Attachment 5

City Council
May 22, 2018

Electric and Water Cost of Service Studies

Electric Cost of Service Study

NewGen Strategies & Solutions
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Memorandum

Date: February 7, 2018

Re: Electric Rate Study Update

On January 24, 2018, the City of Riverside (City) engaged NewGen Strategies and Solutions, LLC (NewGen) to develop an update to a previous electric cost of service (COS) and rate study (Electric Rate Study). The terms and conditions of this assignment are specified in the "Third Amendment to Professional Contract Services Agreement". Since that time, representatives of the Riverside Public Utilities (RPU) and NewGen have collectively adjusted the associated Study model to reflect updates and changes requested by the City. This memorandum summarizes the updates and analyses conducted with respect to the updated COS and rate design efforts conducted by NewGen on behalf of RPU.

The Electric Rate Study determined the total cost of providing electric services, the allocation of costs to the various customer classes, and the design of rates and rate structures for each customer class. The original contract to complete the Electric Rate Study was initiated on July 16, 2015. The Electric Rate Study was completed and provided to RPU on August 13, 2017. Since that time, RPU has undertaken extensive public outreach efforts which resulted in a request of several changes to the underlying costs, cost structures and to the proposed rates. As a result of these requested changes, NewGen was contracted to perform the following:

- Revise the COS model to reflect new revenue requirement, per the revised 10-year financial proforma model,
- Change the effective dates for rate implementation to July 1, 2018, followed by four annual increases on July 1 of each year (from an implementation of April 1, 2018 and four annual increases on January 1 of each year),
- Expand the COS model to include 2023 Fiscal Year projections,
- Revise projected class and sub-class rates to reflect changes in revenue requirement, within specifications requested by RPU,
- Revise projected class and sub-class sales forecast to reflect changes as a result of anticipated reduced electric usage (price elasticity), and
- Review the analysis for revenue adequacy to ensure RPU is projected to collect sufficient revenue and allow for cost recovery from the resulting rates.

The following tables represent the updated results for the key customer classes based on the revised revenue requirement and subsequent analysis and rate evaluations conducted as of the date of this letter report. Table 1 represents the projected revenue requirement for RPU and the anticipated rate revenue from customers by fiscal year under the existing rates and rate structures.

Table 1
Revenue Requirement and Revenue for Study Period ($000)

	FY2019	FY2020	FY2021	FY2022	FY2023	Total
Revenue Requirement	$314,906	$326,927	$339,098	$352,196	$366,455	$1,699,583
Revenue from Customers (1)	$306,428	$309,388	$312,299	$315,241	$318,984	$1,562,340
Difference (2)	($8,478)	($17,539)	($26,799)	($36,955)	($47,471)	($137,243)

(1) Utilizing existing rates, assuming no rate structure changes and no adjustments for elasticity.
(2) Totals may not add due to rounding.

The Revenue Requirement represents the entire annual revenue anticipated to be needed by RPU and includes its projections for power production (and purchases), on-going operations and maintenance (O&M) expenses for all functions, as well as projections for debt service, capital (funded by rates), transfer to the general fund, and reserves (per RPU's reserve policy). The revenue needed is offset by "Other Revenues," which includes transmission revenues, interest income, and other non-rate revenue. A categorization by functional areas of the Revenue Requirements for the Test Year is provided in Table 2.

Table 2
Revenue Requirement by Function for Test Year ($000)

Function	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	Test Year Value	Percent of O&M
Production O&M	$166,366	$173,873	$180,238	$184,068	$185,309	$177,971	58.8%
Transmission O&M	$63,225	$66,317	$68,644	$67,123	$67,431	$66,548	22.0%
Distribution O&M	$17,181	$19,051	$19,515	$17,706	$20,123	$18,715	6.2%
Customer O&M	$10,075	$11,104	$11,387	$10,465	$11,793	$10,965	3.6%
Administrative and General O&M	$26,194	$29,045	$29,752	$26,994	$30,680	$28,533	9.4%
Total O&M	$283,042	$299,390	$309,536	$306,356	$315,335	$302,732	
Debt Service	$43,576	$47,527	$46,304	$48,632	$53,923	$47,992	
Transfer to General Fund	$39,259	$40,738	$42,223	$43,708	$45,313	$42,248	
Capital Funded by Rates	$4,013	$4,486	$5,255	$5,139	$5,751	$4,929	
Allocation to (Use of) Reserves	$1,939	($7,449)	($11,571)	$2,107	$944	($2,806)	
(minus) Other Revenues	($56,923)	($57,764)	($52,650)	($53,745)	($54,811)	($56,549)	
Net Revenue Requirement	$314,906	$326,927	$339,098	$352,196	$366,455	$338,546	

Source: RPU Financial Pro Forma Model and COS Model. Note, numbers may not add due to rounding.

Figure 1 provides a summary of the fixed and variable cost recovery for the RPU system. Fixed cost recovery includes revenue from the customer charge, the Reliability Charge, the proposed Network Access Charge (NAC), and demand charges. Variable cost recovery includes revenue from the energy charge. Revenues from the public benefits charge, taxes, and other fees are not included in this analysis.

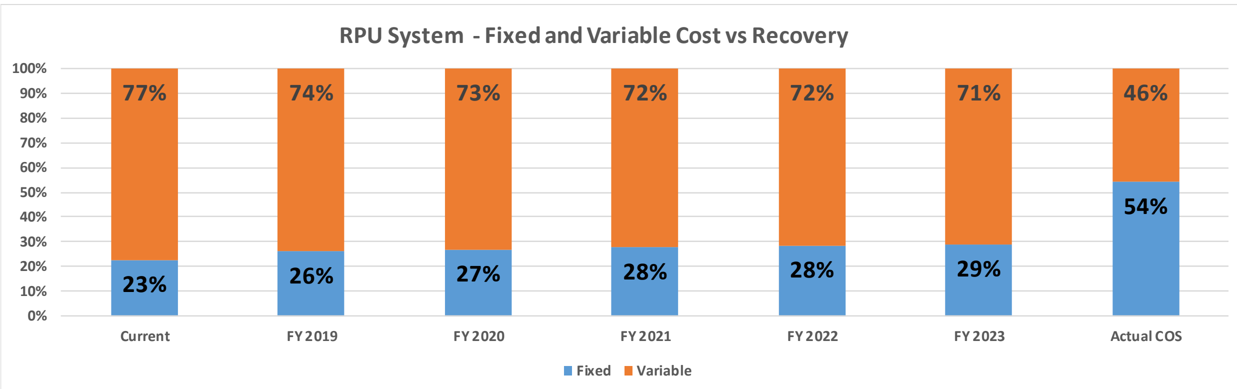


Figure 1: Fixed and Variable Cost vs Recovery

Projected energy sales by customer class are provided in Table 3 (for the major customer classes).

Table 3
Historic and Projected Energy Sales (000 kWh or MWh) (1)

	FY Ending				
	2019	2020	2021	2022	2023
Domestic	692,985	692,266	691,285	689,113	687,934
Commercial – Flat	280,700	284,772	288,794	293,124	298,600
Commercial – Demand	161,161	163,459	165,727	168,171	171,262
Industrial TOU	949,460	963,808	977,872	993,160	1,012,536
Other Classes (2)	91,438	91,283	91,127	90,971	90,816
Total System (3)	2,175,744	2,195,588	2,214,805	2,234,539	2,261,148

(1) Projections include the projected impact associated with price elasticity.
(2) Other classes include contract customers and street lights.
(3) Total System sales excludes losses, totals may not add due to rounding.

Table 4 provides a summary of the proposed rate changes for residential customers (referred to as the Domestic customer class by RPU).

Table 4
Existing and Proposed Rates for Domestic Customers

		Proposed [1]				
Rate Class / Component	Existing	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023
Customer Charge ($/month)	$8.06	$8.86	$9.66	$10.46	$11.26	$12.06
Network Access Charge ($/month) [2]						
Tier 1 (<= 12 kWh Daily Avg Usage)	--	$0.55	$0.97	$1.38	$1.94	$2.49
Tier 2 (>12, <= 25 kWh Daily Avg Usage)	--	$1.33	$2.32	$3.32	$4.65	$5.97
Tier 3 (>25 kWh Daily Avg Usage)	--	$2.92	$5.12	$7.31	$10.24	$13.16
Energy Charge ($/kWh) [3]						
Tier 1 (0–750 S; 0–350 W)	$0.1035	$0.1047	$0.1059	$0.1073	$0.1087	$0.1102
Tier 2 (751–1,500 S; 351–750 W)	$0.1646	$0.1665	$0.1684	$0.1706	$0.1729	$0.1753
Tier 3 (>1,500 S; >750 W)	$0.1867	$0.1889	$0.1910	$0.1936	$0.1961	$0.1988
Reliability Charge ($/month) [4]						
Small Residence (<100 Amp)	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
Medium Residence (101–200 Amp)	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Large Residence (201-400 Amp)	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00
Very Large Residence (>400 Amp)	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00

(1) Rate changes are effective July 1, 2018 and July 1st of each subsequent year.
(2) Daily average usage is determined by dividing the energy usage (kWh) in the billing period by the days of service in the billing period.
(3) Proposed summer season change from current three-month summer season (June 16 to September 15) to four-month (June 1 to September 30).
(4) No change to the Reliability Charge is proposed for this class.

Table 5 provides a summary of the proposed rate changes for the Commercial – Flat customer class

Table 5
Existing and Proposed Rates by Commercial – Flat Class

		Proposed (1)				
Rate Class / Component	Existing	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023
Customer Charge ($/month)	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50
Network Access Charge ($/month)						
Tier 1 (0–500 kWh)	--	$1.12	$1.67	$2.23	$2.79	$3.35
Tier 2 (501–1,500 kWh)	--	$3.17	$4.75	$6.33	$7.91	$9.50
Tier 3 (1501–3000 kWh)	--	$5.63	$8.45	$11.26	$14.08	$16.89
Tier 4 (>3000 kWh)	--	$13.54	$20.32	$27.09	$33.86	$40.63
Energy Charge ($/kWh)						
Tier 1 (0–15,000 kWh)	$0.1351	$0.1366	$0.1390	$0.1418	$0.1450	$0.1486
Tier 2 (>15,000 kWh)	$0.2064	$0.2087	$0.2124	$0.2166	$0.2215	$0.2270
Reliability Charge ($/month) (2)						
Tier 1 (0-500 kWh)	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
Tier 2 (501–1,500 kWh)	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
Tier 3 (>1,500 kWh)	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00

(1) Rate changes are effective July 1, 2018 and July 1st of each subsequent year.
(2) No change to the Reliability Charge is proposed for this class.

Table 6 provides a summary of the proposed rate changes for the Commercial – Demand customer class

Table 6
Existing and Proposed Rates by Commercial – Demand Class

		Proposed (1)				
Rate Class / Component	Existing	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023
Customer Charge ($/month)	--	$4.42	$8.84	$13.26	$17.68	$22.10
Network Access Charge ($/kW)	--	$0.35	$0.70	$1.05	$1.40	$1.75
Energy Charge ($/kWh)						
Tier 1 (0-30,000 kWh)	$0.1111	$0.1131	$0.1157	$0.1183	$0.1212	$0.1242
Tier 2 (>30,000 kWh)	$0.1217	$0.1239	$0.1267	$0.1296	$0.1328	$0.1360
Demand Charge ($/kW) (2)						
First 20 kW / 15 kW	$209.65	$157.95	$158.70	$159.45	$160.20	$160.95
All excess kW	$10.48	$10.53	$10.58	$10.63	$10.68	$10.73
Reliability Charge ($/month) (3)	$90.00	$90.00	$90.00	$90.00	$90.00	$90.00

(1) Rate changes are effective July 1, 2018 and July 1st of each subsequent year.
(2) Demand charge minimum Fixed Charge based on 20 kW (existing); proposed based on 15 kW.
(3) No change to the Reliability Charge is proposed for this class.

Table 7 provides a summary of the proposed rate changes for the Industrial TOU customer class.

Table 7
Existing and Proposed Rates by Industrial TOU Class

Rate Class / Component	Existing	Proposed [1] FY 2019	FY 2020	FY 2021	FY 2022	FY 2023
Customer Charge ($/month)	$704.66	$691.87	$679.08	$672.68	$666.28	$659.88
Network Access Charge ($/Max kW) [2]	--	$0.69	$1.24	$1.79	$2.34	$2.89
Energy Charge ($/kWh)						
On-Peak	$0.1033	$0.1049	$0.1079	$0.1104	$0.1124	$0.1154
Mid-Peak	$0.0828	$0.0845	$0.0874	$0.0898	$0.0922	$0.0946
Off-Peak	$0.0727	$0.0734	$0.0755	$0.0773	$0.0787	$0.0808
Demand Charge ($/kW)						
On-Peak	$6.88	$6.97	$7.06	$7.16	$7.27	$7.38
Mid-Peak	$2.74	$2.93	$3.13	$3.34	$3.64	$3.69
Off-Peak	$1.31	$1.42	$1.53	$1.65	$1.82	$1.85
Reliability Charge ($/month on Max kW) [3]						
<= 100 kW	$1,100.00	$912.50	$725.00	$537.50	$350.00	$350.00
101-150 kW	$1,100.00	$1,012.50	$925.00	$837.50	$750.00	$750.00
151-250 kW	$1,100.00	$1,050.00	$1,000.00	$950.00	$900.00	$900.00
251-500 kW	$1,100.00	$1,100.00	$1,100.00	$1,100.00	$1,100.00	$1,100.00
501-750 kW	$1,100.00	$1,287.50	$1,475.00	$1,662.50	$1,850.00	$1,850.00
> 750 kW	$1,100.00	$1,487.50	$1,875.00	$2,262.50	$2,650.00	$2,650.00

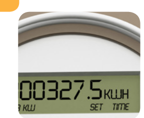
(1) Rate changes are effective July 1, 2018 and July 1st of each subsequent year.
(2) The proposed Network Access Charge for this class is based on maximum monthly demand (kW).
(3) A tiered Reliability Charge is proposed for this class based on maximum monthly demand (kW).

We appreciate the opportunity to be of service to you and Riverside Public Utilities. We have provided to RPU an Excel-based model which includes changes to all rate classes titled “RPU COS 2017 v62”.

August 13, 2017

ELECTRIC SYSTEM COST OF SERVICE AND RATE DESIGN STUDY

City of Riverside, California



PREPARED BY:

NewGen Strategies & Solutions

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EXECUTIVE SUMMARY

Introduction

The City of Riverside, California's (City) Strategic Plan seeks to advance the mission of providing high-quality municipal services to ensure a safe, inclusive, and livable community. As the *City of Arts & Innovation*, the City's leaders aim towards a prosperous future in which the City builds on its assets to implement intelligent growth, and to be a location of choice that drives innovation, provides a high quality of life, and is united in pursuing the common good. In the Riverside 2.0 Strategic Plan, a wide-reaching set of objectives address challenges ranging from uncertain economic conditions, to climate change, to aging infrastructure. Guided by the Riverside 2.0 Strategic Plan, Riverside Public Utilities (RPU) developed the Utility 2.0 Strategic Plan (Utility 2.0 Plan). The Utility 2.0 Plan focuses on providing safe, reliable, affordable, and financially responsible water and electric services for the benefit of the residences and businesses it serves. Specific challenges that RPU is facing include:

- Replacing the coal-fired power from Intermountain Power Plant (IPP), increasing its renewable portfolio, and integrating its power supply and load (demand).
- Replacing aging water and electric infrastructure while balancing cost impacts.
- Developing its workforce such that it addresses the need for changing skill sets.
- Employing advanced technology in all areas of its business to provide more efficient and better customer service, both behind, and in front of, the meter.
- Thriving financially by ensuring costs are recovered and developing a new business model to adapt for the future.

To thrive financially, RPU must balance operating costs, capital expenditures, operating income, and reserves. Spending too much on operations and capital investments requires more revenue from customers, while spending too little degrades safety, reliability, and customer service. If operating income falls short of budgets, reserves can deplete causing borrowing costs to increase. RPU has effective tools to strike the right balance between these competing objectives including its 10-year Financial Pro Forma Model and new fiscal policies, which includes an updated reserves policy. However, RPU needs to develop a business model that is sustainable into the future.

RPU is not alone in its business challenges; the electric utility industry is experiencing rapid change and, as a result, current business models are not sustainable. As energy sales are tempered by increasingly effective energy efficiency, conservation, and customer self-generation through rooftop solar, RPU and electric utilities across the country are losing income needed to pay for the infrastructure that delivers energy to all of its customers. Current rate structures are designed to recover costs through mostly volumetric charges that do not reflect the fixed and variable costs of providing the service. With the current rate structure, approximately 77% of RPU's revenue comes from its variable rate components. When a customer forgoes electricity (through conservation) or generates their own (through on-site solar panels), the resulting loss of revenue to RPU is not off-set by a corresponding decrease in costs. On average, for every $1.00 decrease to revenues as a result of a customer's reduced electricity consumption, RPU costs decrease by about $0.40. With ideally designed rates, when a customer saves a dollar by using less electricity (or generating it themselves), RPU would save a dollar of its variable costs, but lose none of its fixed cost recovery.

Over the past five years, RPU has functioned through a myriad of challenging conditions. Energy sales have returned to levels prior to the economic downturn; however, projections for growth are low. Traditional sources of coal and nuclear power are being replaced by intermittent wind and solar resources, and unusual weather patterns created an all-time peak demand without a corresponding increase in energy consumption. Concurrently, a vital transmission reliability project is undergoing a lengthy regulatory and environmental review; state and federal regulatory uncertainty has never been greater, and distributed solar generation has never been higher. The only constant during this period has been its retail rates, which have been frozen since 2010. Described in the Utility 2.0 Plan as 'Rates 1.0', this business model will not work under Utility 2.0.

Cost of Service Study

In this Electric Cost of Service and Rate Design Study (Study), the costs to electric customers of implementing the Utility 2.0 Plan is explored within the framework required by California state law, and City and Utility policies, which dictate that costs for electric services to municipal customers should be cost-based. The Utility 2.0 Plan provides 10-year financial projections for needed revenue. In developing its strategy, RPU has considered various scenarios and proposes a proactive approach to infrastructure replacement. This Report identifies the costs to customers and defines a business model that can be sustained. The goals of this Study are to determine Revenue Requirements to operate the electric utility, update the cost of providing electric service to various customer classes, and develop electric rates that are adequate to fund RPU's electric operations while being compliant with the requirements of Proposition 26. The previous rate study was completed by a third-party in 2010 and did not result in rate changes for RPU.

This Study relies on the concept of a "Test Year." A Test Year is a standard mechanism utilized in electric cost of service (COS) studies that determines the basis for the proposed rate changes. The Test Year for this Study was determined to be from RPU's fiscal year (FY) 2018 through FY 2022 (RPU's FY is from July 1st through June 30th). This five-year Test Year was selected because of its alignment with the goals and objectives of the Utility 2.0 Plan. A five-year Test Year results in average values that represent the "mid-point" of that five-year period. The Five-Year Rate Plan provides a series of rate changes over the five-year period; it is critical that the entirety of the five-year rate adjustments be reviewed collectively, as the intent is to achieve specific financial and policy objectives at the end of the Five-Year Rate Plan period (Rate Plan period).

Rate Design Objectives/Rate Making Principles

A rate study should culminate in a set of proposed rate designs, in which the cost recovery mechanisms (rates and charges) for each customer class are established. Rates and charges are designed such that the total revenue needed for the system will be recovered in an equitable manner that is consistent with the results of the Study. In addition, rate design considers and reflects RPU's overall revenue stability for the utility (and customer classes), its historical rate structures in place, policy considerations for conservation and energy efficiency, competitiveness with neighboring utility systems, as well as legal requirements and other energy-related policies established by the City Council. The following (Table ES-1) provides a list of RPU's electric rate making principles, with the specific application identified for this Study and the Five-Year Rate Plan.

Table ES-1
RPU Policy Goals and Five-Year Rate Plan

RPU Rate Making Principles	Five-Year Electric Rate Plan – Implementation
Achieve full recovery of costs	Rates designed to recover projected Revenue Requirements over Study period
Equitably allocate costs across and within customer classes	Increase/implement fixed cost recovery mechanisms to align rate structures with costs
Encourage efficient use of water and electricity	Design rates to discourage over use and reward efficiency
Provide rate stability	Maintain consistency between rates within each year of the Study period
Offer flexibility and options	Reduce rate-related bill impacts for customers transitioning between classes
Maintain rate competitiveness in region	Consider/mitigate rate–related impacts to all customers including low use customers
Be simple and easy to understand	Maintain simplicity of rate structures and components of existing rate structures, as appropriate

Additional detail on RPU's Rate making principles is provided in Section 6 of this Report.

Summary of Revenue Needs

The required revenue for RPU for each of the five years of the Five-Year Rate Plan developed by RPU in its Financial Pro Forma Model is provided in Table ES-2. Additionally, Table ES-2 includes a comparison of the total revenues generated by existing rates (current as of 2017) for the system. The difference between these two values represents the necessary rate adjustments for RPU to achieve the investments and policies identified in the Utility 2.0 Plan, and represent a cumulative shortfall of approximately $184.2 million.

Table ES-2
Revenue Requirement and Revenue for Study Period ($000)

	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	Total
Revenue Requirement	$306,266	$327,434	$346,127	$365,574	$385,014	$1,730,413
Revenue from Customers (1)	$303,122	$306,392	$309,335	$312,230	$315,158	$1,546,238
Difference (2)	**$(3,144)**	**$(21,041)**	**$(36,791)**	**$(53,344)**	**$(69,855)**	**$(184,176)**

(1) Utilizing existing rates, assuming no rate structure changes and no adjustments for elasticity. Assumes specific Contract customers are moved to standard rate schedules in FY 2019.

(2) Totals may not add due to rounding.

The Revenue Requirement represents the entire annual revenue anticipated to be needed by RPU, and includes its projections for power production (and purchases), on-going operations and maintenance (O&M) expenses for all of its functions, as well as projections for debt service, capital (funded by rates), transfer to the general fund, and reserves (per RPU's reserve policy). The revenue needed is offset by "Other Revenues," which includes transmission revenues, interest income, and other non-rate revenue. A categorization by functional areas of the Revenue Requirements for the Test Year is provided in Table ES-3. The total value of the Test Year Revenue Requirement (approximately $345.5 million) is close to the projected FY 2020 value in Table ES-3 ($346.1 million) and represents the average value over the Rate Plan period.

Table ES-3
Revenue Requirement by Function for Test Year ($000)

Function	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	Test Year Value	Percent of O&M
Production O&M	$156,173	$167,013	$174,255	$181,190	$186,266	$172,979	57.6%
Transmission O&M	61,927	63,386	66,412	68,880	67,668	65,654	21.9%
Distribution O&M	17,208	18,441	19,796	21,370	21,988	19,761	6.6%
Customer O&M	10,063	10,782	11,558	12,453	12,840	11,539	3.8%
Administrative and General O&M	26,235	28,115	30,181	32,581	33,523	30,127	10.0%
Total O&M	**$271,606**	**$287,737**	**$302,201**	**$316,474**	**$322,284**	**$300,061**	
Debt Service	40,687	44,592	49,706	49,728	54,554	47,853	
Transfer to General Fund	39,831	40,019	42,515	44,741	47,033	42,828	
Capital Funded by Rates	4,186	4,571	5,452	5,826	5,834	5,174	
Allocation to (Use of) Reserves	4,931	10,292	7,162	4,380	11,407	7,634	
(minus) Other Revenues	(54,975)	(59,778)	(60,909)	(55,575)	(56,099)	(58,005)	
Net Revenue Requirement	**$306,266**	**$327,434**	**$346,127**	**$365,574**	**$385,014**	**$345,545**	

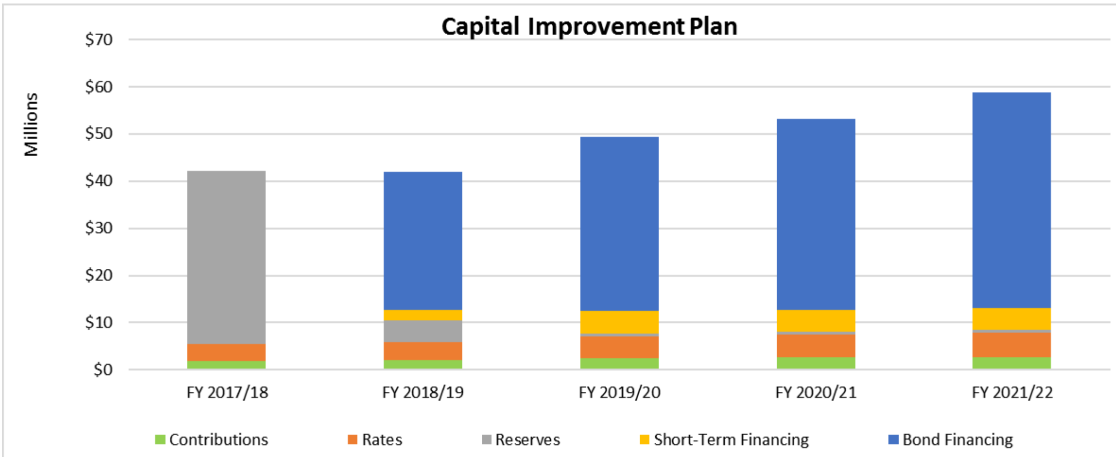
Source: RPU Financial Pro Forma Model and COS Model. Note, numbers may not add due to rounding.

As is typical with most utilities, the production function (generation or purchasing) of electricity is the largest functional element (approximately 58% of the O&M costs). The debt service estimated for the Test Year includes existing debt service (for outstanding bonds) and new debt service. RPU's Financial Pro Forma Model includes approximately $323 million in bond issuances and short-term financing over the Rate Plan period. Bond issuances and short-term financing are projected to fund capital projects for a three year period. The projected bond issuances and short term financing in FY 2022 is in anticipation of the continuation of the Utility 2.0 10 year Capital Improvement Plan and will fund projected capital projects over a 3 year period from FY 2022 through FY 2024. Of the $323 million of bond issuances and short-term financing, $197 million represents the total proceeds to be used to fund capital projects during the Five-Year Rate Plan. The Revenue Requirement off-set (reduction) from other revenues included in Table ES-3 is mainly interest income and transmission revenue from the California Independent System Operator (CAISO) wholesale market.

Capital Improvement Program

RPU's Board of Public Utilities and City Council have conceptually approved the Utility 2.0 Plan. The Utility 2.0 Plan includes a Capital Improvement Plan (CIP) that extends for 10 years and includes several options that relate to rehabilitation and replacement of existing infrastructure, procurement of future power supply, and employing advanced technology to provide more efficient and better customer service.

The results discussed within the body of the report are based on Option 3 in the Utility 2.0 Plan which was conceptually approved by City Council on October 6, 2015. The Utility 2.0 CIP will be funded through a combination of contributions (provided by developers/customers), rates, reserve funds, and debt financing (short-term financing and bond issuances). The sources of funding for the first five years of the Utility 2.0 CIP are shown in Figure ES-1. RPU intends to utilize reserves during the initial funding of its capital plan, which will be replenished with proceeds from bonds issued during the Five-Year Rate Plan.



Note: The figure excludes Riverside Transmission Reliability Project capital costs which are funded separately by Reliability Charge revenues.

Figure ES-1. Capital Funding Sources for Utility 2.0 CIP Option 3 ($000)

Reserve Policy

To accompany the Utility 2.0 CIP, RPU has developed a robust reserve policy, which is designed to promote fiscal sustainability, minimize borrowing costs, and provide a source of emergency funds for unforeseen events. The reserve policy defines the restricted reserves, unrestricted designated reserves, and unrestricted undesignated reserves, while also setting the overall minimum and maximum unrestricted undesignated reserve levels. Detailed information on each specific risk category is provided in Section 3 of this Report. Table ES-4 shows the projected unrestricted undesignated reserve minimum and maximum levels for each year of the Study period.

As part of the Five-Year Rate Plan, RPU will propose updating the reserve policy to include a line of credit (LOC) as available reserves to meet unrestricted undesignated reserve targets. An LOC is a low-cost mechanism that allows RPU to draw upon cash when needed, thus reducing required cash reserve levels, minimizing rate increases to maintain reserve levels, and increasing liquidity. Unrestricted undesignated reserve projections were developed to include the LOC and remain above the target minimum levels.

Table ES-4
RPU Projected Unrestricted, Undesignated Reserve Levels ($000)

		FY Ending				
RPU Reserve Policy	Target	2018	2019	2020	2021	2022
Total	Minimum	$136,675	$152,014	$159,299	$169,441	$182,840
	Maximum	$214,915	$237,271	$249,119	$263,345	$282,272
	Proposed Line of Credit	**$51,010**	**$51,010**	**$51,010**	**$51,010**	**$51,010**

RPU Pro Forma Financial Model, Option 3

Financial Pro-Forma Model vs. Cost of Service Model

RPU has developed its Financial Pro-Forma Model to provide a high-level assessment of the revenue projections by customer class and the total expenses for the utility, including its investments in Utility 2.0 and how they will be financed. Revenue projections for the Financial Pro-Forma Model are based on total existing revenue by class and are summed for the system; the results are a "system-wide" rate increase to arrive at a revenue increase necessary for RPU to fund its future expenses and investments (the Financial Pro Forma Model does not consider changes to rate structures). The COS Model is a detailed analysis of RPU's costs and assigns those costs to the customer classes based on standard industry accepted principles and methodology.

The COS Model is designed to recover the revenues required from RPU's customer classes over the Five-Year Rate Plan. The average revenue to be collected from RPU's customers during this period aligns with the average revenue developed by the Financial Pro Forma Model.

Cost of Service Process

The COS process is an industry accepted framework that assigns costs to customer classes. This process determines the "cost to serve" each customer class within a utility. Electric utility costs are typically characterized as either fixed or variable; fixed costs are those that do not change with the production of electricity, whereas variable costs are directly related to the amount of electricity produced and/or purchased. These costs are typically further characterized as those that are demand-based, customer-based, and energy-based.

Demand-based Costs

Demand-based costs for electric utilities are fixed costs that are related to the existing and future investments made to produce, transmit, and deliver power from the generation resources to its customers. For RPU, these costs include the debt service associated with its generation, transmission, and distribution assets, as well as a portion of its contracts for purchased power. The labor and materials associated with the O&M and administration of these systems is also a demand-based cost, as the labor costs are typically fixed in the short-term (budget cycle). In the short-term, fixed costs do not change and represent the on-going costs to meet the needs of the utility. Fixed costs are allocated primarily to the demand in the COS process because they are designed to support to the system as a whole. This means that as a result of the COS process, these costs are assigned based on the electric demand (measured in kilowatts, or kW) that a specific customer or customer class places on the system. RPU, like most utilities, has a cost structure that is highly fixed, which is typical of highly capital intensive entities.

Customer-based Costs

Customer-based costs for electric utilities are fixed costs as well, but costs that are incurred in direct support of the customers served by a utility. For RPU, this includes the costs associated with the labor, equipment, and investments for customer accounting, billing, and customer assistance (call centers). Additionally, a portion of administrative and general (A&G) costs are allocated to the customer-related costs, as they are designed to support this function for RPU. During the COS process, these costs are allocated by the number of customers within a class.

Energy-based Costs

Energy-based costs for electric utilities are typically variable costs that change with the changes in electric load. The primary example of energy-rated costs for RPU are its fuel and purchased power costs. During the COS process, these are allocated to the customer classes by the amount of energy they are projected to utilize within a selected period of time (during the Test Year).

Existing Rate Structures and Fixed Cost Recovery

RPU's existing rate structures vary by the customer class for which they are designed. All major customer classes include an energy component ($/kilowatt-hour or kWh) and a Reliability Charge ($/month), as well as applicable taxes and surcharges. Most customer classes include a customer component (in $/ per month), and some customer classes include a demand component ($/kW). Residential and small-commercial customers (referred to as Domestic and Commercial – Flat customers by RPU), do not have a demand charge on their bill; rather the fixed costs associated with demand-related costs are recovered in part by the Reliability Charge (for allocated portion of specific project costs), and the energy charge. The RPU Commercial – Demand and the Industrial Time-of-Use (TOU) customer classes include a demand component in their existing rate structures. The Commercial – Demand is the only customer class that currently does not have a customer charge component in its rate structure.

RPU's Reliability Charge recovers fixed costs associated with the Riverside Transmission Reliability Project, which is a second point of interconnection to the regional grid, and the Riverside Energy Resource Center internal generation units, which provide reliability and are used to meet summer peaking needs. The costs associated with these investments are categorized as demand-related costs in the COS analysis for purposes of this Study.

Consistent with its rate making principles, RPU has expressed an interest in increasing the portion of fixed cost recovery in its rates. This is proposed due to the existing "misalignment" in RPU's rate structures compared to its costs. In an era of constant load growth, the recovery of fixed costs through variable rates (energy rates) was commonplace in the industry. However, RPU and many of other utilities in California and elsewhere, have experienced reductions in customer energy consumption and demand due to increases in energy efficiency, conservation, and customer self-generation. As sales decrease, but costs remain the same (or increase), the fixed cost recovery issue has become critical. As proposed in its Five-Year Rate Plan, RPU intends to address this issue by increasing the fixed components (charges) of existing rate structures, as well as introducing new fixed cost recovery rate structures, while adjusting the energy-only portion of its rates.

Besides the Reliability Charge, RPU's existing rate structures are weighted towards revenue recovery from the volumetric or energy charge (in dollars per kWh). For example, the existing Domestic service rates include a fixed customer charge of $8.06 per month, which recovers a portion of the customer-based costs, and a tiered energy charge that ranges from $0.1035/kWh (10.35 cents/kWh) to $0.1867/kWh (or 18.67 cents/kWh), which recovers the remaining revenues for this class. All customers, including Domestic, place a demand on the system through their use of electricity (electric load). The peak electric load (the highest electricity usage during one hour of the month) is referred to as the peak demand of that customer. Demand is measured in kWs; most commercial customers, including Commercial – Demand and Industrial TOU customers, have meters that measure the peak demand and are billed for that usage (billed demand). However, Domestic customers and small commercials customers (RPU's Commercial – Flat customers) do not have demand meters. Therefore, demand-related costs are recovered in the energy portion of their bill (i.e. they are not billed on a demand basis), the customer charge ($/customer) and the Reliability Charge.

The results of this Study indicate that the COS-based costs include a customer charge for the Domestic class that is approximately $13.31/month, a demand rate of approximately $19.25/kW of demand, and an energy rate of approximately $0.0670/kWh, as indicated in Table ES-5. For the Domestic class, this means that the costs to serve each customer is equal to $13.31/month; however, RPU's existing rate structure includes a charge of $8.06/month for this service. Therefore, the remaining customer-related costs are currently included in the energy rate. Additionally, it costs RPU approximately $19.25 per kW of demand to serve each Domestic customer; a portion of these costs are also recovered in the existing energy rates. RPU's Reliability Charges recover fixed costs that are included in the $19.25/kW demand calculation. RPU's COS based energy-related-costs are $0.0670/kWh (not adjusted for tiered costs); however, as a result of a lower customer charge and no demand charge, the existing energy rate is higher than RPU's "pure" energy costs. RPU's energy rates are tiered to encourage conservation; the more energy used by Domestic customer, the higher the "per unit" rate ($/kWh).

Table ES-5 also includes a column titled "COS-Energy"; this data is based on the COS analysis and recognizes that Domestic customers are not charged on a demand basis ($/kW). As indicated, Domestic customers do incur these costs; however, they are recovered from the energy rate ($/kWh). Therefore, this table provides an "adjusted COS-based energy rate," which includes appropriate demand costs and has been calculated to be approximately $0.1739/kWh (not adjusted for the tiered structure). Note that the customer costs for this COS-Energy column are still $13.31/month, compared to the existing rate of $8.06/month.

Table ES-5
Domestic Rates
(Existing and Cost of Service)

Rate Component	Existing	COS	COS – Energy (1)
Customer ($/month)	$8.06	$13.31	$13.31
Demand ($/kW)	--	$19.25	--
Energy ($/kWh) (2)			
Tier 1 (0–750 S; 0–350 W	$0.1035	$0.0670	$0.1739
Tier 2 (751–1,500 S; 351–750 W)	$0.1646	$0.0670	$0.1739
Tier 3 (>1,500 S; >750 W)	$0.1867	$0.0670	$0.1739
Reliability Charge ($/month) (3)			
Small Residence (<100 Amp)	$10.00	--	--
Medium Residence (101–200 Amp)	$20.00	--	--
Large Residence (201–400 Amp)	$40.00	--	--
Very Large Residence (>400 Amp)	$60.00	--	--

(1) Assumes no Demand Charge and bundles demand-related costs within the Energy Charge.

(2) The tiered rates are the same for summer / winter (S/W), however, the characteristics of the tier change with season. See text for details.

(3) The Reliability Charge varies by the size of the customer (measured by the electric panel in Amps), and the costs are included in the Demand COS Charge.

This Study suggests that RPU should increase the fixed component of its cost recovery to align with its cost structures.

Figure ES-2 provides a summary of the fixed and variable cost recovery for the RPU system. Fixed cost recovery includes revenue from the customer charge, the Reliability Charge, the proposed Network Access Charge (NAC) (see text below), and demand charges. Variable cost recovery includes revenue from the energy charge. Revenues from the public benefits charge, taxes, and other fees are not included in this analysis.

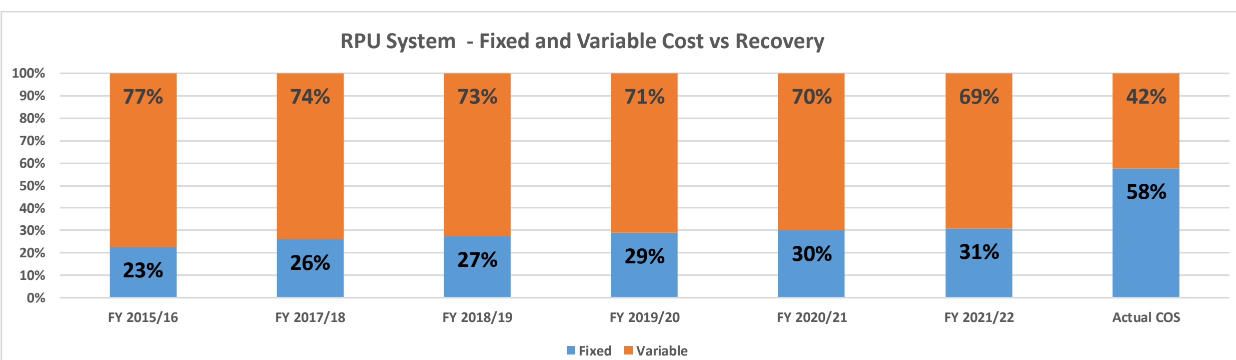


Figure ES-2. Fixed and Variable Cost Recovery for RPU System

The values for FY 2016 and FY 2018–FY 2022 represent the cost recovery from the current and proposed RPU rates. The increase in fixed cost recovery from 23% in FY 2016 to 31% in FY 2022 is a result of the rate design changes proposed in alignment with RPU's rate design principles, including mitigating customer impacts and implementing fixed cost recovery mechanisms to align rate structures with costs. RPU is proposing to gradually transition its rate structures to increase its fixed cost recovery during the Rate Plan; however, it does not plan to transition to full fixed cost recovery due to negative financial impacts to customers.

Cost Adjustments

Cost adjustment mechanisms are used by utilities to allow for the recovery of non-budgeted costs such as costs associated with regulatory requirements, and the production and purchase of energy delivered to the utility that are not recovered through the base rate and to minimize the fluctuations in rates. In light of the current electric demand uncertainty and need for financial resiliency, RPU has explored multiple approaches to increase revenue stability. A rate adjustment mechanism for regulatory and power supply costs was explored as part of this Study, which if used collectively, can help to create revenue stability for RPU.

The Regulatory and Power Cost Adjustment (RPCA) allows for the recovery of non-budgeted costs incurred by the utility that are associated with federal or state climate change laws, renewable portfolio standards (RPS), or other mandated legislation. Such regulatory costs may include, but are not limited to energy efficiency and load reduction, environmental remediation, renewable power supply integration costs, and carbon or other greenhouse gas emission costs. The RPCA also includes power supply costs that may include, but are not limited to power production costs, purchased power costs, and debt service costs. If implemented, the RPCA will be applied to kWh sold. The RPCA, which may be either positive or negative, will be reviewed and revised annually to reflect actual changes in excess of the base rate. The RCPA is proposed to be set at $0.00/kWh at the beginning of the rate adjustment period (FY 2018).

Summary of Proposed Rates

RPU is recommending a redesign of its rates over a five-year period to better align with its cost of serving customers and its future Revenue Requirements. Actual rate increases will vary by customer class and consumption levels; but, on average, the projected rate increases of approximately 4.8% per year will result in annualized compounded average system revenue increases to meet future Revenue Requirements.

Why is this Study needed? RPU faces an income shortfall of about $184.2 million if rates are not increased; reserve levels alone are not enough to avoid the need for increased revenues. Reducing reserve levels below minimum levels impacts financial metrics, which could result in a lower credit rating, thereby increasing its operating (borrowing) costs. Investments in infrastructure have been deferred as long as possible without impacting reliability and customer service.

Tables ES-6 through ES-9 provides a summary of the new rates by Domestic, Commercial, and Industrial customer classes for the proposed rate plan. It should be noted that for all of the customer classes, with the exception of the Industrial TOU, there is no change proposed for the Reliability Charge. Based on discussion with RPU staff and careful review of the COS analysis, the following rate design modifications are proposed to be implemented:

- Increase the fixed cost recovery to better reflect how actual costs are incurred. This adjustment helps RPU meet its objective of increased revenue stability and reflect how costs are incurred.
- Implement an NAC; the NAC is based on the demand-related costs associated with the distribution system. The NAC is a monthly charge that varies by customer class, depending on its allocated share of the distribution demand costs. The customer is paying a fixed charge for the demand they

place on the distribution system. For Domestic – and Commercial – Flat customers, the NAC is a monthly fixed charge that will vary by the amount of energy usage within that month, depending on the applicable NAC tier. For Commercial – Demand and Industrial TOU, the NAC is a $/kW of billed demand.

- The proposed tiered NAC for Domestic – and Commercial – Flat customers is designed to mitigate impacts of increasing fixed charges on low-use customers.
- Implement tiered Reliability charges for the Industrial TOU customers to reduce the financial impact of customers who routinely transition between the Industrial TOU and Commercial – Demand classes.
- Change the Domestic summer season from three months (June 16 through September 15) to four months (June 1 through September 30) to reflect Domestic seasonal usage patterns and align with other seasonal rates.
- Implement Domestic TOU Electric Vehicle (EV) rate options, designed to encourage customers to charge their EV during off peak times (See Section 6).
- Develop a RPCA, which is a cost adjustment mechanism to recover non-budgeted regulatory and power supply costs.

Table ES-6
Existing and Proposed Rates For Domestic Customers

		Proposed (1)				
Rate Class / Component	Existing	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge ($/month)	$8.06	$8.81	$9.56	$10.71	$11.96	$13.21
Network Access Charge ($/month) (2)						
Tier 1 (0–750 S; 0–350 W)	--	$1.08	$2.16	$3.23	$4.31	$5.47
Tier 2 (751–1,500 S; 351–750 W)	--	$2.73	$5.46	$8.19	$10.93	$13.85
Tier 3 (>1,500 S; >750 W)	--	$5.72	$11.43	$17.15	$22.86	$28.98
Energy Charge ($/kWh) (2)						
Tier 1 (0–750 S; 0–350 W)	$0.1035	$0.1060	$0.1073	$0.1093	$0.1126	$0.1161
Tier 2 (751–1,500 S; 351–750 W)	$0.1646	$0.1686	$0.1706	$0.1738	$0.1791	$0.1846
Tier 3 (>1,500 S; >750 W)	$0.1867	$0.1912	$0.1936	$0.1972	$0.2031	$0.2094
Reliability Charge ($/month) (3)						
Small Residence (<100 Amp)	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
Medium Residence (101–200 Amp)	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Large Residence (201-400 Amp)	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00
Very Large Residence (>400 Amp)	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.

(2) Proposed summer season change from current three month summer season (June 16 to September 15) to four month (June 1 to September 30). Four month summer season also applicable to Network Access Charge.

(3) No change to the Reliability Charge is proposed for this class.

Table ES-7
Existing and Proposed Rates by Commercial – Flat Class

Rate Class / Component	Existing	Proposed (1) FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge ($/month)	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50
Network Access Charge ($/month)						
Tier 1 (0–500 kWh)	--	$1.77	$3.55	$5.32	$5.91	$6.50
Tier 2 (501–1,500 kWh)	--	$5.03	$10.06	$15.09	$16.77	$18.45
Tier 3 (1501–3000 kWh)	--	$8.95	$17.90	$26.85	$29.83	$32.82
Tier 4 (>3000 kWh)	--	$21.53	$43.06	$64.59	$71.77	$78.95
Energy Charge ($/kWh)						
Tier 1 (0-15,000 kWh)	$0.1351	$0.1381	$0.1411	$0.1441	$0.1471	$0.1501
Tier 2 (>15,000 kWh)	$0.2064	$0.2110	$0.2156	$0.2201	$0.2247	$0.2293
Reliability Charge ($/month) (2)						
Tier 1 (0-500 kWh)	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
Tier 2 (501–1,500 kWh)	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
Tier 3 (>1,500 kWh)	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.
(2) No change to the Reliability Charge is proposed for this class.

Table ES-8
Existing and Proposed Rates by Commercial – Demand Class

Rate Class / Component	Existing	Proposed (1) FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge ($/month)	--	$8.51	$14.88	$21.26	$27.64	$34.02
Network Access Charge ($/kW)	--	$1.00	$1.50	$2.00	$2.50	$3.10
Energy Charge ($/kWh)						
Tier 1 (0-30,000 kWh)	$0.1111	$0.1131	$0.1171	$0.1211	$0.1261	$0.1321
Tier 2 (>30,000 kWh)	$0.1217	$0.1239	$0.1283	$0.1327	$0.1381	$0.1447
Demand Charge ($/kW) (2)						
First 20 kW / 15 kW	$209.65	$157.95	$159.45	$160.20	$160.95	$161.70
All excess kW	$10.48	$10.53	$10.63	$10.68	$10.73	$10.78
Reliability Charge ($/month) (3)	$90.00	$90.00	$90.00	$90.00	$90.00	$90.00

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.
(2) Demand charge minimum Fixed Charge based on 20 kW (existing); proposed based on 15 kW.
(3) No change to the Reliability Charge is proposed for this class.

Table ES-9
Existing and Proposed Rates by Industrial TOU Class

		Proposed (1)				
Rate Class / Component	Existing	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge ($/month)	$704.66	$653.50	$640.70	$627.91	$621.52	$615.12
Network Access Charge ($/kW)	--	$1.25	$2.60	$4.00	$5.25	$6.25
Energy Charge ($/kWh)						
On-Peak	$0.1033	$0.1075	$0.1113	$0.1157	$0.1204	$0.1256
Mid-Peak	$0.0828	$0.0868	$0.0906	$0.0949	$0.0987	$0.1030
Off-Peak	$0.0727	$0.0753	$0.0779	$0.0810	$0.0843	$0.0879
Demand Charge ($/kW)						
On-Peak	$6.88	$6.88	$7.03	$7.18	$7.23	$7.28
Mid-Peak	$2.74	$2.97	$3.28	$3.59	$3.62	$3.64
Off-Peak	$1.31	$1.45	$1.62	$1.80	$1.81	$1.82
Reliability Charge ($/month) (2)						
<= 100 kW	$1,100.00	$912.50	$725.00	$537.50	$350.00	$350.00
101-150 kW	$1,100.00	$1,012.50	$925.00	$837.50	$750.00	$750.00
151-250 kW	$1,100.00	$1,050.00	$1,000.00	$950.00	$900.00	$900.00
251-500 kW	$1,100.00	$1,100.00	$1,100.00	$1,100.00	$1,100.00	$1,100.00
501-750 kW	$1,100.00	$1,287.50	$1,475.00	$1,662.50	$1,850.00	$1,850.00
> 750 kW	$1,100.00	$1,487.50	$1,875.00	$2,262.50	$2,650.00	$2,650.00

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.
(2) A tiered Reliability Charge is proposed for this class, see text for details.

Further discussion of the proposed rates is provided in Section 6 of this Report. However, the proposed rates are designed to fully recover RPU's Revenue Requirement on average over the Study period. Rate adjustments for the "other" customer classes are also in Section 6 of this Report.

RPU without Rate Adjustments

RPU is going through a challenging period of change over the next five years as it takes action to achieve the strategic visions of the City. The Utility 2.0 Plan includes updating and modernizing operations through technology; replacing aging electrical generation, transmission, and distribution infrastructure; embracing distributed renewable sources of energy; incorporating electric transportation; setting new standards for excellence in operations, safety, efficiency, and reliability; all while maintaining long-term financial strength.

RPU's operations and needed investments cannot be sustained without rate adjustments. Rates must be adjusted to more accurately reflect the high fixed costs relative to variable cost structure. If rates are not adjusted, RPU will not be able to fund its Utility 2.0 investments, its increased operating costs, and will fail to maintain its strong financial metrics. RPU's existing reserves are not sufficient to pay for the planned investments. Additionally, drawing down on its reserves will also lead to higher borrowing costs for the City, as a result of anticipated negative impacts to its credit rating. RPU has deferred its investments for as long as practical; without rate adjustments, these delays will impact utility operations and customer service.

Section 1
INTRODUCTION

Introduction

Riverside Public Utilities (RPU) is a municipal public utility owned by the City of Riverside, California (City) that provides power to the citizens of the City. RPU has some of the lowest commercial electric rates in Southern California and attracts increased electric load to its system by offering attractive economic development electric rates to qualified new and expanded load customers. These rate programs have helped create and retain over 3,600 jobs in the City since 2010, and benefit all customers by providing a larger customer base to spread fixed costs. The City's Green Business Program recognizes local businesses for pursuing sustainability in their facilities and operations. Businesses are evaluated based on their efforts to reduce pollution and waste, and to improve resource use efficiency. Once certified through the program, the businesses are recognized locally and statewide through the California Green Business Network, a network of over 3,500 other businesses in the State of California (State) that have already committed to pursuing greener practices. To-date RPU has certified four Green Businesses under this program.

Beyond rates, RPU offers local businesses a wide variety of water and energy conservation incentive programs. RPU's Small Business Direct Installation Programs, from FY 2014/15 to date, have assisted more than 7,300 participants save over $1.2 million in utility costs and conserve 7.9 million kilowatt-hours (kWh). RPU's grant program helps local universities find new ways to advance energy technology and water conservation techniques. These economic development, sustainability projects, and programs put the Utility on the cutting edge of job creation and resource efficiency, making the City a better place to live and do businesses.

RPU is going through a challenging period of change over the next five years to achieve the strategic visions of the City. The Riverside 2.0 Strategic Plan provided guidance for the development of the Utility 2.0 Plan. The Utility 2.0 Plan includes updating and modernizing operations through technology; replacing aging electrical generation, transmission, and distribution infrastructure; embracing distributed generation; increasing the amount of renewable energy; incorporating electric vehicles setting new standards for excellence in its operations, safety, efficiency, and reliability; all while maintaining an enduring financial strength that ensures the energy lifeline of the community long into the future.

This Electric Cost of Service and Rate Design Study (Study) addresses the RPU's projected income shortfall as future revenue needs driven by the Utility 2.0 vision greatly exceeds forecasted revenue under the existing rate designs. This Study determines the basis for cost causation between customer classes. This Study also considers existing rate trends that other utilities in similar situations are using to construct new rate designs that meet future revenue needs in an environment of increased energy efficiency, energy conservation, regulatory and environmental uncertainty, and customer self-generation.

RPU is not alone in its need to re-evaluate its current rate structures. While its rates have remained the same over the last seven years, the electric utility industry has been going through a period of rapid change. Distributed generation, particularly from residential roof-top solar, along with increased California mandates for renewable power supply and increased energy efficiency opportunities, have caused retail sales to remain flat or decline across the state. Other municipal utilities face similar challenges and are seeking rate adjustments to implement more fixed cost recovery in light of their cost structures, such as Sacramento Municipal Utility District, Roseville Electric Department, and Alameda Electric Utility. Even the largest privately owned utilities in the state, such as Southern California Edison (SCE) and Pacific Gas and Electric (PG&E), are changing their rate structures to reduce the reliance on high volumetric charges.

The process of conducting a cost of service (COS)/rate design analysis generally proceeds as follows:

1. Establish the Revenue Requirement – determine the total revenues the utility must collect over a specified period of time to serve its customers, maintain its debt service obligations, invest in its system, and provide additional funds required by fiscal and reserve policies, as appropriate. The period of time covered by the Revenue Requirement (as well as the Rates) is defined as the Test Year.
2. Functional Unbundling – divide the utility's Revenue Requirement between its four major business units or functions, including:
    a. Production
    b. Transmission
    c. Distribution
    d. Customer service
3. Classify Costs Within Functional Area – classify costs based on the drivers within each functional area. Drivers of cost include system demand, energy consumptions, the number of customers being serviced, or costs that are directly attributed (or allocated) to a specific class or customer.
4. Allocation of Costs across Customer Classes – based on the customer usage characteristics of the system, allocate the classified costs to customer classes, and determine the COS for the classes.
5. Design Rates – rate design is based on a combination of analysis of the customer class Revenue Requirements (the allocated share of the system costs) and policy decisions.

In 2015, the City contracted with Leidos Engineering, LLC (Leidos) to provide a Study to evaluate RPU's existing retail rates. In October 2016, the City contracted with NewGen Strategies and Solutions, LLC (NewGen) to complete the Study.

Schedule

The retail rates proposed herein will be conceptually presented to the City Council, the RPU Board, and community groups before being presented to the City Council and RPU Board for approval. For the purposes of this Report, it was assumed that the first series of rates would take effect on April 1, 2018, and on January 1st the following four years.

Utility 2.0 Plan

The Utility 2.0 Plan has been designed to facilitate and advance the strategic goals adopted by the City Council in the Riverside 2.0 Strategic Plan, as well as the strategic goals adopted by the Board. In developing the Utility 2.0 Plan, a number of "roadmaps" were presented to the City Council and Board, including Utility Infrastructure and Supply, Workforce Development, and Thriving Financially. The Utility 2.0 Plan provides 10-year financial projections for Revenue Requirements needed to fund various paces of implementation for the Utility 2.0 Plan. In selecting the Option 3 strategy of proactive implementation, the Board and City Council recognize that business as usual will fall far short of both the RPU's vision and the City's vision for the future. A summary of each of the utility Infrastructure and Supply roadmaps, as applicable to RPU's electric utility, follows.

Power Supply

An increasingly complex regulatory environment and changing consumer behavior have influenced decisions of the City Council and Board regarding RPU's power supply portfolio. Replacement of the coal-fired Intermountain Power Plant (IPP), increasing RPU's renewable portfolio, and integrating power supply and demand are the significant issues facing RPU in power supply planning. RPU's adopted Integrated Resource Plan outlines strategies to meet current and expected future renewable power standards and replacement of IPP. Integration of power supply and demand will require enhanced collaboration and analytics that are addressed in the Electric Infrastructure and Workforce Development sections of the Roadmap.

Electric Infrastructure

Two-way power flows resulting from distributed generation will dramatically change the nature of our electric grid infrastructure. Additionally, replacement of aging infrastructure needs to be addressed. If not addressed, equipment failures resulting from aging infrastructure will dramatically reduce the reliability of our system and increase customer outages. City Council conceptually approved Option 3 of Utility 2.0 on October 6, 2015.

Technology Revisited

On July 10, 2015 and August 7, 2015, the Board received updates on the Strategic Technology Plan prepared by Leidos. The Strategic Technology Plan outlines 19 recommended projects to be completed over the next 10 years. Many of those projects are embedded within the recommendations outlined in the infrastructure roadmaps. All of the costs associated with the technology projects are outlined in the 10-year financial pro forma and financial plan. The Strategic Technology Plan includes 19 projects categorized as customer focused, information-based, and real-time operational technologies. Three additional technology projects added after the Strategic Technology Plan was issued are the light-emitting diode (LED) streetlight replacement, the Dark Fiber Network, and the Employee Talent Management System. All of the costs associated with the technology project are outlined in the 10-year Financial Pro Forma Model.

Rate Design Objectives/Rate Making Principles

To properly design rates, RPU considered a variety of factors, including its rate making principles. The most critical factor is that rates and charges are designed such that the total Revenue Requirement of the system will be recovered in an equitable manner consistent with the results of the Study. In addition, RPU carefully considered the overall revenue stability for the electric utility (and its customer classes), the historical rate structures in place, policy considerations for conservation and energy efficiency, competitiveness with neighboring utility systems, as well legal requirements and other energy-related policies established by the City Council during the electric rate design. The following (Table 1-1) provides a list of RPU's policy goals related to its electric and water rate design, with the specific application identified for this Study and the Five-Year Rate Plan.

Table 1-1
RPU Policy Goals and Five-Year Rate Plan

RPU Ratemaking Principles	Five-Year Electric Rate Plan – Implementation
Achieve full recovery of costs	Rates designed to recover projected Revenue Requirements over Study period
Equitably allocate costs across and within customer classes	Increase/implement fixed cost recovery mechanisms to align rate structures with costs
Encourage efficient use of water and electricity	Design rates to discourage over use and reward efficiency
Provide rate stability	Maintain consistency between rates within each year of the Study period
Offer flexibility and options	Reduce rate-related bill impacts for customers transitioning between classes
Maintain rate competitiveness in region	Consider/mitigate rate–related impacts to all customers including low use customers
Be simple and easy to understand	Maintain simplicity of rate structures and components of existing rate structures, as appropriate

Additional detail on RPU's Rate Policy/Objectives is provided in Section 6 of this Report.

Riverside Five-Year Rate Plan

The retail rates proposed herein are aligned with the first five-years of its Utility 2.0 planning effort, which is anticipated to continue in FY 2018. The Five-Year Rate Plan is intended to achieve the rate objectives, as defined herein, by the end of the Five-Year Rate Plan period (Rate Plan period) through FY 2022. The Five-Year Rate Plan is intended to be an all-inclusive plan; if only partial years of the plan are approved, RPU may not achieve its rate objectives. The basis for the Five-Year Rate Plan is the capital improvement plan (CIP) designated as "Option 3" of the Utility 2.0 Plan. Proposed rates for the "major" customer classes are provided in the Report; rates for the other or "ancillary" rate classes are provided in Appendix A to this Report. Detailed information that supports the costs associated with Option 3 of the CIP, along with the remainder of the projected Utility 2.0 costs, as well as the development of the retail rates, is provided in the Technical Appendix (Appendix B to this Report).

The first series of rates changes are anticipated to take effect on April 1, 2018, with four subsequent rate changes taking effect on January of each ensuing year.

The first year of the proposed rates are planned for implementation in the fourth quarter of the City's fiscal year (FY) (ending June 30th of each year), with subsequent proposed rates implemented at the beginning of each calendar year, which is approximately half-way through the City's FY. The proposed rates are designed to recover the Revenue Requirement established for each year and driven by the proposed investments, expenses, and other financial needs of the system. The proposed rates recognize the potential financial impacts to customers and are designed to achieve rate stability (in terms of year-to-year changes in the rates). Therefore, the rate plan described herein uses a "gradual" approach to achieving the goals and objectives of RPU by the end of the proposed Rate Plan period.

The changes in rates and rate structures support the equitable cost allocation between customer classes, which includes proposed increases in the fixed cost recovery rate components of each customer class' rate tariff. The Five-Year Rate Plan promotes rate stability by not dramatically altering rates and rate structures each year of the Study. Because this gradual approach is phased-in over the Study period, the exact annual total system revenue for each year derived from the COS analysis does not align with the exact annual total revenue in the Financial Pro Forma Model. The result of the proposed changes to RPU's retail rates in the COS analysis are projected revenues based on defensible rate structure improvements that will support RPU as its moves forward with its Utility 2.0 investments into the future.

Table 1-2 provides a summary of the debt service coverage calculation utilizing the COS Model revenue values applied to the Financial Pro Forma Model. The RPU's reserve policy requires a target minimum debt service coverage ratio of 1.75 (calculated as the ratio of estimated net revenues available for debt service divided by maximum annual debt service) for financial projection purposes. The projected debt service coverage ratios range from 2.18 to 2.45, and average 2.32 over the Study period.

Table 1-2
Financial Metrics for Study Period ($000)

	FY Ending				
Category	2018	2019	2020	2021	2022
Projected Retail Revenue (COSA)	$306,581	$327,724	$346,211	$365,404	$384,880
Projected Other Revenue (1)	$61,875	$66,903	$68,284	$58,225	$58,749
Expenses, Reserves, other Obligations	$271,606	$287,737	$302,201	$316,474	$322,284
Net Revenues Available for Debt Service	$96,849	$106,890	$112,293	$107,155	$121,344
Debt Service (2), (3)	$39,763	$43,703	$48,830	$49,151	$53,969
Debt Service Coverage (4)	2.44	2.45	2.30	2.18	2.25

(1) For purposes of calculating Debt Service Coverage, RPU includes contributions for greenhouse gas allowances and Contributions in Aid of Construction. See text for details.

(2) For purposes of calculating Debt Service Coverage, the Debt Service is limited to the amount due in any given year for Revenue and Pension Obligation Bonds. This debt does not include capital lease, change in interest payable, and general fund allocation (which is included in the Revenue Requirement in Table ES-3).

(3) Net of Build America Bonds Treasury Credit.

(4) Ratio of Net Revenues Available for Debt Service / Debt Service.

RPU Financial Projections

The Revenue Requirement for each of the five years of the Test Year was developed by RPU in its Financial Pro Forma Model as provided in Table 1-3. Additionally, Table 1-3 includes a comparison of the total revenues generated by existing rates (current as of 2017) for the system. The difference between these two values represents the necessary rate adjustments for RPU to achieve the investments and policies identified in the Utility 2.0 Plan, and represent a cumulative revenue shortfall of approximately $184.2 million.

Table 1-3
Revenue Requirement and Revenue for Study Period ($000)

	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	Total
Revenue Requirement	$306,266	$327,434	$346,127	$365,574	$385,014	$1,730,413
Revenue from Customers (1)	$303,122	$306,392	$309,335	$312,230	$315,158	$1,546,238
Difference (2)	**$(3,144)**	**$(21,041)**	**$(36,791)**	**$(53,344)**	**$(69,855)**	**$(184,176)**

(1) Utilizing existing rates, assuming no rate structure changes and no adjustments for elasticity. Assumes specific Contract customers are moved to standard rate schedules in FY 2019.

(2) Totals may not add due to rounding.

RPU Study Test Year

The Test Year for this Study was determined to be from RPU FY 2018 through its FY 2022 (RPU's FY is from July 1st through June 30th; all references are to FY unless otherwise noted). This five-year Test Year was selected because of its alignment with the goals and objectives of the Utility 2.0 Plan. A five-year Test Year results in an average annual value that represents the "mid-point" of that five-year period; however, due to anticipated growth of system sales, the mid-year (FY 2020) does not necessarily represent the median values of the Test Year. The Five-Year Rate Plan provides a series of rate changes over the five-year period; it is critical that the entirety of the five-year rate adjustments be reviewed collectively, as the intent is to achieve specific financial and policy objectives at the end of the Rate Plan period.

RPU serves retail electricity to a variety of customer classes, including residential (referred to herein as Domestic), commercial, industrial, street lighting, and others. Additionally, RPU serves a small number of large customers through direct contracts, which includes the City (see discussion herein). A summary of the rate classes, their existing rate revenues, and their allocated Test Year Revenue Requirement is provided in Table 1-4.

Table 1-4
Existing Test Year Rate Revenues vs Test Year Revenue Requirements ($000)

Rate Class	Test Year Existing Rate Revenues (1)	Test Year Revenue Requirement	Difference
Domestic	$113,556	$136,807	$23,251
Commercial – Flat	47,153	45,902	(1,251)
Commercial – Demand	24,879	23,760	(1,119)
Industrial TOU	111,694	126,082	14,388
Street Lighting (2)	4,647	4,824	177
Other (3)	7,317	8,170	852
Total (4)	**$309,248**	**$345,545**	**$36,297**

(1) Based on existing rates and Test Year (five-year average) billing determinants.
(2) Street Lighting includes Customer Owned and Department Owned.
(3) Includes Contract Customers and other rate classes, see text for details.
(4) Totals may not add due to rounding.

The analysis presented in Table 1-4 indicates that the Domestic, Industrial Time-of-Use (TOU), and Other customer class revenues are not sufficient to meet their respective Test Year Revenue Requirements. This analysis also suggests that existing rates for the Street Lighting customer class are approximately equal to their Test Year Revenue Requirement. The Commercial – Flat and Commercial – Demand customer class revenues are in excess of their projected Test Year Revenue Requirement.

The value of the difference between the total Test Year Existing Rate Revenue and the Test Year Revenue Requirement represents an “average” year (based on the Test Year concept, as discussed). During the course of the Five-Year Rate Plan, it is expected that some customers’ load (sales) will increase, as discussed in Section 2. Additionally, some customers will shift between the “Other” customer class and their Otherwise Applicable Tariff (OAT). Therefore, the average revenue difference for the Test Year will equal the shortfall identified in Table 1-4 when applied to the changes in customer usage characteristics.

Test Year/Audited Year

As indicated, the Test Year for RPU was determined to be within the period from FY 2018 to FY 2022. For the purposes of this Study, audited FY 2016 was utilized. The FY 2016 period was utilized to determine the underling details of the customer usage statistics. Rate class information was based on the FY 2016 data, with adjustments made to reflect known and measurable changes.

RPU Specific Rate Issues

Contract Customers

RPU has historically provided individual rate contracts to selected large use customers. The large customers are generally able to take electricity at a higher voltage and may also internally provide distribution, and their contracts provide these customers with credit for such distribution. These contract rates have been effective in establishing and retaining large industrial load customers for the benefit of the entire RPU system. However, many of the large industrial load contracts have expired or will expire by the time of the initiation, or soon thereafter, of the rates proposed herein. The customers whose contracts have, or soon will, expire, will be moved to their OAT, as specified in their contracts.

California Requirements/Proposition 26

As a municipal public utility, RPU must comply with a number of mandates and requirements enacted by the State of California (State), including a renewable portfolio standard (RPS), energy efficiency programs, public benefits charges, and others.

The voters in the State approved Proposition 26 on November 2, 2010. Proposition 26 amended Article XIII C of the State Constitution to expand the definition of "tax" to include "any levy, charge, or exaction of any kind imposed by a local government" with listed exceptions. By means of these exceptions, Article XIII C classifies several types of charges, in addition to property-related charges, that are not taxes, such as charges for specific services or benefits, regulatory charges and penalties.

