to allocate revenue requirement expenses. For example, maintenance of station equipment can be allocated using station equipment rate base, or property taxes might be allocated using net plant.
- Other Cost Allocation. Other costs are allocated based on specific rate base items, O&M function totals, revenues, labor ratios and other allocation factors. These other allocation factors were used to allocate administrative and general expense items, some other revenues such as dividend income or non-operating rental income.

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

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

- Miscellaneous Other Revenues

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

Review of Customer Classes of Service

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

- Residential
- Residential TOU
- Pump
- Commercial/Industrial
- Marina
- Public Lighting & Highway Lighting

Major Assumptions of the Cost of Service Study

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

- Forecast calendar year 2014 was selected as the period for the allocation of costs within the cost of service study.
- The revenue requirement as outlined in Section 2 was used for the cost of service study.
- Purchased power was assigned to energy and demand based on BPA's rate structure.
- Distribution plant was classified based both on a "minimum system" approach and a "100% demand" approach.
- Load forecast was based on a 1.0 percent growth rate for residential and 0.5 percent for commercial.
- Revenues are based on forecast loads and OPALCO's ***current*** retail rates.

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 10 shows the results of this analysis by function for the minimum system approach for allocation year 2014.

Table 10
Summary of Functionalized Cost of Service – CY 2014
Minimum System Approach

	Production Related	Transmission Related	Distribution Related	Customer Related	Direct Assignment	Net Revenue Requirement
Residential	5,367,355	590,733	4,836,715	5,388,254	0	16,183,057
Residential TOU	68,850	7,584	67,420	38,753	0	182,607
Pump	50,411	4,090	31,101	244,553	0	330,155
Commercial/Industrial	2,260,781	339,485	2,579,255	746,827	0	5,926,348
Marina	90,966	13,602	107,583	90,399	0	302,550
Public Street/Highway Lighting	33	3	2,341	1,228	33,176	36,781
TOTAL	**7,838,396**	**955,497**	**7,624,415**	**6,510,014**	**33,176**	**22,961,498**

Table 11 provides the COSA results using a 100 percent demand methodology.

Table 11 Summary of Functionalized Cost of Service – CY 2014 100 Percent Demand Approach	Production Related	Transmission Related	Distribution Related	Customer Related	Direct Assignment	Net Revenue Requirement
Residential	5,367,355	590,543	7,139,866	2,553,915	0	15,651,679
Residential TOU	68,850	7,586	95,119	20,453	0	192,008
Pump	50,411	4,062	72,612	121,658	0	248,743
Commercial/Industrial	2,260,781	339,700	3,556,478	371,523	0	6,528,482
Marina	90,966	13,603	154,993	44,971	0	304,533
Public Street/Highway Lighting	33	3	2,354	487	33,176	36,052
TOTAL	**7,838,396**	**955,497**	**11,021,422**	**3,113,007**	**33,176**	**22,961,498**

The overall results for CY 2014 are summarized in Table 12 for minimum system and in Table 13 for 100 percent demand. More detail behind the results shown is presented in Schedules 1.1 and 1.2.

Table 12 Summary of CY 2014 Cost of Service Analysis - Minimum System	Present Rate Revenues	Net Revenue Requirement	Surplus/ (Deficiency) in Present Rates	Revenue to Cost Ratio
Residential	$16,580,285	$16,183,057	$397,229	102.5%
Residential TOU	162,769	182,607	(19,839)	89.1%
Pump	276,720	330,155	(53,435)	83.8%
Commercial / Industrial	5,688,548	5,926,348	(237,800)	96.0%
Marina	317,453	302,550	14,903	104.9%
Public Street/ Highway Lighting	31,108	36,781	(5,673)	84.6%
TOTAL	**$23,056,883**	**$22,961,498**	**$95,385**	**100.4%**

Table 13 Summary of CY 2014 Cost of Service Analysis – 100 Percent Demand				
	Present Rate Revenues	**Net Revenue Requirement**	**Surplus/ (Deficiency) in Present Rates**	**Revenue to Cost Ratio**
Residential	$16,580,285	$15,651,679	$928,606	105.9%
Residential TOU	162,769	192,008	(29,240)	84.8%
Pump	276,720	248,743	27,977	111.2%
Commercial / Industrial	5,688,548	6,528,482	(839,934)	87.1%
Marina	317,453	304,533	12,920	104.2%
Public Street/ Highway Lighting	31,108	36,052	(4,944)	86.3%
TOTAL	**$23,056,883**	**$22,961,498**	**$95,385**	**100.4%**

