ELECTRIC RATE STUDY

Final Report

B&V PROJECT NO. 177375

PREPARED FOR

Paducah Power System

MARCH 2013

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1.0 Introduction

The City of Paducah, Kentucky (City) elected to operate its electric plant distribution system pursuant to the provisions of Sections 96.550 through 96.900 of the Kentucky Revised Statutes and authorized the Mayor of the City, subject to the approval of the City's governing body, to appoint a board as therein provided.

The Electric Plant Board of the City of Paducah, Kentucky d/b/a Paducah Power System (PPS) was organized for the purpose of providing an electric distribution and generation system for the City and certain adjacent areas with an ongoing source and supply of electric power to meet their current requirements and anticipated growth in power consumption within the system area. PPS's service area is not subject to incursions from other electric distribution suppliers.

PPS uses a fiscal year (FY) ending June 30. All references to a specific year in this report refer to the fiscal year ending June 30 of the specified year.

1.1 PURPOSE

The purpose of this report is to evaluate the adequacy of PPS's existing rate charges and to recommend fair and equitable adjustments to the rates, if deemed necessary. Black & Veatch designed utility rate studies encompass three principal steps, each intended to answer questions typically asked by utility boards, city councils, and utility management. These questions are:

Revenue Requirements – What is the overall adjustment in rates needed to meet forecast cash requirements of the utility, meet capital requirements, and maintain debt service coverage and appropriate cash reserves?

Cost of Service – What is each class's equitable share of the utility's revenue requirements?

Rate Design – How should rates be adjusted to meet utility revenue requirements and remain sensitive to customer rate impacts?

1.2 SCOPE

This report presents the results of a comprehensive rate study of PPS and includes a projection of financial operations of PPS for the five-year period FY 2013 through FY 2017, a determination the overall adequacy of existing rates, a cost of service analysis, and rate design recommendations for the utility.

The financial forecast of PPS reflects projections developed in collaboration with PPS staff and our analysis of trends in sales, revenues, and costs. Forecast operating conditions and cost levels recognize the amount and degree of service, cost of system expansion and replacement, prudent operating expenses and capital expenditures, anticipated cost escalations, implementing the current policy on operating reserves, and other factors relevant to the utility.

A cost of service analysis of PPS's principal rate classes is presented that allocates the revenue requirements, or total cost of service to be recovered in rates, based on cost causation principles. Using the cost of service results as a guideline, along with policy goals of PPS, rates are designed for each of PPS's rate classes.

1.3 DISCLAIMER

Subject to the limitations set forth herein, this report was prepared for PPS by Black & Veatch Corporation (B&V) and is based on information not within the control of B&V. B&V has not been requested to make an independent analysis, to verify the information provided to it, or to render an independent judgment of the validity of the information provided by others. As such, B&V cannot, and does not, guarantee the accuracy thereof to the extent that such information, data, or opinions were based on information provided by others.

B&V prepared this report in February 2013 based on information and conditions prevailing as of October 2012. Any changes in that information or prevailing conditions may affect the conclusions, recommendations, assumptions, and forecasts set forth in this report. B&V makes no warranty, express or implied, regarding the reasonableness of any information, recommendation, or forecast set forth herein under any conditions other than those assumed in making such projections.

In conducting our analysis and in forming an opinion of the data summarized in this report, B&V has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies utilized in performing the analysis and making the recommendations follow generally accepted industry practices. It is believed that such assumptions and methodologies, as summarized in this report, are reasonable and appropriate for the purpose for which they are used. However, depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those shown. Such factors may include, but are not limited to, the regional and national economic climate and growth in the service area.

2.0 EXECUTIVE SUMMARY

PPS provides service to residential, commercial, industrial, municipal, and private lighting customers in the City of Paducah and outlying communities. PPS currently serves approximately 22,000 customers with projected rate revenues under existing rates for 2013 of $66 million. Total retail energy sales are forecast to be approximately 631,000 megawatt-hours (MWh) with a system peak of 156 MW.

This report presents the results of a comprehensive rate study of PPS and includes a projection of financial operations of PPS for the five-year period FY 2013 through FY 2017, a determination the overall adequacy of existing rates, a cost of service analysis, and rate design recommendations for the utility.

2.1 REVENUES AND REVENUE REQUIREMENTS

Overall adequacy of existing rates is tested by comparing revenues under existing rates with forecast revenue requirements. This is accomplished by first developing a forecast of customer growth and electric sales and calculating how much revenue will be generated during the forecast period. The sales forecast of rate class billing determinants was prepared using the 2011 actual billing determinants as a basis for 2013 through 2017 sales. For 2013 and 2014, the billing determinants (both customer count and energy sales) were held constant to 2011 levels. For 2015-2017, billing determinants were escalated annually at 0.5%. The sales forecast is considered conservative and reflects guidance from PPS management.

The financial forecast of PPS reflects projections developed in collaboration with PPS staff and our analysis of trends in sales, revenues, and costs. Forecast operating conditions and cost levels recognize the amount and degree of service, cost of system expansion and replacement, prudent operating expenses and capital expenditures, anticipated cost escalations, implementing the current policy on operating reserves, and other factors relevant to the utility.

For purposes of this rate study, "Existing Rates" will refer to the schedules of PPS rates and charges for all customer classes in effect as of October 2012, including the Powerl Cost Adjustment charge prevailing at that time. As discussed in detail in Section 3, revenue under Existing Rates under-recover current revenue requirements. As shown below in Table 2-1, revenue under Existing Rates is not sufficient to cover revenue requirements in any year of the forecast period. Debt service coverage is below one (1.0) after 2013, with a low of 0.68 in 2016.

Table 2-1 Projected Sales Revenue and Annual Deficits Under Existing Rates ($ thousands)

	2013	2014	2015	2016	2017
Total Revenue Under Existing Rates	$68,562	$68,748	$69,194	$69,576	$69,950
Total Revenue Requirements	$73,883	$76,505	$81,030	$82,245	$80,848
Annual Operating Surplus (Deficits)	($5,321)	($7,757)	($11,836)	($12,669)	($10,898)
Annual Revenue Deficiency (%)	-7.2%	-10.1%	-14.6%	-15.4%	-13.5%
Debt Service Coverage	1.11	0.84	0.76	0.68	0.71

Based on the projected operating results under Existing Rates, we recommend that the 5% system average rate revenue increase implemented as of November 2012 on an interim basis remain in effect going forward. We further recommend additional 5% system average increases in the base rates be implemented in April 2013 and April 2014. No change in base rates is indicated after this period through 2017. We further recommend implementation of a new Power Cost Adjustment (PCA) clause in April 2013 Under the new rate structure, base rates will have a cost basis of $72/MWh ($0.072/kWh) already built into the charges for fuel, purchased power, and associated transmission costs. When such fuel, purchased power, and transmission costs exceed $72/MWh, the PCA will be applied to collect the difference. When such fuel, purchased power, and transmission costs are below $72/MWh, the PCA will generate a credit against customers' bills unless the PPS Board determines by resolution that retention of the the credits is advisable for sound operation of the utility. Table 2-2 shows the results of these three rate increases on the financial metrics of the utility. PPS will still have negative cash flow for FY 2103, but all subsequent years are positive. Debt service coverage is maintained above the minimum requirements and PPS reserve funds have been funded.

In accordance with prudent utility practices and expectations of credit rating agencies, PPS has a policy to maintain three operating reserve funds. To date, none of these has been fully funded. One goal of this rate study is to fund these reserves by 2017, the end of the study period. By gradually building up these reserves over time, the impact on rates will be minimized.

Table 2-2 Financial Results Under Proposed Rates [1]($ thousands)

	2013	2014	2015	2016	2017
Total Revenue Under Proposed Rates	$71,626	$76,586	$81,277	$ 82,470	$ 82,260
Total Revenue Requirements	$73,883	$76,505	$ 81,213	$ 82,427	$ 81,031
Annual Operating Surplus (Deficits)	($2,257)	$ 81	$64	$ 42	$ 1,228
Debt Service Coverage	1.36	1.44	1.75	1.73	1.71
Amount in Reserve Funds	$0	$800	$5,300	$9,400	$11,976

As with the November 1, 2012 interim rate increase, the 5% systemwide revenue increase recommended for April 1, 2013 will be allocated differently among the various customer rate

[1] All forecasts of revenues from rates this report are based on constant fuel, purchased power, and transmission costs totaling $72/MWh resulting in a PCA equal to zero. All recommended base rates in this report include recovery of fuel, purchased power, and transmission costs totaling $72/MWh.

classes. The increase on April 1, 2014, however, will be a 5% across-the-board increase to all rate classes. The overall adjustment of rates described above includes not only an increase in PPS's tariff rates, but also implementation of the Power Cost Adjustment (PCA) that is more particularly described in Appendix A of this rate study. The net effect is an overall base rate revenue increase in 2013 of $3.1 million.

2.2 COST OF SERVICE ANALYSIS

A cost of service analysis of PPS's principal rate classes is presented in Section 4.0 that allocates the revenue requirements, or total cost of service to be recovered in rates, based on cost causation principles.

The Black & Veatch cost of service analysis is a two-dimensional cost matrix that allocates PPS's total cost of service to each rate class. The unbundled cost of service is analyzed first by function (production, transmission, distribution, or customer) in order to properly categorize costs to the various utility functions. These functions are further classified to energy, capacity, customer, and direct assignments. Functional costs are then allocated to classes on the basis of each class' cost responsibility for energy, capacity, and customer-related costs.

The unbundled cost of service results by class can be summarized by comparing the revenue under Existing Rates for each class with the unbundled cost of service. By calculating the percentage difference between the revenues and costs, the indicated change in revenue or rate adjustment for each class is determined. The cost of service summary is shown below on Table 2-3.

Table 2-3 Cost of Service Study Results

		[A]	[B]	[C]	[D]
		Revenue Under	**Unbundled**	**(Over)/Under Recovery**	
Line	**Rate Class**	**Existing Rates**	**COS**	**Amount**	**Percent**
		$	$	[B] - [A]	[C] / [A]
1	Residential	$ 25,942,729	$ 30,894,773	$ 4,952,044	19.1%
2	GSA 1	$ 7,210,301	$ 7,672,784	$ 462,483	6.4%
3	Drainage Pumps	$ 110,699	$ 171,163	$ 60,464	54.6%
4	GSA 2	$ 23,543,759	$ 24,294,010	$ 750,251	3.2%
5	GSA 3	$ 6,737,638	$ 5,779,296	$ (958,342)	-14.2%
6	Industrial	$ 1,416,742	$ 1,285,594	$ (131,148)	-9.3%
7	Security Lights	$ 885,477	$ 952,812	$ 67,335	7.6%
8	City Street Lights	$ 400,277	$ 518,368	$ 118,091	29.5%
9	TOTAL SYSTEM	$ 66,247,622	$ 71,568,800	$ 5,321,178	8.0%

2.3 RATE DESIGN

Rates have been redesigned for all of the principal rate classes.

The rate process began with a review of the class cost of service results. The results shown on Table 2-3 show that, on an absolute dollar basis, the bulk of the new revenue burden will be picked up by Residential, GSA-1, and GSA-2 customers. The proposed rates include the following characteristics:

- Implement cost of service-based rates and develop class target revenue based on the cost of service results. As with the November 2012 rate increase, the April 2013 rate increase will have varying rate adjustments by class.
- The "customer charge" component of PPS's rate tariff has been increased to recover more fixed customer costs in fixed rate components.
- Apply an across the board increase of 5.0% to all classes on April 1, 2014.
- The power charge adjustment component of PPS's Existing Rates will be discontinued and the PCA described in Appendix A implemented.
- Base rates will have a fuel and purchased power cost basis of $72/MWh ($0.72/kWh) in the charges. When fuel and purchased power costs exceed $72/MWh, the PCA will be applied to collect the difference. Should the fuel and purchased power costs dip below $72 / MWh, the PCA will operate as a credit against customer's bills.
- The Power Cost Adjustment mechanism described in Appendix A has been proposed for application beginning in the second quarter of 2013.

The detailed rate proposal is presented in Section 5.0.

3.0 REVENUES AND REVENUE REQUIREMENTS

Overall adequacy of existing rates is tested by comparing revenues under the Existing Rates with forecast revenue requirements, as presented toward the end of this section in Table 3-6. This section presents the components of revenue requirements as well as the forecast of revenue under Existing Rates for fiscal years 2013 through 2017.

3.1 REVENUES UNDER EXISTING RATES

The revenue forecast under Existing Rates was generated by applying the Existing Rates (including its power cost adjustment charge component as of October 2012) to the forecast of rate class billing determinants. The sales forecast of rate class billing determinants was prepared using the 2011 actual billing determinants[2] as a basis for 2013 through 2017 sales. For 2013 and 2014, the billing determinants (both customer count and energy sales) were held constant to 2011 levels. For 2015-2017, billing determinants were escalated annually at 0.5%. The sales forecast is considered conservative and reflects guidance from PPS management.

Total energy sales in 2013 are projected at 631.4 GWh. The projections of energy sales by class are shown on Table 3-1.

Table 3-1 Projected Electric Sales (MWh)

		Projected				
Line No.	**Description**	**2013**	**2014**	**2015**	**2016**	**2017**
	Forecast of Energy Sales by Class (MWh)					
1	Residential	252,666	252,666	253,929	255,199	256,475
2	GSA 1	61,293	61,293	61,599	61,907	62,217
3	Drainage Pumps	1,471	1,471	1,479	1,486	1,493
4	GSA 2	219,389	219,389	220,486	221,588	222,696
5	GSA 3	69,487	69,487	69,834	70,184	70,534
6	Industrial	16,866	16,866	16,950	17,035	17,120
7	Security Lights	6,896	6,896	6,896	6,896	6,896
8	City Street Lights	3,364	3,364	3,364	3,364	3,364
9	Total Energy Sales	631,431	631,431	634,537	637,658	640,795

Revenues under Existing Rates reflect the two current sources of revenue: electric rate revenue and other revenue (where electric rates are the rates that were in effect as of October 2012). The forecast of operating revenues under existing rates are shown in Table 3-2. Rate revenue shown on

[2] 2012 billing determinants were reviewed and reflected above normal weather variations and were not used. 2011 billing determinants reflected a more weather normal.

Line 11 ranges nominally from $66.2 million in 2013 to $67.2 million in 2017. Other revenue from operating and non-operating sources is shown on Line 21 and ranges from $2.3 million in 2013 to $2.7 million in 2017.

Total revenue under Existing Rates is summarized on Line 20 of Table 3-2 and ranges from nominally $68.6 million in 2013 to $69.9 million in 2017.

Table 3-2 Projected Revenue Under Existing Rates

Line No.	Description	Projected 2013	2014	2015	2016	2017
	Rate Revenue ($000)					
1	Residential	$ 25,943	$ 25,943	$ 26,072	$ 26,203	$ 26,334
2	GSA 1	7,210	7,210	7,246	7,283	7,319
3	Drainage Pumps	111	111	111	112	112
4	GSA 2	23,544	23,544	23,661	23,780	23,899
5	GSA 3	6,738	6,738	6,771	6,805	6,839
6	Industrial	1,417	1,417	1,424	1,431	1,438
7	Security Lights	885	885	885	885	885
8	City Street Lights	400	400	400	400	400
9	Total Rate Revenue	$ 66,248	$ 66,248	$ 66,572	$ 66,899	$ 67,227
	Other Revenue ($000)					
10	Forfeited Discount	$ 406	$ 435	$ 435	$ 435	$ 435
11	Misc. Service Revenue	$ 372	$ 372	$ 372	$ 372	$ 372
12	Total Rent From Electric Property	394	405	418	430	443
13	Other Electric Revenues	14	14	14	14	14
14	Rev. Merchandising & Jobbing	20	23	20	20	20
15	Non-Operating Rental Income.	1	1	1	1	1
16	Fiber Rental Income	852	996	1,082	1,082	1,082
17	Interest Income - Reserve Funds	-	4	31	74	107
18	Int. & Div. Inc. - Sinking Fund	256	250	250	250	250
19	Total Other Revenue	$ 2,315	$ 2,500	$ 2,622	$ 2,677	$ 2,724
20	**Total Revenue ($000)**	$ 68,562	$ 68,748	$ 69,194	$ 69,576	$ 69,950

3.2 REVENUE REQUIREMENTS

The overall adequacy of the Existing Rates is tested by comparing revenues under Existing Rates with revenue requirements. Revenue requirements are developed on a cash basis and consist primarily of costs for purchased power and fuel, operation and maintenance (O&M) expenses, debt service, payments in lieu of property taxes, capital plan spending, and other non-operating expenses. The forecast of annual revenue requirements is shown in Table 3-3 and discussed in the following sections.