Article XIII C's definition of "tax" includes the following exceptions: (1) a charge imposed for a specific benefit conferred or privilege granted directly to the payor that is not provided to those not charged, and which does not exceed the reasonable costs to the local government of conferring the benefit or granting the privilege; (2) a charge imposed for a specific government service or product provided directly to the payor that is not provided to those not charged, and which does not exceed the reasonable costs to the local government of providing the service or product; (3) a charge imposed for the reasonable regulatory costs to a local government for issuing licenses and permits, performing investigations, inspections, and audits, enforcing agricultural marketing orders, and the administrative enforcement and adjudication thereof; (4) a charge imposed for entrance to or use of local government property, or the purchase, rental, or lease of local government property; (5) a fine, penalty, or other monetary charge imposed by the judicial branch of government or a local government, as a result of a violation of law; (6) a charge imposed as a condition of property development; and (7) assessments and property-related fees imposed in accordance with the provisions of Article XIII D. Proposition 26 also exempts or "grandfathers" any charges that predate the November 3, 2010 passage of Proposition 26.

Proposition 26 also provides that the local government bears the burden of proving by a preponderance of the evidence that a levy, charge, or other exaction is not a tax; that the amount is no more than necessary to cover the reasonable costs of the governmental activity; and that the manner in which those costs are allocated to a payor bear a fair or reasonable relationship to the payor's burdens on, or benefits received from, the governmental activity. Like the proportionality requirements of Article XIII D, assessment of rates under these requirements, if applicable, would be supported by the COS approach.

Simply put, Proposition 26 limits RPU from recovering costs not related to the provision of electric service in its retail rates, without approval by voters. A definitive interpretation by the California courts of the implications of Proposition 26 has not been achieved, as it is currently being adjudicated. However, actions and policies established by municipal utilities prior to the enactment of Proposition 26 (November 3, 2010) are allowed to remain in place. This "grandfathering" of the rate structures, as well as inter-class subsidies that RPU established, or had in effect, in 2010 can be incorporated into the proposed rate design for this Study.

Net Energy Metering Regulations

Net Energy Metering (NEM) legislation was passed by the State to stimulate private investment in renewable forms of electrical generation (Public Utilities Code section 2827 et seq.). California law imposed these requirements on investor-owned and publicly-owned utilities. Under NEM legislation, customers are able to receive compensation from their utility for excess energy that is returned to the grid. Under NEM, customers are compensated for such excess energy at the utility's average cost of renewable energy.

In essence, NEM customers return excess energy to the grid during the day and consume it during the evening. Customers under an NEM rate are metered for the energy delivered and receive a credit for energy provided to the grid. At the end of the month, the customer is billed for the "net" difference of the two.

However, Public Utilities Code section 2827 (g) precludes RPU from charging any stand-by charges to the customer-generator. This means that RPU cannot bill the customer-generator for the costs associated with serving that customer during periods when the customer's solar system is not producing energy or costs associated with "storing" excess production on the grid during the day. Instead, RPU must pass these costs on to non-NEM customers within the customer class, or the utility, effectively creating a subsidy between customer classes, or even within customer classes (solar versus non-solar residential customers, for example). The NEM legislation provides that when a utility achieves 5% of its total capacity (in megawatts or MW) available at peak usage, it could differentiate such rates for new NEM customers.

As of March 2017, RPU has approximately 19.03 MW of distributed solar capacity installed by its customers, which represents approximately 3.15% of RPU's peak demand of 604 MW. It is anticipated that customer-owned distributed solar will continue to grow within the RPU service territory. Current estimates are that as early as FY ending June 30, 2018, RPU will have met its 5% target under the NEM regulations. RPU plans to develop rates for NEM prior to meeting the 5% target and bring the recommendations forward subsequent to the approval of this rate plan.

Report Outline

The remaining sections of this Report provides a summary of the system and customer class characteristics (Section 2), RPU's Revenue Requirement (Section 3), the methods utilized for the cost allocation process (Section 4), the results of the cost allocation (Section 5), and the proposed rate design utilizing Option 3 (Section 6). Appendix A provides a summary of the proposed rates for RPU's ancillary rate/customer classes. Appendix B provides a technical appendix of the analysis, data sources, and other supporting information utilized in development of this Report.

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Section 2
SYSTEM CHARACTERISTICS

Introduction

RPU operates the Electric System as a vertically integrated utility providing service to virtually all electric consumers within the City's limits, which encompasses 81.5 square miles. The City is the sole provider of electric service within its territory. RPU's power supply consists of electric generation facilities owned by the City, entitlements to other generation facilities, power purchase contracts, and open market purchases.

RPU had 98.6 circuit miles of sub-transmission and 1,330 circuit miles of distribution lines as of the FY ending June 30, 2016**.** Of the distribution lines, 821 circuit miles of underground lines are primarily in commercial and new residential areas. There are 14 substations within the electrical system that have a combined capacity of 1,106 megavolt-amperes (MVa).

Demand and Energy Requirements

The system peak for the FY ending June 30, 2016 was 599 MW, which included providing service to approximately 108,776 meters. Table 2-1 provides a summary of the system usage characteristics for RPU, including total retail customers, megawatt-hours (MWh) of electricity (adjusted for losses), and the total peak load (MW) for the Electric System during the FY 2016, FY 2017, and each of the projected years of the Test Year (FY 2018 – FY 2022)

Table 2-1
System Usage Characteristics

	FY Ending						
	2016	2017	2018	2019	2020	2021	2022
Total Meters	108,776	109,197	109,777	110,367	110,971	111,583	112,203
Total Energy (MWh) (1)	2,327,400	2,269,421	2,292,411	2,315,828	2,345,778	2,366,412	2,399,331
Total Demand (MW) (2)	599	578	581	584	587	590	595

(1) Energy projections for 2017–2022 on a Calendar Year Basis for System, includes losses and off-system sales. Updated August 2016. 2016 represents actual energy and peak demand for FY 2016 (ending June 2016).

(2) Demand is projected peak demand for year, anticipated to occur in August of calendar year.

Demand

Demand is a measurement of energy for a short period of time, typically an hour or 15-minute interval. Demand is measured in kilowatts (kW) or in thousands of kW (1000 kW), which are reported as MW. A utility must be able to meet the demands of its systems, which represent the total hourly demands of its customers at any given time. To meet these demands, utilities will typically invest in generation facilities that are appropriately sized to meet the peak demand or purchase demand (in the form of capacity contracts) from the power market, or some combination thereof. Utilities must plan and invest for the system peak capacity, which may go unused during periods of low electrical use. For RPU, the system typically peaks in the months of June through September. During the non-summer months, there is a significant drop-off in system demand. The ambient temperature drives RPU's system peak; as outside temperatures increase, residential customers will utilize their air conditioning units to provide relief. Therefore, from a cost causation perspective, the residential class is driving the majority of the system peak demand.

The peak demand for RPU for FY 2016 was approximately 599 MW, which occurred on June 20, 2016 at 5:00 p.m. The peak demand is often referred to as the "Coincident Peak" (CP) because it is the amount of total load from all customers collectively at the same time (coincident with each other). CP is an important tool utilized in allocating costs for a COS Study and is further discussed in Section 4 of this Report.

Energy Sales

Energy is the demand that is measured over multiple hours. Energy is measured in kWh and is the product (and service) that most people associate with purchasing from their electric utility. A utility must provide energy to its customers in a reliable, continuous, and safe fashion. Energy is primarily instantaneous – it cannot be effectively stored in large amounts for later use. A utility will use the installed investment in generation (capacity or available demand) to produce energy, typically by burning fossil fuel (either gas or coal, depending on the resource) or with renewable resources (solar, wind, geothermal). Alternatively, a utility may purchase energy in the power market to meet its customers' load.

Figure 2-1 provides a representation of the total energy used by RPU's primary customer classes for FY 2016**.** Given the historically low energy usage and lack of meters, the street light classes are collectively included in the "Other Classes" category for the purposes of the system characteristics (Section 2).

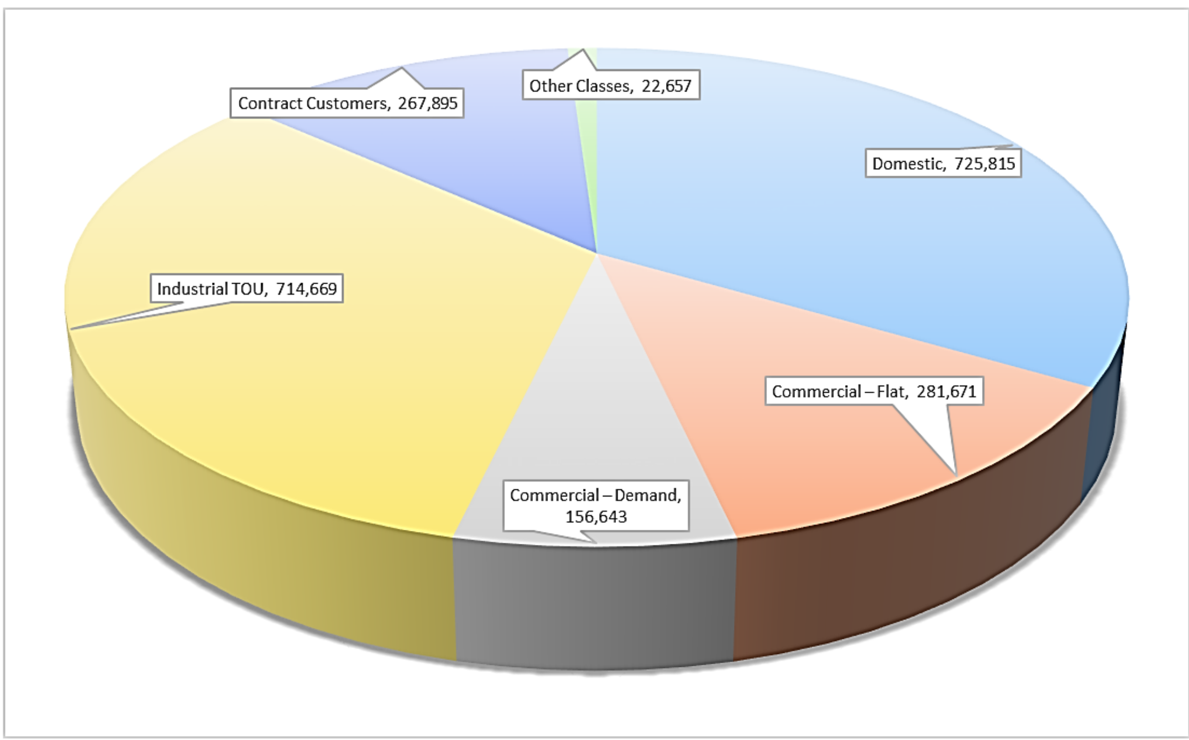

Figure 2-1. Total Energy Consumption by Customer Class for FY 2016 (kWh)

Historical and projected energy sales by customer class are provided in Table 2-2 (for the major customer classes).

Table 2-2
Historic and Projected Energy Sales (000 kWh or MWh)

	FY Ending						
	2016	2017	2018	2019	2020	2021	2022
Domestic	725,815	724,642	693,538	690,063	687,940	685,556	682,295
Commercial – Flat	281,671	277,127	276,893	280,085	283,861	287,579	291,662
Commercial – Demand	156,643	158,698	159,013	160,810	162,940	165,036	167,340
Industrial TOU (2)	714,669	868,867	935,824	946,299	959,135	971,644	985,668
Contract Customers (2)	267,895	124,624	69,155	68,835	68,575	68,316	68,081
Other Classes (3)	22,657	22,373	22,373	22,373	22,373	22,373	22,373
Total System (1)(4)(5)	**2,169,350**	**2,176,330**	**2,156,796**	**2,168,465**	**2,184,823**	**2,200,504**	**2,217,419**

(1) Projections include the projected impact associated with price elasticity; see text for discussion.

(2) Contract customers ROHR, Kaiser, and UCR are moved to OAT effective FY 2017, and Ralphs will be moved to the Industrial TOU rate effective FY 2019; see text for discussion.

(3) Other classes includes street lights.

(4) Total System sales excludes losses.

(5) Totals may not add due to rounding.

Actual energy sales in FY 2016 for the Domestic customer class were higher than those projected for FY 2018. This is because FY 2016 was an exceptionally hot summer period while projections for FY 2018 and beyond are based on normalized weather patterns. Based on statistical analysis completed by RPU's Resource Planning Team, it is anticipated that total system load growth will increase over the course of the Test Year at a rate of approximately 0.75% per year.

In addition to normalizing for weather, the total projected energy sales have been adjusted for the anticipated effects of price elasticity. Price elasticity is an economic theory that suggests that when prices increase/decrease for any item, that customers respond in an economic fashion by either purchasing more or less of that item. Price elasticity has been proven to exist for electricity sales. The RPU Financial Pro Forma Model includes estimates of price elasticity on its projections for energy sales. The impacts from the system-wide rate adjustments in the Financial Pro Forma Model have been incorporated into the customer class analyses for this Study, as presented in Table 2-2 and in the energy sales projections throughout this Report.

Average Number of Meters by Customer Class

The average number of meters by major customer class served by RPU for the period of FY 2016 and projected for FY 2017 through FY 2022 is provided in Table 2-3.

Table 2-3
Historic and Projected Meters by Class

	FY Ending						
	2016	2017	2018	2019	2020	2021	2022
Domestic	96,934	97,320	97,730	98,115	98,502	98,892	99,285
Commercial – Flat	10,111	10,197	10,350	10,540	10,741	10,947	11,159
Commercial – Demand	787	800	813	828	843	859	875
Industrial TOU	490	507	511	511	511	511	511
Contract Customers (1)	401	324	324	324	324	324	324
Other Classes (2)	53	49	49	49	49	49	49
Total System (3)	**108,776**	**109,197**	**109,777**	**110,367**	**110,971**	**111,583**	**112,203**

(1) Contract customers ROHR, Kaiser, and UCR are moved to standard rate schedules effective FY 2017 and Ralphs will move to the Industrial TOU April 2018.

(2) Other classes includes street lights.

(3) Projected meters are the average monthly projected meters for each fiscal year.

Customer Statistics

Projected meter statistics by major rate class for FY 2016 is provided in Table 2-4.

Table 2-4
Actual Customer Usage Statistics for FY 2016

	FY Ending			
	Number of Meters	Percent of Total	Annual Sales (MWh)	Percent of Total
Domestic	96,934	89.2%	725,815	33.7%
Commercial – Flat	10,111	9.3%	281,671	13.1%
Commercial – Demand	787	0.7%	156,643	7.3%
Industrial TOU	490	0.5%	714,669	33.2%
Contract Customers (1)	401	0.3%	267,895	11.7%
Other Classes (2)	53	0.0%	22,657	1.0%
Total System	**108,776**		**2,169,350**	

(1) Contract customers ROHR, Kaiser, and UCR are moved to standard rate schedules effective FY 2017 and Ralph's moved to the Industrial TOU April 2018.

(2) Other classes includes street lights.

Fixed/Variable Costs and Cost Recovery

As indicated previously, RPU's cost structure does not align with its existing rate structure. System costs for the Test Year based on the COS analysis have been identified as approximately 58% fixed, reflecting costs for investments (financed with both cash and debt service), power supply contracts, labor, and equipment. The remaining costs of approximately 42% are variable, which includes fuel/purchased power (not under long-term contracts).

The revenues generated from retail sales under RPU's existing rates for FY 2016 are estimated to be approximately 23% fixed (which includes the customer charge, reliability charge, and minimum demand charge, as applicable), and 77% variable (which includes the energy charge). Figure 2-2 provides a graphic of the mix between the fixed and variable nature of the Test Year costs (on the right) and the revenues for FY 2016 (on the left).

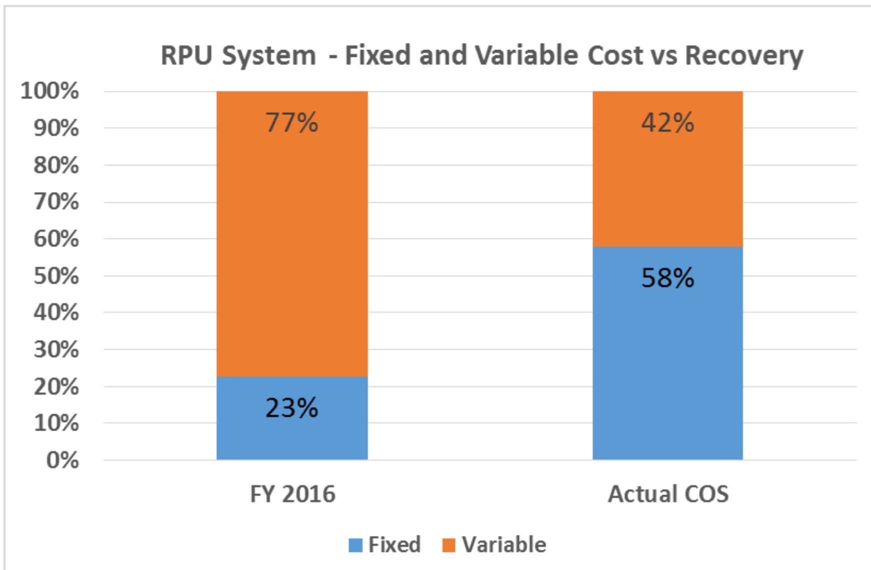

Figure 2-2. Structure of Test Year (COS) Costs versus FY 2016 Revenues

Section 3
REVENUE REQUIREMENT

Summary

Revenue requirement refers to the amount of rate-related revenue a utility is projected to need during the Study period. As indicated earlier, for the purposes of this Study, RPU is utilizing a Test Year that represents the average of the five-year period beginning in FY 2018 and ending in FY 2022. RPU's net Revenue Requirement for the Test Year is $345,544,652 (rounded to $345,545,000). This value is driven by the specific "known and measurable changes" related to the investments projected in its Pro Forma Financial Model, as a result of its Utility 2.0 Plan cost increases. Because the Test Year is a multi-year representation, this value represents the average annual revenue to be collected by RPU's retail rates. For purposes of rate design, provided in Section 6 of this Report, revenues collected over the Study period will vary by year, however, RPU is projecting that revenues collected in the last year FY 2022 will be slightly less than the projected revenue required for that year.

Detailed information regarding each component of RPU's Revenue Requirement for each year of the Study period is provided in the Technical Appendix B. These projections were obtained from RPU's Pro Forma Financial Model. A summary of the Test Year Revenue Requirements is provided in Table 3-1.

Table 3-1
Revenue Requirement by Function for Test Year ($000)

Function	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	Test Year Value	Percent of O&M
Production O&M	$156,173	$167,013	$174,255	$181,190	$186,266	$172,979	57.6%
Transmission O&M	61,927	63,386	66,412	68,880	67,668	65,654	21.9%
Distribution O&M	17,208	18,441	19,796	21,370	21,988	19,761	6.6%
Customer O&M	10,063	10,782	11,558	12,453	12,840	11,539	3.8%
Administrative and General O&M	26,235	28,115	30,181	32,581	33,523	30,127	10.0%
Total O&M	**$271,606**	**$287,737**	**$302,201**	**$316,474**	**$322,284**	**$300,061**	
Debt Service	40,687	44,592	49,706	49,728	54,554	47,853	
Transfer to General Fund	39,831	40,019	42,515	44,741	47,033	42,828	
Capital Funded by Rates	4,186	4,571	5,452	5,826	5,834	5,174	
Allocation to (Use of) Reserves	4,931	10,292	7,162	4,380	11,407	7,634	
(minus) Other Revenues	(54,975)	(59,778)	(60,909)	(55,575)	(56,099)	(58,005)	
Net Revenue Requirement	**$306,266**	**$327,434**	**$346,127**	**$365,574**	**$385,014**	**$345,545**	

Source: RPU Financial Pro Forma Model and COS Model. Note, numbers may not add due to rounding.

As Table 3-1 indicates, and is typical for electric utilities, the production function is the costliest function for RPU to serve its customers. Non-O&M costs include debt service, associated with existing and future debt issues required to fund existing and future investments in the system; the transfer to the General Fund (as determined by the City); capital funded by revenue, which are investments that are made to the system and are paid for by rate revenue (not debt financed); and reserves, which is driven by the City's reserve policy (discussed below).

The calculation of the Revenue Requirement includes an offset (or credit) for revenues that are obtained by RPU from other sources, including interest income, as well as the California Independent System Operator (CAISO) (transmission-related). The credit of "non-retail" revenues recognizes the net Revenue Requirement is associated only with the revenue needed from retail sales.

RPU Reserve Policy

To support the Utility 2.0 Plan, RPU has developed a robust reserve policy, which is designed to promote fiscal sustainability, minimize borrowing costs, and provide a source of funds to rapidly respond to market volatility, emergencies, demand reductions, or regulatory changes. The reserve policy guidelines were adopted by City Council on March 22, 2016 and later incorporated into the fiscal policy, which was adopted by City Council on July 26, 2016.

The overall reserve target is designed to address five risk categories, each with a minimum and maximum target based on specific metrics. Table 3-2 provides a summary of the metrics that are used to calculate the unrestricted undesignated target minimum and maximum reserve levels for each risk category.

Table 3-2
RPU Reserve Policy Summary

Risk Category	Minimum	Maximum
Operating (Working Capital): maintain sufficient resources to pay budgeted O&M expenses recognizing the timing differences between payment of expenditures and receipt of revenues.	60 Days of Operating Expenses	90 Days of Operating Expenses
Rate Stabilization: mitigates rate shock due to temporary and transitional regulatory changes, loss of a major resource, sharp demand reduction, or market volatility.	10% of Operating Revenues	20% of Operating Revenues
Emergency Capital: provides funds to maintain ability to repair system after an emergency or natural disaster such as a flood, earthquake, or major storm.	1% of Depreciable Assets	2% of Depreciable Assets
System Improvements Capital: provide funds to maintain continuity of construction over FYs to be reimbursed by bond proceeds or other resources.	6 Months of Annual CIP	9 Months of Annual CIP
Debt Service: maintain ability to make debt service payments in an extreme event that may impact RPU's ability to provide services, thus impacting revenues at a time critical infrastructure repairs are needed to restore systems. The Debt Service Reserve is intended to prevent an event where RPU would be unable to pay its debt service obligations during such emergencies, or extreme market disruptions.	Maximum Annual Debt Service in Upcoming FY	Maximum Annual Debt Service in Upcoming FY

As part of the Five-Year Rate Plan, RPU will propose updating the reserve policy to include a line of credit (LOC) as available reserves to meet unrestricted undesignated reserve targets. An LOC is a low-cost mechanism that allows RPU to draw upon cash when needed, thus reducing required cash reserve levels, minimizing rate increases to maintain reserve levels, and increasing liquidity. The LOC is currently projected as the highest of the five-year maximum system improvements capital to provide for capital funding if bond proceeds or other resources are not available.

The reserve levels vary in each year based on the expenditures or revenues used to calculate each component. Table 3-3 provides the projected target minimum and maximum reserve for each year of the Five-Year Rate Plan. The Revenue Requirements from RPU's Pro Forma Financial Model were set to include unrestricted undesignated reserves combined with the LOC to remain above the minimum targets identified.

Table 3-3
RPU Reserve Policy – Minimum and Maximum by Risk Category ($000)

		FY Ending				
Risk Category	**Target**	**2018**	**2019**	**2020**	**2021**	**2022**
Working Capital	Minimum	$44,497	$47,138	$49,506	$51,843	$52,788
	Maximum	$66,745	$70,707	$74,259	$77,764	$79,183
Rate Stabilization	Minimum	$35,593	$37,993	$39,909	$40,898	$42,885
	Maximum	$71,187	$75,986	$79,818	$81,797	$85,770
Capital- Emergency	Minimum	$11,043	$11,481	$11,992	$12,545	$13,150
	Maximum	$22,086	$22,961	$23,985	$25,089	$26,299
Capital-Sys Improvements	Minimum	$18,711	$24,429	$26,331	$29,079	$34,007
	Maximum	$28,067	$36,644	$39,497	$43,618	$51,010
Debt Service	Minimum	$26,831	$30,973	$31,560	$35,076	$40,011
	Maximum	$26,831	$30,973	$31,560	$35,076	$40,011
Total (1)	**Minimum**	**$136,675**	**$152,014**	**$159,299**	**$169,441**	**$182,840**
	Maximum	**$214,915**	**$237,271**	**$249,119**	**$263,345**	**$282,272**
Proposed Line of Credit		**$51,010**	**$51,010**	**$51,010**	**$51,010**	**$51,010**

Source: RPU Pro forma Financial Model Option 3

(1) Totals may not add due to rounding.

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Section 4
ALLOCATION OF SYSTEM COSTS

Functionalization and Classification

Allocating cost to a utility's customer classes is achieved through three major processes – 1) functionalization, 2) classification, and 3) allocation. The functionalization and classification of the Test Year Revenue Requirement are discussed in the first part of this Section. The development of the allocation factors for the Test Year Revenue Requirement is discussed in the second portion of this Section.

Functionalization of Test Year Expenditures

Although budgeting and accounting systems generally follow functional groups (i.e. production, transmission, etc.) certain costs, such as those associated with administrative and general (A&G) expenses, generally are not assigned by accounting and budgetary convention to major function. A COS study usually requires the rearrangement of certain expenditures into functional groups: 1) to be more representative of the expenditure causation, 2) to combine costs that have been incurred for a similar purpose, and 3) to facilitate the allocation of cost responsibility. Thus, the functionalization of certain costs is a rate making mechanism to apportion such costs to the common utility functions. Table 4-1 provides a categorization of the COS by function (as a result of the cost allocation process).

Table 4-1
Cost of Service by Function

Function	Test Year Value ($000)	Percent
Production	$234,767	67.9%
Transmission	26,283	7.6%
Distribution	73,351	21.2%
Customer	11,884	3.4%
Direct Assignment (1)	(740)	-0.2%
Total (2)	**$345,545**	

(1) Direct Assignment of revenues derived from RPU services provided to other utilities.

(2) Numbers may not add due to rounding.

Classification of Various Costs

Electric utility costs are generally classified as either 1) demand-related, 2) energy-related, 3) customer-related, 4) revenue-related, or 5) directly assigned. A discussion of the cost classifications is provided in this section.

Demand (fixed) cost are defined as those that are incurred to maintain a "readiness to serve;" an electric system capable of meeting the total combined demands of all customers at all hours, including peak demand. Demand costs are those that are generally fixed in the short run, do not materially vary directly with the number of kWh generated or sold, and are not defined as customer costs. Demand costs include a portion of the O&M expenses, debt service, renewal and replacements (ongoing improvements and investments), and other costs that are not defined as specifically customer or variable energy costs.

Energy (Variable) costs are defined as those expenses that vary substantially or directly with the amount of energy sold (either generated or purchased), including such items as fuel and a portion of the O&M expense for production facilities (known as variable O&M). However, not all energy procurement contracts are variable; contracts may be known as “take or pay” – in which a utility either accepts the associated energy or not, but is still responsible for a fixed amount of annual capacity costs. RPU has several such contracts, which are defined as fixed costs.

Customer costs are defined as those directly related to the number, type, and size of customer, such as customer accounting and bill collecting, and the costs of meters and services. Also, a portion of the distribution investment and operating costs are classified to customer costs because the size and design of the distribution system is a function of both the number of customers and their load (demand). The customer portion of the distribution system for RPU was determined from a minimum system analysis.

Revenue-related costs are associated with the amount of revenue generated by RPU. Taxes are a general example of revenue-related costs. However, for municipal entities such as RPU, that do not pay taxes, revenue-related costs include the transfer to the general fund, as discussed in Section 3.

There is another category of cost classification that is known as “direct assignment.” The direct assignment costs may be related to demand, energy, customer, or other type of classification; however, these costs are removed from the overall Revenue Requirement and allocated directly to a specific customer class or customer. The example most often cited for direct assignment is the costs associated with providing electric service to street lights because the Federal Energy Regulatory Commission (FERC) chart of accounts includes specific cost accounts for street lighting expenses. For the purposes of this Study, both street lighting costs and specific RPU derived revenues (credits) are directly assigned to those individual customer classes. Additionally, because the street lighting class contributes minimally to the total load and energy of the system, for the purposes of this section, they are included in the Other Classes category.

Development of Allocation Factors

General

This Section discusses the development of the factors utilized to allocate the capacity-related, energy-related, customer-related, and other costs to the various RPU customer classes. The aforementioned costs are allocated to the customer classes according to their respective customer class, and the particular cost allocation factor developed for each class and for each type of cost. The customer classes include Domestic, Commercial – Flat (non-Demand), Commercial – Demand, Industrial TOU, Contract customers, and Others (including Street Lights).

Demand Allocation Factors

Demand allocation refers to the basis on which capacity and other demand-related costs are distributed or assigned (allocated) among the various customer classes for the purposes of determining the revenues required from each class to recover such costs. The demand allocation factors, as developed and used herein, reflect the cost responsibility for each of the various customer classes in relation to the capacity-or demand-related costs to be allocated. The demand allocation factors were used to apportion the following capacity- or demand-related costs among the various customer classes:

- Production expenses (not including fuel)
- Transmission and distribution expenses
- Debt service requirements

For this COS analysis, two different demand allocators were utilized; a 4 Coincident Peak (4 CP) and a 4 Non-Coincident Peak (4 NCP). The peak demand is often referred to as the "Coincident Peak" because it is the amount of total load from all customers collectively at the same time (coincident with each other).

4 CP Method

The CP demand allocation methodology allocates costs based on the customer class contributions to the system CP. Typically, CP allocators are utilized to assign production demand-related costs to customer classes, because production demand costs are driven by the utility's need to meet its system peak. A 4 CP is utilized for this Study to allocate production costs for RPU. The projected monthly demand for each major customer class for the Study period is provided in Appendix B. The results of the 4 CP demand cost allocation process are provided in Table 4-2.

Table 4-2
4 CP Cost Allocation

Customer Class	4 CP (MW)	Allocation (%)
Domestic	757	44.8%
Commercial – Flat	202	12.0%
Commercial – Demand	114	6.7%
Industrial TOU	570	33.8%
Contact Customers (1)	44	2.6%
Other Classes (2)	1	0.1%
Total System (3)	**1,688**	

(1) As Contract customers are moved to OAT, their allocated costs are moved as appropriate.

(2) Other classes include street lights.

(3) Based on Test Year projections provided by RPU.

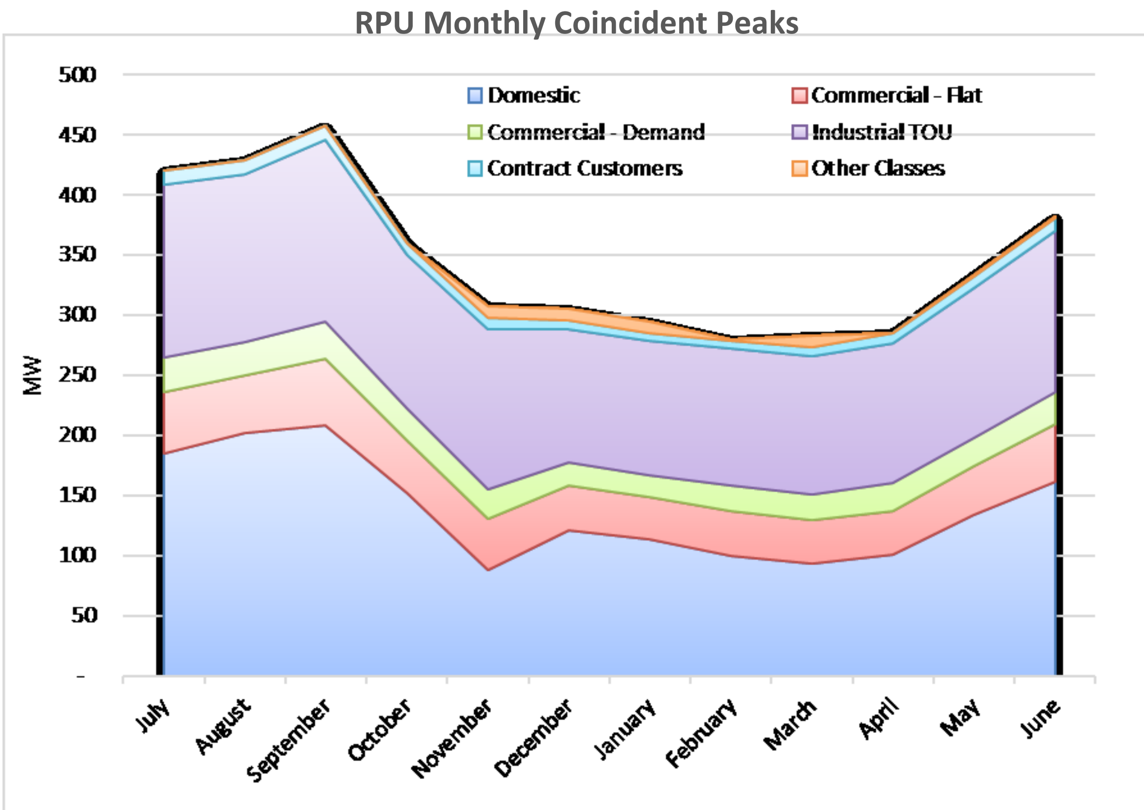

Figure 4-1. 4 CP Demand Cost Allocation

As provided in Figure 4-1, the peak demand months for RPU typically occur in June, July, August, and September. The peak demand is primarily driven by the increase in electricity usage by the Domestic class.

4 NCP Method

The NCP demand allocation method is based on the theory that demand costs are strongly influenced by the highest demand of each customer class, regardless of when that class peak demand occurs. NCP demand allocators are primarily used to allocate transmission and distribution-related costs, because the design of these facilities is more consistent with the demand of the classes, rather than the demand of the entire system. A 4 NCP is used to allocate distribution demand-related costs for RPU (see Table 4-3).

Table 4-3
4 NCP Cost Allocation

Customer Class	4 NCP (MW)	Allocation (%)
Domestic	802	40.0%
Commercial – Flat	268	13.4%
Commercial – Demand	142	7.1%
Industrial TOU	716	35.7%
Contact Customers (1)	54	2.7%
Other Classes (2)	21	1.1%
Total System (3)	2,003	

(1) As Contract customers are moved to OAT, their allocated costs are moved as appropriate.

(2) Other classes include street lights.

(3) Based on Test Year.

Energy Allocation Factors

Energy allocation factors are the basis for apportioning those costs or expenses classified as variable or energy-related and assumed to vary directly with the level of kWh sales or generation. The costs classified herein as variable or energy-related are fuel and the variable portion of other production expenses.

Total Energy Sales are used to allocate energy-related costs; cost allocations are based on customers' consumption of energy in kWh. For this analysis, Total Energy Sales is used to allocate energy-related production costs (See Figure 4-2 and Table 4-4). In Figure 4-2, the left side of the figure represents the allocated costs by major customer class (the blue bars) in thousands of dollars. The right side (the red line) represents the total energy (in MWh, or 1,000 kWh).

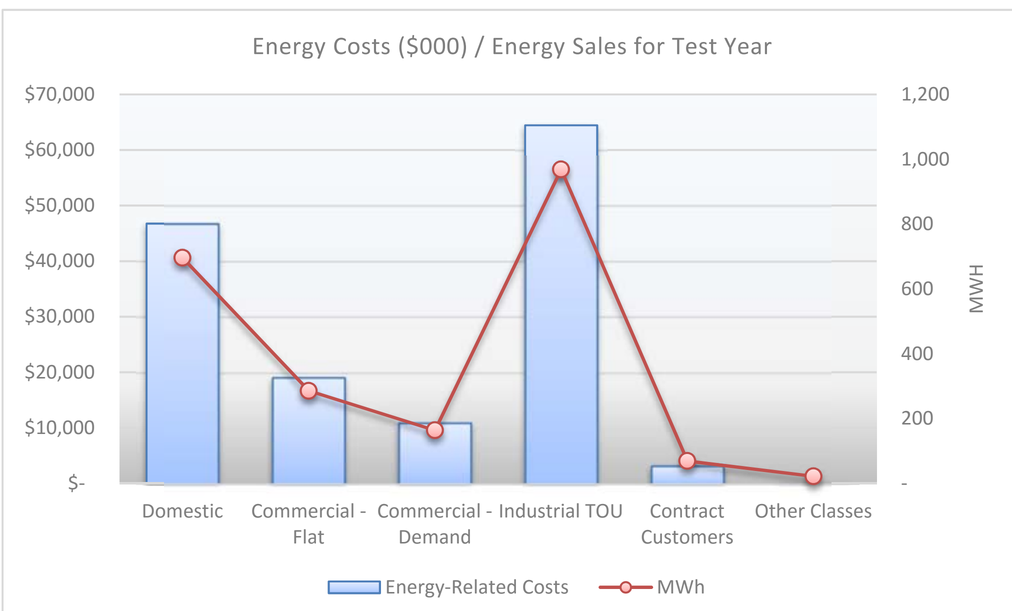

Figure 4-2. Allocation of Energy Costs based on MWh Sales

Table 4-4
Energy Cost Allocation

Customer Class	MWh Sales	Allocation (%)
Domestic	696,137	31.6%
Commercial – Flat	285,755	13.0%
Commercial – Demand	164,025	7.4%
Industrial TOU	968,601	43.9%
Contract Customers (1)	69,219	3.1%
Other Classes (2)	22,056	1.0%
Total	**2,205,794**	

(1) As Contract customers are moved to OAT, their allocated costs are moved as appropriate. Allocated prior to elasticity impacts, see text.

(2) Other classes include street lights.

Customer Allocation Factors

Customer costs are defined herein as those costs related to the number of customers and the size of service required. Included in the customer-related costs are the costs associated with meter reading, meter maintenance, customer installations, billing, collecting, and other customer-related accounting, service, and information functions. The customer allocation factors developed for this Study were based on the projected average number of customers in each class during the Test Year.

In allocating customer-related costs and revenues to the various customer classes, customer allocation factors were utilized that recognized weighted and un-weighted number of customers by class. The un-weighted factors are simply the number of customers. The weighted customer allocation factor is based on the number of customers in a particular class times a weighting factor. The weighting factors were developed based on the estimated costs associated with serving non-domestic customer classes; recognizing that serving these customer classes is more expensive on a per-customer basis than domestic classes.

Adjustments to Allocation Factors

Other adjustments were made to specific customer classes recognizing their unique characteristics, either defined by their usage, contracts, or accounting. A summary of these adjustments is provided below.

High Voltage Customers

Some customers on the RPU system take service at a "high-voltage" level; they either use that energy at that voltage or own their own voltage regulating equipment. Because these customers are not utilizing the entirety of RPU's distribution system (they are only using the "primary" system, not the "secondary" or lower voltage system), they should not be assigned the costs associated with the entire distribution system. Therefore, the cost allocation has been adjusted for the Industrial TOU class (the class in which these customers exist) to recognize this reduction in cost causation.

The resulting rate design for a High-Voltage Adjustment is presented in Section 6 of this Report.

City Contract

The City has a unique contract with its electric utility that includes all of its metered accounts. This contract specifies the amount that the City will pay to RPU for service, based upon production (energy) services to the City from "designated resources." Specifically, these resources include the Hoover Hydroelectric Project, the Intermountain Power Project, and the Palo Verde Nuclear Generating Station. A cost differentiation associated with the designated resources identified in the City contract as compared to the other resources in RPU's power supply portfolio has been determined. Additionally, professional Utility staff provide services for scheduling electricity from the California market to neighboring utilities for a fee. Fees are utilized to offset the City's allocated costs. These cost differentiations are used to create an adjusted cost allocation utilized in this Study, as an adjustment to the standard cost allocation methods identified herein.

Other

Other adjustment factors utilized during the cost allocation process include the use of direct assignment for street lighting. RPU operates and maintains the City's street lighting system, and recovers the cost for such operation and maintenance (O&M) (including electricity) through a specific rate tariff. The direct assignment for street lighting includes assigning costs that are categorized as street lighting related directly to street lighting, to ensure that other customer classes are not allocated those costs.

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Section 5
ALLOCATED COST OF SERVICE

General

As one of the factors considered in the evaluation of RPU's existing retail rate levels and rate structures included herein, certain analyses have been employed that provides a reasonable indication of the revenue required by RPU's major customer classes, which include the following:

- Domestic
- Commercial – Flat
- Commercial – Demand
- Industrial TOU
- Street Lighting
- Other

Allocation and Assignment of Cost of Service

The results of the cost allocation analysis are presented in Table 5-1, along with a comparison of the cost recovery currently projected for the Test Year under existing retail rate structures.

Table 5-1
Existing Test Year Rate Revenues vs Test Year Revenue Requirements ($000)

Customer Class	Test Year Existing Rate Revenue (1)	Test Year Revenue Requirement	Difference
Domestic	$113,556	$136,807	$23,251
Commercial – Flat	47,153	45,902	(1,251)
Commercial – Demand	24,879	23,760	(1,119)
Industrial TOU	111,694	126,082	14,388
Street Lighting (2)	4,647	4,824	177
Other (3)	7,317	8,170	852
Total (4)	**$309,248**	**$345,545**	**$36,297**

(1) Based on existing rates and Test Year (five-year average) billing determinants.
(2) Street Lighting includes Customer Owned and Department Owned.
(3) Includes Contract Customers and other rate classes, see text for details.
(4) Totals may not add due to rounding.

According to the results of this Study, RPU's Domestic, Industrial TOU, and Other Customer rates are below the costs RPU incurs to serve these customers, and Commercial – Flat and Commercial – Demand are above the COS. Street Lighting customers are generally in-line with RPU's costs to serve. The difference between the Test Year existing rate revenue projections and the Test Year Revenue Requirements helps drive cost recovery by customer class in the rate design process.

Cost of Service Process

The COS process is an industry accepted framework that assigns or allocates costs to each customer class served by a utility. This process determines the "cost to serve" each customer class within the utility. Electric utility costs are typically characterized as either fixed or variable; fixed costs are those that do not change with the production of electricity, whereas variable costs are directly related to the amount of electricity produced and/or purchased. These costs are typically further characterized as those that are demand-based, customer-based, and energy-based.

Demand-based Costs

Most of an electric utility cost structure are demand-based costs. Demand-based costs are associated with fixed costs related to existing and future investments made to produce, transmit, and deliver electrical power from the generation resources to its customers. For RPU, these costs include the debt service associated with its generation, transmission, and distribution assets, as well as a portion of its contracts for purchased power. The labor and materials associated with the O&M and administration of these systems are also demand-based costs, as the labor costs are typically fixed in the short-term (budget cycle). In the short-term, fixed costs do not change and represent the on-going costs to meet the needs of the utility. Fixed costs are allocated primarily to the demand in the COS process because they are designed to support to the system as a whole. This means that as a result of the COS process, these costs are assigned based on the electric demand (measured in kilowatts, or kW) that a specific customer or customer class places on the system. RPU, like most utilities, has a cost structure that is highly fixed, which is typical of highly capital intensive entities.

Customer-based Costs

Customer-based costs for electric utilities are fixed costs as well, but are costs incurred in direct support of the customers served by a utility. For RPU, this includes the costs associated with the labor, equipment, and investments for customer accounting, billing, and customer assistance (call centers). Additionally, a portion of A&G costs are allocated to the customer-related costs, as they are designed to support this function for RPU. During the COS process, these costs are allocated by the number of customers within a class.

Energy-based Costs

Energy-based costs for electric utilities are typically variable costs that change with the fluctuations in electric load. The primary example of energy-related costs for RPU are its fuel and purchased power costs. During the COS process, these are allocated to the customer classes by the amount of energy they are projected to utilize within a selected period of time (during the Test Year).

Retail Rate Review

Background information on the existing rate structure of RPU's major customer classes is presented below. This includes a comparison of the existing rates to the COS-based rates and a description of the development of cost curve. These elements were considered for the individual customer class rate proposals provided in Section 6 of this Report.

The proposed NAC, more fully discussed in Section 6, is a mechanism to recover a portion of the fixed demand-related costs associated with use of the electric distribution system. The NAC is designed to recover these costs in the form of a monthly charge for Residential and Commercial – Flat customers, which is tiered based on the amount of energy used within a month. For Commercial – Demand and Industrial TOU customers, the NAC is a demand charge recovered on a $/kW basis.

Domestic

Table 5-2 provides a summary of RPU's existing Domestic class rates, compared to the COS-based rates developed for this Study. The existing rate includes an $8.06 per month customer service charge and a tiered energy rate. The tiered energy rate is the same for summer and winter; however, the requirements for the tier change between the seasons. The summer Tier 1 is monthly energy usage from 0–750 kWh, Tier 2 is for 751–1,500 kWh, and Tier 3 is for energy used over 1,500 kWh. The winter Tier 1 is from 0–350 kWh, Tier 2 is for 351–750 kWh, and Tier 3 is for over 750 kWh.

Table 5-2
Domestic Rates
(Existing and Cost of Service)

Rate Component	Existing	COS	COS – Energy (1)
Customer ($/month)	$8.06	$13.31	$13.31
Demand ($/kW)	--	$19.25	--
Energy ($/kWh) (2)			
Tier 1 (0–750 S; 0–350 W)	$0.1035	$0.0670	$0.1739
Tier 2 (751–1,500 S; 351–750 W)	$0.1646	$0.0670	$0.1739
Tier 3 (>1,500 S; >750 W)	$0.1867	$0.0670	$0.1739
Reliability Charge ($/month) (3)			
Small Residence (<100 Amp)	$10.00	--	--
Medium Residence (101-200 Amp)	$20.00	--	--
Large Residence (201-400 Amp)	$40.00	--	--
Very Large Residence (>400 Amp)	$60.00	--	--

(1) Assumes no Demand Charge and bundles demand-related costs within the Energy Charge.

(2) The tiered rates are the same for summer / winter (S/W); however, the characteristics of the tier change with season. See text for details.

(3) The Reliability Charge varies by the size of the customer (measured by the electric panel in Amps), and the costs are included in the Demand COS Charge.

The tiers have been established to reduce the bill impact for customers that use more energy during the three-month summer period (June 16th through September 15th). Because the rates are the same for the tiers, a customer is paying the lower tier rate for more energy (kWh) during the summer than in the winter. For the purposes of this analysis, the impact of state surcharges, including the Public Benefits Charge, are ignored because these changes presented costs that are beyond RPU's control and are structures mandated by state regulations. Any new rates and rate structures will include these surcharges.

Table 5-2 provides a summary of the rates derived from the COS analysis. This includes a customer charge of \$13.31/month, a demand rate of \$19.25/kW, and an energy rate of \$0.0670/kWh. The COS-based customer charge represents the sum of the costs of metering, billing collections, customer service, and an allocated portion of the distribution system costs on a per customer per month basis. The demand charge represents the cost associated with production, transmission, and the non-customer portion of the distribution system (this includes the investment cost, as well as the fixed costs for operating and maintaining these systems). The costs associated with the projects identified for the “Reliability Charge” are included in the demand component of the COS analysis; however, these costs are collected in the Reliability Charge (the revenues from this charge are dedicated to those projects identified to enhance the system reliability).

For the Domestic class, the customer-related costs to serve each customer is \$13.31/month; however, RPU’s existing rate structure includes a charge of \$8.06/month for this service. Therefore, the remaining customer-related costs are included in the energy rate. Additionally, it costs RPU approximately \$19.25/kW of demand-related costs to serve Domestic customers; these costs are also recovered in the existing energy rates. The Reliability Charges recover a portion of the fixed costs that are included in the \$19.25/kW demand calculation. RPU’s energy costs are \$0.0670/kWh (not adjusted for tiered costs); however, as a result of a lower customer charge and no demand charge, the existing energy rate is higher than RPU’s “pure” energy costs. RPU’s energy rates are tiered to encourage conservation; the more energy used by Domestic customer, the higher the “per unit” rate (\$/kWh).

It is important to note that RPU’s Domestic – and most Commercial – Flat customers do not have a demand meter (which is capable of measuring both energy and demand at the customer’s location). As indicated previously, RPU’s Commercial – Demand and Industrial TOU customers do have a demand meter and are billed on their monthly demand. Most electric utilities have not installed demand meters at residential customer locations because of the costs (demand meters have historically been more expensive than energy-only meters). However, as part of the Utility 2.0 Plan, RPU intends to install meters at residential and commercial locations that are capable of reading demand. While this effort will likely begin during the next five years, demand rates for residential and Commercial – Flat customers are not proposed for the Five-Year Rate Plan.

Therefore, Table 5-2 includes a column for the COS that shifts the demand costs to the energy rate. This data is based on the COS analysis and recognizes that Domestic customers are not charged on a demand basis (\$/kW). As indicated, Domestic customers do incur these costs; however, they are recovered from the energy rate (\$/kWh). Therefore, this table provides an “adjusted COS-based energy rate,” which includes appropriate demand costs, and has been calculated to be approximately \$0.1739/kWh (not adjusted for the tiered structure). Note that the customer costs for this COS-Energy column are still \$13.31/month; compared to the existing rate of \$8.06/month.

The proposed Domestic rates discussed in Section 6 recognize the existing and COS rates, as well as the specific rate proposal. It is important to understand that the proposed rates are designed to generate the Revenue Requirements for the customer class (as identified in Table 5-2). These rate components are designed to recover the Revenue Requirement, as adjusted, for the entire customer class, not for each component. As mentioned, RPU does not intend to require demand rates for the Domestic customer class within this Five-Year Rate Plan; therefore, the demand-related costs must be recovered from a combination of the customer charge, the Reliability Charge, and the proposed NAC, as well as the energy rate.

Domestic Cost Curve

Figure 5-1 provides an illustration of a "cost curve" for RPU's Domestic customer class. A cost curve represents the total costs ($) to serve a customer within a specific rate class over a range of monthly energy usage. The total costs are divided by the total monthly energy usage (in kWh) to calculate an "all-in" cost ($/kWh) to serve customers. A cost curve is a convenient tool to understand how unit costs (all-in $/kWh) for fixed cost industries (such as electric utilities) behave. If the customer is using only very small amounts of energy in a month, the all-in costs are high, because of the high fixed costs. However, if the customer is using large amounts of energy in a month, the fixed costs are spread over more energy, so the all-in costs are lower. This is why the cost curves for RPU (and generally speaking, any utility), have the characteristic shape of a high "tail"" end on the left, then a rapidly decreasing shape that eventually becomes flatter towards the right end.

Cost curves are useful in rate design to allow a comparison of how rates and rate structures compare to a utility's costs. For the example in Figure 5-1, the Existing Rate curve is a representation of RPU's existing Domestic rate (the Customer Service charge, the tiered energy charge, and the Reliability Charge). This rate curve has been calculated over a series of usage levels using a "blended month" that represents the impacts of the existing summer and winter rate schedules. Because of the relatively low fixed charge and the relatively high-tiered energy charges for the existing rate, the "all-in" existing rate curve is lower in the front end and slowly gets higher in the tail end, which is the inverse of the cost curve. This supports increases in the fixed cost recovery rate mechanisms in the Domestic customer class.

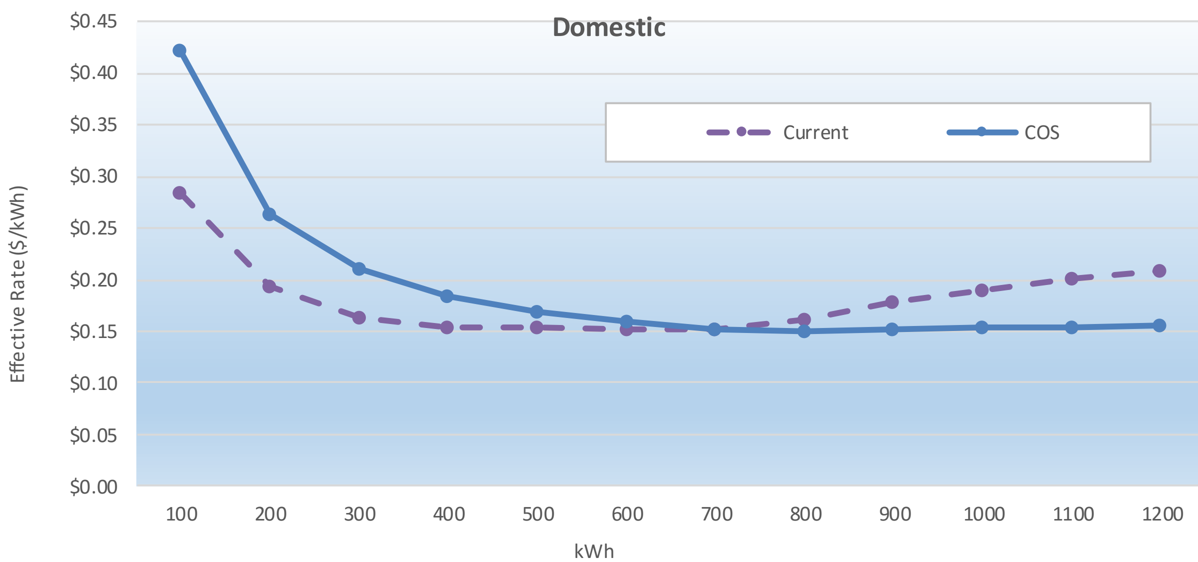

Figure 5-1. Cost Curve for Domestic Rate

Non-Domestic/Commercial Rate Review

Similar to the information provided for the Domestic customer class, the following provides a summary of the existing Non-Domestic/Commercial customer class rates compared to the COS analysis. Each sub-section details the three major customer classes; Commercial – Flat, Commercial – Demand, and Industrial TOU. Other rate classes are discussed at the end of this Section.

Commercial – Flat

The Commercial – Flat customer class represents businesses that are relatively low energy users and are not subject to a demand charge. Examples of Commercial – Flat customers may include a doctor's office, a retail commercial store (within minimal load), or a small office building. The applicability for this rate class (which defines the characteristics of this customer class) includes any "commercial" energy use with a monthly maximum demand not exceeding 20 kW in any 2 of the preceding 12 months. If that threshold is exceeded, the customer is moved to the Commercial – Demand rate (note, for larger Commercial – Flat customers, RPU typically installs a demand meter to monitor usage in the event that they may need to "move-up" to the next rate class (Commercial – Demand)).

According to RPU's tariff schedule, these customers are receiving service under "Schedule A – General Service," under the terms of the "Flat Rate." These include a customer charge of $20.50 per month, a tiered Reliability Charge (tiered by energy), and a tiered energy charge that is non-seasonally differentiated. Table 5-3 provides a summary of RPU's existing Commercial – Flat rates, compared to the COS-based rates. As with the Domestic rates, the impact of state surcharges, including the Public Benefits Charge, is ignored because these changes presented costs that are beyond RPU's control and are structures mandated by state regulations. Any new rates and rate structures will include these surcharges.

Table 5-3 also provides a summary of the rates derived from the COS analysis. This includes a customer charge of $33.17/month, a demand rate of $24.02/kW**,** and an energy rate of $0.0670/kWh. The customer charge represents the costs of metering, billing collections, customer service, and a minimum system connection. The demand charge represents the cost associated with production, transmission, and the non-customer portion of the distribution system (this includes the investment cost, as well as the fixed costs for operating and maintaining these systems). As with the Domestic rates, the costs associated with the projects identified for the Reliability Charge are included in the Demand component of the COS analysis; however, these costs are collected from the Reliability Charge.

As indicated, the Commercial – Flat customers do not have a demand meter (which is capable of measuring both energy and demand at the customer's location). However, similar to the Domestic customer class and as part of the Utility 2.0 Plan, RPU intends to install meters at all commercial customer locations that are capable of reading demand. While this effort will likely begin during the next two years, demand rates for the Commercial – Flat customers are not proposed for the Five-Year Rate Plan.

Table 5-3
Commercial – Flat Rates
(Existing and Cost of Service)

Rate Component	Existing	COS	COS – Energy [(1)]
Customer ($/month)	$20.50	$33.17	$33.17
Demand ($/kW	--	$24.02	--
Energy ($/kWh)			
Tier 1 (0-15,000 kWh)	$0.1351	$0.0670	$0.1457
Tier 2 (>15,000 kWh)	$0.2064	$0.0670	$0.1457
Reliability Charge ($/month)			
Tier 1 (0-500 kWh)	$10.00	--	--
Tier 2 (501–1,500 kWh)	$30.00	--	--
Tier 3 (>1,500 kWh)	$60.00	--	--

(1) Assumes no Demand Charge and bundles demand-related costs within the Energy Charge.

Commercial – Flat Cost Curve

Similar to the Domestic rate class review, a cost curve comparison to the existing rate curve for the Commercial – Flat customer class is represented in Figure 5-2. This shows the relationship between the COS and existing rate recovery (including the tiered Reliability Charge) for a wide range of monthly usage characteristics for this class. Commercial customers, including those within the Commercial – Flat customer class, tend to exhibit a wide range of monthly energy usage within the class, given that customers may include very small applications (such as timers for water sprinkler systems), as well as much larger monthly energy usage (such as a small restaurant or business office).

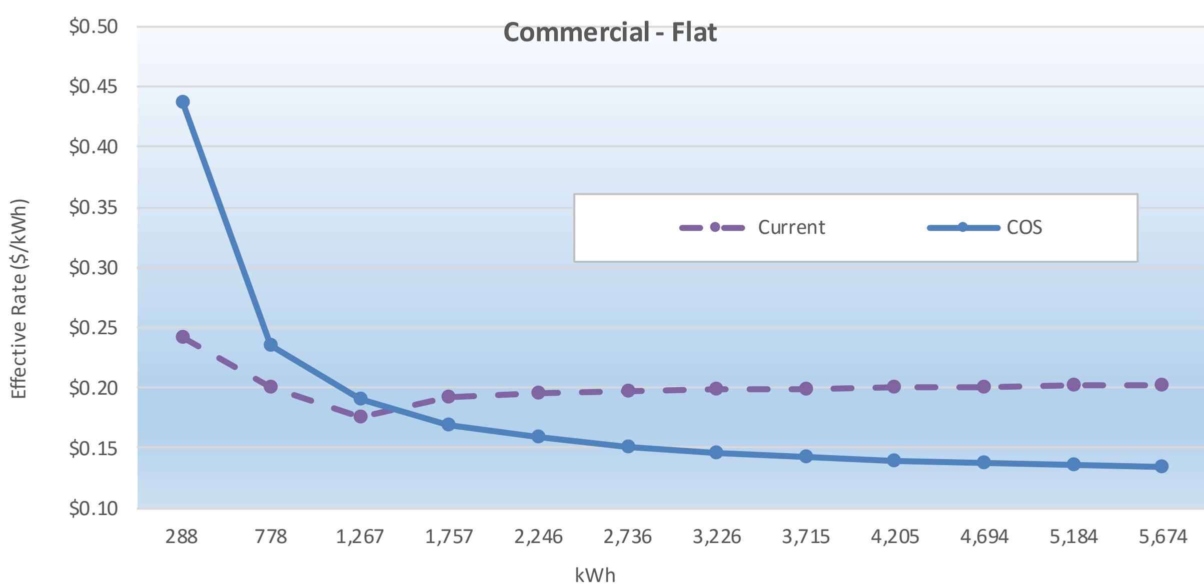

Figure 5-2. Cost Curve for Commercial – Flat Rate

Commercial – Demand

The Commercial – Demand customer class represents businesses that are relatively higher energy users and are subject to a demand charge. Examples of Commercial – Demand customers may include a medium sized restaurant, office building, or retail commercial store. The applicability for this rate class includes any "commercial" energy use with a billing demand equal or exceeding 20 kW, but less than 150 kW in any 2 of the preceding 12 months. If that threshold is exceeded, the customer is moved to the Industrial TOU rate.

According to RPU's tariff schedule, these customers are receiving service under "Schedule A – General Service," under the terms of the Demand Rate. These terms include a flat Reliability Charge ($90 per month), a tiered demand charge (the first 20 kW of demand are charged a flat rate of $209.65, above which demand is charged $10.48/kW), and a tiered energy charge that is not seasonally differentiated. The tiered demand charge is a common rate structure that essentially acts as a "minimum bill" for customers in this rate class, and is mathematically determined by the sum of the $10.48/kW times the minimum monthly 20 kW.

Table 5-4 provides a summary of RPU's existing Commercial – Demand rates compared to the COS-based rates developed. This includes a customer charge of $53.02/month, a demand rate of $23.55/kW, and an energy rate of $0.0670/kWh. The customer charge represents the costs of metering, billing collections, customer service, and a minimum system connection. The demand rate represents the cost associated with production, transmission, and the non-customer portion of the distribution system (this includes the investment cost as well as the fixed costs for operating and maintaining these systems). The costs associated with the projects identified for the Reliability Charge are included in the Demand component of the COS analysis.

Table 5-4
Commercial – Demand Rates
(Existing and Cost of Service)

Rate Component	Existing	Cost of Service
Customer Charge	--	$53.02
Demand Charge		
Fixed - First 20 kW	$209.65	$471.09
Excess - Per kW	$10.48	$23.55
Energy Charge		
First 30,000 kWh	$0.1111	$0.0670
All Other kWh	$0.1217	$0.0670
Reliability Charge	$90.00	--

Commercial – Demand Cost Curve

Because these customers are measured by their demand on the system (i.e. the peak hour of energy usage during a month is their billed demand). To effectively review cost and rate relationships, such customers are often compared across a range of load factors.

A load factor is the ratio of a customer's energy (in kWh) to its peak demand (in kW) over a period of time. The period of time may be a month (approximately 720 hours), or even a year (8,760 hours). The load factor is the energy (kWh) divided by the product of the demand (kW) times the number of hours (h);

therefore, load factor is expressed as a percent (as it is the ratio of kWh / (kWh)). Load factor is a measure of efficiency; the higher the load factor (closer to 100%), the more efficiently a customer is using its demand. An electric system can also have a load factor, which is a measure of how efficiently it is using its investments (in demand).

A simplified example is a customer with one single 60-watt light bulb (and no other electric load). If that customer leaves the light bulb on all day, for 24-hours a day, and 7 days a week, then the load factor is 100%. However, if that customer only leaves the light on for 12 hours a day, the load factor is 50%. Generally, utilities will try to encourage customers to have a higher load factor, as that increases the load factor for the system and suggests that the utility is efficiently utilizing its investments.

A cost curve comparison to the existing rate curve for the Commercial – Demand customer class is represented in Figure 5-3. This shows the relationship between the COS and existing rate recovery (including the Reliability Charge) for a wide range of monthly usage characteristics (or load factors) for this class.

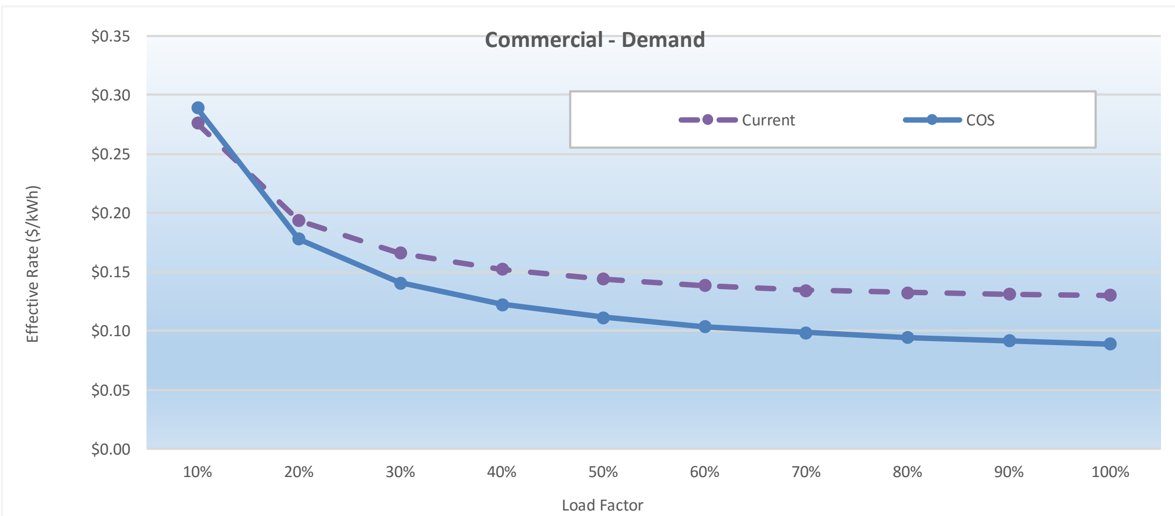

Figure 5-3. Cost Curve for Commercial – Demand Rate

Figure 5-3 assumes an "average" demand of 56 kW per month (based on information provided by RPU). The relationship between the existing rates and the COS is applicable only to the average customer in this class. Larger customers (greater than 56 kW) and smaller customers (less than 56 kW) will have a different relationship to costs, although the shape of the cost curve will essentially remain the same.

Industrial TOU

The Industrial TOU customer class represents businesses that are large energy users and are subject to a time differentiated demand and energy charge. Examples of Industrial TOU customers may include a large restaurant, a large sized office, or a large retail commercial store. The applicability for this rate class includes any customers whose service is designed for a 150 kW load or greater, or whose monthly demand level is equal to or exceeding 150 kW for any 2 of the preceding 12 months.

According to RPU's tariff schedule, these customers are receiving service under "Schedule TOU Large General and Industrial Service." These terms include a customer charge of $704.66 per month, a flat Reliability Charge ($1,100 per month), and a time differentiated demand and energy charge. The time periods include "On-Peak," "Mid-Peak," and "Off-Peak." On-Peak is defined as 12:00 p.m. to 6: 00 p.m. summer weekdays, and 5:00 p.m. to 9:00 p.m. winter weekdays (excluding holidays). The Mid-Peak is defined as 8:00 a.m. to 12:00 p.m. and 6:00 p.m. to 11:00 p.m. summer weekdays, and 8:00 a.m. to 5:00 p.m. winter weekdays (excluding holidays). The Off-Peak period is defined as all other hours (including holidays). The summer period is defined as June 1st through September 30th, and the winter period is the remaining eight months of the year. Customers in this class have time-differentiated demand and energy meters that are able to log and provide 15-minute interval load data.

Table 5-5 provides a summary of RPU's existing Industrial TOU rates, compared to the COS-based rates. This includes a customer charge of $192.01/month, a demand rate of $28.72/kW (On-Peak), and an energy rate of $0.0664/kWh (On-Peak). The On-/Mid-/Off-Peak rates for the COS analysis was determined from an evaluation by RPU of its existing and projected production costs. The customer charge represents the costs of metering, billing collections, customer service, and a minimum system connection. The demand rate represents the cost associated with production, transmission, and the non-customer portion of the distribution system (this includes the investment cost, as well as the fixed costs for operating and maintaining these systems). The costs associated with the projects identified for the Reliability Charge are included in the Demand component of the COS analysis.

Table 5-5
Industrial TOU Rates
(Existing and Cost of Service)

Rate Component	Existing	Cost of Service
Customer Charge	$704.66	$192.01
Demand Charge ($/kW) (1)		
On-Peak	$6.88	$28.72
Mid-Peak	$2.74	--
Off-Peak	$1.31	--
Energy Charge ($/kWh)		
On-Peak	$0.1033	$0.0664
Mid-Peak	$0.0828	--
Off-Peak*	$0.0727	--
Reliability Charge	$1,100	--

(1) See text for discussion of time differentiated COS rates.

Industrial TOU – Cost Curve

A cost curve comparison to the existing rate curve for the Industrial TOU customer class is represented in Figure 5-4. This shows the relationship between the COS and existing rate recovery for a wide range of load factor characteristics for this class (see discussion in Commercial – Flat for explanation of load factor). For the purposes of this graph, the cost and rate curves represent a "blended" month of the On-/Mid-/Off-Peak demand and energy rates (assuming a demand of 692 kW and varying levels of energy, represented by the range of load factors). The existing Reliability Charge is included in the current rate. It should be noted that the relationship between the existing rates and the COS is applicable only to a customer in this class with 692 kW demand per month. Larger customers (greater than 692 kW) and smaller customers (less than 692 kW) will have a different relationship to costs, although the shape of the cost curve will essentially remain the same.