Given a number of assumptions, the results show that using present rates, OPALCO is not collecting sufficient revenues to meet projected 2014 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 33 percent of OPALCO's annual revenue requirement. OPALCO currently receives, and is expected to continue to receive, 100 percent of its wholesale power requirements from the Bonneville Power Administration (BPA). OPALCO also purchases transmission service from BPA. Since OPALCO 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, one nuclear project, 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.

Power Business Line ("PBL")

OPALCO currently purchases power from BPA as a Load Following customer under a 17-year contract that expires at the end of September 2028. BPA's rate structure changed dramatically in October 2011. The new rate structure was developed through a formal proceeding known as the Tiered Rate Methodology ("TRM"). Beginning in October 2011 BPA's rates became tiered with market-based rates serving load growth above 2010 weather- and conservation-adjusted loads (the high water mark or "HWM"). Under TRM, total Tier 1 allocations are roughly equal to the capability of the Federal Base System ("FBS") under critical water conditions. Under this approach, each BPA customer effectively receives a share of output from the FBS through September 2028. Power requirements above Tier 1 allocations may be purchased from BPA at Tier 2 rates or from alternative suppliers.

Tier 1 Power Costs: The Tier 1 power costs are based on forecast Federal Base System FBS costs. Tier 1 rates are determined every two years during BPA's formal rate case proceedings. The costs of Tier 1 resources are recovered through composite customer charges included in BPA's rates. Composite customer charges are determined for each two-year rate period and result in fixed costs to utilities that do not vary by month. In addition to composite customer charges, Tier 1 purchases also include the following billing components:

Non-Slice Customer Charge: The non-Slice customer charge results in a monthly credit on utilities' power bills. Each utility receives an allocation of BPA's projected revenue from surplus energy sales. BPA calculates projected revenue from surplus energy sales based on planned generation at each Tier 1 resource and forecast wholesale energy market prices. Non-slice customer charges are determined for each two-year rate period and result in credits to utilities that do not vary by month.

Demand Charges: Demand rates are determined for each two-year rate period based on BPA's projection of the fixed costs associated with a Simple Cycle Combustion Turbine. Demand rates vary by month. The monthly shape is based on the shape of projected wholesale market energy prices. Final 2014 monthly demand rates vary between \$7.61 per kilowatt-month and \$11.47 per kilowatt-month. The billing determinant for demand charges is equal to a utility's monthly system peak demand less average Tier 1 heavy load hour energy purchases less Tier 2 purchases less non-federal power purchases less the Contract Demand Quantity ("CDQ"). Monthly CDQs were set for each utility for the contract term. CDQs were calculated by applying BPA fiscal year 2005-2007 heavy load hour load factors to fiscal year 2010 loads. On average the demand billing determinant is equal to 8 to 12 percent of each utility's monthly system peak demand.

Load Shaping Charges: Load shaping rates are determined for each two-year rate period and are equal to BPA's projection of monthly and diurnal wholesale market prices. Load shaping rates are applied to the difference between a utility's monthly and diurnal load and the utility's share of the projected monthly and diurnal energy available from the Tier 1 resource pool. During months when a utility's share of the Tier 1 resource pool is less than its power requirements, load shaping charges apply. During months when a utility's power requirements are less than its share of the Tier 1 resource pool load shaping credits apply. Projections of Tier 1 resource pool generation are determined every two years during each rate case. While the resources included in the Tier 1 resource pool are fixed, the generating capability of individual resources varies between rate cases. For example, the total Tier 1 resource pool was 7,181 aMW (annual average) during the first rate period under the TRM contracts (October 2011 – September 2013) and is 7,116 aMW during the second rate period (October 2013-September 2015).