Table 3-3 Revenue Requirements ($)

Line	Description	2012	2013	2014	2015	2016	2017
		$	$	$	$	$	$
	REVENUE REQUIREMENTS ($)						
	Power Costs						
1	Purchase Power	32,446,316	41,357,400	42,921,300	43,879,500	44,867,600	44,461,100
2	Generation Fuel Costs	1,307,323	1,870,300	2,676,900	3,399,800	3,399,800	3,399,800
3	**Total Power Costs**	33,753,639	43,227,700	45,598,200	47,279,300	48,267,400	47,860,900
	Operation and Maintenance Expense						
4	Production	1,216,398	1,083,100	1,115,600	1,149,100	1,183,600	1,219,100
5	Transmission	22,973	69,700	70,200	70,700	71,200	71,800
6	Distribution	3,267,099	3,343,000	3,443,300	3,546,600	3,653,000	3,762,600
7	Customer Accounts	1,524,726	1,652,800	1,712,100	1,755,900	1,801,000	1,847,400
8	Sales	976,983	851,500	871,800	904,200	931,400	959,300
9	Administrative and General	2,586,614	2,512,900	2,591,900	2,673,600	2,757,300	2,843,900
10	**Total O&M Expense**	9,594,793	9,513,000	9,804,900	10,100,100	10,397,500	10,704,100
	Other Expenses						
11	Payment in lieu of Property Taxes	2,112,143	2,200,000	2,310,000	2,425,500	2,546,800	2,674,100
12	Amortization of Debt Discount	276,036	276,000	276,000	276,000	276,000	276,000
13	Other Interest Expenses	372	500	500	500	500	500
14	**Total Other Expenses**	2,388,551	2,476,500	2,586,500	2,702,000	2,823,300	2,950,600
15	**Total Expenses**	45,736,983	55,217,200	57,989,600	60,081,400	61,488,200	61,515,600
16	**Net Revenues**	17,754,264	13,345,000	10,758,000	9,112,800	8,087,900	8,434,800
	Debt Service						
17	Existing Debt Service	12,255,800	12,295,300	13,145,700	12,284,000	12,289,400	12,278,900
18	**Total Debt Service**	12,255,800	12,295,300	13,145,700	12,284,000	12,289,400	12,278,900
19	Revenue After Debt Service Obligation	5,498,464	1,049,700	(2,387,700)	(3,171,200)	(4,201,500)	(3,844,100)
	Capital Expenditures						
20	Miscellaneous Equipment / Projects	62,500	100,000	400,000	150,000	150,000	150,000
21	Engineering/Operations Equipment	2,376,100	2,045,000	200,000	150,000	200,000	200,000
22	Vehicle Replacements	-	402,100	232,000	205,000	250,000	250,000
23	Engineering Projects	4,064,200	3,480,300	3,581,700	3,686,200	3,793,800	3,904,600
24	Special Projects	748,900	343,500	156,000	156,000	156,000	156,000
25	**Total Capital Expenditures**	7,251,700	6,370,900	4,569,700	4,347,200	4,549,800	4,660,600
26	Transfers to Reserve Funds	-	-	800,000	4,500,000	4,100,000	2,576,000
27	**Total Revenue Requirement**	**65,244,483**	**73,883,400**	**76,505,000**	**81,212,600**	**82,427,400**	**81,031,100**

3.2.1 Power Supply Costs

PPS has primarily four sources of power supply:

1. Nominally 105 MW ownership interest in the coal fired Prairie State Generating Center (PSGC) through membership in the Kentucky Municipal Power Agency (KMPA),
2. Ownership of nominally 110 MW of natural gas fired simple cycle combustion turbine capacity in the city and
3. Approximately 2.5 MW of capacity and energy allocation from the Southeast Power Administration (SEPA).
4. Beginning January 2015 PPS has contracted with American Municipal Power (AMP) for nominally 15 MW of hydropower. Those costs are included in the KMPA costs shown in Table 3-4.

A forecast of the power supply costs from each source can be found in Table 3-4.

Table 3-4 Projected Power Supply Cost ($)

SOURCE	2013	2014	2015	2016	2017
KMPA	$41,028,800	$42,592,700	$43,550,900	$44,539,000	$44,132,500
SEPA	$328,600	$328,600	$328,600	$328,600	$328,600
Fuel	$1,870,300	$2,676,900	$3,399,800	$3,399,800	$3,399,800
Total Power Supply Cost	$43,227,700	$45,598,200	$47,279,300	$48,267,400	$47,860,900

Source: power supply forecast provided by SAIC, October 2012

The power supply costs that KMPA charges PPS include the following:

- Fixed O&M on PSGC
- Variable O&M on PSGC
- Debt service on PSGC
- Debt service on coal supply
- Transmission Costs
- Hydro costs
- KMPA overhead costs

It is of note that the fuel supply that PPS pays for PSGC is in the form of a debt service payment. This results in the cost of coal being fixed for 30 years, which will result in a stable cost fuel source for PPS for many years.

3.2.2 Operation and Maintenance Expense

Operation and Maintenance (O&M) expenses, in the forecast period are based on the 2013 budget and escalated in 2014 and 2015 based on assumptions made by PPS. For 2016 and 2017, the same growth assumptions were applied where appropriate. The majority of O&M costs are escalated annually at 3%.

O&M expenses are summarized by function on Lines 4 through 10 of Table 3-3.

3.2.3 Capital Expenditures

The Capital Budget is from the 2013 Proposed Budget, which also includes projections for 2014 and 2015. The primary and preferred source of funds to finance the Capital Budget is with annual operating revenues. The utility has no plans to issue additional debt for any capital projects during the study period.

The Capital Budget is summarized on Lines 20 through 25 of Table 3-3. The projects are grouped into five sections. Miscellaneous Equipment/Projects includes items such as minor office renovations and equipment and roof repairs. Engineering/Operations equipment primarily includes substation projects with some additional electric operations projects. Engineering Projects include projects in the distribution system including lines, transformers, meters and lighting equipment. Special Projects are for Fiber services and equipment.

3.2.4 Other Revenue Requirements

Other Revenue Requirements include Other Expenses, Debt Service, and Reserve Funds.

Other Expenses are primarily composed of payments in lieu of property taxes and interest expenses. The forecast of Other Expenses can be seen on Lines 11-14 on Table 3-3.

Existing debt service currently totals about $12.3 million each year and is primarily related to the construction of PPS's combustion turbine generating facility. The forecast of Debt Service can be seen on Line 17 on Table 3-3.

3.2.5 Reserve Funds

In accordance with prudent utility practices and expectations of credit rating agencies, PPS has a policy to maintain the following three operating reserve funds. To date, none of these has been fully funded. One goal of this rate study is to fund these reserves by 2017, the end of the study period. By gradually building up these reserves over time, the impact on rates will be minimized. PPS's description and rationale for each fund is described below, with values displayed in Table 3-5.

- **Operating and Maintenance Reserve.** 25% of the annual operating and maintenance expenses excluding depreciation and power supply/generation expenditures. It is intended to provide an adequate level of working capital to cover any unforeseen cost contingencies.
- **Power Supply/Generation Reserve.** This reserve is based on 10% of the annual power supply/generation expenditures. While the implementation of a "power cost adjustment" will recover any volatility in power supply/generation cost over a six month period, an adequate working capital reserve balance must be met to ensure all bills are paid in a timely manner.
- **Catastrophic or Natural Disasters Reserve**. This reserve is an amount equal to the cost of the January 2009 Ice Storm, which was $4.5 million. This was the worst natural disaster to hit Paducah Power System in its 40-year history. The $4.5 million cost factor will be evaluated annually, and may be revised upwards for inflationary factors over time.

Table 3-5 Reserve Fund Schedule

Line	Description		2013	2014	2015	2016	2017
	Reserve Fund Policies						
	O&M Expenses						**1.00%**
1	The Cash Reserve Policy calculation will include 25% of the annual operating and maintenance expenses						
2	excluding depreciation and power supply/generation expenditures						
3	O&M Expense:		9,513,000	9,804,900	10,100,100	10,397,500	10,704,100
4	Reserve Target:	25%					
5	**Target Reserve**		**2,378,300**	**2,451,200**	**2,525,000**	**2,599,400**	**2,676,000**
6	Beginning Balance		-	-	200,000	1,200,000	1,900,000
7	Transfer in		-	200,000	1,000,000	700,000	776,000
8	End Balance		-	200,000	1,200,000	1,900,000	2,676,000
9	Interest Income			1,000	7,000	15,500	22,880
	Power Supply/Generation Costs						
10	The Cash Reserve Policy calculation will include 10% of the annual power supply/generation expenditures						
11	Production Expense		43,227,700	45,598,200	47,096,500	48,084,600	47,678,100
12	Reserve Target:	10%					
13	**Target Reserve**		**4,322,800**	**4,559,800**	**4,709,700**	**4,808,500**	**4,767,800**
14	Beginning Balance		-	-	300,000	2,300,000	3,700,000
15	Transfer in		-	300,000	2,000,000	1,400,000	1,100,000
16	End Balance		-	300,000	2,300,000	3,700,000	4,800,000
17	Interest Income			1,500	13,000	30,000	42,500
	Catastrophic or Natural Disasters						
18	The Cash Reserve Policy calculation will include an amount equivalent to cost of the January 2009 Ice Storm						
19	Production Expense		4,500,000	4,500,000	4,500,000	4,500,000	4,500,000
20	Reserve Target:	100%					
21	**Target Reserve**		**4,500,000**	**4,500,000**	**4,500,000**	**4,500,000**	**4,500,000**
22	Beginning Balance		-	-	300,000	1,800,000	3,800,000
23	Transfer in		-	300,000	1,500,000	2,000,000	700,000
24	End Balance		-	300,000	1,800,000	3,800,000	4,500,000
25	Interest Income			1,500	10,500	28,000	41,500
26	**Reserve Fund End Balance**		**-**	**800,000**	**5,300,000**	**9,400,000**	**11,976,000**
27	**Total Annual Deposits to Reserve Funds**		**-**	**800,000**	**4,500,000**	**4,100,000**	**2,576,000**
28	Total Interest Income on Reserve Funds			4,000	30,500	73,500	106,880

3.3 PROJECTED OPERATING RESULTS UNDER EXISTING RATES

Table 3-6 combines the forecast of revenue under Existing Rates with the forecast cash revenue requirements to project operating results under Existing Rates. Based on the results shown, the revenue forecast from the existing electric rates will not cover the revenue requirements of the utility. The annual cash flows become increasingly negative (Line 22), ranging from a $5.3 million deficit in 2013 to $12.9 million deficit in 2016. Cumulative cash deficit by 2017 is $50.8 million and debt service coverage decreases from 1.47 to a low of 0.68 (in 2016). PPS is required by the covenants made in the indentures for its outstanding bond issuances to maintain a debt service coverage of 1.20 at a minimum.

Table 3-6 Projected Operating Results under Existing Rates

Line No.	Description	2012	2013	2014	2015	2016	2017
	REVENUES ($)						
1	Total Rate Revenue	61,322,163	66,247,600	66,247,600	66,572,500	66,898,900	67,226,800
2	Total Other Revenue	2,169,084	2,314,600	2,500,000	2,621,800	2,677,300	2,723,600
3	**Total Revenue**	63,491,247	68,562,200	68,747,600	69,194,300	69,576,200	69,950,400
	REVENUE REQUIREMENTS ($)						
	Power Costs						
4	Purchase Power	32,446,316	41,357,400	42,921,300	43,879,500	44,867,600	44,461,100
5	Generation Fuel Costs	1,307,323	1,870,300	2,676,900	3,399,800	3,399,800	3,399,800
6	**Total Power Costs**	33,753,639	43,227,700	45,598,200	47,279,300	48,267,400	47,860,900
	Operation and Maintenance Expense						
7	Production	1,216,398	1,083,100	1,115,600	1,149,100	1,183,600	1,219,100
8	Transmission	22,973	69,700	70,200	70,700	71,200	71,800
9	Distribution	3,267,099	3,343,000	3,443,300	3,546,600	3,653,000	3,762,600
10	Customer Accounts	1,524,726	1,652,800	1,712,100	1,755,900	1,801,000	1,847,400
11	Sales	976,983	851,500	871,800	904,200	931,400	959,300
12	Administrative and General	2,586,614	2,512,900	2,591,900	2,673,600	2,757,300	2,843,900
13	**Total O&M Expense**	9,594,793	9,513,000	9,804,900	10,100,100	10,397,500	10,704,100
14	Other Expenses	2,388,551	2,476,500	2,586,500	2,702,000	2,823,300	2,950,600
15	**Total Expenses**	45,736,983	55,217,200	57,989,600	60,081,400	61,488,200	61,515,600
16	**Net Revenues**	17,754,264	13,345,000	10,758,000	9,112,800	8,087,900	8,434,800
17	Debt Service	12,255,800	12,295,300	13,145,700	12,284,000	12,289,400	12,278,900
18	Revenue After Debt Service Obligation	5,498,464	1,049,700	(2,387,700)	(3,171,200)	(4,201,500)	(3,844,100)
19	Capital Expenditures	7,251,700	6,370,900	4,569,700	4,347,200	4,549,800	4,660,600
20	Transfers to Reserve Funds	-	-	800,000	4,500,000	4,100,000	2,576,000
21	**Total Revenue Requirement**	**65,244,483**	**73,883,400**	**76,505,000**	**81,212,600**	**82,427,400**	**81,031,100**
22	Annual Revenue Surplus / (Deficiency)	(1,753,236)	(5,321,200)	(7,757,400)	(12,018,300)	(12,851,200)	(11,080,700)
23	Cumulative Revenue Surplus / (Deficien	(1,753,236)	(7,074,436)	(14,831,836)	(26,850,136)	(39,701,336)	(50,782,036)
24	**Debt Service Coverage**	**1.47**	**1.11**	**0.84**	**0.76**	**0.68**	**0.71**

3.4 RECOMMENDED RATE ADJUSTMENTS

Based on the projected operating results under Existing Rates, we recommend maintaining in place the rate revenue increase of 5% that was implemented on an interim basis in November 2012 and that additional 5% increases be made in both April 2013 and April 2014. No change in base rates is indicated for the remaining period of this study (i.e., 2017). Under the new rate structure, base rates will have a cost basis of $72/MWh ($0.072/kWh) already built into the charges for fuel, purchased power, and associated transmission costs. When such fuel, purchased power, and transmission costs exceed $72/MWh, the PCA will be applied to collect the difference. No change in base rates is indicated for the remaining period through 2017.

3.5 PROJECTED OPERATING RESULTS UNDER RECOMMENDED RATES

The forecast of financial operations under the recommended rates is presented in Table 3-7. The 5% rate increase implemented in November 2012 is expected to result in an increase of $2.2 million in revenue in FY 2013 (Line 11). Revenues under the recommended rate structure (Line 16) reach a projected $10.6 million in 2017. While the annual net cash flow (Line 61) remains negative in 2013 due to planned capital spending, all future annual balances are positive and the reserve funds are funded to target requirements by 2017. The total amount in reserve funds after 2017 is forecast to be $11,976,000 as shown on Table 3-5 (Line 26). Debt service coverage under proposed rate ranges from 1.36 to 1.75.