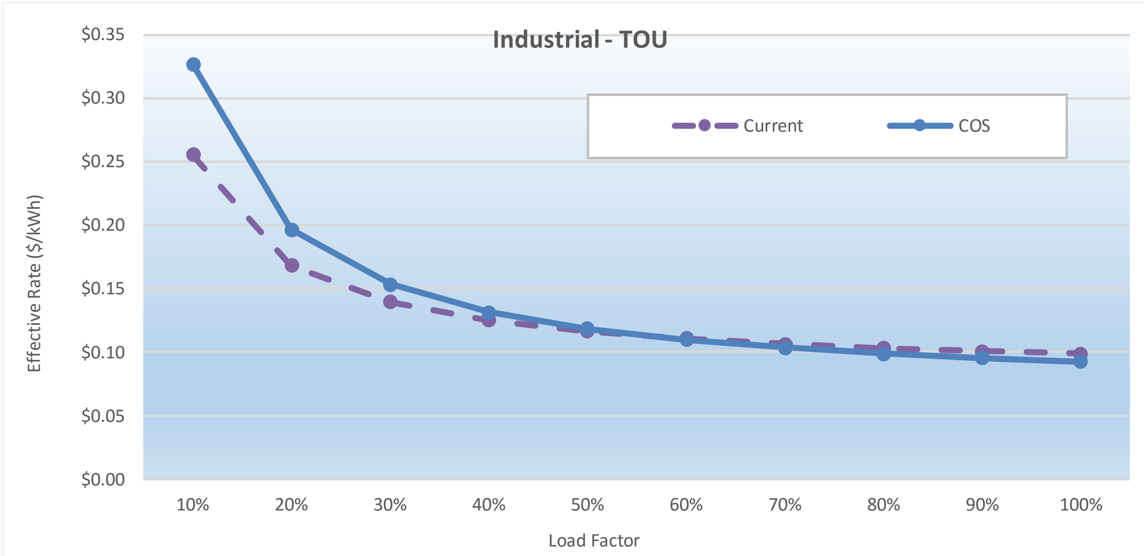

Figure 5-4. Cost Curve for Industrial TOU Rate

TOU Price Differentiation

RPU provided an analysis of the cost differential for its generation resources by TOU, which aligns with the periods within the Industrial TOU rate (see Section 6 for specific time periods). Generally, these periods are defined as On-Peak, Mid-Peak, and Off-Peak. For RPU's system, and most utility systems, only the generation function includes pricing that varies by TOU; the transmission, distribution, and customer functions do not vary by time, as they are primarily fixed costs. For generation assets in general, resources associated with peak load (referred to as peaking resources) have historically been more expensive to operate than base load resources (which typically have continuous, or near continuous, operations). Peaking resources are typically smaller and less expensive than base load resources; however, because the peaking resource runs less frequently, there are few operating hours over which to recover the fixed or capacity costs of the unit.

RPU's analysis suggest that on a fixed and variable costs, there is a cost differential between the resources that support the On-Peak, Mid-Peak, and Off-Peak load. This cost differential was analyzed as a ratio to the On-Peak costs. Therefore, if On-Peak costs were set to be the basis, the Mid-Peak and Off-Peak can be determined to be a discount to the On-Peak costs. For the purposes of this Study, the variable Mid-Peak costs were determined to represent approximately 94% of the costs of the On-Peak resource (an approximate 6% discount). The variable Off-Peak costs were determined to represent approximately 69% of the On-Peak costs (an approximate 31% discount).

For the fixed production costs, Mid-Peak costs were determined to represent approximately 49% of the costs of the On-Peak resource (an approximate 51% discount). The fixed Off-Peak costs were determined to represent approximately 32% of the On-Peak costs (an approximate 68% discount). This information was used to assist in the development of the proposed Industrial TOU energy (variable cost recovery) and demand (fixed cost recovery) rates. See Appendix B for detailed information on cost differentials for TOU periods. As noted, adjustments to the ratio of On-/Mid- and On-/Off-Peak periods were made as necessary to collect the allocated revenue from this class (see Section 6).

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Section 6
PROPOSED RATES

General

As previously noted, rate design is the end result of a COS study, in which the cost recovery mechanisms (rates and charges) for each customer class are established. Rates and charges are set for each customer class to collectively meet the utilities Revenue Requirement, as well as to address specific policy goals and objectives as determined by RPU. For the purposes of this Study, the following rate design objectives were considered during the rate design process, which are inclusive of the rate making principles established by RPU and discussed in Section 1 of this Report.

RPU's rates are designed to follow the subsequent principles:

- Achieve full recovery of costs.
- Equitably allocate costs across and within customer classes.
- Encourage efficient use of water and electricity.
- Provide rate stability.
- Offer flexibility and options.
- Maintain rate competitiveness in the region.
- Be simple and easy to understand.

The recovery of the projected Revenue Requirements is the primary objective of rate design. This means that the specific components of the rates for each customer class must be paired with their respective projected billing determinants (in the form of energy, demand, and number of customers) to collect sufficient revenues for RPU to maintain operations and fund its historic and planned capital investments (including those identified in its Utility 2.0 Plan).

RPU has expressed an interest in increasing the portion of fixed cost recovery in its rates. This is proposed due to the "misalignment" in its existing rate structures relative to its costs structures, as previously discussed. In an era of constant load growth, the recovery of fixed costs through variable (energy) rates made sense and was commonplace in the industry. However, RPU (and many other utilities in California and elsewhere) have experienced reductions in customer energy consumption and demand over the recent past due to poor economic conditions and increases in energy efficiency, conservation, and customer self-generation. As sales decrease, but costs remain the same (or increase), the fixed cost recovery issue becomes critical for utilities. One partial solution is to increase the fixed components of existing rate structures, or introduce new fixed cost recovery rate structures, while adjusting the energy-only rates of customers.

A related objective is to consider and mitigate the overall bill impacts associated with low-use customers. While increasing the fixed charges reduce the revenue risk for RPU as a whole, such increases tend to impact low-use customers more than high-use customers. This is because the energy-only portion of a low-use customer's bill is a smaller percentage than that for a high-use customer. Therefore, on a total unit basis (total dollars for the bill divided by the total energy consumed, $/kWh), the relative increase in fixed charges represents a higher increase for low-use customers than high-use customers.

An objective established by RPU is to recognize and reduce impacts associated with customers that transition between rate classes. For commercial rate classes, and specifically for Commercial – Demand, there is a concern about the rate impacts of customers that shift between rate classes during the year. For example, the Commercial – Demand customers will be placed in the Industrial TOU rate class if their demand exceeds 150 kW in two months during the year. Therefore, RPU has proposed to make adjustments to the demand- and energy-related costs, as well as the Reliability Charge, to reduce the likelihood of such a transition resulting in a significant rate change. This objective has been established based on feedback RPU has received from its Customer Relations group.

RPU is proposing to change some of its retail rate structures to reflect its costs and policy objectives. For some rate classes, the existing rate structures will change to reflect increased cost allocation to the class, including introduction of the NAC. These rate classes are primarily the "minor" RPU rate classes (such as Agricultural Pumping and Wind Machines Frost Protection, see Table 6-1), with relatively few customers and relatively little revenue. Similarly, RPU is proposing to maintain the structure, with the addition of the NAC, for its existing rate programs, including its All Electric and Multi-family rates, as described herein.

Current Rate Classifications

As of the time of this Study, RPU has 14 rate schedules in effect and has not raised these rates since 2010. A summary of the current rate schedules and their customer classes is provided in Table 6-1:

Table 6-1
Current Rate Schedules and Customer Class

Rate Schedule	Rate Code	Customer Class
Domestic Service	Schedule D	Domestic (Residential); DTOU Tiered, All Electric, Electric Water Heater, Multi-family
General Service	Schedule A - Flat Rate	Commercial – Flat (Small Commercial, No Demand Charge); Includes Non-Metered Commercial, Schedule PW-1
General Service	Schedule A – Demand	Commercial – Demand (Medium Commercial)
Large General & Industrial	Schedule TOU	Industrial TOU; Includes customers moved from Contract Service and Schedules BR, ED, TED, and S (as applicable)
Contract Service	Schedule CS	Contract Customers
Street Lighting – City	Schedule LS-1	Department Financed Street Lights
Street Lighting – Customer	Schedule LS-2	Customer Financed Street Lights
Outdoor Lighting – City Owned	Schedule OL	Department Financed Outdoor Lights
Traffic Control	Schedule TC	Traffic Lights; Includes City Owned and Cal-Trans (State Owned)
Agricultural Pumping	Schedule PA	Other Classes
Wind Machines Frost Protection	Schedule PW-1	Commercial – Flat (Small Commercial, No Demand Charge)
Economic Development Rate	Schedule ED	Contract Service
Net Energy Metering	Schedule NEM	Other Applicable Tariff (depending on Customer)
Stand By Service	Schedule S	Contract Service

Existing and Proposed Fixed Cost Recovery

As with most utilities, RPU operational costs are primarily fixed and include debt service, labor, and investments in equipment. Variable costs are primarily related to fuel and purchase power. However, RPU is typical of many electric utilities in that it currently recovers the majority of its fixed costs from the variable portion of its rate structures (the energy charge or cents per kWh). Figure 6-1 provides a summary of the fixed cost recovery (defined as revenue from customer charges) compared to the variable cost recovery. As shown in Table 5-2 for existing Domestic rates, this non-alignment between costs, cost causation, and the revenue recovery results in customer energy charges that are higher than the COS and fixed charges that are lower than the COS. However, by not pricing the fixed rates at the costs incurred by RPU, the rates can send improper price signals to customers and encourage inefficient use of the system resulting in poor load factor (as discussed in Section 5), which under-utilizes RPU's assets. Additionally, higher energy rates can encourage customers to install distributed generation resources to avoid energy-only charges. This can result in higher costs for customers that do not install distributed generation resources.

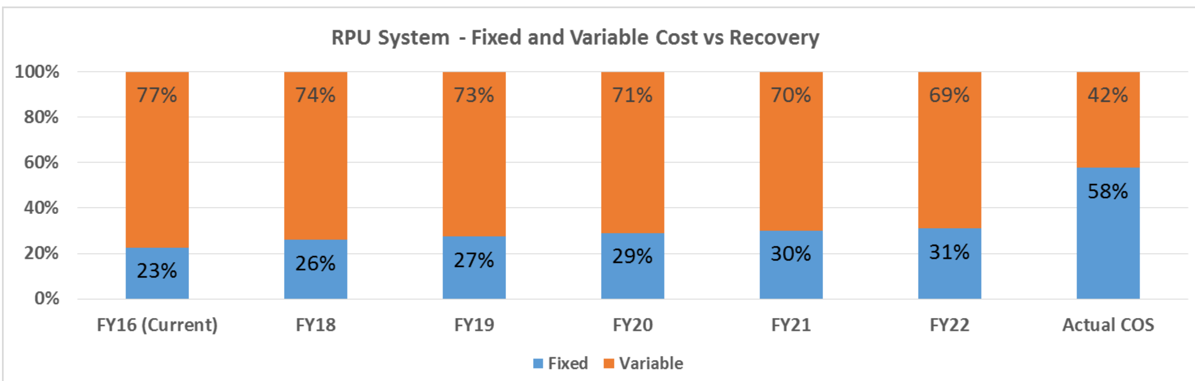

Figure 6-1. Fixed and Variable Cost vs. Recovery

Reliability Charge

RPU has established a Reliability Charge for all of its customers. This charge is intended to fund specific generation and transmission improvements to the RPU system to increase the reliability of service. For the purposes of this Study, there are no changes proposed for the Reliability Charge with the exception of a modification of the existing charge for the Industrial TOU customers. This proposed change includes the development of a "tiered" Reliability Charge (similar to that of the Domestic customer class). The reason for these proposed changes is consistent with the rate objectives identified herein in that customers that were regularly transitioning between Commercial – Demand and Industrial TOU rate classes were experiencing a significant increase in their Reliability Charge due to that transition.

The new Reliability Charge tier for the Industrial TOU will be based on increments of approximately 100 kW of billed demand, and range from approximately $912 per month to approximately $1,487 per month (in 2018) as indicated in Table 6-2. These charges are proposed to change over the first four years of the Five-Year Rate Plan, so that at the end of FY 2021, customers who regularly transition between the two customers' classes (due to their changes in demand), will see a reduced impact associated with the Reliability Charge. The proposed FY 2022 values are equal to the proposed FY 2021 values. The overall impact of this change in the Reliability Charge for the Industrial TOU class is designed to be revenue neutral (the overall amount collected will not change from the existing charges); however, the impacts to individual customers will change depending on their demand.

Table 6-2
Industrial TOU
Tiered Reliability Charge

Proposed Tier	Existing Charge	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
<= 100 kW Demand	$1,100.00	$912.50	$725.00	$537.50	$350.00	$350.00
101-150 kW Demand	$1,100.00	$1,012.50	$925.00	$837.50	$750.00	$750.00
151-250 kW Demand	$1,100.00	$1,050.00	$1,000.00	$950.00	$900.00	$900.00
251-500 kW Demand	$1,100.00	$1,100.00	$1,100.00	$1,100.00	$1,100.00	$1,100.00
501-750 kW Demand	$1,100.00	$1,287.50	$1,475.00	$1,662.50	$1,850.00	$1,850.00
> 750 kW Demand	$1,100.00	$1,487.50	$1,875.00	$2,262.50	$2,650.00	$2,650.00

Network Access Charge

One rate structure recommendation to address the fixed cost recovery issue is the implementation of an NAC. The NAC is based on the demand-related costs associated with the distribution system. The NAC is proposed to be a tiered fixed monthly charge for Domestic – and Commercial – Flat customer classes and a peak monthly demand charge ($/kW) for Commercial – Demand and Industrial TOU customer classes. The cost basis for the NAC varies by customer class, depending on its allocated share of the distribution demand costs as determined by the COS study.

Contract Rates

RPU has historically provided rates to selected large use customers through individualized contracts. These contractual rates have been effective in establishing and retaining large industrial load customers for the benefit of the entire RPU system. The entities served by contractual rates included several large industrial load customers, as well as the City and the University of California – Riverside campus. However, many of the large industrial load contracts have expired or will expire by the time of the initiation, or soon thereafter, of the rates proposed herein. By the end of the Five-Year Rate Plan, the only contractual rate will be the City. The customers whose contracts have, or soon will, expire, will be moved to the OAT, as specified in their contracts.

However, the City will experience a rate increase equivalent to its COS, which recognizes that the City is charged production-related costs associated with specific resources, as defined in its contract. The result of this analysis is a proposed revenue increase to the City contract per year over the Five-Year Rate Plan consistent with the system average rate of 4.8% per year.

Proposed Rate Design

This section of the Report provides a summary of the proposed rate design for each year of the Five-Year Rate Plan for each major customer class. Included in this summary is an analysis of the proposed rates, including rate impacts for the selected customer types. Proposed adjustments to the “other” customer classes are discussed at the end of this Section, with specific rates included in Appendix A.

Domestic Rates and Bill Comparison Analysis

Table 6-3 provides a summary of the proposed rate adjustments for the Domestic rate class for each of the years of the Five-Year Rate Plan and a comparison of the rate components to the existing rate structure.

Table 6-3
Domestic Rates
(Existing and Proposed)

		Proposed (1)				
Rate Component	Existing	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge ($/month)	$8.06	$8.81	$9.56	$10.71	$11.96	$13.21
Network Access Charge ($/month) (2)						
Tier 1 (0–750 S; 0–350 W)	--	$1.08	$2.16	$3.23	$4.31	$5.47
Tier 2 (751–1,500 S; 351–750 W)	--	$2.73	$5.46	$8.19	$10.93	$13.85
Tier 3 (>1,500 S; >750 W)	--	$5.72	$11.43	$17.15	$22.86	$28.98
Energy Charge ($/kWh) (2)						
Tier 1 (0–750 S; 0–350 W)	$0.1035	$0.1060	$0.1073	$0.1093	$0.1126	$0.1161
Tier 2 (751–1,500 S; 351–750 W)	$0.1646	$0.1686	$0.1706	$0.1738	$0.1791	$0.1846
Tier 3 (>1,500 S; >750 W)	$0.1867	$0.1912	$0.1936	$0.1972	$0.2031	$0.2094
Reliability Charge ($/month) (3)						
Small Residence (<100 Amp)	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
Medium Residence (101–200 Amp)	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Large Residence (201–400 Amp)	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00
Very Large Residence (>400 Amp)	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.
(2) Proposed summer season change from current three month summer season (June 16 to September 15) to four month (June 1 to September 30). Four month summer season also applicable to Network Access Charge.
(3) No changes to the Reliability Charge are proposed.

There are several important changes proposed for the Domestic rate schedules. The COS-based rates, provided in Table 5-2 for the Domestic class, indicate a customer charge of $13.31 per month. The proposed customer charge starts at $8.81 per month (FY 2018) and is increased over the Study period to $13.21 per month (FY 2022). The proposed Tier 1 NAC charge starts at $1.08 per month (FY 2018) and is increased over the Study period to $5.47 per month (FY 2022). Similarly, the proposed Tier 2 NAC charge starts at $2.73 per month and is increased annually to $13.85 per month (FY 2018 – FY 2022). The proposed Tier 3 NAC charge starts at $5.72 per month (FY 2018) and increases annually to $28.98 by FY 2022.

The proposed energy rates for the Domestic rate class reflect the same relationship between the tier structures as the existing rates and increase annually over time. The energy rates in Table 6-3 reflect the cost recovery for the energy and demand-related costs, as well as the recognition of the revenue received from the Reliability Charge. The proposed energy rates include changing the summer season from the current three months (June 16th through September15th) to a four month summer (June 1st through September 30th) to reflect Domestic seasonal usage patterns and align with other seasonal rates.

The proposed NAC tiered approach is based on the average distribution demand-related costs allocated to each tier based on their energy usage. The proposed tiers for the Domestic customer class are identical to the energy tiers (the tiers change for the energy rate by summer/winter). The average customer represents the average distribution demand costs for this class as represented by the Tier 2 NAC. The Tier 1 NAC is set at 39% of the average (based on energy usage for Tier 1 customers), and the Tier 3 NAC is set at 209% of the average. The Domestic NAC is phased in over the Five-Year Rate Plan to minimize the potential for dramatic changes in average bills between each year.

Distribution of Bill Impacts – Domestic Customers

Figure 6-2 provides an analysis of the distribution of electricity consumption within RPU's existing Domestic customer class, as determined from RPU Domestic customer billing data. This graph shows the average monthly kWh for FY 2016 and shows that approximately 90% of Domestic customers utilize between 200 to 1,400 kWh per month.

Figure 6-3 and Table 6-4 quantify the expected bill impacts to Domestic customers for various levels of representative consumption for the first year (FY 2018) and over the Five-Year period. An analysis was conducted to determine the first year bill impacts to representative customers within the class, for small, medium, and large users. Small use Domestic customers (0–600 kWh/month) should expect to see their average monthly bill increase from $2.22 to $3.42 (approximately 4.5% to 6.5%) during the first year of the rate plan. Medium use customers (600-1,000 kWh/month) should expect to see their average monthly bill increase from $4.23 to $5.13 (approximately a 3.7% to 4.0% increase). Large use customers (1,000–1,400 kWh/month) should expect to see bill increases in the range of $6.64 to $7.89 (3.7% to 3.8% increases) during this time.

As discussed above, this bill impact will vary based on individual customer usage patterns. However, approximately 90% of RPU Domestic customers are expected to receive a typical first year bill increase of between 3.1% to 6.4%, and see typical monthly bill increase of between $2.21 to $7.52 per account. Over the Five-Year period, approximately 90% RPU Domestic customers are expected to receive a typical bill increase of between 4.3% to 6.3%, and see typical monthly bill increases of between $2.57 to $9.88 per account (note, this information is based on a combination of Figure 6-2 and Table 6-4).

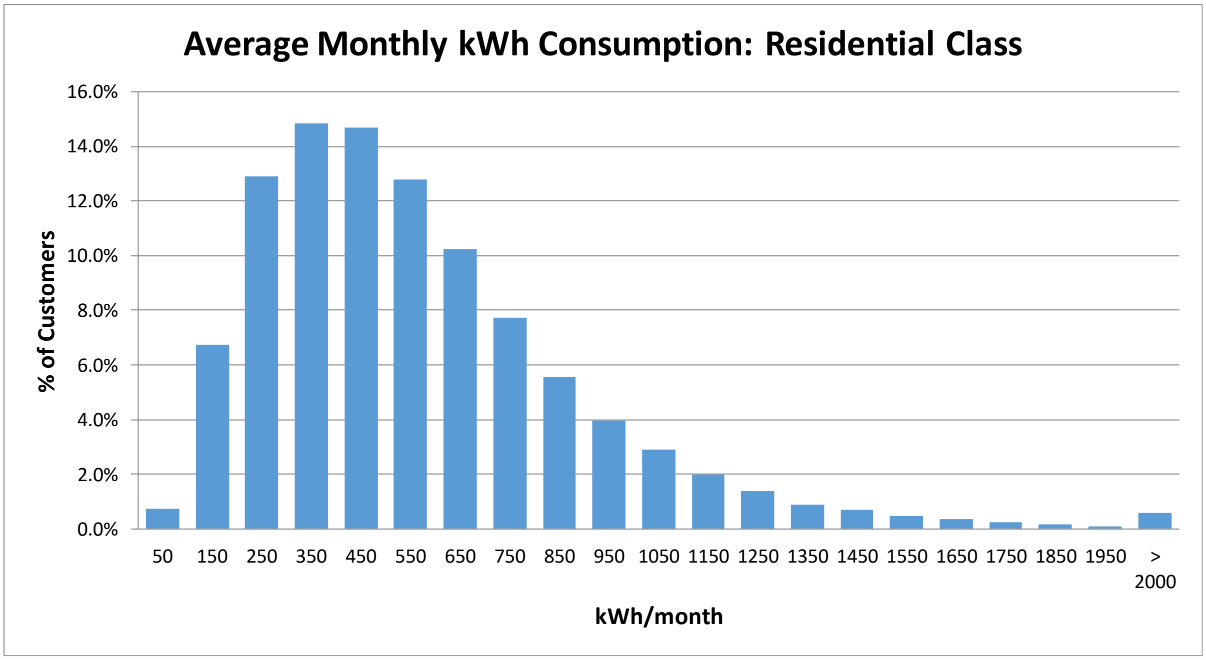

Figure 6-2. Distribution of RPU Domestic Customers Monthly Usage (FY 2016)

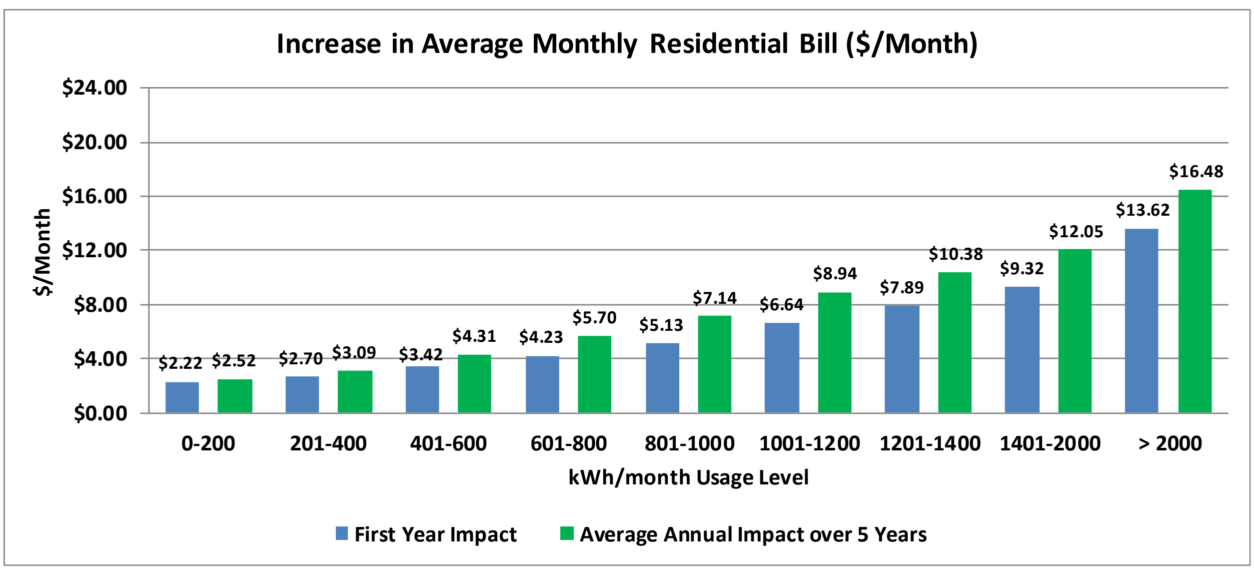

Figure 6-3. Average Domestic Bill Increase - First Year and Average for 5 Year

Table 6-4
Domestic Bill Impacts
Year 1 and Year 5; Average Annual Percent

Avg Monthly kWh Usage	Avg Monthly Current Bill	Avg Monthly New Bill – Yr 1	Annual Increase 1 Yr %)	Avg Monthly New Bill – Yr 5	Annual Increase 5 Yr (%)
0-200	$34.12	$36.34	6.5%	$46.71	6.5%
201-400	$50.92	$53.62	5.3%	$66.36	5.4%
401-600	$75.75	$79.17	4.5%	$97.29	5.1%
601-800	$106.49	$110.73	4.0%	$134.99	4.9%
801-1,000	$140.35	$145.48	3.7%	$176.05	4.6%
1,001-1,200	$175.77	$182.41	3.8%	$220.48	4.6%
1,201-1,400	$212.93	$220.81	3.7%	$264.82	4.5%
1,401-2,000	$271.96	$281.28	3.4%	$332.20	4.1%
> 2,000	$448.79	$462.41	3.0%	$531.17	3.4%

Fixed vs. Variable Cost Recovery

As indicated previously, RPU's existing rate structures rely primarily on volumetric energy charges to recover both fixed and variable costs (although the customer charge and the Reliability Charge do provide fixed cost recovery in the form of fixed charges). One of RPU's objectives for this Study was to increase the amount of fixed cost recovery from fixed charges. The proposed Domestic rates achieve this by including the tiered NAC. Figure 6-4 provides a summary of the analysis of the fixed versus variable cost recovery in the existing rates (indicated by FY 2016, or FY 16), as well as the proposed changes in rates over the Five-Year Rate Plan. Additionally, this figure includes a comparison to the COS analysis, which indicates that RPU's costs are approximately 66% fixed and 34% variable for the Domestic customer class.

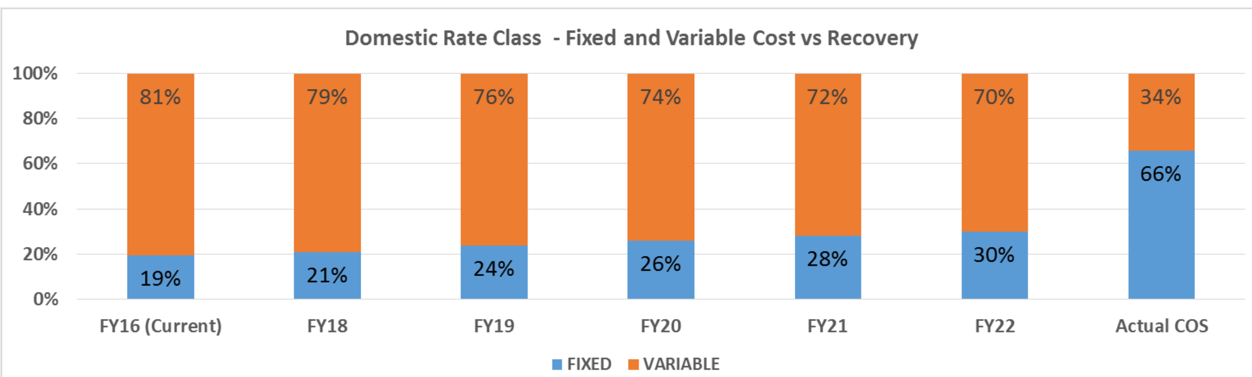

Figure 6-4. Fixed vs Variable Cost Recovery by Year – Domestic

Non-Domestic/Commercial Rate and Bill Comparison Analysis

The following provides a summary of the bill impact from the proposed rate changes for the non-domestic rate classes, including Commercial – Flat, Commercial – Demand, and Industrial TOU.

Commercial – Flat

Table 6-5 provides a summary of the proposed rate adjustments for the Commercial – Flat rate class for each of the years of the Five-Year Rate Plan and a comparison of the rate components to the existing rate structure. The existing and proposed rates will include the tiered energy charge, with Tier 1 including monthly energy up to 15,000 kWh in a month and Tier 2 set at above 15,000 kWh. As indicated below, the majority of customers in this class do not use greater than 15,000 kWh in a month; this tier is effectively utilized as a pricing mechanism to effectively move larger users into the next commercial class (Commercial – Demand).

The Commercial – Flat rate has two tiers, based on 15,000 kWh per month energy usage; however, the Tier 2 is set to encourage customers to either lower their energy usage (and remain in the Commercial – Flat class) or switch to the next level of commercial service (Commercial – Demand). Therefore, there are very few customers that utilize greater than 15,000 kWh per month on a consistent basis. If a Commercial – Flat customer utilized greater than 15,000 kWh, they would utilize greater than 20 kW of demand, thus be moved to the Commercial – Demand class. The Commercial – Demand class has a tiered energy rate based on 30,000 kWh. The existing tiered energy rate differential for the Domestic, Commercial – Flat and Commercial – Demand rate classes are proposed to remain constant over the Rate Plan period.

Table 6-5
Commercial – Flat
(Existing and Proposed)

		Proposed (1)				
Rate Component	Existing	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge ($/month)	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50
Network Access Charge ($/month)						
Tier 1 (0–500 kWh)	--	$1.77	$3.55	$5.32	$5.91	$6.50
Tier 2 (501–1500 kWh)	--	$5.03	$10.06	$15.09	$16.77	$18.45
Tier 3 (1501–3000 kWh)	--	$8.95	$17.90	$26.85	$29.83	$32.82
Tier 4 (>3000 kWh)	--	$21.53	$43.06	$64.59	$71.77	$78.95
Energy Charge ($/kWh)						
Tier 1 (0-15,000 kWh)	$0.1351	$0.1381	$0.1411	$0.1441	$0.1471	$0.1501
Tier 2 (>15,000 kWh)	$0.2064	$0.2110	$0.2156	$0.2201	$0.2247	$0.2293
Reliability Charge ($/month) (2)						
Tier 1 (0-500 kWh)	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
Tier 2 (501–1,500 kWh)	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
Tier 3 (>1,500 kWh)	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.

(2) No changes to the Reliability Charge for the Commercial – Flat class are proposed.

Rate changes proposed for Commercial – Flat include a new tiered NAC that increases over time and an increase in the Tier 1 and Tier 2 energy rates (however, the relationship between Tier 1 and Tier 2 energy rates remains constant over the Rate Plan period). The energy rate is proposed to increase annually over time, as does the NAC.

The NAC is proposed to be tiered based on monthly energy usage by customers in this class. The Tier 1 NAC is for customers ranging from 0 to 500 kWh and starts at $1.77 per month (FY 2018) and is increased over the Study period to $6.50 per month (FY 2022). The Tier 4 NAC is for customers over 3,000 kWh per month, and is a monthly charge that starts at $21.53 (FY 2018) and is increased to $78.95 by FY 2022.

The COS-based rates for the Commercial – Flat class, provided in Table 5-3, indicate a Test Year customer charge of $33.17 per month. The customer charge is proposed to remain the same as the existing charge through the Study period at $20.50 /month.

The COS-Energy rate (Table 5-3) suggests a "demand-adjusted" energy rate of $0.1457/kWh; however, that rate has not been adjusted for the tiers and does not reflect the revenue received from Commercial – Flat customers from the Reliability Charge. The energy rates in Table 6-5 reflect the cost recovery for the demand-related costs and the recognition of the revenue received from the Reliability Charge. As indicated, the tiered rate structure associated with this class has been maintained from the existing rate structure and is designed to equitably recover costs from customers who may move between this rate class and the Commercial – Demand rate class.

The proposed tiers for the Commercial – Flat customers are based on an analysis of the energy and associated demand of the customers in that class. For the Commercial – Flat NAC, the proposed fixed monthly charge is categorized by four tiers, given the range of energy/demand usage by customers within this class. Tier 3 is based on the average usage within the class, Tier 1 is set to 20% of the average, and the Tier 2 is set at 56% of the average. Tier 4 is set to 241% of the average and represents the distribution demand-related costs associated with serving the largest energy/demand users within the class.

Distribution of Bill Impacts – Commercial – Flat Customers

Figure 6-5 provides an analysis of the distribution of electricity consumption within RPU's existing Commercial – Flat customer class, as determined from RPU customer billing data. The energy usage in this customer class is highly diverse (i.e., the data distribution is strongly right-skewed). This graph shows the average monthly kWh for FY 2016 and shows that approximately 90% of Commercial – Flat customers utilize between 200 to 6,250 kWh per month.

Figure 6-6 and Table 6-6 quantify the expected bill impacts to Commercial – Flat customers for various levels of representative consumption for the first year (FY 2018) and over the Five-Year period. An analysis was conducted to determine the first year bill impacts to representative customers within the class, for small, medium, and large users. Small customers, defined as those using between 0 and 500 kWh per month, would be expected to see an average increase of approximately $2.79 on their monthly bill, or approximately 4.2% increase in year one (FY 2018). Medium sized users, defined as those using between 3,000 and 5,000 kWh per month, would be expected to see an average year one monthly bill increase of approximately $30.75, or 5.1% compared to 2016 rates. Large users, defined as those using greater than 10,000 kWh, would be expected to see an average monthly bill increase of approximately $75.73, or 3.0% compared to 2016 rates.

The impact from the proposed rate changes to these customers will vary based on individual customer usage patterns. However, approximately 90% of RPU Commercial – Flat customers are expected to receive a typical first year bill change of 3.5% to 5.3%, and see typical monthly bill increases of $2.03 to $49.54 per account. Over the Five-Year period, approximately 90% of RPU Commercial – Flat customers are expected to receive a typical bill increase of 2.9% to 3.9%, and see a typical monthly bill increase of between $1.56 to $43.81 per account (note, this information is based on a combination of Figure 6-5 and Table 6-6).

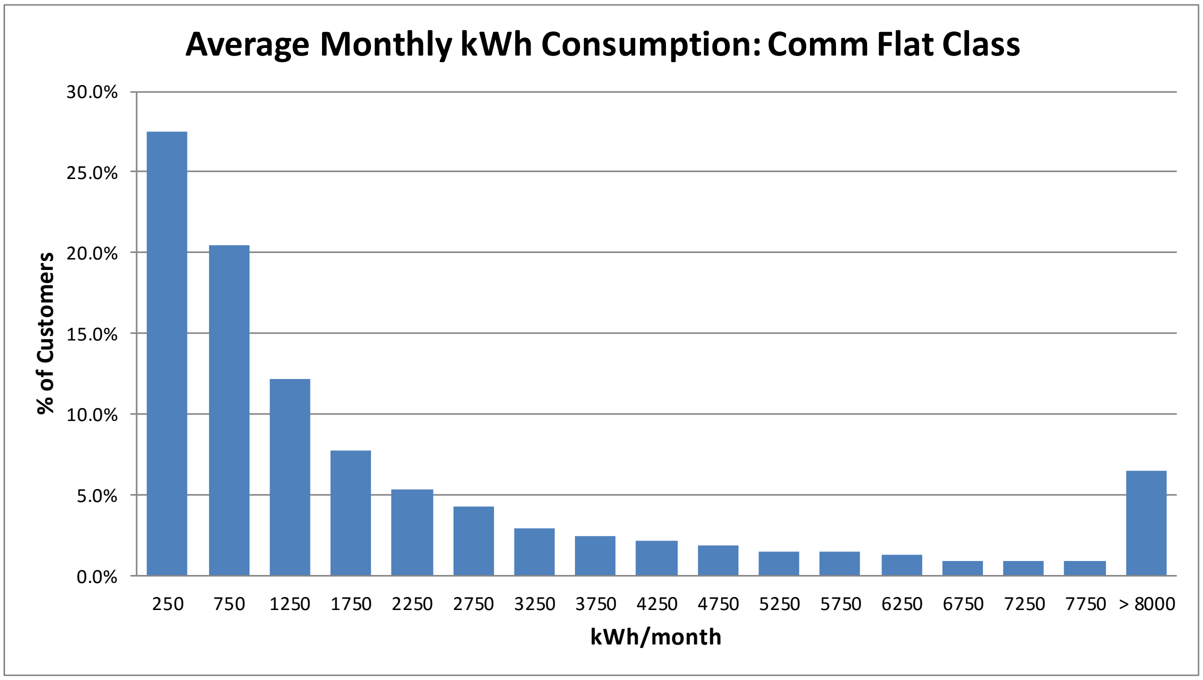

Figure 6-5. Distribution of RPU Commercial – Flat Customers Monthly Usage (FY 2016)

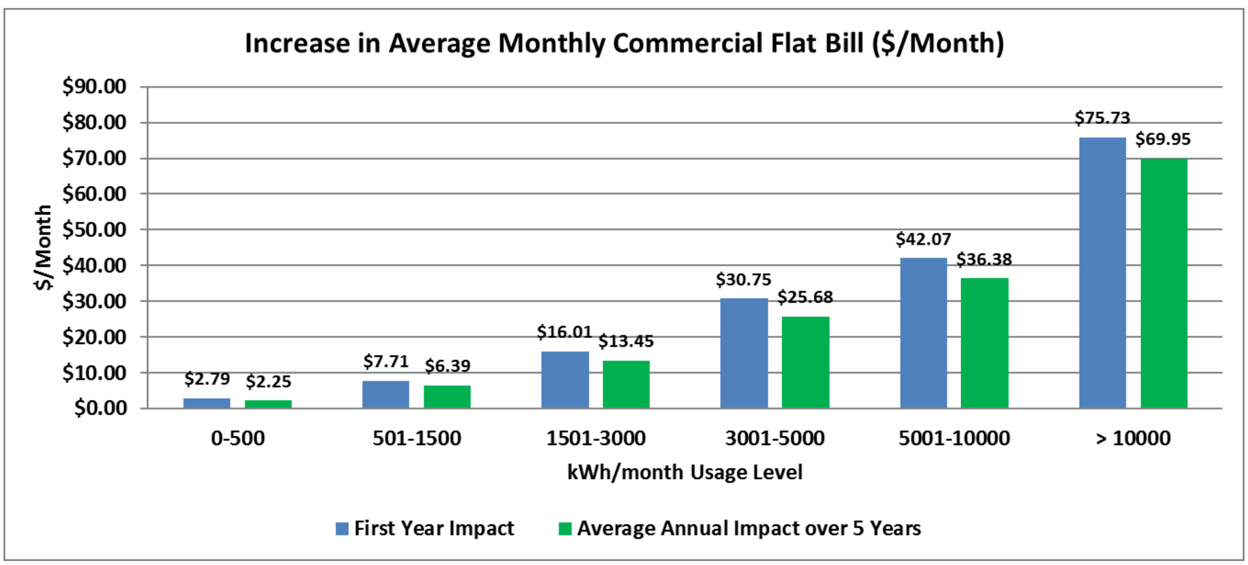

Figure 6-6. Average Commercial Flat - Bill Increase - First Year and Average for 5 Year

Table 6-6
Commercial - Flat Bill Impacts
Year 1 and Year 5; Average Annual Percent

Avg Monthly kWh Usage	Avg Monthly Current Bill	Avg Monthly New Bill – Yr 1	Annual Increase 1 Yr %)	Avg Monthly New Bill – Yr 5	Annual Increase 5 Yr (%)
0–500	$66.12	$68.91	4.2%	$77.36	3.2%
501–1,500	$173.97	$181.68	4.4%	$205.90	3.4%
1,501–3,000	$363.53	$379.54	4.4%	$430.78	3.4%
3,001–5,000	$608.03	$638.78	5.1%	$736.42	3.9%
5,001–10,000	$1,013.31	$1,055.37	4.1%	$1,195.18	3.4%
> 10,000	$2,523.68	$2,599.41	3.0%	$2,873.42	2.6%

Fixed vs. Variable Cost Recovery

Figure 6-7 provides a summary of the fixed versus variable cost recovery in the existing rates for Commercial – Flat customers (indicated by FY 2016), as well as the proposed rate changes over the Five-Year Rate Plan. Figure 6-7 includes a comparison to the COS analysis, which indicates that for the Commercial – Flat class, RPU's costs are approximately 58% fixed and 42% variable.

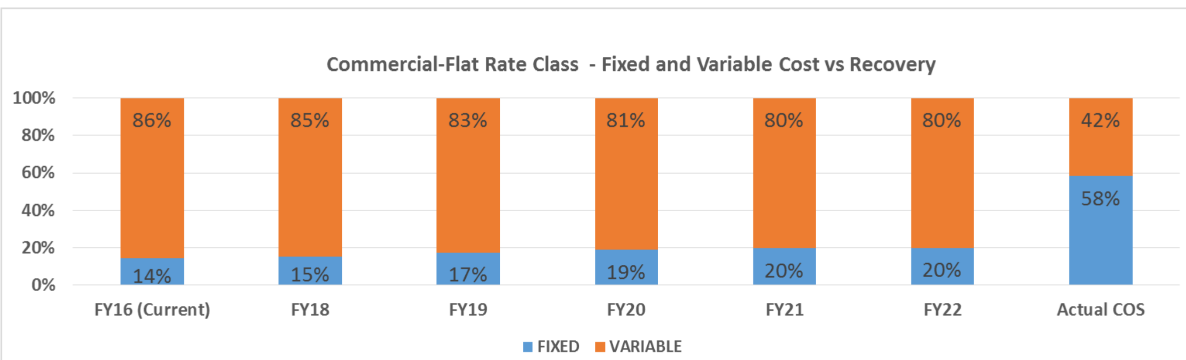

Figure 6-7. Fixed vs Variable Cost Recovery by Year – Commercial – Flat

Commercial – Demand

Table 6-7 provides a summary of the proposed rate adjustments for the Commercial – Demand rate class for each of the years of the Five-Year Rate Plan and a comparison of the rate components to the existing rate structure. The existing and proposed rates will include the tiered energy charge, with Tier 1 including monthly energy up to 30,000 kWh in a month and Tier 2 set at above 30,000 kWh. The existing and proposed rate differences between these tiers is proposed to remain constant over the proposed Five-Year Rate Plan.

Table 6-7
Commercial – Demand
(Existing and Proposed Rates)

Rate Component	Existing	Proposed (1)				
		FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge ($/month)	--	$8.51	$14.88	$21.26	$27.64	$34.02
Network Access Charge ($/kW)	--	$1.00	$1.50	$2.00	$2.50	$3.10
Energy Charge						
Tier 1 (0-30,000 kWh)	$0.1111	$0.1131	$0.1171	$0.1211	$0.1261	$0.1321
Tier 2 (> 30,000 kWh)	$0.1217	$0.1239	$0.1283	$0.1327	$0.1381	$0.1447
Demand Charge ($/kW) (2)						
Fixed Charge	$209.65	$157.95	$159.45	$160.20	$160.95	$161.70
All excess kW	$10.48	$10.53	$10.63	$10.68	$10.73	$10.78
Reliability Charge ($/month) (3)	$90.00	$90.00	$90.00	$90.00	$90.00	$90.00

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.
(2) Demand charge minimum Fixed Charge based on 20 kW (existing); proposed based on 15 kW.
(3) No changes to the Reliability Charge are proposed.

Changes proposed for Commercial – Demand include an establishment of a customer charge and NAC (both of which are not currently in effect), an increase in the energy charge, and a change in the demand rate and structure. The demand charge has two components – a fixed charge and a variable charge. The existing fixed rate charge is based on 20 kW (20 times the existing demand rate). The proposed fixed charge is based on 15 kW (15 times the proposed demand rate). The demand rate is proposed to increase in each year of the rate plan. No changes are proposed for the Reliability Charge for this customer class.

The COS-based rates for the Commercial – Demand class, provided in Table 5-4, indicate a Test Year customer charge of $53.02 per month. The proposed customer charge starts at $8.51 per month (FY 2018) and is increased over the Study period to $34.02 per month (FY 2022). The proposed NAC is based on the peak demand for the month and starts at $1.00/kW (FY 2018) and is increased over the Study period to $3.10/kW per month (FY 2022).

The COS-based rates indicate a demand charge of $23.55 per kW for the Commercial – Demand class. The proposed demand rate changes start at $10.48/kW (FY 2018) and increase slightly each year to $10.78/kW by FY 2022. As noted, the COS demand rate includes fixed costs that are currently recovered from the Reliability Charge.

The COS for this class indicates an energy rate of $0.0670/kWh; however, that rate has not been adjusted for the tiers. The energy rates in Table 6-7 reflect the cost recovery for the demand-related costs, not recovered through the combination of the proposed customer and NAC charges, the demand charge, or the Reliability Charge. As indicated, the tiered rate structure associated with this class has been maintained from the existing rate structure and is designed to equitably recover costs from customers who may move between this rate class and the Industrial TOU rate class.

Distribution of Bill Impacts - Commercial – Demand Customers

Figure 6-8 provides an analysis of the distribution of electricity consumption within RPU's existing Commercial – Demand customer class, as determined from RPU customer billing data. This graph shows the average monthly kWh for FY 2016 and shows that approximately 90% of Commercial – Demand customers utilize between 1,300 to 36,300 kWh per month.

Expected bill impacts for Commercial – Demand customers are quantified in Figure 6-9 and Table 6-8 for various levels of representative consumption for the first year (FY 2018) and over the Five-Year period. An analysis was conducted to determine the first year bill impacts to representative customers within the class, for small, medium, and large users. Small customers, defined as those using between 0 and 5,000 kWh per month, would be expected to see an average increase of approximately $6.59 on their monthly bill, or approximately 1.0% increase in year one (FY 2018). Medium sized users, defined as those using between 15,000 and 25,000 kWh per month, would be expected to see an average year one monthly bill increase of approximately $114.17, or 3.9% compared to 2016 rates. Large users, defined as those using greater than 50,000 kWh, would be expected to see an average monthly bill increase of approximately $303.22, or 3.4% compared to 2016 rates.

The proposed rate impact will vary based on individual customer usage patterns. However, approximately 90% of RPU's Commercial – Demand customers are expected to receive a typical first year bill change of between -4.2% to 5.4%, and see typical monthly bill changes of -$22.27 (decrease) to $230.34 per account. The reason for the monthly bill decrease is that very low energy users in this class will pay less as a result of the change in the minimum demand portion of their bill from $209.65 (20 kW) to $157.95 (15 kW), as provided in Table 6-7. Over the Five-Year period, approximately 90% of RPU's Commercial – Demand customers are expected to receive a typical bill increase of between 2.8% to 4.6%, and see a typical monthly bill increase of between $15.32 to $285.03 per account (note, this information is based on a combination of Figure 6-8 and Table 6-8).

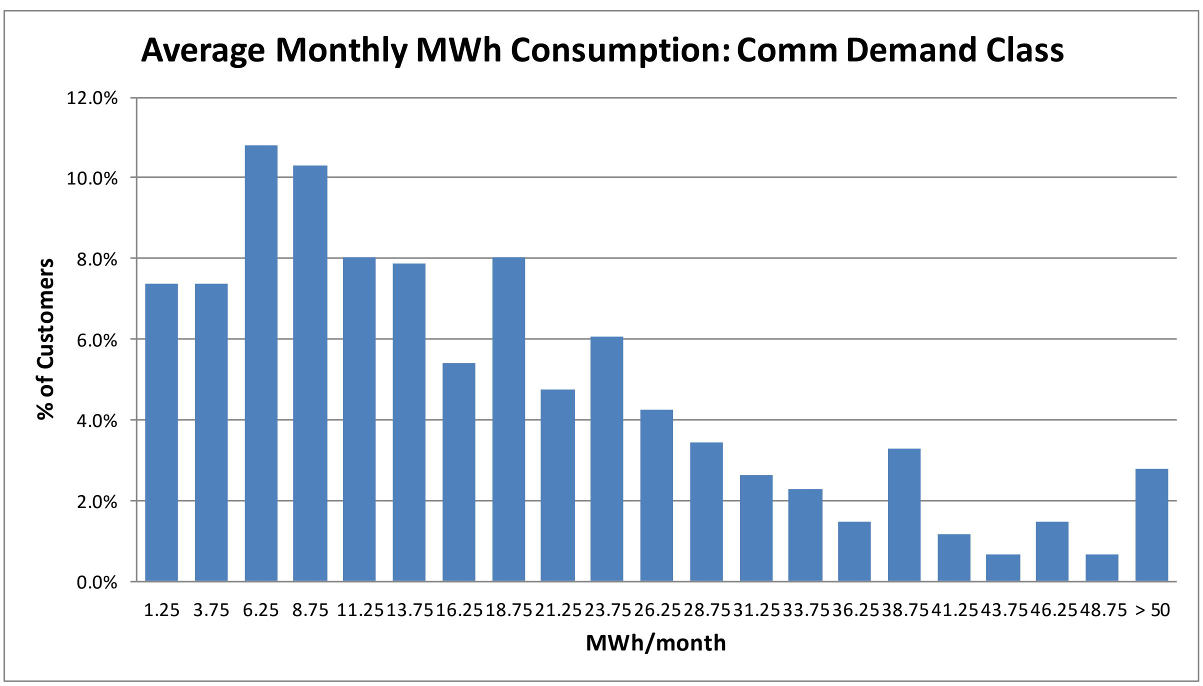

Figure 6-8. Distribution of RPU Commercial – Demand Customers Monthly Energy Usage (MWh = 1,000 kWh) (FY 2016)

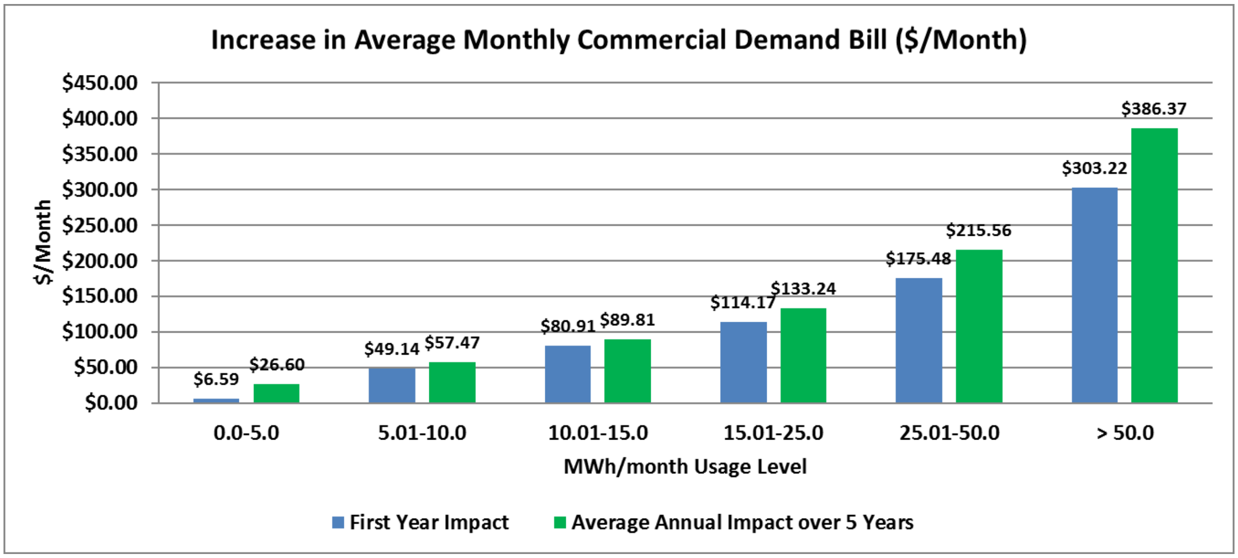

Figure 6-9. Average Commercial Demand Bill Increase – First Year and Average for 5 Year (MWh = 1,000 kWh)

Table 6-8
Commercial – Demand Class Bill Impacts
Year 1 and Year 5; Average Annual Percent

Avg Monthly kWh Usage	Avg Monthly Load Factor	Avg Monthly Current Bill	Avg Monthly New Bill – Yr 1	Annual Increase 1 Yr (%)	Avg Monthly New Bill Yr 5	Annual Increase 5 Yr (%)
0-5,000	24%	$637.35	$643.94	1.0%	$770.33	3.9%
5,001-10,000	38%	$1,241.02	$1,290.16	4.0%	$1,528.39	4.3%
10,001-15,000	43%	$1,944.92	$2,025.83	4.2%	$2,393.96	4.2%
15,001-25,000	48%	$2,964.06	$3,078.23	3.9%	$3,630.26	4.1%
25,001-50,000	54%	$4,914.34	$5,089.82	3.6%	$5,992.15	4.0%
> 50,000	59%	$8,955.80	$9,259.02	3.4%	$10,887.62	4.0%

Fixed vs. Variable Cost Recovery

Figure 6-10 provides a summary of the fixed versus variable cost recovery in the existing rates for the Commercial – Demand customer class over the Five-Year Rate Plan. This figure includes a comparison to the COS analysis, which indicates that RPU's costs for the Commercial – Demand class are approximately 54% fixed and 46% variable.

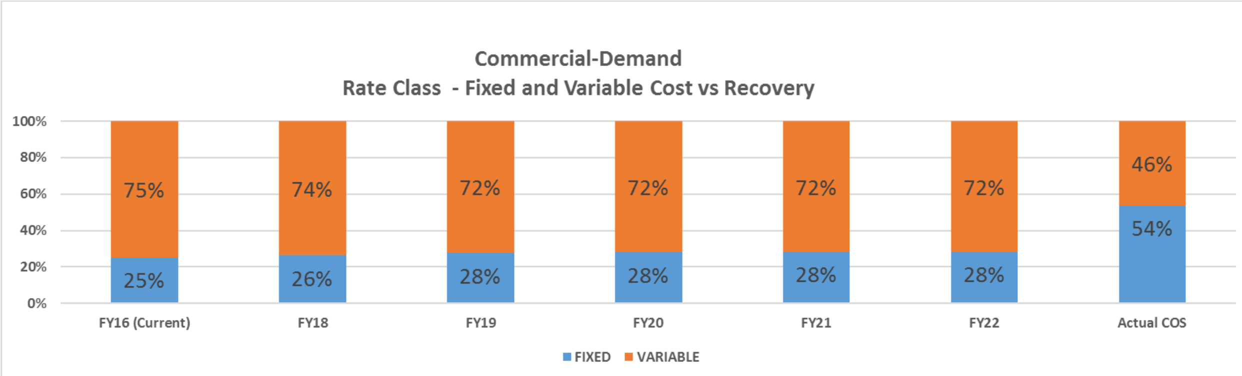

Figure 6-10. Fixed vs Variable Cost Recovery by Year – Commercial – Demand

Industrial – TOU

Table 6-9 provides a summary of the proposed rate adjustments for the Industrial TOU rate class for each of the years of the Five-Year Rate Plan and a comparison of the rate components to the existing rate structure.

Table 6-9
Industrial TOU
(Existing and Proposed Rates)

		Proposed (1)				
Rate Component	Existing	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge ($/month)	$704.66	$653.50	$640.70	$627.91	$621.52	$615.12
Network Access Charge ($/kW)	--	$1.25	$2.60	$4.00	$5.25	$6.25
Energy Charge ($/kWh)						
On-Peak	$0.1033	$0.1075	$0.1113	$0.1157	$0.1204	$0.1256
Mid-Peak	$0.0828	$0.0868	$0.0906	$0.0949	$0.0987	$0.1030
Off-Peak	$0.0727	$0.0753	$0.0779	$0.0810	$0.0843	$0.0879
Demand Charge ($/kW)						
On-Peak	$6.88	$6.88	$7.03	$7.18	$7.23	$7.28
Mid-Peak	$2.74	$2.97	$3.28	$3.59	$3.62	$3.64
Off-Peak	$1.31	$1.45	$1.62	$1.80	$1.81	$1.82
Reliability Charge ($/month) (2)						
<= 100 kW	$1,100.00	$912.50	$725.00	$537.50	$350.00	$350.00
101-150 kW	$1,100.00	$1,012.50	$925.00	$837.50	$750.00	$750.00
151-250 kW	$1,100.00	$1,050.00	$1,000.00	$950.00	$900.00	$900.00
251-500 kW	$1,100.00	$1,100.00	$1,100.00	$1,100.00	$1,100.00	$1,100.00
501-750 kW	$1,100.00	$1,287.50	$1,475.00	$1,662.50	$1,850.00	$1,850.00
> 750 kW	$1,100.00	$1,487.50	$1,875.00	$2,262.50	$2,650.00	$2,650.00

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.
(2) Reliability Charge proposed to change to tiered charge based on-peak demand (kW), see text for discussion.

Changes proposed for Industrial TOU include a reduction in the customer charge, a new NAC that increases over time, and increases in the energy and demand charges for the On-, Mid-, and Off-Peak times. The Reliability Charge is also proposed to change from the existing structure to a tiered structure, as discussed herein.

The COS-based rates for Industrial TOU class, provided in Table 5-5, indicate a Test Year customer charge of $192.01 per month. The proposed customer charge is reduced to $653.50 per month (FY 2018) and is decreased over the Study period to $615.12 per month (FY 2022). The proposed NAC charge starts at $1.25/kW (FY 2018) and is increased over the Study period to $6.25/kW (FY 2022). The proposed On-Peak Energy charge is $0.1075/kWh in FY 2018, increasing to $0.1256/kWh in FY 2022.

The COS-based rates indicate a demand charge of $28.72/kW for the On-Peak period for Industrial TOU class. The proposed changes to the On-Peak demand rates start in FY 2019 at $7.03/kW and increase to $7.28/kW (FY 2022). The relationship between the On-Peak, Mid-Peak, and Off-Peak prices represent the time-based cost difference of RPU's resources and the existing rate structure differentials. RPU also recognizes that many customers in this class have shifted resources to respond to the existing rate structures (i.e. they have shifted load to the Mid- and Off-Peak times). Therefore, RPU has determined to adjust the rate component relationships in a manner that minimizes rate impacts to customers in this class. It should be noted that the COS-based demand rate includes fixed costs that are currently recovered from customers from the Reliability Charge.

The COS for this class indicates an energy rate of $0.0664/kWh for the On-Peak period. As with the proposed demand charges, the difference between the On-Peak, Mid-Peak, and Off-Peak energy rates reflect the cost difference of RPU's resources and the existing rate structure differentials. The energy rates proposed in Table 6-9 reflect the cost recovery for the demand-related costs not recovered through the combination of the proposed customer, NAC charges, demand charge, or the Reliability Charge. The change in the Reliability Charge is proposed to address the concerns of customers that regularly transition between this class and the Commercial – Demand class (see Table 6-2 and related discussion).

Distribution of Bill Impacts - Industrial TOU Customers

Figure 6-11 provides an analysis of the distribution of electricity consumption within RPU's existing Industrial TOU customer class, as determined from RPU customer billing data. This graph shows the average monthly kWh for FY 2016 and shows that approximately 90% of Industrial TOU customers utilize between 12,500 kWh and 287,500 kWh per month (between 12.5 and 287.5 MWh, as 1,000 kWh equals 1 MWh).

Expected bill impacts for Industrial TOU customers are quantified in Figure 6-12 and Table 6-10 for various levels of representative consumption for the first year (FY 2018) and over the Five-Year period. An analysis was conducted to determine the first year bill impacts to representative customers within the class, for small, medium, and large users. Small customers, defined as those using between 0 and 100,000 kWh per month, would be expected to see an average increase between $172.72 and $492.21 on their monthly bill, or approximately between 3.2% and 5.0% increase in year one (FY 2018). Medium sized users, defined as those using between 100,000 and 250,000 kWh per month, would be expected to see an average year one monthly bill increase of between $902.43 and $1,356.93, or between 5.9% and 6.1% compared to 2016 rates. Large users, defined as those using greater than 500,000 kWh, would be expected to see a year one average monthly bill increase of approximately $4,459.10 or 6.2% compared to 2016 rates.

As with the other classes, the proposed rate impact to the Industrial TOU customers' bill will vary based on individual customer usage patterns. However, approximately 90% of RPU Industrial TOU customers are expected to receive an average first year bill change of between -1.4% to 7.6%, and see typical monthly bill changes of -$59.38 (decrease) to $3,337.88 per account. The reason for the decrease is that very low energy users in this class (approximately 5% of the customers) will see a reduction as a result of the reduction in the customer charge and the change in the structure of the Reliability Charge as provided in Table 6-9. Over the Five-Year period, approximately 90% of RPU's Industrial TOU customers are expected to receive a typical monthly bill increase of between 0.4% to 6.9%, and see a typical monthly bill change of between $16.98 to $3,444.99 per account (note, this information is based on a combination of Figure 6-11 and Table 6-10).

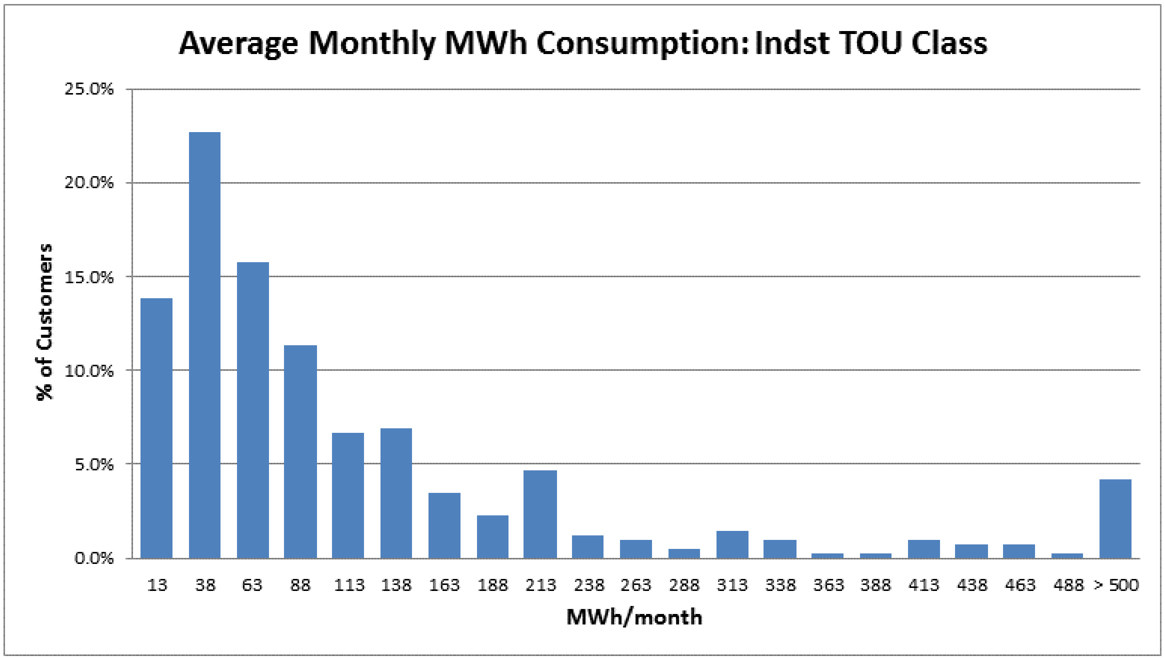

Figure 6-11. Distribution of RPU Industrial TOU Customers Monthly Energy Usage (MWh = 1,000 kWh) (FY 2016)

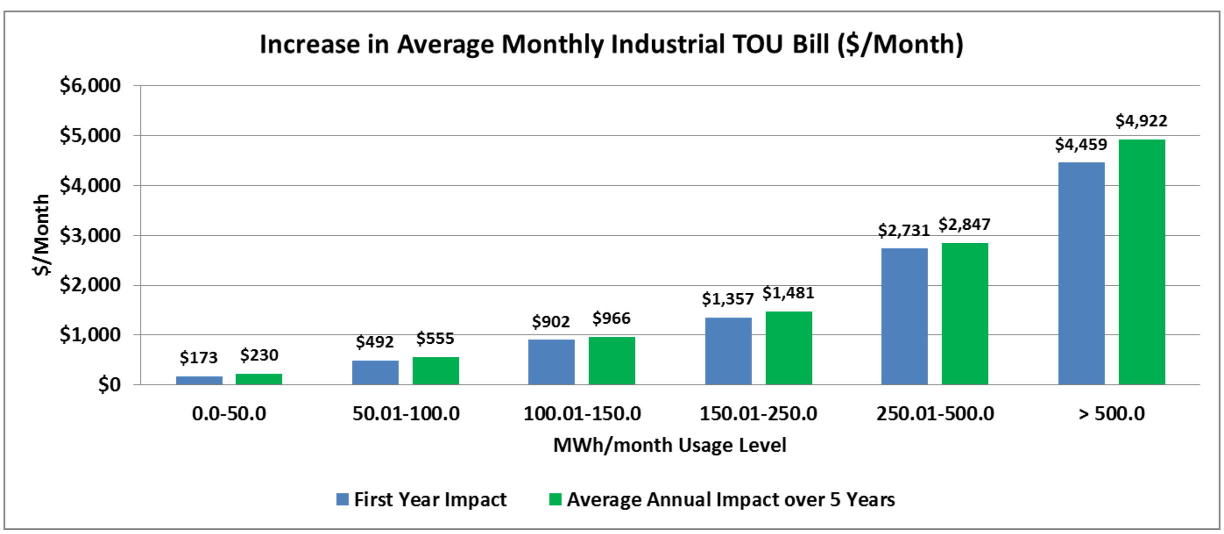

Figure 6-12. Average Commercial Demand Bill Increase - First Year and Average for 5 Year (MWh = 1,000 kWh)

Table 6-10
Industrial TOU Class Bill Impacts
Year 1 and Year 5; Average Annual Percent

Avg Monthly kWh Usage	Avg Monthly Load Factor	Avg Monthly Current Bill	Avg Monthly Bill Yr 1	Annual Increase 1 Yr (%)	Avg Monthly New Bill Yr 5	Annual Increase 5 Yr (%)
0–50,000	31%	$5,404.12	$5,576.84	3.2%	$6,555.52	3.9%
50,001–100,000	49%	$9,845.31	$10,337.53	5.0%	$12,618.39	5.1%
100,001–150,000	54%	$15,234.89	$16,137.32	5.9%	$20,064.44	5.7%
150,001–250,000	61%	$22,321.56	$23,678.50	6.1%	$29,724.67	5.9%
250,001–500,000	61%	$39,305.64	$42,036.95	6.9%	$53,542.42	6.4%
> 500,000	68%	$72,178.27	$76,637.37	6.2%	$96,790.63	6.0%

Fixed vs. Variable Cost Recovery

Figure 6-13 provides a summary of the fixed versus variable cost recovery in the existing rates for the Industrial – TOU customer class over the Five-Year Rate Plan. Figure 6-13 includes a comparison to the COS analysis, which indicates that for the Industrial TOU class, RPU's costs are approximately 49% fixed and 51% variable.