Energy requirements in excess of each utility's HWM are served via BPA's Tier 2 products or from non-federal resources. The rates for BPA's Tier 2 products are based on market purchases and/or the cost of resources used to serve Tier 2 purchases. Bonneville offers utilities several Tier 2 power products and associated pricing. Tier 2 product choices include:

Short-Term Tier 2: Utilities commit to purchase power for two year rate period. Rates are determined each rate period and reflect the cost of market purchases to serve short-term Tier 2 purchases

Vintage Tier 2: Utilities make a long-term commitment to purchase the output from a specific generating resource. Rates are based on the projected costs of the resources.

Load Growth Tier 2: Utilities must commit to purchase all load growth requirements for the entire contract period. Rates are determined every two years and are designed to recover the full costs of the required generating resources, or market purchases.

All BPA power rates in fiscal years 2014 through 2015 are based on BPA's final rates issued July 2013. Rates are assumed to escalate 6 percent in October 2015 and October 2017, coinciding with BPA's rate periods.

Transmission Business Line ("TBL")

OPALCO purchases transmission from TBL under a Network Transmission ("NT") contract. BPA'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. BPA and its customers reached agreement in the 2011 transmission rate case which set rates for federal fiscal years 2012 and 2013. The agreement resulted in no rate increase on a net basis. Final NT rates for fiscal years 2014 and 2015 are based on BPA's final rates issued July 2013. NT Rates are assumed to escalate 6 percent in October 2015 and October 2017, coinciding with BPA's rate periods.

Orcas Power and Light's Present and COSA Rates

This section of the report will review the present rate structures for OPALCO and will provide a comparison with the unit costs developed in the cost of service study for allocation years 2014.

Residential

The present Residential rate design is composed of a monthly facility charge (base charge) and a block energy charge.

Presented below, in Table 14, are the present rates for the Residential service and the CY 2014 unit costs developed from the COSA using both the minimum system approach and the 100 percent demand approach. Two rate options are included.

Table 14
Comparison of Rates to Unit Costs
Residential

	Present	Minimum System	100 Percent Demand
Basic Charge ($/month)	$28.60	$39.02	$18.5
Energy Charge ($/kWh)		$0.0772	$0.0902
First 5,000 kWh	$0.0852		
Over 5,000 kWh	$0.1006		
Rate Change over Present		***(2.40%)***	***(5.60%)***

Residential TOU

The present Residential TOU rate design is composed of a monthly facility charge (base charge) and a TOU energy charge.

Presented below, in Table 15, are the present rates for the Residential TOU service and the CY 2014 unit costs developed from the COSA using both the minimum system approach and the 100 percent demand approach.

Table 15 Comparison of Rates to Unit Costs Residential TOU			
	Present	**Minimum System**	**100 Percent Demand**
Basic Charge ($/month)	$32.20	$43.47	$22.94
Energy Charge ($/kWh)		$0.0772	$0.0921
On-Peak ($/kWh)	$0.1294		
Mid-Peak ($/kWh)	$0.0590		
Off-Peak ($/kWh)	$0.0507		
Rate Change over Present		***12.19%***	***17.96%***

Pump

The present Pump rate design is composed of a monthly facility charge (base charge) and a block energy charge and a demand charge.

Presented below, in Table 16, are the present rates for the Pump service and the CY 2014 unit costs developed from the COSA using both the minimum system approach and the 100 percent demand approach.

Table 16 Comparison of Rates to Unit Costs Pump			
	Present	**Minimum System**	**100 Percent Demand**
Basic Charge ($/month)	$25.30	$40.85	$20.32
Energy Charge ($/kWh)		$0.0313	$0.0313
First 370 kWh	$0.0978		
Next 4,630 kWh	$0.0752		
Over 5,000 kWh	$0.0900		
Demand Rate ($/kW)		$4.77[2]	$9.61[2]
Over 20 kW	$3.15[1]		
Rate Change over Present		***19.31%***	***(10.11%)***

1. Over 20 kW only
2. All kW

Commercial

The present Commercial rate design is composed of a facility charge (basic charge), block energy charges and a demand charge over 20 kW.

Presented below, in Table 17 are the present rates for the Commercial customer class and the CY 2014 unit costs developed from the COSA using both the minimum system approach and the 100 percent demand approach.