Table 3-7 Projected Operating Results under Recommended Rates (1 of 2)

Line No.	Description			2012	2013	2014	2015	2016	2017
1	Retail Sales (MWh)			631,431	631,431	631,431	634,588	637,761	640,950
	REVENUES ($)								
2	**Revenue Under Existing Rates**								
3	Base Rate Revenue				58,537,800	58,537,800	58,824,100	59,111,700	59,400,800
4	PCA Revenue ($0.0122 / kWh)				7,709,800	7,709,800	7,748,300	7,787,100	7,826,000
5	**Total Rate Revenue**			**61,322,163**	**66,247,600**	**66,247,600**	**66,572,400**	**66,898,800**	**67,226,800**
6	**Fuel & PP in Base Rates ($/MWh)**		$ 72.00						
7	Fuel & PP Revenue in Base				45,463,000	45,463,000	45,690,300	45,918,800	46,148,400
8	Future PCA Revenue				-	135,200	1,589,000	2,348,600	1,712,500
9	**Additional Rate Revenue**		Months in						
10	Date Effective	% Increase	First Year						
11	November 1, 2012	5.00%	8		2,208,300	3,312,400	3,328,600	3,344,900	3,361,300
12	April 1, 2013	5.00%	3		855,700	3,478,000	3,495,100	3,512,200	3,529,400
13	April 1, 2014	5.00%	3			913,000	3,669,800	3,687,800	3,705,900
13	July 1, 2014	0.00%	12				-	-	-
14	July 1, 2015	0.00%	12					-	-
15	July 1, 2016	0.00%	12						-
16	Projected Rate Revenue Increases			-	3,064,000	7,703,400	10,493,500	10,544,900	10,596,600
17	**Total Rate Revenue**			**61,322,163**	**69,311,600**	**74,086,200**	**78,654,900**	**79,792,300**	**79,535,900**
18	**Other Revenue:**								
19	Forfeited Discount			347,405	406,400	435,400	435,400	435,400	435,400
20	Misc. Service Revenue			381,675	371,500	371,500	371,500	371,500	371,500
21	Total Rent From Electric Property			397,354	393,600	405,400	417,600	430,100	443,000
22	Other Electric Revenues			14,423	14,000	14,000	14,000	14,000	14,000
23	Rev. Merchandising & Jobbing			31,631	20,000	23,000	20,000	20,000	20,000
24	Non-Operating Rental Income.			5,400	600	600	600	600	600
25	Fiber Rental Income			728,109	852,400	996,100	1,082,200	1,082,200	1,082,200
26	Interest Income - Reserve Funds			-	-	4,000	30,500	73,500	106,900
27	Int. & Div. Inc. - Sinking Fund			263,088	256,100	250,000	250,000	250,000	250,000
28	**Total Other Revenue**			**2,169,084**	**2,314,600**	**2,500,000**	**2,621,800**	**2,677,300**	**2,723,600**
29	**Total Revenue**			**63,491,247**	**71,626,200**	**76,586,200**	**81,276,700**	**82,469,600**	**82,259,500**

Table 3-7 Projected Operating Results under Recommended Rates (2 of 2)

Line No.	Description	2012	2013	2014	2015	2016	2017
30	**REVENUE REQUIREMENTS ($)**						
31	**Power Costs**						
32	Purchase Power	32,446,316	41,357,400	42,921,300	43,879,500	44,867,600	44,461,100
33	Generation Fuel Costs	1,307,323	1,870,300	2,676,900	3,399,800	3,399,800	3,399,800
34	**Total Power Costs**	**33,753,639**	**43,227,700**	**45,598,200**	**47,279,300**	**48,267,400**	**47,860,900**
35	**Operation and Maintenance Expense**						
36	Production	1,216,398	1,083,100	1,115,600	1,149,100	1,183,600	1,219,100
37	Transmission	22,973	69,700	70,200	70,700	71,200	71,800
38	Distribution	3,267,099	3,343,000	3,443,300	3,546,600	3,653,000	3,762,600
39	Customer Accounts	1,524,726	1,652,800	1,712,100	1,755,900	1,801,000	1,847,400
40	Sales	976,983	851,500	871,800	904,200	931,400	959,300
41	Administrative and General	2,586,614	2,512,900	2,591,900	2,673,600	2,757,300	2,843,900
42	**Total O&M Expense**	**9,594,793**	**9,513,000**	**9,804,900**	**10,100,100**	**10,397,500**	**10,704,100**
43	**Other Expenses**						
44	Payment in lieu of Property Taxes	2,112,143	2,200,000	2,310,000	2,425,500	2,546,800	2,674,100
45	Amortization of Debt Discount	276,036	276,000	276,000	276,000	276,000	276,000
46	Other Interest Expenses	372	500	500	500	500	500
47	**Total Other Expenses**	**2,388,551**	**2,476,500**	**2,586,500**	**2,702,000**	**2,823,300**	**2,950,600**
48	**Total Expenses**	45,736,983	55,217,200	57,989,600	60,081,400	61,488,200	61,515,600
49	**Net Revenues**	**17,754,264**	**16,409,000**	**18,596,600**	**21,195,300**	**20,981,400**	**20,743,900**
50	**Debt Service**	**12,255,800**	**12,295,300**	**13,145,700**	**12,284,000**	**12,289,400**	**12,278,900**
51	Balance Available for Capital Projects/Reserves	5,498,464	4,113,700	5,450,900	8,911,300	8,692,000	8,465,000
52	**Capital Expenditures**						
53	Miscellaneous Equipment / Projects	62,500	100,000	400,000	150,000	150,000	150,000
54	Engineering/Operations Equipment	2,376,100	2,045,000	200,000	150,000	200,000	200,000
55	Vehicle Replacements	-	402,100	232,000	205,000	250,000	250,000
56	Engineering Projects	4,064,200	3,480,300	3,581,700	3,686,200	3,793,800	3,904,600
57	Special Projects	748,900	343,500	156,000	156,000	156,000	156,000
58	**Total Capital Expenditures**	**7,251,700**	**6,370,900**	**4,569,700**	**4,347,200**	**4,549,800**	**4,660,600**
59	**Transfers to Reserve Funds**		-	800,000	4,500,000	4,100,000	2,576,000
60	**Total Revenue Requirement**	**65,244,483**	**73,883,400**	**76,505,000**	**81,212,600**	**82,427,400**	**81,031,100**
61	Net Annual Cash Flow	(1,753,236)	(2,257,200)	81,200	64,100	42,200	1,228,400
62	**Debt Service Coverage**						
63	Net Revenues Available for Debt Service (1)	18,030,300	16,685,000	18,872,600	21,471,300	21,257,400	21,019,900
64	Debt Service Payment	12,255,800	12,295,300	13,145,700	12,284,000	12,289,400	12,278,900
65	**Debt Service Coverage Ratio**	**1.47**	**1.36**	**1.44**	**1.75**	**1.73**	**1.71**

Notes:
(1) Net Revenues (ln 49) plus Amort. Of Debt Discount (ln 45)

3.6 POWER COST ADJUSTMENT

As part of this study, PPS is replacing its power cost adjustment with the Power Cost Adjustment (PCA) more particularly described in Appendix A. As mentioned in Section 3.4 above, the PCA will recover all fuel, purchased power, and related transmission expenses over the amount included in base rates ($72/MWh). The proposed PCA will be set quarterly based on the projected fuel, purchased power, and transmission costs for the current quarter. The PCA will include a reconciliation adjustment to recover or refund any variance between actual and projected cost recovery.

4.0 COST OF SERVICE ANALYSIS

The overall adequacy of rates is tested by comparing class revenues under a utility's existing rates for a test year with the class allocated test year cost of service requirements. PPS's cost of service requirements are set equal to the net revenue requirements of the utility to be recovered from rates. Test year costs of service are first classified to cost functions, and then allocated to customer classes on appropriate allocation bases, and finally the allocated class cost of service is compared to test year class revenue.

4.1 TEST YEAR COST OF SERVICE

This section presents the unbundled class cost of service analysis for PPS based on actual and projected revenues and costs for the 2013 test year. Allocation of costs of service to rate classes provides a measure of the proportionate responsibility of each customer class for the total cost of utility service provided by PPS. A comparison of the class net cost of service or net revenue requirements with class revenues under the Existing Rates provides a guide for the development of fair and equitable class rate adjustments.

Table 4-1 presents a summary of PPS's 2013 test year net revenue requirements, or cost of service to be allocated to classes. Gross revenue requirements include purchased power, O&M expenses, other expenses, capital expenditures, and debt service. Credits to the cost of service include other revenues, which reduce gross revenue requirements to net revenue requirements.

The net revenue requirement is the test year cost of service and the amount to be collected from rates. The total cost of service to be allocated among PPS's customer classes is $71.6 million, as shown on Line 26 of Table 4-1.

Table 4-1 2013 Test Year Cost of Service

Line	Description		Test Year COS
	CASH BASIS		
	Revenue Requirements:		
	Power Costs		
1	Purchase Power	$	41,357,400
2	Generation Fuel Costs		1,870,300
3	Total Power Costs	**$**	**43,227,700**
	Operation and Maintenance Expense		
4	Production	$	1,083,100
5	Transmission		69,700
6	Distribution		3,343,000
7	Customer Accounts		1,652,800
8	Sales		851,500
9	Administrative and General		2,512,900
10	**Total O&M Expense**	**$**	**9,513,000**
	Other Expenses		
11	Payment in lieu of Property Taxes	$	2,200,000
12	Amortization of Debt Discount		276,000
13	Other Interest Expenses		500
14	**Total Other Expenses**	**$**	**2,476,500**
	Debt Service		
15	Existing Debt Service	$	12,295,300
16	**Total Debt Service**	**$**	**12,295,300**
	Capital Expenditures		
17	Miscellaneous Equipment / Projects		100,000
18	Engineering/Operations Equipment		2,045,000
19	Vehicle Replacements		402,100
20	Engineering Projects		3,480,300
21	Special Projects		343,500
22	**Total Capital Expenditures**	**$**	**6,370,900**
23	**Transfers to Reserve Funds**		-
24	**Gross Revenue Requirements**	**$**	**73,883,400**
25	**Less: Other Revenue**	**$**	**(2,314,600)**
26	**Net Revenue Requirement**	**$**	**71,568,800**
	Revenues Under Existing Rates:		
27	Base Rate Revenue	$	58,537,800
28	PCA Revenue		7,709,800
29	**Total Rate Revenue**	**$**	**66,247,600**
	Rate Revenue Increase:		
30	Amount	**$**	**5,321,200**
31	Percent		**8.03%**

4.2 FUNCTIONALIZATION AND CLASSIFICATION OF REVENUE REQUIREMENTS

Black & Veatch uses a systematic process for identifying cost functions based on the traditional categories of production, transmission, distribution, and customer. Black & Veatch further split customer between direct connection costs and general customer costs. This latter split is useful for assuring that rate design at least identifies the connection costs (meter, service line, transformer investment and customer service and billing) and reflects those costs in the customer component of rates. General customer-related costs for the distribution system are tracked separately as well as the customer components of general plant and non-payroll-related overheads (which are allocated on labor-related i.e. supervised O&M). To the extent permitted by the accounting data, this functionalization may include subcategories such as primary distribution and secondary distribution and directly assigned dollars based on unique facilities that need to be assigned rather than allocated. Cost classification reflects the most detailed analysis as the accounting data permits. Costs are classified as demand, energy, customer, and direct. Only costs that vary with energy are classified as energy. Black & Veatch has developed careful theoretical and practical bases for functionalization and classification. Please refer to Figure B-6 in Appendix B for a flow chart demonstrating the functionalization and classification process of revenue requirements.

4.2.1 Functionalization of Test Year Cost of Service

The process of functionalization requires determining the utility costs associated with each of the functions provided by the utility. The principal functions used in a cost study are as follows:

- Power Supply/Production
- Transmission
- Distribution
- Customer
- Direct

Each of these functions is described below.

- The production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power along with the cost of the delivery of purchased power is also functionalized as production.
- The transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the grid and to move power from generation to load.
- The distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system. Therefore, it is common for the distribution system to be divided into sub-functions such as primary and secondary. In addition, some distribution facilities serve a customer function and are further subdivided based on the type of facilities used by customer groups.
- The customer function includes plant and expenses associated with individual customers. Examples of these expenses include meters, services, as well as meter reading and billing (accounts and services).
- The direct function is used to assign certain costs directly to a specific class, such as Security Lighting and City Street Lighting. It is also used to allocate specific costs on a basis not covered by the other functions. These include Direct Assignment, Sales Revenue, and kWh Sales.

The functionalization process has been greatly simplified by the adoption of FERC uniform systems of accounts (USOA). Thus, plant accounts from 310-346 represent production plant and expenses from 500-

557 represent expenses for production. Similar accounts exist for the other functions. Each of the accounts identifies a specific cost component such as land and land rights. There is an account for this category of expense for each type of production capacity and for transmission, distribution, and general plant. The accounting system provides most of the functionalization necessary for cost allocation.

Despite this detailed accounting system, issues still arise with functionalization when assets serve multiple functions. Transmission plant generally serves a generation-related function by interconnecting generation to the interconnected transmission system for delivery to the distribution system. In some cases transmission laterals serve only a large industrial customer directly and if the plant accounting data can identify that investment it should be directly assigned to the customer.

Subaccounts are useful for administrative and general expenses. In particular, certain expenses are plant-related such as property insurance. Other general expenses are related to payroll expenses for example.

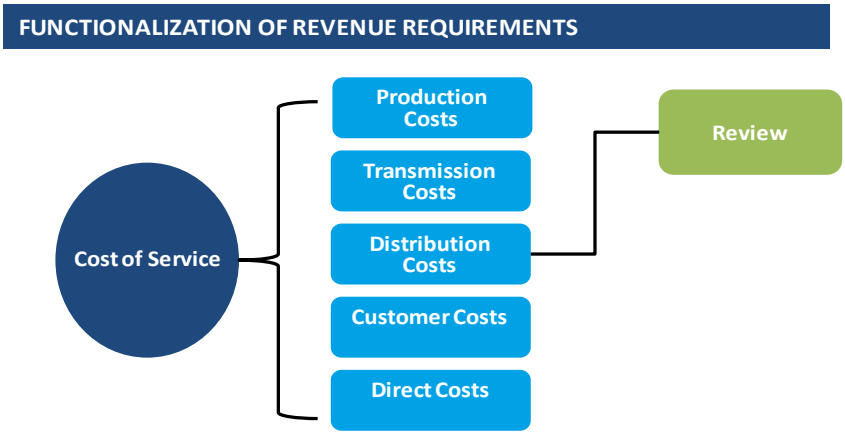

Figure 4-1 Functionalization of Revenue Requirements

Once costs are functionalized, they must be classified based on customer, demand, and energy. The classification step is critical to develop allocation factors that reflect cost causation. In particular, it is important to understand not only the accounting basis for costs but the engineering and operation analyses that drive those costs.

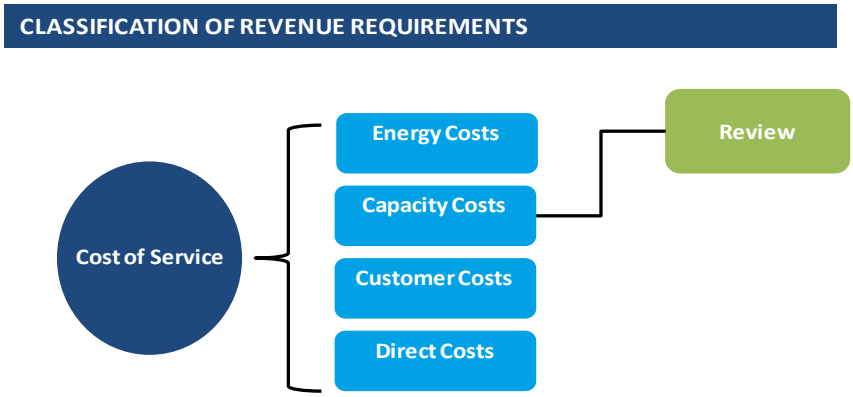

Figure 4-2 Classification of Revenue Requirements

4.2.2 Classification of PPS Test Year Cost of Service

Costs are classified as energy, capacity, customer, and direct. Energy costs are those costs that vary generally with the production of energy such as fuel costs, the variable portion of KMPA costs, or other variable generation costs. Capacity costs are those costs that vary generally with some measure of maximum demand. Measures of maximum demand include system coincident peak demand, class non-coincident peak demand, and customer non-coincident peak demand. Customer costs are those costs that vary generally with the number of customers such as meters and service lines. Some costs may be classified into more than one category. For example, distribution line costs may have both a capacity and a customer cost component because the costs of the line is a function of the miles of line required, customer density, and load to be served. Black & Veatch classified PPS Distribution Lines as 60 percent Primary (capacity) and 40 percent Laterals and Secondary (customer). Primary reflects the plant investment in three phase lines, which are allocated on a capacity basis. Laterals are allocated on a customer basis and reflect the remaining investment in two phase, one phase, and secondary lines.

The functionalized fixed assets, which are used as a proxy to functionalize revenue requirements, are shown on Table 4-2, followed by the functionalized revenue requirement, shown on Table 4-3.