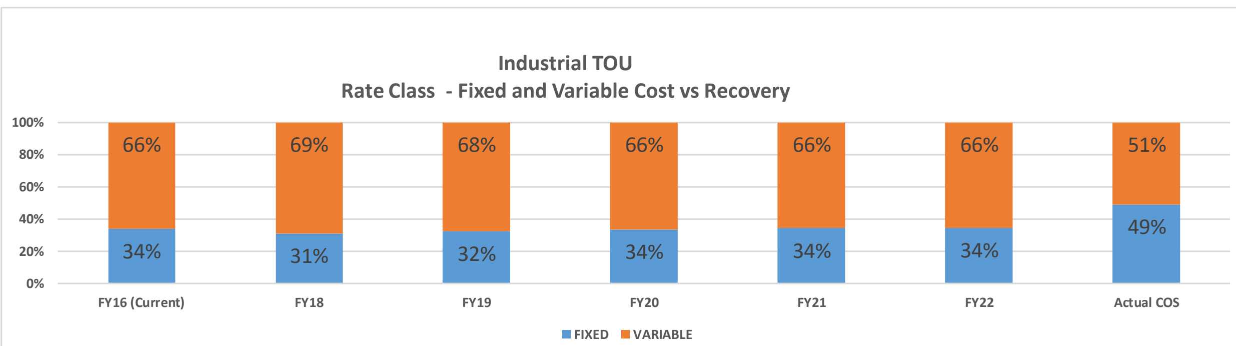

Figure 6-13. Fixed vs Variable Cost Recovery by Year – Industrial TOU

Revenue Impact Analysis

Table 6-11 provides a summary of the overall revenue contributions by customer class under the proposed rates, as well as the total system revenue projected to be collected in each year of the Five-Year Rate Plan.

Table 6-11
Projected Revenue by Class ($000)

Customer Class	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Residential	$114,406	$120,993	$126,202	$132,527	$139,623
Commercial – Flat	$46,112	$49,064	$51,718	$54,069	$56,170
Commercial – Demand	$24,373	$25,866	$27,245	$28,708	$30,432
Industrial TOU	$107,666	$119,426	$128,245	$136,831	$144,907
Other (1)	$14,023	$12,376	$12,800	$13,268	$13,747
Total(2)	**$306,581**	**$327,724**	**$346,211**	**$365,404**	**$384,880**

(1) Other Classes includes street lights.

(2) Numbers may not add due to rounding.

Table 6-11 suggests that the revenues from the Domestic rate class are projected to increase from approximately $114.4 million in FY 2018 to $139.6 million in FY 2022. The Commercial – Flat, Commercial – Demand, and Industrial TOU customer classes will also see an increase in the total revenue generated by the class. The Other Rates are projected to slightly decrease in total revenue; however, this is because the Contract customers that are within this group will move to their OAT during the course of the Five-Year Rate Plan.

High Voltage Adjustment

RPU is proposing a high-voltage adjustment for customers that take service at the primary level (4 kV to 69 kV). These customers are, by definition, served under the Industrial TOU rate. The rationale for offering a high voltage adjustment to these customers is that these customers do not incur the costs associated with the equipment and maintenance necessary for secondary service (less than 4 kV). It is more efficient to transmit electricity at higher voltages (which reduces the energy lost to resistance) and these customers do not require utility investment in step-down converters. In order to qualify for this adjustment, the customer must supply the appropriate transformation equipment to reduce the incoming voltage for their use, as appropriate.

Based on an analysis of the costs associated with the equipment, the proposed rate design for the high voltage adjustment is equal to approximately $1.15 per kW of NAC demand. This was determined by analyzing the costs associated with the equipment required to serve all distribution customers compared to the equipment required to serve high-voltage customers. The reduction in the equipment costs, as a percent of total delivery costs (distribution and transmission equipment) was applied to the distribution demand costs for customers in this class, resulting in a discount applied to that portion of the rate. The cost of this discount was determined as applied to the load of specific applicable customers. This cost is recovered from the non-high voltage customers on the system (i.e. all other customers). A high voltage adjustment is a recognition of the reduced cost causation from high-voltage customers in the form of a decrease to the NAC demand rate, provided that all other (low-voltage) customers are charged their allocated COS. The Industrial TOU rates for NAC demand provided herein include this adjustment.

Other Rate Changes

There are several other rate changes that RPU is proposing as part of this Five-Year Rate Plan. A discussion of each of these “other” customer and rate classes, and the changes proposed, is provided below.

Street lighting

RPU is initiating efforts to fully replace its existing inventory of City-owned street lights LED lamps. This effort will result in lower energy costs, but will require a significant capital investment. The capital investment for the replacement is being funded from non-retail rate revenues. The schedule for replacement of approximately 29,000 lamps currently under the Schedule LS-1 (Street Lighting Service – Department Financed) is to begin in FY 2017 and be complete before the end of the Five-Year Rate Plan. The existing rates are charged on a per lamp/per month basis, and is differentiated by the type of lamp (incandescent, mercury vapor, and sodium vapor), and the "lumen" rating (which is related to the wattage and size of the lamp). This type of street light rate structure is common for municipal electric utilities. The existing rates are sufficient to recover the costs associated with street lighting, capital costs (hardware), O&M-related costs, and the cost of electricity.

The LED lighting program will replace the various types of lights with a LED light that is within the same range of lumens (light output). For example, a 100-Watt incandescent lamp is rated at 1,000 lumens, which can be replaced with a 42-Watt LED lamp. Similarly, a 42-Watt LED lamp has an equivalent lumen rating as a 70-Watt high-pressure sodium lamp (5,800 lumens). The proposed rate for this LED lamp of $10.38 per lamp/per month, which is equal to the weighted average (based on RPU's installed number and exiting rates) of replacing the 100-Watt incandescent lamps and the 70-Watt high-pressure sodium lamps with 42-Watt LED lamps. Therefore, customers are paying the same rate for an equivalent amount of light, regardless of the type of lamp providing the light (incandescent, mercury vapor, high-pressure sodium, or LED). Proposed LED street light rates for all applicable customer classes will continue to be evaluated as RPU implements its LED street light replacement program. The proposed LED street lighting rates for LS-1 compared to existing rates as provided in Table 6-12

Table 6-12
Street Lighting Rates with Replacement LED (LS-1)

Bulb Type – Existing	Rates – Existing	Existing Bulbs (Watts)	LED Lamps (Watts)	Lumen Range (lumens)	LED Rate
Incandescent	$6.82	100	42	1,000 – 5,800	$10.38
	$13.44	300	58	3,500 – 4,000	$11.83
Mercury Vapor	$10.77	100	58	3,500 – 4,000	$11.83
	$12.76	175	93	7,000 – 9,500	$13.24
	$15.68	400	139	10,000 – 23,000	$15.75
High Pressure Sodium	$10.51	70	42	1,000 – 5,800	$10.38
	$11.85	100	58	3,500 – 4,000	$11.83
	$13.88	150	93	7,000 – 9,500	$13.24
	$15.75	200	139	10,000 – 23,000	$15.75
	$17.39	250	185	25,000	$17.39
	$21.84	400	275	40,000	$21.84

Electric Vehicle – Level 3 Public Charging Station

RPU temporarily provides no-cost electric vehicle (EV) charging at its fast charging station located in downtown Riverside. This charging station is a Level 3 charger, which is served at 277/480 volts utilizing a three-phase distribution circuit. RPU has entered into a contract with GreenLots, Inc. (GreenLots) to maintain these charging stations in exchange for providing data on customer usage patterns. This charging station has been available since January 1, 2016 at no cost to the end users. As part of this Study, the usage data provided by GreenLots, as well as information from the Utilities metering equipment was evaluated to establish a rate for this Level 3 public EV charging station. It should be noted that home/business charging of EVs would be applicable under a customer's OAT, unless otherwise scheduled. Specifically, RPU offers the Domestic TOU Tiered (DTOU Tiered) rate to its residential EV customers as an incentive to charge EV's during Off-Peak hours. Additionally, other RPU publicly available charging stations (such as the Level 2 stations) would not qualify for this proposed rate.

The Level 3 charging station was utilized approximately 2,665 times (unique charging events) over the course of approximately 12 months in 2016. The peak demand placed on the system per day averaged to approximately 26.11 kW, which is a function of the type of battery system unique to the EV, as well as its status of charge during the time it is plugged into the public charging station. The average charging event was approximately 26 minutes, and the average energy was approximately 10.56 kWh. An analysis of the distribution of the load observed at these charging stations was also conducted, which resulted in the development of a standard deviation of the results. The standard deviation measures the range of results relative to the average; a measure of one standard deviation from the average encompasses approximately 67% of the data. Table 6-13 provides a summary of the data analysis conducted for RPU's public Level 3 EV charging station.

Table 6-13
Customer Usage Characteristics for
RPU Public Level 3 EV Charging Station

EV Public Charging Data (1)	Average	Standard Deviation	Low Range	High Range
# of Charging Events/month	222	75.87	146.30	298.04
Demand/day (kW)	26.11	11.63	14.48	37.74
Duration/event (min:sec)	26.00	16.17	9.83	42.17
Energy/event (kWh)	10.56	6.59	3.96	17.15

(1) Collected from January 1, 2016 to December 31, 2016.

The COS analysis provides the embedded (or average) system costs on the basis of the system demand, energy, and customers. Utilizing the average system demand costs of $22.89/kW applied to the number of events per month results in a per demand charge of approximately $0.1031/kW (billed on the peak KW per charging event). A similar analysis of the average system energy rate of $0.0658/kWh (the average system energy costs) would apply to the energy charged per event. A "hook up charge" equal to the system average customer charge ($18.19), divided by the number of events per month results in a $0.0819 fixed charge per event. RPU proposes to charge customers the sum of their peak demand, total energy, and fixed charge to utilize its public EV charging stations. The public EV charging station rate increases at the annual system average rate increase of 4.8% per year. Table 6-14 provides a summary of the derivation of these charges.

Table 6-14
Derivation of Charges for RPU EV Level 3
Public Charging Stations

Rate Component	COS	Charging Events	FY 2018 Rates	FY 2019 Rates	FY 2020 Rates	FY 2021 Rates	FY 2022 Rates
Demand Rate ($/kW)	$22.89	222	$0.1031	$0.1081	$0.1133	$0.1187	$0.1244
Energy Rate ($/kWh)	$0.0658	–	$0.0658	$0.0690	$0.0723	$0.0758	$0.0794
Customer-Related ($/Charge)	$18.19	222	$0.0819	$0.0859	$0.0900	$0.0943	$0.0988

Proposed Rate Schedules – Domestic TOU EV Rates

RPU is proposing to introduce optional Domestic TOU rates for EV owners that intend to charge their electric vehicles at their residences. There are two new rate offerings proposed to be available to RPU customers; one is a tiered TOU (DTOU Tiered EV) and the other is a tiered TOU for EV only (DTOU EV Only). The DTOU Tiered EV is meant to be a rate that would replace the existing or proposed Domestic rate for customers that wish to benefit by shifting EV load. This rate would not require an additional meter, and all other applicable rate charges (e.g. customer charge, NAC charge, public benefits fee, taxes, etc.) would apply. This rate is provided in Table 6-15.

Table 6-15
Proposed DTOU Tiered EV Rates

Rate Component	Existing	Proposed Rates (1) FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge	--	$8.81	$9.56	$10.71	$11.96	$13.21
Network Access Charge (2)						
Tier 1 (0–750 S; 0–350 W)	--	$1.08	$2.16	$3.23	$4.31	$5.47
Tier 2 (751–1,500 S; 351–750 W)	--	$2.73	$5.46	$8.19	$10.93	$13.85
Tier 3 (>1,500 S; >750 W)	--	$5.72	$11.43	$17.15	$22.86	$28.98
Energy Charge ($/kWh) (2)						
Summer On-Peak						
Tier 1 (0–330 kWh)	--	$0.1788	$0.1810	$0.1844	$0.1900	$0.1960
Tier 2 (>330 kWh)	--	$0.2861	$0.2896	$0.2950	$0.3040	$0.3136
Summer Mid-Peak						
Tier 1 (0–550 kWh)	--	$0.1162	$0.1177	$0.1199	$0.1235	$0.1274
Tier 2 (> 550 kWh)	--	$0.1859	$0.1883	$0.1918	$0.1976	$0.2038
Summer Off-Peak						
Tier 1 (0–220 kWh)	--	$0.0894	$0.0905	$0.0922	$0.0950	$0.0980
Tier 2 (>220 kWh)	--	$0.1430	$0.1448	$0.1475	$0.1520	$0.1568
Winter On-Peak						
Tier 1 (0–135 kWh)	--	$0.1341	$0.1358	$0.1383	$0.1425	$0.1470
Tier 2 (>135 kWh)	--	$0.2146	$0.2173	$0.2213	$0.2280	$0.2352
Winter Mid-Peak						
Tier 1 (0-250 kWh)	--	$0.1073	$0.1086	$0.1106	$0.1140	$0.1176
Tier 2 (>250 kWh)	--	$0.1717	$0.1738	$0.1770	$0.1824	$0.1882
Winter Off-Peak						
Tier 1 (0–115 kWh)	--	$0.0894	$0.0905	$0.0922	$0.0950	$0.0980
Tier 2 (>115 kWh)	--	$0.1430	$0.1448	$0.1475	$0.1520	$0.1568
Reliability Charge						
Small Residence (<100 Amp)	--	$10.00	$10.00	$10.00	$10.00	$10.00
Medium Residence (101–200 Amp)	--	$20.00	$20.00	$20.00	$20.00	$20.00
Large Residence (201-400 Amp)	--	$40.00	$40.00	$40.00	$40.00	$40.00
Very Large Residence (>400 Amp)	--	$60.00	$60.00	$60.00	$60.00	$60.00

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.
(2) Proposed four month summer season of June 1 to September 30 Energy Charge and Network Access Charge. On-peak hours are 2:00 PM to 7:00 PM during summer months and 4:00 PM to 9:00 PM during winter months. Mid-peak hours are 6:00 AM to 2:00 PM and 7:00 PM to 11:00 PM during summer months, and 6:00 AM to 4:00 PM and 9:00 PM to 11:00 PM during winter months. Off-peak hours are 11:00 PM to 6:00 AM throughout the year.

The DTOU EV Only would be applicable only to those customers with an EV and a separately metered dedicated EV charger. This rate includes a customer charge, but does not have a separate reliability charge or NAC. Upon election to receive service under the DTOU EV Only rate, the customer's standard domestic service will receive the tier 3 NAC charge. The DTOU EV Only rate is not tiered by usage, but does include a TOU component for On-/Mid-peak period energy usage. Table 6-16 provides the proposed DTOU EV Only Rates.

Table 6-16
Proposed DTOU EV Only Rates

		Proposed Rates (1)				
Rate Component	Existing	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge	--	$8.81	$9.56	$10.71	$11.96	$13.21
Energy Charge ($/kWh) (2)						
Summer – On-Peak	--	$0.2646	$0.2679	$0.2729	$0.2812	$0.2901
Summer – Mid-Peak	--	$0.1511	$0.1530	$0.1559	$0.1606	$0.1656
Summer – Off-Peak	--	$0.1001	$0.1014	$0.1033	$0.1064	$0.1098
Winter – On-Peak	--	$0.1985	$0.2010	$0.2047	$0.2109	$0.2176
Winter – Mid-Peak	--	$0.1395	$0.1412	$0.1438	$0.1482	$0.1529
Winter – Off-Peak	--	$0.1001	$0.1014	$0.1033	$0.1064	$0.1098

(1) Rate changes are effective April 1st of 2018 and January 1st of each subsequent year.

(2) Proposed four month summer season of June 1 to September 30 Energy Charge. On-peak hours are 2:00 PM to 7:00 PM during summer months and 4:00 PM to 9:00 PM during winter months. Mid-peak hours are 6:00 AM to 2:00 PM and 7:00 PM to 11:00 PM during summer months, and 6:00 AM to 4:00 PM and 9:00 PM to 11:00 PM during winter months. Off-peak hours are 11:00 PM to 6:00 AM throughout the year.

Other Existing Rates Schedules

RPU provides a variety of services to other rate classes that are collectively referred to as “Other Rates” for this Study. These rates include “classes within classes,” such as Domestic TOU Tiered (DTOU Tiered), as well as various lighting classes, renewable type classes, agricultural electric use classes and stand-by service, as well as “rate programs” offered by RPU. Each rate was reviewed relative to either its own COS or a comparison to similar RPU class costs (as determined by this Study). Generally speaking, these rate classes have less customers, lower loads, or some other unique applicability relative to the other “major” described herein. Because of these characteristics, it is a challenge to apply system-wide cost allocation factors to these classes. Therefore, many of the rates for these classes and programs are subject to the annual system average rate increase of 4.8% per year. A description of each rate class and programs, as well as proposed rate/rate structure changes, as appropriate, is discussed below. Each proposed rate schedule is provided in Appendix A to this Report.

Schedule DTOU Tiered

This rate class includes approximately 80 customers that are on a DTOU Service. The existing rate includes a customer charge, a tiered summer/winter On-/Off-Peak energy charge, and a tiered reliability charge (identical to the Domestic Reliability Charge). Proposed changes to this rate include an increase in the customer charge and the addition of the NAC (both rates are set to be identical to the proposed Domestic class) and an increase in each energy rate consistent with the increase in the Domestic energy rate change per year. Proposed rates are provided in Table Appendix A-1.

Schedule ED – Economic Development Rates

Many utilities, including RPU, have developed Economic Development (ED) Rates. RPU's ED Rate is tied to the OAT and requires a certain level of investment for specified industries (defined by government codes). The ED Rate provides a gradual increase on a percentage basis over a three-year period to the full implementation of the OAT. The increased load benefits all customers as RPU's fixed costs are allocated to more units. No changes are proposed to this rate or rate structure as a result of this Study.

Schedule Feed-In-Tariff

RPU provides a Feed-in Tariff (FIT) rate for customer-generators of no more than 3 MW who wish to sell output from renewable generation to RPU. The FIT is defined by a tariff and is adjusted annually to reflect RPU's average cost of all renewable energy purchased by RPU. There are currently no customers that are provided service under the RPU's FIT. No changes are proposed to the FIT tariff as a result of this Study.

Schedule LS-2

RPU provides two types of services to customers who install and own their own street lighting systems. The first service is an "Energy Only" service, whereas the customer is responsible for the maintenance and operations of their systems and RPU provides the necessary energy. The second type of services is "Energy and Maintenance" whereas RPU provides the energy and maintenance services on the customer-owned lighting facilities. Both services are charged an annual fee on a per light per lumen basis (there are different rates for Incandescent, Mercury Vapor, and Sodium Vapor type lights, as well as varying lumens within each light type). The existing differential between the Energy Only and Energy and Maintenance is based on costs, and averages approximately $20.59 per month. Proposed changes to this rate class include an annual increase of 4.8% per year for existing lights, as well as the development of Energy Only, and Energy and Maintenance services for customer-owned LED lighting. This is done on an "equivalent lumen" basis utilizing the existing rates and rate structures. See Tables Appendix A-2 through A-5 for revised Energy Only and Energy and Maintenance rates for non-LED lights and LED lights for the Schedule LS-2.

Schedule NEM

As indicated, RPU provides a NEM tariff for eligible customer-generators. The "Standard Contract" provides the terms and conditions for NEM customers under their OAT, and includes specific provisions with regard to the size of the renewable electrical generation facility of up to 1MW and to compensation for the customer's net generation. NEM customers that could qualify for the FIT rate choose NEM because it is financially advantageous. No changes to the existing Schedule NEM are proposed as a result of this Study.

Schedule OL

Similar to Schedule LS-1, RPU offers services for outdoor lighting whereby the equipment is owned, installed, and maintained by RPU. The rates for this tariff are applicable to two specific lumen ratings for two types of lighting fixtures (Mercury Vapor and Sodium Vapor). RPU proposes to increase the existing rate structure at the annual rate of 4.8%. RPU also proposes to offer an "LED" lumen equivalent rate for this tariff. Proposed changes for these rates are provided in Tables Appendix A-6 and A-7.

Schedule PA

RPU offers a specific rate for water pumping services for general agricultural use, referred to as "Power – Agricultural Pumping." This rate is based on an annual service charge that varies by the horsepower rating of the pump, as well as a flat energy rate and Reliability Charge. Proposed changes to this rate include an increase in each energy rate by approximately 4.8% per year, which results in a total rate class revenue increase on a percentage basis similar to the increase required for the system over the Study period (the Revenue Requirement). Additionally, customers in this class will be subject to the Commercial – Flat tiered NAC. Proposed rate tariff additions are provided in Table Appendix A-8.

Schedule PW 1

RPU offers a specific rate for agricultural customers that utilize wind machines for frost protection of their crops. This rate includes a customer charge and a tiered energy change (based on a tier of 15,000 kWh). Given the seasonality of this specific load, the meters on this tariff are read annually. Proposed changes to this tariff include the addition of a NAC, as well as adjustments to the energy rate (based on the proposed Commercial – Flat NAC and energy rate changes). Table Appendix A-9 includes the proposed rate changes for this tariff.

Schedule S

RPU offers Stand-by Service to non-residential customers that provide all or part of their load with generation located on the customer's premises. The stand-by service includes a demand charge based on the size of the customer's contract demand that is tiered at 50 kilo-volts (kV). The standby charge is designed to recover a portion of RPU's fixed costs investment that stands ready to serve the customer's load in the event their on-site generation fails or is off-line due to scheduled maintenance.

The customer is also responsible for customer, energy, demand, NAC, and reliability charges as defined in their OAT. Proposed changes to this tariff include adjustments to the Stand-by Charge based on adjustments to the On-Peak demand rate proposed for the Industrial TOU tariff. Table Appendix A-10 includes the proposed rate changes for this tariff.

Schedule TC

RPU offers service under its Traffic Control tariff for all traffic signals. This service is charged on an energy only rate. Proposed changes to this tariff are based on the analysis conducted for the Study and include annual adjustments of 4.8%. Table Appendix A-11 includes the proposed changes to this tariff.

RPU Rate Programs

RPU provides service under a variety of rate programs designed to address unique rate options. Several of these programs are designed for residential customers with qualifying medical equipment, as well as its Multi-Family program that is designed to provide service to master metered dwellings, such as mobile-home parks. RPU has offered All-Electric, Electric Water Heater, and Electric Space Heater rate programs in the past; however, these specific rate programs are no longer open to additional customers. RPU is proposing to maintain the structure of these programs, as they existed prior to November 2010; however, the NAC charges will apply. Additionally, rates for these services will change with the changes in RPU's system costs.

RPU offers service to the California Department of Transportation (CalTrans) for street lights along the state owned highways within its service territory. The CalTrans rate is equivalent to the Commercial – Flat energy rate based on estimated energy usage. The intent is to meter this service in the future. Specific proposed changes to the rate programs are discussed below.

All Electric Service

RPU offered service to customers with "All –Electric" appliances and load, as well as to customers with Electric Water Heater and Electric Space Heater appliances. RPU currently services approximately 1,400 customers within these three programs; however, these rates are closed to new customers who did not take building permits or wiring permits before March 1, 1974. Proposed changes for this rate program include an increased customer charge, addition of a NAC (based on the changes for the Domestic rate), and an increase in the energy charge. The energy rate is adjusted to increase the revenue for each of these rate programs to recognize the Revenue Requirement for the system. Proposed rates for these three programs is included in Table Appendix A-12A, A-12B and A-12C.

Multi-Family Service

RPU offers service for "master-meter" communities under its Multi-Family Service rate program to approximately 200 customers. Service under this rate program is currently charged a customer charge, a tiered energy charge, and a Reliability Charge similar to the Domestic rates. Proposed changes include an increased customer charge, the addition of the NAC, and increased energy charges. See Table 6-3 for the proposed changes to the rate components applicable to this rate program, which are equivalent to the Domestic rates.

CalTrans Service

Service provided to the CalTrans for street lights is charged for estimated energy utilizing the Commercial – Flat energy rate. The rates for this program do not include the associated customer service or proposed NAC charges. However, to move this program closer to its COS, the energy rate will increase over the Rate Plan period similar to the Commercial – Flat energy rate, as provided in Table 6-5. As indicated, RPU intends to meter this service in the future.

Adjustable Rate Mechanisms

The following adjustable rate mechanism is under consideration by RPU for inclusion in this Five-Year Rate Plan.

Regulatory and Power Cost Adjustment

Regulatory and Power Cost Adjustment (RPCA) is a mechanism used by utilities to allow for the recovery of non-budgeted costs associated with regulatory requirements, and the production and purchase of energy delivered to the utility that are not recovered through the base rate in order to minimize the fluctuations in rates. The RPCA allows for the recovery of non-budgeted costs incurred by the utility that are associated with federal or state climate change laws, RPS, or other mandated legislation. Such regulatory costs may include, but are not limited to energy efficiency and load reduction, environmental remediation, renewable power supply integration costs, and carbon or other greenhouse gas emission costs. The RPCA also includes power supply costs that may include, but are not limited to power production costs, purchased power costs, and debt service costs. If implemented, the RPCA will be applied to kWh sold. The RPCA, which may be either positive or negative, will be reviewed and revised annually to reflect actual changes in excess of the base rate. The RCPA is proposed to be set at $0.00/kWh at the beginning of the rate adjustment period (FY 2018).

Conclusions

Based on the results of the analysis completed for this Study, the following conclusions are presented:

- RPU seeks to advance the City's mission to provide high-quality municipal water and electric utility services to its customers. This mission is detailed in the infrastructure improvements and upgrades identified in RPU's Utility 2.0 Plan. RPU's current rates and rate structures are insufficient to provide the revenue necessary to support these improvements. Based on the development of the Test Year Revenue Requirement from RPU's Pro Forma Financial Model, current rates are not projected to generate sufficient revenues to cover its projected costs. This shortfall is expected to be approximately $184.2 million at the end of the Five-Year Rate Plan.
- RPU's existing rate components (e.g. demand, customer charge and energy) are not properly aligned with its fixed and variable costs. These existing rates and rate structures contribute to RPU's current under-recovery of its fixed costs from fixed revenues. The proposed changes herein provide for an increase in RPU's fixed cost recovery through fixed revenues, consistent with its established rate objectives.

Recommendations

Based on the conclusions and supporting analyses, presented herein, the following recommendations are proposed:

- The City should adopt rates as described and proposed in Five-Year Rate Plan and this Report.
- The City should continue its efforts to increase the fixed cost recovery mechanisms in its rate structures.
- The City should continue to invest in infrastructure, equipment, and personnel to ensure its ability to meet customer demand for innovation and reliable power supply.
- The City should continue to monitor and evaluate evolving technologies, systems, and operations to maximize its investments.

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Appendix A
PROPOSED RATES – OTHER CUSTOMER CLASSES

The following provides a summary of the proposed rates for RPU's Other Classes, including Domestic TOU Tiered (DTOU Tiered), LED and non-LED rates for customer owned street lights (LS-2) and Department owned outdoor lights (OL), power agriculture (PA), wind frost protection rate (PW-1), Standby Service (Schedule S), and Traffic Control (Schedule TC). See text for details on proposed rate changes.

Additionally, proposed rate changes for RPU's Rate Programs, including All Electric, Electric Water Heater, and Electric Space Heater are included following the Other Class rates. See text for additional information on proposed changes to the rates for these programs.

Schedule DTOU Tiered

Table A-1
Schedule DTOU Tiered (1)

Rate Component	Existing	Proposed Rates				
		FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge	$8.06	$8.81	$9.56	$10.71	$11.96	$13.21
Network Access Charge						
Tier 1 (0–750 S; 0–350 W)	--	$1.08	$2.16	$3.23	$4.31	$5.47
Tier 2 (751–1,500 S; 351–750 W)	--	$2.73	$5.46	$8.19	$10.93	$13.85
Tier 3 (>1,500 S; >750 W)	--	$5.72	$11.43	$17.15	$22.86	$28.98
Energy Charge						
Summer On-Peak						
0 - 145 kWh	$0.1800	$0.1843	$0.1866	$0.1901	$0.1958	$0.2019
> 145 kWh	$0.4500	$0.4608	$0.4666	$0.4754	$0.4897	$0.5050
Summer Off-Peak						
0 - 1,125 kWh	$0.0850	$0.0871	$0.0882	$0.0898	$0.0925	$0.0954
> 1,125 kWh	$0.1200	$0.1230	$0.1246	$0.1269	$0.1307	$0.1348
Winter On-Peak						
0 - 60 kWh	$0.2000	$0.2048	$0.2073	$0.2112	$0.2176	$0.2244
> 60 kWh	$0.3550	$0.3635	$0.3679	$0.3748	$0.3862	$0.3983
Winter Off-Peak						
0 - 500 kWh	$0.0950	$0.0973	$0.0985	$0.1003	$0.1033	$0.1065
> 500 kWh	$0.1520	$0.1557	$0.1576	$0.1605	$0.1653	$0.1704
Reliability Charge						
Small Residence (<100 Amp)	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
Medium Residence (101–200 Amp)	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Large Residence (201-400 Amp)	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00
Very Large Residence (>400 Amp)	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.

Schedule LS-2

Table A-2
Existing Schedule LS-2 (Energy Only) (1)

Light Type (Wattage)	Existing Rate	FY 2018 Energy Only	FY 2019 Energy Only	FY 2020 Energy Only	FY 2021 Energy Only	FY 2022 Energy Only
Incandescent						
1,000	$42.52	$44.56	$46.70	$48.94	$51.29	$53.75
2,500	$88.83	$93.09	$97.56	$102.25	$107.15	$112.30
4,000	$135.72	$142.23	$149.06	$156.22	$163.72	$171.57
6,000	$156.13	$163.62	$171.48	$179.71	$188.34	$197.38
Mercury Vapor						
7,000	$95.46	$100.04	$104.84	$109.88	$115.15	$120.68
10,000	$131.66	$137.98	$144.60	$151.54	$158.82	$166.44
20,000	$209.59	$219.65	$230.19	$241.24	$252.82	$264.96
35,000	$361.49	$378.84	$397.03	$416.08	$436.06	$456.99
55,000	$508.17	$532.56	$558.13	$584.92	$612.99	$642.41
High Pressure Sodium						
5,800	$40.37	$42.31	$44.34	$46.47	$48.70	$51.03
9,500	$63.74	$66.80	$70.01	$73.37	$76.89	$80.58
16,000	$92.56	$97.00	$101.66	$106.54	$111.65	$117.01
22,000	$119.23	$124.95	$130.95	$137.24	$143.82	$150.73
25,000	$143.81	$150.71	$157.95	$165.53	$173.47	$181.80
40,000	$219.57	$230.11	$241.15	$252.73	$264.86	$277.57

(1) LS-2 Rate Schedule is for Customer Owned Lights, whereby RPU provides either the energy or the energy and maintenance for the light. The rates are proposed to be charged annually per LED light by watt rating. Rate changes are effective April 1, 2018 and January 1st of each subsequent year.

Table A-3
Existing LS-2 Street Lights (Energy and Maintenance) (1)

Light Type (Wattage)	Existing Rate	FY 2018 Energy and Maintenance	FY 2019 Energy and Maintenance	FY 2020 Energy and Maintenance	FY 2021 Energy and Maintenance	FY 2022 Energy and Maintenance
Incandescent						
1,000	$54.19	$56.79	$59.52	$62.37	$65.37	$68.51
2,500	$103.43	$108.39	$113.60	$119.05	$124.76	$130.75
4,000	$156.13	$163.62	$171.48	$179.71	$188.34	$197.38
6,000	$196.96	$206.41	$216.32	$226.71	$237.59	$248.99
Mercury Vapor						
7,000	$115.88	$121.44	$127.27	$133.38	$139.78	$146.49
10,000	$155.00	$162.44	$170.24	$178.41	$186.97	$195.95
20,000	$237.29	$248.68	$260.62	$273.13	$286.24	$299.98
35,000	$399.38	$418.55	$438.64	$459.70	$481.76	$504.89
55,000	$559.21	$586.05	$614.18	$643.66	$674.56	$706.94
High Pressure Sodium						
5,800	$53.50	$56.07	$58.76	$61.58	$64.54	$67.63
9,500	$78.32	$82.08	$86.02	$90.15	$94.48	$99.01
16,000	$108.61	$113.82	$119.29	$125.01	$131.01	$137.30
22,000	$135.28	$141.77	$148.58	$155.71	$163.18	$171.02
25,000	$161.30	$169.04	$177.16	$185.66	$194.57	$203.91
40,000	$244.36	$256.09	$268.38	$281.26	$294.76	$308.91

(1) LS-2 Rate Schedule is for Customer Owned Lights, whereby RPU provides either the energy or the energy and maintenance for the light. The rates are proposed to be charged annually per LED light by watt rating. Rate changes are effective April 1, 2018 and January 1st of each subsequent year.

Table A-4
LED Additions to Schedule LS-2 (Energy Only) (1)

LED Watt Size	Lumen Equivalent (Average)	FY 2018 LED Rate – Energy Only	FY 2019 LED Rate – Energy Only	FY 2020 LED Rate – Energy Only	FY 2021 LED Rate – Energy Only	FY 2022 LED Rate – Energy Only
42	3,100	$57.71	$60.48	$63.38	$66.43	$69.61
58	6,750	$94.72	$99.27	$104.03	$109.02	$114.26
93	9,667	$109.20	$114.44	$119.93	$125.69	$131.72
139	17,333	$130.22	$136.47	$143.02	$149.89	$157.08
185	25,000	$146.23	$153.25	$160.61	$168.31	$176.39
275	37,500	$231.20	$242.30	$253.93	$266.12	$278.89
432	55,000	$302.02	$316.52	$331.71	$347.63	$364.32

(1) LS-2 Rate Schedule is for Customer Owned Lights, whereby RPU provides either the energy or the energy and maintenance for the light. The rates are proposed to be charged annually per LED light by watt rating. Rate changes are effective April 1, 2018 and January 1st of each subsequent year.

Table A-5
LED Additions to Schedule LS-2 (Energy and Maintenance) (1)

LED Watt Size	Lumen Equivalent (Average)	FY 2018 LED Rate – Energy and Maintenance	FY 2019 LED Rate – Energy and Maintenance	FY 2020 LED Rate – Energy and Maintenance	FY 2021 LED Rate – Energy and Maintenance	FY 2022 LED Rate – Energy and Maintenance
42	3,100	$71.48	$74.91	$78.51	$82.28	$86.22
58	6,750	$113.06	$118.49	$124.17	$130.13	$136.38
93	9,667	$136.21	$142.75	$149.60	$156.78	$164.31
139	17,333	$153.65	$161.03	$168.75	$176.85	$185.34
185	25,000	$164.56	$172.46	$180.74	$189.41	$198.50
275	37,500	$264.05	$276.72	$290.01	$303.93	$318.52
432	55,000	$355.51	$372.57	$390.46	$409.20	$428.84

(1) LS-2 Rate Schedule is for Customer Owned Lights, whereby RPU provides either the energy or the energy and maintenance for the light. The rates are proposed to be charged annually per LED light by watt rating. Rate changes are effective April 1, 2018 and January 1st of each subsequent year.

Schedule OL

Table A-6
Schedule OL (1)

Light Type/Lumen	Rates – Existing	Proposed 2018	Proposed 2019	Proposed 2020	Proposed 2021	Proposed 2022
Mercury Vapor						
7,000	$10.33	$10.83	$11.35	$11.89	$12.46	$13.06
20,000	$18.25	$19.13	$20.05	$21.01	$22.02	$23.08
High Pressure Sodium						
9,500	$10.39	$10.89	$11.41	$11.96	$12.53	$13.13
16,000	$14.55	$15.25	$15.98	$16.75	$17.55	$18.39

(1) OL Rate Schedule is for Outdoor Lights that are owned, installed, and maintained by RPU. The rates are charged monthly per light by watt rating. Rate changes are effective April 1, 2018 and January 1st of each subsequent year.

Table A-7
LED Additions to Schedule OL

Light Type/Lumen	Rates – Existing	LED Bulbs (Watts)	Proposed LED Rate
Mercury Vapor			
7,000	$10.33	93	$13.24
20,000	$18.25	139	$15.75
High Pressure Sodium			
9,500	$10.39	58	$11.83
16,000	$14.55	93	$13.24

Schedule PA

Table A-8
Power – Agricultural Pumping (1)

Rate Component	Existing	Proposed Rates FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Effective Customer Charge	$45.38	$47.56	$49.84	$52.23	$54.74	$57.37
Network Access Charge ($/month)						
Tier 1 (0–500 kWh)	--	$1.77	$3.55	$5.32	$5.91	$6.50
Tier 2 (501-1500 kWh)	--	$5.03	$10.06	$15.09	$16.77	$18.45
Tier 3 (1501 – 3000 kWh)	--	$8.95	$17.90	$26.85	$29.83	$32.82
Tier 4 (>3000 kWh)	--	$21.53	$43.06	$64.59	$71.77	$78.95
Energy Charge						
All kWh (kWh)	$0.0962	$0.1008	$0.1057	$0.1107	$0.1160	$0.1216
Reliability Charge ($/month)	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.
(2) Effective Customer Charge is an annual service charge that varies by the horsepower rating of the pump.
(3) Reliability Charge same as Commercial – Flat Tier 3.

Schedule PW 1

Table A-9
Wind Frost Protection (1)

Rate Component	Existing	Proposed Rates FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge	$20.50	$20.50	$20.50	$20.50	$20.50	$20.50
Network Access Charge						
Tier 1 (0–500 kWh)	--	$1.77	$3.55	$5.32	$5.91	$6.50
Tier 2 (501–1500 kWh)	--	$5.03	$10.06	$15.09	$16.77	$18.45
Tier 3 (1501–3000 kWh)	--	$8.95	$17.90	$26.85	$29.83	$32.82
Tier 4 (>3000 kWh)	--	$21.53	$43.06	$64.59	$71.77	$78.95
Energy Charge						
Tier 1 (0–15,000 kWh)	$0.1351	$0.1381	$0.1411	$0.1441	$0.1471	$0.1501
Tier 2 (> 15,000 kWh)	$0.2064	$0.2110	$0.2156	$0.2201	$0.2247	$0.2293

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.

Schedule S

Table A-10
Schedule S (Standby Service) (1)

Rate Component	Existing	Proposed Rates FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Demand Charge						
Tier 1 - <= 50 kV	$6.11	$6.88	$7.03	$7.18	$7.23	$7.28
Tier 2 - > 50 kV	$4.10	$4.62	$4.72	$4.82	$4.85	$4.89

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.

Schedule TC

Table A-11
Schedule TC (Traffic Control) (1)

Rate Component	Existing	Proposed Rates FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Energy Charge (all kWh)						
$/kWh	$0.0948	$0.0994	$0.1041	$0.1091	$0.1144	$0.1198

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.

RPU Rate Programs

All Electric Service

Table A-12A
All Electric [1], [2]

Rate Component	Existing	Proposed Rates FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge	$8.06	$8.81	$9.56	$10.71	$11.96	$13.21
Network Access Charge						
Tier 1 (0–750 S; 0–350 W)	--	$1.08	$2.16	$3.23	$4.31	$5.47
Tier 2 (751–1,500 S; 351–750 W)	--	$2.73	$5.46	$8.19	$10.93	$13.85
Tier 3 (>1,500 S; >750 W)	--	$5.72	$11.43	$17.15	$22.86	$28.98
Energy Charge - Summer						
0–750 kWh	$0.1035	$0.1060	$0.1073	$0.1093	$0.1126	$0.1161
751–1,500 kWh	$0.1646	$0.1686	$0.1706	$0.1738	$0.1791	$0.1846
> 1,500 kWh	$0.1637	$0.1677	$0.1697	$0.1728	$0.1781	$0.1836
Energy Charge - Winter						
0–350 kWh	$0.1035	$0.1060	$0.1073	$0.1093	$0.1126	$0.1161
351–750 kWh	$0.1646	$0.1686	$0.1706	$0.1738	$0.1791	$0.1846
>750 kWh	$0.1637	$0.1677	$0.1697	$0.1728	$0.1781	$0.1836

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.
(2) Reliability charged as Domestic.

Table A-12B
Electric Water Heater (1), (2)

Rate Component	Existing	Proposed Rates FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge	$8.06	$8.81	$9.56	$10.71	$11.96	$13.21
Network Access Charge						
Tier 1 (0–750 S; 0–350 W)	--	$1.08	$2.16	$3.23	$4.31	$5.47
Tier 2 (751–1,500 S; 351–750 W)	--	$2.73	$5.46	$8.19	$10.93	$13.85
Tier 3 (>1,500 S; >750 W)	--	$5.72	$11.43	$17.15	$22.86	$28.98
Energy Charge - Summer						
0–600 kWh	$0.1035	$0.1060	$0.1073	$0.1093	$0.1126	$0.1161
601–950 kWh	$0.1169	$0.1197	$0.1212	$0.1234	$0.1272	$0.1311
951–1500 kWh	$0.1646	$0.1686	$0.1706	$0.1738	$0.1791	$0.1846
> 1,500 kWh	$0.1867	$0.1912	$0.1936	$0.1972	$0.2031	$0.2094
Energy Charge - Winter						
0–350 kWh	$0.1035	$0.1060	$0.1073	$0.1093	$0.1126	$0.1161
351–600 kWh	$0.1646	$0.1686	$0.1706	$0.1738	$0.1791	$0.1846
601–950 kWh	$0.1169	$0.1197	$0.1212	$0.1234	$0.1272	$0.1311
>950 kWh	$0.1867	$0.1912	$0.1936	$0.1972	$0.2031	$0.2094

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.
(2) Reliability charged as Domestic.

Table A-12C
Electric Space Heater (1), (2)

Rate Component	Existing	Proposed Rates				
		FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Customer Charge	$8.06	$8.81	$9.56	$10.71	$11.96	$13.21
Network Access Charge						
Tier 1 (0–750 S; 0–350 W)	--	$1.08	$2.16	$3.23	$4.31	$5.47
Tier 2 (751–1,500 S; 351–750 W)	--	$2.73	$5.46	$8.19	$10.93	$13.85
Tier 3 (>1,500 S; >750 W)	--	$5.72	$11.43	$17.15	$22.86	$28.98
Energy Charge - Summer						
0–750 kWh	$0.1035	$0.1060	$0.1073	$0.1093	$0.1126	$0.1161
751–1500 kWh	$0.1646	$0.1686	$0.1706	$0.1738	$0.1791	$0.1846
> 1,500 kWh	$0.1867	$0.1912	$0.1936	$0.1972	$0.2031	$0.2094
Energy Charge - Winter						
0–350 kWh	$0.1035	$0.1060	$0.1073	$0.1093	$0.1126	$0.1161
351–750 kWh	$0.1646	$0.1686	$0.1706	$0.1738	$0.1791	$0.1846
>750 kWh	$0.1637	$0.1677	$0.1697	$0.1728	$0.1781	$0.1836

(1) Rate changes are effective April 1, 2018 and January 1st of each subsequent year.

(2) Reliability charged as Domestic.

Appendix B
TECHNICAL APPENDIX

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NewGen Strategies & Solutions

Model Developer Statement:

Low Intro/Mid NAC

Rate Design

Res.

Item	Rates 2016		Rates 2018	Rates 2019	Rates 2020	Rates 2021	Rates 2022	TY COS-RC	2022 COS-RC
Customer	$8.06		$8.81	$9.56	$10.71	$11.96	$13.21	$12.81	$14.26
Network Access Charge ($/month)									
Tier 1 (0–750 S; 0–350 W)			$1.08	$2.16	$3.23	$4.31	$5.47	$19.51	$21.71
Tier 2 (751–1,500 S; 351–750 W)			$2.73	$5.46	$8.19	$10.93	$13.85	$19.51	$21.71
Tier 3 (>1,500 S; >750 W)			$5.72	$11.43	$17.15	$22.86	$28.98	$19.51	$21.71
Energy Charge ($/kWh)									
Tier 1 (0–750 S; 0–350 W)	$0.1035		$0.1060	$0.1073	$0.1093	$0.1126	$0.1161	$0.1387	$0.1478
Tier 2 (751–1,500 S; 351–750 W)	$0.1646		$0.1686	$0.1706	$0.1738	$0.1791	$0.1846	$0.1387	$0.1478
Tier 3 (>1,500 S; >750 W)	$0.1867		$0.1912	$0.1936	$0.1972	$0.2031	$0.2094	$0.1387	$0.1478
Reliability Charge									
Small Residence (<100 Amp)	$10.00		$10.00	$10.00	$10.00	$10.00	$10.00		
Medium Residence (101–200 Amp)	$20.00		$20.00	$20.00	$20.00	$20.00	$20.00		
Large Residence (201–400 Amp)	$40.00		$40.00	$40.00	$40.00	$40.00	$40.00		
Very Large Residence (>400 Amp)	$60.00		$60.00	$60.00	$60.00	$60.00	$60.00		
Option 1: Delivery Charge (Phase In) = NAC$/kWh			$0.0010	$0.0063	$0.0105	$0.0148	$0.0193		
Option 2: Delivery Charge (Immediate)) - TY			$0.0352						
Distribution Demand Costs			$ 21,742,454	$ 23,245,163	$ 24,572,217	$ 25,952,799	$ 27,332,881		
mwh FULL YEAR			693,538	690,063	687,940	685,556	682,295		
RATE			$0.0314	$0.0337	$0.0357	$0.0379	$0.0401		
NAC Scenario	Cust Incr		$0.75	$0.75	$1.15	$1.25	$1.25		
Low	Energy Incr	T1	$0.0025	$0.0013	$0.0020	$0.0033	$0.0035		
		T2			$0.0032	$0.0053	$0.0055		
		T3			$0.0036	$0.0059	$0.0063		
Average Energy Rate									

Rate Design

Com-Flat

	Rates		Rates	Rates	Rates	Rates	Rates		
Item	2016		2018	2019	2020	2021	2022	TY COS-RC	2022 COS-RC
Customer Charge	$20.50		$20.50	$20.50	$20.50	$20.50	$20.50	$32.67	$36.35
Network Access Charge ($/month)									
Tier 1 (0–500 kWh)			$1.77	$3.55	$5.32	$5.91	$6.50	$59.67	$66.39
Tier 2 (501–1500 kWh)			$5.03	$10.06	$15.09	$16.77	$18.45	$59.67	$66.39
Tier 3 (1501–3000 kWh)			$8.95	$17.90	$26.85	$29.83	$32.82	$59.67	$66.39
Tier 4 (>3000 kWh)			$21.53	$43.06	$64.59	$71.77	$78.95	$59.67	$66.39
Energy Charge ($/kWh)									
Tier 1 (0-15,000 kWh)	$0.1351		$0.1381	$0.1411	$0.1441	$0.1471	$0.1501	$0.1170	$0.1248
Tier 2 (>15,000 kWh)	$0.2064		$0.2110	$0.2156	$0.2201	$0.2247	$0.2293	$0.1170	$0.1248
Reliability Charge									
Tier 1 (0-500 kWh)	$10.00		$10.00	$10.00	$10.00	$10.00	$10.00		
Tier 2 (501–1,500 kWh)	$30.00		$30.00	$30.00	$30.00	$30.00	$30.00		
Tier 3 (>1,500 kWh)	$60.00		$60.00	$60.00	$60.00	$60.00	$60.00		
Option 1: Delivery Charge (Phase In) = NAC$/kWh			$0.0151	$0.0152	$0.0153	$0.0154	$0.0155		
Option 2: Delivery Charge (Immediate)) - TY			$0.0286						
Distribution Demand Costs			$ 7,253,116	$ 7,754,408	$ 8,197,103	$ 8,657,655	$ 9,118,040		
mwh FULL YEAR			276,893.34	280,084.83	283,860.95	287,579.24	291,662.34		
RATE			$0.0262	$0.0277	$0.0289	$0.0301	$0.0313		
	Energy Incr		$0.0030	$0.0030	$0.0030	$0.0030	$0.0030		
	Tier 2 Incr		$0.0713	1.5278					
	NAC Incr								
	Tier 1		$1.77	$3.55	$5.32	$5.91	$6.50		
	Tier 2		$5.03	$10.06	$15.09	$16.77	$18.45		
	Tier 3		$8.95	$17.90	$26.85	$29.83	$32.82		
	Tier 4		$21.53	$43.06	$64.59	$71.77	$78.95		
Average Energy Rate									

Rate Design

	Item	Rates								
		Rates		Rates	Rates	Rates	Rates	Rates		
	Item	2016		2018	2019	2020	2021	2022	TY COS-RC	2022 COS-RC
Com-Dmd	Customer Charge			$8.51	$14.88	$21.26	$27.64	$34.02	$52.52	$58.44
	NAC - $/kW			$1.00	$1.50	$2.00	$2.50	$3.10	$7.96	$8.86
	Energy Charge									
	Tier 1 (0-30,000 kWh)	$0.1111		$0.1131	$0.1171	$0.1211	$0.1261	$0.1321	$0.0670	$0.0715
	Tier 2 (> 30,000 kWh)	$0.1217		$0.1239	$0.1283	$0.1327	$0.1381	$0.1447	$0.0670	$0.0715
	Demand - Fixed Charge	$209.65		$157.95	$159.45	$160.20	$160.95	$161.70	$227.68	$240.66
	Demand - Unit Charge	$10.48		$10.53	$10.63	$10.68	$10.73	$10.78	$15.18	$16.04
	Flat Rate/Reliability Charge	$90.00		$90.00	$90.00	$90.00	$90.00	$90.00		
						kw	kwh			
		Cust Start		$8.51		76.00	17,348.00			
		Cust Incr		$6.38		$88.26				
		NAC Start		$1.00						
		NAC Incr		$0.00	$0.5000	$0.5000	$0.5000	$0.6000		
		Energy Incr		$0.002000	$0.004000	$0.004000	$0.005000	$0.006000		
		Dmd Incr		$0.94						
		Dmd Incr		$0.0500	$0.1000					
		Energy Factor		1.09541						
		Demd Fx		15 kW						
	Average Energy Rate									
TOU	Customer Charge	$704.66		$653.50	$640.70	$627.91	$621.52	$615.12	$191.51	$213.09
	NAC - $/kW			$1.25	$2.60	$4.00	$5.25	$6.25	$10.38	$11.55
	Demand On-Peak	$6.88		$6.88	$7.03	$7.18	$7.23	$7.28	$18.77	$19.83
	Demand Mid-Peak	$2.74		$2.97	$3.28	$3.59	$3.62	$3.64	$18.77	$19.83
	Demand Off-Peak	$1.31		$1.45	$1.62	$1.80	$1.81	$1.82	$18.77	$19.83
	Energy On-Peak	$0.1033		$0.1075	$0.1113	$0.1157	$0.1204	$0.1256	$0.0664	$0.0708
	Energy Mid-Peak	$0.0828		$0.0868	$0.0906	$0.0949	$0.0987	$0.1030	$0.0664	$0.0708
	Energy Off-Peak	$0.0727		$0.0753	$0.0779	$0.0810	$0.0843	$0.0879	$0.0664	$0.0708
	Reliability Charge	$1,100.00								
	<= 100			$912.50	$725.00	$537.50	$350.00	$350.00		
	(100, 150]			$1,012.50	$925.00	$837.50	$750.00	$750.00		
	(150, 250]			$1,050.00	$1,000.00	$950.00	$900.00	$900.00		
	(250, 500]			$1,100.00	$1,100.00	$1,100.00	$1,100.00	$1,100.00		
	(500, 750]			$1,287.50	$1,475.00	$1,662.50	$1,850.00	$1,850.00		
	> 750			$1,487.50	$1,875.00	$2,262.50	$2,650.00	$2,650.00		
	NAC - $/ kW (Average)			$1.35	$2.60	$3.85	$5.10	$6.10		
	NAC High Voltage Adjustment / Rate	-$1.15		$0.20	$1.45	$2.70	$3.95	$4.95		
	NAC Low Voltage Adjustment / Rate	$0.15		$1.25	$2.60	$4.00	$5.25	$6.25		
	Detla	$1.30		$1.05	$1.15	$1.30	$1.30	$1.30		
		LV Incr		-$0.25	-$0.15					
		Cust Incr		-$51.1650	-$12.79	-$12.79	-$6.40	-$6.40		
		NAC Incr		$1.00	$1.25	$1.25	$1.25	$1.00		
		Dmd Incr		$0.0000	$0.1500	$0.1500	$0.0500	$0.0500		
			Current	Proposed						
		Dmd Mid	39.83%	43.22%	46.61%	50.00%	50.00%	50.00%		
		Dmd Off	19.04%	21.03%	23.01%	25.00%	25.00%	25.00%		
		Energy Mid	80.15%	80.77%	81.38%	82.00%	82.00%	82.00%		
		Energy Off	70.38%	70.00%	70.00%	70.00%	70.00%	70.00%		
		Energy Incr		$0.0042	$0.0038	$0.0044	$0.0047	$0.0052		
	Average Energy Rate									

Rate Design

Other

Item	Rates 2016		Rates 2018	Rates 2019	Rates 2020	Rates 2021	Rates 2022	TY COS-RC	2022 COS-RC
					Rates				
City Contract	0.0%		*0.00%*	*3.00%*	*4.00%*	*6.00%*	*6.00%*		
			Aplicable to Energy Only						
Street Lights Cust. Owned	0.0%		4.8%	4.8%	4.8%	4.8%	4.8%		
Street Lights Dept. Owned	0.0%		0.0%	0.0%	0.0%	0.0%	0.0%		
Includes OL Rate Changes			4.8%	4.8%	4.8%	4.8%	4.8%		
Traffic Lights	0.0%		4.8%	4.8%	4.8%	4.8%	4.8%		
Ag Pumping	0.0%		4.8%	4.8%	4.8%	4.8%	4.8%		
Misc. Lighting	0.0%		4.8%	4.8%	4.8%	4.8%	4.8%		
UCR (expires 8/31/2016)									
Ralphs (expires 5/1/2018)									
ROHR (expires 10/1/2015)									
Kaiser (expires 1/1/2016)									
Average Energy Rate									

Rate Design

		Rates								
		Rates		Rates	Rates	Rates	Rates	Rates		
	Item	2016		2018	2019	2020	2021	2022	TY COS-RC	2022 COS-RC
Sub-Classes		**# Meters**								
Res.	RESIDENTIAL- GENERAL SERVICE	93,084		94,459	94,844	95,231	95,621	96,013		
	RESIDENTIAL- LIFELINE 500	1,134		1,174	1,174	1,174	1,174	1,174		
	RESIDENTIAL- LIFELINE 1000	523		540	540	540	540	540		
	RESIDENTIAL- ALL ELECTRIC	538		525	525	525	525	525		
	RESIDENTIAL- Water Heater	490		484	484	484	484	484		
	RESIDENTIAL- Space Heater	290		276	276	276	276	276		
	RESIDENTIAL- Domestic TOU- TIERED	10		83	83	83	83	83		
	RESIDENTIAL- Multi Family	190		190	190	190	190	190		
Com-Flat	COMMERCIAL- FLAT	10,043		10,343	10,534	10,735	10,941	11,152		
	COMMERCIAL- WIND MACHINES	7		7	7	7	7	7		
	COMMERCIAL- UNMETERED- CABLE TV									
Com-Dmd	COMMERCIAL- DEMAND	785		813	828	843	859	875		
TOU	COMMERCIAL- TOU	486		506	507	507	507	507		
	CONTRACT- STAND-BY	5		5	5	5	5	5		
City	CITY CONTRACT RATE- FLAT	231		234	234	234	234	234		
	CITY CONTRACT- DEMAND	60		62	62	62	62	62		
	CITY CONTRACT- TOU	28		28	28	28	28	28		
	CITY CONTRACT AG & PUMPING RATE	5								
SL-Cust.	SCHEDULE LS-2									
SL-Dept.	SCHEDULE LS-1									
	OUTDOOR LIGHTING	450		450	450	450	450	450		
Traffic	TRAFFIC CONTROL- TRAFFIC SIGNALS									
Ag Pump.	POWER-AGRICULTURAL AND PUMPING	48		44	44	44	44	44		
CalTrans	STATE OF CA									
UCR	UCR (expires 8/31/2016)									
Ralphs	Ralphs (expires 5/1/2018)									
ROHR	ROHR (expires 10/1/2015)									
Kaiser	Kaiser (expires 1/1/2016)									
	Total	108,643		110,223	110,813	111,417	112,028	112,648		

Low Intro/Mid NAC

Rate Design

Rate Revenue

Res.

Item	Item		Revenue 2018	Revenue 2019	Revenue 2020	Revenue 2021	Revenue 2022
Customer	Customer Charge		$9,672,685	$10,814,677	$11,980,526	$13,452,046	$14,994,696
Network Access Charge ($/month)							
Tier 1 (0–750 S; 0–350 W)	Network Access Charge		$713,412	$4,354,106	$7,240,123	$10,150,706	$13,193,974
Tier 2 (751–1,500 S; 351–750 W)	Reliability Charge		$13,508,678	$13,561,785	$13,615,231	$13,669,025	$13,723,179
Tier 3 (>1,500 S; >750 W)	Meter Charges		$23,894,775	$28,730,568	$32,835,880	$37,271,777	$41,911,849
Energy Charge ($/kWh)							
Tier 1 (0–750 S; 0–350 W)	*Meter-months*		*1,172,763*	*1,177,381*	*1,182,028*	*1,186,706*	*1,191,415*
Tier 2 (751–1,500 S; 351–750 W)	Energy Charges		$90,511,126	$92,262,672	$93,366,168	$95,255,703	$97,710,888
Tier 3 (>1,500 S; >750 W)	*kWh*		*693,538,240*	*690,063,397*	*687,939,742*	*685,556,224*	*682,294,849*
Reliability Charge							
Small Residence (<100 Amp)	Total $		**$114,405,901**	**$120,993,240**	**$126,202,048**	**$132,527,480**	**$139,622,737**
Medium Residence (101–200 Amp)			-	-	-	-	-
Large Residence (201–400 Amp)	Fixed		21%	24%	26%	28%	30%
Very Large Residence (>400 Amp)	Variable (Energy Only)		79%	76%	74%	72%	70%
Option 1: Delivery Charge (Phase In) = NAC$/kWh	COS		$121,067,119	$129,434,554	$136,823,907	$144,511,311	$152,195,935
Option 2: Delivery Charge (Immediate)) - TY	*% Over/(Under)*		*-5.5%*	*-6.5%*	*-7.8%*	*-8.3%*	*-8.3%*
Distribution Demand Costs					*7.4%*		
mwh FULL YEAR							
RATE							
NAC Scenario							
Low							
Average Energy Rate							

Rate Design

Com-Flat

Item	Item		Revenue 2018	Revenue 2019	Revenue 2020	Revenue 2021	Revenue 2022
Customer Charge	Customer Charge		$2,546,103	$2,592,946	$2,642,373	$2,693,058	$2,745,037
Network Access Charge ($/month)							
Tier 1 (0–500 kWh)	Network Access Charge		$270,102	$1,575,876	$2,665,777	$3,435,181	$3,868,519
Tier 2 (501–1500 kWh)	Reliability Charge		$4,183,903	$4,261,030	$4,342,580	$4,426,204	$4,511,963
Tier 3 (1501–3000 kWh)	Meter Charges		$7,000,109	$8,429,851	$9,650,729	$10,554,442	$11,125,519
Tier 4 (>3000 kWh)	*Meter-months*		*124,200*	*126,485*	*128,896*	*131,369*	*133,904*
Energy Charge ($/kWh)							
Tier 1 (0-15,000 kWh)	Energy Charges		$39,112,199	$40,633,939	$42,067,674	$43,514,763	$45,044,533
Tier 2 (>15,000 kWh)	*kWh*		*276,893,338*	*280,084,829*	*283,860,948*	*287,579,243*	*291,662,343*
Reliability Charge							
Tier 1 (0-500 kWh)	Total $		**$46,112,308**	**$49,063,790**	**$51,718,403**	**$54,069,205**	**$56,170,051**
Tier 2 (501–1,500 kWh)			-	-	-	-	-
Tier 3 (>1,500 kWh)							
	COS		$40,620,835	$43,428,304	$45,907,604	$48,486,906	$51,065,277
Option 1: Delivery Charge (Phase In) = NAC$/kWh							
Option 2: Delivery Charge (Immediate)) - TY							
Distribution Demand Costs							
mwh FULL YEAR							
RATE	*%*		*13.5%*	*13.0%*	*12.7%*	*11.5%*	*10.0%*
Average Energy Rate							

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CITY OF RIVERSIDE
PUBLIC UTILITIES

Rate Design

Rate Revenue

	Item	Item	Revenue 2018	Revenue 2019	Revenue 2020	Revenue 2021	Revenue 2022
Com-Dmd	Customer Charge	Customer Charge	$20,881	$116,306	$182,988	$252,126	$323,814
	NAC - $/kW	Network Access Charge	$0	$0	$0	$0	$0
	Energy Charge						
	Tier 1 (0-30,000 kWh)	Reliability Charge	$878,318	$893,974	$910,494	$927,435	$944,808
	Tier 2 (> 30,000 kWh)	Meter Charges	$899,198	$1,010,279	$1,093,482	$1,179,560	$1,268,622
	Demand - Fixed Charge	*Meter-months*	*9,759*	*9,933*	*10,117*	*10,305*	*10,498*
	Demand - Unit Charge	Energy Charges	$17,952,090	$18,704,565	$19,612,862	$20,610,015	$21,824,358
	Flat Rate/Reliability Charge	*kWh*	*159,012,746*	*160,810,298*	*162,939,582*	*165,036,166*	*167,339,555*
		Demand-Related	$5,522,161	$6,151,051	$6,538,228	$6,918,340	$7,339,512
		kW	*514,265*	*520,578*	*527,595*	*534,555*	*542,019*
		Total $	**$24,373,450**	**$25,865,895**	**$27,244,572**	**$28,707,915**	**$30,432,491**
			-	-	-	-	-
		COS	$21,026,647	$22,479,884	$23,763,249	$25,098,379	$26,433,026
		%	*15.9%*	*15.1%*	*14.7%*	*14.4%*	*15.1%*
	Average Energy Rate						
TOU	Customer Charge	Customer Charge	$4,197,901	$3,933,121	$3,855,376	$3,797,041	$3,758,169
	NAC - $/kW	Network Access Charge	$0	$0	$0	$0	$0
	Demand On-Peak	Reliability Charge	$6,678,447	$6,707,605	$6,722,149	$6,736,692	$6,743,973
	Demand Mid-Peak	Meter Charges	$10,876,348	$10,640,727	$10,577,525	$10,533,733	$10,502,142
	Demand Off-Peak	*Meter-months*	*6,127*	*6,137*	*6,137*	*6,137*	*6,137*
	Energy On-Peak	Energy Charges	$74,182,668	$80,888,147	$85,254,557	$89,935,258	$95,048,650
	Energy Mid-Peak	*kWh*	*910,321,091*	*946,298,813*	*959,134,688*	*971,644,035*	*985,668,299*
	Energy Off-Peak	Demand-Related	$20,591,953	$22,870,324	$24,295,509	$25,333,376	$25,915,722
		NAC - High Voltage	$128,921	$916,217	$1,703,513	$2,490,809	$3,120,646
		NAC - Low Voltage	$1,885,917	$4,110,403	$6,414,271	$8,537,630	$10,319,684
	Reliability Charge	*kW*	*2,133,773*	*2,208,340*	*2,231,808*	*2,254,818*	*2,279,934*
	<= 100	Total $	**$107,665,806**	**$119,425,817**	**$128,245,375**	**$136,830,806**	**$144,906,844**
	(100, 150]		-	-	-	-	-
	(150, 250]	Less Voltage Adjustment	-$801,079	-$801,079	-$801,079	-$801,079	-$801,079
	(250, 500]						
	(500, 750]	COS	$111,576,587	$119,288,094	$126,098,190	$133,182,973	$140,265,195
	> 750	*%*	*-3.5%*	*0.1%*	*1.7%*	*2.7%*	*3.3%*
	NAC - $/ kW (Average)						
	NAC High Voltage Adjustment / Rate						
	NAC Low Voltage Adjustment / Rate						
	Detla						
	Average Energy Rate						

Rate Design

Item	Item		Rate Revenue: Revenue 2018	Revenue 2019	Revenue 2020	Revenue 2021	Revenue 2022
Other							
City Contract	Total $		$7,222,263	$7,548,006	$7,948,322	$8,393,061	$8,849,112
	COS $		$7,085,994	$7,575,735	$8,008,230	$8,458,170	$8,907,947
	%		*1.923%*	*-0.366%*	*-0.748%*	*-0.770%*	*-0.660%*
Street Lights Cust. Owned	Total $		$38,378	$40,697	$42,650	$44,697	$46,843
	COS $		$58,967	$63,043	$66,642	$70,386	$74,129
	%		*-35%*	*-35%*	*-36%*	*-36%*	*-37%*
Street Lights Dept. Owned	Total $		$4,490,027	$4,496,443	$4,501,848	$4,507,512	$4,513,448
Includes OL Rate Changes	COS $		$3,910,636	$4,180,916	$4,419,602	$4,667,916	$4,916,140
	%		*15%*	*8%*	*2%*	*-3%*	*-8%*
Traffic Lights	Total $		$122,213	$129,597	$135,818	$142,337	$149,169
	COS $		$299,457	$320,154	$338,431	$357,446	$376,454
	%		*-59%*	*-60%*	*-60%*	*-60%*	*-60%*
Ag Pumping	Total $		$127,145	$138,405	$147,913	$156,074	$162,903
	COS $		$101,889	$108,931	$115,150	$121,619	$128,086
	%		*25%*	*27%*	*28%*	*28%*	*27%*
Misc. Lighting	Total $		$21,276	$22,562	$23,645	$24,780	$25,969
	COS $		$41,985	$44,887	$47,449	$50,115	$52,780
	%		*-49%*	*-50%*	*-50%*	*-51%*	*-51%*
UCR (expires 8/31/2016)	Total $		$0	$0	$0	$0	$0
Ralphs (expires 5/1/2018)	Total $		$2,002,005	$0	$0	$0	$0
ROHR (expires 10/1/2015)	Total $		$0	$0	$0	$0	$0
Kaiser (expires 1/1/2016)	Total $		$0	$0	$0	$0	$0
Average Energy Rate			**$14,023,306**	**$12,375,709**	**$12,800,195**	**$13,268,461**	**$13,747,444**