Table 17
Comparison of Rates to Unit Costs
Commercial

	Present	Minimum System	100 Percent Demand
Basic Charge ($/day)	$40.40	$40.85	$20.32
Energy Charge ($/kWh)		$0.0313	$0.0313
First 5,000 kWh	$0.0866		
Over 5,000 kWh	$0.0781		
Demand Charge Over 20 kW ($/kW)	$3.15[1]	$14.51[2]	$18.69[2]
Rate Change over Present		*4.18%*	*14.77%*

1. Over 20 kW only
2. All kW

Marina

The present Marina rate design is composed of a facility charge (basic charge), block energy charges and a demand charge over 20 kW.

Presented below, in Table 18 are the present rates for the Marina customer class and the CY 2014 unit costs developed from the COSA using both the minimum system approach and the 100 percent demand approach.

Table 18
Comparison of Rates to Unit Costs
Marina

	Present	Minimum System	100 Percent Demand
Basic Charge ($/day)	$40.40	$40.85	$20.32
Energy Charge ($/kWh)		$0.0313	$0.0313
First 5,000 kWh	$0.0866		
Over 5,000 kWh	$0.0781		
Demand Charge Over 20 kW ($/kW)	$3.15[1]	$14.95[2]	$20.00[2]
Rate Change over Present		*(4.69%)*	*(4.07%)*

1. Over 20 kW only
2. All kW

Public Street/Highway Lighting Services

Based on the load information for the Public Street/Highway Lighting class and projected CY 2014 revenues of this class, an average rate *increase* of approximately 15 to 18 percent is required for minimum system and for 100 percent demand methodologies. In order to develop specific lighting charges, a detailed lighting study would be needed.

Summary

In creating options for proposed rates, OPALCO will have to balance the needs of the utility, its customers and society. The selection of a rate design that is fair and equitable is a complex process. To select an option, OPALCO will have to incorporate generally accepted methodologies with the financial considerations of the utility and its customers to make a selection that is fair and equitable for all classes. Selection of the optimum rate design will also have to balance the need for financial integrity, social responsibility and practicality. In addition, consideration will have to be given to how various pricing structures will affect the average monthly bill by the various customer classes.

Technical Appendix

April 7, 2015

TO: Foster Hildreth

FROM: Anne Falcon

SUBJECT: Rate Design Process & Final 2015 Rates

Introduction

The rate process that culminated in final electric rates effective as of February 1, 2015 was a long-term process intended to provide a comprehensive review of rate design principles, objectives and customer impacts. The process included the following steps:

- Review rate objectives
- Determine cost of service by rate class
- Develop rate design options
- Receive customer input and suggestions
- Finalization of rate structure and rates
- Implement new rates

Utility rates need to be designed to recover a utility's cost of service. In the current environment, with increasing participation in energy efficiency and customer generation, OPALCO will have to be increasingly diligent in reviewing certain key components of its revenue requirement to ensure revenue sufficiency, such that the fixed costs of operating the OPALCO system will be collected from customers.

This memo will discuss rate setting principles determined by the OPALCO Board guiding the overall rate design discussion, describe the overall methodology used to determine the new rates and provide a description of the new rates implemented on February 1, 2015.

What is the Process for Setting Retail Rates?

Developing and implementing fair, equitable and financially sensible utility rates is a critical component in the operation of any electric utility. OPALCO strives to set retail rates that are fair and equitable across the residential, commercial industrial and lighting customer classes.

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The first step in developing retail rates is to determine if revenues from rates are sufficient to meet projected expenses, also known as the "revenue requirement", and financial targets.

The second step is to allocate projected expenses and investments in assets among the utility's customer classes. The allocation of expenses and assets is accomplished by performing a Cost of Service Analysis (COSA). The goal is for every rate class to pay its fair share. In a COSA cost allocations are driven by the usage, density and delivery voltage of each customer class.

The final step in retail rate setting is to design rates for each customer class. Retail rates include base, energy and demand rates. The COSA-recommended rate components (base, energy and demand rates) are compared to current rate components for each customer class. The utility then considers options to change rate structures based on the output from the COSA.

What is a Cost of Service Analysis?

OPALCO uses a Cost of Service Analysis (COSA) performed by an independent consulting firm to estimate the cost to serve each customer class. A COSA is an analytical exercise that allocates OPALCO's total revenues, revenue requirement and investments in assets among the residential, commercial, industrial and lighting customer classes based on how each customer class uses the system. 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.