Table 4-2 Functional Classification of Plant in Service

Line	Acct	Description	Total	Power Supply Energy	Power Supply Capacity Average	Power Supply Capacity Excess	Transmission Capacity Average	Transmission Capacity Excess	Distribution Capacity Substations	Distribution Capacity Line Transformers	Distribution Capacity Lines 60%	Distribution Customer Laterals 40%	Distribution Customer Services	Distribution Customer Meters	Customer Accounts and Service	Direct Security Lights	Direct Street Lights
		ORIGINAL PLANT															
		Generation															
1	340	Land and Land Rights	$ 845,491	0	411,147	434,344	0	0	0	0	0	0	0	0	0	0	0
2	341	Structures and Improvements	$ 29,506,686	0	14,348,572	15,158,114	0	0	0	0	0	0	0	0	0	0	0
3	342	Fuel Holders, Producers, and Accessories	$ 1,700,394	0	826,871	873,523	0	0	0	0	0	0	0	0	0	0	0
4	344	Generators	$ 60,152,878	0	29,251,265	30,901,613	0	0	0	0	0	0	0	0	0	0	0
5	345	Accessory Electric Equipment	$ 19,005,740	0	9,242,150	9,763,590	0	0	0	0	0	0	0	0	0	0	0
6		Total	$ 111,211,188	$ -	$ 54,080,005	$ 57,131,184	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7		**Transmission**															
8	350	Land and Land Rights	$ 418,926	0	0	0	203,716	215,210	0	0	0	0	0	0	0	0	0
9	351	Clearing Trans Line Right of Way	$ 1,855	0	0	0	902	953	0	0	0	0	0	0	0	0	0
10	352	Structures and Improvements	$ 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	353	Station Equipment	$ 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	354	Towes and Fixtures	$ 81,586	0	0	0	39,674	41,912	0	0	0	0	0	0	0	0	0
13	355	Poles and Fixtures	$ 6,920,879	0	0	0	3,365,499	3,555,380	0	0	0	0	0	0	0	0	0
14	357	Underground Conduit	$ 1,310,268	0	0	0	637,160	673,108	0	0	0	0	0	0	0	0	0
15	358	Underground Conductor and Devices	$ 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	359	Roads and Trails	$ 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17		Total	$ 8,733,513	$ -	$ -	$ -	$ 4,246,951	$ 4,486,563	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		**Distribution**															
19	360	Land and Land Rights	$ 764,091	0	0	0	0	0	764,091	0	0	0	0	0	0	0	0
20	361	Structures and Improvements	$ 525	0	0	0	0	0	525	0	0	0	0	0	0	0	0
21	362	Station Equipment	$ 15,773,180	0	0	0	0	0	15,773,180	0	0	0	0	0	0	0	0
22	363	Storage Battery Equipment	$ 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	364	Poles, Towers, and Fixtures	$ 8,600,465	0	0	0	0	0	0	0	5,160,279	3,440,186	0	0	0	0	0
24	365	Overhead Conductor and Devices	$ 4,503,852	0	0	0	0	0	0	0	2,702,311	1,801,541	0	0	0	0	0
25	366	Underground Conduit	$ 3,833,544	0	0	0	0	0	0	0	2,300,126	1,533,418	0	0	0	0	0
26	367	Underground Conductor and Devices	$ 14,320,349	0	0	0	0	0	0	0	8,592,210	5,728,140	0	0	0	0	0
27	368	Line Transformers	$ 13,817,234	0	0	0	0	0	0	13,817,234	0	0	0	0	0	0	0
28	369	Services	$ 4,180,253	0	0	0	0	0	0	0	0	0	4,180,253	0	0	0	0
29	370	Meters	$ 3,874,842	0	0	0	0	0	0	0	0	0	0	3,874,842	0	0	0
30	371	Installations on Customer Premises	$ 3,093,406	0	0	0	0	0	0	0	0	0	0	0	0	3,093,406	0
31	372	Leased Property on Customer Premises	$ 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	373	Street Lighting and Signal Systems	$ 1,802,437	0	0	0	0	0	0	0	0	0	0	0	0	0	1,802,437
33		Total	$ 74,564,179	$ -	$ -	$ -	$ -	$ -	$ 16,537,796	$ 13,817,234	$ 18,754,926	$ 12,503,284	$ 4,180,253	$ 3,874,842	$ -	$ 3,093,406	$ 1,802,437
34		**Total Plant before General Plant**	$ 194,508,881	$ -	$ 54,080,005	$ 57,131,184	$ 4,246,951	$ 4,486,563	$ 16,537,796	$ 13,817,234	$ 18,754,926	$ 12,503,284	$ 4,180,253	$ 3,874,842	$ -	$ 3,093,406	$ 1,802,437
35		**General**															
36	389	Land and Land Rights	$ 583,121	18,046	11,080	11,705	1,196	1,263	59,250	0	108,373	72,249	0	67,352	198,112	12,056	22,439
37	390	Structures and Improvements	$ 4,341,566	134,359	82,495	87,149	8,904	9,406	441,138	0	806,884	537,922	0	501,466	1,475,020	89,759	167,064
38	391	Office Furniture and Equipment	$ 1,118,809	34,624	21,259	22,458	2,295	2,424	113,680	0	207,932	138,621	0	129,226	380,108	23,131	43,052
39	392	Transportation Equipment	$ 2,178,776	67,427	41,399	43,735	4,468	4,721	221,381	0	404,927	269,952	0	251,656	740,225	45,045	83,840
40	393	Stores Equipment	$ 83,958	2,598	1,595	1,685	172	182	8,531	0	15,604	10,402	0	9,697	28,524	1,736	3,231
41	394	Tools, Shop, and Garage Equipment	$ 198,721	6,150	3,776	3,989	408	431	20,192	0	36,932	24,622	0	22,953	67,514	4,108	7,647
42	395	Laboratory Equipment	$ 91,409	2,829	1,737	1,835	187	198	9,288	0	16,989	11,326	0	10,558	31,056	1,890	3,517
43	396	Power Operated Equipment	$ 271,359	8,398	5,156	5,447	557	588	27,572	0	50,432	33,622	0	31,343	92,192	5,610	10,442
44	397	Communication Equipment	$ 156,821	4,853	2,980	3,148	322	340	15,934	0	29,145	19,430	0	18,113	53,279	3,242	6,034
45	398	Miscellaneous Equipment	$ 88,052	2,725	1,673	1,767	181	191	8,947	0	16,365	10,910	0	10,170	29,915	1,820	3,388
46	399	Other Tangible Property	$ 7,176,158	222,081	136,355	144,049	14,718	15,548	729,156	0	1,333,695	889,130	0	828,871	2,438,054	148,362	276,140
47		Total	$ 16,288,750	$ 504,088	$ 309,505	$ 326,968	$ 33,406	$ 35,291	$ 1,655,069	$ -	$ 3,027,278	$ 2,018,185	$ -	$ 1,881,407	$ 5,533,999	$ 336,759	$ 626,794
		Total Original Cost	$ 210,797,631	$ 504,088	$ 54,389,510	$ 57,458,151	$ 4,280,357	$ 4,521,854	$ 18,192,865	$ 13,817,234	$ 21,782,204	$ 14,521,469	$ 4,180,253	$ 5,756,250	$ 5,533,999	$ 3,430,164	$ 2,429,231
		Allocation Reference															
93		Generation OC		0.00%	48.63%	51.37%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
94		Transmission OC		0.00%	0.00%	0.00%	48.63%	51.37%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
95		Distribution OC		0.00%	0.00%	0.00%	0.00%	0.00%	22.18%	18.53%	25.15%	16.77%	5.61%	5.20%	0.00%	4.15%	2.42%
95		Total Plant OC		0.24%	25.80%	27.26%	2.03%	2.15%	8.63%	6.55%	10.33%	6.89%	1.98%	2.73%	2.63%	1.63%	1.15%
96		Total Plant Before General Plant		0.00%	27.80%	29.37%	2.18%	2.31%	8.50%	7.10%	9.64%	6.43%	2.15%	1.99%	0.00%	1.59%	0.93%
97		Total Net Plant		0.09%	30.08%	31.78%	1.79%	1.89%	5.88%	5.65%	9.42%	6.28%	1.16%	2.77%	0.98%	1.34%	0.88%
98		Supervised O&M Expenses before General Plant		3.09%	1.90%	2.01%	0.21%	0.22%	10.16%	0.00%	18.59%	12.39%	0.00%	11.55%	33.97%	3.85%	2.07%
99		Generation and General Plant		0.40%	42.66%	45.07%	0.03%	0.03%	1.30%	0.00%	2.37%	1.58%	0.00%	1.48%	4.34%	0.26%	0.49%

Table 4-3 Functional Classification of Cost of Service (1 of 2)

Test Year: 2013

Line	Acct	Description	Total	Func. Class.	Production			Transmission		Distribution						Customer	Direct		
						Capacity		Capacity		Capacity			Customer			Accounts and			
					Energy	Average	Excess	Average	Excess	Substations	Line Transformers	Lines	Laterals	Services	Meters	Service	Security Lights	City Street Lights	Rate Revenue
		REVENUE REQUIREMENTS																	
1		**Power Costs**																	
2		Purchase Power																	
3		Fixed	33,085,920	1	0	16,089,089	16,996,831	0	0	0	0	0	0	0	0	0	0	0	0
4		Variable	8,271,480	12	8,271,480	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5		Generation Fuel Costs	1,870,300	12	1,870,300	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6		Total Power Costs	$ 43,227,700		$ 10,141,780	$ 16,089,089	$ 16,996,831	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7		**Production Plant Expenses**																	
8	54800	Generation Expense	469,166	1	0	228,147	241,019	0	0	0	0	0	0	0	0	0	0	0	0
9	55300	Generation-Maintenance	613,972	12	613,972	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10		Total Production	$ 1,083,138		$ 613,972	$ 228,147	$ 241,019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		**Transmission Plant Expenses**																	
12	56000	Operation Super & Eng - Transmission	$ 8,503	2	$ 0	$ 0	$ 0	$ 4,135	$ 4,368	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
13	56600	Misc. Transmission Expense	-	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	56700	Rents - Transmission	28,125	2	0	0	0	13,677	14,448	0	0	0	0	0	0	0	0	0	0
15	56800	Maint. Super & Eng. - Transmission	8,048	2	0	0	0	3,913	4,134	0	0	0	0	0	0	0	0	0	0
16	57100	Maint. of Overhead Lines - Transmission	25,000	2	0	0	0	12,157	12,843	0	0	0	0	0	0	0	0	0	0
17		Total Transmission	$ 69,675		$ -	$ -	$ -	$ 33,882	$ 35,793	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		**Distribution Plant Expenses**																	
19	58000	Operation Super & Eng	$ 202,135	3	0	0	0	0	0	44,832	37,457	50,843	33,895	11,332	10,504	0	8,386	4,886	0
20	58200	Station Expenses	115,891	6	0	0	0	0	0	115,891	0	0	0	0	0	0	0	0	0
21	58300	Overhead Line Expenses	133,197	5	0	0	0	0	0	0	0	79,918	53,279	0	0	0	0	0	0
22	58400	Underground Line Expenses	111,908	5	0	0	0	0	0	0	0	67,145	44,763	0	0	0	0	0	0
23	58500	St. Lighting & Signal System Expenses	88,484	11	0	0	0	0	0	0	0	0	0	0	0	0	0	88,484	0
24	58510	LO St. Lgt & Signal	-	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	58600	Meter Expenses	262,927	14	0	0	0	0	0	0	0	0	0	0	262,927	0	0	0	0
26	58610	Meter Installation Expenses	168,708	14	0	0	0	0	0	0	0	0	0	0	168,708	0	0	0	0
27	58700	Cust Installation Expenses	33,386	15	0	0	0	0	0	0	33,386	0	0	0	0	0	0	0	0
28	58710	Sec Light Installation on Cust. Prem.	112,008	10	0	0	0	0	0	0	0	0	0	0	0	0	112,008	0	0
29	58720	Temp. Meter Plant Installation on Cust. Prem.	19,069	14	0	0	0	0	0	0	0	0	0	0	19,069	0	0	0	0
30	58800	Misc. Distribution Expenses	814,818	3	0	0	0	0	0	180,721	150,991	204,949	136,633	45,680	42,344	0	33,804	19,697	0
31	58900	Rents	88,000	3	0	0	0	0	0	19,518	16,307	22,134	14,756	4,933	4,573	0	3,651	2,127	0
32	59000	Maint. Super & Eng.	41,842	3	0	0	0	0	0	9,280	7,754	10,524	7,016	2,346	2,174	0	1,736	1,011	0
33	59200	Maint. of Station	299,132	6	0	0	0	0	0	299,132	0	0	0	0	0	0	0	0	0
34	59300	Maint. of Overhead Lines	745,910	5	0	0	0	0	0	0	0	447,546	298,364	0	0	0	0	0	0
35	59400	Maint. of Underground Lines	35,849	5	0	0	0	0	0	0	0	21,509	14,340	0	0	0	0	0	0
36	59500	Maint. of Line Transformers	50,000	15	0	0	0	0	0	0	50,000	0	0	0	0	0	0	0	0
37	59600	Maint. of St. Light & Signal System	1,000	11	0	0	0	0	0	0	0	0	0	0	0	0	0	1,000	0
38	59700	Maint. of Meters	18,231	14	0	0	0	0	0	0	0	0	0	0	18,231	0	0	0	0
39	59800	Maint. of Misc. Distribution Plant - Sec Lighting	500	10	0	0	0	0	0	0	0	0	0	0	0	0	500	0	0
40	59810	Maint. of Misc. Distribution Plant - Temp. Services	-	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41		Total Distribution	$ 3,342,995		$ -	$ -	$ -	$ -	$ -	$ 669,374	$ 295,895	$ 904,568	$ 603,046	$ 64,291	$ 528,530	$ -	$ 160,085	$ 117,205	$ -
42		**Customer Accounts Expense**																	
43	90200	Meter Reading Expenses	$ 200,829	14	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 200,829	$ 0	$ 0	$ 0	$ 0
44	90300	Cust. Rec. & Collection Expenses	1,032,576	13	0	0	0	0	0	0	0	0	0	0	0	1,032,576	0	0	0
45	90350	Credit Department Expenses	183,034	13	0	0	0	0	0	0	0	0	0	0	0	183,034	0	0	0
46	90400	Uncollectable Accounts	236,331	19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	236,331
47		Total Customer Accounts	$ 1,652,770		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 200,829	$ 1,215,610	$ -	$ -	$ 236,331
48		**Sales Expense**																	
49	91200	Demonstration & Selling Expenses	$ 280,315	13	0	0	0	0	0	0	0	0	0	0	0	280,315	0	0	0
50	91210	Telecom Expenses	$ 455,470	17	0	0	0	0	0	157,596	0	178,724	119,150	0	0	0	0	0	0
51	91300	Sales - Advertising Expenses	115,750	13	0	0	0	0	0	0	0	0	0	0	0	115,750	0	0	0
52		Total Sales	$ 851,535		$ -	$ -	$ -	$ -	$ -	$ 157,596	$ -	$ 178,724	$ 119,150	$ -	$ -	$ 396,065	$ -	$ -	$ -
53		**Admin and General Expense**																	
54	92000	Administrative & General Salaries	$ 812,480	8	$ 25,144	$ 15,438	$ 16,309	$ 1,666	$ 1,760	$ 82,555	$ 0	$ 151,000	$ 100,667	$ 0	$ 93,844	$ 276,035	$ 31,264	$ 16,797	$ 0
55	92100	Office Supplies & Expenses	278,100	8	8,606	5,284	5,582	570	603	28,257	0	51,685	34,457	0	32,122	94,483	10,701	5,750	0
56	92110	Network Expense	194,000	8	6,004	3,686	3,894	398	420	19,712	0	36,055	24,037	0	22,408	65,910	7,465	4,011	0
57	92300	Outside Services Rendered	511,500	8	15,829	9,719	10,267	1,049	1,108	51,973	0	95,063	63,375	0	59,080	173,779	19,683	10,575	0
58	92400	Property Insurance	337,800	20	1,336	144,100	152,230	89	94	4,385	0	8,021	5,347	0	4,985	14,662	892	1,661	0
59	92500	Injuries & Damages	120,900	8	3,741	2,297	2,427	248	262	12,284	0	22,469	14,980	0	13,964	41,075	4,652	2,500	0
60	92600	Employee Pension & Benefits	-	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	92900	Duplicate Charges	(226,318)	8	(7,004)	(4,300)	(4,543)	(464)	(490)	(22,996)	0	(42,061)	(28,041)	0	(26,141)	(76,890)	(8,709)	(4,679)	0
62	93000	Misc. General Expenses	349,563	8	10,818	6,642	7,017	717	757	35,518	0	64,967	43,311	0	40,376	118,762	13,451	7,227	0
63	93200	Maint. of General Plant	77,262	8	2,391	1,468	1,551	158	167	7,850	0	14,359	9,573	0	8,924	26,249	2,973	1,597	0
64	93210	Telecom Maintenance	57,643	17	0	0	0	0	0	19,945	0	22,619	15,079	0	0	0	0	0	0
65		Total A&G	$ 2,512,930		$ 66,865	$ 184,334	$ 194,734	$ 4,431	$ 4,681	$ 239,483	$ -	$ 424,177	$ 282,785	$ -	$ 249,562	$ 734,065	$ 82,372	$ 45,439	$ -
66		**Total Operating & Maintenance Expenses**	**$ 9,513,043**		**$ 680,837**	**$ 412,481**	**$ 435,753**	**$ 38,313**	**$ 40,474**	**$ 1,066,453**	**$ 295,895**	**$ 1,507,469**	**$ 1,004,981**	**$ 64,291**	**$ 978,921**	**$ 2,345,740**	**$ 242,457**	**$ 162,644**	**$ 236,331**

Table 4-3 Functional Classification of Cost of Service (2 of 2)