Rate Design

Sub-Classes	Item	Item / Rates	Revenue 2018	Revenue 2019	Revenue 2020	Revenue 2021	Revenue 2022
			-	-	-	-	-
Res.	RESIDENTIAL- GENERAL SERVICE	Inputs	$ 108,149,736	$ 114,478,155	$ 119,500,977	$ 125,583,103	$ 132,382,607
	RESIDENTIAL- LIFELINE 500	Inputs	$ 1,597,919	$ 1,679,103	$ 1,739,598	$ 1,814,942	$ 1,903,352
	RESIDENTIAL- LIFELINE 1000	Inputs	$ 769,959	$ 807,724	$ 835,935	$ 871,318	$ 912,943
	RESIDENTIAL- ALL ELECTRIC	Unique Tier 3 kWh, see comment	$ 748,552	$ 785,419	$ 812,877	$ 847,598	$ 888,102
	RESIDENTIAL- Water Heater	Unique Tier 3 kWh, see comment	$ 810,196	$ 846,265	$ 872,753	$ 906,851	$ 948,597
	RESIDENTIAL- Space Heater	Inputs	$ 316,008	$ 334,205	$ 347,913	$ 364,724	$ 384,066
	RESIDENTIAL- Domestic TOU- TIERED	Unique kWh charges, see comment	$ 181,771	$ 188,603	$ 193,547	$ 200,087	$ 208,025
	RESIDENTIAL- Multi Family	Inputs	$ 1,831,760	$ 1,873,766	$ 1,898,450	$ 1,938,858	$ 1,995,045
Com-Flat	COMMERCIAL- FLAT	Inputs	$ 45,871,837	$ 48,817,129	$ 51,466,482	$ 53,812,287	$ 55,908,283
	COMMERCIAL- WIND MACHINES	Inputs	$ 59,991	$ 61,781	$ 63,542	$ 65,060	$ 66,401
	COMMERCIAL- UNMETERED- CABLE TV	Inputs	$ 180,479	$ 184,880	$ 188,379	$ 191,859	$ 195,368
Com-Dmd	COMMERCIAL- DEMAND	Inputs	$ 24,373,450	$ 25,865,895	$ 27,244,572	$ 28,707,915	$ 30,432,491
TOU	COMMERCIAL- TOU	Inputs	$ 107,342,490	$ 119,098,976	$ 127,911,485	$ 136,492,217	$ 144,565,905
	CONTRACT- STAND-BY	Unique, see comment	$ 323,316	$ 326,841	$ 333,890	$ 338,589	$ 340,939
City	CITY CONTRACT RATE- FLAT	Inputs	$ 856,509	$ 891,886	$ 936,695	$ 985,121	$ 1,035,670
	CITY CONTRACT- DEMAND	Inputs	$ 1,556,364	$ 1,618,338	$ 1,679,650	$ 1,756,097	$ 1,849,311
	CITY CONTRACT- TOU	Inputs	$ 4,809,390	$ 5,037,782	$ 5,331,977	$ 5,651,843	$ 5,964,131
	CITY CONTRACT AG & PUMPING RATE	No change	$ -	$ -	$ -	$ -	$ -
SL-Cust.	SCHEDULE LS-2	Inputs	$ 38,378	$ 40,697	$ 42,650	$ 44,697	$ 46,843
SL-Dept.	SCHEDULE LS-1	Inputs	$ 4,383,844	$ 4,383,844	$ 4,383,844	$ 4,383,844	$ 4,383,844
	OUTDOOR LIGHTING	Inputs	$ 106,183	$ 112,599	$ 118,004	$ 123,668	$ 129,604
Traffic	TRAFFIC CONTROL- TRAFFIC SIGNALS	Inputs	$ 122,213	$ 129,597	$ 135,818	$ 142,337	$ 149,169
Ag Pump.	POWER-AGRICULTURAL AND PUMPING	Inputs	$ 127,145	$ 138,405	$ 147,913	$ 156,074	$ 162,903
CalTrans	STATE OF CA	Inputs	$ 21,276	$ 22,562	$ 23,645	$ 24,780	$ 25,969
UCR	UCR (expires 8/31/2016)	No change	$ -	$ -	$ -	$ -	$ -
Ralphs	Ralphs (expires 5/1/2018)	No change	$ 2,002,005	$ -	$ -	$ -	$ -
ROHR	ROHR (expires 10/1/2015)	No change					
Kaiser	Kaiser (expires 1/1/2016)	No change					
	Total		$306,580,770	$327,724,452	$346,210,593	$365,403,868	$384,879,568

Other Rates		Rates 2016	2017	2018	2019	2020	2021	2022		Revenue 2018	2019	2020	2021	2022
SEE 19 NAC Charges for Units														
RESIDENTIAL- GENERAL SERVICE	Customer	8.06	8.06	8.81	9.56	10.71	11.96	13.21	Customer	9,348,909	10,453,922	11,582,366	13,006,754	14,500,338
RESIDENTIAL- GENERAL SERVICE	NAC	-	-	-	-	-	-	-	NAC	689,421	4,208,052	6,998,639	9,813,731	12,757,849
RESIDENTIAL- GENERAL SERVICE	Energy - Tier 1	0.10	0.10	0.11	0.11	0.11	0.11	0.12	Reliability	13,035,362	13,088,469	13,141,915	13,195,710	13,249,863
RESIDENTIAL- GENERAL SERVICE	Energy - Tier 2	0.16	0.16	0.17	0.17	0.17	0.18	0.18	Total Meter Charges	23,073,693	27,750,444	31,722,920	36,016,194	40,508,049
RESIDENTIAL- GENERAL SERVICE	Energy - Tier 3	0.19	0.19	0.19	0.19	0.20	0.20	0.21						
RESIDENTIAL- GENERAL SERVICE	Reliability - Tier 1	10.00	10.00	10.00	10.00	10.00	10.00	10.00	Energy Charges	85,076,043	86,727,711	87,778,056	89,566,908	91,874,557
RESIDENTIAL- GENERAL SERVICE	Reliability - Tier 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00						
RESIDENTIAL- GENERAL SERVICE	Reliability - Tier 3	40.00	40.00	40.00	40.00	40.00	40.00	40.00	Total	$ 108,149,736	$ 114,478,155	$ 119,500,977	$ 125,583,103	$ 132,382,607
RESIDENTIAL- GENERAL SERVICE	Reliability - Tier 4	60.00	60.00	60.00	60.00	60.00	60.00	60.00	Check	-	-	-	-	-
RESIDENTIAL-GENERAL- OLD DTOU	Customer	8.06	-	-	-	-	-	-	Customer	-	-	-	-	-
RESIDENTIAL-GENERAL- OLD DTOU	NAC	-	-	-	-	-	-	-	NAC	-	-	-	-	-
RESIDENTIAL-GENERAL- OLD DTOU	Energy - Tier 1	0.10	-	-	-	-	-	-	Reliability	-	-	-	-	-
RESIDENTIAL-GENERAL- OLD DTOU	Energy - Tier 2	0.16	-	-	-	-	-	-	Total Meter Charges	-	-	-	-	-
RESIDENTIAL-GENERAL- OLD DTOU	Energy - Tier 3	0.19	-	-	-	-	-	-						
RESIDENTIAL-GENERAL- OLD DTOU	Reliability - Tier 1	10.00	-	-	-	-	-	-	Energy Charges	-	-	-	-	-
RESIDENTIAL-GENERAL- OLD DTOU	Reliability - Tier 2	20.00	-	-	-	-	-	-						
RESIDENTIAL-GENERAL- OLD DTOU	Reliability - Tier 3	40.00	-	-	-	-	-	-	Total	$ -	$ -	$ -	$ -	$ -
RESIDENTIAL-GENERAL- OLD DTOU	Reliability - Tier 4	60.00	-	-	-	-	-	-	Check	-	-	-	-	-
RESIDENTIAL- LIFELINE 500	Customer	8.06	8.06	8.81	9.56	10.71	11.96	13.21	Customer	116,291	129,634	143,140	160,077	177,688
RESIDENTIAL- LIFELINE 500	NAC	-	-	-	-	-	-	-	NAC	8,862	52,889	87,107	121,348	156,937
RESIDENTIAL- LIFELINE 500	Energy - Tier 1	0.10	0.10	0.11	0.11	0.11	0.11	0.12	Reliability	164,052	164,052	164,052	164,052	164,052
RESIDENTIAL- LIFELINE 500	Energy - Tier 2	0.16	0.16	0.17	0.17	0.17	0.18	0.18	Total Meter Charges	289,206	346,575	394,299	445,478	498,678
RESIDENTIAL- LIFELINE 500	Energy - Tier 3	0.19	0.19	0.19	0.19	0.20	0.20	0.21						
RESIDENTIAL- LIFELINE 500	Reliability - Tier 1	10.00	10.00	10.00	10.00	10.00	10.00	10.00	Energy Charges	1,308,714	1,332,527	1,345,299	1,369,464	1,404,674
RESIDENTIAL- LIFELINE 500	Reliability - Tier 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00						
RESIDENTIAL- LIFELINE 500	Reliability - Tier 3	40.00	40.00	40.00	40.00	40.00	40.00	40.00	Total	$ 1,597,919	$ 1,679,103	$ 1,739,598	$ 1,814,942	$ 1,903,352
RESIDENTIAL- LIFELINE 500	Reliability - Tier 4	60.00	60.00	60.00	60.00	60.00	60.00	60.00	Check	-	-	-	-	-

Other Rates		Rates								Revenue				
		2016	2017	2018	2019	2020	2021	2022		2018	2019	2020	2021	2022
RESIDENTIAL- LIFELINE 1000	Customer	8.06	8.06	8.81	9.56	10.71	11.96	13.21	Customer	53,501	59,609	65,809	73,597	81,698
RESIDENTIAL- LIFELINE 1000	NAC	-	-	-	-	-	-	-	NAC	4,092	24,219	39,940	55,672	72,017
RESIDENTIAL- LIFELINE 1000	Energy - Tier 1	0.10	0.10	0.11	0.11	0.11	0.11	0.12	Reliability	74,532	74,532	74,532	74,532	74,532
RESIDENTIAL- LIFELINE 1000	Energy - Tier 2	0.16	0.16	0.17	0.17	0.17	0.18	0.18	Total Meter Charges	132,124	158,360	180,281	203,800	228,247
RESIDENTIAL- LIFELINE 1000	Energy - Tier 3	0.19	0.19	0.19	0.19	0.20	0.20	0.21						
RESIDENTIAL- LIFELINE 1000	Reliability - Tier 1	10.00	10.00	10.00	10.00	10.00	10.00	10.00	Energy Charges	637,835	649,364	655,654	667,518	684,697
RESIDENTIAL- LIFELINE 1000	Reliability - Tier 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00						
RESIDENTIAL- LIFELINE 1000	Reliability - Tier 3	40.00	40.00	40.00	40.00	40.00	40.00	40.00	Total	$ 769,959	$ 807,724	$ 835,935	$ 871,318	$ 912,943
RESIDENTIAL- LIFELINE 1000	Reliability - Tier 4	60.00	60.00	60.00	60.00	60.00	60.00	60.00	Check	-	-	-	-	-
RESIDENTIAL- ALL ELECTRIC	Customer	8.06	8.06	8.81	9.56	10.71	11.96	13.21	Customer	51,861	57,756	63,707	71,252	79,120
RESIDENTIAL- ALL ELECTRIC	NAC	-	-	-	-	-	-	-	NAC	3,671	23,153	38,482	53,820	69,725
RESIDENTIAL- ALL ELECTRIC	Energy - Tier 1	0.10	0.10	0.11	0.11	0.11	0.11	0.12	Reliability	74,017	74,017	74,017	74,017	74,017
RESIDENTIAL- ALL ELECTRIC	Energy - Tier 2	0.16	0.16	0.17	0.17	0.17	0.18	0.18	Total Meter Charges	129,550	154,927	176,206	199,090	222,862
RESIDENTIAL- ALL ELECTRIC	Energy - Tier 3	0.16	0.16	0.17	0.17	0.17	0.18	0.18						
RESIDENTIAL- ALL ELECTRIC	Reliability - Tier 1	10.00	10.00	10.00	10.00	10.00	10.00	10.00	Energy Charges	619,003	630,493	636,670	648,508	665,240
RESIDENTIAL- ALL ELECTRIC	Reliability - Tier 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00						
RESIDENTIAL- ALL ELECTRIC	Reliability - Tier 3	40.00	40.00	40.00	40.00	40.00	40.00	40.00	Total	$ 748,552	$ 785,419	$ 812,877	$ 847,598	$ 888,102
RESIDENTIAL- ALL ELECTRIC	Reliability - Tier 4	60.00	60.00	60.00	60.00	60.00	60.00	60.00	Check	-	-	-	-	-
RESIDENTIAL- Water Heater	Customer	8.06	8.06	8.81	9.56	10.71	11.96	13.21	Customer	47,886	53,329	58,838	65,805	73,065
RESIDENTIAL- Water Heater	NAC	-	-	-	-	-	-	-	NAC	3,484	21,452	35,578	49,713	64,378
RESIDENTIAL- Water Heater	Energy - Tier 1	0.10	0.10	0.11	0.11	0.11	0.11	0.12	Reliability	71,508	71,508	71,508	71,508	71,508
RESIDENTIAL- Water Heater	Energy - Tier 2	0.16	0.16	0.17	0.17	0.17	0.18	0.18	Total Meter Charges	122,878	146,290	165,924	187,026	208,951
RESIDENTIAL- Water Heater	Energy - Tier 3	0.12	0.12	0.12	0.12	0.12	0.13	0.13						
RESIDENTIAL- Water Heater	Energy - Tier 4	0.19	0.19	0.19	0.19	0.20	0.20	0.21	Energy Charges	687,318	699,976	706,829	719,825	739,647
RESIDENTIAL- Water Heater	Reliability - Tier 1	10.00	10.00	10.00	10.00	10.00	10.00	10.00						
RESIDENTIAL- Water Heater	Reliability - Tier 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00	Total	$ 810,196	$ 846,265	$ 872,753	$ 906,851	$ 948,597
RESIDENTIAL- Water Heater	Reliability - Tier 3	40.00	40.00	40.00	40.00	40.00	40.00	40.00	Check	-	-	-	-	-
RESIDENTIAL- Water Heater	Reliability - Tier 4	60.00	60.00	60.00	60.00	60.00	60.00	60.00						

Other Rates		Rates								Revenue				
		2016	2017	2018	2019	2020	2021	2022		2018	2019	2020	2021	2022
RESIDENTIAL- Space Heater	Customer	8.06	8.06	8.81	9.56	10.71	11.96	13.21	Customer	27,227	30,342	33,470	37,434	41,566
RESIDENTIAL- Space Heater	NAC	-	-	-	-	-	-	-	NAC	1,890	12,216	20,297	28,383	36,768
RESIDENTIAL- Space Heater	Energy - Tier 1	0.10	0.10	0.11	0.11	0.11	0.11	0.12	Reliability	33,771	33,771	33,771	33,771	33,771
RESIDENTIAL- Space Heater	Energy - Tier 2	0.16	0.16	0.17	0.17	0.17	0.18	0.18	Total Meter Charges	62,888	76,328	87,537	99,587	112,105
RESIDENTIAL- Space Heater	Energy - Tier 3	0.19	0.19	0.19	0.19	0.20	0.20	0.21						
RESIDENTIAL- Space Heater	Reliability - Tier 1	10.00	10.00	10.00	10.00	10.00	10.00	10.00	Energy Charges	253,120	257,877	260,375	265,137	271,961
RESIDENTIAL- Space Heater	Reliability - Tier 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00						
RESIDENTIAL- Space Heater	Reliability - Tier 3	40.00	40.00	40.00	40.00	40.00	40.00	40.00	Total	$ 316,008	$ 334,205	$ 347,913	$ 364,724	$ 384,066
RESIDENTIAL- Space Heater	Reliability - Tier 4	60.00	60.00	60.00	60.00	60.00	60.00	60.00	Check	-	-	-	-	-
	-	0.16	0.16	#REF!	#REF!	#REF!	#REF!	#REF!						
RESIDENTIAL- Domestic TOU	Customer	18.87	-	-	-	-	-	-	Customer	-	-	-	-	-
RESIDENTIAL- Domestic TOU	NAC	-	-	-	-	-	-	-	NAC	-	-	-	-	-
RESIDENTIAL- Domestic TOU	ON PEAK- TIER 1 - Summer	0.24	-	-	-	-	-	-	Reliability	-	-	-	-	-
RESIDENTIAL- Domestic TOU	ON PEAK- TIER 2 - Summer	0.24	-	-	-	-	-	-	Total Meter Charges	-	-	-	-	-
RESIDENTIAL- Domestic TOU	OFF PEAK- TIER 1 - Summer	0.06	-	-	-	-	-	-						
RESIDENTIAL- Domestic TOU	OFF PEAK- TIER 2 - Summer	0.06	-	-	-	-	-	-	Energy Charges	-	-	-	-	-
RESIDENTIAL- Domestic TOU	ON PEAK- TIER 1 - Winter	0.20	-	-	-	-	-	-						
RESIDENTIAL- Domestic TOU	ON PEAK- TIER 2 - Winter	0.20	-	-	-	-	-	-	Total	$ -	$ -	$ -	$ -	$ -
RESIDENTIAL- Domestic TOU	OFF PEAK- TIER 1 - Winter	0.05	-	-	-	-	-	-	Check	-	-	-	-	-
RESIDENTIAL- Domestic TOU	OFF PEAK- TIER 2 - Winter	0.05	-	-	-	-	-	-						
RESIDENTIAL- Domestic TOU- TIERED	Customer	8.06	8.06	8.81	9.56	10.71	11.96	13.21	Customer	8,249	9,188	10,140	11,340	12,590
RESIDENTIAL- Domestic TOU- TIERED	NAC	-	-	-	-	-	-	-	NAC	612	3,710	6,141	8,572	11,097
RESIDENTIAL- Domestic TOU- TIERED	ON PEAK- TIER 1 - Summer	0.18	0.18	0.18	0.19	0.19	0.20	0.20	Reliability	18,064	18,064	18,064	18,064	18,064
RESIDENTIAL- Domestic TOU- TIERED	ON PEAK- TIER 2 - Summer	0.45	0.45	0.46	0.47	0.48	0.49	0.50	Total Meter Charges	26,925	30,963	34,344	37,977	41,751
RESIDENTIAL- Domestic TOU- TIERED	OFF PEAK- TIER 1 - Summer	0.09	0.09	0.09	0.09	0.09	0.09	0.10						
RESIDENTIAL- Domestic TOU- TIERED	OFF PEAK- TIER 2 - Summer	0.12	0.12	0.12	0.12	0.13	0.13	0.13	Energy Charges	154,845	157,640	159,203	162,111	166,274
RESIDENTIAL- Domestic TOU- TIERED	ON PEAK- TIER 1 - Winter	0.20	0.20	0.20	0.21	0.21	0.22	0.22						
RESIDENTIAL- Domestic TOU- TIERED	ON PEAK- TIER 2 - Winter	0.36	0.36	0.36	0.37	0.37	0.39	0.40	Total	$ 181,771	$ 188,603	$ 193,547	$ 200,087	$ 208,025
RESIDENTIAL- Domestic TOU- TIERED	OFF PEAK- TIER 1 - Winter	0.10	0.10	0.10	0.10	0.10	0.10	0.11	Check	-	-	-	-	-
RESIDENTIAL- Domestic TOU- TIERED	OFF PEAK- TIER 2 - Winter	0.15	0.15	0.16	0.16	0.16	0.17	0.17						

Other Rates

		Rates 2016	2017	2018	2019	2020	2021	2022
RESIDENTIAL- Multi Family	Customer	8.06	8.06	8.81	9.56	10.71	11.96	13.21
RESIDENTIAL- Multi Family	NAC	-	-	-	-	-	-	-
RESIDENTIAL- Multi Family	Energy - Tier 1	0.10	0.10	0.11	0.11	0.11	0.11	0.12
RESIDENTIAL- Multi Family	Energy - Tier 2	0.16	0.16	0.17	0.17	0.17	0.18	0.18
RESIDENTIAL- Multi Family	Energy - Tier 3	0.19	0.19	0.19	0.19	0.20	0.20	0.21
RESIDENTIAL- Multi Family	Reliability - Tier 1	10.00	10.00	10.00	10.00	10.00	10.00	10.00
RESIDENTIAL- Multi Family	Reliability - Tier 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00
RESIDENTIAL- Multi Family	Reliability - Tier 3	40.00	40.00	40.00	40.00	40.00	40.00	40.00
RESIDENTIAL- Multi Family	Reliability - Tier 4	60.00	60.00	60.00	60.00	60.00	60.00	60.00

	Revenue 2018	2019	2020	2021	2022
Customer	18,762	20,896	23,058	25,788	28,632
NAC	1,378	8,415	13,939	19,467	25,203
Reliability	37,371	37,371	37,371	37,371	37,371
Total Meter Charges	57,511	66,683	74,368	82,626	91,206
Energy Charges	1,774,248	1,807,083	1,824,081	1,856,232	1,903,838
Total	$ 1,831,760	$ 1,873,766	$ 1,898,450	$ 1,938,858	$ 1,995,045
Check	-	-	-	-	-

Proposed PH-EV (D-TOU) Rate

New Rate - no Billing Determinants

	Winter			Summer		
	Off	Mid	Peak	Off	Mid	Peak
Tier-1	$0.0873	$0.1048	$0.1310	$0.0873	$0.1135	$0.1746
Tier-2	$0.1397	$0.1676	$0.2095	$0.1397	$0.1816	$0.2794
Tier Allotments	115	250	135	220	550	330
Total Allotment		500			1100	
	23%	*50%*	*27%*	*20%*	*50%*	*30%*
Tier Blending:	80/20	50/50	20/80	80/20	50/50	20/80
EV Only Rate:	$0.0978	$0.1362	$0.1938	$0.0978	$0.1475	$0.2584

Proposed DTOU Tiered EV Rates Energy Charge ($/kWh)		2018	2019	2020	2021	2022
Summer On-Peak						
Tier 1 (0–330 kWh)	--	0.1788	0.1810	0.1844	0.1900	0.1960
Tier 2 (>330 kWh)	--	0.2861	0.2896	0.2950	0.3040	0.3136
Summer– Mid Peak						
Tier 1 (0–550 kWh)		0.1162	0.1177	0.1199	0.1235	0.1274
Tier 2 (> 550 kWh)		0.1859	0.1883	0.1918	0.1976	0.2038
Summer Off-Peak						
Tier 1 (0–220 kWh)	--	0.0894	0.0905	0.0922	0.0950	0.0980
Tier 2 (>220 kWh)	--	0.1430	0.1448	0.1475	0.1520	0.1568
Winter – On-Peak						
Tier 1 (0–135 kWh)	--	0.1341	0.1358	0.1383	0.1425	0.1470
Tier 2 (>135 kWh)	--	0.2146	0.2173	0.2213	0.2280	0.2352
Winter – Mid Peak						
Tier 1 (0-250 kWh)		0.1073	0.1086	0.1106	0.1140	0.1176
Tier 2 (>250 kWh)		0.1717	0.1738	0.1770	0.1824	0.1882
Winter Off-Peak						
Tier 1 (0–115 kWh)	--	0.0894	0.0905	0.0922	0.0950	0.0980
Tier 2 (>115 kWh)	--	0.1430	0.1448	0.1475	0.1520	0.1568

Proposed DTOU Tiered EV Rates Energy Charge ($/kWh)(2)					
Summer On-Peak	0.2646	0.2679	0.2729	0.2812	0.2901
Summer– Mid Peak	0.1511	0.153	0.1559	0.1606	0.1656
Summer Off-Peak	0.1001	0.1014	0.1033	0.1064	0.1098
Winter – Off-Peak	0.1985	0.201	0.2047	0.2109	0.2176
Winter – Mid Peak	0.1395	0.1412	0.1438	0.1482	0.1529
Winter Off-Peak	0.1001	0.1014	0.1033	0.1064	0.1098

Other Rates		Rates 2016	2017	2018	2019	2020	2021	2022	Revenue 2018	2019	2020	2021	2022
		NAC Revenues											
		2016	2017	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022
RESIDENTIAL- GENERAL SERVICE	NAC Tier 1	$ -	$ -	$ 142,942	$ 838,531	$ 1,415,083	$ 1,995,949	$ 2,604,353	21%	20%	20%	20%	20%
	NAC Tier 2	$ -	$ -	$ 291,781	$ 1,785,172	$ 2,967,634	$ 4,162,036	$ 5,409,320	42%	42%	42%	42%	42%
	NAC Tier 3	$ -	$ -	$ 254,699	$ 1,584,349	$ 2,615,922	$ 3,655,746	$ 4,744,176	37%	38%	37%	37%	37%
RESIDENTIAL-GENERAL- OLD DTOU	NAC Tier 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
	NAC Tier 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
	NAC Tier 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
RESIDENTIAL- LIFELINE 500	NAC Tier 1	$ -	$ -	$ 1,834	$ 10,505	$ 17,561	$ 24,614	$ 31,954	21%	20%	20%	20%	20%
	NAC Tier 2	$ -	$ -	$ 3,751	$ 22,441	$ 36,942	$ 51,472	$ 66,550	42%	42%	42%	42%	42%
	NAC Tier 3	$ -	$ -	$ 3,277	$ 19,942	$ 32,604	$ 45,262	$ 58,433	37%	38%	37%	37%	37%
RESIDENTIAL- LIFELINE 1000	NAC Tier 1	$ -	$ -	$ 849	$ 4,828	$ 8,081	$ 11,332	$ 14,715	21%	20%	20%	20%	20%
	NAC Tier 2	$ -	$ -	$ 1,732	$ 10,274	$ 16,935	$ 23,610	$ 30,534	42%	42%	42%	42%	42%
	NAC Tier 3	$ -	$ -	$ 1,511	$ 9,117	$ 14,924	$ 20,730	$ 26,769	37%	38%	37%	37%	37%
RESIDENTIAL- ALL ELECTRIC	NAC Tier 1	$ -	$ -	$ 757	$ 4,579	$ 7,716	$ 10,851	$ 14,108	21%	20%	20%	20%	20%
	NAC Tier 2	$ -	$ -	$ 1,554	$ 9,826	$ 16,325	$ 22,836	$ 29,577	42%	42%	42%	42%	42%
	NAC Tier 3	$ -	$ -	$ 1,360	$ 8,748	$ 14,441	$ 20,133	$ 26,040	37%	38%	38%	37%	37%
RESIDENTIAL- Water Heater	NAC Tier 1	$ -	$ -	$ 718	$ 4,253	$ 7,156	$ 10,055	$ 13,069	21%	20%	20%	20%	20%
	NAC Tier 2	$ -	$ -	$ 1,475	$ 9,103	$ 15,090	$ 21,089	$ 27,304	42%	42%	42%	42%	42%
	NAC Tier 3	$ -	$ -	$ 1,291	$ 8,096	$ 13,332	$ 18,568	$ 24,004	37%	38%	37%	37%	37%
RESIDENTIAL- Space Heater	NAC Tier 1	$ -	$ -	$ 386	$ 2,394	$ 4,031	$ 5,667	$ 7,367	20%	20%	20%	20%	20%
	NAC Tier 2	$ -	$ -	$ 801	$ 5,187	$ 8,615	$ 12,049	$ 15,605	42%	42%	42%	42%	42%
	NAC Tier 3	$ -	$ -	$ 703	$ 4,635	$ 7,651	$ 10,667	$ 13,796	37%	38%	38%	38%	38%
RESIDENTIAL- Domestic TOU	NAC Tier 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
	NAC Tier 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
	NAC Tier 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
RESIDENTIAL- Domestic TOU- TIERED	NAC Tier 1	$ -	$ -	$ 127	$ 737	$ 1,238	$ 1,738	$ 2,257	21%	20%	20%	20%	20%
	NAC Tier 2	$ -	$ -	$ 259	$ 1,574	$ 2,604	$ 3,636	$ 4,706	42%	42%	42%	42%	42%
	NAC Tier 3	$ -	$ -	$ 226	$ 1,399	$ 2,299	$ 3,199	$ 4,133	37%	38%	37%	37%	37%
RESIDENTIAL- Multi Family	NAC Tier 1	$ -	$ -	$ 285	$ 1,675	$ 2,815	$ 3,954	$ 5,138	21%	20%	20%	20%	20%
	NAC Tier 2	$ -	$ -	$ 583	$ 3,570	$ 5,911	$ 8,256	$ 10,687	42%	42%	42%	42%	42%
	NAC Tier 3	$ -	$ -	$ 510	$ 3,170	$ 5,214	$ 7,256	$ 9,378	37%	38%	37%	37%	37%

Summary KWh

		2018	2019	2020	2021	2022
		Unadjusted				
Res.	RESIDENTIAL- GENERAL SERVICE	648,412,287	649,182,871	650,557,402	651,675,895	651,595,200
	RESIDENTIAL- LIFELINE 500	11,365,978	11,365,978	11,365,978	11,365,978	11,365,978
	RESIDENTIAL- LIFELINE 1000	5,826,056	5,826,056	5,826,056	5,826,056	5,826,056
	RESIDENTIAL- ALL ELECTRIC	4,575,774	4,575,774	4,575,774	4,575,774	4,575,774
	RESIDENTIAL- Water Heater	5,125,343	5,125,343	5,125,343	5,125,343	5,125,343
	RESIDENTIAL- Space Heater	1,977,892	1,977,892	1,977,892	1,977,892	1,977,892
	RESIDENTIAL- Domestic TOU- TIERED	1,094,376	1,094,376	1,094,376	1,094,376	1,094,376
	RESIDENTIAL- Multi Family	15,886,867	15,886,867	15,886,867	15,886,867	15,886,867
	RESIDENTIAL-GENERAL- OLD DTOU	-	-	-	-	-
	RESIDENTIAL- Domestic TOU	-	-	-	-	-
	Total Res	694,264,573	695,035,157	696,409,688	697,528,181	697,447,486
	Pro Forma	694,264,573	695,035,157	696,409,688	697,528,181	697,447,486
		-	-	-	-	-
Com-Flat	COMMERCIAL- FLAT	274,969,414	279,024,940	283,532,545	288,003,340	292,797,831
	COMMERCIAL- WIND MACHINES	385,678	385,678	385,678	385,678	385,678
	COMMERCIAL- UNMETERED- CABLE TV	1,329,360	1,329,360	1,329,360	1,329,360	1,329,360
	Total Com-Flat	276,684,452	280,739,978	285,247,583	289,718,378	294,512,869
	Pro Forma	276,684,452	280,739,978	285,247,583	289,718,378	294,512,869
		-	-	-	-	-
Com-Dmd	COMMERCIAL- DEMAND	156,462,932	158,756,301	161,305,317	163,833,517	166,544,764
	Total Com-Dmd	156,462,932	158,756,301	161,305,317	163,833,517	166,544,764
	Pro Forma	156,462,932	158,756,301	161,305,317	163,833,517	166,544,764
		-	-	-	-	-

Summary KWh

			2018	2019	2020	2021	2022
TOU	COMMERCIAL- TOU		792,029,982	806,908,631	823,471,667	839,823,017	857,484,399
	CONTRACT- STAND-BY		-	-	-	-	-
City	CITY CONTRACT RATE- FLAT		10,024,976	10,024,976	10,024,976	10,024,976	10,024,976
	CITY CONTRACT- DEMAND		14,503,195	14,503,195	14,503,195	14,503,195	14,503,195
	CITY CONTRACT- TOU		44,690,840	44,690,840	44,690,840	44,690,840	44,690,840
	CITY CONTRACT AG & PUMPING RATE		-	-	-	-	-
UCR	UCR CONTRACT		116,914,851	116,914,851	116,914,851	116,914,851	116,914,851
Ralphs	RALPHS CONTRACT		30,761,616	30,761,616	30,761,616	30,761,616	30,761,616
ROHR	GOODRICH (ROHR) CONTRACT		-	-	-	-	-
Kaiser	KAISER CONTRACT		-	-	-	-	-
		Total TOU	1,008,925,460	1,023,804,109	1,040,367,145	1,056,718,495	1,074,379,877
		Pro Forma	1,008,925,460	1,023,804,109	1,040,367,145	1,056,718,495	1,074,379,877
			-	-	-	-	-

SL-Cust.	SCHEDULE LS-2		316,226	316,226	316,226	316,226	316,226
SL-Dept.	SCHEDULE LS-1		19,155,515	19,155,515	19,155,515	19,155,515	19,155,515
	OUTDOOR LIGHTING		683,930	683,930	683,930	683,930	683,930
Traffic	TRAFFIC CONTROL- TRAFFIC SIGNALS		1,273,854	1,273,854	1,273,854	1,273,854	1,273,854
Ag Pump.	POWER-AGRICULTURAL AND PUMPING		787,485	787,485	787,485	787,485	787,485
CalTrans	STATE OF CA		155,616	155,616	155,616	155,616	155,616
		Total Other	22,372,626	22,372,626	22,372,626	22,372,626	22,372,626
		Pro Forma	22,372,626	22,372,626	22,372,626	22,372,626	22,372,626
			-	-	-	-	-

Total RPU	2,158,710,043	2,180,708,171	2,205,702,359	2,230,171,197	2,255,257,622
Pro Forma	2,158,710,043	2,180,708,171	2,205,702,359	2,230,171,197	2,255,257,622
	-	-	-	-	-

Summary KWh

			2018	2019	2020	2021	2022
			Adjusted				
Res.	RESIDENTIAL- GENERAL SERVICE		647,727,882	644,529,500	642,635,107	640,480,850	637,422,377
	RESIDENTIAL- LIFELINE 500		11,354,920	11,286,588	11,229,758	11,172,928	11,120,610
	RESIDENTIAL- LIFELINE 1000		5,820,127	5,785,166	5,756,036	5,726,906	5,700,127
	RESIDENTIAL- ALL ELECTRIC		4,571,473	4,543,080	4,520,201	4,497,322	4,476,406
	RESIDENTIAL- Water Heater		5,120,416	5,089,049	5,063,422	5,037,795	5,022,836
	RESIDENTIAL- Space Heater		1,976,230	1,964,007	1,954,118	1,944,228	1,935,138
	RESIDENTIAL- Domestic TOU- TIERED		1,093,233	1,086,693	1,081,221	1,075,749	1,070,720
	RESIDENTIAL- Multi Family		15,873,960	15,779,314	15,699,880	15,620,446	15,546,635
	RESIDENTIAL-GENERAL- OLD DTOU		-	-	-	-	-
	RESIDENTIAL- Domestic TOU		-	-	-	-	-
		Total Res	693,538,240	690,063,397	687,939,742	685,556,224	682,294,849
		Pro Forma	693,074,542	690,819,826	689,052,177	687,160,639	684,361,676
			463,698	(756,429)	(1,112,435)	(1,604,414)	(2,066,827)
Com-Flat	COMMERCIAL- FLAT		274,805,459	278,003,186	281,784,530	285,508,048	289,595,840
	COMMERCIAL- WIND MACHINES		385,084	384,120	383,155	382,191	381,346
	COMMERCIAL- UNMETERED- CABLE TV		1,328,529	1,324,375	1,321,052	1,317,728	1,314,737
		Total Com-Flat	276,519,072	279,711,681	283,488,736	287,207,968	291,291,923
		Pro Forma	276,414,381	279,853,256	283,704,817	287,532,835	291,719,042
			104,691	(141,576)	(216,081)	(324,868)	(427,119)
Com-Dmd	COMMERCIAL- DEMAND		156,369,411	158,174,806	160,310,702	162,413,899	164,723,344
		Total Com-Dmd	156,369,411	158,174,806	160,310,702	162,413,899	164,723,344
		Pro Forma	156,309,003	158,253,571	160,431,578	162,596,421	164,963,745
			60,407	(78,765)	(120,876)	(182,522)	(240,401)

Summary KWh

			2018	2019	2020	2021	2022
TOU	COMMERCIAL- TOU		791,280,795	802,427,693	815,806,031	828,857,843	843,375,869
	CONTRACT- STAND-BY		-	-	-	-	-
City	CITY CONTRACT RATE- FLAT		10,015,908	9,969,986	9,932,392	9,894,799	9,860,684
	CITY CONTRACT- DEMAND		14,489,422	14,424,586	14,370,199	14,315,812	14,266,269
	CITY CONTRACT- TOU		44,649,861	44,440,393	44,272,802	44,105,212	43,954,192
	CITY CONTRACT AG & PUMPING RATE		-	-	-	-	-
UCR	UCR CONTRACT		116,818,859	116,285,950	115,851,294	115,416,637	115,020,830
Ralphs	RALPHS CONTRACT		30,741,896	30,593,810	30,478,454	30,363,098	30,258,232
ROHR	GOODRICH (ROHR) CONTRACT		-	-	-	-	-
Kaiser	KAISER CONTRACT		-	-	-	-	-
		Total TOU	1,007,996,740	1,018,142,418	1,030,711,173	1,042,953,401	1,056,736,077
		Pro Forma	1,007,409,771	1,018,912,220	1,031,884,876	1,044,723,249	1,059,055,952
			586,968	(769,801)	(1,173,703)	(1,769,848)	(2,319,876)
SL-Cust.	SCHEDULE LS-2		316,226	316,226	316,226	316,226	316,226
SL-Dept.	SCHEDULE LS-1		19,155,515	19,155,515	19,155,515	19,155,515	19,155,515
	OUTDOOR LIGHTING		683,930	683,930	683,930	683,930	683,930
Traffic	TRAFFIC CONTROL- TRAFFIC SIGNALS		1,273,854	1,273,854	1,273,854	1,273,854	1,273,854
Ag Pump.	POWER-AGRICULTURAL AND PUMPING		787,485	787,485	787,485	787,485	787,485
CalTrans	STATE OF CA		155,616	155,616	155,616	155,616	155,616
		Total Other	22,372,626	22,372,626	22,372,626	22,372,626	22,372,626
		Pro Forma	22,372,626	22,372,626	22,372,626	22,372,626	22,372,626
			-	-	-	-	-
		Total RPU	2,156,796,088	2,168,464,928	2,184,822,980	2,200,504,118	2,217,418,818
		Pro Forma	2,155,580,323	2,170,211,500	2,187,446,075	2,204,385,770	2,222,473,041
			1,215,765	(1,746,572)	(2,623,095)	(3,881,652)	(5,054,222)
							-0.22741%

Revenue Requirement by Test Year

Line No.	Item	Account/ID	Fiscal Year 2017/18	Fiscal Year 2018/19	Fiscal Year 2019/20	Fiscal Year 2020/21	Fiscal Year 2021/22
1	REVENUE REQUIREMENTS CALCULATION						
2							
3	Production O&M						
4	**Steam Production Operation**						
5	Supervision & Engineering	0500	$ -	$ -	$ -	$ -	$ -
6	Fuel (Transportation & Handling)	0501	-	-	-	-	-
7	Steam Power Fuel - Gas	50110	-	-	-	-	-
8	Steam Power Fuel - Oil	50120	-	-	-	-	-
9	Steam Power Fuel - Coal	50130	-	-	-	-	-
10	Steam Expense	0502	-	-	-	-	-
11	Electric Expense	0505	-	-	-	-	-
12	Miscellaneous	0506	-	-	-	-	-
13	Rent	0507	-	-	-	-	-
14	**Total Steam Production Operation**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
15							
16	**Steam Production Maintenance**						
17	Supervision & Engineering	0510	$ -	$ -	$ -	$ -	$ -
18	Structures	0511	-	-	-	-	-
19	Boilers	0512	-	-	-	-	-
20	Electric Plant	0513	-	-	-	-	-
21	Miscellaneous Labor	0515	-	-	-	-	-
22	**Total Steam Production Maintenance**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
23							
24	**Nuclear Production Operation**						
25	Supervision & Engineering	0517	$ -	$ -	$ -	$ -	$ -
26	Nuclear Fuel Expense	0518	-	-	-	-	-
27	Electric Expense - Turbine Generators	0523	-	-	-	-	-
28	Reserved	NA	-	-	-	-	-
29	Miscellaneous Power Expenses	0524	2,050,000	2,050,000	2,050,000	2,050,000	2,050,000
30	Reserved	NA	-	-	-	-	-
31	**Total Nuclear Production Operation**		**$ 2,050,000**	**$ 2,050,000**	**$ 2,050,000**	**$ 2,050,000**	**$ 2,050,000**
32							
33	**Nuclear Production Maintenance**						
34	Supervision & Engineering	0528	$ -	$ -	$ -	$ -	$ -
35	Reserved	NA	-	-	-	-	-
36	Reserved	NA	-	-	-	-	-
37	Reserved	NA	-	-	-	-	-
38	Miscellaneous Plant	0530	800,000	800,000	800,000	800,000	800,000

Revenue Requirement by Test Year

Line No.	Item	Account/ID		Fiscal Year 2017/18		Fiscal Year 2018/19		Fiscal Year 2019/20		Fiscal Year 2020/21		Fiscal Year 2021/22
1	REVENUE REQUIREMENTS CALCULATION											
39	**Total Nuclear Production Maintenance**		**$**	**800,000**	**$**	**800,000**	**$**	**800,000**	**$**	**800,000**	**$**	**800,000**
40												
41	**Combined Cycle Operation**											
42	Supervision & Engineering	NA	$	-	$	-	$	-	$	-	$	-
43	Fuel	NA		-		-		-		-		-
44	Combined Cycle Fuel - Gas	NA		-		-		-		-		-
45	Combined Cycle Fuel - Oil	NA		-		-		-		-		-
46	Generation Expense	NA		-		-		-		-		-
47	Miscellaneous	NA		-		-		-		-		-
48	**Total Combined Cycle Operation**		**$**	**-**	**$**	**-**	**$**	**-**	**$**	**-**	**$**	**-**
49												
50	**Combined Cycle Maintenance**											
51	Supervision & Engineering	NA	$	-	$	-	$	-	$	-	$	-
52	Structures	NA		-		-		-		-		-
53	Electric Plant	NA		-		-		-		-		-
54	Miscellaneous Plant	NA		-		-		-		-		-
55	**Total Combined Cycle Maintenance**		**$**	**-**	**$**	**-**	**$**	**-**	**$**	**-**	**$**	**-**
56												
57	**Other Production**											
58	Intermountain Power (take or pay)	0546	$	44,325,000	$	48,361,000	$	50,072,000	$	51,409,000	$	41,145,000
59	Fuel expense	0547		848,000		1,232,000		1,557,000		2,006,000		1,904,000
60	Hoover (take or Pay)	0548		867,000		865,000		866,000		868,000		870,000
61	Misc Other Power Gen	0549		-		-		-		-		-
62	Palo Verde Power (take or pay)	0550		3,941,000		4,065,000		4,198,000		4,322,000		4,464,000
63	Deseret Power (take or pay)	0552		-		-		-		-		-
64	Maint/Generating & Elec Equip	0553		4,764,586		5,106,044		5,481,086		5,917,014		6,088,086
65	System Load Control	0556		4,064,487		4,355,772		4,675,707		5,047,580		5,193,516
66	Other Expenditures	0557		2,836,000		2,994,000		2,037,000		1,787,000		3,128,000
67	Purchased Power	0555		91,677,000		97,184,000		102,518,000		106,983,000		120,623,000
68	Purchased Power - Energy Direct Assignment	55501		-		-		-		-		-
69	**Total Other Production**		**$**	**153,323,073**	**$**	**164,162,816**	**$**	**171,404,793**	**$**	**178,339,594**	**$**	**183,415,602**
70												
71	**Total Production O&M**		**$**	**156,173,073**	**$**	**167,012,816**	**$**	**174,254,793**	**$**	**181,189,594**	**$**	**186,265,602**
72												
73	**Fuel & Purchased Power**		**$**	**141,658,000**	**$**	**151,707,000**	**$**	**159,211,000**	**$**	**165,588,000**	**$**	**169,006,000**
74												
75	**Total Production O&M less Fuel & Purchased Powe**		**$**	**14,515,073**	**$**	**15,305,816**	**$**	**15,043,793**	**$**	**15,601,594**	**$**	**17,259,602**

Line No.	Item	Account/ID	Fiscal Year 2017/18	Fiscal Year 2018/19	Fiscal Year 2019/20	Fiscal Year 2020/21	Fiscal Year 2021/22
1	REVENUE REQUIREMENTS CALCULATION						
76							
77	Transmission O&M						
78	**Transmission Operation**						
79	Supervision & Engineering	0560	$ -	$ -	$ -	$ -	$ -
80	Load Dispatch	0561	-	-	-	-	-
81	Station Equipment	0562	119,835	128,424	137,856	148,820	153,123
82	Overhead Lines	0563	-	-	-	-	-
83	Underground Lines	0564	-	-	-	-	-
84	Transmission of Electricity by Others (Wheeling)	G110	-	-	-	-	-
85	Miscellaneous	0566	235,176	252,030	270,542	292,059	300,503
86	Rents	0567	-	-	-	-	-
87	**Total Transmission Operation**		**$ 355,012**	**$ 380,454**	**$ 408,398**	**$ 440,880**	**$ 453,626**
88							
89	**Transmission Maintenance**						
90	Supervision & Engineering	0568	$ -	$ -	$ -	$ -	$ -
91	Structures	0569	-	-	-	-	-
92	Station Equipment	0570	299,858	321,348	344,951	372,386	383,152
93	Overhead Lines	0571	3,654	3,916	4,204	4,538	4,669
94	Underground Lines	0572	-	-	-	-	-
95	Miscellaneous	0573	1,532,022	1,641,816	1,762,408	1,902,578	1,957,585
96	**Total Transmission Maintenance**		**$ 1,835,534**	**$ 1,967,080**	**$ 2,111,563**	**$ 2,279,502**	**$ 2,345,407**
97							
98	**Wheeling**						
99	Transmission Cost Fixed	0565	$ 30,940,522	$ 31,614,898	$ 33,093,140	$ 34,267,861	$ 33,599,182
100	Transmission cost Variable	0565	28,795,478	29,423,102	30,798,860	31,892,139	31,269,818
101	**Total Wheeling**		**$ 59,736,000**	**$ 61,038,000**	**$ 63,892,000**	**$ 66,160,000**	**$ 64,869,000**
102							
103	**Total Transmission O&M**		**$ 61,926,546**	**$ 63,385,533**	**$ 66,411,961**	**$ 68,880,382**	**$ 67,668,033**
104							
105	Distribution O&M						
106	**Distribution Operations**						
107	Operation Maintenance and Engineering	0580	$ 3,960,712	$ 4,244,560	$ 4,556,326	$ 4,918,704	$ 5,060,914
108	Load Dispatch	0581	2,255,957	2,417,632	2,595,209	2,801,614	2,882,614
109	Station Equipment	0582	31,732	34,006	36,504	39,407	40,546
110	Overhead Lines	0583	10,207	10,938	11,741	12,675	13,042
111	Underground Lines	0584	748	802	861	929	956
112	Street Lighting & Signal Expenses	0585	-	-	-	-	-

Revenue Requirement by Test Year

Line No.	Item	Account/ID	Fiscal Year 2017/18	Fiscal Year 2018/19	Fiscal Year 2019/20	Fiscal Year 2020/21	Fiscal Year 2021/22
1	REVENUE REQUIREMENTS CALCULATION						
113	Metering	0586	135,706	145,432	156,114	168,530	173,403
114	Customer Installations	0587	21,877	23,445	25,167	27,168	27,954
115	Miscellaneous	0588	347,217	372,101	399,432	431,200	443,667
116	Rents	0589	-	-	-	-	-
117	**Total Distribution Operations**		**$ 6,764,156**	**$ 7,248,915**	**$ 7,781,353**	**$ 8,400,228**	**$ 8,643,095**
117							
118	**Distribution Maintenance**						
119	Supervision	0590	$ -	$ -	$ -	$ -	$ -
120	Structures	0591	56,569	60,623	65,076	70,251	72,282
121	Station Equipment	0592	1,249,562	1,339,113	1,437,471	1,551,798	1,596,663
122	Overhead Lines	0593	5,027,980	5,388,314	5,784,090	6,244,116	6,424,646
123	Underground Lines	0594	2,377,807	2,548,214	2,735,382	2,952,936	3,038,311
124	Transformers	0595	69,348	74,318	79,777	86,121	88,611
125	Street Lighting & Signals	0596	775,466	831,040	892,081	963,031	990,874
126	Metering	0597	292,945	313,940	336,999	363,801	374,319
127	Miscellaneous	0598	594,328	636,921	683,703	738,080	759,419
128	**Total Distribution Maintenance**		**$ 10,444,004**	**$ 11,192,482**	**$ 12,014,578**	**$ 12,970,134**	**$ 13,345,126**
129							
130	**Total Distribution O&M**		**$ 17,208,160**	**$ 18,441,397**	**$ 19,795,931**	**$ 21,370,362**	**$ 21,988,220**
131							
132	Customer O&M						
133	**Customer Accounting Expense**						
134	Supervision	0901	$ 174,833	$ 187,363	$ 201,125	$ 217,121	$ 223,398
135	Meter Reading	0902	987,260	1,058,013	1,135,725	1,226,053	1,261,500
136	Customer Records and Collection Expenses	0903	5,422,351	5,810,948	6,237,766	6,733,875	6,928,564
137	Reserved	NA	-	-	-	-	-
138	Uncollectible Accounts	0904	919,000	982,301	1,038,380	1,096,721	1,155,041
139	Miscellaneous	0905	-	-	-	-	-
140	**Total Customer Accounting Expense**		**$ 7,503,444**	**$ 8,038,624**	**$ 8,612,995**	**$ 9,273,769**	**$ 9,568,503**
141							
142	**Other Customer Costs**						
143	Supervision	0907	$ -	$ -	$ -	$ -	$ -
144	Customer Assistance	0908	1,334,158	1,429,772	1,534,790	1,656,856	1,704,759
145	Advertisement	0909	1,018,047	1,091,007	1,171,142	1,264,286	1,300,839
146	Miscellaneous	0910	-	-	-	-	-
147	**Total Other Customer Costs**		**$ 2,352,206**	**$ 2,520,779**	**$ 2,705,932**	**$ 2,921,143**	**$ 3,005,598**
148							

Revenue Requirement by Test Year

Line No.	Item	Account/ID	Fiscal Year 2017/18	Fiscal Year 2018/19	Fiscal Year 2019/20	Fiscal Year 2020/21	Fiscal Year 2021/22
1	REVENUE REQUIREMENTS CALCULATION						
149	**Sales Expense**						
150	Sales Expense - Supv.	0911	$ -	$ -	$ -	$ -	$ -
151	Demonstrations & Selling	0912	204,120	218,748	234,816	253,491	260,820
152	Advertising Expenses	0913	3,596	3,854	4,137	4,466	4,595
153	Miscellaneous Sales Expense	0916	-	-	-	-	-
154	**Total Sales Expense**		**$ 207,716**	**$ 222,602**	**$ 238,953**	**$ 257,957**	**$ 265,415**
155							
156	**Total Customer O&M**		**$ 10,063,366**	**$ 10,782,005**	**$ 11,557,880**	**$ 12,452,869**	**$ 12,839,517**
157							
158	Administrative & General Expense						
159	Administrative Salaries & Misc. Labor	0920	$ 741,182	$ 794,299	$ 852,641	$ 920,454	$ 947,066
160	Office Supplies & Expense	0921	781,486	837,492	899,006	970,507	998,566
161	Interdepartmental Charges	0922	(21,191,303)	(22,709,995)	(24,378,061)	(26,316,923)	(27,077,796)
162	Outside Services	0923	4,179,539	4,479,069	4,808,060	5,190,459	5,340,526
163	Property Insurance	0924	-	-	-	-	-
164	Injuries and Damages	0925	-	-	-	-	-
165	Employee Pensions and Benefits	0926	21,241,001	22,763,255	24,435,232	26,378,642	27,141,299
166	Franchise Requirements	0927	-	-	-	-	-
167	Compliance & Consultants (Regulatory Commission Expense	0928	24,854	26,635	28,591	30,865	31,758
168	General Advertising Expense	0930	24,292	26,033	27,945	30,168	31,040
169	Rents	0931	2,095,272	2,245,431	2,410,360	2,602,063	2,677,294
170	Miscellaneous General Expenses	0933	2,229,588	2,389,373	2,564,874	2,768,866	2,848,920
171	Maintenance of General Plant	0932	1,032	1,106	1,188	1,282	1,319
172	Duplicate Charges - Credit	0929	-	-	-	-	-
173	**Total Administrative & General Expense**		**$ 10,126,942**	**$ 10,852,698**	**$ 11,649,836**	**$ 12,576,383**	**$ 12,939,991**
174							
175	Miscellaneous and Clearing Accounts						
176	General Government Charges	0701	$ 10,953,229	$ 11,738,202	$ 12,600,381	$ 13,602,528	$ 13,995,803
177	Expenses Transferred From Electric	0702	3,782,780	4,053,876	4,351,637	4,697,736	4,833,556
178	IDI Utility Charges	0703	838	898	964	1,041	1,071
179	Removal Expenses	0704	-	-	-	-	-
180	Taxes	0707	-	-	-	-	-
181	Stores Expenses	0781	-	-	-	-	-
182	Transportation Expenses	0782	1,415,078	1,516,491	1,627,879	1,757,349	1,808,157
183	Tool and Shop Expenses	0783	(613,216)	(657,162)	(705,431)	(761,537)	(783,554)
184	Insurance	0788	569,631	610,454	655,293	707,410	727,863
185	Non-Operating expenses	0790	-	-	-	-	-

Revenue Requirement by Test Year

Line No.	Item	Account/ID	Fiscal Year 2017/18	Fiscal Year 2018/19	Fiscal Year 2019/20	Fiscal Year 2020/21	Fiscal Year 2021/22
1	REVENUE REQUIREMENTS CALCULATION						
186	**Total Miscellaneous and Clearing Accounts**		**$ 16,108,342**	**$ 17,262,759**	**$ 18,530,721**	**$ 20,004,527**	**$ 20,582,896**
187							
188	**Total O&M Expense**		**$ 271,606,428**	**$ 287,737,209**	**$ 302,201,122**	**$ 316,474,117**	**$ 322,284,259**
189	Check		-	-	-	-	-
190							
191	**Total O&M Expense less Purchased Power**		**$ 129,948,428**	**$ 136,030,209**	**$ 142,990,122**	**$ 150,886,117**	**$ 153,278,259**
192							
193	Additional Expenses & Deductions						
194	**Debt Service**						
195	Generation		$ 20,573,469	$ 20,579,063	$ 20,582,623	$ 20,431,586	$ 20,418,873
196	Transmission		-	-	-	-	-
197	Distribution		19,882,531	19,887,937	19,891,377	19,745,414	19,733,127
198	Customer		-	-	-	-	-
199	New Debt		231,000	4,125,000	9,232,000	9,551,000	14,402,000
200	**Total Debt Service**		**$ 40,687,000**	**$ 44,592,000**	**$ 49,706,000**	**$ 49,728,000**	**$ 54,554,000**
201							
202	**Taxes and Transfer to General Fund**						
203	Contribution to General Fund		$ 39,831,497	$ 40,018,802	$ 42,514,697	$ 44,740,668	$ 47,033,249
204	Other		-	-	-	-	-
205	Other		-	-	-	-	-
206	Other		-	-	-	-	-
207	**Total Taxes and Transfer to General Fund**		**$ 39,831,497**	**$ 40,018,802**	**$ 42,514,697**	**$ 44,740,668**	**$ 47,033,249**
208							
209	**Capital Paid from Current Earnings**						
210	Production		$ -	$ -	$ -	$ -	$ -
211	Transmission		-	-	-	-	-
212	Distribution		3,829,504	4,253,997	4,947,210	5,338,923	5,379,757
213	Customer		356,496	317,003	504,790	487,077	454,243
214	Street Lighting Capital		-	-	-	-	-
215	N/A		-	-	-	-	-
216	**Total Capital Paid from Current Earnings**		**$ 4,186,000**	**$ 4,571,000**	**$ 5,452,000**	**$ 5,826,000**	**$ 5,834,000**
217							
218	**Reserves - Additional Cash Requirements**		**$ 4,930,657**	**$ 10,292,384**	**$ 7,161,572**	**$ 4,379,629**	**$ 11,406,710**
219							
220	**Total Additional Expenses & Deductions**		**$ 89,635,153**	**$ 99,474,186**	**$ 104,834,269**	**$ 104,674,297**	**$ 118,827,960**
221							
222	**Subtotal Revenue Requirement**		**$ 361,241,582**	**$ 387,211,394**	**$ 407,035,391**	**$ 421,148,415**	**$ 441,112,218**

Revenue Requirement by Test Year

Line No.	Item	Account/ID		Fiscal Year 2017/18		Fiscal Year 2018/19		Fiscal Year 2019/20		Fiscal Year 2020/21		Fiscal Year 2021/22
1	REVENUE REQUIREMENTS CALCULATION											
223	Check			-		-		-		-		-
224												
225	Other Income											
226	**Other Operating Revenue:**											
227	Gain on retirement of assets (proforma)		$	482,000	$	482,000	$	482,000	$	482,000	$	482,000
228	Uncollectible accounts (proforma)											
229	Diversion	344400		-		-		-		-		-
230	Service Connect Charges-Elec	344410		371,000		378,420		385,988		393,708		401,582
231	Misc Service Revenues-Electric	344491		2,861,000		2,918,220		2,976,584		3,036,116		3,096,838
232	Misc Operating Revenues-Elec	344492		17,800		17,800		17,800		17,800		17,800
233	Corona Fees- Rev	344493		-		-		-		-		-
234	Cap and Trade Auction			2,944,000		5,235,000		5,043,000		-		-
235	Non Energy Recpts ABC Admin OH	344513		749,100		760,337		771,742		783,318		795,067
236	**Total Other Operating Revenue:**		**$**	**7,424,900**	**$**	**9,791,777**	**$**	**9,677,114**	**$**	**4,712,942**	**$**	**4,793,288**
237												
238	**Other Non-Operating Revenue:**											
239	Corona Fees- Rev	344493	$	20,000	$	20,000	$	20,000	$	20,000	$	20,000
240	Misc Settlement Reimb	344494		-		-		-		-		-
241	Late Payment Penalties	353400		-		-		-		-		-
242	Land and Building Rental	373100		1,821,000		1,821,000		1,821,000		1,821,000		1,821,000
243	Other Property Rental	373120		74,000		75,480		76,990		78,529		80,100
244	Pole Attachments	373125		216,900		221,238		225,663		230,176		234,780
245	Substation Operation & Maint	373126		325,833		-		-		-		-
246	Substation Leasing	373127		289,500		-		-		-		-
247	Communication Services	373128		268,200		268,200		268,200		268,200		268,200
248	CIS User Fee	373132		688,600		688,600		688,600		688,600		688,600
249	Refunds and Reimbursements	374000		-		-		-		-		-
250	Miscellaneous Receipts	374200		115,000		115,000		115,000		115,000		115,000
251	Cash Over/Shortage	374207		-		-		-		-		-
252	Asset Forfeiture Revenue	374500		-		-		-		-		-
253	Bad Debt Recovery	374800		-		-		-		-		-
254	Settlement Recovery	374801		-		-		-		-		-
255	Settlement Recovery - SONGS	374802		-		-		-		-		-
256	Liquidated Damages	374810		-		-		-		-		-
257	Operating Transfer from 650 Fund	985650		-		-		-		-		-
258	Utilization Charges	6125000		409,400		218,559		19,269		19,412		19,377
259	**Total Other Non-Operating Revenue:**		**$**	**4,228,433**	**$**	**3,428,077**	**$**	**3,234,721**	**$**	**3,240,917**	**$**	**3,247,057**

Revenue Requirement by Test Year

Line No.	Item	Account/ID	Fiscal Year 2017/18	Fiscal Year 2018/19	Fiscal Year 2019/20	Fiscal Year 2020/21	Fiscal Year 2021/22
1	REVENUE REQUIREMENTS CALCULATION						
260							
261	**Interest income**		4,679,000	7,391,000	8,188,000	7,344,000	7,378,578
262							
263	**Wholesale sales**		-	-	-	-	-
264							
265	**Transmission revenue**		38,643,000	39,167,000	39,809,000	40,277,000	40,679,770
266							
267	**Total Other Income**		**$ 54,975,333**	**$ 59,777,854**	**$ 60,908,836**	**$ 55,574,859**	**$ 56,098,693**
268							
269							
270	**Total Retail Revenue Requirement**		**$ 306,266,249**	**$ 327,433,541**	**$ 346,126,555**	**$ 365,573,555**	**$ 385,013,525**

Functional Unbundling

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
2											
3	Production O&M										
4	**Steam Production Operation**										
5	Supervision & Engineering	0500	$ -		NA	-	-	-	-	-	-
6	Fuel (Transportation & Handling)	0501	-		NA	-	-	-	-	-	-
7	Steam Power Fuel - Gas	50110	-		NA	-	-	-	-	-	-
8	Steam Power Fuel - Oil	50120	-		NA	-	-	-	-	-	-
9	Steam Power Fuel - Coal	50130	-		NA	-	-	-	-	-	-
10	Steam Expense	0502	-		NA	-	-	-	-	-	-
11	Electric Expense	0505	-		NA	-	-	-	-	-	-
12	Miscellaneous	0506	-		NA	-	-	-	-	-	-
13	Rent	0507	-		NA	-	-	-	-	-	-
14	**Total Steam Production Operation**		**$ -**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
15											
16	**Steam Production Maintenance**										
17	Supervision & Engineering	0510	$ -		NA	-	-	-	-	-	-
18	Structures	0511	-		NA	-	-	-	-	-	-
19	Boilers	0512	-		NA	-	-	-	-	-	-
20	Electric Plant	0513	-		NA	-	-	-	-	-	-
21	Miscellaneous Labor	0515	-		NA	-	-	-	-	-	-
22	**Total Steam Production Maintenance**		**$ -**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
23											
24	**Nuclear Production Operation**										
25	Supervision & Engineering	0517	$ -		NA	-	-	-	-	-	-
26	Nuclear Fuel Expense	0518	-		NA	-	-	-	-	-	-
27	Electric Expense - Turbine Generators	0523	-		NA	-	-	-	-	-	-
28	Reserved	NA	-		NA	-	-	-	-	-	-
29	Miscellaneous Power Expenses	0524	2,050,000		Production	2,050,000	-	-	-	-	2,050,000
30	Reserved	NA	-		NA	-	-	-	-	-	-
31	**Total Nuclear Production Operation**		**$ 2,050,000**			**$ 2,050,000**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2,050,000**
32											
33	**Nuclear Production Maintenance**										
34	Supervision & Engineering	0528	$ -		NA	-	-	-	-	-	-
35	Reserved	NA	-		NA	-	-	-	-	-	-
36	Reserved	NA	-		NA	-	-	-	-	-	-
37	Reserved	NA	-		NA	-	-	-	-	-	-
38	Miscellaneous Plant	0530	800,000		Production	800,000	-	-	-	-	800,000
39	**Total Nuclear Production Maintenance**		**$ 800,000**			**$ 800,000**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 800,000**
40											
41	**Combined Cycle Operation**										
42	Supervision & Engineering	NA	$ -		NA	-	-	-	-	-	-
43	Fuel	NA	-		NA	-	-	-	-	-	-
44	Combined Cycle Fuel - Gas	NA	-		NA	-	-	-	-	-	-
45	Combined Cycle Fuel - Oil	NA	-		NA	-	-	-	-	-	-
46	Generation Expense	NA	-		NA	-	-	-	-	-	-
47	Miscellaneous	NA	-		NA	-	-	-	-	-	-
48	**Total Combined Cycle Operation**		**$ -**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
49											
50	**Combined Cycle Maintenance**										
51	Supervision & Engineering	NA	$ -		NA	-	-	-	-	-	-
52	Structures	NA	-		NA	-	-	-	-	-	-
53	Electric Plant	NA	-		NA	-	-	-	-	-	-
54	Miscellaneous Plant	NA	-		NA	-	-	-	-	-	-
55	**Total Combined Cycle Maintenance**		**$ -**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
56											
57	**Other Production**										
58	Intermountain Power (take or pay)	0546	$ 47,062,400		Production	47,062,400	-	-	-	-	47,062,400

Functional Unbundling

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
59	Fuel expense	0547	1,509,400		Production	1,509,400	-	-	-	-	1,509,400
60	Hoover (take or Pay)	0548	867,200		Production	867,200	-	-	-	-	867,200
61	Misc Other Power Gen	0549	-		NA	-	-	-	-	-	-
62	Palo Verde Power (take or pay)	0550	4,198,000		Production	4,198,000	-	-	-	-	4,198,000
63	Deseret Power (take or pay)	0552	-		NA	-	-	-	-	-	-
64	Maint/Generating & Elec Equip	0553	5,471,363		Production	5,471,363	-	-	-	-	5,471,363
65	System Load Control	0556	4,667,413		Production	4,667,413	-	-	-	-	4,667,413
66	Other Expenditures	0557	2,556,400		Production	2,556,400	-	-	-	-	2,556,400
67	Purchased Power	0555	103,797,000		Production	103,797,000	-	-	-	-	103,797,000
68	Purchased Power - Energy Direct Assignment	55501	-		NA	-	-	-	-	-	-
69	**Total Other Production**		**$ 170,129,176**			**$ 170,129,176**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 170,129,176**
70											
71	**Total Production O&M**		**$ 172,979,176**			**$ 172,979,176**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 172,979,176**
72											
73	**Fuel & Purchased Power**		**$ 157,434,000**			**$ 157,434,000**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 157,434,000**
74											
75	**Total Production O&M less Fuel & Purchased Power**		**$ 15,545,176**			**$ 15,545,176**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 15,545,176**
76											
77	Transmission O&M										
78	**Transmission Operation**										
79	Supervision & Engineering	0560	$ -		NA	-	-	-	-	-	-
80	Load Dispatch	0561	-		NA	-	-	-	-	-	-
81	Station Equipment	0562	137,612		Distribution	-	-	137,612	-	-	137,612
82	Overhead Lines	0563	-		NA	-	-	-	-	-	-
83	Underground Lines	0564	-		NA	-	-	-	-	-	-
84	Transmission of Electricity by Others (Wheeling)	G110	-		NA	-	-	-	-	-	-
85	Miscellaneous	0566	270,062		Distribution	-	-	270,062	-	-	270,062
86	Rents	0567	-		NA	-	-	-	-	-	-
87	**Total Transmission Operation**		**$ 407,674**			**$ -**	**$ -**	**$ 407,674**	**$ -**	**$ -**	**$ 407,674**
88											
89	**Transmission Maintenance**										
90	Supervision & Engineering	0568	$ -		NA	-	-	-	-	-	-
91	Structures	0569	-		NA	-	-	-	-	-	-
92	Station Equipment	0570	344,339		Distribution	-	-	344,339	-	-	344,339
93	Overhead Lines	0571	4,196		Distribution	-	-	4,196	-	-	4,196
94	Underground Lines	0572	-		NA	-	-	-	-	-	-
95	Miscellaneous	0573	1,759,282		Distribution	-	-	1,759,282	-	-	1,759,282
96	**Total Transmission Maintenance**		**$ 2,107,817**			**$ -**	**$ -**	**$ 2,107,817**	**$ -**	**$ -**	**$ 2,107,817**
97											
98	**Wheeling**										
99	Transmission Cost Fixed	0565	$ 32,703,121		Transmission	-	32,703,121	-	-	-	32,703,121
100	Transmission cost Variable	0565	30,435,879		Transmission	-	30,435,879	-	-	-	30,435,879
101	**Total Wheeling**		**$ 63,139,000**			**$ -**	**$ 63,139,000**	**$ -**	**$ -**	**$ -**	**$ 63,139,000**
102											
103	**Total Transmission O&M**		**$ 65,654,491**			**$ -**	**$ 63,139,000**	**$ 2,515,491**	**$ -**	**$ -**	**$ 65,654,491**
104											
105	Distribution O&M										
106	**Distribution Operations**										
107	Operation Maintenance and Engineering	0580	$ 4,548,243		Distribution	-	-	4,548,243	-	-	4,548,243
108	Load Dispatch	0581	2,590,605		Distribution	-	-	2,590,605	-	-	2,590,605
109	Station Equipment	0582	36,439		Distribution	-	-	36,439	-	-	36,439
110	Overhead Lines	0583	11,721		Distribution	-	-	11,721	-	-	11,721
111	Underground Lines	0584	859		Distribution	-	-	859	-	-	859
112	Street Lighting & Signal Expenses	0585	-		NA	-	-	-	-	-	-
113	Metering	0586	155,837		Distribution	-	-	155,837	-	-	155,837
114	Customer Installations	0587	25,122		Distribution	-	-	25,122	-	-	25,122
115	Miscellaneous	0588	398,723		Distribution	-	-	398,723	-	-	398,723