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. 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.

The final step in a COSA is to "allocate" the three cost components (demand, energy and customer) to each class of service based upon the most equitable method available for each specific expense. For example, expenses that have been classified as energy-related are allocated based on the amount of energy consumed by the residential, commercial, industrial and lighting customer classes. 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.

What is Rate Design?

The final step in the rate setting process is to design rates for each customer class taking into consideration the results of the 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.

Utilities have a variety of rate design alternatives at their disposal. Good customer service would dictate that more pricing alternatives be provided to customers for their power supply. 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 CEC follow.

- Flat Rates
- Block Rates
- Time of Use Rates

Flat Rates: Flat rates are the most basic and commonly used type in the electric utility industry. This basic rate design is composed of two parts, a customer component and a usage charge. The customer charge applies to the 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 an energy charge and a demand charge, if the customer is demand metered. The energy charge is a flat rate charged on the basis of kWh. The demand charge is a flat rate that is usually charged on a peak monthly kW or kilovolt-ampere (kVA) basis.

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, especially given varying load characteristics and time-of-day power supply costs. 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.

Block Rates: Block rates are generally of two types, declining and inverted blocks. A block rate separates a consumer's energy usage into "blocks" and applies a different rate to each block. Block rates were developed principally to reflect the cost of power supply. If power supply is a surplus commodity, declining block rates are deemed appropriate to encourage consumption. Declining-block rates tend to provide incentive to consume more electricity. If power supply is a scarce commodity, inverted block rates are appropriate to discourage consumption. Inverted-block rates provide the exact opposite incentive as declining block rates. These rates encourage conservation of energy resources, since greater consumption levels lead to higher prices.

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. It is important to note that Bonneville uses both time-of-day and seasonal (i.e. monthly) periods in its wholesale power rate design.

What is a Base Charge?

Most utilities charge some type of facilities or base charge. OPALCO's service territory has a low population density and high system costs due to the service area covering several islands. Only about half of customer's power bill goes to the actual purchase of electrical energy. The rest of the bill goes to maintenance of the power lines and the fixed costs of operating the utility including maintenance of lines, poles, substations, rights-of-way (tree trimming and brushing), interest expense, insurance, taxes, trucks and equipment, billing, administrative and miscellaneous services. The base charge is a contribution toward those fixed costs of operation and maintenance.

The amount of electricity used from month to month varies greatly but the base costs are fixed. They occur whether customers use the power or not. As a result, as participation in energy efficiency and customer generation increases, OPALCO has to review the rate structure to ensure the cost of the distribution system will still be collected from customers even when energy usage decrease.

Selection of Rate Design Alternatives

To facilitate the selection of rate design alternatives, OPALCO Staff and Board, embarked on a long-term rate process to ensure a comprehensive review of the current rate structure, changes occurring in the community and the design of new rates. The policy framework balances the needs for financial integrity, social responsibility and practicality. There were four basic steps in this evaluation process. These are discussed below:

- Step 1—Evaluation of Utility's Circumstances

  The first step in evaluating OPALCO's rate design alternatives was to make clear the physical, financial, legislative and social environment in which the utility operates. Below is a list of issues that OPALCO considered.

  - OPALCO's history
  - Composition of major customer groups
  - Utility's power supply costs
  - Utility's non-power supply costs
  - COSA results
  - Energy efficiency

- Distributed generation
- Infrastructure needs
- Utility and customer concerns
- Customer service
- Billing system
- Metering

- Step 2—Identify Alternatives

  Next, several rate design alternatives were considered. Included in the alternatives were the current rate structure and a similar rate structure with rates that reflect cost of service. These rate designs served as a basis for comparison. In addition, alternatives chosen based on the needs of the utility and its customers were presented to the Board. These rate alternatives reflected the issues raised in the first step of the evaluation process.

- Step 3—Evaluation of Alternative Rates

  Lastly, the various rate design options were evaluated. The criteria for evaluation included:

  - Adequacy for covering revenue requirement
  - Alignment with cost of service
  - Comparable rates for like services
  - Rate impact and continuity
  - Simplicity and practicality of rates
  - Ease of administration
  - Promotion of economic efficiency
  - Competitiveness

  Only after careful scrutiny and public involvement should the decision be made on the most appropriate rate design for CEC's customers.