Line	Acct	Description	Total	Func. Class.	Production			Transmission		Distribution						Customer	Direct		
						Capacity		Capacity		Capacity			Customer			Accounts and			
					Energy	Average	Excess	Average	Excess	Substations	Line Transformers	Lines	Laterals	Services	Meters	Service	Security Lights	City Street Lights	Rate Revenue
67		**Other Expenses**																	
68		Payment in lieu of Property Taxes	$ 2,200,000	9	$ 1,973	$ 661,864	$ 699,206	$ 39,272	$ 41,488	$ 129,455	$ 124,320	$ 207,270	$ 138,180	$ 25,470	$ 61,019	$ 21,655	$ 29,412	$ 19,414	$ 0
69		Amortization of Debt Discount	$ 276,000	1	$ 0	$ 134,214	$ 141,786	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
70		Other Interest Expenses	$ 500	8	$ 15	$ 10	$ 10	$ 1	$ 1	$ 51	$ 0	$ 93	$ 62	$ 0	$ 58	$ 170	$ 19	$ 10	$ 0
71		Total Capital Expenditures	$ 2,476,500		$ 1,988	$ 796,088	$ 841,002	$ 39,273	$ 41,489	$ 129,506	$ 124,320	$ 207,363	$ 138,242	$ 25,470	$ 61,077	$ 21,825	$ 29,431	$ 19,424	$ 0
72		**Debt Service**																	
73		Existing Debt Service	$ 12,295,300	1	$ 0	$ 5,978,984	$ 6,316,316	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
74		Total Debt Service	$ 12,295,300		$ -	$ 5,978,984	$ 6,316,316	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66		**Capital Expenditures**																	
75		Miscellaneous Equipment / Projects	$ 100,000	8	$ 3,095	$ 1,900	$ 2,007	$ 205	$ 217	$ 10,161	$ 0	$ 18,585	$ 12,390	$ 0	$ 11,550	$ 33,974	$ 3,848	$ 2,067	$ 0
76		Engineering/Operations Equipment	$ 2,045,000	6	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,045,000	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
77		Vehicle Replacements	$ 402,100	8	$ 12,444	$ 7,640	$ 8,071	$ 825	$ 871	$ 40,857	$ 0	$ 74,731	$ 49,820	$ 0	$ 46,444	$ 136,611	$ 15,473	$ 8,313	$ 0
78		Engineering Projects	$ 3,480,300	3	$ 0	$ 0	$ 0	$ 0	$ 0	$ 771,906	$ 644,924	$ 875,389	$ 583,594	$ 195,113	$ 180,861	$ 0	$ 144,384	$ 84,129	$ 0
79		Special Projects	$ 343,500	17	$ 0	$ 0	$ 0	$ 0	$ 0	$ 118,854	$ 0	$ 134,788	$ 89,859	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
80		Total Capital Expenditures	$ 6,370,900		$ 15,539	$ 9,540	$ 10,078	$ 1,030	$ 1,088	$ 2,986,778	$ 644,924	$ 1,103,493	$ 735,663	$ 195,113	$ 238,855	$ 170,585	$ 163,705	$ 94,509	$ 0
81		**Other Revenue**																	
82		Forfeited Discount	$ (406,400)	13	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (406,400)	$ 0	$ 0	$ 0
83		Misc. Service Revenue	(371,500)	13	0	0	0	0	0	0	0	0	0	0	0	(371,500)	0	0	0
84		Total Rent From Electric Property	(393,600)	17	0	0	0	0	0	(136,189)	0	(154,447)	(102,965)	0	0	0	0	0	0
85		Other Electric Revenues	(14,000)	13	0	0	0	0	0	0	0	0	0	0	0	(14,000)	0	0	0
86		Rev. Merchandising & Jobbing	(20,000)	13	0	0	0	0	0	0	0	0	0	0	0	(20,000)	0	0	0
87		Non-Operating Rental Income.	(600)	13	0	0	0	0	0	0	0	0	0	0	0	(600)	0	0	0
88		Fiber Rental Income	(852,400)	17	0	0	0	0	0	(294,937)	0	(334,478)	(222,985)	0	0	0	0	0	0
89		Interest Income - Reserve Funds	-	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
90		Int. & Div. Inc. - Sinking Fund	(256,100)	1	0	(124,537)	(131,563)	0	0	0	0	0	0	0	0	0	0	0	0
91		Total Other Revenue	$ (2,314,600)		$ -	$ (124,537)	$ (131,563)	$ -	$ -	$ (431,126)	$ -	$ (488,925)	$ (325,950)	$ -	$ -	$ (812,500)	$ -	$ -	$ -
92		**Total Net Revenue Requirement**	**$ 71,568,843**		**$ 10,840,144**	**$ 23,161,645**	**$ 24,468,417**	**$ 78,616**	**$ 83,051**	**$ 3,751,611**	**$ 1,065,139**	**$ 2,329,400**	**$ 1,552,936**	**$ 284,874**	**$ 1,278,853**	**$ 1,725,650**	**$ 435,593**	**$ 276,577**	**$ 236,331**
93		**Rate Annualization Adjustment**	**$ 0**	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
94		**Total Cost of Service**	**$ 71,568,843**		**$ 10,840,144**	**$ 23,161,645**	**$ 24,468,417**	**$ 78,616**	**$ 83,051**	**$ 3,751,611**	**$ 1,065,139**	**$ 2,329,400**	**$ 1,552,936**	**$ 284,874**	**$ 1,278,853**	**$ 1,725,650**	**$ 435,593**	**$ 276,577**	**$ 236,331**
95		**Supervised O&M Expenses**	**$ 3,663,429**		**$ 113,372**	**$ 69,609**	**$ 73,537**	**$ 7,513**	**$ 7,937**	**$ 372,234**	**$ 0**	**$ 680,851**	**$ 453,901**	**$ 0**	**$ 423,139**	**$ 1,244,627**	**$ 140,969**	**$ 75,739**	**$ 0**
96		**Allocation Reference**																	
97		Generation OC		1	0.0%	**48.6%**	**51.4%**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
98		Transmission OC		2	0.0%	0.0%	0.0%	**48.6%**	**51.4%**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
99		Distribution OC		3	0.0%	0.0%	0.0%	0.0%	0.0%	**22.2%**	**18.5%**	**25.2%**	**16.8%**	**5.6%**	**5.2%**	0.0%	**4.1%**	**2.4%**	0.0%
100		Total OC Plant		4	**0.2%**	**25.8%**	**27.3%**	**2.0%**	**2.1%**	**8.6%**	**6.6%**	**10.3%**	**6.9%**	**2.0%**	**2.7%**	**2.6%**	**1.6%**	**1.2%**	0.0%
101		Line & Laterals		5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**60.0%**	**40.0%**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
102		Substation		6	0.0%	0.0%	0.0%	0.0%	0.0%	**100.0%**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
103		Total Plant Before General Plant		7	0.0%	**27.8%**	**29.4%**	**2.2%**	**2.3%**	**8.5%**	**7.1%**	**9.6%**	**6.4%**	**2.1%**	**2.0%**	0.0%	**1.6%**	**0.9%**	0.0%
104		Supervised O&M Expenses before General Plant		8	**3.1%**	**1.9%**	**2.0%**	**0.2%**	**0.2%**	**10.2%**	0.0%	**18.6%**	**12.4%**	0.0%	**11.6%**	**34.0%**	**3.8%**	**2.1%**	0.0%
105		Net Plant		9	**0.1%**	**30.1%**	**31.8%**	**1.8%**	**1.9%**	**5.9%**	**5.7%**	**9.4%**	**6.3%**	**1.2%**	**2.8%**	**1.0%**	**1.3%**	**0.9%**	0.0%
106		Security Lights		10	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**100.0%**	0.0%	0.0%
107		Street Lights		11	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**100.0%**	0.0%
108		Energy		12	**100.0%**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
109		Accounts & Services		13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**100.0%**	0.0%	0.0%	0.0%
110		Meters		14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**100.0%**	0.0%	0.0%	0.0%	0.0%
111		Line Transformers		15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**100.0%**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
112		Direct Assignment		16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**100.0%**
113		Substation, Lines, and Laterals OC		17	0.0%	0.0%	0.0%	0.0%	0.0%	**34.6%**	0.0%	**39.2%**	**26.2%**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
114		Net Revenue Requirement		18	**15.1%**	**32.4%**	**34.2%**	**0.1%**	**0.1%**	**5.2%**	**1.5%**	**3.3%**	**2.2%**	**0.4%**	**1.8%**	**2.4%**	**0.6%**	**0.4%**	**0.3%**
115		Rate Revenue		19	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**100.0%**
116		Generation and General Plant OC		20	**0.4%**	**42.7%**	**45.1%**	**0.0%**	**0.0%**	**1.3%**	0.0%	**2.4%**	**1.6%**	0.0%	**1.5%**	**4.3%**	**0.3%**	**0.5%**	0.0%

4.3 UNITS OF SERVICE

The allocation of functionalized and classified cost of service components to classes is based upon the development of allocation factors in Table 4-4 and Table 4-5. Table 4-4 shows the development of energy and capacity (demand)-related allocation factors and Table 4-5 shows the development of customer-related allocation factors.

The energy allocator (ENR1), shown in Column D of Table 4-4, is based on projected sales for test year 2013, including an allowance for system energy losses to the customer meter. The average loss factor (Column B) for the PPS's electric system is nominally 4.98 percent. Energy losses vary by class of customer to reflect the delivered energy losses to serve secondary voltage and primary voltage connected customers.

The average and excess demand (AED) method for allocation of system capacity costs to classes is used because it gives recognition to both peak demand and the annual average demand (proportional to annual energy use) use of system capacity designed to deliver energy. Under this method, a 100 percent load factor service class is allocated only the portion of the plant costs equal to its share of the capacity. Off-peak service classes, such as lighting, are assigned no excess demand and are allocated costs based on their average demand (energy use). Annual load factors for each customer class (Column F) are based on our experience with other utilities and consideration of class demand metered billing data obtained from the PPS.

In the AED method, each customer class is responsible for contributing to the system peak demand equal to at least the class average demand during the test year. System peak for firm load projected by PPS is 156,000 kW. The difference between system peak demand and system average demand is system excess demand and is allocated to customer classes in proportion to respective class non-coincident excess demands (Table 4-4, Column K). The total demand responsibility of each customer class is the sum of the class average demand plus allocated excess demand. Column R shows the average and excess demand responsibility for each customer class. Security Lighting and City Street Lighting is not assigned excess capacity responsibility to reflect the off-peak nature of the load.

Customer-related plant investment and expenses generally vary with the number of customers or the number of bills rendered. The development of customer-related allocation factors is shown on Table 4-5. In order to recognize relative cost differences between facilities used to serve individual customers in the various customer classes, the number of customers is weighted using appropriate weighting factors based on our experience. We have developed allocation factors for customer-related costs, services, meters, and laterals.

Table 4-4 Energy and Capacity Allocation Factors

		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]
				Energy Responsibility				Maximum Class Demand		Maximum Non-Coincident Demand			Secondary Service Demand		Class Excess Demand			AED Responsibility	
Line	Customer Class	Energy Sales	Loss Factor	Amount	Percent	Average Annual Demand	Annual Load Factor	Amount	Percent	Coin. Factor	Amount	Percent	Amount	Percent	Amount	Percent	Allocated System Excess	Amount	Percent
		kWh		*kWh*		*kW*	Percent	*kW*			*kW*		*kW*		*kW*		*kW*	*kW*	
				[A] / (1-[B])	ENR1	[C]/8760		[E]/[F]	CAP1		[G]/[I]	CAP3	[G]/[I]	CAP3-P	[G] - [E]	CAP2		[E] + [P]	CAP4
1	Residential	252,665,906	5.63%	267,739,648	40.29%	30,564	40%	76,410	41.72%	80%	95,513	42.09%	95,513	46.43%	45,846	43.51%	34,871	65,435	41.95%
2	GSA 1	61,292,885	5.63%	64,949,544	9.77%	7,414	38%	19,511	10.65%	80%	24,389	10.75%	24,389	11.86%	12,097	11.48%	9,201	16,615	10.65%
3	GSA 1 Seasonal	80	5.63%	85	0.00%	-	35%	-	0.00%	80%	-	0.00%	-	0.00%	-	0.00%	-	-	0.00%
4	Drainage Pumps	1,471,195	4.50%	1,540,518	0.23%	176	20%	880	0.48%	80%	1,100	0.48%	1,100	0.53%	176	0.17%	134	310	0.20%
5	GSA 2	218,743,661	4.50%	229,050,954	34.47%	26,147	40%	65,515	35.77%	80%	81,894	36.08%	81,894	39.81%	39,368	37.36%	29,944	56,091	35.96%
6	GSA 2 Seasonal	645,000	4.50%	675,393	0.10%	77	60%	129	0.07%	80%	161	0.07%	161	0.08%	52	0.05%	40	117	0.07%
7	GSA 3	69,486,950	3.75%	72,194,234	10.86%	8,241	55%	14,888	8.13%	85%	17,515	7.72%	0	0.00%	6,647	6.31%	5,056	13,297	8.52%
8	Industrial	16,865,700	3.75%	17,522,805	2.64%	2,000	63%	3,176	1.73%	85%	3,736	1.65%	0	0.00%	1,176	1.12%	895	2,895	1.86%
9	Security Lights	6,895,512	5.63%	7,306,890	1.10%	834	47%	1,774	0.97%	100%	1,774	0.78%	1,774	0.86%	0	0.00%	-	834	0.53%
10	City Street Lights	3,363,846	5.63%	3,564,529	0.54%	407	47%	866	0.47%	100%	866	0.38%	866	0.42%	0	0.00%	-	407	0.26%
11	Total	631,430,735	4.98%	664,544,600	100%	75,860		183,149	100%		226,948	100%	205,697	100%	105,362	100%	80,140	156,000	100%

System Peak Demand	156,000
System Excess Demand	80,140

Table 4-5 Customer-Related Allocation Factors

Line	Customer Class	[A] Number of Meters	[B] Customer Weighting Factors	[C] Customer Weighted Meters	[D] Customer Percent	[E] Services Weighting Factors	[F] Services Weighted Meters	[G] Services Percent	[H] Meters Weighting Factors	[I] Meters Weighted Meters	[J] Meters Percent	[K] Laterals and Secondary Weighting Factors	[L] Laterals and Secondary Weighted Meters	[M] Laterals and Secondary Percent	[K] Rate Revenue TY Rev	[M] Rate Revenue Percent
				[A] * [B]	CUS1		[A] * [E]	CUS2		[A] * [H]	CUS3		[A] * [K]	CUS4		REV
1	Residential	18,634	1.00	18,634	59.99%	1.00	18,634	62.33%	1.00	18,634	65.23%	1.00	18,634	83.80%	$ 25,942,729	39.16%
2	GSA 1	2,698	2.00	5,396	17.37%	2.00	5,396	18.05%	1.50	4,047	14.17%	1.00	2,698	12.13%	$ 7,210,081	10.88%
3	GSA 1 Seasonal	1	2.00	2	0.01%	2.00	2	0.01%	1.50	2	0.01%	1.00	1	0.00%	$ 220	0.00%
4	Drainage Pumps	20	10.00	200	0.64%	10.00	200	0.67%	1.50	30	0.11%	1.00	20	0.09%	$ 110,699	0.17%
5	GSA 2	555	10.00	5,550	17.87%	10.00	5,550	18.56%	10.00	5,550	19.43%	0.50	278	1.25%	$ 23,475,023	35.44%
6	GSA 2 Seasonal	2	10.00	20	0.06%	10.00	20	0.07%	10.00	20	0.07%	0.50	1	0.00%	$ 68,736	0.10%
7	GSA 3	9	15.00	141	0.45%	10.00	94	0.31%	25.00	235	0.82%	0.00	-	0.00%	$ 6,737,638	10.17%
8	Industrial	2	20.00	40	0.13%	0.00	-	0.00%	25.00	50	0.18%	0.00	-	0.00%	$ 1,416,742	2.14%
9	Security Lights	6,031	0.10	603	1.94%	0.00	-	0.00%	0.00	-	0.00%	0.10	603	2.71%	$ 885,477	1.34%
10	City Street Lights	4,755	0.10	476	1.53%	0.00	-	0.00%	0.00	-	0.00%	0.00	-	0.00%	$ 400,277	0.60%
11	**TOTAL ALL GROUPS**	32,707		31,062	100%		29,896	100%		28,568	100%		22,235	100%	$ 66,247,622	100%

4.4 UNBUNDLED COST OF SERVICE

A summary of the allocation factors used to allocate the functionalized revenue requirement to each of the customer classes is shown on Table 4-6. The allocation reference for each functional area is shown on Line 1 and refers back to the headings on Table 4-4 and Table 4-5.