Functional Unbundling

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
116	Rents	0589	-		NA	-	-	-	-	-	-
117	**Total Distribution Operations**		**$ 7,767,549**			**$ -**	**$ -**	**$ 7,767,549**	**$ -**	**$ -**	**$ 7,767,549**
117											
118	**Distribution Maintenance**										
119	Supervision	0590	$ -		NA	-	-	-	-	-	-
120	Structures	0591	64,960		Distribution	-	-	64,960	-	-	64,960
121	Station Equipment	0592	1,434,921		Distribution	-	-	1,434,921	-	-	1,434,921
122	Overhead Lines	0593	5,773,829		Distribution	-	-	5,773,829	-	-	5,773,829
123	Underground Lines	0594	2,730,530		Distribution	-	-	2,730,530	-	-	2,730,530
124	Transformers	0595	79,635		Distribution	-	-	79,635	-	-	79,635
125	Street Lighting & Signals	0596	890,498		Distribution	-	-	890,498	-	-	890,498
126	Metering	0597	336,401		Distribution	-	-	336,401	-	-	336,401
127	Miscellaneous	0598	682,490		Distribution	-	-	682,490	-	-	682,490
128	**Total Distribution Maintenance**		**$ 11,993,265**			**$ -**	**$ -**	**$ 11,993,265**	**$ -**	**$ -**	**$ 11,993,265**
129											
130	**Total Distribution O&M**		**$ 19,760,814**			**$ -**	**$ -**	**$ 19,760,814**	**$ -**	**$ -**	**$ 19,760,814**
131											
132	Customer O&M										
133	**Customer Accounting Expense**										
134	Supervision	0901	$ 200,768		Customer	-	-	-	200,768	-	200,768
135	Meter Reading	0902	1,133,710		Customer	-	-	-	1,133,710	-	1,133,710
136	Customer Records and Collection Expenses	0903	6,226,701		Customer	-	-	-	6,226,701	-	6,226,701
137	Reserved	NA	-		NA	-	-	-	-	-	-
138	Uncollectible Accounts	0904	1,038,288		Customer	-	-	-	1,038,288	-	1,038,288
139	Miscellaneous	0905	-		NA	-	-	-	-	-	-
140	**Total Customer Accounting Expense**		**$ 8,599,467**			**$ -**	**$ -**	**$ -**	**$ 8,599,467**	**$ -**	**$ 8,599,467**
141											
142	**Other Customer Costs**										
143	Supervision	0907	$ -		NA	-	-	-	-	-	-
144	Customer Assistance	0908	1,532,067		Customer	-	-	-	1,532,067	-	1,532,067
145	Advertisement	0909	1,169,064		Customer	-	-	-	1,169,064	-	1,169,064
146	Miscellaneous	0910	-		NA	-	-	-	-	-	-
147	**Total Other Customer Costs**		**$ 2,701,131**			**$ -**	**$ -**	**$ -**	**$ 2,701,131**	**$ -**	**$ 2,701,131**
148											
149	**Sales Expense**										
150	Sales Expense - Supv.	0911	$ -		NA	-	-	-	-	-	-
151	Demonstrations & Selling	0912	234,399		Customer	-	-	-	234,399	-	234,399
152	Advertising Expenses	0913	4,130		Customer	-	-	-	4,130	-	4,130
153	Miscellaneous Sales Expense	0916	-		NA	-	-	-	-	-	-
154	**Total Sales Expense**		**$ 238,529**			**$ -**	**$ -**	**$ -**	**$ 238,529**	**$ -**	**$ 238,529**
155											
156	**Total Customer O&M**		**$ 11,539,127**			**$ -**	**$ -**	**$ -**	**$ 11,539,127**	**$ -**	**$ 11,539,127**
157											
158	Administrative & General Expense										
159	Administrative Salaries & Misc. Labor	0920	$ 851,129		Total Labor	168,226	-	491,056	191,847	-	851,129
160	Office Supplies & Expense	0921	897,411		A&G	231,005	-	666,407	-	-	897,411
161	Interdepartmental Charges	0922	(24,334,816)		Total Labor	(4,809,795)	-	(14,039,885)	(5,485,136)	-	(24,334,816)
162	Outside Services	0923	4,799,530		A&G	1,235,457	-	3,564,073	-	-	4,799,530
163	Property Insurance	0924	-		NA	-	-	-	-	-	-
164	Injuries and Damages	0925	-		NA	-	-	-	-	-	-
165	Employee Pensions and Benefits	0926	24,391,886		Total Labor	4,821,074	-	14,072,811	5,498,000	-	24,391,886
166	Franchise Requirements	0927	-		NA	-	-	-	-	-	-
167	Compliance & Consultants (Regulatory Commission Expens	0928	28,541		A&G	7,347	-	21,194	-	-	28,541
168	General Advertising Expense	0930	27,896		A&G	7,181	-	20,715	-	-	27,896
169	Rents	0931	2,406,084		Total Labor	475,564	-	1,388,181	542,338	-	2,406,084
170	Miscellaneous General Expenses	0933	2,560,324		A&G	659,058	-	1,901,266	-	-	2,560,324
171	Maintenance of General Plant	0932	1,186		A&G	305	-	880	-	-	1,186

Functional Unbundling

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
172	Duplicate Charges - Credit	0929	-		NA	-	-	-	-	-	-
173	**Total Administrative & General Expense**		**$ 11,629,170**			**$ 2,795,423**	**$ -**	**$ 8,086,698**	**$ 747,049**	**$ -**	**$ 11,629,170**
174											
175	Miscellaneous and Clearing Accounts										
176	General Government Charges	0701	$ 12,578,029		RevReq- Exl TRANS	9,227,770	-	2,883,161	467,097	-	12,578,029
177	Expenses Transferred From Electric	0702	4,343,917		RevReq- Exl TRANS	3,186,880	-	995,722	161,316	-	4,343,917
178	IDI Utility Charges	0703	962		RevReq- Exl TRANS	706	-	221	36	-	962
179	Removal Expenses	0704	-		RevReq- Exl TRANS	-	-	-	-	-	-
180	Taxes	0707	-		NA	-	-	-	-	-	-
181	Stores Expenses	0781	-		NA	-	-	-	-	-	-
182	Transportation Expenses	0782	1,624,991		Net Plant	535,741	-	1,089,250	-	-	1,624,991
183	Tool and Shop Expenses	0783	(704,180)		Net Plant	(232,160)	-	(472,020)	-	-	(704,180)
184	Insurance	0788	654,130		Net Plant	215,659	-	438,471	-	-	654,130
185	Non-Operating expenses	0790	-		NA	-	-	-	-	-	-
186	**Total Miscellaneous and Clearing Accounts**		**$ 18,497,849**			**$ 12,934,596**	**$ -**	**$ 4,934,804**	**$ 628,449**	**$ -**	**$ 18,497,849**
187											
188	**Total O&M Expense**		**$ 300,060,627**			**$ 188,709,194**	**$ 63,139,000**	**$ 35,297,808**	**$ 12,914,625**	**$ -**	**$ 300,060,627**
189	Check										
190											
191	**Total O&M Expense less Purchased Power**		**$ 142,626,627**			**$ 31,275,194**	**$ 63,139,000**	**$ 35,297,808**	**$ 12,914,625**	**$ -**	**$ 142,626,627**
192											
193	Additional Expenses & Deductions										
194	**Debt Service**										
195	Generation		$ 20,517,123		Production	20,517,123	-	-	-	-	20,517,123
196	Transmission		-		Transmission	-	-	-	-	-	-
197	Distribution		19,828,077		Distribution	-	-	19,828,077	-	-	19,828,077
198	Customer		-		NA	-	-	-	-	-	-
199	New Debt		7,508,200		CIP	-	-	6,892,528	615,672	-	7,508,200
200	**Total Debt Service**		**$ 47,853,400**			**$ 20,517,123**	**$ -**	**$ 26,720,605**	**$ 615,672**	**$ -**	**$ 47,853,400**
201											
202	**Taxes and Transfer to General Fund**										
203	Contribution to General Fund		$ 42,827,783		RevReq	29,035,445	3,250,651	9,071,951	1,469,736	-	42,827,783
204	Other		-		NA	-	-	-	-	-	-
205	Other		-		NA	-	-	-	-	-	-
206	Other		-		NA	-	-	-	-	-	-
207	**Total Taxes and Transfer to General Fund**		**$ 42,827,783**			**$ 29,035,445**	**$ 3,250,651**	**$ 9,071,951**	**$ 1,469,736**	**$ -**	**$ 42,827,783**
208											
209	**Capital Paid from Current Earnings**										
210	Production		$ -		Production	-	-	-	-	-	-
211	Transmission		-		Distribution	-	-	-	-	-	-
212	Distribution		4,749,448		Distribution	-	-	4,749,448	-	-	4,749,448
213	Customer		424,352		Customer	-	-	-	424,352	-	424,352
214	Street Lighting Capital		-		Distribution	-	-	-	-	-	-
215	N/A		-		NA	-	-	-	-	-	-
216	**Total Capital Paid from Current Earnings**		**$ 5,173,800**			**$ -**	**$ -**	**$ 4,749,448**	**$ 424,352**	**$ -**	**$ 5,173,800**
217											
218	**Reserves - Additional Cash Requirements**		7,634,190		RevReq	5,175,662	579,439	1,617,104	261,985	-	7,634,190
219											
220	**Total Additional Expenses & Deductions**		**$ 103,489,173**			**$ 54,728,229**	**$ 3,830,090**	**$ 42,159,109**	**$ 2,771,745**	**$ -**	**$ 103,489,173**
221											
222	**Subtotal Revenue Requirement**		**$ 403,549,800**			**$ 243,437,424**	**$ 66,969,090**	**$ 77,456,917**	**$ 15,686,369**	**$ -**	**$ 403,549,800**
223	Check										
224											
225	Other Income										
226	**Other Operating Revenue:**										
227	Gain on retirement of assets (proforma)		$ 482,000		Distribution	-	-	482,000	-	-	482,000

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
228	Uncollectible accounts (proforma)		-		NA	-	-	-	-	-	-
229	Diversion	344400	-		RevReq	-	-	-	-	-	-
230	Service Connect Charges-Elec	344410	386,140		Customer	-	-	-	386,140	-	386,140
231	Misc Service Revenues-Electric	344491	2,977,752		Customer	-	-	-	2,977,752	-	2,977,752
232	Misc Operating Revenues-Elec	344492	17,800		RevReq	12,068	1,351	3,770	611	-	17,800
233	Corona Fees- Rev	344493	-		NA	-	-	-	-	-	-
234	Cap and Trade Auction		3,305,500		RevReq	2,240,991	250,889	700,184	113,436	-	3,305,500
235	Non Energy Recpts ABC Admin OH	344513	771,913		Rev Req / City	21,635	2,422	6,760	1,095	740,000	771,913
236	**Total Other Operating Revenue:**		**$ 7,941,104**			**$ 2,274,694**	**$ 254,662**	**$ 1,192,714**	**$ 3,479,034**	**$ 740,000**	**$ 7,941,104**
237											
238	**Other Non-Operating Revenue:**										
239	Corona Fees- Rev	344493	$ 20,000		RevReq	13,559	1,518	4,236	686	-	20,000
240	Misc Settlement Reimb	344494	-		NA	-	-	-	-	-	-
241	Late Payment Penalties	353400	-		RevReq	-	-	-	-	-	-
242	Land and Building Rental	373100	1,821,000		RevReq	1,234,562	138,215	385,731	62,492	-	1,821,000
243	Other Property Rental	373120	77,020		RevReq	52,216	5,846	16,315	2,643	-	77,020
244	Pole Attachments	373125	225,751		Distribution	-	-	225,751	-	-	225,751
245	Substation Operation & Maint	373126	-		Direct Assign	-	-	-	-	-	-
246	Substation Leasing	373127	-		Direct Assign	-	-	-	-	-	-
247	Communication Services	373128	268,200		RevReq	181,828	20,357	56,811	9,204	-	268,200
248	CIS User Fee	373132	688,600		Distribution	-	-	688,600	-	-	688,600
249	Refunds and Reimbursements	374000	-		RevReq	-	-	-	-	-	-
250	Miscellaneous Receipts	374200	115,000		RevReq	77,965	8,729	24,360	3,946	-	115,000
251	Cash Over/Shortage	374207	-		RevReq	-	-	-	-	-	-
252	Asset Forfeiture Revenue	374500	-		RevReq	-	-	-	-	-	-
253	Bad Debt Recovery	374800	-		RevReq	-	-	-	-	-	-
254	Settlement Recovery	374801	-		RevReq	-	-	-	-	-	-
255	Settlement Recovery - SONGS	374802	-		RevReq	-	-	-	-	-	-
256	Liquidated Damages	374810	-		RevReq	-	-	-	-	-	-
257	Operating Transfer from 650 Fund	985650	-		NA	-	-	-	-	-	-
258	Utilization Charges	6125000	137,203		RevReq	93,018	10,414	29,063	4,708	-	137,203
259	**Total Other Non-Operating Revenue:**		**$ 3,352,774**			**$ 1,653,149**	**$ 185,078**	**$ 1,430,868**	**$ 83,680**	**$ -**	**$ 3,352,774**
260											
261	**Interest income**		6,996,116		RevReq	4,743,074	531,009	1,481,945	240,088	-	6,996,116
262											
263	**Wholesale sales**		-		Production	-	-	-	-	-	-
264											
265	**Transmission revenue**		39,715,154		Transmission	-	39,715,154	-	-	-	39,715,154
266											
267	**Total Other Income**		**$ 58,005,148**			**$ 8,670,916**	**$ 40,685,903**	**$ 4,105,527**	**$ 3,802,802**	**$ 740,000**	**$ 58,005,148**
268											
269											
270	**Total Retail Revenue Requirement**		**$ 345,544,652**			**$ 234,766,507**	**$ 26,283,187**	**$ 73,351,390**	**$ 11,883,568**	**$ (740,000)**	**$ 345,544,652**
271	Check					68%	8%	21%	3%	0%	
272	Difference between Acutal and Budget (Pro Forma)										
273	Revenue From Current Retail Rates										
274	Residential		$ 126,750,285								
275	Commercial-Flat		51,426,752								
276	Commercial-Demand		27,324,865								
277	Industrial-TOU		127,414,930								
278	City Contract		7,992,153								
279	Other		5,250,870								
280	**Total Revenue From Current Retail Rates**		**$ 346,159,853**								
281											
282											
283											
284	PLANT IN SERVICE										

Functional Unbundling

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
285											
286	Gross Plant in Service										
287	**Intangible Plant**										
288	Organization	301	$ -		NA	-	-	-	-	-	-
289	Franchises and Consents	302	-		NA	-	-	-	-	-	-
290	Misc. Intangible Plant	303	29,611,844		Net Plant	9,762,690	-	19,849,154	-	-	29,611,844
291	Misc. Computer Software	3030	-		NA	-	-	-	-	-	-
292	**Total Intangible Plant**		**$ 29,611,844**			**$ 9,762,690**	**$ -**	**$ 19,849,154**	**$ -**	**$ -**	**$ 29,611,844**
293											
294	**Production Plant**										
295	**Steam Production**										
296	Land and Land Rights	310	$ 17,142		Production	17,142	-	-	-	-	17,142
297	Structures & Improvements	311	-		NA	-	-	-	-	-	-
298	Boiler Plant Equipment	312	-		NA	-	-	-	-	-	-
299	Engines and Engine Generators	313	-		NA	-	-	-	-	-	-
300	Turbo-Generator Units	314	-		NA	-	-	-	-	-	-
301	Accessory Electric Equipment	315	-		NA	-	-	-	-	-	-
302	Misc. Power Plant Equipment	316	-		NA	-	-	-	-	-	-
303	**Total Steam Production**		**$ 17,142**			**$ 17,142**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 17,142**
304											
305	**Hydraulic Production**										
306	Land and Land Rights	330	$ -		NA	-	-	-	-	-	-
307	Structures & Improvements	331	-		NA	-	-	-	-	-	-
308	Reservoirs, Dams and Water Ways	332	-		NA	-	-	-	-	-	-
309	Water Wheel, Turbine and Generator	333	-		NA	-	-	-	-	-	-
310	Accessory Electric Equipment	334	-		NA	-	-	-	-	-	-
311	Misc. Power Plant Equipment	335	-		NA	-	-	-	-	-	-
312	Roads, Railroads and Bridges	336	-		NA	-	-	-	-	-	-
313	**Total Hydraulic Production**		**$ -**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
314											
315	**Combustion Turbine & Other Production**										
316	Land and Land Rights	340	$ 1,036,916		Production	1,036,916	-	-	-	-	1,036,916
317	Structures & Improvements	341	149,894		Production	149,894	-	-	-	-	149,894
318	Fuel Holders, Prod & Acc	342	-		NA	-	-	-	-	-	-
319	Prime Movers	343	-		NA	-	-	-	-	-	-
320	Generators & Other Production	344	267,162,932		Production	267,162,932	-	-	-	-	267,162,932
321	Accessory Electric Equipment	345	-		NA	-	-	-	-	-	-
322	Misc. Production Plant	2000	-		NA	-	-	-	-	-	-
323	**Total Combustion Turbine & Other Production**		**$ 268,349,742**			**$ 268,349,742**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 268,349,742**
324											
325	**Total Production Plant**		**$ 268,366,884**			**$ 268,366,884**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 268,366,884**
326											
327	**Transmission Plant**										
328	Land and Land Rights	350	$ 1,711,343		Distribution	-	-	1,711,343	-	-	1,711,343
329	Reserved	351	-		NA	-	-	-	-	-	-
330	Structures & Improvements	352	980,750		Distribution	-	-	980,750	-	-	980,750
331	Station Equipment - System	353	4,863,356		Distribution	-	-	4,863,356	-	-	4,863,356
332	Towers and Fixtures	354	3,532,104		Distribution	-	-	3,532,104	-	-	3,532,104
333	Poles and Fixtures	355	18,659,015		Distribution	-	-	18,659,015	-	-	18,659,015
334	Overhead Conductor	356	8,592,606		Distribution	-	-	8,592,606	-	-	8,592,606
335	Underground Conductor	357	5,727,571		Distribution	-	-	5,727,571	-	-	5,727,571
336	Underground Conduit	358	2,058,122		Distribution	-	-	2,058,122	-	-	2,058,122
337	Misc. Transmission Plant	359	-		NA	-	-	-	-	-	-
338	**Total Transmission Plant**		**$ 46,124,867**			**$ -**	**$ -**	**$ 46,124,867**	**$ -**	**$ -**	**$ 46,124,867**
339											
340	**Distribution Plant**										
341	Land and Land Rights	360	$ 10,553,496		Distribution	-	-	10,553,496	-	-	10,553,496

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
342	Structures & Improvements	361	10,678,983		Distribution	-	-	10,678,983	-	-	10,678,983
343	Station Equipment	362	123,449,575		Distribution	-	-	123,449,575	-	-	123,449,575
344	Misc. Plant	363	-		NA	-	-	-	-	-	-
345	Towers and Fixtures	364	31,980,198		Distribution	-	-	31,980,198	-	-	31,980,198
346	Overhead Conductor	365	38,718,492		Distribution	-	-	38,718,492	-	-	38,718,492
347	Underground Conduit	366	109,279,967		Distribution	-	-	109,279,967	-	-	109,279,967
348	Underground Conductor	367	126,112,503		Distribution	-	-	126,112,503	-	-	126,112,503
349	Line Transformers	368	53,163,303		Distribution	-	-	53,163,303	-	-	53,163,303
350	Services	369	26,592,360		Distribution	-	-	26,592,360	-	-	26,592,360
351	Meters	370	15,232,659		Distribution	-	-	15,232,659	-	-	15,232,659
352	Inst. on Customer Premises	371	839,555		Distribution	-	-	839,555	-	-	839,555
353	Street Light / Signal Systems	373	47,962,902		Distribution	-	-	47,962,902	-	-	47,962,902
354	**Total Distribution Plant**		**$ 594,563,994**			**$ -**	**$ -**	**$ 594,563,994**	**$ -**	**$ -**	**$ 594,563,994**
355											
356	**Subtotal Plant Before General**		**$ 909,055,745**			**$ 268,366,884**	**$ -**	**$ 640,688,861**	**$ -**	**$ -**	**$ 909,055,745**
357											
358	**General Plant**										
359	Land and Land Rights	389	$ 8,119,611		Net Plant	2,676,944	-	5,442,667	-	-	8,119,611
360	Structures & Improvements	390	64,396,440		Net Plant	21,230,778	-	43,165,662	-	-	64,396,440
361	Structures & Improvements - Other	3900	-		NA	-	-	-	-	-	-
362	Office Furniture & Equipment	391	9,436,741		Net Plant	3,111,187	-	6,325,554	-	-	9,436,741
363	Info System Computers	3910	-		NA	-	-	-	-	-	-
364	Transportation Equipment	392	11,734,667		Net Plant	3,868,787	-	7,865,880	-	-	11,734,667
365	Stores Equipment	393	45,523		Net Plant	15,008	-	30,515	-	-	45,523
366	Tools, Shop & Garage Equip.	394	519,337		Net Plant	171,219	-	348,117	-	-	519,337
367	Laboratory Equipment	395	933,333		Net Plant	307,709	-	625,624	-	-	933,333
368	Power Operated Equipment	396	1,462,581		Net Plant	482,196	-	980,384	-	-	1,462,581
369	Communication Equipment	397	17,141,618		Net Plant	5,651,397	-	11,490,220	-	-	17,141,618
370	Miscellaneous Equipment	398	1,076,588		Net Plant	354,939	-	721,649	-	-	1,076,588
371	Other Tangible Property	399	-		NA	-	-	-	-	-	-
372	**Total General Plant**		**$ 114,866,439**			**$ 37,870,166**	**$ -**	**$ 76,996,273**	**$ -**	**$ -**	**$ 114,866,439**
373											
374	**Total Gross Plant in Service**		**$ 1,053,534,029**			**$ 315,999,741**	**$ -**	**$ 737,534,288**	**$ -**	**$ -**	**$ 1,053,534,029**
375	Check										
376											
377	Accumulated Depreciation										
378	**Intangible Plant**										
379	Organization	301	$ -		NA	-	-	-	-	-	-
380	Franchises and Consents	302	-		NA	-	-	-	-	-	-
381	Misc. Intangible Plant	303	1,825,287		Net Plant	601,776	-	1,223,510	-	-	1,825,287
382	Misc. Computer Software	3030	-		NA	-	-	-	-	-	-
383	**Total Intangible Plant**		**$ 1,825,287**			**$ 601,776**	**$ -**	**$ 1,223,510**	**$ -**	**$ -**	**$ 1,825,287**
384											
385	**Production Plant**										
386	**Steam Production**										
387	Land and Land Rights	310	$ -		NA	-	-	-	-	-	-
388	Structures & Improvements	311	-		NA	-	-	-	-	-	-
389	Boiler Plant Equipment	312	-		NA	-	-	-	-	-	-
390	Engines and Engine Generators	313	-		NA	-	-	-	-	-	-
391	Turbo-Generator Units	314	-		NA	-	-	-	-	-	-
392	Accessory Electric Equipment	315	-		NA	-	-	-	-	-	-
393	Misc. Power Plant Equipment	316	-		NA	-	-	-	-	-	-
394	**Total Steam Production**		**$ -**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
395											
396	**Hydraulic Production**										
397	Land and Land Rights	330	$ -		NA	-	-	-	-	-	-
398	Structures & Improvements	331	-		NA	-	-	-	-	-	-

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
399	Reservoirs, Dams and Water Ways	332	-		NA	-	-	-	-	-	-
400	Water Wheel, Turbine and Generator	333	-		NA	-	-	-	-	-	-
401	Accessory Electric Equipment	334	-		NA	-	-	-	-	-	-
402	Misc. Power Plant Equipment	335	-		NA	-	-	-	-	-	-
403	Roads, Railroads and Bridges	336	-		NA	-	-	-	-	-	-
404	**Total Hydraulic Production**		$ -			$ -	$ -	$ -	$ -	$ -	$ -
405											
406	**Combustion Turbine & Other Production**										
407	Land and Land Rights	340	$ -		NA	-	-	-	-	-	-
408	Structures & Improvements	341	21,235		Production	21,235	-	-	-	-	21,235
409	Fuel Holders, Prod & Acc	342	-		NA	-	-	-	-	-	-
410	Prime Movers	343	-		NA	-	-	-	-	-	-
411	Generators & Other Production	344	70,802,165		Production	70,802,165	-	-	-	-	70,802,165
412	Accessory Electric Equipment	345	-		NA	-	-	-	-	-	-
413	Misc. Production Plant	2000	-		NA	-	-	-	-	-	-
414	**Total Combustion Turbine & Other Production**		**$ 70,823,401**			**$ 70,823,401**	$ -	$ -	$ -	$ -	**$ 70,823,401**
415											
416	**Total Production Plant**		**$ 70,823,401**			**$ 70,823,401**	$ -	$ -	$ -	$ -	**$ 70,823,401**
417											
418	**Transmission Plant**										
419	Land and Land Rights	350	$ -		NA	-	-	-	-	-	-
420	Reserved	351	-		NA	-	-	-	-	-	-
421	Structures & Improvements	352	641,394		Distribution	-	-	641,394	-	-	641,394
422	Station Equipment - System	353	4,385,910		Distribution	-	-	4,385,910	-	-	4,385,910
423	Towers and Fixtures	354	808,468		Distribution	-	-	808,468	-	-	808,468
424	Poles and Fixtures	355	6,310,350		Distribution	-	-	6,310,350	-	-	6,310,350
425	Overhead Conductor	356	2,681,443		Distribution	-	-	2,681,443	-	-	2,681,443
426	Underground Conductor	357	1,283,113		Distribution	-	-	1,283,113	-	-	1,283,113
427	Underground Conduit	358	880,098		Distribution	-	-	880,098	-	-	880,098
428	Misc. Transmission Plant	359	-		NA	-	-	-	-	-	-
429	**Total Transmission Plant**		**$ 16,990,776**			$ -	$ -	**$ 16,990,776**	$ -	$ -	**$ 16,990,776**
430											
431	**Distribution Plant**										
432	Land and Land Rights	360	$ -		NA	-	-	-	-	-	-
433	Structures & Improvements	361	2,514,219		Distribution	-	-	2,514,219	-	-	2,514,219
434	Station Equipment	362	40,040,406		Distribution	-	-	40,040,406	-	-	40,040,406
435	Misc. Plant	363	-		NA	-	-	-	-	-	-
436	Towers and Fixtures	364	13,510,816		Distribution	-	-	13,510,816	-	-	13,510,816
437	Overhead Conductor	365	18,402,517		Distribution	-	-	18,402,517	-	-	18,402,517
438	Underground Conduit	366	26,031,289		Distribution	-	-	26,031,289	-	-	26,031,289
439	Underground Conductor	367	48,413,025		Distribution	-	-	48,413,025	-	-	48,413,025
440	Line Transformers	368	27,607,645		Distribution	-	-	27,607,645	-	-	27,607,645
441	Services	369	10,963,449		Distribution	-	-	10,963,449	-	-	10,963,449
442	Meters	370	4,308,301		Distribution	-	-	4,308,301	-	-	4,308,301
443	Inst. on Customer Premises	371	713,846		Distribution	-	-	713,846	-	-	713,846
444	Street Light / Signal Systems	373	29,554,194		Distribution	-	-	29,554,194	-	-	29,554,194
445	**Total Distribution Plant**		**$ 222,059,707**			$ -	$ -	**$ 222,059,707**	$ -	$ -	**$ 222,059,707**
446											
447	**Subtotal Plant Before General**		**$ 309,873,884**			**$ 70,823,401**	$ -	**$ 239,050,483**	$ -	$ -	**$ 309,873,884**
448											
449	**General Plant**										
450	Land and Land Rights	389	$ -		NA	-	-	-	-	-	-
451	Structures & Improvements	390	6,960,593		Net Plant	2,294,829	-	4,665,764	-	-	6,960,593
452	Structures & Improvements - Other	3900	-		NA	-	-	-	-	-	-
453	Office Furniture & Equipment	391	5,225,504		Net Plant	1,722,790	-	3,502,715	-	-	5,225,504
454	Info System Computers	3910	-		NA	-	-	-	-	-	-
455	Transportation Equipment	392	6,330,159		Net Plant	2,086,982	-	4,243,177	-	-	6,330,159

Functional Unbundling

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
456	Stores Equipment	393	45,523		Net Plant	15,008	-	30,515	-	-	45,523
457	Tools, Shop & Garage Equip.	394	442,411		Net Plant	145,858	-	296,553	-	-	442,411
458	Laboratory Equipment	395	915,690		Net Plant	301,893	-	613,797	-	-	915,690
459	Power Operated Equipment	396	1,023,696		Net Plant	337,501	-	686,195	-	-	1,023,696
460	Communication Equipment	397	10,750,342		Net Plant	3,544,266	-	7,206,076	-	-	10,750,342
461	Miscellaneous Equipment	398	773,205		Net Plant	254,917	-	518,288	-	-	773,205
462	Other Tangible Property	399	-		NA	-	-	-	-	-	-
463	**Total General Plant**		**$ 32,467,125**			**$ 10,704,044**	**$ -**	**$ 21,763,081**	**$ -**	**$ -**	**$ 32,467,125**
464											
465	**Total Accumulated Depreciation**		**$ 344,166,295**			**$ 82,129,221**	**$ -**	**$ 262,037,075**	**$ -**	**$ -**	**$ 344,166,295**
466	Check										
467											
468	Net Plant in Service										
469	**Intangible Plant**										
470	Organization	301	$ -			-	-	-	-	-	-
471	Franchises and Consents	302	-			-	-	-	-	-	-
472	Misc. Intangible Plant	303	27,786,558			9,160,914	-	18,625,644	-	-	27,786,558
473	Misc. Computer Software	3030	-			-	-	-	-	-	-
474	**Total Intangible Plant**		**$ 27,786,558**			**$ 9,160,914**	**$ -**	**$ 18,625,644**	**$ -**	**$ -**	**$ 27,786,558**
475											
476	**Production Plant**										
477	**Steam Production**										
478	Land and Land Rights	310	$ 17,142			17,142	-	-	-	-	17,142
479	Structures & Improvements	311	-			-	-	-	-	-	-
480	Boiler Plant Equipment	312	-			-	-	-	-	-	-
481	Engines and Engine Generators	313	-			-	-	-	-	-	-
482	Turbo-Generator Units	314	-			-	-	-	-	-	-
483	Accessory Electric Equipment	315	-			-	-	-	-	-	-
484	Misc. Power Plant Equipment	316	-			-	-	-	-	-	-
485	**Total Steam Production**		**$ 17,142**			**$ 17,142**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 17,142**
486											
487	**Hydraulic Production**										
488	Land and Land Rights	330	$ -			-	-	-	-	-	-
489	Structures & Improvements	331	-			-	-	-	-	-	-
490	Reservoirs, Dams and Water Ways	332	-			-	-	-	-	-	-
491	Water Wheel, Turbine and Generator	333	-			-	-	-	-	-	-
492	Accessory Electric Equipment	334	-			-	-	-	-	-	-
493	Misc. Power Plant Equipment	335	-			-	-	-	-	-	-
494	Roads, Railroads and Bridges	336	-			-	-	-	-	-	-
495	**Total Hydraulic Production**		**$ -**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
496											
497	**Combustion Turbine & Other Production**										
498	Land and Land Rights	340	$ 1,036,916			1,036,916	-	-	-	-	1,036,916
499	Structures & Improvements	341	128,659			128,659	-	-	-	-	128,659
500	Fuel Holders, Prod & Acc	342	-			-	-	-	-	-	-
501	Prime Movers	343	-			-	-	-	-	-	-
502	Generators & Other Production	344	196,360,767			196,360,767	-	-	-	-	196,360,767
503	Accessory Electric Equipment	345	-			-	-	-	-	-	-
504	Misc. Production Plant	2000	-			-	-	-	-	-	-
505	**Total Combustion Turbine & Other Production**		**$ 197,526,342**			**$ 197,526,342**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 197,526,342**
506											
507	**Total Production Plant**		**$ 197,543,484**			**$ 197,543,484**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 197,543,484**
508											
509	**Transmission Plant**										
510	Land and Land Rights	350	$ 1,711,343			-	-	1,711,343	-	-	1,711,343
511	Reserved	351	-			-	-	-	-	-	-
512	Structures & Improvements	352	339,356			-	-	339,356	-	-	339,356

Functional Unbundling

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
513	Station Equipment - System	353	477,446			-	-	477,446	-	-	477,446
514	Towers and Fixtures	354	2,723,636			-	-	2,723,636	-	-	2,723,636
515	Poles and Fixtures	355	12,348,665			-	-	12,348,665	-	-	12,348,665
516	Overhead Conductor	356	5,911,163			-	-	5,911,163	-	-	5,911,163
517	Underground Conductor	357	4,444,457			-	-	4,444,457	-	-	4,444,457
518	Underground Conduit	358	1,178,024			-	-	1,178,024	-	-	1,178,024
519	Misc. Transmission Plant	359	-			-	-	-	-	-	-
520	**Total Transmission Plant**		**$ 29,134,091**			**$ -**	**$ -**	**$ 29,134,091**	**$ -**	**$ -**	**$ 29,134,091**
521											
522	**Distribution Plant**										
523	Land and Land Rights	360	$ 10,553,496			-	-	10,553,496	-	-	10,553,496
524	Structures & Improvements	361	8,164,764			-	-	8,164,764	-	-	8,164,764
525	Station Equipment	362	83,409,169			-	-	83,409,169	-	-	83,409,169
526	Misc. Plant	363	-			-	-	-	-	-	-
527	Towers and Fixtures	364	18,469,382			-	-	18,469,382	-	-	18,469,382
528	Overhead Conductor	365	20,315,975			-	-	20,315,975	-	-	20,315,975
529	Underground Conduit	366	83,248,679			-	-	83,248,679	-	-	83,248,679
530	Underground Conductor	367	77,699,479			-	-	77,699,479	-	-	77,699,479
531	Line Transformers	368	25,555,658			-	-	25,555,658	-	-	25,555,658
532	Services	369	15,628,911			-	-	15,628,911	-	-	15,628,911
533	Meters	370	10,924,357			-	-	10,924,357	-	-	10,924,357
534	Inst. on Customer Premises	371	125,709			-	-	125,709	-	-	125,709
535	Street Light / Signal Systems	373	18,408,708			-	-	18,408,708	-	-	18,408,708
536	**Total Distribution Plant**		**$ 372,504,287**			**$ -**	**$ -**	**$ 372,504,287**	**$ -**	**$ -**	**$ 372,504,287**
537											
538	**Subtotal Plant Before General**		**$ 599,181,862**			**$ 197,543,484**	**$ -**	**$ 401,638,378**	**$ -**	**$ -**	**$ 599,181,862**
539											
540	**General Plant**										
541	Land and Land Rights	389	$ 8,119,611			2,676,944	-	5,442,667	-	-	8,119,611
542	Structures & Improvements	390	57,435,847			18,935,949	-	38,499,898	-	-	57,435,847
543	Structures & Improvements - Other	3900	-			-	-	-	-	-	-
544	Office Furniture & Equipment	391	4,211,237			1,388,397	-	2,822,840	-	-	4,211,237
545	Info System Computers	3910	-			-	-	-	-	-	-
546	Transportation Equipment	392	5,404,508			1,781,805	-	3,622,703	-	-	5,404,508
547	Stores Equipment	393	-			-	-	-	-	-	-
548	Tools, Shop & Garage Equip.	394	76,926			25,362	-	51,564	-	-	76,926
549	Laboratory Equipment	395	17,643			5,817	-	11,826	-	-	17,643
550	Power Operated Equipment	396	438,884			144,695	-	294,189	-	-	438,884
551	Communication Equipment	397	6,391,275			2,107,131	-	4,284,144	-	-	6,391,275
552	Miscellaneous Equipment	398	303,383			100,022	-	203,361	-	-	303,383
553	Other Tangible Property	399	-			-	-	-	-	-	-
554	**Total General Plant**		**$ 82,399,314**			**$ 27,166,122**	**$ -**	**$ 55,233,192**	**$ -**	**$ -**	**$ 82,399,314**
555											
556	**Total Net Plant in Service**		**$ 709,367,733**			**$ 233,870,520**	**$ -**	**$ 475,497,214**	**$ -**	**$ -**	**$ 709,367,733**
557	Check										
558											
559											
560	LABOR										
561											
562	Production Labor										
563	**Steam Production Operation**										
564	Supervision & Engineering		$ -		NA	-	-	-	-	-	-
565	Fuel (Transportation & Handling)		-		NA	-	-	-	-	-	-
566	Steam Expense		-		NA	-	-	-	-	-	-
567	Electric Expense		-		NA	-	-	-	-	-	-
568	Miscellaneous		-		NA	-	-	-	-	-	-
569	Rent		-		NA	-	-	-	-	-	-

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
570	**Total Steam Production Operation**		$ -			$ -	$ -	$ -	$ -	$ -	$ -
571											
572	**Steam Production Maintenance**										
573	Supervision & Engineering		$ -		NA	-	-	-	-	-	-
574	Structures		-		NA	-	-	-	-	-	-
575	Boilers		-		NA	-	-	-	-	-	-
576	Electric Plant		-		NA	-	-	-	-	-	-
577	Miscellaneous Labor		-		NA	-	-	-	-	-	-
578	**Total Steam Production Maintenance**		$ -			$ -	$ -	$ -	$ -	$ -	$ -
579											
580	**Hydro Production Operation**										
581	Supervision & Engineering		$ -		NA	-	-	-	-	-	-
582	Water for Power		-		NA	-	-	-	-	-	-
583	Hydraulic Expense		-		NA	-	-	-	-	-	-
584	Electric Expense		-		NA	-	-	-	-	-	-
585	Miscellaneous		-		NA	-	-	-	-	-	-
586	Rent		-		NA	-	-	-	-	-	-
587	**Total Hydro Production Operation**		$ -			$ -	$ -	$ -	$ -	$ -	$ -
588											
589	**Hydro Production Maintenance**										
590	Supervision & Engineering		$ -		NA	-	-	-	-	-	-
591	Structures		-		NA	-	-	-	-	-	-
592	Reservoirs & Dams		-		NA	-	-	-	-	-	-
593	Electric Plant		-		NA	-	-	-	-	-	-
594	Miscellaneous Plant		-		NA	-	-	-	-	-	-
595	**Total Hydro Production Maintenance**		$ -			$ -	$ -	$ -	$ -	$ -	$ -
596											
597	**Combined Cycle Operation**										
598	Labor		$ -		Production	-	-	-	-	-	-
599	Fuel Handling		-		NA	-	-	-	-	-	-
600	Generation Expense		-		NA	-	-	-	-	-	-
601	Miscellaneous		-		NA	-	-	-	-	-	-
602	**Total Combined Cycle Operation**		$ -			$ -	$ -	$ -	$ -	$ -	$ -
603											
604	**Combined Cycle Maintenance**										
605	Supervision & Engineering		$ -		NA	-	-	-	-	-	-
606	Structures		-		NA	-	-	-	-	-	-
607	Electric Plant		-		NA	-	-	-	-	-	-
608	Miscellaneous Plant		-		NA	-	-	-	-	-	-
609	**Total Combined Cycle Maintenance**		$ -			$ -	$ -	$ -	$ -	$ -	$ -
610											
611	**Other Production**										
612	RERC/Acorn Gen. Plant	612013	$ 2,491,754		Production	2,491,754	-	-	-	-	2,491,754
613	Clearwater Generating Plant	612014	933,985		Production	933,985	-	-	-	-	933,985
614	PU Elec Power Supply Operations	612000	6,110,675		Production	6,110,675	-	-	-	-	6,110,675
615	**Total Other Production**		**$ 9,536,414**			**$ 9,536,414**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9,536,414**
616											
617	**Total Production Labor**		**$ 9,536,414**			**$ 9,536,414**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9,536,414**
618											
619	Transmission Labor										
620	**Transmission Operations**										
621	Supervision & Engineering		$ -		NA	-	-	-	-	-	-
622	Load Dispatch		-		NA	-	-	-	-	-	-
623	Station Equipment		-		NA	-	-	-	-	-	-
624	Overhead Lines		-		NA	-	-	-	-	-	-
625	Underground Lines		-		NA	-	-	-	-	-	-
626	General Labor		-		NA	-	-	-	-	-	-

Functional Unbundling

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
627	Miscellaneous		-		NA	-	-	-	-	-	-
628	Rents		-		NA	-	-	-	-	-	-
629	**Total Transmission Operations**		$ -			$ -	$ -	$ -	$ -	$ -	$ -
630											
631	**Transmission Maintenance**										
632	Supervision & Engineering		$ -		NA	-	-	-	-	-	-
633	Structures		-		NA	-	-	-	-	-	-
634	Station Equipment		-		NA	-	-	-	-	-	-
635	Overhead Lines		-		NA	-	-	-	-	-	-
636	Underground Lines		-		NA	-	-	-	-	-	-
637	Miscellaneous		-		NA	-	-	-	-	-	-
638	**Total Transmission Maintenance**		$ -			$ -	$ -	$ -	$ -	$ -	$ -
639											
640	**Wheeling**										
641	Wheeling		$ -		NA	-	-	-	-	-	-
642	Wheeling		-		NA	-	-	-	-	-	-
643	**Total Wheeling**		$ -			$ -	$ -	$ -	$ -	$ -	$ -
644											
645	**Total Transmission Labor**		$ -			$ -	$ -	$ -	$ -	$ -	$ -
646											
647	Distribution Labor										
648	**Distribution Operations**										
649	Electric Operations	610000	$ 9,280,013		Distribution	-	-	9,280,013	-	-	9,280,013
650	PU Electric Field Operations	610500	11,052,109		Distribution	-	-	11,052,109	-	-	11,052,109
651	Energy Deliv Engineering	611000	7,508,316		Distribution	-	-	7,508,316	-	-	7,508,316
652	Customer Engineering-GIS	611500	-		Distribution	-	-	-	-	-	-
653	Underground Lines		-		NA	-	-	-	-	-	-
654	Street Lighting		-		NA	-	-	-	-	-	-
655	Metering		-		NA	-	-	-	-	-	-
656	Customer Installations		-		NA	-	-	-	-	-	-
657	Miscellaneous		-		NA	-	-	-	-	-	-
658	Rents		-		NA	-	-	-	-	-	-
659	**Total Distribution Operations**		**$ 27,840,438**			$ -	$ -	**$ 27,840,438**	$ -	$ -	**$ 27,840,438**
660											
661	**Distribution Maintenance**										
662	Supervision		$ -		NA	-	-	-	-	-	-
663	Structures		-		NA	-	-	-	-	-	-
664	Station Equipment		-		NA	-	-	-	-	-	-
665	Overhead Lines		-		NA	-	-	-	-	-	-
666	Underground Lines		-		NA	-	-	-	-	-	-
667	Transformers		-		NA	-	-	-	-	-	-
668	Street Lighting		-		NA	-	-	-	-	-	-
669	Metering		-		NA	-	-	-	-	-	-
670	Miscellaneous		-		NA	-	-	-	-	-	-
671	**Total Distribution Maintenance**		$ -			$ -	$ -	$ -	$ -	$ -	$ -
672											
673	**Total Distribution Labor**		**$ 27,840,438**			$ -	$ -	**$ 27,840,438**	$ -	$ -	**$ 27,840,438**
674											
675	Customer Labor										
676	**Customer Accounting Expense**										
677	Pub Util Business Support	600400	$ 730,534		Customer	-	-	-	730,534	-	730,534
678	Pub Util Admin-Utility Billing	600500	823,026		Customer	-	-	-	823,026	-	823,026
679	Pub Util Admin-Customer Service	601500	4,243,613		Customer	-	-	-	4,243,613	-	4,243,613
680	Pub Util Adm-Marketing Service	602000	2,066,236		Customer	-	-	-	2,066,236	-	2,066,236
681	Miscellaneous		-		NA	-	-	-	-	-	-
682	**Total Customer Accounting Expense**		**$ 7,863,409**			$ -	$ -	$ -	**$ 7,863,409**	$ -	**$ 7,863,409**
683											

Functional Unbundling

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
684	**Customer Service Expense**										
685	Customer Engineering-GIS		$ -		NA	-	-	-	-	-	-
686	Customer Assistance		-		NA	-	-	-	-	-	-
687	Advertisement / Marketing		-		NA	-	-	-	-	-	-
688	Miscellaneous		-		NA	-	-	-	-	-	-
689	**Total Customer Service Expense**		**$ -**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
690											
691	**Sales Expense**										
692	Sales Expense		$ -		NA	-	-	-	-	-	-
693	Demonstrations & Selling		-		NA	-	-	-	-	-	-
694	Miscellaneous Sales Expense		-		NA	-	-	-	-	-	-
695	**Total Sales Expense**		**$ -**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
696											
697	**Total Customer Labor**		**$ 7,863,409**			**$ -**	**$ -**	**$ -**	**$ 7,863,409**	**$ -**	**$ 7,863,409**
698											
699	**Total Labor Expense excluding A&G**		**$ 45,240,261**			**$ 9,536,414**	**$ -**	**$ 27,840,438**	**$ 7,863,409**	**$ -**	**$ 45,240,261**
700											
701	Administrative & General Labor										
702	Pub Util Admin-Mgmt Service	600000	$ 86,554		A&G	22,280	-	64,274	-	-	86,554
703	Pub Util Admin-Field Services	601000	3,127,327		Customer	-	-	-	3,127,327	-	3,127,327
704	Legislative & Regulator Risk	602500	306,276		A&G	78,839	-	227,437	-	-	306,276
705	Outside Services		-		NA	-	-	-	-	-	-
706	Outside Services		-		NA	-	-	-	-	-	-
707	Property Insurance		-		NA	-	-	-	-	-	-
708	Injuries and Damages		-		NA	-	-	-	-	-	-
709	Electric Utility Communication Labor		-		NA	-	-	-	-	-	-
710	Miscellaneous		-		NA	-	-	-	-	-	-
711	Rents		-		NA	-	-	-	-	-	-
712	Transportation Pool General Labor		-		NA	-	-	-	-	-	-
713	Maintenance of General Plant		-		NA	-	-	-	-	-	-
714	N/A		-		NA	-	-	-	-	-	-
715	**Total Administrative & General Labor**		**$ 3,520,157**			**$ 101,119**	**$ -**	**$ 291,711**	**$ 3,127,327**	**$ -**	**$ 3,520,157**
716											
717	**Total Labor Expense**		**$ 48,760,418**			**$ 9,637,533**	**$ -**	**$ 28,132,149**	**$ 10,990,736**	**$ -**	**$ 48,760,418**
718	Check										
719											
720	**Allocation Factors**										
721	Production				Production	100%	0%	0%	0%	0%	100%
722						1	-	-	-	-	1
723	Transmission				Transmission	0%	100%	0%	0%	0%	100%
724						-	1	-	-	-	1
725	Distribution				Distribution	0%	0%	100%	0%	0%	100%
726						-	-	1	-	-	1
727	Customer				Customer	0%	0%	0%	100%	0%	100%
728						-	-	-	1	-	1
729	Direct Assign				Direct Assign	0%	0%	0%	0%	100%	100%
730						-	-	-	-	1	1
731	Labor W/O Admin & Gen Labor				Labor Exc A&G	21%	0%	62%	17%	0%	100%
732						9,536,414	-	27,840,438	7,863,409	-	45,240,261
733	N/A				NA	0%	0%	0%	0%	0%	0%
734						-	-	-	-	-	-
735	Total Gross Plant In Service				Total Gross Plant	30%	0%	70%	0%	0%	100%
736						315,999,741	-	737,534,288	-	-	1,053,534,029
737	Net Plant (Gross Less Depr)				Net Plant	33%	0%	67%	0%	0%	100%
738						233,870,520	-	475,497,214	-	-	709,367,733
739	Gross T&D				Gross T&D	0%	0%	100%	0%	0%	100%
740						-	-	640,688,861	-	-	640,688,861

Functional Unbundling

Line No.	Item	Account/ID	Adjusted Test Year	Adjustment Citation	Allocation Factor	Production	Transmission	Distribution	Customer	Direct Assign	Total
1	REVENUE REQUIREMENTS CALCULATION										
741	Gross General Plant				Gross General Plant	33%	0%	67%	0%	0%	100%
742						37,870,166	-	76,996,273	-	-	114,866,439
743	Total Revenue Requirement Excluding Other				RevReq	68%	8%	21%	3%	0%	100%
744						234,766,507	26,283,187	73,351,390	11,883,568	-	346,284,652
745	Total Capital				Total Capital	0%	0%	92%	8%	0%	100%
746						-	-	4,749,448	424,352	-	5,173,800
747	Total Labor				Total Labor	20%	0%	58%	23%	0%	100%
748						9,637,533	-	28,132,149	10,990,736	-	48,760,418
749	Total Labor- exl Prod				Total Labor- Exl Prod	0%	0%	72%	28%	0%	100%
750						-	-	28,132,149	10,990,736	-	39,122,885
751	Debt Service - Subtotal				Debt Service ST	43%	0%	56%	1%	0%	100%
752						20,517,123	-	26,720,605	615,672	-	47,853,400
753	Total O&M Less AG				Total O&M Less AG	64%	23%	8%	4%	0%	100%
754						172,979,176	63,139,000	22,276,305	11,539,127	-	269,933,608
755	A&G				A&G	26%	0%	74%	0%	0%	100%
756						6,336,965	-	18,281,013	-	-	24,617,978
757	Total Revenue Requirement Excluding Transmission				RevReq- Exl TRANS	73%	0%	23%	4%	0%	100%
758						234,766,507	-	73,351,390	11,883,568	-	320,001,464
759	CIP				CIP	0%	0%	92%	8%	0%	100%
760						-	-	0.92	0.08	-	1
761	Rev Req / City				Rev Req / City	3%	0%	1%	0%	96%	100%
762					-	21,635	2,422	6,760	1,095	740,000	771,913
763	Blank				Blank	0%	0%	0%	0%	100%	100%
764						-	-	-	-	1	1
765	Blank				Blank	0%	0%	0%	0%	100%	100%
766						-	-	-	-	1	1
767	Blank				Blank	0%	0%	0%	0%	100%	100%
768						-	-	-	-	1	1
769	Blank				Blank	0%	0%	0%	0%	100%	100%
770						-	-	-	-	1	1
771	Blank				Blank	0%	0%	0%	0%	100%	100%
772						-	-	-	-	1	1
773	Blank				Blank	0%	0%	0%	0%	100%	100%
774						-	-	-	-	1	1
775	Blank				Blank	0%	0%	0%	0%	100%	100%
776						-	-	-	-	1	1
777	Blank				Blank	0%	0%	0%	0%	100%	100%
778						-	-	-	-	1	1
779	Blank				Blank	0%	0%	0%	0%	100%	100%
780						-	-	-	-	1	1
781	Blank				Blank	0%	0%	0%	0%	100%	100%
						-	-	-	-	1	1
	Blank				Blank	0%	0%	0%	0%	100%	100%
						-	-	-	-	1	1

Production Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Production Demand	Demand Related: Blank	Energy Related: Fuel & Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
2											
3	Production O&M										
4	**Steam Production Operation**										
5	Supervision & Engineering	0500	$ -	NA	-	-	-	-	-	-	-
6	Fuel (Transportation & Handling)	0501	-	NA	-	-	-	-	-	-	-
7	Steam Power Fuel - Gas	50110	-	NA	-	-	-	-	-	-	-
8	Steam Power Fuel - Oil	50120	-	NA	-	-	-	-	-	-	-
9	Steam Power Fuel - Coal	50130	-	NA	-	-	-	-	-	-	-
10	Steam Expense	0502	-	NA	-	-	-	-	-	-	-
11	Electric Expense	0505	-	NA	-	-	-	-	-	-	-
12	Miscellaneous	0506	-	NA	-	-	-	-	-	-	-
13	Rent	0507	-	NA	-	-	-	-	-	-	-
14	**Total Steam Production Operation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	**Steam Production Maintenance**										
17	Supervision & Engineering	0510	$ -	NA	-	-	-	-	-	-	-
18	Structures	0511	-	NA	-	-	-	-	-	-	-
19	Boilers	0512	-	NA	-	-	-	-	-	-	-
20	Electric Plant	0513	-	NA	-	-	-	-	-	-	-
21	Miscellaneous Labor	0515	-	NA	-	-	-	-	-	-	-
22	**Total Steam Production Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
23											
24	**Nuclear Production Operation**										
25	Supervision & Engineering	0517	$ -	NA	-	-	-	-	-	-	-
26	Nuclear Fuel Expense	0518	-	NA	-	-	-	-	-	-	-
27	Electric Expense - Turbine Generators	0523	-	NA	-	-	-	-	-	-	-
28	Reserved	NA	-	NA	-	-	-	-	-	-	-
29	Miscellaneous Power Expenses	0524	2,050,000	Baseload	2,050,000	-	-	-	-	-	2,050,000
30	Reserved	NA	-	NA	-	-	-	-	-	-	-
31	**Total Nuclear Production Operation**		**$ 2,050,000**		**$ 2,050,000**	$ -	$ -	$ -	$ -	$ -	**$ 2,050,000**
32											
33	**Nuclear Production Maintenance**										
34	Supervision & Engineering	0528	$ -	NA	-	-	-	-	-	-	-
35	Reserved	NA	-	NA	-	-	-	-	-	-	-
36	Reserved	NA	-	NA	-	-	-	-	-	-	-
37	Reserved	NA	-	NA	-	-	-	-	-	-	-
38	Miscellaneous Plant	0530	800,000	Baseload	800,000	-	-	-	-	-	800,000
39	**Total Nuclear Production Maintenance**		**$ 800,000**		**$ 800,000**	$ -	$ -	$ -	$ -	$ -	**$ 800,000**
40											
41	**Combined Cycle Operation**										
42	Supervision & Engineering	NA	$ -	NA	-	-	-	-	-	-	-
43	Fuel	NA	-	NA	-	-	-	-	-	-	-
44	Combined Cycle Fuel - Gas	NA	-	NA	-	-	-	-	-	-	-
45	Combined Cycle Fuel - Oil	NA	-	NA	-	-	-	-	-	-	-
46	Generation Expense	NA	-	NA	-	-	-	-	-	-	-
47	Miscellaneous	NA	-	NA	-	-	-	-	-	-	-
48	**Total Combined Cycle Operation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
49											
50	**Combined Cycle Maintenance**										
51	Supervision & Engineering	NA	$ -	NA	-	-	-	-	-	-	-
52	Structures	NA	-	NA	-	-	-	-	-	-	-
53	Electric Plant	NA	-	NA	-	-	-	-	-	-	-
54	Miscellaneous Plant	NA	-	NA	-	-	-	-	-	-	-
55	**Total Combined Cycle Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
56											
57	**Other Production**										
58	Intermountain Power (take or pay)	0546	$ 47,062,400	Purch Pwr	17,103,965	-	29,958,435	-	-	-	47,062,400

Production Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Production Demand	Demand Related: Blank	Energy Related: Fuel & Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
59	Fuel expense	0547	1,509,400	Fuel	-	-	1,509,400	-	-	-	1,509,400
60	Hoover (take or Pay)	0548	867,200	Purch Pwr	315,168	-	552,032	-	-	-	867,200
61	Misc Other Power Gen	0549	-	NA	-	-	-	-	-	-	-
62	Palo Verde Power (take or pay)	0550	4,198,000	Purch Pwr	1,525,686	-	2,672,314	-	-	-	4,198,000
63	Deseret Power (take or pay)	0552	-	NA	-	-	-	-	-	-	-
64	Maint/Generating & Elec Equip	0553	5,471,363	Baseload	5,471,363	-	-	-	-	-	5,471,363
65	System Load Control	0556	4,667,413	Baseload	4,667,413	-	-	-	-	-	4,667,413
66	Other Expenditures	0557	2,556,400	Baseload	2,556,400	-	-	-	-	-	2,556,400
67	Purchased Power	0555	103,797,000	Fuel	-	-	103,797,000	-	-	-	103,797,000
68	Purchased Power - Energy Direct Assignment	55501	-	NA	-	-	-	-	-	-	-
69	**Total Other Production**		**$ 170,129,176**		**$ 31,639,995**	**$ -**	**$ 138,489,181**	**$ -**	**$ -**	**$ -**	**$ 170,129,176**
70											
71	**Total Production O&M**		**$ 172,979,176**		**$ 34,489,995**	**$ -**	**$ 138,489,181**	**$ -**	**$ -**	**$ -**	**$ 172,979,176**
72											
73	**Fuel & Purchased Power**										
74											
75	**Total Production O&M less Fuel & Purchased Pow**		**$ 172,979,176**		**$ 34,489,995**	**$ -**	**$ 138,489,181**	**$ -**	**$ -**	**$ -**	**$ 172,979,176**
76											
157											
158	Administrative & General Expense										
159	Administrative Salaries & Misc. Labor	0920	$ 168,226	Baseload	168,226	-	-	-	-	-	168,226
160	Office Supplies & Expense	0921	231,005	Baseload	231,005	-	-	-	-	-	231,005
161	Interdepartmental Charges	0922	(4,809,795)	Baseload	(4,809,795)	-	-	-	-	-	(4,809,795)
162	Outside Services	0923	1,235,457	Baseload	1,235,457	-	-	-	-	-	1,235,457
163	Property Insurance	0924	-	NA	-	-	-	-	-	-	-
164	Injuries and Damages	0925	-	NA	-	-	-	-	-	-	-
165	Employee Pensions and Benefits	0926	4,821,074	Baseload	4,821,074	-	-	-	-	-	4,821,074
166	Franchise Requirements	0927	-	NA	-	-	-	-	-	-	-
167	Compliance & Consultants (Regulatory Commission Expense	0928	7,347	Baseload	7,347	-	-	-	-	-	7,347
168	General Advertising Expense	0930	7,181	Baseload	7,181	-	-	-	-	-	7,181
169	Rents	0931	475,564	Baseload	475,564	-	-	-	-	-	475,564
170	Miscellaneous General Expenses	0933	659,058	Baseload	659,058	-	-	-	-	-	659,058
171	Maintenance of General Plant	0932	305	Baseload	305	-	-	-	-	-	305
172	Duplicate Charges - Credit	0929	-	NA	-	-	-	-	-	-	-
173	**Total Administrative & General Expense**		**$ 2,795,423**		**$ 2,795,423**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2,795,423**
174											
175	Miscellaneous and Clearing Accounts										
176	General Government Charges	0701	$ 9,227,770	Baseload	9,227,770	-	-	-	-	-	9,227,770
177	Expenses Transferred From Electric	0702	3,186,880	Baseload	3,186,880	-	-	-	-	-	3,186,880
178	IDI Utility Charges	0703	706	Baseload	706	-	-	-	-	-	706
179	Removal Expenses	0704	-	Baseload	-	-	-	-	-	-	-
180	Taxes	0707	-	NA	-	-	-	-	-	-	-
181	Stores Expenses	0781	-	NA	-	-	-	-	-	-	-
182	Transportation Expenses	0782	535,741	Baseload	535,741	-	-	-	-	-	535,741
183	Tool and Shop Expenses	0783	(232,160)	Baseload	(232,160)	-	-	-	-	-	(232,160)
184	Insurance	0788	215,659	Baseload	215,659	-	-	-	-	-	215,659
185	Non-Operating expenses	0790	-	NA	-	-	-	-	-	-	-
186	**Total Miscellaneous and Clearing Accounts**		**$ 12,934,596**		**$ 12,934,596**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 12,934,596**
187											
188	**Total O&M Expense**		**$ 188,709,194**		**$ 50,220,014**	**$ -**	**$ 138,489,181**	**$ -**	**$ -**	**$ -**	**$ 188,709,194**
189	Check		-								
190											
191	**Total O&M Expense less Purchased Power**		**$ 188,709,194**		**$ 50,220,014**	**$ -**	**$ 138,489,181**	**$ -**	**$ -**	**$ -**	**$ 188,709,194**
192											
193	Additional Expenses & Deductions										
194	**Debt Service**										
195	Generation		$ 20,517,123	Baseload	20,517,123	-	-	-	-	-	20,517,123

Production Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Production Demand	Demand Related: Blank	Energy Related: Fuel & Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
196	Transmission		-	NA	-	-	-	-	-	-	-
197	Distribution		-	NA	-	-	-	-	-	-	-
198	Customer		-	NA	-	-	-	-	-	-	-
199	New Debt		-	NA	-	-	-	-	-	-	-
200	**Total Debt Service**		**$ 20,517,123**		**$ 20,517,123**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 20,517,123**
201											
202	**Taxes and Transfer to General Fund**										
203	Contribution to General Fund		$ 29,035,445	RevReq	9,722,394	-	19,313,051	-	-	-	29,035,445
204	Other		-	NA	-	-	-	-	-	-	-
205	Other		-	NA	-	-	-	-	-	-	-
206	Other		-	NA	-	-	-	-	-	-	-
207	**Total Taxes and Transfer to General Fund**		**$ 29,035,445**		**$ 9,722,394**	**$ -**	**$ 19,313,051**	**$ -**	**$ -**	**$ -**	**$ 29,035,445**
208											
209	**Capital Paid from Current Earnings**										
210	Production		$ -	NA	-	-	-	-	-	-	-
211	Transmission		-	NA	-	-	-	-	-	-	-
212	Distribution		-	NA	-	-	-	-	-	-	-
213	Customer		-	NA	-	-	-	-	-	-	-
214	Street Lighting Capital		-	NA	-	-	-	-	-	-	-
215	N/A		-	NA	-	-	-	-	-	-	-
216	**Total Capital Paid from Current Earnings**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
217											
218	**Reserves - Additional Cash Requirements**		5,175,662	Baseload	5,175,662	-	-	-	-	-	5,175,662
219											
220	**Total Additional Expenses & Deductions**		**$ 54,728,229**		**$ 35,415,178**	**$ -**	**$ 19,313,051**	**$ -**	**$ -**	**$ -**	**$ 54,728,229**
221											
222	**Subtotal Revenue Requirement**		**$ 243,437,424**		**$ 85,635,192**	**$ -**	**$ 157,802,232**	**$ -**	**$ -**	**$ -**	**$ 243,437,424**
223	Check		-								
224											
225	Other Income										
226	**Other Operating Revenue:**										
227	Gain on retirement of assets (proforma)		$ -	Baseload	-	-	-	-	-	-	-
228	Uncollectible accounts (proforma)		-	Baseload	-	-	-	-	-	-	-
229	Diversion	344400	-	Baseload	-	-	-	-	-	-	-
230	Service Connect Charges-Elec	344410	-	NA	-	-	-	-	-	-	-
231	Misc Service Revenues-Electric	344491	-	Baseload	-	-	-	-	-	-	-
232	Misc Operating Revenues-Elec	344492	12,068	Baseload	12,068	-	-	-	-	-	12,068
233	Corona Fees- Rev	344493	-	NA	-	-	-	-	-	-	-
234	Cap and Trade Auction		2,240,991	RevReq	750,386	-	1,490,605	-	-	-	2,240,991
235	Non Energy Recpts ABC Admin OH	344513	21,635	Baseload	21,635	-	-	-	-	-	21,635
236	**Total Other Operating Revenue:**		**$ 2,274,694**		**$ 784,089**	**$ -**	**$ 1,490,605**	**$ -**	**$ -**	**$ -**	**$ 2,274,694**
237											
238	**Other Non-Operating Revenue:**										
239	Corona Fees- Rev	344493	$ 13,559	Baseload	13,559	-	-	-	-	-	13,559
240	Misc Settlement Reimb	344494	-	Baseload	-	-	-	-	-	-	-
241	Late Payment Penalties	353400	-	Baseload	-	-	-	-	-	-	-
242	Land and Building Rental	373100	1,234,562	Baseload	1,234,562	-	-	-	-	-	1,234,562
243	Other Property Rental	373120	52,216	RevReq	17,484	-	34,732	-	-	-	52,216
244	Pole Attachments	373125	-	NA	-	-	-	-	-	-	-
245	Substation Operation & Maint	373126	-	NA	-	-	-	-	-	-	-
246	Substation Leasing	373127	-	NA	-	-	-	-	-	-	-
247	Communication Services	373128	181,828	RevReq	60,884	-	120,944	-	-	-	181,828
248	CIS User Fee	373132	-	Baseload	-	-	-	-	-	-	-
249	Refunds and Reimbursements	374000	-	Baseload	-	-	-	-	-	-	-
250	Miscellaneous Receipts	374200	77,965	Baseload	77,965	-	-	-	-	-	77,965
251	Cash Over/Shortage	374207	-	Baseload	-	-	-	-	-	-	-
252	Asset Forfeiture Revenue	374500	-	Baseload	-	-	-	-	-	-	-

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Production Demand	Demand Related: Blank	Energy Related: Fuel & Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
253	Bad Debt Recovery	374800	-	Baseload	-	-	-	-	-	-	-
254	Settlement Recovery	374801	-	Baseload	-	-	-	-	-	-	-
255	Settlement Recovery - SONGS	374802	-	Baseload	-	-	-	-	-	-	-
256	Liquidated Damages	374810	-	Baseload	-	-	-	-	-	-	-
257	Operating Transfer from 650 Fund	985650	-	NA	-	-	-	-	-	-	-
258	Utilization Charges	6125000	93,018	Baseload	93,018	-	-	-	-	-	93,018
259	**Total Other Non-Operating Revenue:**		**$ 1,653,149**		**$ 1,497,473**	**$ -**	**$ 155,676**	**$ -**	**$ -**	**$ -**	**$ 1,653,149**
260											
261	**Interest income**		4,743,074	Baseload	4,743,074	-	-	-	-	-	4,743,074
262											
263	**Wholesale sales**		-	Baseload	-	-	-	-	-	-	-
264											
265	**Transmission revenue**		-	NA	-	-	-	-	-	-	-
266											
267	**Total Other Income**		**$ 8,670,916**		**$ 7,024,636**	**$ -**	**$ 1,646,280**	**$ -**	**$ -**	**$ -**	**$ 8,670,916**
268											
269											
270	**Total Retail Revenue Requirement**		**$ 234,766,507**		**$ 78,610,556**	**$ -**	**$ 156,155,952**	**$ -**	**$ -**	**$ -**	**$ 234,766,507**
271	Check		-		33%	0%	67%	0%	0%	0%	
272											
273	Revenue From Current Retail Rates										
274	Residential										
275	Commercial-Flat										
276	Commercial-Demand										
277	Industrial-TOU										
278	City Contract										
279	Other										
280	**Total Revenue From Current Retail Rates**		**$ -**								
281											
282											
283											
284	PLANT IN SERVICE										
285											
286	Gross Plant in Service										
287	**Intangible Plant**										
288	Organization	301	$ -	NA	-	-	-	-	-	-	-
289	Franchises and Consents	302	-	NA	-	-	-	-	-	-	-
290	Misc. Intangible Plant	303	9,762,690	Baseload	9,762,690	-	-	-	-	-	9,762,690
291	Misc. Computer Software	3030	-	NA	-	-	-	-	-	-	-
292	**Total Intangible Plant**		**$ 9,762,690**		**$ 9,762,690**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9,762,690**
293											
294	**Production Plant**										
295	**Steam Production**										
296	Land and Land Rights	310	$ 17,142	Baseload	17,142	-	-	-	-	-	17,142
297	Structures & Improvements	311	-	NA	-	-	-	-	-	-	-
298	Boiler Plant Equipment	312	-	NA	-	-	-	-	-	-	-
299	Engines and Engine Generators	313	-	NA	-	-	-	-	-	-	-
300	Turbo-Generator Units	314	-	NA	-	-	-	-	-	-	-
301	Accessory Electric Equipment	315	-	NA	-	-	-	-	-	-	-
302	Misc. Power Plant Equipment	316	-	NA	-	-	-	-	-	-	-
303	**Total Steam Production**		**$ 17,142**		**$ 17,142**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 17,142**
304											
305	**Hydraulic Production**										
306	Land and Land Rights	330	$ -	NA	-	-	-	-	-	-	-
307	Structures & Improvements	331	-	NA	-	-	-	-	-	-	-
308	Reservoirs, Dams and Water Ways	332	-	NA	-	-	-	-	-	-	-
309	Water Wheel, Turbine and Generator	333	-	NA	-	-	-	-	-	-	-