OPALCO Rate Setting Principles

As part of the rate process performed by the Board and Staff over the last 8 months, OPALCO developed Policy 29 which addresses Energy Services Rate Design. It is the policy of the OPALCO Board to develop electric rates that allow OPALCO to provide electricity to its customers that is reliable, cost-based, and considerate of the environment and maintains the cooperative's financial strength. According to Policy 29 of OPALCO, the rate structure shall also:

- Meet revenue requirement
- Fairly allocate expenses in relation to each member's use of and impact on the system
- Reduce the effect of weather, market and other volatility, and
- Promote stability in OPALCO's financial position

In addition, the policy states that rates will be developed and implemented using the following charges:

- Facility: Collects OPALCO's fixed expenses
- Energy: A variable component that passes energy costs to members based on usage
- Demand: Reflects the costs associated with system capacity
- Cost Recovery Charge (CRC): Recoups lost revenues caused by fluctuations in energy consumption

As rate structures and design were proposed and discussed with the Board, the principles listed above were in the forefront of all considerations.

OPALCO's Rate Design Process

A COSA was conducted in 2014 to make sure each member pays their fair share. Based on the results of the COSA, OPALCO's rate making principles and the projected revenue shortfall, rate design options were presented to the Board.

The sequence of events and timeline in Table 1 was determined for the Rate Design process.

Table 1
Rate Design Process

	Rate Design Process at OPALCO	Board Meeting Dates
A	Review of BPA Billing Determinants	April 2014
B	Cost of Service Review (Revenue Requirements/Rates Classes and Cost Allocations), with Member Comment	June 2014
C	Review of New Rate Design Proposed by Staff	July 2014
D	Board discussion/modification of proposed rate design, with Member comment	August and September 2014
E	EES Review of Final Rate Design (First Reading)	October 2014
F	Final Board Approval (Second Reading) of Final Rate Design	November 2014
G	New Rate Design Goes Into Effect With the March 2015 Billing Period	Rates Effective February 1, 2015

The following information was presented and discussed at each of the relevant OPALCO Board meetings:

April 2014: BPA power bills were reviewed as the first step in the cost of service study. The different bill components and how each component impacts OPALCO's costs was explained. The goal is to avoid Tier 2 power, which is the market rate for purchased power.

June 2014: Cost of Service Study was presented. The cost of service study allocates OPALCO's costs across rate classes and determines how much revenues will need to be collected from each of the rate classes.

The following strategies were discussed to assist OPALCO in thriving under changing electricity use profiles:

- Continue to promote/fund energy efficiency
- Providing resources to members interested in distributed generation and net metering
- Conduct cost of service studies to understand cost causation
- Implement small rate changes that reflect the cost of providing electric service
- Increase facility charges when necessary to bridge the gap between existing facility charges and cost of service recommended rates
- Educate members on rate components and why rates are changing
- Take care of vulnerable customers (low and fixed income) by providing access to resources that will allow them to participate in energy efficiency programs
- Don't forget about commercial members

July 2014: At the July meeting, the objectives and principles of rate setting were discussed. In addition, rate design options were presented to the Board. The Board was interested in:

- Implementing a demand charge ($/kW) for all customers
- Simplifying rate schedules
- Consideration of conservation price signals
- Reflect cost of delivering power (facilities charge or demand charge)
- Be aware of heat pump customers

Rates presented indicated an overall six (6) percent increase that would be effective with the March 2015 billing.

The residential rate design included a seasonal block to address the heat pump customers. In addition, a fixed demand/facilities charge was added to reflect the cost of delivering power.

The commercial rate design explored separating the commercial customers into a small and a large commercial class. Demand charges were suggested for all commercial customers.

August 2014: At this meeting the proposed rates designed to collect an increase of 6 percent were presented. Based on the goals determined during the July Board Meeting:

- Implementing a demand charge ($/kW) for all customers
- Simplifying rate schedules
- Consideration of conservation price signals
- Reflect cost of delivering power (facilities charge or demand charge)
- Be aware of heat pump customers

Rate designs were further fine-tuned. Impacts to customers were also presented using actual billing information in each of the following customer categories: residential, commercial, time-of-use and pump rates.