The unbundled cost of service is calculated by taking the total cost of service by function (Table 4-3, Line 104) and multiplying by the allocation factors from Table 4-6. This step allocates the functional costs to each of the rate classes. The total cost of service for each class is the sum of functionalized costs allocated to it, as shown in Table 4-7.

Table 4-8 presents the unit costs of service by class. This table takes the results of Table 4-6 and divides the costs by appropriate class billing units to determine unit costs of service. For example, customer-related costs are divided by the number of bills. Energy-related costs are divided by kWh billing units. Capacity-related costs are divided by kWh or kW billing units appropriate to the metering basis of the class. These unit costs may then be used as a guideline in designing rates for each class.

Table 4-6 Summary of Allocation Factors by Function

		Power Supply			Transmission		Distribution						Customer	Direct		
			Capacity		Capacity		Capacity			Customers						
Line	Customer Class	Energy	Average	Excess	Average	Excess	Substations	Line Transformers	Lines	Laterals	Services	Meters	Accounts and Service	Security Lights	City Street Lights	Rate Revenue
1	**COS_Units Reference**	**ENR1**	**ENR1**	**CAP2**	**ENR1**	**CAP2**	**CAP1**	**CAP3-P**	**CAP3**	**CUS4**	**CUS2**	**CUS3**	**CUS1**	**SL**	**CSL**	**REV**
2	Residential	40.3%	40.3%	43.5%	40.3%	43.5%	41.7%	46.4%	42.1%	83.8%	62.3%	65.2%	60.0%	0.0%	0.0%	39.2%
3	GSA 1	9.8%	9.8%	11.5%	9.8%	11.5%	10.7%	11.9%	10.7%	12.1%	18.0%	14.2%	17.4%	0.0%	0.0%	10.9%
4	GSA 1 Seasonal	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	Drainage Pumps	0.2%	0.2%	0.2%	0.2%	0.2%	0.5%	0.5%	0.5%	0.1%	0.7%	0.1%	0.6%	0.0%	0.0%	0.2%
6	GSA 2	34.5%	34.5%	37.4%	34.5%	37.4%	35.8%	39.8%	36.1%	1.3%	18.6%	19.4%	17.9%	0.0%	0.0%	35.4%
7	GSA 2 Seasonal	0.1%	0.1%	0.0%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%
8	GSA 3	10.9%	10.9%	6.3%	10.9%	6.3%	8.1%	0.0%	7.7%	0.0%	0.3%	0.8%	0.5%	0.0%	0.0%	10.2%
9	Industrial	2.6%	2.6%	1.1%	2.6%	1.1%	1.7%	0.0%	1.6%	0.0%	0.0%	0.2%	0.1%	0.0%	0.0%	2.1%
10	Security Lights	1.1%	1.1%	0.0%	1.1%	0.0%	1.0%	0.9%	0.8%	2.7%	0.0%	0.0%	1.9%	100.0%	0.0%	1.3%
11	City Street Lights	0.5%	0.5%	0.0%	0.5%	0.0%	0.5%	0.4%	0.4%	0.0%	0.0%	0.0%	1.5%	0.0%	100.0%	0.6%
12	TOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 4-7 Unbundled Cost of Service

Line	Customer Class	Total	Production			Transmission		Distribution						Customer	Direct		
				Capacity		Capacity		Capacity			Customer			Accounts			
			Energy	Average	Excess	Average	Excess	Substations	Line Transformers	Lines	Laterals	Services	Meters	and Service	Security Lights	City Street Lights	Rate Revenue
	Total Revenue Requirements		ENR1	ENR1	CAP2	ENR1	CAP2	CAP1	CAP3-P	CAP3	CUS4	CUS2	CUS3	CUS1	SL	CSL	REV
1	Residential	30,894,773	4,367,407	9,331,641	10,646,893	31,674	36,138	1,565,176	494,585	980,349	1,301,435	177,560	834,155	1,035,212	-	-	92,548
2	GSA 1	7,672,494	1,059,461	2,263,703	2,809,317	7,684	9,535	399,663	126,291	250,329	188,433	51,417	181,165	299,775	-	-	25,721
3	GSA 1 Seasonal	290	-	-	-	-	-	-	-	-	70	19	90	110	-	-	1
4	Drainage Pumps	171,163	25,127	53,689	40,862	182	139	18,026	5,696	11,291	1,396	1,906	1,343	11,111	-	-	395
5	GSA 2	24,239,617	3,736,316	7,983,217	9,142,502	27,097	31,032	1,342,004	424,063	840,562	19,416	52,885	248,447	308,331	-	-	83,745
6	GSA 2 Seasonal	54,393	11,014	23,532	12,087	80	41	2,641	834	1,652	70	191	895	1,111	-	-	245
7	GSA 3	5,779,296	1,177,641	2,516,212	1,543,639	8,541	5,239	304,965	-	179,774	-	896	10,520	7,833	-	-	24,036
8	Industrial	1,285,594	285,833	610,726	273,116	2,073	927	65,057	-	38,347	-	-	2,238	2,223	-	-	5,054
9	Security Lights	952,812	119,187	254,662	-	864	-	36,338	9,186	18,209	42,114	-	-	33,500	435,593	-	3,159
10	City Street Lights	518,368	58,147	124,239	-	422	-	17,738	4,484	8,889	-	-	-	26,444	-	276,577	1,428
11	Total Cost of Service	71,568,800	10,840,133	23,161,621	24,468,416	78,617	83,051	3,751,608	1,065,139	2,329,402	1,552,934	284,874	1,278,853	1,725,650	435,593	276,577	236,332

Table 4-8 Unit Cost of Service

Line	Customer Class	Units	Production			Transmission		Distribution						Customer Accounts and Service	Direct			Total
				Capacity		Capacity		Capacity			Customer							
			Energy	Average	Excess	Average	Excess	Substations	Line Transformers	Lines	Laterals	Services	Meters		Security Lights	City Street Lights	Rate Revenue	
	Energy Sales ($/MWh)																	
1	Residential	252,666	$ 17.29	$ 36.93	$ 42.14	$ 0.13	$ 0.14	$ 6.20	$ 1.96	$ 3.88							$ 0.37	$ 109.02
2	GSA 1	61,293	$ 17.29	$ 36.93	$ 45.83	$ 0.13	$ 0.16	$ 6.52	$ 2.06	$ 4.08							$ 0.42	$ 113.42
3	GSA 1 Seasonal	0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -							$ 12.50	$ 12.50
4	Drainage Pumps	1,471	$ 17.08	$ 36.49	$ 27.78	$ 0.12	$ 0.09	$ 12.25	$ 3.87	$ 7.68							$ 0.27	$ 105.63
5	GSA 2	218,744	$ 17.08	$ 36.50	$ 41.80	$ 0.12	$ 0.14	$ 6.14	$ 1.94	$ 3.84							$ 0.38	$ 107.94
6	GSA 2 Seasonal	645	$ 17.08	$ 36.48	$ 18.74	$ 0.12	$ 0.06	$ 4.10	$ 1.29	$ 2.56							$ 0.38	$ 80.82
7	GSA 3	69,487	$ 16.95	$ 36.21	$ 22.22	$ 0.12	$ 0.08	$ 4.39	$ -	$ 2.59							$ 0.35	$ 82.89
8	Industrial	16,866	$ 16.95	$ 36.21	$ 16.19	$ 0.12	$ 0.06	$ 3.86	$ -	$ 2.27							$ 0.30	$ 75.96
9	Security Lights	6,896	$ 17.29	$ 36.93	$ -	$ 0.13	$ -	$ 5.27	$ 1.33	$ 2.64							$ 0.46	$ 64.04
10	City Street Lights	3,364	$ 17.29	$ 36.93	$ -	$ 0.13	$ -	$ 5.27	$ 1.33	$ 2.64							$ 0.43	$ 64.02
		631,431																
11	**Demand (Monthly $/kW)**																	
12	Residential	-																
13	GSA 1	-																
14	GSA 1 Seasonal	-																
15	Drainage Pumps	-																
16	GSA 2	631,188		$ 12.65	$ 14.49	$ 0.04	$ 0.05	$ 2.13	$ 0.67	$ 1.33								$ 31.36
17	GSA 2 Seasonal	1,004		$ 23.44	$ 12.04	$ 0.08	$ 0.04	$ 2.63	$ 0.83	$ 1.65								$ 40.70
18	GSA 3	145,483		$ 17.30	$ 10.61	$ 0.06	$ 0.04	$ 2.10	$ -	$ 1.24								$ 31.33
19	Industrial	32,334		$ 18.89	$ 8.45	$ 0.06	$ 0.03	$ 2.01	$ -	$ 1.19								$ 30.63
20	Security Lights																	
21	City Street Lights																	
		810,009																
22	**Customer Bills (Monthly $/bill)**																	
23	Residential	223,608									$ 5.82	$ 0.79	$ 3.73	$ 4.63	$ -	$ -		$ 14.97
24	GSA 1	32,376									$ 5.82	$ 1.59	$ 5.60	$ 9.26	$ -	$ -		$ 22.26
25	GSA 1 Seasonal	12									$ 5.83	$ 1.58	$ 7.50	$ 9.17	$ -	$ -		$ 24.08
26	Drainage Pumps	240									$ 5.82	$ 7.94	$ 5.60	$ 46.30	$ -	$ -		$ 65.65
27	GSA 2	6,660									$ 2.92	$ 7.94	$ 37.30	$ 46.30	$ -	$ -		$ 94.46
28	GSA 2 Seasonal	24									$ 2.92	$ 7.96	$ 37.29	$ 46.29	$ -	$ -		$ 94.46
29	GSA 3	113									$ -	$ 7.93	$ 93.10	$ 69.32	$ -	$ -		$ 170.35
30	Industrial	24									$ -	$ -	$ 93.25	$ 92.63	$ -	$ -		$ 185.88
31	Security Lights	72,372									$ 0.58	$ -	$ -	$ 0.46	$ 6.02	$ -		$ 7.06
32	City Street Lights	57,060									$ -	$ -	$ -	$ 0.46	$ -	$ 4.85		$ 5.31

4.5 SUMMARY OF COST OF SERVICE

The unbundled cost of service results by class can be summarized by comparing the revenue under Existing Rates for each class with the unbundled cost of service. By calculating the percentage difference between the two numbers, the indicated change in revenue for each class is determined. The cost of service summary by rate class is shown on Table 4-9. The resulting percentage difference is the indicated change in rates to bring rates equal to cost of service. These results by class are then used as a guideline for developing rate adjustments by class to meet the overall revenue change of the utility.

Looking at the percentages of over or under-recovery in Column D, the classes significantly under-recovering their cost of service are Residential, Drainage Pumps, and City Street Lights. GSA 1, GSA 2, and Security Lights are at or within a reasonable range of cost of service. The two largest classes (GSA 3 and Industrial) are over-recovering their costs of service.

Table 4-9 Summary of Class Cost of Service

		[A]	[B]	[C]	[D]
Line	Rate Class	Revenue Under Existing Rates	Unbundled COS	(Over)/Under Recovery Amount	(Over)/Under Recovery Percent
		$	$	[B] - [A]	[C] / [A]
1	Residential	$ 25,942,729	$ 30,894,773	$ 4,952,044	19.1%
2	GSA 1	$ 7,210,301	$ 7,672,784	$ 462,483	6.4%
3	Drainage Pumps	$ 110,699	$ 171,163	$ 60,464	54.6%
4	GSA 2	$ 23,543,759	$ 24,294,010	$ 750,251	3.2%
5	GSA 3	$ 6,737,638	$ 5,779,296	$ (958,342)	-14.2%
6	Industrial	$ 1,416,742	$ 1,285,594	$ (131,148)	-9.3%
7	Security Lights	$ 885,477	$ 952,812	$ 67,335	7.6%
8	City Street Lights	$ 400,277	$ 518,368	$ 118,091	29.5%
9	TOTAL SYSTEM	$ 66,247,622	$ 71,568,800	$ 5,321,178	8.0%

5.0 RATE DESIGN

The rate design process begins with a review of the class cost of service results. Black & Veatch generally follows certain guidelines when bringing cost of service imbalances closer to acceptable levels while preventing any extreme changes or "rate shock." These guidelines include:

- No principal rate class should have more than 150% of the system average rate increase
- No rate decreases except in cases of extreme imbalances
- Other classes share remaining increases equally

Black & Veatch developed proposed rate adjustments by class that follow these guidelines and produce the three 5% overall rate adjustments of shown in the financial forecast. The proposed rate increases by class are shown in the Table 5-1 below. The Residential class receives 150% of the system average rate increase in the first two increases. Drainage Pumps and City Street Lights, because they are significantly under recovering their cost of service receive two increases of 15% and 10%, respectively. The two classes that were over recovering their costs of service receive no increase, but no decrease for the first two adjustments, then the system average in the third. The balance of the overall rate increase is recovered equally from the remaining classes, with the increase being below the system average. This rate design accomplishes the goal of working towards more equitable rates without any extreme changes to any particular classes. The target percentage revenue increases for rate design for each class are shown on Table 5-1.

Table 5-1 Allocation of Target Revenue Increases by Class

RATE CLASS	RATE INCREASE EFFECTIVE 11/1/12	RATE INCREASE EFFECTIVE 4/1/13	RATE INCREASE EFFECTIVE 4/1/14
Residential	7.50%	7.50%	5.00%
GSA 1	4.14%	4.02%	5.00%
Drainage Pumps	15.00%	15.00%	5.00%
GSA 2	4.14%	4.02%	5.00%
GSA 3	0.00%	0.00%	5.00%
Industrial	0.00%	0.00%	5.00%
Security Lights	4.14%	4.02%	5.00%
City Street Lights	10.00%	10.00%	5.00%
System Average	5.00%	5.00%	5.00%

Within these class rate increase targets, Black & Veatch has proposed other changes to rate design components to meet the goals of PPS. These goals include:

- In general maintain the current structure of the existing customer rate classifications for continuity and ease of application
- Recover a higher percentage fixed costs in fixed charges based on the allocation of customer-related costs in the cost of service study

- Work towards equitable cost recovery from each rate class.
- For all classes, the PCA component of the PPS rates will be set at zero ($0.00/kWh) for the period beginning on November 1, 2012 and running through at least March 31, 2013. Thereafter, the PCA will serve as an upward adjustment of the base rates when PPS's power supply costs exceed $0.072/kWh.

5.1 RESIDENTIAL RATE CLASS

The residential class is under-recovering its cost of service by 19.1 percent. Under the proposal, the Customer Charge which was set at $14.75 as part of the interim rate increase effective as of November 1, 2012, will remain at that level during the subsequent rate adjustments.

The Energy Charge will continue as a flat energy rate and increase during each rate adjustment to meet the class target rate adjustment. The Existing Rates and the recommended rates for residential customers are shown in Table 5-2.

Table 5-2 Present and Recommended Residential Rates

Description	Present Rate	Recommended Rate Effective 11/1/12	4/1/13	4/1/14
Customer Charge ($/bill)	$ 9.25	$ 14.75	$ 14.75	$ 14.75
Energy Charge ($/kWh)				
All KWh	$ 0.08228	$ 0.09732	$ 0.10560	$ 0.11153
PCA Charge	$ 0.01221	$ -	$ -	$ -
Total Energy Charge	$ 0.09449	$ 0.09732	$ 0.10560	$ 0.11153

5.2 GSA-1 RATE CLASS

The GSA-1 class is under-recovering its cost of service by 6.4 percent. As recommended by Black & Veatch, the Customer Charge was increased to $22 on November 1, 2012. It is our recommendation that this Customer Charge stay constant during the subsequent rate adjustments. GSA-1 customers do not pay a Demand Charge.

The Energy Charge will continue as a flat energy rate and increase during each rate adjustment to meet the class target rate adjustment. The Existing Rates and recommended rates for GSA-1 customers are shown in Table 5-3 and Table 5-4.

Table 5-3 Present and Recommended GSA-1 Rates

Description	Present Rate	Recommended Rate Effective 11/1/12	4/1/13	4/1/14
Customer Charge ($/bill)	$ 17.50	$ 22.00	$ 22.00	$ 22.00
Energy Charge ($/kWh)				
All KWh	$ 0.09618	$ 0.11088	$ 0.11580	$ 0.12217
PCA Charge	$ 0.01221	$ -	$ -	$ -
Total Energy Charge	$ 0.10839	$ 0.11088	$ 0.11580	$ 0.12217

Table 5-4 Present and Recommended GSA-1 Seasonal Rates

Description	Present Rate	Recommended Rate Effective 11/1/12	4/1/13	4/1/14
Customer Charge ($/bill)	$ 17.50	$ 22.00	$ 22.00	$ 22.00
Energy Charge ($/kWh)				
All KWh	$ 0.10948	$ 0.12621	$ 0.13222	$ 0.13883
PCA Charge	$ 0.01221	$ -	$ -	$ -
Total Energy Charge	$ 0.12169	$ 0.12621	$ 0.13222	$ 0.13883

5.3 DRAINAGE PUMPS RATE CLASS

The Drainage Pump class is under-recovering its cost of service by 54.6 percent. The Customer Charge was increased to $65 as part of the November 1, 2012 interim rate increase, and we propose that this charge stay constant during the subsequent rate adjustments. There will continue to be no Demand Charge.