Production Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related		Energy Related		Direct Assignment		Total
					Production Demand	Blank	Fuel & Energy	Blank	Direct Assign A	Blank	
1	REVENUE REQUIREMENTS CALCULATION										
310	Accessory Electric Equipment	334	-	NA	-	-	-	-	-	-	-
311	Misc. Power Plant Equipment	335	-	NA	-	-	-	-	-	-	-
312	Roads, Railroads and Bridges	336	-	NA	-	-	-	-	-	-	-
313	**Total Hydraulic Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
314											
315	**Combustion Turbine & Other Production**										
316	Land and Land Rights	340	$ 1,036,916	Baseload	1,036,916	-	-	-	-	-	1,036,916
317	Structures & Improvements	341	149,894	Baseload	149,894	-	-	-	-	-	149,894
318	Fuel Holders, Prod & Acc	342	-	NA	-	-	-	-	-	-	-
319	Prime Movers	343	-	NA	-	-	-	-	-	-	-
320	Generators & Other Production	344	267,162,932	Baseload	267,162,932	-	-	-	-	-	267,162,932
321	Accessory Electric Equipment	345	-	NA	-	-	-	-	-	-	-
	Misc. Production Plant	2000	-	NA	-	-	-	-	-	-	-
322	**Total Combustion Turbine & Other Production**		$ 268,349,742		$ 268,349,742	$ -	$ -	$ -	$ -	$ -	$ 268,349,742
322											
323	**Total Production Plant**		$ 268,366,884		$ 268,366,884	$ -	$ -	$ -	$ -	$ -	$ 268,366,884
324											
325	**Transmission Plant**										
326	Land and Land Rights	350	$ -	NA	-	-	-	-	-	-	-
327	Reserved	351	-	NA	-	-	-	-	-	-	-
328	Structures & Improvements	352	-	NA	-	-	-	-	-	-	-
329	Station Equipment - System	353	-	NA	-	-	-	-	-	-	-
330	Towers and Fixtures	354	-	NA	-	-	-	-	-	-	-
331	Poles and Fixtures	355	-	NA	-	-	-	-	-	-	-
332	Overhead Conductor	356	-	NA	-	-	-	-	-	-	-
333	Underground Conductor	357	-	NA	-	-	-	-	-	-	-
334	Underground Conduit	358	-	NA	-	-	-	-	-	-	-
335	Misc. Transmission Plant	359	-	NA	-	-	-	-	-	-	-
336	**Total Transmission Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
337											
338	**Distribution Plant**										
339	Land and Land Rights	360	$ -	NA	-	-	-	-	-	-	-
340	Structures & Improvements	361	-	NA	-	-	-	-	-	-	-
341	Station Equipment	362	-	NA	-	-	-	-	-	-	-
342	Misc. Plant	363	-	NA	-	-	-	-	-	-	-
343	Towers and Fixtures	364	-	NA	-	-	-	-	-	-	-
344	Overhead Conductor	365	-	NA	-	-	-	-	-	-	-
345	Underground Conduit	366	-	NA	-	-	-	-	-	-	-
346	Underground Conductor	367	-	NA	-	-	-	-	-	-	-
347	Line Transformers	368	-	NA	-	-	-	-	-	-	-
348	Services	369	-	NA	-	-	-	-	-	-	-
349	Meters	370	-	NA	-	-	-	-	-	-	-
350	Inst. on Customer Premises	371	-	NA	-	-	-	-	-	-	-
351	Street Light / Signal Systems	373	-	NA	-	-	-	-	-	-	-
352	**Total Distribution Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
353											
354	**Subtotal Plant Before General**		$ 278,129,575		$ 278,129,575	$ -	$ -	$ -	$ -	$ -	$ 278,129,575
355											
356	**General Plant**										
357	Land and Land Rights	389	$ 2,676,944	Total Gross Plant	2,676,944	-	-	-	-	-	2,676,944
358	Structures & Improvements	390	21,230,778	Total Gross Plant	21,230,778	-	-	-	-	-	21,230,778
359	Structures & Improvements - Other	3900	-	NA	-	-	-	-	-	-	-
360	Office Furniture & Equipment	391	3,111,187	Total Gross Plant	3,111,187	-	-	-	-	-	3,111,187
361	Info System Computers	3910	-	NA	-	-	-	-	-	-	-
362	Transportation Equipment	392	3,868,787	Total Gross Plant	3,868,787	-	-	-	-	-	3,868,787
363	Stores Equipment	393	15,008	Total Gross Plant	15,008	-	-	-	-	-	15,008
364	Tools, Shop & Garage Equip.	394	171,219	Total Gross Plant	171,219	-	-	-	-	-	171,219

Production Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Production Demand	Demand Related: Blank	Energy Related: Fuel & Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
365	Laboratory Equipment	395	307,709	Total Gross Plant	307,709	-	-	-	-	-	307,709
366	Power Operated Equipment	396	482,196	Total Gross Plant	482,196	-	-	-	-	-	482,196
367	Communication Equipment	397	5,651,397	Total Gross Plant	5,651,397	-	-	-	-	-	5,651,397
368	Miscellaneous Equipment	398	354,939	Total Gross Plant	354,939	-	-	-	-	-	354,939
369	Other Tangible Property	399	-	NA	-	-	-	-	-	-	-
370	**Total General Plant**		**$ 37,870,166**		**$ 37,870,166**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 37,870,166**
371											
372	**Total Gross Plant in Service**		**$ 315,999,741**		**$ 315,999,741**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 315,999,741**
373	Check		-								
374											
375	Accumulated Depreciation										
376	**Intangible Plant**										
377	Organization	301	$ -	NA	-	-	-	-	-	-	-
378	Franchises and Consents	302	-	NA	-	-	-	-	-	-	-
379	Misc. Intangible Plant	303	601,776	Baseload	601,776	-	-	-	-	-	601,776
380	Misc. Computer Software	3030	-	NA	-	-	-	-	-	-	-
381	**Total Intangible Plant**		**$ 601,776**		**$ 601,776**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 601,776**
382											
383	**Production Plant**										
384	**Steam Production**										
385	Land and Land Rights	310	$ -	Baseload	-	-	-	-	-	-	-
386	Structures & Improvements	311	-	NA	-	-	-	-	-	-	-
387	Boiler Plant Equipment	312	-	NA	-	-	-	-	-	-	-
388	Engines and Engine Generators	313	-	NA	-	-	-	-	-	-	-
389	Turbo-Generator Units	314	-	NA	-	-	-	-	-	-	-
390	Accessory Electric Equipment	315	-	NA	-	-	-	-	-	-	-
391	Misc. Power Plant Equipment	316	-	NA	-	-	-	-	-	-	-
392	**Total Steam Production**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
393											
394	**Hydraulic Production**										
395	Land and Land Rights	330	$ -	NA	-	-	-	-	-	-	-
396	Structures & Improvements	331	-	NA	-	-	-	-	-	-	-
397	Reservoirs, Dams and Water Ways	332	-	NA	-	-	-	-	-	-	-
398	Water Wheel, Turbine and Generator	333	-	NA	-	-	-	-	-	-	-
399	Accessory Electric Equipment	334	-	NA	-	-	-	-	-	-	-
400	Misc. Power Plant Equipment	335	-	NA	-	-	-	-	-	-	-
401	Roads, Railroads and Bridges	336	-	NA	-	-	-	-	-	-	-
402	**Total Hydraulic Production**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
403											
404	**Combustion Turbine & Other Production**										
405	Land and Land Rights	340	$ -	Baseload	-	-	-	-	-	-	-
406	Structures & Improvements	341	21,235	Baseload	21,235	-	-	-	-	-	21,235
407	Fuel Holders, Prod & Acc	342	-	NA	-	-	-	-	-	-	-
408	Prime Movers	343	-	NA	-	-	-	-	-	-	-
409	Generators & Other Production	344	70,802,165	Baseload	70,802,165	-	-	-	-	-	70,802,165
410	Accessory Electric Equipment	345	-	NA	-	-	-	-	-	-	-
411	Misc. Production Plant	2000	-	NA	-	-	-	-	-	-	-
412	**Total Combustion Turbine & Other Production**		**$ 70,823,401**		**$ 70,823,401**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 70,823,401**
413											
414	**Total Production Plant**		**$ 70,823,401**		**$ 70,823,401**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 70,823,401**
415											
416	**Transmission Plant**										
417	Land and Land Rights	350	$ -	NA	-	-	-	-	-	-	-
418	Reserved	351	-	NA	-	-	-	-	-	-	-
419	Structures & Improvements	352	-	NA	-	-	-	-	-	-	-
420	Station Equipment - System	353	-	NA	-	-	-	-	-	-	-
421	Towers and Fixtures	354	-	NA	-	-	-	-	-	-	-

Production Function

Line			Adjusted	Allocation	Demand Related		Energy Related		Direct Assignment		
No.	Item	Account/ID	Test Year	Factor	Production Demand	Blank	Fuel & Energy	Blank	Direct Assign A	Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
422	Poles and Fixtures	355	-	NA	-	-	-	-	-	-	-
423	Overhead Conductor	356	-	NA	-	-	-	-	-	-	-
424	Underground Conductor	357	-	NA	-	-	-	-	-	-	-
425	Underground Conduit	358	-	NA	-	-	-	-	-	-	-
426	Misc. Transmission Plant	359	-	NA	-	-	-	-	-	-	-
427	**Total Transmission Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
428											
429	**Distribution Plant**										
430	Land and Land Rights	360	$ -	NA	-	-	-	-	-	-	-
431	Structures & Improvements	361	-	NA	-	-	-	-	-	-	-
432	Station Equipment	362	-	NA	-	-	-	-	-	-	-
433	Misc. Plant	363	-	NA	-	-	-	-	-	-	-
434	Towers and Fixtures	364	-	NA	-	-	-	-	-	-	-
435	Overhead Conductor	365	-	NA	-	-	-	-	-	-	-
436	Underground Conduit	366	-	NA	-	-	-	-	-	-	-
437	Underground Conductor	367	-	NA	-	-	-	-	-	-	-
438	Line Transformers	368	-	NA	-	-	-	-	-	-	-
439	Services	369	-	NA	-	-	-	-	-	-	-
440	Meters	370	-	NA	-	-	-	-	-	-	-
441	Inst. on Customer Premises	371	-	NA	-	-	-	-	-	-	-
442	Street Light / Signal Systems	373	-	NA	-	-	-	-	-	-	-
443	**Total Distribution Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
444											
445	**Subtotal Plant Before General**		**$ 71,425,177**		**$ 71,425,177**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 71,425,177**
446											
447	**General Plant**										
448	Land and Land Rights	389	$ -	Total Gross Plant	-	-	-	-	-	-	-
449	Structures & Improvements	390	2,294,829	Total Gross Plant	2,294,829	-	-	-	-	-	2,294,829
450	Structures & Improvements - Other	3900	-	NA	-	-	-	-	-	-	-
451	Office Furniture & Equipment	391	1,722,790	Total Gross Plant	1,722,790	-	-	-	-	-	1,722,790
452	Info System Computers	3910	-	NA	-	-	-	-	-	-	-
453	Transportation Equipment	392	2,086,982	Total Gross Plant	2,086,982	-	-	-	-	-	2,086,982
454	Stores Equipment	393	15,008	Total Gross Plant	15,008	-	-	-	-	-	15,008
455	Tools, Shop & Garage Equip.	394	145,858	Total Gross Plant	145,858	-	-	-	-	-	145,858
456	Laboratory Equipment	395	301,893	Total Gross Plant	301,893	-	-	-	-	-	301,893
457	Power Operated Equipment	396	337,501	Total Gross Plant	337,501	-	-	-	-	-	337,501
458	Communication Equipment	397	3,544,266	Total Gross Plant	3,544,266	-	-	-	-	-	3,544,266
459	Miscellaneous Equipment	398	254,917	Total Gross Plant	254,917	-	-	-	-	-	254,917
460	Other Tangible Property	399	-	NA	-	-	-	-	-	-	-
461	**Total General Plant**		**$ 10,704,044**		**$ 10,704,044**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 10,704,044**
462											
463	**Total Accumulated Depreciation**		**$ 82,129,221**		**$ 82,129,221**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 82,129,221**
464	Check		-								
465											
466	Net Plant in Service										
467	**Intangible Plant**										
468	Organization	301	$ -		-	-	-	-	-	-	-
469	Franchises and Consents	302	-		-	-	-	-	-	-	-
470	Misc. Intangible Plant	303	9,160,914		9,160,914	-	-	-	-	-	9,160,914
471	Misc. Computer Software	3030	-		-	-	-	-	-	-	-
472	**Total Intangible Plant**		**$ 9,160,914**		**$ 9,160,914**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9,160,914**
473											
474	**Production Plant**										
475	**Steam Production**										
476	Land and Land Rights	310	$ 17,142		17,142	-	-	-	-	-	17,142
477	Structures & Improvements	311	-		-	-	-	-	-	-	-
478	Boiler Plant Equipment	312	-		-	-	-	-	-	-	-

Production Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Production Demand	Demand Related: Blank	Energy Related: Fuel & Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
479	Engines and Engine Generators	313	-		-	-	-	-	-	-	-
480	Turbo-Generator Units	314	-		-	-	-	-	-	-	-
481	Accessory Electric Equipment	315	-		-	-	-	-	-	-	-
482	Misc. Power Plant Equipment	316	-		-	-	-	-	-	-	-
483	**Total Steam Production**		**$ 17,142**		**$ 17,142**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 17,142**
484											
485	**Hydraulic Production**										
486	Land and Land Rights	330	$ -		-	-	-	-	-	-	-
487	Structures & Improvements	331	-		-	-	-	-	-	-	-
488	Reservoirs, Dams and Water Ways	332	-		-	-	-	-	-	-	-
489	Water Wheel, Turbine and Generator	333	-		-	-	-	-	-	-	-
490	Accessory Electric Equipment	334	-		-	-	-	-	-	-	-
491	Misc. Power Plant Equipment	335	-		-	-	-	-	-	-	-
492	Roads, Railroads and Bridges	336	-		-	-	-	-	-	-	-
493	**Total Hydraulic Production**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
494											
495	**Combustion Turbine & Other Production**										
496	Land and Land Rights	340	$ 1,036,916		1,036,916	-	-	-	-	-	1,036,916
497	Structures & Improvements	341	128,659		128,659	-	-	-	-	-	128,659
498	Fuel Holders, Prod & Acc	342	-		-	-	-	-	-	-	-
499	Prime Movers	343	-		-	-	-	-	-	-	-
500	Generators & Other Production	344	196,360,767		196,360,767	-	-	-	-	-	196,360,767
501	Accessory Electric Equipment	345	-		-	-	-	-	-	-	-
502	Misc. Production Plant	2000	-		-	-	-	-	-	-	-
503	**Total Combustion Turbine & Other Production**		**$ 197,526,342**		**$ 197,526,342**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 197,526,342**
504											
505	**Total Production Plant**		**$ 197,543,484**		**$ 197,543,484**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 197,543,484**
506											
507	**Transmission Plant**										
508	Land and Land Rights	350	$ -		-	-	-	-	-	-	-
509	Reserved	351	-		-	-	-	-	-	-	-
510	Structures & Improvements	352	-		-	-	-	-	-	-	-
511	Station Equipment - System	353	-		-	-	-	-	-	-	-
512	Towers and Fixtures	354	-		-	-	-	-	-	-	-
513	Poles and Fixtures	355	-		-	-	-	-	-	-	-
514	Overhead Conductor	356	-		-	-	-	-	-	-	-
515	Underground Conductor	357	-		-	-	-	-	-	-	-
516	Underground Conduit	358	-		-	-	-	-	-	-	-
517	Misc. Transmission Plant	359	-		-	-	-	-	-	-	-
518	**Total Transmission Plant**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
519											
520	**Distribution Plant**										
521	Land and Land Rights	360	$ -		-	-	-	-	-	-	-
522	Structures & Improvements	361	-		-	-	-	-	-	-	-
523	Station Equipment	362	-		-	-	-	-	-	-	-
524	Misc. Plant	363	-		-	-	-	-	-	-	-
525	Towers and Fixtures	364	-		-	-	-	-	-	-	-
526	Overhead Conductor	365	-		-	-	-	-	-	-	-
527	Underground Conduit	366	-		-	-	-	-	-	-	-
528	Underground Conductor	367	-		-	-	-	-	-	-	-
529	Line Transformers	368	-		-	-	-	-	-	-	-
530	Services	369	-		-	-	-	-	-	-	-
531	Meters	370	-		-	-	-	-	-	-	-
532	Inst. on Customer Premises	371	-		-	-	-	-	-	-	-
533	Street Light / Signal Systems	373	-		-	-	-	-	-	-	-
534	**Total Distribution Plant**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
535											
536	**Subtotal Plant Before General**		**$ 206,704,398**		**$ 206,704,398**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 206,704,398**

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Production Demand	Demand Related: Blank	Energy Related: Fuel & Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
537											
538	**General Plant**										
539	Land and Land Rights	389	$ 2,676,944		2,676,944	-	-	-	-	-	2,676,944
540	Structures & Improvements	390	18,935,949		18,935,949	-	-	-	-	-	18,935,949
541	Structures & Improvements - Other	3900	-		-	-	-	-	-	-	-
542	Office Furniture & Equipment	391	1,388,397		1,388,397	-	-	-	-	-	1,388,397
543	Info System Computers	3910	-		-	-	-	-	-	-	-
544	Transportation Equipment	392	1,781,805		1,781,805	-	-	-	-	-	1,781,805
545	Stores Equipment	393	-		-	-	-	-	-	-	-
546	Tools, Shop & Garage Equip.	394	25,362		25,362	-	-	-	-	-	25,362
547	Laboratory Equipment	395	5,817		5,817	-	-	-	-	-	5,817
548	Power Operated Equipment	396	144,695		144,695	-	-	-	-	-	144,695
549	Communication Equipment	397	2,107,131		2,107,131	-	-	-	-	-	2,107,131
550	Miscellaneous Equipment	398	100,022		100,022	-	-	-	-	-	100,022
551	Other Tangible Property	399	-		-	-	-	-	-	-	-
552	**Total General Plant**		**$ 27,166,122**		**$ 27,166,122**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 27,166,122**
553											
554	**Total Net Plant in Service**		**$ 233,870,520**		**$ 233,870,520**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 233,870,520**
555	Check		-								
556											
557											
558	LABOR										
559											
560	Production Labor										
561	**Steam Production Operation**										
562	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
563	Fuel (Transportation & Handling)		-	NA	-	-	-	-	-	-	-
564	Steam Expense		-	NA	-	-	-	-	-	-	-
565	Electric Expense		-	NA	-	-	-	-	-	-	-
566	Miscellaneous		-	NA	-	-	-	-	-	-	-
567	Rent		-	NA	-	-	-	-	-	-	-
568	**Total Steam Production Operation**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
569											
570	**Steam Production Maintenance**										
571	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
572	Structures		-	NA	-	-	-	-	-	-	-
573	Boilers		-	NA	-	-	-	-	-	-	-
574	Electric Plant		-	NA	-	-	-	-	-	-	-
575	Miscellaneous Labor		-	NA	-	-	-	-	-	-	-
576	**Total Steam Production Maintenance**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
577											
578	**Hydro Production Operation**										
579	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
580	Water for Power		-	NA	-	-	-	-	-	-	-
581	Hydraulic Expense		-	NA	-	-	-	-	-	-	-
582	Electric Expense		-	NA	-	-	-	-	-	-	-
583	Miscellaneous		-	NA	-	-	-	-	-	-	-
584	Rent		-	NA	-	-	-	-	-	-	-
585	**Total Hydro Production Operation**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
586											
587	**Hydro Production Maintenance**										
588	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
589	Structures		-	NA	-	-	-	-	-	-	-
590	Reservoirs & Dams		-	NA	-	-	-	-	-	-	-
591	Electric Plant		-	NA	-	-	-	-	-	-	-
592	Miscellaneous Plant		-	NA	-	-	-	-	-	-	-
593	**Total Hydro Production Maintenance**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Production Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Production Demand	Demand Related: Blank	Energy Related: Fuel & Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
594											
595	**Combined Cycle Operation**										
596	Labor		$ -	Baseload	-	-	-	-	-	-	-
597	Fuel Handling		-	NA	-	-	-	-	-	-	-
598	Generation Expense		-	NA	-	-	-	-	-	-	-
599	Miscellaneous		-	NA	-	-	-	-	-	-	-
600	**Total Combined Cycle Operation**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
601											
602	**Combined Cycle Maintenance**										
603	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
604	Structures		-	NA	-	-	-	-	-	-	-
605	Electric Plant		-	NA	-	-	-	-	-	-	-
606	Miscellaneous Plant		-	NA	-	-	-	-	-	-	-
607	**Total Combined Cycle Maintenance**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
608											
609	**Other Production**										
610	RERC/Acorn Gen. Plant	612013	$ 2,491,754	Baseload	2,491,754	-	-	-	-	-	2,491,754
611	Clearwater Generating Plant	612014	933,985	Baseload	933,985	-	-	-	-	-	933,985
612	PU Elec Power Supply Operations	612000	6,110,675	Baseload	6,110,675	-	-	-	-	-	6,110,675
613	**Total Other Production**		**$ 9,536,414**		**$ 9,536,414**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9,536,414**
614											
615	**Total Production Labor**		**$ 9,536,414**		**$ 9,536,414**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9,536,414**
616											
617	Transmission Labor										
618	**Transmission Operations**										
619	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
620	Load Dispatch		-	NA	-	-	-	-	-	-	-
621	Station Equipment		-	NA	-	-	-	-	-	-	-
622	Overhead Lines		-	NA	-	-	-	-	-	-	-
623	Underground Lines		-	NA	-	-	-	-	-	-	-
624	General Labor		-	NA	-	-	-	-	-	-	-
625	Miscellaneous		-	NA	-	-	-	-	-	-	-
626	Rents		-	NA	-	-	-	-	-	-	-
627	**Total Transmission Operations**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
628											
629	**Transmission Maintenance**										
630	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
631	Structures		-	NA	-	-	-	-	-	-	-
632	Station Equipment		-	NA	-	-	-	-	-	-	-
633	Overhead Lines		-	NA	-	-	-	-	-	-	-
634	Underground Lines		-	NA	-	-	-	-	-	-	-
635	Miscellaneous		-	NA	-	-	-	-	-	-	-
636	**Total Transmission Maintenance**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
637											
638	**Wheeling**										
639	Wheeling		$ -	NA	-	-	-	-	-	-	-
640	Wheeling		-	NA	-	-	-	-	-	-	-
641	**Total Wheeling**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
642											
643	**Total Transmission Labor**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
644											
645	Distribution Labor										
646	**Distribution Operations**										
647	Electric Operations	610000	$ -	NA	-	-	-	-	-	-	-
648	PU Electric Field Operations	610500	-	NA	-	-	-	-	-	-	-
649	Energy Deliv Engineering	611000	-	NA	-	-	-	-	-	-	-
650	Customer Engineering-GIS	611500	-	NA	-	-	-	-	-	-	-

Production Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Production Demand	Demand Related: Blank	Energy Related: Fuel & Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
651	Underground Lines		-	NA	-	-	-	-	-	-	-
652	Street Lighting		-	NA	-	-	-	-	-	-	-
653	Metering		-	NA	-	-	-	-	-	-	-
654	Customer Installations		-	NA	-	-	-	-	-	-	-
655	Miscellaneous		-	NA	-	-	-	-	-	-	-
656	Rents		-	NA	-	-	-	-	-	-	-
657	**Total Distribution Operations**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
658											
659	**Distribution Maintenance**										
660	Supervision		$ -	NA	-	-	-	-	-	-	-
661	Structures		-	NA	-	-	-	-	-	-	-
662	Station Equipment		-	NA	-	-	-	-	-	-	-
663	Overhead Lines		-	NA	-	-	-	-	-	-	-
664	Underground Lines		-	NA	-	-	-	-	-	-	-
665	Transformers		-	NA	-	-	-	-	-	-	-
666	Street Lighting		-	NA	-	-	-	-	-	-	-
667	Metering		-	NA	-	-	-	-	-	-	-
668	Miscellaneous		-	NA	-	-	-	-	-	-	-
669	**Total Distribution Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
670											
671	**Total Distribution Labor**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
672											
673	Customer Labor										
674	**Customer Accounting Expense**										
675	Pub Util Business Support	600400	$ -	NA	-	-	-	-	-	-	-
676	Pub Util Admin-Utility Billing	600500	-	NA	-	-	-	-	-	-	-
677	Pub Util Admin-Customer Service	601500	-	NA	-	-	-	-	-	-	-
678	Pub Util Adm-Marketing Service	602000	-	NA	-	-	-	-	-	-	-
679	Miscellaneous		-	NA	-	-	-	-	-	-	-
680	**Total Customer Accounting Expense**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
681											
682	**Customer Service Expense**										
683	Customer Engineering-GIS		$ -	NA	-	-	-	-	-	-	-
684	Customer Assistance		-	NA	-	-	-	-	-	-	-
685	Advertisement / Marketing		-	NA	-	-	-	-	-	-	-
686	Miscellaneous		-	NA	-	-	-	-	-	-	-
687	**Total Customer Service Expense**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
688											
689	**Sales Expense**										
690	Sales Expense		$ -	NA	-	-	-	-	-	-	-
691	Demonstrations & Selling		-	NA	-	-	-	-	-	-	-
692	Miscellaneous Sales Expense		-	NA	-	-	-	-	-	-	-
693	**Total Sales Expense**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
694											
695	**Total Customer Labor**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
696											
697	**Total Labor Expense excluding A&G**		**$ 9,536,414**		**$ 9,536,414**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9,536,414**
698											
699	Administrative & General Labor										
700	Pub Util Admin-Mgmt Service	600000	$ 22,280	Baseload	22,280	-	-	-	-	-	22,280
701	Pub Util Admin-Field Services	601000	-	NA	-	-	-	-	-	-	-
702	Legislative & Regulator Risk	602500	78,839	Baseload	78,839	-	-	-	-	-	78,839
703	Outside Services		-	NA	-	-	-	-	-	-	-
704	Outside Services		-	NA	-	-	-	-	-	-	-
705	Property Insurance		-	NA	-	-	-	-	-	-	-
706	Injuries and Damages		-	NA	-	-	-	-	-	-	-
707	Electric Utility Communication Labor		-	NA	-	-	-	-	-	-	-

Production Function

Line			Adjusted	Allocation	Demand Related		Energy Related		Direct Assignment		
No.	Item	Account/ID	Test Year	Factor	Production Demand	Blank	Fuel & Energy	Blank	Direct Assign A	Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
708	Miscellaneous		-	NA	-	-	-	-	-	-	-
709	Rents		-	NA	-	-	-	-	-	-	-
710	Transportation Pool General Labor		-	NA	-	-	-	-	-	-	-
711	Maintenance of General Plant		-	NA	-	-	-	-	-	-	-
712	N/A		-	NA	-	-	-	-	-	-	-
713	**Total Administrative & General Labor**		**$ 101,119**		**$ 101,119**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 101,119**
714											
715	**Total Labor Expense**		**$ 9,637,533**		**$ 9,637,533**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 9,637,533**
716	Check		-								
717											
718	**Allocation Factors**										
719	Baseload			Baseload	100%	0%	0%	0%	0%	0%	100%
720					1	-	-	-	-	-	1
721	Blank			Blank	0%	0%	0%	0%	0%	0%	0%
722					-	-	-	-	-	-	-
723	Fuel & Energy			Fuel	0%	0%	100%	0%	0%	0%	100%
724					-	-	1	-	-	-	1
725	Blank			Blank	0%	0%	0%	0%	0%	0%	0%
726					-	-	-	-	-	-	-
727	Direct Assign A			Direct Assign A	0%	0%	0%	0%	100%	0%	100%
728					-	-	-	-	1	-	1
729	Purchased Power			Purch Pwr	36%	0%	64%	0%	0%	0%	100%
730					49,127,140	-	86,048,598	-	-	-	135,175,738
731	Revenue Requirement			RevReq	33%	0%	67%	0%	0%	0%	100%
732					78,610,556	-	156,155,952	-	-	-	234,766,507
733	Steam Operations - Labor			SteamOps - Labor	0%	0%	0%	0%	0%	0%	0%
734					-	-	-	-	-	-	-
735	Steam Maintenance - Labor			SteamMaint - Labor	0%	0%	0%	0%	0%	0%	0%
736					-	-	-	-	-	-	-
737	Steam Operations			SteamOps	0%	0%	0%	0%	0%	0%	0%
738					-	-	-	-	-	-	-
739	Steam Maintenance			SteamMaint	0%	0%	0%	0%	0%	0%	0%
740					-	-	-	-	-	-	-
741	Gross Plant w/o General			Gross Plant w/o Gen	100%	0%	0%	0%	0%	0%	100%
742					278,129,575	-	-	-	-	-	278,129,575
743	Gross General Plant			Gross General Plant	100%	0%	0%	0%	0%	0%	100%
744					37,870,166	-	-	-	-	-	37,870,166
745	Gross Steam Plant			Gross Plant - Steam	100%	0%	0%	0%	0%	0%	100%
746					17,142	-	-	-	-	-	17,142
747	Gross CT Plant			Gross Plant - CT	100%	0%	0%	0%	0%	0%	100%
748					268,349,742	-	-	-	-	-	268,349,742
749	Total Gross Plant			Total Gross Plant	100%	0%	0%	0%	0%	0%	100%
750					315,999,741	-	-	-	-	-	315,999,741
751	Total Net Plant			Net Plant - Prod	100%	0%	0%	0%	0%	0%	100%
752					233,870,520	-	-	-	-	-	233,870,520
753	Labor Excluding A&G			Labor Exc A&G	100%	0%	0%	0%	0%	0%	100%
754					9,536,414	-	-	-	-	-	9,536,414
755	Total Labor			Total Labor	100%	0%	0%	0%	0%	0%	100%
756					9,637,533	-	-	-	-	-	9,637,533
757	CIP			CIP	0%	0%	0%	0%	0%	0%	0%
758					-	-	-	-	-	-	-
759	N/A			NA	0%	0%	0%	0%	0%	100%	100%
760					-	-	-	-	-	1	1
761	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
762					-	-	-	-	-	1	1
763	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
764					-	-	-	-	-	1	1
765	Blank			Blank	0%	0%	0%	0%	0%	100%	100%

Production Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Production Demand	Demand Related: Blank	Energy Related: Fuel & Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
766					-	-	-	-	-	1	1
767	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
768					-	-	-	-	-	1	1
769	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
770					-	-	-	-	-	1	1
771	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
772					-	-	-	-	-	1	1
773	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
774					-	-	-	-	-	1	1
775	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
776					-	-	-	-	-	1	1
777	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
778					-	-	-	-	-	1	1
779	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
					-	-	-	-	-	1	1
	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
					-	-	-	-	-	1	1

Transmission Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Transmission Demand	Demand Related: Blank	Energy Related: Transmission Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
2											
76											
77	Transmission O&M										
78	**Transmission Operation**										
79	Supervision & Engineering	0560	$ -	NA	-	-	-	-	-	-	-
80	Load Dispatch	0561	-	NA	-	-	-	-	-	-	-
81	Station Equipment	0562	-	NA	-	-	-	-	-	-	-
82	Overhead Lines	0563	-	NA	-	-	-	-	-	-	-
83	Underground Lines	0564	-	NA	-	-	-	-	-	-	-
84	Transmission of Electricity by Others (Wheeling)	G110	-	NA	-	-	-	-	-	-	-
85	Miscellaneous	0566	-	NA	-	-	-	-	-	-	-
86	Rents	0567	-	NA	-	-	-	-	-	-	-
87	**Total Transmission Operation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
88											
89	**Transmission Maintenance**										
90	Supervision & Engineering	0568	$ -	NA	-	-	-	-	-	-	-
91	Structures	0569	-	NA	-	-	-	-	-	-	-
92	Station Equipment	0570	-	NA	-	-	-	-	-	-	-
93	Overhead Lines	0571	-	NA	-	-	-	-	-	-	-
94	Underground Lines	0572	-	NA	-	-	-	-	-	-	-
95	Miscellaneous	0573	-	NA	-	-	-	-	-	-	-
96	**Total Transmission Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
97											
98	**Wheeling**										
99	Transmission Cost Fixed	0565	$ 32,703,121	Subs #	32,703,121	-	-	-	-	-	32,703,121
100	Transmission cost Variable	0565	30,435,879	Energy	-	-	30,435,879	-	-	-	30,435,879
101	**Total Wheeling**		**$ 63,139,000**		**$ 32,703,121**	**$ -**	**$ 30,435,879**	**$ -**	**$ -**	**$ -**	**$ 63,139,000**
102											
103	**Total Transmission O&M**		**$ 63,139,000**		**$ 32,703,121**	**$ -**	**$ 30,435,879**	**$ -**	**$ -**	**$ -**	**$ 63,139,000**
104											
157											
158	Administrative & General Expense										
159	Administrative Salaries & Misc. Labor	0920	$ -	NA	-	-	-	-	-	-	-
160	Office Supplies & Expense	0921	-	NA	-	-	-	-	-	-	-
161	Interdepartmental Charges	0922	-	NA	-	-	-	-	-	-	-
162	Outside Services	0923	-	NA	-	-	-	-	-	-	-
163	Property Insurance	0924	-	NA	-	-	-	-	-	-	-
164	Injuries and Damages	0925	-	NA	-	-	-	-	-	-	-
165	Employee Pensions and Benefits	0926	-	NA	-	-	-	-	-	-	-
166	Franchise Requirements	0927	-	NA	-	-	-	-	-	-	-
167	Compliance & Consultants (Regulatory Commission Expense	0928	-	NA	-	-	-	-	-	-	-
168	General Advertising Expense	0930	-	NA	-	-	-	-	-	-	-
169	Rents	0931	-	NA	-	-	-	-	-	-	-
170	Miscellaneous General Expenses	0933	-	NA	-	-	-	-	-	-	-
171	Maintenance of General Plant	0932	-	NA	-	-	-	-	-	-	-
172	Duplicate Charges - Credit	0929	-	NA	-	-	-	-	-	-	-
173	**Total Administrative & General Expense**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
174											
175	Miscellaneous and Clearing Accounts										
176	General Government Charges	0701	$ -	NA	-	-	-	-	-	-	-
177	Expenses Transferred From Electric	0702	-	NA	-	-	-	-	-	-	-
178	IDI Utility Charges	0703	-	NA	-	-	-	-	-	-	-
179	Removal Expenses	0704	-	NA	-	-	-	-	-	-	-
180	Taxes	0707	-	NA	-	-	-	-	-	-	-
181	Stores Expenses	0781	-	NA	-	-	-	-	-	-	-
182	Transportation Expenses	0782	-	NA	-	-	-	-	-	-	-
183	Tool and Shop Expenses	0783	-	NA	-	-	-	-	-	-	-
184	Insurance	0788	-	NA	-	-	-	-	-	-	-
185	Non-Operating expenses	0790	-	NA	-	-	-	-	-	-	-
186	**Total Miscellaneous and Clearing Accounts**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
187											
188	**Total O&M Expense**		**$ 63,139,000**		**$ 32,703,121**	**$ -**	**$ 30,435,879**	**$ -**	**$ -**	**$ -**	**$ 63,139,000**

Transmission Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Transmission Demand	Demand Related: Blank	Energy Related: Transmission Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
189	Check		-								
190											
191	**Total O&M Expense less Purchased Power**		**$ 63,139,000**		**$ 32,703,121**	**$ -**	**$ 30,435,879**	**$ -**	**$ -**	**$ -**	**$ 63,139,000**
192											
193	Additional Expenses & Deductions										
194	**Debt Service**										
195	Generation		$ -	NA	-	-	-	-	-	-	-
196	Transmission		-	Subs #	-	-	-	-	-	-	-
197	Distribution		-	NA	-	-	-	-	-	-	-
198	Customer		-	NA	-	-	-	-	-	-	-
199	New Debt		-	NA	-	-	-	-	-	-	-
200	**Total Debt Service**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
201											
202	**Taxes and Transfer to General Fund**										
203	Contribution to General Fund		$ 3,250,651	RevReq	4,517,265	-	(1,266,614)	-	-	-	3,250,651
204	Other		-	NA	-	-	-	-	-	-	-
205	Other		-	NA	-	-	-	-	-	-	-
206	Other		-	NA	-	-	-	-	-	-	-
207	**Total Taxes and Transfer to General Fund**		**$ 3,250,651**		**$ 4,517,265**	**$ -**	**$ (1,266,614)**	**$ -**	**$ -**	**$ -**	**$ 3,250,651**
208											
209	**Capital Paid from Current Earnings**										
210	Production		$ -	NA	-	-	-	-	-	-	-
211	Transmission		-	NA	-	-	-	-	-	-	-
212	Distribution		-	NA	-	-	-	-	-	-	-
213	Customer		-	NA	-	-	-	-	-	-	-
214	Street Lighting Capital		-	NA	-	-	-	-	-	-	-
215	N/A		-	NA	-	-	-	-	-	-	-
216	**Total Capital Paid from Current Earnings**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
217											
218	**Reserves - Additional Cash Requirements**		579,439	Subs #	579,439	-	-	-	-	-	579,439
219											
220	**Total Additional Expenses & Deductions**		**$ 3,830,090**		**$ 5,096,704**	**$ -**	**$ (1,266,614)**	**$ -**	**$ -**	**$ -**	**$ 3,830,090**
221											
222	**Subtotal Revenue Requirement**		**$ 66,969,090**		**$ 37,799,824**	**$ -**	**$ 29,169,266**	**$ -**	**$ -**	**$ -**	**$ 66,969,090**
223	Check		-								
224											
225	Other Income										
226	**Other Operating Revenue:**										
227	Gain on retirement of assets (proforma)		$ -	NA	-	-	-	-	-	-	-
228	Uncollectible accounts (proforma)		-	NA	-	-	-	-	-	-	-
229	Diversion	344400	-	NA	-	-	-	-	-	-	-
230	Service Connect Charges-Elec	344410	-	NA	-	-	-	-	-	-	-
231	Misc Service Revenues-Electric	344491	-	NA	-	-	-	-	-	-	-
232	Misc Operating Revenues-Elec	344492	1,351	Subs #	1,351	-	-	-	-	-	1,351
233	Corona Fees- Rev	344493	-	NA	-	-	-	-	-	-	-
234	Cap and Trade Auction		250,889	RevReq	348,648	-	(97,759)	-	-	-	250,889
235	Non Energy Recpts ABC Admin OH	344513	2,422	Subs #	2,422	-	-	-	-	-	2,422
236	**Total Other Operating Revenue:**		**$ 254,662**		**$ 352,421**	**$ -**	**$ (97,759)**	**$ -**	**$ -**	**$ -**	**$ 254,662**
237											
238	**Other Non-Operating Revenue:**										
239	Corona Fees- Rev	344493	$ 1,518	Subs #	1,518	-	-	-	-	-	1,518
240	Misc Settlement Reimb	344494	-	NA	-	-	-	-	-	-	-
241	Late Payment Penalties	353400	-	NA	-	-	-	-	-	-	-
242	Land and Building Rental	373100	138,215	Subs #	138,215	-	-	-	-	-	138,215
243	Other Property Rental	373120	5,846	Subs #	5,846	-	-	-	-	-	5,846
244	Pole Attachments	373125	-	NA	-	-	-	-	-	-	-
245	Substation Operation & Maint	373126	-	NA	-	-	-	-	-	-	-
246	Substation Leasing	373127	-	NA	-	-	-	-	-	-	-
247	Communication Services	373128	20,357	Subs #	20,357	-	-	-	-	-	20,357
248	CIS User Fee	373132	-	NA	-	-	-	-	-	-	-
249	Refunds and Reimbursements	374000	-	Subs #	-	-	-	-	-	-	-

Transmission Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Transmission Demand	Demand Related: Blank	Energy Related: Transmission Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
250	Miscellaneous Receipts	374200	8,729	Subs #	8,729	-	-	-	-	-	8,729
251	Cash Over/Shortage	374207	-	Subs #	-	-	-	-	-	-	-
252	Asset Forfeiture Revenue	374500	-	Subs #	-	-	-	-	-	-	-
253	Bad Debt Recovery	374800	-	Subs #	-	-	-	-	-	-	-
254	Settlement Recovery	374801	-	Subs #	-	-	-	-	-	-	-
255	Settlement Recovery - SONGS	374802	-	Subs #	-	-	-	-	-	-	-
256	Liquidated Damages	374810	-	Subs #	-	-	-	-	-	-	-
257	Operating Transfer from 650 Fund	985650	-	NA	-	-	-	-	-	-	-
258	Utilization Charges	6125000	10,414	Subs #	10,414	-	-	-	-	-	10,414
259	**Total Other Non-Operating Revenue:**		**$ 185,078**		**$ 185,078**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 185,078**
260											
261	**Interest income**		531,009	RevReq	737,916	-	(206,907)	-	-	-	531,009
262											
263	**Wholesale sales**		-	NA	-	-	-	-	-	-	-
264											
265	**Transmission revenue**		39,715,154	Energy	-	-	39,715,154	-	-	-	39,715,154
266											
267	**Total Other Income**		**$ 40,685,903**		**$ 1,275,415**	**$ -**	**$ 39,410,488**	**$ -**	**$ -**	**$ -**	**$ 40,685,903**
268											
269											
270	**Total Retail Revenue Requirement**		**$ 26,283,187**		**$ 36,524,410**	**$ -**	**$ (10,241,222)**	**$ -**	**$ -**	**$ -**	**$ 26,283,187**
271	Check		-		139%	0%	-39%	0%	0%	0%	
272											
273	Revenue From Current Retail Rates										
274	Residential										
275	Commercial-Flat										
276	Commercial-Demand										
277	Industrial-TOU										
278	City Contract										
279	Other										
280	**Total Revenue From Current Retail Rates**		**$ -**								
281											
282											
283											
284	PLANT IN SERVICE										
285											
286	Gross Plant in Service										
287	**Intangible Plant**										
288	Organization	301	$ -	NA	-	-	-	-	-	-	-
289	Franchises and Consents	302	-	NA	-	-	-	-	-	-	-
290	Misc. Intangible Plant	303	-	Subs #	-	-	-	-	-	-	-
291	Misc. Computer Software	3030	-	NA	-	-	-	-	-	-	-
292	**Total Intangible Plant**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
293											
294	**Production Plant**										
295	**Steam Production**										
296	Land and Land Rights	310	$ -	NA	-	-	-	-	-	-	-
297	Structures & Improvements	311	-	NA	-	-	-	-	-	-	-
298	Boiler Plant Equipment	312	-	NA	-	-	-	-	-	-	-
299	Engines and Engine Generators	313	-	NA	-	-	-	-	-	-	-
300	Turbo-Generator Units	314	-	NA	-	-	-	-	-	-	-
301	Accessory Electric Equipment	315	-	NA	-	-	-	-	-	-	-
302	Misc. Power Plant Equipment	316	-	NA	-	-	-	-	-	-	-
303	**Total Steam Production**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
304											
305	**Hydraulic Production**										
306	Land and Land Rights	330	$ -	NA	-	-	-	-	-	-	-
307	Structures & Improvements	331	-	NA	-	-	-	-	-	-	-
308	Reservoirs, Dams and Water Ways	332	-	NA	-	-	-	-	-	-	-
309	Water Wheel, Turbine and Generator	333	-	NA	-	-	-	-	-	-	-
310	Accessory Electric Equipment	334	-	NA	-	-	-	-	-	-	-
311	Misc. Power Plant Equipment	335	-	NA	-	-	-	-	-	-	-

Transmission Function

Line			Adjusted	Allocation	Demand Related		Energy Related		Direct Assignment		
No.	Item	Account/ID	Test Year	Factor	Transmission Demand	Blank	Transmission Energy	Blank	Direct Assign A	Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
312	Roads, Railroads and Bridges	336	-	NA	-	-	-	-	-	-	-
313	**Total Hydraulic Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
314											
315	**Combustion Turbine & Other Production**										
316	Land and Land Rights	340	$ -	NA	-	-	-	-	-	-	-
317	Structures & Improvements	341	-	NA	-	-	-	-	-	-	-
318	Fuel Holders, Prod & Acc	342	-	NA	-	-	-	-	-	-	-
319	Prime Movers	343	-	NA	-	-	-	-	-	-	-
320	Generators & Other Production	344	-	NA	-	-	-	-	-	-	-
321	Accessory Electric Equipment	345	-	NA	-	-	-	-	-	-	-
	Misc. Production Plant	2000	-	NA	-	-	-	-	-	-	-
322	**Total Combustion Turbine & Other Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
322											
323	**Total Production Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
324											
325	**Transmission Plant**										
326	Land and Land Rights	350	$ -	Subs #	-	-	-	-	-	-	-
327	Reserved	351	-	NA	-	-	-	-	-	-	-
328	Structures & Improvements	352	-	Subs #	-	-	-	-	-	-	-
329	Station Equipment - System	353	-	Subs #	-	-	-	-	-	-	-
330	Towers and Fixtures	354	-	Subs #	-	-	-	-	-	-	-
331	Poles and Fixtures	355	-	Subs #	-	-	-	-	-	-	-
332	Overhead Conductor	356	-	Subs #	-	-	-	-	-	-	-
333	Underground Conductor	357	-	Subs #	-	-	-	-	-	-	-
334	Underground Conduit	358	-	Subs #	-	-	-	-	-	-	-
335	Misc. Transmission Plant	359	-	NA	-	-	-	-	-	-	-
336	**Total Transmission Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
337											
338	**Distribution Plant**										
339	Land and Land Rights	360	$ -	NA	-	-	-	-	-	-	-
340	Structures & Improvements	361	-	NA	-	-	-	-	-	-	-
341	Station Equipment	362	-	NA	-	-	-	-	-	-	-
342	Misc. Plant	363	-	NA	-	-	-	-	-	-	-
343	Towers and Fixtures	364	-	NA	-	-	-	-	-	-	-
344	Overhead Conductor	365	-	NA	-	-	-	-	-	-	-
345	Underground Conduit	366	-	NA	-	-	-	-	-	-	-
346	Underground Conductor	367	-	NA	-	-	-	-	-	-	-
347	Line Transformers	368	-	NA	-	-	-	-	-	-	-
348	Services	369	-	NA	-	-	-	-	-	-	-
349	Meters	370	-	NA	-	-	-	-	-	-	-
350	Inst. on Customer Premises	371	-	NA	-	-	-	-	-	-	-
351	Street Light / Signal Systems	373	-	NA	-	-	-	-	-	-	-
352	**Total Distribution Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
353											
354	**Subtotal Plant Before General**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
355											
356	**General Plant**										
357	Land and Land Rights	389	$ -	Subs #	-	-	-	-	-	-	-
358	Structures & Improvements	390	-	Subs #	-	-	-	-	-	-	-
359	Structures & Improvements - Other	3900	-	NA	-	-	-	-	-	-	-
360	Office Furniture & Equipment	391	-	Subs #	-	-	-	-	-	-	-
361	Info System Computers	3910	-	NA	-	-	-	-	-	-	-
362	Transportation Equipment	392	-	Subs #	-	-	-	-	-	-	-
363	Stores Equipment	393	-	Subs #	-	-	-	-	-	-	-
364	Tools, Shop & Garage Equip.	394	-	Subs #	-	-	-	-	-	-	-
365	Laboratory Equipment	395	-	Subs #	-	-	-	-	-	-	-
366	Power Operated Equipment	396	-	Subs #	-	-	-	-	-	-	-
367	Communication Equipment	397	-	Subs #	-	-	-	-	-	-	-
368	Miscellaneous Equipment	398	-	Subs #	-	-	-	-	-	-	-
369	Other Tangible Property	399	-	NA	-	-	-	-	-	-	-
370	**Total General Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
371											

Transmission Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Transmission Demand	Demand Related: Blank	Energy Related: Transmission Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
372	**Total Gross Plant in Service**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
373	Check		-								
374											
375	Accumulated Depreciation										
376	**Intangible Plant**										
377	Organization	301	$ -	NA	-	-	-	-	-	-	-
378	Franchises and Consents	302	-	NA	-	-	-	-	-	-	-
379	Misc. Intangible Plant	303	-	Subs #	-	-	-	-	-	-	-
380	Misc. Computer Software	3030	-	NA	-	-	-	-	-	-	-
381	**Total Intangible Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
382											
383	**Production Plant**										
384	**Steam Production**										
385	Land and Land Rights	310	$ -	NA	-	-	-	-	-	-	-
386	Structures & Improvements	311	-	NA	-	-	-	-	-	-	-
387	Boiler Plant Equipment	312	-	NA	-	-	-	-	-	-	-
388	Engines and Engine Generators	313	-	NA	-	-	-	-	-	-	-
389	Turbo-Generator Units	314	-	NA	-	-	-	-	-	-	-
390	Accessory Electric Equipment	315	-	NA	-	-	-	-	-	-	-
391	Misc. Power Plant Equipment	316	-	NA	-	-	-	-	-	-	-
392	**Total Steam Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
393											
394	**Hydraulic Production**										
395	Land and Land Rights	330	$ -	NA	-	-	-	-	-	-	-
396	Structures & Improvements	331	-	NA	-	-	-	-	-	-	-
397	Reservoirs, Dams and Water Ways	332	-	NA	-	-	-	-	-	-	-
398	Water Wheel, Turbine and Generator	333	-	NA	-	-	-	-	-	-	-
399	Accessory Electric Equipment	334	-	NA	-	-	-	-	-	-	-
400	Misc. Power Plant Equipment	335	-	NA	-	-	-	-	-	-	-
401	Roads, Railroads and Bridges	336	-	NA	-	-	-	-	-	-	-
402	**Total Hydraulic Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
403											
404	**Combustion Turbine & Other Production**										
405	Land and Land Rights	340	$ -	NA	-	-	-	-	-	-	-
406	Structures & Improvements	341	-	NA	-	-	-	-	-	-	-
407	Fuel Holders, Prod & Acc	342	-	NA	-	-	-	-	-	-	-
408	Prime Movers	343	-	NA	-	-	-	-	-	-	-
409	Generators & Other Production	344	-	NA	-	-	-	-	-	-	-
410	Accessory Electric Equipment	345	-	NA	-	-	-	-	-	-	-
411	Misc. Production Plant	2000	-	NA	-	-	-	-	-	-	-
412	**Total Combustion Turbine & Other Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
413											
414	**Total Production Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
415											
416	**Transmission Plant**										
417	Land and Land Rights	350	$ -	NA	-	-	-	-	-	-	-
418	Reserved	351	-	NA	-	-	-	-	-	-	-
419	Structures & Improvements	352	-	Subs #	-	-	-	-	-	-	-
420	Station Equipment - System	353	-	Subs #	-	-	-	-	-	-	-
421	Towers and Fixtures	354	-	Subs #	-	-	-	-	-	-	-
422	Poles and Fixtures	355	-	Subs #	-	-	-	-	-	-	-
423	Overhead Conductor	356	-	Subs #	-	-	-	-	-	-	-
424	Underground Conductor	357	-	Subs #	-	-	-	-	-	-	-
425	Underground Conduit	358	-	Subs #	-	-	-	-	-	-	-
426	Misc. Transmission Plant	359	-	NA	-	-	-	-	-	-	-
427	**Total Transmission Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
428											
429	**Distribution Plant**										
430	Land and Land Rights	360	$ -	NA	-	-	-	-	-	-	-
431	Structures & Improvements	361	-	NA	-	-	-	-	-	-	-
432	Station Equipment	362	-	NA	-	-	-	-	-	-	-
433	Misc. Plant	363	-	NA	-	-	-	-	-	-	-

Transmission Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Transmission Demand	Demand Related: Blank	Energy Related: Transmission Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
434	Towers and Fixtures	364	-	NA	-	-	-	-	-	-	-
435	Overhead Conductor	365	-	NA	-	-	-	-	-	-	-
436	Underground Conduit	366	-	NA	-	-	-	-	-	-	-
437	Underground Conductor	367	-	NA	-	-	-	-	-	-	-
438	Line Transformers	368	-	NA	-	-	-	-	-	-	-
439	Services	369	-	NA	-	-	-	-	-	-	-
440	Meters	370	-	NA	-	-	-	-	-	-	-
441	Inst. on Customer Premises	371	-	NA	-	-	-	-	-	-	-
442	Street Light / Signal Systems	373	-	NA	-	-	-	-	-	-	-
443	**Total Distribution Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
444											
445	**Subtotal Plant Before General**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
446											
447	**General Plant**										
448	Land and Land Rights	389	$ -	NA	-	-	-	-	-	-	-
449	Structures & Improvements	390	-	Subs #	-	-	-	-	-	-	-
450	Structures & Improvements - Other	3900	-	NA	-	-	-	-	-	-	-
451	Office Furniture & Equipment	391	-	Subs #	-	-	-	-	-	-	-
452	Info System Computers	3910	-	NA	-	-	-	-	-	-	-
453	Transportation Equipment	392	-	Subs #	-	-	-	-	-	-	-
454	Stores Equipment	393	-	Subs #	-	-	-	-	-	-	-
455	Tools, Shop & Garage Equip.	394	-	Subs #	-	-	-	-	-	-	-
456	Laboratory Equipment	395	-	Subs #	-	-	-	-	-	-	-
457	Power Operated Equipment	396	-	Subs #	-	-	-	-	-	-	-
458	Communication Equipment	397	-	Subs #	-	-	-	-	-	-	-
459	Miscellaneous Equipment	398	-	Subs #	-	-	-	-	-	-	-
460	Other Tangible Property	399	-	NA	-	-	-	-	-	-	-
461	**Total General Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
462											
463	**Total Accumulated Depreciation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
464	Check		-								
465											
466	Net Plant in Service										
467	**Intangible Plant**										
468	Organization	301	$ -		-	-	-	-	-	-	-
469	Franchises and Consents	302	-		-	-	-	-	-	-	-
470	Misc. Intangible Plant	303	-		-	-	-	-	-	-	-
471	Misc. Computer Software	3030	-		-	-	-	-	-	-	-
472	**Total Intangible Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
473											
474	**Production Plant**										
475	**Steam Production**										
476	Land and Land Rights	310	$ -		-	-	-	-	-	-	-
477	Structures & Improvements	311	-		-	-	-	-	-	-	-
478	Boiler Plant Equipment	312	-		-	-	-	-	-	-	-
479	Engines and Engine Generators	313	-		-	-	-	-	-	-	-
480	Turbo-Generator Units	314	-		-	-	-	-	-	-	-
481	Accessory Electric Equipment	315	-		-	-	-	-	-	-	-
482	Misc. Power Plant Equipment	316	-		-	-	-	-	-	-	-
483	**Total Steam Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
484											
485	**Hydraulic Production**										
486	Land and Land Rights	330	$ -		-	-	-	-	-	-	-
487	Structures & Improvements	331	-		-	-	-	-	-	-	-
488	Reservoirs, Dams and Water Ways	332	-		-	-	-	-	-	-	-
489	Water Wheel, Turbine and Generator	333	-		-	-	-	-	-	-	-
490	Accessory Electric Equipment	334	-		-	-	-	-	-	-	-
491	Misc. Power Plant Equipment	335	-		-	-	-	-	-	-	-
492	Roads, Railroads and Bridges	336	-		-	-	-	-	-	-	-
493	**Total Hydraulic Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
494											
495	**Combustion Turbine & Other Production**										

Transmission Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Transmission Demand	Demand Related: Blank	Energy Related: Transmission Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
496	Land and Land Rights	340	$ -		-	-	-	-	-	-	-
497	Structures & Improvements	341	-		-	-	-	-	-	-	-
498	Fuel Holders, Prod & Acc	342	-		-	-	-	-	-	-	-
499	Prime Movers	343	-		-	-	-	-	-	-	-
500	Generators & Other Production	344	-		-	-	-	-	-	-	-
501	Accessory Electric Equipment	345	-		-	-	-	-	-	-	-
502	Misc. Production Plant	2000	-		-	-	-	-	-	-	-
503	**Total Combustion Turbine & Other Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
504											
505	**Total Production Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
506											
507	**Transmission Plant**										
508	Land and Land Rights	350	$ -		-	-	-	-	-	-	-
509	Reserved	351	-		-	-	-	-	-	-	-
510	Structures & Improvements	352	-		-	-	-	-	-	-	-
511	Station Equipment - System	353	-		-	-	-	-	-	-	-
512	Towers and Fixtures	354	-		-	-	-	-	-	-	-
513	Poles and Fixtures	355	-		-	-	-	-	-	-	-
514	Overhead Conductor	356	-		-	-	-	-	-	-	-
515	Underground Conductor	357	-		-	-	-	-	-	-	-
516	Underground Conduit	358	-		-	-	-	-	-	-	-
517	Misc. Transmission Plant	359	-		-	-	-	-	-	-	-
518	**Total Transmission Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
519											
520	**Distribution Plant**										
521	Land and Land Rights	360	$ -		-	-	-	-	-	-	-
522	Structures & Improvements	361	-		-	-	-	-	-	-	-
523	Station Equipment	362	-		-	-	-	-	-	-	-
524	Misc. Plant	363	-		-	-	-	-	-	-	-
525	Towers and Fixtures	364	-		-	-	-	-	-	-	-
526	Overhead Conductor	365	-		-	-	-	-	-	-	-
527	Underground Conduit	366	-		-	-	-	-	-	-	-
528	Underground Conductor	367	-		-	-	-	-	-	-	-
529	Line Transformers	368	-		-	-	-	-	-	-	-
530	Services	369	-		-	-	-	-	-	-	-
531	Meters	370	-		-	-	-	-	-	-	-
532	Inst. on Customer Premises	371	-		-	-	-	-	-	-	-
533	Street Light / Signal Systems	373	-		-	-	-	-	-	-	-
534	**Total Distribution Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
535											
536	**Subtotal Plant Before General**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
537											
538	**General Plant**										
539	Land and Land Rights	389	$ -		-	-	-	-	-	-	-
540	Structures & Improvements	390	-		-	-	-	-	-	-	-
541	Structures & Improvements - Other	3900	-		-	-	-	-	-	-	-
542	Office Furniture & Equipment	391	-		-	-	-	-	-	-	-
543	Info System Computers	3910	-		-	-	-	-	-	-	-
544	Transportation Equipment	392	-		-	-	-	-	-	-	-
545	Stores Equipment	393	-		-	-	-	-	-	-	-
546	Tools, Shop & Garage Equip.	394	-		-	-	-	-	-	-	-
547	Laboratory Equipment	395	-		-	-	-	-	-	-	-
548	Power Operated Equipment	396	-		-	-	-	-	-	-	-
549	Communication Equipment	397	-		-	-	-	-	-	-	-
550	Miscellaneous Equipment	398	-		-	-	-	-	-	-	-
551	Other Tangible Property	399	-		-	-	-	-	-	-	-
552	**Total General Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
553											
554	**Total Net Plant in Service**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
555	Check		-								
556											
557											

Transmission Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Transmission Demand	Demand Related: Blank	Energy Related: Transmission Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
558	LABOR										
559											
560	Production Labor										
561	**Steam Production Operation**										
562	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
563	Fuel (Transportation & Handling)		-	NA	-	-	-	-	-	-	-
564	Steam Expense		-	NA	-	-	-	-	-	-	-
565	Electric Expense		-	NA	-	-	-	-	-	-	-
566	Miscellaneous		-	NA	-	-	-	-	-	-	-
567	Rent		-	NA	-	-	-	-	-	-	-
568	**Total Steam Production Operation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
569											
570	**Steam Production Maintenance**										
571	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
572	Structures		-	NA	-	-	-	-	-	-	-
573	Boilers		-	NA	-	-	-	-	-	-	-
574	Electric Plant		-	NA	-	-	-	-	-	-	-
575	Miscellaneous Labor		-	NA	-	-	-	-	-	-	-
576	**Total Steam Production Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
577											
578	**Hydro Production Operation**										
579	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
580	Water for Power		-	NA	-	-	-	-	-	-	-
581	Hydraulic Expense		-	NA	-	-	-	-	-	-	-
582	Electric Expense		-	NA	-	-	-	-	-	-	-
583	Miscellaneous		-	NA	-	-	-	-	-	-	-
584	Rent		-	NA	-	-	-	-	-	-	-
585	**Total Hydro Production Operation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
586											
587	**Hydro Production Maintenance**										
588	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
589	Structures		-	NA	-	-	-	-	-	-	-
590	Reservoirs & Dams		-	NA	-	-	-	-	-	-	-
591	Electric Plant		-	NA	-	-	-	-	-	-	-
592	Miscellaneous Plant		-	NA	-	-	-	-	-	-	-
593	**Total Hydro Production Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
594											
595	**Combined Cycle Operation**										
596	Labor		$ -	NA	-	-	-	-	-	-	-
597	Fuel Handling		-	NA	-	-	-	-	-	-	-
598	Generation Expense		-	NA	-	-	-	-	-	-	-
599	Miscellaneous		-	NA	-	-	-	-	-	-	-
600	**Total Combined Cycle Operation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
601											
602	**Combined Cycle Maintenance**										
603	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
604	Structures		-	NA	-	-	-	-	-	-	-
605	Electric Plant		-	NA	-	-	-	-	-	-	-
606	Miscellaneous Plant		-	NA	-	-	-	-	-	-	-
607	**Total Combined Cycle Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
608											
609	**Other Production**										
610	RERC/Acorn Gen. Plant	612013	$ -	NA	-	-	-	-	-	-	-
611	Clearwater Generating Plant	612014	-	NA	-	-	-	-	-	-	-
612	PU Elec Power Supply Operations	612000	-	NA	-	-	-	-	-	-	-
613	**Total Other Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
614											
615	**Total Production Labor**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
616											
617	Transmission Labor										
618	**Transmission Operations**										
619	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-

Transmission Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Transmission Demand	Demand Related: Blank	Energy Related: Transmission Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
620	Load Dispatch		-	NA	-	-	-	-	-	-	-
621	Station Equipment		-	NA	-	-	-	-	-	-	-
622	Overhead Lines		-	NA	-	-	-	-	-	-	-
623	Underground Lines		-	NA	-	-	-	-	-	-	-
624	General Labor		-	NA	-	-	-	-	-	-	-
625	Miscellaneous		-	NA	-	-	-	-	-	-	-
626	Rents		-	NA	-	-	-	-	-	-	-
627	**Total Transmission Operations**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
628											
629	**Transmission Maintenance**										
630	Supervision & Engineering		$ -	NA	-	-	-	-	-	-	-
631	Structures		-	NA	-	-	-	-	-	-	-
632	Station Equipment		-	NA	-	-	-	-	-	-	-
633	Overhead Lines		-	NA	-	-	-	-	-	-	-
634	Underground Lines		-	NA	-	-	-	-	-	-	-
635	Miscellaneous		-	NA	-	-	-	-	-	-	-
636	**Total Transmission Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
637											
638	**Wheeling**										
639	Wheeling		$ -	NA	-	-	-	-	-	-	-
640	Wheeling		-	NA	-	-	-	-	-	-	-
641	**Total Wheeling**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
642											
643	**Total Transmission Labor**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
644											
645	Distribution Labor										
646	**Distribution Operations**										
647	Electric Operations	610000	$ -	NA	-	-	-	-	-	-	-
648	PU Electric Field Operations	610500	-	NA	-	-	-	-	-	-	-
649	Energy Deliv Engineering	611000	-	NA	-	-	-	-	-	-	-
650	Customer Engineering-GIS	611500	-	NA	-	-	-	-	-	-	-
651	Underground Lines		-	NA	-	-	-	-	-	-	-
652	Street Lighting		-	NA	-	-	-	-	-	-	-
653	Metering		-	NA	-	-	-	-	-	-	-
654	Customer Installations		-	NA	-	-	-	-	-	-	-
655	Miscellaneous		-	NA	-	-	-	-	-	-	-
656	Rents		-	NA	-	-	-	-	-	-	-
657	**Total Distribution Operations**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
658											
659	**Distribution Maintenance**										
660	Supervision		$ -	NA	-	-	-	-	-	-	-
661	Structures		-	NA	-	-	-	-	-	-	-
662	Station Equipment		-	NA	-	-	-	-	-	-	-
663	Overhead Lines		-	NA	-	-	-	-	-	-	-
664	Underground Lines		-	NA	-	-	-	-	-	-	-
665	Transformers		-	NA	-	-	-	-	-	-	-
666	Street Lighting		-	NA	-	-	-	-	-	-	-
667	Metering		-	NA	-	-	-	-	-	-	-
668	Miscellaneous		-	NA	-	-	-	-	-	-	-
669	**Total Distribution Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
670											
671	**Total Distribution Labor**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
672											
673	Customer Labor										
674	**Customer Accounting Expense**										
675	Pub Util Business Support	600400	$ -	NA	-	-	-	-	-	-	-
676	Pub Util Admin-Utility Billing	600500	-	NA	-	-	-	-	-	-	-
677	Pub Util Admin-Customer Service	601500	-	NA	-	-	-	-	-	-	-
678	Pub Util Adm-Marketing Service	602000	-	NA	-	-	-	-	-	-	-
679	Miscellaneous		-	NA	-	-	-	-	-	-	-
680	**Total Customer Accounting Expense**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
681											