The Board provided further input on the refinement of rates. Members were invited to comment during September and October.

Policy 29 Energy Rate Design was offered as a template to use in the rate design process. Determination should be made where it is appropriate to include rates for funding programs and what percentage of the system is used by each rate category. Staff to present revisions at a future meeting.

September 2014: September's meeting allowed for further refinement in the proposed rates and input from members. Rate structures and bill impacts for the next three years (2015, 2016 and 2017) were presented. These rate structures are the first stage of a progression to Policy 29 Rate Design.

It was determined that Policy 29 Energy Rate Design would be re-written and presented to the Board for review at the October meeting.

October 2014: Discussions continued at October's meeting regarding new rate structures for residential, residential TOU, small commercial, large commercial and pumps. The goal is to produce rate structures which fairly allocate OPALCO expenses in relation to members' use of the electric system and impact on the cooperative's operations. Staff is striving to reduce revenue volatility so OPALCO will be better positioned to meet its financial and service level commitments. Staff recommended rate structures with the following changes:

- Align the fixed expense components of operating OPALCO to be included in the facility charge (base rate).
- Introduce a "demand" billing component over time to coincide with power purchases from BPA.
- Transition the residential rate structure to differentiate summer versus winter usage.
- Reinstate a time-of-use (TOU) rate.
- Separate small (less than 20kW) versus large (more than 20kW) commercial services.
- Introduce a new block rate for high usage commercial services (more than 150,000 kWh).
- Pump rate is to be more aligned with the cost of service.

Based on discussion, it was suggested the TOU rate begin at 10:00pm rather than 6:00pm; this time change would be phased in over time (i.e., year one would be 8:00pm, year two would be 9:00pm). The Board requested staff to develop alternatives to meeting revenue requirements for reduction in energy sales, including a rate adjustment mechanism on member bills to reduce revenue volatility.

Modifications were made to Policy 29 Rate Design regarding revenue requirements to allow for monthly adjustments to member bills to cover revenue short falls; the facility charge would be based on a fixed cost methodology whereby the facility charge collects the costs associated with the fixed expenses to operate OPALCO.

November 2014: Final rate design was presented to the Board. The rate structure shown did not include any needed rate increase.

Alternatives to meeting revenue requirements, as requested in the October Board meeting, were suggested. These options include:

- Implement a high fixed charge.
- Implement a minimum bill.
- Implement a cost recovery charge.
- A combination of the options.

It was noted that regardless of the strategy used to ensure recovery of lost revenues due to low energy consumption and fixed costs, it is important to keep in mind the following:

- Vulnerable members (low and fixed income) by providing access to resources that will allow them to participate in energy efficiency programs.
- Consider the impact on energy efficiency participation.
- Consider the impact on local distributed generation cost effectiveness.
- Continue to monitor the fixed cost of the system and consider options for long-term savings.
- Educate members on rate components and why rates are changing.
- Consider the additional member education needs and front office staffing needs as members may object to bill increases.

The rate structure was approved by the Board.

Policy 29 Rate Design name was changed to “Energy Services Rate Design” and approved as amended.

January 2015: Final rates based on the new rate structure and financial projection were presented to the Board and approved. Rates to be effective with the February billing cycle.

The resulting calculations predicted a 10.4 percent increase in revenue for 2015. Energy charges were adjusted for residential, pumps, small commercial and large commercial in order to reach the targeted revenue increase of 12 percent that was approved in the 2015 budget at December's meeting.

New Electric Rates

New electric rates were implemented at the beginning of February, 2015. The new rate structure changes how revenue is collected to meet OPALCO's fixed operational costs, as well as, ensuring that the utility will be held harmless from weather fluctuations and other uncertainty.

The Residential rate design includes the following:

- Different summer and winter blocks to reflect electric heating loads during the winter.
- Three energy price tiers to reflect the increasing cost of power.
- A place holder for a demand rate once demand meters are installed on all accounts.
- A facility charge that increased from \$28.60 per month to \$38.90 per month to reflect the high fixed costs of the OPALCO system.