The Energy Charge will continue as a flat energy rate and increase during each rate adjustment to meet the class target rate adjustment. The Existing Rates and recommended rates for the Drainage Pump rate class are shown in Table 5-5.

Table 5-5 Present and Recommended Drainage Pump Rates

Description	Present Rate	Recommended Rate Effective 11/1/12	4/1/13	4/1/14
Customer Charge ($/bill)	$ 10.00	$ 65.00	$ 65.00	$ 65.00
Energy Charge ($/kWh)				
All KWh	$ 0.06141	$ 0.07597	$ 0.08894	$ 0.09391
PCA Charge	$ 0.01221	$ -	$ -	$ -
Total Energy Charge	$ 0.07362	$ 0.07597	$ 0.08894	$ 0.09391

5.4 GSA-2 RATE CLASS

The GSA-2 class is under-recovering its cost of service by 3.2 percent. As we had previously recommended, the Customer Charge was increased to $115 on November 1, 2012. We now recommend that this Customer Charge stay constant during the subsequent rate adjustments. The first demand block of up to 50 kW will continue at no charge as those costs are considered to be recovered in the Customer Charge. Customers in the 51-1,000 kW demand block will continue to pay a Demand Charge that was increased as part of the November 1, 2012 rate adjustment and increases during each of the subsequent rate adjustments proposed in this study.

The Energy Charge will continue to be split over two energy blocks, with the breakpoint at 15,000 kWh. The relative difference between the first and second blocks remains the same and is adjusted to meet the target revenue increase. The recommended rates are shown in Table 5-6 and Table 5-7.

Table 5-6 Present and Recommended GSA-2 Demand Rates

Description	Present Rate	Recommended Rate Effective 11/1/12	4/1/13	4/1/14
Customer Charge ($/bill)	$ 109.00	$ 115.00	$ 115.00	$ 115.00
Demand Charge				
Demand 0-50 kW	$ -	$ -	$ -	$ -
Demand Charges 51 - 1,000 kW	$ 14.44	$ 15.04	$ 15.70	$ 16.49
Energy Charge ($/kWh)				
Energy 1-15,000 kWh	$ 0.09555	$ 0.11116	$ 0.11470	$ 0.11938
PCA Charge	$ 0.01221	$ -	$ -	$ -
Total Energy Charge (1-15,000 kWh)	$ 0.10776	$ 0.11116	$ 0.11470	$ 0.11938
Energy > 15,000 kWh	$ 0.05112	$ 0.06673	$ 0.07027	$ 0.07495
PCA Charge	$ 0.01221	$ -	$ -	$ -
Total Energy Charge (>15,000 kWh)	$ 0.06333	$ 0.06673	$ 0.07027	$ 0.07495

Table 5-7 Present and Recommended GSA-2 Seasonal Rates

Description	Present Rate	Recommended Rate Effective 11/1/12	4/1/13	4/1/14
Customer Charge ($/bill)	$ 109.00	$ 115.00	$ 115.00	$ 115.00
Demand Charge				
Demand 0-50 kW	$ -	$ -	$ -	$ -
Demand Charges 51 - 1,000 kW	$ 18.40	$ 19.04	$ 19.70	$ 20.69
Energy Charge ($/kWh)				
Energy 1-15,000 kWh	$ 0.10885	$ 0.12516	$ 0.12958	$ 0.13529
PCA Charge	$ 0.01221	$ -	$ -	$ -
Total Energy Charge (1-15,000 kWh)	$ 0.12106	$ 0.12516	$ 0.12958	$ 0.13529
Energy > 15,000 kWh	$ 0.06442	$ 0.08073	$ 0.08515	$ 0.09086
PCA Charge	$ 0.01221	$ -	$ -	$ -
Total Energy Charge (>15,000 kWh)	$ 0.07663	$ 0.08073	$ 0.08515	$ 0.09086

5.5 GSA-3 RATE CLASS

The GSA-3 class is over-recovering its cost of service by 14.2 percent. The Customer Charge will stay constant at $275 every year. The Demand Charge for both demand blocks was not changed as part of the November 1, 2012 rate adjustment and will stay constant for both demand blocks through the April 1, 2013 rate adjustment. This Demand Charge will then increase by 5 percent on April 1, 2014.

The Energy Charge will continue as a flat energy rate and increase only in the final rate adjustment to meet the class target rate adjustment of 5 percent. The recommended rates are shown in Table 5-8.

Table 5-8 Present and Recommended GSA-3 Rates

Description	Present Rate	Recommended Rate Effective 11/1/12	4/1/13	4/1/14
Customer Charge ($/bill)	$ 275.00	$ 275.00	$ 275.00	$ 275.00
Demand Charge				
Demand 0-1,000 kW	$ 14.52	$ 14.52	$ 14.52	$ 15.25
Demand Charges 1,001 - 5,000 kW	$ 16.78	$ 16.78	$ 16.78	$ 17.62
Energy Charge ($/kWh)				
Energy Block 1 kWh	$ 0.05193	$ 0.06414	$ 0.06414	$ 0.06736
PCA Charge	$ 0.01221	$ -	$ -	$ -
Total Energy Charge	$ 0.06414	$ 0.06414	$ 0.06414	$ 0.06736

5.6 INDUSTRIAL RATE CLASS

The Industrial class is over-recovering its cost of service by 9.3 percent. The Customer Charge will stay constant at $275 every year. The Demand Charge was not changed as part of the November 1, 2012 rate adjustment and will stay constant through the April 1, 2013 rate adjustment. This Demand Charge will then increase by 5 percent on April 1, 2014.

The Energy Charge will continue as a flat energy rate and increase only in the final rate adjustment to meet the class target rate adjustment of 5 percent. The recommended rates are shown in Table 5-9.

Table 5-9 Present and Recommended Industrial Rates

Description	Present Rate	Recommended Rate Effective 11/1/12	4/1/13	4/1/14
Customer Charge ($/bill)	$ 275.00	$ 275.00	$ 275.00	$ 275.00
Demand Charge				
Billed KW Demand	$ 17.50	$ 17.50	$ 17.50	$ 18.38
Energy Charge ($/kWh)				
Billed KWh	$ 0.03785	$ 0.05006	$ 0.05006	$ 0.05257
PCA Charge	$ 0.01221	$ -	$ -	$ -
Total Energy Charge	$ 0.05006	$ 0.05006	$ 0.05006	$ 0.05257

5.7 SECURITY LIGHTS RATE CLASS

The Security Light class is over-recovered by 7.6 percent. This rate class has a monthly Facilities Charge based on the size of light, plus an Energy Charge applied to the estimated monthly usage. Both components increase at the same rate, based on the target for the year. The rates implemented on November 1, 2012 and the recommended rates going forward are shown in Table 5-10.

Table 5-10 Present and Recommended Security Lights Rates

Description	Present Rate	Recommended Rate Effective 11/1/12	4/1/13	4/1/14
Facilities Charge ($/Light)				
100 W HPS	$ 4.12	$ 4.29	$ 4.46	$ 4.68
200 W HPS	$ 4.61	$ 4.80	$ 4.99	$ 5.24
250 W HPS	$ 7.05	$ 7.34	$ 7.64	$ 8.02
400 W HPS	$ 5.78	$ 6.02	$ 6.26	$ 6.57
1000 W Metal Halide	$ 12.44	$ 12.96	$ 13.48	$ 14.15
1500 W Metal Halide	$ 17.83	$ 18.57	$ 19.32	$ 20.29
175 W Mercury Vapor	$ 2.71	$ 2.82	$ 2.93	$ 3.08
400 W Mercury Vapor	$ 4.06	$ 4.23	$ 4.40	$ 4.62
1000 W Mercury Vapor	$ 6.98	$ 7.27	$ 7.56	$ 7.94
Energy Charge ($/kWh)				
Billed KWh	$ 0.06186	$ 0.07714	$ 0.08024	$ 0.08425
PCA Charge	$ 0.01221	$ -	$ -	$ -
Total Energy Charge	$ 0.07407	$ 0.07714	$ 0.08024	$ 0.08425

5.8 CITY STREET LIGHTS RATE CLASS

The City Street Light class under-recovers rate revenue by 29.5 percent, which is the second highest under-recovery of any class. This rate class has a Facilities Charge based on 1 percent of the net book value (NBV) of street light investment, plus an energy charge.

The Facilities Charge will continue to be based on 1 percent of NBV. The Energy Charge was increased proportionally as part of the November 1, 2012 rate adjustment and will also increase proportionately in the April 1, 2013 and April 1, 2014 rate adjustments to meet the target rate increase for the class. The recommended rates are shown in Table 5-11.

Table 5-11 Present and Recommended City Street Lights Rates

Description	Present Rate	Recommended Rate Effective 11/1/12	4/1/13	4/1/14
Facilities Charge (per month)	1% of NBV	1% of NBV	1% of NBV	1% of NBV
Energy Charge ($/kWh)				
Billed KWh	$ 0.06186	$ 0.08597	$ 0.09905	$ 0.10625
PCA Charge	$ 0.01221	$ -	$ -	$ -
Total Energy Charge	$ 0.07407	$ 0.08597	$ 0.09905	$ 0.10625

5.9 TYPICAL BILL COMPARISON

Table 5-12 shows a comparison of the Existing Rates and recommended rates at various usage and demand levels for the Residential, General Service, and Industrial classes.

Table 5-12 Typical Monthly Bill Comparison

			Load	Existing	Monthly Bill Under Recommended Rates					
						%		%		%
Rate Class	Energy	Demand	Factor	Bill	1-Nov-12	Change	1-Apr-13	Change	1-Apr-14	Change
	kWh	kW		$	$		$		$	
				Monthly						
Rate Class: Residential	500			$56.50	$63.41	12%	$67.55	7%	$ 70.52	4%
Rate Class: Residential	1,000			$103.74	$112.07	8%	$120.35	7%	$ 126.28	5%
Rate Class: Residential	2,000			$198.23	$209.39	6%	$225.95	8%	$ 237.81	5%
Rate Class: GSA-1	1,500			$ 180	$ 188	5%	$ 196	4%	$ 205	5%
Rate Class: GSA-1	2,500			$ 288	$ 299	4%	$ 312	4%	$ 327	5%
Rate Class: GSA-1	5,000			$ 559	$ 576	3%	$ 601	4%	$ 633	5%
Rate Class: GSA-1	15,000			$ 1,643	$ 1,685	3%	$ 1,759	4%	$ 1,855	5%
Rate Class: GSA-2	15,000	50	41%	$1,725	$1,782	3%	$1,836	3%	$1,906	4%
Rate Class: GSA-2	30,000	100	41%	$3,397	$3,535	4%	$3,675	4%	$3,854	5%
Rate Class: GSA-2	50,000	150	46%	$5,386	$5,622	4%	$5,865	4%	$6,178	5%
Rate Class: GSA-3	500,000	1,000	68%	$ 49,012	$49,012	0%	$ 49,012	0%	$ 51,457	5%
Rate Class: GSA-3	1,000,000	2,000	68%	$ 97,862	$97,862	0%	$ 97,862	0%	$ 102,757	5%
Rate Class: GSA-3	2,000,000	4,000	68%	$ 195,562	$195,562	0%	$ 195,562	0%	$ 205,357	5%
Rate Class: Industrial	575,000	1,000	79%	$46,560	$46,560	0%	$46,560	0%	$48,883	5%
Rate Class: Industrial	875,000	1,500	80%	$70,328	$70,328	0%	$70,328	0%	$73,844	5%

Note: All monthly bill calculations for recommended rates assume a PCA of zero

Appendix A – Power Cost Adjustment

POWER COST ADJUSTMENT CLAUSE

PURPOSE:

The purpose of Power Cost Adjustment clause is to provide for recovery of PPS's power supply costs not recovered in its base energy charges. The treatment of over/under recoveries of such costs is described below.

APPLICABILITY:

The Power Cost Adjustment charge will be applicable to all retail electricity billed under any PPS electric rate schedules, whether metered or unmetered.

POWER COST ADJUSTMENT:

PPS shall recover its power supply costs by multiplying the Customer's electric energy use for billing purposes under the applicable PPS electric rate schedule in a billing period by the applicable Power Cost Adjustment (PCA), expressed in dollars per kilowatt hour, for the billing period. The PCA shall be calculated on a calendar quarterly basis as provided below. For purposes of the PCA calculation, the unit cost of PPS's projected power costs under normalized conditions was estimated to be $0.07200 per kWh. Such projected power costs include (i) fossil fuel costs for self-generation by PPS; (ii) purchased power costs from wholesale suppliers such as KMPA and SEPA; (iii) transmission costs related to delivery of purchased power; and (iv) all market participation costs related to the purchased power. This level of projected power costs ($0.07200 per kWh) has been built into the base electric rate schedules effective November 1, 2012..

1. Calculation: The formula for calculating the Power Cost Adjustment component of a customer's bill is:

$$PCA = \frac{PPC + RA}{S}$$

Less: $0.0720 per kWh

Where:

PPC = Projected power costs by calendar quarter period as defined below, expressed in dollars.

RA = Reconciliation adjustment by calendar quarter period as defined below, expressed in dollars.

S = Projected retail sales of electricity by calendar quarter period as defined below, expressed in kilowatt-hours (kWh).

2. Definitions:

PPC = Projected power supply costs for the upcoming calendar quarter period, which is calculated as the sum of: (i) fossil fuel costs for self-generation (ii) KMPA, SEPA and any other supplier total purchased power costs, (iii) all transmission costs related to the delivery of purchased power, and (iv) all purchased power market participation-related costs all for such calendar quarter.

APC = Actual power cost for the most recent three months prior to the calendar quarter for which a PPC is then being determined. Such actual power cost shall be calculated as the sum of: (i) fossil fuel costs for self-generation (ii) KMPA, SEPA, and any other supplier total purchased power costs, (iii) all transmission costs related to the delivery of purchased power, and (iv) all purchased power market participation-related costs, all for such prior calendar quarter.

S = Projected sales of electricity, by calendar quarter period, under all of the PPS retail rate schedules, whether metered or unmetered, for the applicable calendar quarter, expressed in kilowatt-hours (kWh).

RA = APC, plus or minus any over/under collection from previous quarter periods, as the case may be, less the revenue collected from the PCA applied during the same period. The PPS may also direct that adjustments be made to the RA for purposes of calculating the PCA for the upcoming calendar quarter(s) as may be deemed prudent to accomplish sound utility purposes including, but not limited to, minimizing PCA volatility.