The Residential rates for 2015 are provided below in Table 2:

Table 2
Residential Rate

	Present	2015 Rates	
		Summer Rate	Winter Rate
Basic Charge ($/Service/Month)	$28.60	$38.90	$38.90
Energy Charge ($/kWh)			
First 5,000 kWh	$0.0852		
Over 5,000 kWh	$0.1006		
First 1,500 kWh		$0.0855	
1,500-3,000 kWh		$0.0970	
Over 3,000		$0.1150	
First 3,000 kWh			$0.0855
3,000-5,000 kWh			$0.0970
Over 5,000			$0.1150
Demand Charge	$0.00	$0.00	$0.00

The Residential TOU rate design includes the following:

- A change in TOU periods to better reflect BPA's pricing.
- A place holder for a demand rate once demand meters are installed on all accounts.

- A facility charge that increased from $32.20 per month to $54.90 per month to reflect the high fixed costs of the OPALCO system.

The Residential TOU rates for 2015 are provided below in Table 3:

Table 3
Residential TOU Rate

	Present	2015 Rates
Basic Charge ($/Service/Month)	$32.20	$43.80
Energy Charge ($/kWh)		
TOU Period 1 (6 AM – Noon)	$0.1294	
TOU Period 2 (Noon- 6 PM)	$0.0590	
TOU Period 3 (6 PM – 6AM)	$0.0507	
TOU Period 1 (6 AM – Noon)		$0.1450
TOU Period 2 (Noon- 8 PM)		$0.0900
TOU Period 3 (8 PM – 6AM)		$0.0400
Demand Charge	$0.00	$0.00

The Small Commercial rate design includes the following:

- Increasing two-tier energy block rate to better reflect BPA's pricing.
- A flat monthly demand fee to account for capacity costs. Once all members are demand metered this fee will change to a $/kW rate.
- A facility charge that increased from $40.40 per month to $54.90 per month to reflect the high fixed costs of the OPALCO system.

The Small Commercial rates for 2015 are provided below in Table 4:

Table 4
Small Commercial Rate (<20 kW)

	Present	2015 Rates
Basic Charge ($/Service/Month)	$40.40	$54.90
Energy Charge ($/kWh)		
First 5,000 kWh	$0.0866	$0.0870
Over 5,000 kWh	$0.0781	$0.0970
Demand Charge (Flat Fee $/Month)		$5.00
Demand Charge > 20 kW ($/kW)	$3.15	

The Large Commercial rate design includes the following:

- Increasing three-tier energy block rate to better reflect BPA's pricing.
- A two-tiered demand rate for all metered demand.
- A facility charge that increased from $40.40 per month to $54.90 per month to reflect the high fixed costs of the OPALCO system.

The Large Commercial rates for 2015 are provided below in Table 5:

Table 5
Large Commercial Rate (>20 kW)

	Present	2015 Rates
Basic Charge ($/Service/Month)	$40.40	$54.90
Energy Charge ($/kWh)		
Block 1 (< 5,000 kWh)	$0.0866	
Block 2 (> 5,000 kWh)	$0.0781	
Block 1 (< 5,000 kWh)		$0.0790
Block 2 (5,000 – 150,000 kWh)		$0.0873
Block 3 (> 150,000 kWh)		$0.1162
Demand Charge > 20 kW ($/kW)	$3.15	
Demand Charge < 300 kW ($/kW)		$3.15
Demand Charge > 300 kW ($/kW)		$4.73

The Pump rate design includes the following:

- A three-tier energy block rate which reduce the rate differential between blocks.
- A demand rate for all capacity over 20 kW.
- A facility charge that increased from $25.30 per month to $34.40 per month to reflect the high fixed costs of the OPALCO system.

The Pump rates for 2015 are provided below in Table 6:

Table 6 Pumps Rate		
	Present	**2015 Rates**
Basic Charge ($/Service/Month)	$25.30	$34.40
Energy Charge ($/kWh)		
First 370 kWh	$0.0978	$0.0923
371 – 5,000 kWh	$0.0752	$0.0802
Over 5,000 kWh	$0.0900	$0.0900
Demand Charge (Flat Fee $/Month) Demand Charge > 20 kW ($/kW)	$3.15	$3.15