Appendix B – Rate Study Process Flowcharts

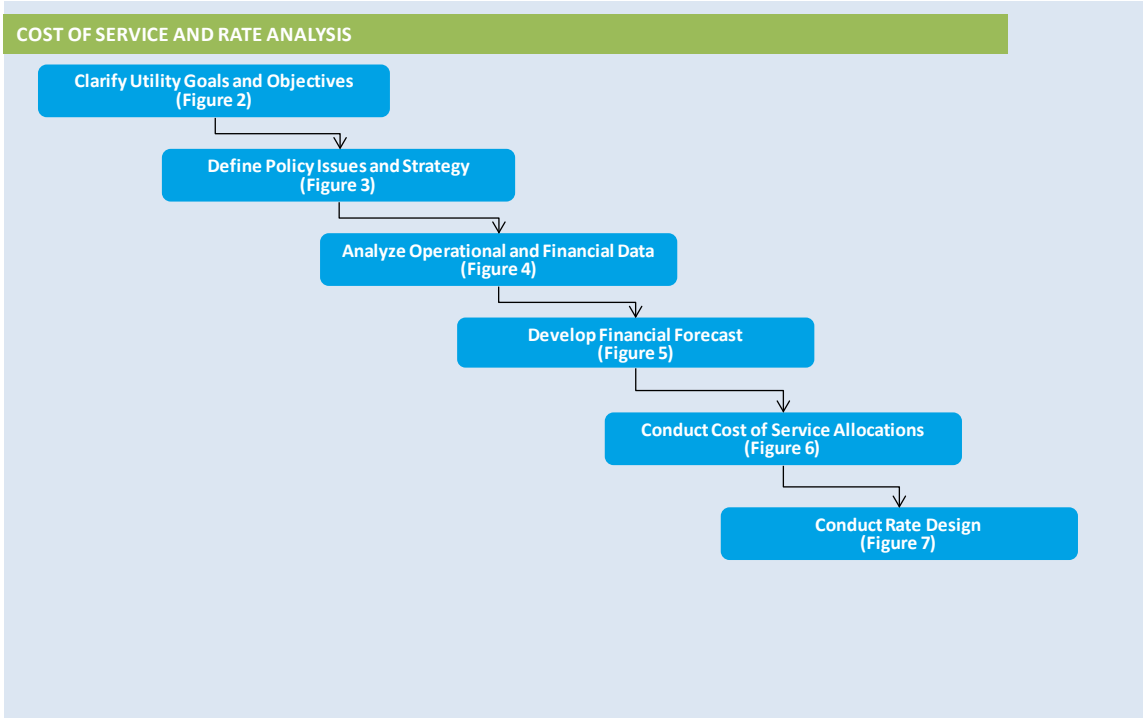

Figure B-1 Rate Making and Financial Planning/COS Overview

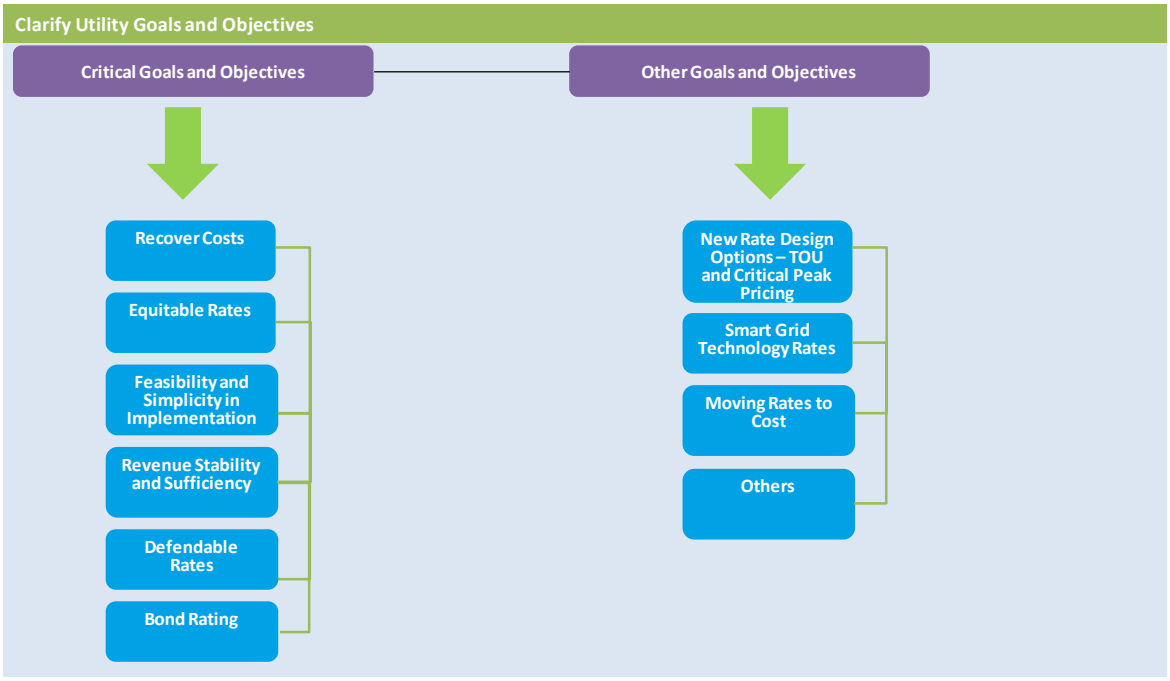

Figure B-2 Clarify Utility Goals and Objectives

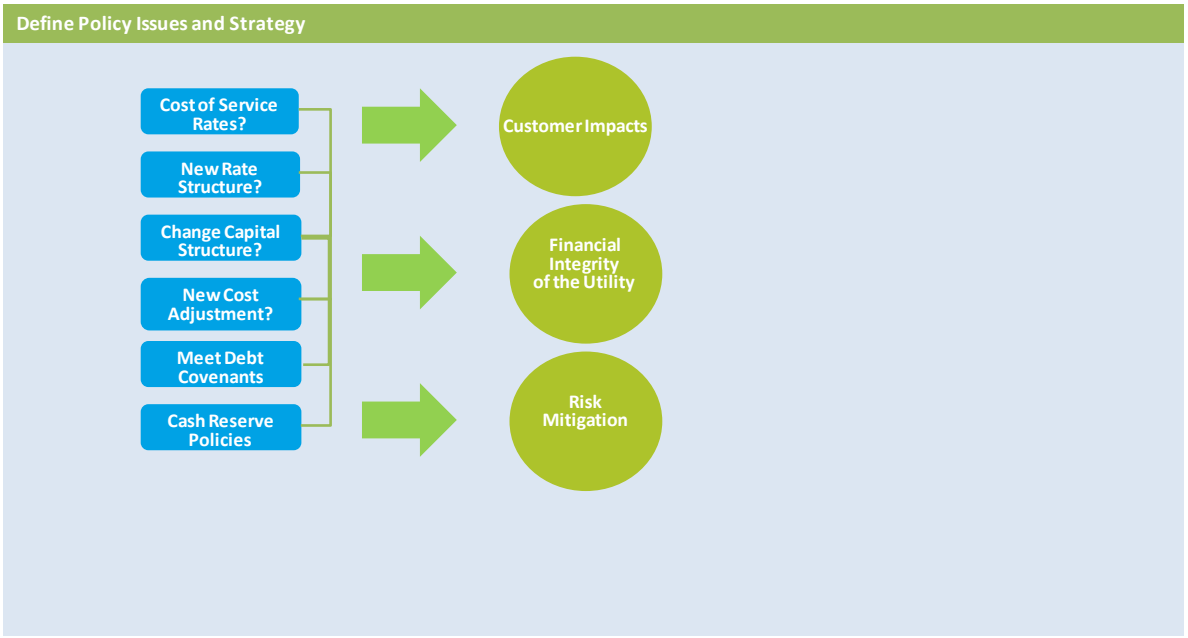

Figure B-3 Define Policy Issues and Strategy

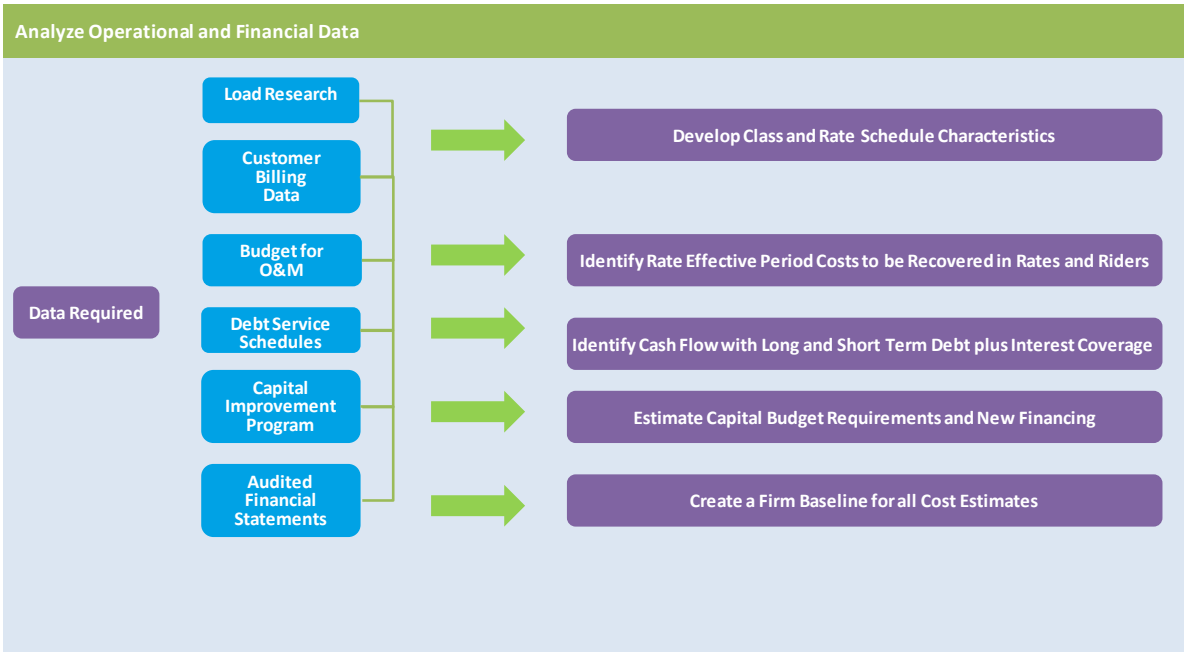

Figure B-4 Analyze Operational and Financial Data

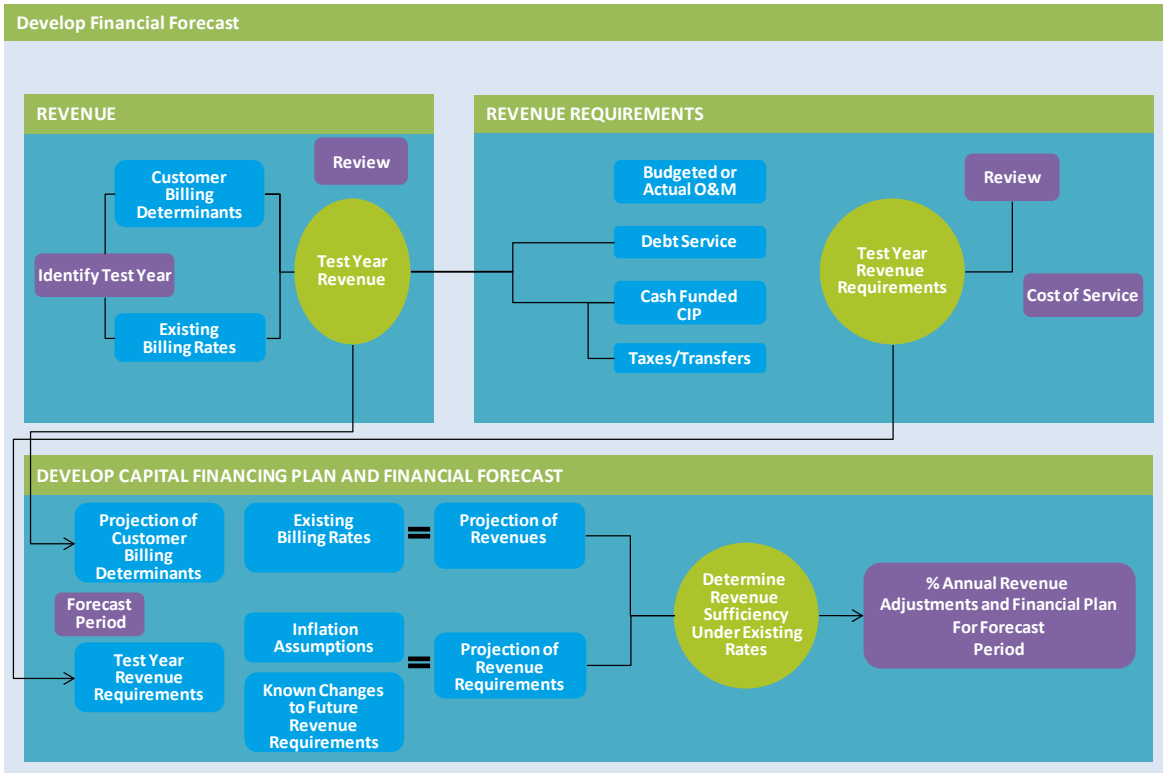

Figure B-5 Develop Financial Forecast

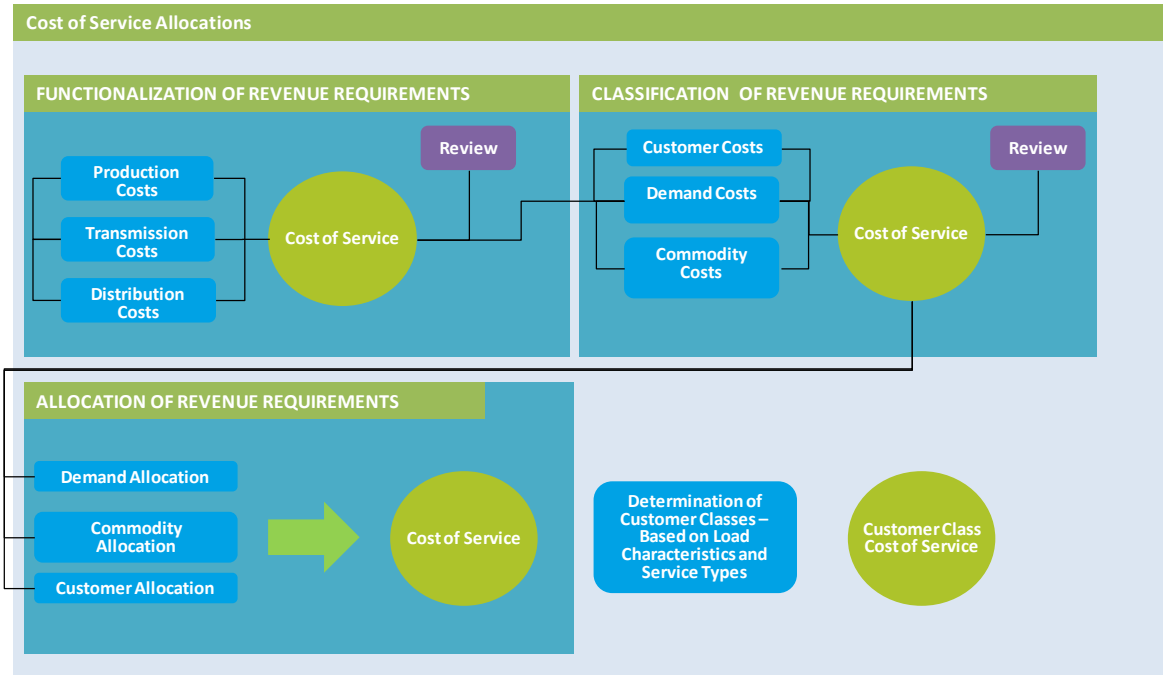

Figure B-6 Cost of Service Allocations

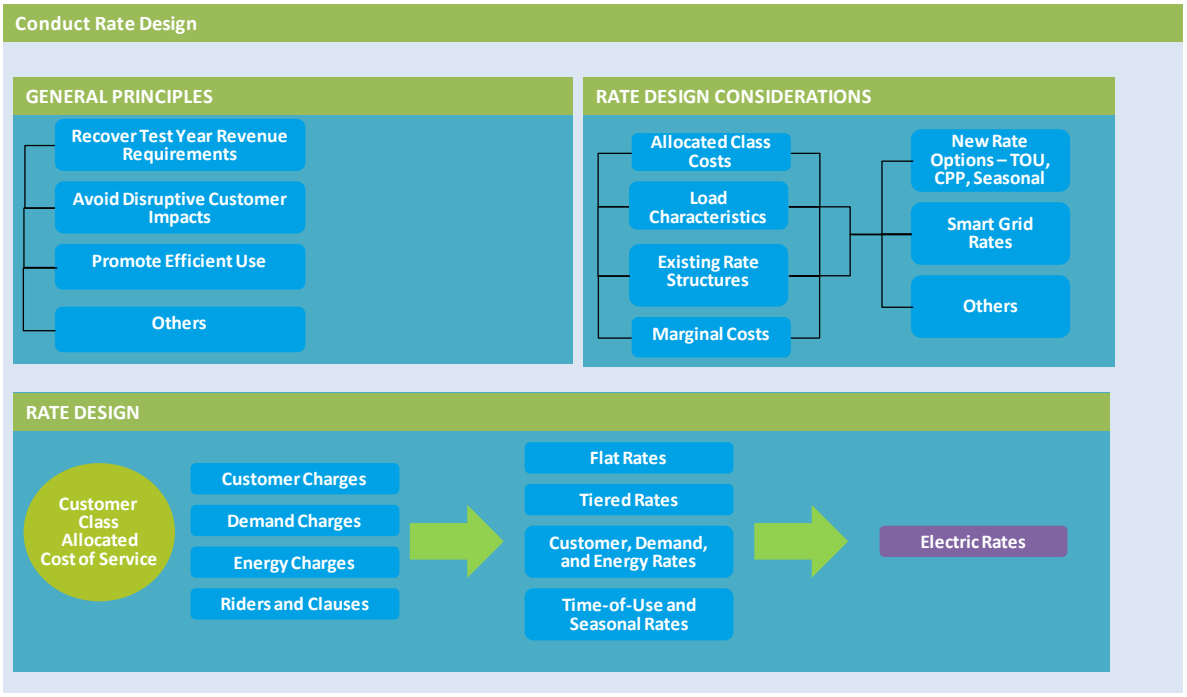

Figure B-7 Conduct Rate Design