Transmission Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Transmission Demand	Demand Related: Blank	Energy Related: Transmission Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
682	**Customer Service Expense**										
683	Customer Engineering-GIS		$ -	NA	-	-	-	-	-	-	-
684	Customer Assistance		-	NA	-	-	-	-	-	-	-
685	Advertisement / Marketing		-	NA	-	-	-	-	-	-	-
686	Miscellaneous		-	NA	-	-	-	-	-	-	-
687	**Total Customer Service Expense**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
688											
689	**Sales Expense**										
690	Sales Expense		$ -	NA	-	-	-	-	-	-	-
691	Demonstrations & Selling		-	NA	-	-	-	-	-	-	-
692	Miscellaneous Sales Expense		-	NA	-	-	-	-	-	-	-
693	**Total Sales Expense**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
694											
695	**Total Customer Labor**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
696											
697	**Total Labor Expense excluding A&G**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
698											
699	Administrative & General Labor										
700	Pub Util Admin-Mgmt Service	600000	$ -	NA	-	-	-	-	-	-	-
701	Pub Util Admin-Field Services	601000	-	NA	-	-	-	-	-	-	-
702	Legislative & Regulator Risk	602500	-	NA	-	-	-	-	-	-	-
703	Outside Services		-	NA	-	-	-	-	-	-	-
704	Outside Services		-	NA	-	-	-	-	-	-	-
705	Property Insurance		-	NA	-	-	-	-	-	-	-
706	Injuries and Damages		-	NA	-	-	-	-	-	-	-
707	Electric Utility Communication Labor		-	NA	-	-	-	-	-	-	-
708	Miscellaneous		-	NA	-	-	-	-	-	-	-
709	Rents		-	NA	-	-	-	-	-	-	-
710	Transportation Pool General Labor		-	NA	-	-	-	-	-	-	-
711	Maintenance of General Plant		-	NA	-	-	-	-	-	-	-
712	N/A		-	NA	-	-	-	-	-	-	-
713	**Total Administrative & General Labor**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
714											
715	**Total Labor Expense**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
716	Check		-								
717											
718	**Allocation Factors**										
719	No. of Substations			Subs #	100%	0%	0%	0%	0%	0%	100%
720					1	-	-	-	-	-	1
721	Blank			Blank	0%	0%	0%	0%	0%	0%	0%
722					-	-	-	-	-	-	-
723	Energy			Energy	0%	0%	100%	0%	0%	0%	100%
724					-	-	1	-	-	-	1
725	Blank			Blank	0%	0%	0%	0%	0%	0%	0%
726					-	-	-	-	-	-	-
727	Direct Assign A			Direct Assign A	0%	0%	0%	0%	100%	0%	100%
728					-	-	-	-	1	-	1
729	Blank			Blank	0%	0%	0%	0%	0%	0%	0%
730					-	-	-	-	-	-	-
731	Revenue Requirement less Direct Assignment			RevReq	139%	0%	-39%	0%	0%	0%	100%
732					36,524,410	-	(10,241,222)	-	-	-	26,283,187
733	N/A			NA	0%	0%	0%	0%	0%	100%	100%
734					-	-	-	-	-	1	1
735	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
736					-	-	-	-	-	1	1
737	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
738					-	-	-	-	-	1	1
739	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
740					-	-	-	-	-	1	1
741	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
742					-	-	-	-	-	1	1
743	Blank			Blank	0%	0%	0%	0%	0%	100%	100%

Transmission Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Transmission Demand	Demand Related: Blank	Energy Related: Transmission Energy	Energy Related: Blank	Direct Assignment: Direct Assign A	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
744					-	-	-	-	-	1	1
745	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
746					-	-	-	-	-	1	1
747	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
748					-	-	-	-	-	1	1
749	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
750					-	-	-	-	-	1	1
751	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
752					-	-	-	-	-	1	1
753	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
					-	-	-	-	-	1	1
	Blank			Blank	0%	0%	0%	0%	0%	100%	100%
					-	-	-	-	-	1	1

Distribution Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Distribution Demand	Demand Related: Substations	Customer Related: Distribution Customer	Customer Related: Blank	Direct Assignment: Lighting	Direct Assignment: Blank	Total
1	REVENUE REQUIREMENTS CALCULATION										
2											
76											
77	Transmission O&M										
78	**Transmission Operation**										
79	Supervision & Engineering	0560	$ -	N/A	-	-	-	-	-	-	-
80	Load Dispatch	0561	-	N/A	-	-	-	-	-	-	-
81	Station Equipment	0562	137,612	Substations	-	137,612	-	-	-	-	137,612
82	Overhead Lines	0563	-	N/A	-	-	-	-	-	-	-
83	Underground Lines	0564	-	N/A	-	-	-	-	-	-	-
84	Transmission of Electricity by Others (Wheeling)	G110	-	N/A	-	-	-	-	-	-	-
85	Miscellaneous	0566	270,062	Demand	270,062	-	-	-	-	-	270,062
86	Rents	0567	-	N/A	-	-	-	-	-	-	-
87	**Total Transmission Operation**		**$ 407,674**		**$ 270,062**	**$ 137,612**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 407,674**
88											
89	**Transmission Maintenance**										
90	Supervision & Engineering	0568	$ -	N/A	-	-	-	-	-	-	-
91	Structures	0569	-	N/A	-	-	-	-	-	-	-
92	Station Equipment	0570	344,339	Substations	-	344,339	-	-	-	-	344,339
93	Overhead Lines	0571	4,196	Circuit - OH	3,764	-	433	-	-	-	4,196
94	Underground Lines	0572	-	N/A	-	-	-	-	-	-	-
95	Miscellaneous	0573	1,759,282	Demand	1,759,282	-	-	-	-	-	1,759,282
96	**Total Transmission Maintenance**		**$ 2,107,817**		**$ 1,763,046**	**$ 344,339**	**$ 433**	**$ -**	**$ -**	**$ -**	**$ 2,107,817**
97											
98	**Wheeling**										
99	Transmission Cost Fixed	0565	$ -	N/A	-	-	-	-	-	-	-
100	Transmission cost Variable	0565	-	N/A	-	-	-	-	-	-	-
101	**Total Wheeling**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
102											
103	**Total Transmission O&M**		**$ 2,515,491**		**$ 2,033,108**	**$ 481,951**	**$ 433**	**$ -**	**$ -**	**$ -**	**$ 2,515,491**
104											
105	Distribution O&M										
106	**Distribution Operations**										
107	Operation Maintenance and Engineering	0580	$ 4,548,243	Super-Ops	4,029,120	51,481	467,642	-	-	-	4,548,243
108	Load Dispatch	0581	2,590,605	Demand	2,590,605	-	-	-	-	-	2,590,605
109	Station Equipment	0582	36,439	Substations	-	36,439	-	-	-	-	36,439
110	Overhead Lines	0583	11,721	Circuit - OH	10,512	-	1,208	-	-	-	11,721
111	Underground Lines	0584	859	Circuit - UG	771	-	89	-	-	-	859
112	Street Lighting & Signal Expenses	0585	-	N/A	-	-	-	-	-	-	-
113	Metering	0586	155,837	Customer	-	-	155,837	-	-	-	155,837
114	Customer Installations	0587	25,122	Customer	-	-	25,122	-	-	-	25,122
115	Miscellaneous	0588	398,723	Wghtd Avg Min Sys	249,976	-	148,747	-	-	-	398,723
116	Rents	0589	-	N/A	-	-	-	-	-	-	-
117	**Total Distribution Operations**		**$ 7,767,549**		**$ 6,880,984**	**$ 87,920**	**$ 798,645**	**$ -**	**$ -**	**$ -**	**$ 7,767,549**
117					2,851,864	36,439	331,003				
118	**Distribution Maintenance**										
119	Supervision	0590	$ -	N/A	-	-	-	-	-	-	-
120	Structures	0591	64,960	Wghtd Avg Min Sys	40,726	-	24,234	-	-	-	64,960
121	Station Equipment	0592	1,434,921	Substations	-	1,434,921	-	-	-	-	1,434,921
122	Overhead Lines	0593	5,773,829	Circuit - OH	5,178,634	-	595,195	-	-	-	5,773,829
123	Underground Lines	0594	2,730,530	Circuit - UG	2,449,053	-	281,477	-	-	-	2,730,530
124	Transformers	0595	79,635	Transformers	36,303	-	43,332	-	-	-	79,635
125	Street Lighting & Signals	0596	890,498	Street Light	-	-	-	-	890,498	-	890,498
126	Metering	0597	336,401	Customer	-	-	336,401	-	-	-	336,401
127	Miscellaneous	0598	682,490	Wghtd Avg Min Sys	427,881	-	254,609	-	-	-	682,490
128	**Total Distribution Maintenance**		**$ 11,993,265**		**$ 8,132,597**	**$ 1,434,921**	**$ 1,535,248**	**$ -**	**$ 890,498**	**$ -**	**$ 11,993,265**
129											
130	**Total Distribution O&M**		**$ 19,760,814**		**$ 15,013,582**	**$ 1,522,842**	**$ 2,333,893**	**$ -**	**$ 890,498**	**$ -**	**$ 19,760,814**
131											
157											
158	Administrative & General Expense										
159	Administrative Salaries & Misc. Labor	0920	$ 491,056	RevReq w/o SL	345,326	72,414	73,316	-	-	-	491,056
160	Office Supplies & Expense	0921	666,407	RevReq w/o SL	468,638	98,273	99,496	-	-	-	666,407
161	Interdepartmental Charges	0922	(14,039,885)	RevReq w/o SL	(9,873,286)	(2,070,416)	(2,096,182)	-	-	-	(14,039,885)
162	Outside Services	0923	3,564,073	RevReq w/o SL	2,506,368	525,582	532,123	-	-	-	3,564,073
163	Property Insurance	0924	-	N/A	-	-	-	-	-	-	-

Distribution Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Distribution Demand	Demand Related: Substations	Customer Related: Distribution Customer	Customer Related: Blank	Direct Assignment: Lighting	Direct Assignment: Blank	Total
164	Injuries and Damages	0925	-	N/A	-	-	-	-	-	-	-
165	Employee Pensions and Benefits	0926	14,072,811	RevReq w/o SL	9,896,441	2,075,272	2,101,098	-	-	-	14,072,811
166	Franchise Requirements	0927	-	N/A	-	-	-	-	-	-	-
167	Compliance & Consultants (Regulatory Commission Expens	0928	21,194	RevReq w/o SL	14,904	3,125	3,164	-	-	-	21,194
168	General Advertising Expense	0930	20,715	RevReq w/o SL	14,567	3,055	3,093	-	-	-	20,715
169	Rents	0931	1,388,181	RevReq w/o SL	976,213	204,711	207,258	-	-	-	1,388,181
170	Miscellaneous General Expenses	0933	1,901,266	RevReq w/o SL	1,337,030	280,373	283,863	-	-	-	1,901,266
171	Maintenance of General Plant	0932	880	RevReq w/o SL	619	130	131	-	-	-	880
172	Duplicate Charges - Credit	0929	-	N/A	-	-	-	-	-	-	-
173	**Total Administrative & General Expense**		**$ 8,086,698**		**$ 5,686,819**	**$ 1,192,519**	**$ 1,207,360**	**$ -**	**$ -**	**$ -**	**$ 8,086,698**
174											
175	Miscellaneous and Clearing Accounts										
176	General Government Charges	0701	$ 2,883,161	RevReq w/o SL	2,027,529	425,170	430,462	-	-	-	2,883,161
177	Expenses Transferred From Electric	0702	995,722	RevReq w/o SL	700,223	146,836	148,663	-	-	-	995,722
178	IDI Utility Charges	0703	221	RevReq w/o SL	155	33	33	-	-	-	221
179	Removal Expenses	0704	-	RevReq w/o SL	-	-	-	-	-	-	-
180	Taxes	0707	-	N/A	-	-	-	-	-	-	-
181	Stores Expenses	0781	-	N/A	-	-	-	-	-	-	-
182	Transportation Expenses	0782	1,089,250	RevReq w/o SL	765,994	160,628	162,627	-	-	-	1,089,250
183	Tool and Shop Expenses	0783	(472,020)	RevReq w/o SL	(331,939)	(69,607)	(70,473)	-	-	-	(472,020)
184	Insurance	0788	438,471	RevReq w/o SL	308,346	64,660	65,465	-	-	-	438,471
185	Non-Operating expenses	0790	-	N/A	-	-	-	-	-	-	-
186	**Total Miscellaneous and Clearing Accounts**		**$ 4,934,804**		**$ 3,470,309**	**$ 727,720**	**$ 736,776**	**$ -**	**$ -**	**$ -**	**$ 4,934,804**
187											
188	**Total O&M Expense**		**$ 35,297,808**		**$ 26,203,817**	**$ 3,925,031**	**$ 4,278,461**	**$ -**	**$ 890,498**	**$ -**	**$ 35,297,808**
189	Check		-								
190											
191	**Total O&M Expense less Purchased Power**		**$ 35,297,808**		**$ 26,203,817**	**$ 3,925,031**	**$ 4,278,461**	**$ -**	**$ 890,498**	**$ -**	**$ 35,297,808**
192											
193	Additional Expenses & Deductions										
194	**Debt Service**										
195	Generation		$ -	N/A	-	-	-	-	-	-	-
196	Transmission		-	N/A	-	-	-	-	-	-	-
197	Distribution		19,828,077	Net Dist. Plant	12,178,909	3,513,196	3,365,010	-	770,962	-	19,828,077
198	Customer		-	N/A	-	-	-	-	-	-	-
199	New Debt		6,892,528	Net Dist. Plant	4,233,566	1,221,238	1,169,726	-	267,998	-	6,892,528
200	**Total Debt Service**		**$ 26,720,605**		**$ 16,412,475**	**$ 4,734,434**	**$ 4,534,737**	**$ -**	**$ 1,038,960**	**$ -**	**$ 26,720,605**
201											
202	**Taxes and Transfer to General Fund**										
203	Contribution to General Fund		$ 9,071,951	RevReq	6,172,115	1,294,285	1,310,392	-	295,158	-	9,071,951
204	Other		-	N/A	-	-	-	-	-	-	-
205	Other		-	N/A	-	-	-	-	-	-	-
206	Other		-	N/A	-	-	-	-	-	-	-
207	**Total Taxes and Transfer to General Fund**		**$ 9,071,951**		**$ 6,172,115**	**$ 1,294,285**	**$ 1,310,392**	**$ -**	**$ 295,158**	**$ -**	**$ 9,071,951**
208											
209	**Capital Paid from Current Earnings**										
210	Production		$ -	N/A	-	-	-	-	-	-	-
211	Transmission		-	N/A	-	-	-	-	-	-	-
212	Distribution		4,749,448	Net Dist. Plant	2,917,232	841,521	806,026	-	184,670	-	4,749,448
213	Customer		-	N/A	-	-	-	-	-	-	-
214	Street Lighting Capital		-	Street Light	-	-	-	-	-	-	-
215	N/A		-	N/A	-	-	-	-	-	-	-
216	**Total Capital Paid from Current Earnings**		**$ 4,749,448**		**$ 2,917,232**	**$ 841,521**	**$ 806,026**	**$ -**	**$ 184,670**	**$ -**	**$ 4,749,448**
217											
218	**Reserves - Additional Cash Requirements**		1,617,104	RevReq w/o SL	1,137,198	238,469	241,437	-	-	-	1,617,104
219											
220	**Total Additional Expenses & Deductions**		**$ 42,159,109**		**$ 26,639,021**	**$ 7,108,709**	**$ 6,892,592**	**$ -**	**$ 1,518,787**	**$ -**	**$ 42,159,109**
221											
222	**Subtotal Revenue Requirement**		**$ 77,456,917**		**$ 52,842,838**	**$ 11,033,740**	**$ 11,171,053**	**$ -**	**$ 2,409,286**	**$ -**	**$ 77,456,917**
223	Check		-								
224											
225	Other Income										
226	**Other Operating Revenue:**										
227	Gain on retirement of assets (proforma)		$ 482,000	RevReq w/o SL	338,957	71,079	71,964	-	-	-	482,000
228	Uncollectible accounts (proforma)		-	N/A	-	-	-	-	-	-	-
229	Diversion	344400	-	N/A	-	-	-	-	-	-	-

Distribution Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Distribution Demand	Demand Related: Substations	Customer Related: Distribution Customer	Customer Related: Blank	Direct Assignment: Lighting	Direct Assignment: Blank	Total
230	Service Connect Charges-Elec	344410	-	N/A	-	-	-	-	-	-	-
231	Misc Service Revenues-Electric	344491	-	N/A	-	-	-	-	-	-	-
232	Misc Operating Revenues-Elec	344492	3,770	RevReq w/o SL	2,652	556	563	-	-	-	3,770
233	Corona Fees- Rev	344493	-	N/A	-	-	-	-	-	-	-
234	Cap and Trade Auction		700,184	RevReq	476,371	99,894	101,138	-	22,781	-	700,184
235	Non Energy Recpts ABC Admin OH	344513	6,760	RevReq w/o SL	4,754	997	1,009	-	-	-	6,760
236	**Total Other Operating Revenue:**		**$ 1,192,714**		**$ 822,734**	**$ 172,526**	**$ 174,673**	**$ -**	**$ 22,781**	**$ -**	**$ 1,192,714**
237											
238	**Other Non-Operating Revenue:**										
239	Corona Fees- Rev	344493	$ 4,236	RevReq w/o SL	2,979	625	633	-	-	-	4,236
240	Misc Settlement Reimb	344494	-	N/A	-	-	-	-	-	-	-
241	Late Payment Penalties	353400	-	N/A	-	-	-	-	-	-	-
242	Land and Building Rental	373100	385,731	RevReq w/o SL	271,258	56,883	57,590	-	-	-	385,731
243	Other Property Rental	373120	16,315	RevReq w/o SL	11,473	2,406	2,436	-	-	-	16,315
244	Pole Attachments	373125	225,751	Demand	225,751	-	-	-	-	-	225,751
245	Substation Operation & Maint	373126	-	N/A	-	-	-	-	-	-	-
246	Substation Leasing	373127	-	N/A	-	-	-	-	-	-	-
247	Communication Services	373128	56,811	RevReq w/o SL	39,951	8,378	8,482	-	-	-	56,811
248	CIS User Fee	373132	688,600	RevReq w/o SL	484,245	101,546	102,809	-	-	-	688,600
249	Refunds and Reimbursements	374000	-	RevReq w/o SL	-	-	-	-	-	-	-
250	Miscellaneous Receipts	374200	24,360	RevReq w/o SL	17,131	3,592	3,637	-	-	-	24,360
251	Cash Over/Shortage	374207	-	RevReq w/o SL	-	-	-	-	-	-	-
252	Asset Forfeiture Revenue	374500	-	RevReq w/o SL	-	-	-	-	-	-	-
253	Bad Debt Recovery	374800	-	RevReq w/o SL	-	-	-	-	-	-	-
254	Settlement Recovery	374801	-	RevReq w/o SL	-	-	-	-	-	-	-
255	Settlement Recovery - SONGS	374802	-	RevReq w/o SL	-	-	-	-	-	-	-
256	Liquidated Damages	374810	-	RevReq w/o SL	-	-	-	-	-	-	-
257	Operating Transfer from 650 Fund	985650	-	N/A	-	-	-	-	-	-	-
258	Utilization Charges	6125000	29,063	RevReq w/o SL	20,438	4,286	4,339	-	-	-	29,063
259	**Total Other Non-Operating Revenue:**		**$ 1,430,868**		**$ 1,073,227**	**$ 177,715**	**$ 179,926**	**$ -**	**$ -**	**$ -**	**$ 1,430,868**
260											
261	**Interest income**		1,481,945	RevReq w/o SL	1,042,150	218,538	221,257	-	-	-	1,481,945
262											
263	**Wholesale sales**		-	N/A	-	-	-	-	-	-	-
264											
265	**Transmission revenue**		-	N/A	-	-	-	-	-	-	-
266											
267	**Total Other Income**		**$ 4,105,527**		**$ 2,938,111**	**$ 568,779**	**$ 575,857**	**$ -**	**$ 22,781**	**$ -**	**$ 4,105,527**
268											
269											
270	**Total Retail Revenue Requirement**		**$ 73,351,390**		**$ 49,904,727**	**$ 10,464,961**	**$ 10,595,196**	**$ -**	**$ 2,386,505**	**$ -**	**$ 73,351,390**
271	Check		-		68%	14%	14%	0%	3%	0%	
272											
273	Revenue From Current Retail Rates										
274	Residential										
275	Commercial-Flat										
276	Commercial-Demand										
277	Industrial-TOU										
278	City Contract										
279	Other										
280	**Total Revenue From Current Retail Rates**		**$ -**								
281											
282											
283											
284	PLANT IN SERVICE										
285											
286	Gross Plant in Service										
287	**Intangible Plant**										
288	Organization	301	$ -	N/A	-	-	-	-	-	-	-
289	Franchises and Consents	302	-	N/A	-	-	-	-	-	-	-
290	Misc. Intangible Plant	303	19,849,154	Demand	19,849,154	-	-	-	-	-	19,849,154
291	Misc. Computer Software	3030	-	N/A	-	-	-	-	-	-	-
292	**Total Intangible Plant**		**$ 19,849,154**		**$ 19,849,154**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 19,849,154**
293											
294	**Production Plant**										
295	**Steam Production**										

Distribution Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related		Customer Related		Direct Assignment		Total
					Distribution Demand	Substations	Distribution Customer	Blank	Lighting	Blank	
296	Land and Land Rights	310	$ -	N/A	-	-	-	-	-	-	-
297	Structures & Improvements	311	-	N/A	-	-	-	-	-	-	-
298	Boiler Plant Equipment	312	-	N/A	-	-	-	-	-	-	-
299	Engines and Engine Generators	313	-	N/A	-	-	-	-	-	-	-
300	Turbo-Generator Units	314	-	N/A	-	-	-	-	-	-	-
301	Accessory Electric Equipment	315	-	N/A	-	-	-	-	-	-	-
302	Misc. Power Plant Equipment	316	-	N/A	-	-	-	-	-	-	-
303	**Total Steam Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
304											
305	**Hydraulic Production**										
306	Land and Land Rights	330	$ -	N/A	-	-	-	-	-	-	-
307	Structures & Improvements	331	-	N/A	-	-	-	-	-	-	-
308	Reservoirs, Dams and Water Ways	332	-	N/A	-	-	-	-	-	-	-
309	Water Wheel, Turbine and Generator	333	-	N/A	-	-	-	-	-	-	-
310	Accessory Electric Equipment	334	-	N/A	-	-	-	-	-	-	-
311	Misc. Power Plant Equipment	335	-	N/A	-	-	-	-	-	-	-
312	Roads, Railroads and Bridges	336	-	N/A	-	-	-	-	-	-	-
313	**Total Hydraulic Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
314											
315	**Combustion Turbine & Other Production**										
316	Land and Land Rights	340	$ -	N/A	-	-	-	-	-	-	-
317	Structures & Improvements	341	-	N/A	-	-	-	-	-	-	-
318	Fuel Holders, Prod & Acc	342	-	N/A	-	-	-	-	-	-	-
319	Prime Movers	343	-	N/A	-	-	-	-	-	-	-
320	Generators & Other Production	344	-	N/A	-	-	-	-	-	-	-
321	Accessory Electric Equipment	345	-	N/A	-	-	-	-	-	-	-
	Misc. Production Plant	2000	-	N/A	-	-	-	-	-	-	-
322	**Total Combustion Turbine & Other Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
322											
323	**Total Production Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
324											
325	**Transmission Plant**										
326	Land and Land Rights	350	$ 1,711,343	Net Dist. Plant	1,051,150	303,221	290,431	-	66,541	-	1,711,343
327	Reserved	351	-	N/A	-	-	-	-	-	-	-
328	Structures & Improvements	352	980,750	Net Dist. Plant	602,402	173,772	166,442	-	38,134	-	980,750
329	Station Equipment - System	353	4,863,356	Substations	-	4,863,356	-	-	-	-	4,863,356
330	Towers and Fixtures	354	3,532,104	Demand	3,532,104	-	-	-	-	-	3,532,104
331	Poles and Fixtures	355	18,659,015	Demand	18,659,015	-	-	-	-	-	18,659,015
332	Overhead Conductor	356	8,592,606	Circuit - OH	7,706,837	-	885,769	-	-	-	8,592,606
333	Underground Conductor	357	5,727,571	Circuit - UG	5,137,144	-	590,427	-	-	-	5,727,571
334	Underground Conduit	358	2,058,122	Circuit - UG	1,845,961	-	212,162	-	-	-	2,058,122
335	Misc. Transmission Plant	359	-	N/A	-	-	-	-	-	-	-
336	**Total Transmission Plant**		**$ 46,124,867**		**$ 38,534,613**	**$ 5,340,349**	**$ 2,145,231**	**$ -**	**$ 104,675**	**$ -**	**$ 46,124,867**
337											
338	**Distribution Plant**										
339	Land and Land Rights	360	$ 10,553,496	Demand	10,553,496	-	-	-	-	-	10,553,496
340	Structures & Improvements	361	10,678,983	Wghtd Avg Min Sys	6,695,093	-	3,983,890	-	-	-	10,678,983
341	Station Equipment	362	123,449,575	Substations	-	123,449,575	-	-	-	-	123,449,575
342	Misc. Plant	363	-	N/A	-	-	-	-	-	-	-
343	Towers and Fixtures	364	31,980,198	Demand	31,980,198	-	-	-	-	-	31,980,198
344	Overhead Conductor	365	38,718,492	Circuit - OH	34,727,195	-	3,991,297	-	-	-	38,718,492
345	Underground Conduit	366	109,279,967	Circuit - UG	98,014,839	-	11,265,128	-	-	-	109,279,967
346	Underground Conductor	367	126,112,503	Circuit - UG	113,112,192	-	13,000,311	-	-	-	126,112,503
347	Line Transformers	368	53,163,303	Transformers	24,235,435	-	28,927,868	-	-	-	53,163,303
348	Services	369	26,592,360	Services	-	-	26,592,360	-	-	-	26,592,360
349	Meters	370	15,232,659	Customer	-	-	15,232,659	-	-	-	15,232,659
350	Inst. on Customer Premises	371	839,555	Customer	-	-	839,555	-	-	-	839,555
351	Street Light / Signal Systems	373	47,962,902	Street Light	-	-	-	-	47,962,902	-	47,962,902
352	**Total Distribution Plant**		**$ 594,563,994**		**$ 319,318,449**	**$ 123,449,575**	**$ 103,833,068**	**$ -**	**$ 47,962,902**	**$ -**	**$ 594,563,994**
353											
354	**Subtotal Plant Before General**		**$ 660,538,015**		**$ 377,702,215**	**$ 128,789,924**	**$ 105,978,299**	**$ -**	**$ 48,067,577**	**$ -**	**$ 660,538,015**
355											
356	**General Plant**										
357	Land and Land Rights	389	$ 5,442,667	Demand	5,442,667	-	-	-	-	-	5,442,667
358	Structures & Improvements	390	43,165,662	Wghtd Avg Min Sys	27,062,325	-	16,103,337	-	-	-	43,165,662
359	Structures & Improvements - Other	3900	-	N/A	-	-	-	-	-	-	-

Distribution Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Distribution Demand	Demand Related: Substations	Customer Related: Distribution Customer	Customer Related: Blank	Direct Assignment: Lighting	Direct Assignment: Blank	Total
360	Office Furniture & Equipment	391	6,325,554	Wghtd Avg Min Sys	3,965,750	-	2,359,805	-	-	-	6,325,554
361	Info System Computers	3910	-	N/A	-	-	-	-	-	-	-
362	Transportation Equipment	392	7,865,880	Wghtd Avg Min Sys	4,931,443	-	2,934,437	-	-	-	7,865,880
363	Stores Equipment	393	30,515	Demand	30,515	-	-	-	-	-	30,515
364	Tools, Shop & Garage Equip.	394	348,117	Demand	348,117	-	-	-	-	-	348,117
365	Laboratory Equipment	395	625,624	Demand	625,624	-	-	-	-	-	625,624
366	Power Operated Equipment	396	980,384	Demand	980,384	-	-	-	-	-	980,384
367	Communication Equipment	397	11,490,220	Demand	11,490,220	-	-	-	-	-	11,490,220
368	Miscellaneous Equipment	398	721,649	Wghtd Avg Min Sys	452,431	-	269,218	-	-	-	721,649
369	Other Tangible Property	399	-	N/A	-	-	-	-	-	-	-
370	**Total General Plant**		**$ 76,996,273**		**$ 55,329,477**	**$ -**	**$ 21,666,796**	**$ -**	**$ -**	**$ -**	**$ 76,996,273**
371											
372	**Total Gross Plant in Service**		**$ 737,534,288**		**$ 433,031,692**	**$ 128,789,924**	**$ 127,645,095**	**$ -**	**$ 48,067,577**	**$ -**	**$ 737,534,288**
373	Check		-								
374											
375	Accumulated Depreciation										
376	**Intangible Plant**										
377	Organization	301	$ -	N/A	-	-	-	-	-	-	-
378	Franchises and Consents	302	-	N/A	-	-	-	-	-	-	-
379	Misc. Intangible Plant	303	1,223,510	Demand	1,223,510	-	-	-	-	-	1,223,510
380	Misc. Computer Software	3030	-	N/A	-	-	-	-	-	-	-
381	**Total Intangible Plant**		**$ 1,223,510**		**$ 1,223,510**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,223,510**
382											
383	**Production Plant**										
384	**Steam Production**										
385	Land and Land Rights	310	$ -	N/A	-	-	-	-	-	-	-
386	Structures & Improvements	311	-	N/A	-	-	-	-	-	-	-
387	Boiler Plant Equipment	312	-	N/A	-	-	-	-	-	-	-
388	Engines and Engine Generators	313	-	N/A	-	-	-	-	-	-	-
389	Turbo-Generator Units	314	-	N/A	-	-	-	-	-	-	-
390	Accessory Electric Equipment	315	-	N/A	-	-	-	-	-	-	-
391	Misc. Power Plant Equipment	316	-	N/A	-	-	-	-	-	-	-
392	**Total Steam Production**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
393											
394	**Hydraulic Production**										
395	Land and Land Rights	330	$ -	N/A	-	-	-	-	-	-	-
396	Structures & Improvements	331	-	N/A	-	-	-	-	-	-	-
397	Reservoirs, Dams and Water Ways	332	-	N/A	-	-	-	-	-	-	-
398	Water Wheel, Turbine and Generator	333	-	N/A	-	-	-	-	-	-	-
399	Accessory Electric Equipment	334	-	N/A	-	-	-	-	-	-	-
400	Misc. Power Plant Equipment	335	-	N/A	-	-	-	-	-	-	-
401	Roads, Railroads and Bridges	336	-	N/A	-	-	-	-	-	-	-
402	**Total Hydraulic Production**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
403											
404	**Combustion Turbine & Other Production**										
405	Land and Land Rights	340	$ -	N/A	-	-	-	-	-	-	-
406	Structures & Improvements	341	-	N/A	-	-	-	-	-	-	-
407	Fuel Holders, Prod & Acc	342	-	N/A	-	-	-	-	-	-	-
408	Prime Movers	343	-	N/A	-	-	-	-	-	-	-
409	Generators & Other Production	344	-	N/A	-	-	-	-	-	-	-
410	Accessory Electric Equipment	345	-	N/A	-	-	-	-	-	-	-
411	Misc. Production Plant	2000	-	N/A	-	-	-	-	-	-	-
412	**Total Combustion Turbine & Other Production**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
413											
414	**Total Production Plant**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
415											
416	**Transmission Plant**										
417	Land and Land Rights	350	$ -	Net Dist. Plant	-	-	-	-	-	-	-
418	Reserved	351	-	N/A	-	-	-	-	-	-	-
419	Structures & Improvements	352	641,394	Net Dist. Plant	393,960	113,644	108,851	-	24,939	-	641,394
420	Station Equipment - System	353	4,385,910	Substations	-	4,385,910	-	-	-	-	4,385,910
421	Towers and Fixtures	354	808,468	Demand	808,468	-	-	-	-	-	808,468
422	Poles and Fixtures	355	6,310,350	Demand	6,310,350	-	-	-	-	-	6,310,350
423	Overhead Conductor	356	2,681,443	Circuit - OH	2,405,027	-	276,417	-	-	-	2,681,443
424	Underground Conductor	357	1,283,113	Circuit - UG	1,150,844	-	132,270	-	-	-	1,283,113
425	Underground Conduit	358	880,098	Circuit - UG	789,373	-	90,725	-	-	-	880,098

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Distribution Demand	Demand Related: Substations	Customer Related: Distribution Customer	Customer Related: Blank	Direct Assignment: Lighting	Direct Assignment: Blank	Total
426	Misc. Transmission Plant	359	-	N/A	-	-	-	-	-	-	-
427	**Total Transmission Plant**		**$ 16,990,776**		**$ 11,858,022**	**$ 4,499,554**	**$ 608,262**	**$ -**	**$ 24,939**	**$ -**	**$ 16,990,776**
428											
429	**Distribution Plant**										
430	Land and Land Rights	360	$ -	Demand	-	-	-	-	-	-	-
431	Structures & Improvements	361	2,514,219	Wghtd Avg Min Sys	1,576,267	-	937,952	-	-	-	2,514,219
432	Station Equipment	362	40,040,406	Substations	-	40,040,406	-	-	-	-	40,040,406
433	Misc. Plant	363	-	N/A	-	-	-	-	-	-	-
434	Towers and Fixtures	364	13,510,816	Demand	13,510,816	-	-	-	-	-	13,510,816
435	Overhead Conductor	365	18,402,517	Circuit - OH	16,505,493	-	1,897,024	-	-	-	18,402,517
436	Underground Conduit	366	26,031,289	Circuit - UG	23,347,853	-	2,683,436	-	-	-	26,031,289
437	Underground Conductor	367	48,413,025	Circuit - UG	43,422,367	-	4,990,658	-	-	-	48,413,025
438	Line Transformers	368	27,607,645	Transformers	12,585,435	-	15,022,210	-	-	-	27,607,645
439	Services	369	10,963,449	Services	-	-	10,963,449	-	-	-	10,963,449
440	Meters	370	4,308,301	Customer	-	-	4,308,301	-	-	-	4,308,301
441	Inst. on Customer Premises	371	713,846	Customer	-	-	713,846	-	-	-	713,846
442	Street Light / Signal Systems	373	29,554,194	Street Light	-	-	-	-	29,554,194	-	29,554,194
443	**Total Distribution Plant**		**$ 222,059,707**		**$ 110,948,230**	**$ 40,040,406**	**$ 41,516,877**	**$ -**	**$ 29,554,194**	**$ -**	**$ 222,059,707**
444											
445	**Subtotal Plant Before General**		**$ 240,273,994**		**$ 124,029,762**	**$ 44,539,960**	**$ 42,125,139**	**$ -**	**$ 29,579,133**	**$ -**	**$ 240,273,994**
446											
447	**General Plant**										
448	Land and Land Rights	389	$ -	Demand	-	-	-	-	-	-	-
449	Structures & Improvements	390	4,665,764	Wghtd Avg Min Sys	2,925,159	-	1,740,605	-	-	-	4,665,764
450	Structures & Improvements - Other	3900	-	N/A	-	-	-	-	-	-	-
451	Office Furniture & Equipment	391	3,502,715	Wghtd Avg Min Sys	2,195,996	-	1,306,719	-	-	-	3,502,715
452	Info System Computers	3910	-	N/A	-	-	-	-	-	-	-
453	Transportation Equipment	392	4,243,177	Wghtd Avg Min Sys	2,660,222	-	1,582,955	-	-	-	4,243,177
454	Stores Equipment	393	30,515	Demand	30,515	-	-	-	-	-	30,515
455	Tools, Shop & Garage Equip.	394	296,553	Demand	296,553	-	-	-	-	-	296,553
456	Laboratory Equipment	395	613,797	Demand	613,797	-	-	-	-	-	613,797
457	Power Operated Equipment	396	686,195	Demand	686,195	-	-	-	-	-	686,195
458	Communication Equipment	397	7,206,076	Demand	7,206,076	-	-	-	-	-	7,206,076
459	Miscellaneous Equipment	398	518,288	Wghtd Avg Min Sys	324,936	-	193,352	-	-	-	518,288
460	Other Tangible Property	399	-	N/A	-	-	-	-	-	-	-
461	**Total General Plant**		**$ 21,763,081**		**$ 16,939,449**	**$ -**	**$ 4,823,632**	**$ -**	**$ -**	**$ -**	**$ 21,763,081**
462											
463	**Total Accumulated Depreciation**		**$ 262,037,075**		**$ 140,969,211**	**$ 44,539,960**	**$ 46,948,771**	**$ -**	**$ 29,579,133**	**$ -**	**$ 262,037,075**
464	Check		-								
465											
466	Net Plant in Service										
467	**Intangible Plant**										
468	Organization	301	$ -		-	-	-	-	-	-	-
469	Franchises and Consents	302	-		-	-	-	-	-	-	-
470	Misc. Intangible Plant	303	18,625,644		18,625,644	-	-	-	-	-	18,625,644
471	Misc. Computer Software	3030	-		-	-	-	-	-	-	-
472	**Total Intangible Plant**		**$ 18,625,644**		**$ 18,625,644**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 18,625,644**
473											
474	**Production Plant**										
475	**Steam Production**										
476	Land and Land Rights	310	$ -		-	-	-	-	-	-	-
477	Structures & Improvements	311	-		-	-	-	-	-	-	-
478	Boiler Plant Equipment	312	-		-	-	-	-	-	-	-
479	Engines and Engine Generators	313	-		-	-	-	-	-	-	-
480	Turbo-Generator Units	314	-		-	-	-	-	-	-	-
481	Accessory Electric Equipment	315	-		-	-	-	-	-	-	-
482	Misc. Power Plant Equipment	316	-		-	-	-	-	-	-	-
483	**Total Steam Production**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
484											
485	**Hydraulic Production**										
486	Land and Land Rights	330	$ -		-	-	-	-	-	-	-
487	Structures & Improvements	331	-		-	-	-	-	-	-	-
488	Reservoirs, Dams and Water Ways	332	-		-	-	-	-	-	-	-
489	Water Wheel, Turbine and Generator	333	-		-	-	-	-	-	-	-
490	Accessory Electric Equipment	334	-		-	-	-	-	-	-	-
491	Misc. Power Plant Equipment	335	-		-	-	-	-	-	-	-

Line			Adjusted	Allocation	Demand Related		Customer Related		Direct Assignment		
No.	Item	Account/ID	Test Year	Factor	Distribution Demand	Substations	Distribution Customer	Blank	Lighting	Blank	Total
492	Roads, Railroads and Bridges	336	-		-	-	-	-	-	-	-
493	**Total Hydraulic Production**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
494											
495	**Combustion Turbine & Other Production**										
496	Land and Land Rights	340	$ -		-	-	-	-	-	-	-
497	Structures & Improvements	341	-		-	-	-	-	-	-	-
498	Fuel Holders, Prod & Acc	342	-		-	-	-	-	-	-	-
499	Prime Movers	343	-		-	-	-	-	-	-	-
500	Generators & Other Production	344	-		-	-	-	-	-	-	-
501	Accessory Electric Equipment	345	-		-	-	-	-	-	-	-
502	Misc. Production Plant	2000	-		-	-	-	-	-	-	-
503	**Total Combustion Turbine & Other Production**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
504											
505	**Total Production Plant**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
506											
507	**Transmission Plant**										
508	Land and Land Rights	350	$ 1,711,343		1,051,150	303,221	290,431	-	66,541	-	1,711,343
509	Reserved	351	-		-	-	-	-	-	-	-
510	Structures & Improvements	352	339,356		208,441	60,128	57,592	-	13,195	-	339,356
511	Station Equipment - System	353	477,446		-	477,446	-	-	-	-	477,446
512	Towers and Fixtures	354	2,723,636		2,723,636	-	-	-	-	-	2,723,636
513	Poles and Fixtures	355	12,348,665		12,348,665	-	-	-	-	-	12,348,665
514	Overhead Conductor	356	5,911,163		5,301,810	-	609,352	-	-	-	5,911,163
515	Underground Conductor	357	4,444,457		3,986,300	-	458,157	-	-	-	4,444,457
516	Underground Conduit	358	1,178,024		1,056,588	-	121,437	-	-	-	1,178,024
517	Misc. Transmission Plant	359	-		-	-	-	-	-	-	-
518	**Total Transmission Plant**		**$ 29,134,091**		**$ 26,676,591**	**$ 840,795**	**$ 1,536,969**	**$ -**	**$ 79,736**	**$ -**	**$ 29,134,091**
519											
520	**Distribution Plant**										
521	Land and Land Rights	360	$ 10,553,496		10,553,496	-	-	-	-	-	10,553,496
522	Structures & Improvements	361	8,164,764		5,118,826	-	3,045,938	-	-	-	8,164,764
523	Station Equipment	362	83,409,169		-	83,409,169	-	-	-	-	83,409,169
524	Misc. Plant	363	-		-	-	-	-	-	-	-
525	Towers and Fixtures	364	18,469,382		18,469,382	-	-	-	-	-	18,469,382
526	Overhead Conductor	365	20,315,975		18,221,702	-	2,094,273	-	-	-	20,315,975
527	Underground Conduit	366	83,248,679		74,666,987	-	8,581,692	-	-	-	83,248,679
528	Underground Conductor	367	77,699,479		69,689,826	-	8,009,653	-	-	-	77,699,479
529	Line Transformers	368	25,555,658		11,650,000	-	13,905,658	-	-	-	25,555,658
530	Services	369	15,628,911		-	-	15,628,911	-	-	-	15,628,911
531	Meters	370	10,924,357		-	-	10,924,357	-	-	-	10,924,357
532	Inst. on Customer Premises	371	125,709		-	-	125,709	-	-	-	125,709
533	Street Light / Signal Systems	373	18,408,708		-	-	-	-	18,408,708	-	18,408,708
534	**Total Distribution Plant**		**$ 372,504,287**		**$ 208,370,219**	**$ 83,409,169**	**$ 62,316,191**	**$ -**	**$ 18,408,708**	**$ -**	**$ 372,504,287**
535											
536	**Subtotal Plant Before General**		**$ 420,264,021**		**$ 253,672,453**	**$ 84,249,965**	**$ 63,853,160**	**$ -**	**$ 18,488,444**	**$ -**	**$ 420,264,021**
537											
538	**General Plant**										
539	Land and Land Rights	389	$ 5,442,667		5,442,667	-	-	-	-	-	5,442,667
540	Structures & Improvements	390	38,499,898		24,137,166	-	14,362,732	-	-	-	38,499,898
541	Structures & Improvements - Other	3900	-		-	-	-	-	-	-	-
542	Office Furniture & Equipment	391	2,822,840		1,769,754	-	1,053,086	-	-	-	2,822,840
543	Info System Computers	3910	-		-	-	-	-	-	-	-
544	Transportation Equipment	392	3,622,703		2,271,221	-	1,351,482	-	-	-	3,622,703
545	Stores Equipment	393	-		-	-	-	-	-	-	-
546	Tools, Shop & Garage Equip.	394	51,564		51,564	-	-	-	-	-	51,564
547	Laboratory Equipment	395	11,826		11,826	-	-	-	-	-	11,826
548	Power Operated Equipment	396	294,189		294,189	-	-	-	-	-	294,189
549	Communication Equipment	397	4,284,144		4,284,144	-	-	-	-	-	4,284,144
550	Miscellaneous Equipment	398	203,361		127,495	-	75,866	-	-	-	203,361
551	Other Tangible Property	399	-		-	-	-	-	-	-	-
552	**Total General Plant**		**$ 55,233,192**		**$ 38,390,028**	**$ -**	**$ 16,843,165**	**$ -**	**$ -**	**$ -**	**$ 55,233,192**
553											
554	**Total Net Plant in Service**		**$ 475,497,214**		**$ 292,062,481**	**$ 84,249,965**	**$ 80,696,324**	**$ -**	**$ 18,488,444**	**$ -**	**$ 475,497,214**
555	Check		-								
556											
557											

Line			Adjusted	Allocation	Demand Related		Customer Related		Direct Assignment		
No.	Item	Account/ID	Test Year	Factor	Distribution Demand	Substations	Distribution Customer	Blank	Lighting	Blank	Total
558	LABOR										
559											
560	Production Labor										
561	**Steam Production Operation**										
562	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-	-
563	Fuel (Transportation & Handling)		-	N/A	-	-	-	-	-	-	-
564	Steam Expense		-	N/A	-	-	-	-	-	-	-
565	Electric Expense		-	N/A	-	-	-	-	-	-	-
566	Miscellaneous		-	N/A	-	-	-	-	-	-	-
567	Rent		-	N/A	-	-	-	-	-	-	-
568	**Total Steam Production Operation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
569											
570	**Steam Production Maintenance**										
571	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-	-
572	Structures		-	N/A	-	-	-	-	-	-	-
573	Boilers		-	N/A	-	-	-	-	-	-	-
574	Electric Plant		-	N/A	-	-	-	-	-	-	-
575	Miscellaneous Labor		-	N/A	-	-	-	-	-	-	-
576	**Total Steam Production Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
577											
578	**Hydro Production Operation**										
579	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-	-
580	Water for Power		-	N/A	-	-	-	-	-	-	-
581	Hydraulic Expense		-	N/A	-	-	-	-	-	-	-
582	Electric Expense		-	N/A	-	-	-	-	-	-	-
583	Miscellaneous		-	N/A	-	-	-	-	-	-	-
584	Rent		-	N/A	-	-	-	-	-	-	-
585	**Total Hydro Production Operation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
586											
587	**Hydro Production Maintenance**										
588	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-	-
589	Structures		-	N/A	-	-	-	-	-	-	-
590	Reservoirs & Dams		-	N/A	-	-	-	-	-	-	-
591	Electric Plant		-	N/A	-	-	-	-	-	-	-
592	Miscellaneous Plant		-	N/A	-	-	-	-	-	-	-
593	**Total Hydro Production Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
594											
595	**Combined Cycle Operation**										
596	Labor		$ -	N/A	-	-	-	-	-	-	-
597	Fuel Handling		-	N/A	-	-	-	-	-	-	-
598	Generation Expense		-	N/A	-	-	-	-	-	-	-
599	Miscellaneous		-	N/A	-	-	-	-	-	-	-
600	**Total Combined Cycle Operation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
601											
602	**Combined Cycle Maintenance**										
603	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-	-
604	Structures		-	N/A	-	-	-	-	-	-	-
605	Electric Plant		-	N/A	-	-	-	-	-	-	-
606	Miscellaneous Plant		-	N/A	-	-	-	-	-	-	-
607	**Total Combined Cycle Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
608											
609	**Other Production**										
610	RERC/Acorn Gen. Plant	612013	$ -	N/A	-	-	-	-	-	-	-
611	Clearwater Generating Plant	612014	-	N/A	-	-	-	-	-	-	-
612	PU Elec Power Supply Operations	612000	-	N/A	-	-	-	-	-	-	-
613	**Total Other Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
614											
615	**Total Production Labor**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
616											
617	Transmission Labor										
618	**Transmission Operations**										
619	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-	-
620	Load Dispatch		-	N/A	-	-	-	-	-	-	-
621	Station Equipment		-	N/A	-	-	-	-	-	-	-
622	Overhead Lines		-	N/A	-	-	-	-	-	-	-
623	Underground Lines		-	N/A	-	-	-	-	-	-	-

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Distribution Demand	Demand Related: Substations	Customer Related: Distribution Customer	Customer Related: Blank	Direct Assignment: Lighting	Direct Assignment: Blank	Total
624	General Labor		-	N/A	-	-	-	-	-	-	-
625	Miscellaneous		-	N/A	-	-	-	-	-	-	-
626	Rents		-	N/A	-	-	-	-	-	-	-
627	**Total Transmission Operations**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
628											
629	**Transmission Maintenance**										
630	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-	-
631	Structures		-	N/A	-	-	-	-	-	-	-
632	Station Equipment		-	N/A	-	-	-	-	-	-	-
633	Overhead Lines		-	N/A	-	-	-	-	-	-	-
634	Underground Lines		-	N/A	-	-	-	-	-	-	-
635	Miscellaneous		-	N/A	-	-	-	-	-	-	-
636	**Total Transmission Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
637											
638	**Wheeling**										
639	Wheeling		$ -	N/A	-	-	-	-	-	-	-
640	Wheeling		-	N/A	-	-	-	-	-	-	-
641	**Total Wheeling**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
642											
643	**Total Transmission Labor**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
644											
645	Distribution Labor										
646	**Distribution Operations**										
647	Electric Operations	610000	$ 9,280,013	Wghtd Avg Min Sys	5,818,021	-	3,461,992	-	-	-	9,280,013
648	PU Electric Field Operations	610500	11,052,109	Wghtd Avg Min Sys	6,929,021	-	4,123,088	-	-	-	11,052,109
649	Energy Deliv Engineering	611000	7,508,316	Wghtd Avg Min Sys	4,707,271	-	2,801,045	-	-	-	7,508,316
650	Customer Engineering-GIS	611500	-	N/A	-	-	-	-	-	-	-
651	Underground Lines		-	N/A	-	-	-	-	-	-	-
652	Street Lighting		-	N/A	-	-	-	-	-	-	-
653	Metering		-	N/A	-	-	-	-	-	-	-
654	Customer Installations		-	N/A	-	-	-	-	-	-	-
655	Miscellaneous		-	N/A	-	-	-	-	-	-	-
656	Rents		-	N/A	-	-	-	-	-	-	-
657	**Total Distribution Operations**		**$ 27,840,438**		**$ 17,454,313**	$ -	**$ 10,386,125**	$ -	$ -	$ -	**$ 27,840,438**
658											
659	**Distribution Maintenance**										
660	Supervision		$ -	N/A	-	-	-	-	-	-	-
661	Structures		-	N/A	-	-	-	-	-	-	-
662	Station Equipment		-	N/A	-	-	-	-	-	-	-
663	Overhead Lines		-	N/A	-	-	-	-	-	-	-
664	Underground Lines		-	N/A	-	-	-	-	-	-	-
665	Transformers		-	N/A	-	-	-	-	-	-	-
666	Street Lighting		-	N/A	-	-	-	-	-	-	-
667	Metering		-	N/A	-	-	-	-	-	-	-
668	Miscellaneous		-	N/A	-	-	-	-	-	-	-
669	**Total Distribution Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
670											
671	**Total Distribution Labor**		**$ 27,840,438**		**$ 17,454,313**	$ -	**$ 10,386,125**	$ -	$ -	$ -	**$ 27,840,438**
672											
673	Customer Labor										
674	**Customer Accounting Expense**										
675	Pub Util Business Support	600400	$ -	N/A	-	-	-	-	-	-	-
676	Pub Util Admin-Utility Billing	600500	-	N/A	-	-	-	-	-	-	-
677	Pub Util Admin-Customer Service	601500	-	N/A	-	-	-	-	-	-	-
678	Pub Util Adm-Marketing Service	602000	-	N/A	-	-	-	-	-	-	-
679	Miscellaneous		-	N/A	-	-	-	-	-	-	-
680	**Total Customer Accounting Expense**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
681											
682	**Customer Service Expense**										
683	Customer Engineering-GIS		$ -	N/A	-	-	-	-	-	-	-
684	Customer Assistance		-	N/A	-	-	-	-	-	-	-
685	Advertisement / Marketing		-	N/A	-	-	-	-	-	-	-
686	Miscellaneous		-	N/A	-	-	-	-	-	-	-
687	**Total Customer Service Expense**		$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -
688											
689	**Sales Expense**										

Line			Adjusted	Allocation	Demand Related		Customer Related		Direct Assignment		
No.	Item	Account/ID	Test Year	Factor	Distribution Demand	Substations	Distribution Customer	Blank	Lighting	Blank	Total
690	Sales Expense		$ -	N/A	-	-	-	-	-	-	-
691	Demonstrations & Selling		-	N/A	-	-	-	-	-	-	-
692	Miscellaneous Sales Expense		-	N/A	-	-	-	-	-	-	-
693	**Total Sales Expense**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
694											
695	**Total Customer Labor**		**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
696											
697	**Total Labor Expense excluding A&G**		**$ 27,840,438**		**$ 17,454,313**	**$ -**	**$ 10,386,125**	**$ -**	**$ -**	**$ -**	**$ 27,840,438**
698											
699	Administrative & General Labor										
700	Pub Util Admin-Mgmt Service	600000	$ 64,274	Wghtd Avg Min Sys	40,296	-	23,978	-	-	-	64,274
701	Pub Util Admin-Field Services	601000	-	N/A	-	-	-	-	-	-	-
702	Legislative & Regulator Risk	602500	227,437	Wghtd Avg Min Sys	142,590	-	84,847	-	-	-	227,437
703	Outside Services		-	N/A	-	-	-	-	-	-	-
704	Outside Services		-	N/A	-	-	-	-	-	-	-
705	Property Insurance		-	N/A	-	-	-	-	-	-	-
706	Injuries and Damages		-	N/A	-	-	-	-	-	-	-
707	Electric Utility Communication Labor		-	N/A	-	-	-	-	-	-	-
708	Miscellaneous		-	N/A	-	-	-	-	-	-	-
709	Rents		-	N/A	-	-	-	-	-	-	-
710	Transportation Pool General Labor		-	N/A	-	-	-	-	-	-	-
711	Maintenance of General Plant		-	N/A	-	-	-	-	-	-	-
712	N/A		-	N/A	-	-	-	-	-	-	-
713	**Total Administrative & General Labor**		**$ 291,711**		**$ 182,885**	**$ -**	**$ 108,825**	**$ -**	**$ -**	**$ -**	**$ 291,711**
714											
715	**Total Labor Expense**		**$ 28,132,149**		**$ 17,637,199**	**$ -**	**$ 10,494,950**	**$ -**	**$ -**	**$ -**	**$ 28,132,149**
716	Check		-								
717											
718	**Allocation Factors**										
719	Substations			Substations	0%	100%	0%	0%	0%	0%	100%
720					-	1	-	-	-	-	1
721	Circuits - OH - see WP-MIN SYS			Circuit - OH	90%	0%	10%	0%	0%	0%	100%
722					90%	-	10%	-	-	-	1
723	Circuits - UG - See WP-MIN SYS			Circuit - UG	90%	0%	10%	0%	0%	0%	100%
724					0.90	-	0.10	-	-	-	1
725	Transformers			Transformers	46%	0%	54%	0%	0%	0%	100%
726					0.46	-	0.54	-	-	-	1
727	Services			Services	0%	0%	100%	0%	0%	0%	100%
728					0%	0%	100%	-	-	-	1
729	Meters			Meters	29%	0%	71%	0%	0%	0%	100%
730					29%	0%	71%	-	-	-	1
731	Street Lighting			Street Light	0%	0%	0%	0%	100%	0%	100%
732					-	-	-	-	1	-	1
733	Supervision - Ops			Super-Ops	89%	1%	10%	0%	0%	0%	100%
734					2,851,864	36,439	331,003	-	-	-	3,219,306
735	Supervision - Maint			Super-Maint	100%	0%	0%	0%	0%	0%	100%
736					1	-	-	-	-	-	1
737	Total Distribution w/o Gen - Plant			N/A	0%	0%	0%	0%	0%	0%	0%
738					-	-	-	-	-	-	-
739	Total Distribution - Plant			Net Dist. Plant	61%	18%	17%	0%	4%	0%	100%
740					292,062,481	84,249,965	80,696,324	-	18,488,444	-	475,497,214
741	CIP w/o Subs			CIP w/o Subs	0%	100%	0%	0%	0%	0%	100%
742					-	1	-	-	-	-	1
743	Gross General Plant			Gross Gen Plant	72%	0%	28%	0%	0%	0%	100%
744					55,329,477	-	21,666,796	-	-	-	76,996,273
745	Capital			CIP	61%	18%	17%	0%	4%	0%	100%
746					2,917,232	841,521	806,026	-	184,670	-	4,749,448
747	Not Applicable			Customer	0%	0%	100%	0%	0%	0%	100%
748					-	-	1	-	-	-	1
741	Labor Excluding A&G			Labor w/o A&G	63%	0%	37%	0%	0%	0%	100%
749					17,454,313	-	10,386,125	-	-	-	27,840,438
750	Total Labor			Total Labor	63%	0%	37%	0%	0%	0%	100%
751					17,637,199	-	10,494,950	-	-	-	28,132,149
752	Revenue Requirement			RevReq	68%	14%	14%	0%	3%	0%	100%
753					49,904,727	10,464,961	10,595,196	-	2,386,505	-	73,351,390
754	Revenue Requirement- Exlucding St Lighting			RevReq w/o SL	70%	15%	15%	0%	0%	0%	100%

Distribution Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Demand Related: Distribution Demand	Demand Related: Substations	Customer Related: Distribution Customer	Customer Related: Blank	Direct Assignment: Lighting	Direct Assignment: Blank	Total
755					49,904,727	10,464,961	10,595,196	-	-	-	70,964,885
756	Weighted Average Minimum System			Wghtd Avg Min Sys	63%	0%	37%	0%	0%	0%	100%
757					63%	-	37%	-	-	-	1
758	Demand / Customer - 50/50			50/50 Dem/Cust	50%	0%	50%	0%	0%	0%	100%
759					1	-	1	-	-	-	2
760	Demand			Demand	100%	0%	0%	0%	0%	0%	100%
761					1	-	-	-	-	-	1
762	Customer			Customer	0%	0%	100%	0%	0%	0%	100%
763					-	-	1	-	-	-	1

Customer Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Meter Reading	Customer Accounting	Customer Service	Sales	Blank	Total
1	REVENUE REQUIREMENTS CALCULATION									
2										
131										
132	Customer O&M									
133	**Customer Accounting Expense**									
134	Supervision	0901	$ 200,768	Cust Acctng - Super	-	200,768	-	-	-	200,768
135	Meter Reading	0902	1,133,710	Mtr Read Exp	1,133,710	-	-	-	-	1,133,710
136	Customer Records and Collection Expenses	0903	6,226,701	Cust Serv	-	-	6,226,701	-	-	6,226,701
137	Reserved	NA	-	N/A	-	-	-	-	-	-
138	Uncollectible Accounts	0904	1,038,288	Sales	-	-	-	1,038,288	-	1,038,288
139	Miscellaneous	0905	-	N/A	-	-	-	-	-	-
140	**Total Customer Accounting Expense**		**$ 8,599,467**		**$ 1,133,710**	**$ 200,768**	**$ 6,226,701**	**$ 1,038,288**	**$ -**	**$ 8,599,467**
141										
142	**Other Customer Costs**									
143	Supervision	0907	$ -	N/A	-	-	-	-	-	-
144	Customer Assistance	0908	1,532,067	Cust Serv	-	-	1,532,067	-	-	1,532,067
145	Advertisement	0909	1,169,064	Sales	-	-	-	1,169,064	-	1,169,064
146	Miscellaneous	0910	-	N/A	-	-	-	-	-	-
147	**Total Other Customer Costs**		**$ 2,701,131**		**$ -**	**$ -**	**$ 1,532,067**	**$ 1,169,064**	**$ -**	**$ 2,701,131**
148										
149	**Sales Expense**									
150	Sales Expense - Supv.	0911	$ -	N/A	-	-	-	-	-	-
151	Demonstrations & Selling	0912	234,399	Sales	-	-	-	234,399	-	234,399
152	Advertising Expenses	0913	4,130	Sales	-	-	-	4,130	-	4,130
153	Miscellaneous Sales Expense	0916	-	N/A	-	-	-	-	-	-
154	**Total Sales Expense**		**$ 238,529**		**$ -**	**$ -**	**$ -**	**$ 238,529**	**$ -**	**$ 238,529**
155										
156	**Total Customer O&M**		**$ 11,539,127**		**$ 1,133,710**	**$ 200,768**	**$ 7,758,768**	**$ 2,445,881**	**$ -**	**$ 11,539,127**
157										
158	Administrative & General Expense									
159	Administrative Salaries & Misc. Labor	0920	$ 191,847	Labor Exc A&G	-	20,080	171,767	-	-	191,847
160	Office Supplies & Expense	0921	-	N/A	-	-	-	-	-	-
161	Interdepartmental Charges	0922	(5,485,136)	Labor Exc A&G	-	(574,103)	(4,911,033)	-	-	(5,485,136)
162	Outside Services	0923	-	N/A	-	-	-	-	-	-
163	Property Insurance	0924	-	N/A	-	-	-	-	-	-
164	Injuries and Damages	0925	-	N/A	-	-	-	-	-	-
165	Employee Pensions and Benefits	0926	5,498,000	Labor Exc A&G	-	575,450	4,922,550	-	-	5,498,000
166	Franchise Requirements	0927	-	N/A	-	-	-	-	-	-
167	Compliance & Consultants (Regulatory Commission Expens	0928	-	N/A	-	-	-	-	-	-
168	General Advertising Expense	0930	-	N/A	-	-	-	-	-	-
169	Rents	0931	542,338	Cust Acct Supervision	-	542,338	-	-	-	542,338
170	Miscellaneous General Expenses	0933	-	N/A	-	-	-	-	-	-
171	Maintenance of General Plant	0932	-	N/A	-	-	-	-	-	-
172	Duplicate Charges - Credit	0929	-	N/A	-	-	-	-	-	-
173	**Total Administrative & General Expense**		**$ 747,049**		**$ -**	**$ 563,764**	**$ 183,284**	**$ -**	**$ -**	**$ 747,049**
174										
175	Miscellaneous and Clearing Accounts									
176	General Government Charges	0701	$ 467,097	Labor Exc A&G	-	48,889	418,209	-	-	467,097
177	Expenses Transferred From Electric	0702	161,316	Labor Exc A&G	-	16,884	144,431	-	-	161,316
178	IDI Utility Charges	0703	36	Labor Exc A&G	-	4	32	-	-	36
179	Removal Expenses	0704	-	Labor Exc A&G	-	-	-	-	-	-
180	Taxes	0707	-	N/A	-	-	-	-	-	-
181	Stores Expenses	0781	-	N/A	-	-	-	-	-	-
182	Transportation Expenses	0782	-	Labor Exc A&G	-	-	-	-	-	-
183	Tool and Shop Expenses	0783	-	Labor Exc A&G	-	-	-	-	-	-
184	Insurance	0788	-	Labor Exc A&G	-	-	-	-	-	-
185	Non-Operating expenses	0790	-	N/A	-	-	-	-	-	-
186	**Total Miscellaneous and Clearing Accounts**		**$ 628,449**		**$ -**	**$ 65,777**	**$ 562,672**	**$ -**	**$ -**	**$ 628,449**
187										
188	**Total O&M Expense**		**$ 12,914,625**		**$ 1,133,710**	**$ 830,309**	**$ 8,504,724**	**$ 2,445,881**	**$ -**	**$ 12,914,625**
189	Check		-							
190										
191	**Total O&M Expense less Purchased Power**		**$ 12,914,625**		**$ 1,133,710**	**$ 830,309**	**$ 8,504,724**	**$ 2,445,881**	**$ -**	**$ 12,914,625**
192										
193	Additional Expenses & Deductions									
194	**Debt Service**									
195	Generation		$ -	N/A	-	-	-	-	-	-
196	Transmission		-	N/A	-	-	-	-	-	-
197	Distribution		-	N/A	-	-	-	-	-	-
198	Customer		-	N/A	-	-	-	-	-	-
199	New Debt		615,672	MR-CA-CS	205,224	205,224	205,224	-	-	615,672
200	**Total Debt Service**		**$ 615,672**		**$ 205,224**	**$ 205,224**	**$ 205,224**	**$ -**	**$ -**	**$ 615,672**
201										
202	**Taxes and Transfer to General Fund**									
203	Contribution to General Fund		$ 1,469,736	RevReq	210,206	167,125	745,103	347,301	-	1,469,736
204	Other		-	N/A	-	-	-	-	-	-

Customer Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Meter Reading	Customer Accounting	Customer Service	Sales	Blank	Total
205	Other		-	N/A	-	-	-	-	-	-
206	Other		-	N/A	-	-	-	-	-	-
207	**Total Taxes and Transfer to General Fund**		**$ 1,469,736**		**$ 210,206**	**$ 167,125**	**$ 745,103**	**$ 347,301**	**$ -**	**$ 1,469,736**
208										
209	**Capital Paid from Current Earnings**									
210	Production		$ -	N/A	-	-	-	-	-	-
211	Transmission		-	N/A	-	-	-	-	-	-
212	Distribution		-	N/A	-	-	-	-	-	-
213	Customer		424,352	MR-CA-CS	141,451	141,451	141,451	-	-	424,352
214	Street Lighting Capital		-	N/A	-	-	-	-	-	-
215	N/A		-	N/A	-	-	-	-	-	-
216	**Total Capital Paid from Current Earnings**		**$ 424,352**		**$ 141,451**	**$ 141,451**	**$ 141,451**	**$ -**	**$ -**	**$ 424,352**
217										
218	**Reserves - Additional Cash Requirements**		261,985	RevReq	37,470	29,791	132,817	61,908	-	261,985
219										
220	**Total Additional Expenses & Deductions**		**$ 2,771,745**		**$ 594,351**	**$ 543,590**	**$ 1,224,595**	**$ 409,209**	**$ -**	**$ 2,771,745**
221										
222	**Subtotal Revenue Requirement**		**$ 15,686,369**		**$ 1,728,061**	**$ 1,373,899**	**$ 9,729,319**	**$ 2,855,090**	**$ -**	**$ 15,686,369**
223	Check		-							
224										
225	Other Income									
226	**Other Operating Revenue:**									
227	Gain on retirement of assets (proforma)		$ -	N/A	-	-	-	-	-	-
228	Uncollectible accounts (proforma)		-	Sales	-	-	-	-	-	-
229	Diversion	344400	-	N/A	-	-	-	-	-	-
230	Service Connect Charges-Elec	344410	386,140	Cust Serv	-	-	386,140	-	-	386,140
231	Misc Service Revenues-Electric	344491	2,977,752	Cust Serv	-	-	2,977,752	-	-	2,977,752
232	Misc Operating Revenues-Elec	344492	611	RevReq	87	69	310	144	-	611
233	Corona Fees- Rev	344493	-	N/A	-	-	-	-	-	-
234	Cap and Trade Auction		113,436	RevReq	16,224	12,899	57,508	26,805	-	113,436
235	Non Energy Recpts ABC Admin OH	344513	1,095	RevReq	157	125	555	259	-	1,095
236	**Total Other Operating Revenue:**		**$ 3,479,034**		**$ 16,468**	**$ 13,093**	**$ 3,422,264**	**$ 27,208**	**$ -**	**$ 3,479,034**
237										
238	**Other Non-Operating Revenue:**									
239	Corona Fees- Rev	344493	$ 686	RevReq	98	78	348	162	-	686
240	Misc Settlement Reimb	344494	-	N/A	-	-	-	-	-	-
241	Late Payment Penalties	353400	-	N/A	-	-	-	-	-	-
242	Land and Building Rental	373100	62,492	RevReq	8,938	7,106	31,681	14,767	-	62,492
243	Other Property Rental	373120	2,643	RevReq	378	301	1,340	625	-	2,643
244	Pole Attachments	373125	-	N/A	-	-	-	-	-	-
245	Substation Operation & Maint	373126	-	N/A	-	-	-	-	-	-
246	Substation Leasing	373127	-	N/A	-	-	-	-	-	-
247	Communication Services	373128	9,204	RevReq	1,316	1,047	4,666	2,175	-	9,204
248	CIS User Fee	373132	-	N/A	-	-	-	-	-	-
249	Refunds and Reimbursements	374000	-	RevReq	-	-	-	-	-	-
250	Miscellaneous Receipts	374200	3,946	RevReq	564	449	2,001	933	-	3,946
251	Cash Over/Shortage	374207	-	RevReq	-	-	-	-	-	-
252	Asset Forfeiture Revenue	374500	-	RevReq	-	-	-	-	-	-
253	Bad Debt Recovery	374800	-	RevReq	-	-	-	-	-	-
254	Settlement Recovery	374801	-	RevReq	-	-	-	-	-	-
255	Settlement Recovery - SONGS	374802	-	RevReq	-	-	-	-	-	-
256	Liquidated Damages	374810	-	RevReq	-	-	-	-	-	-
257	Operating Transfer from 650 Fund	985650	-	N/A	-	-	-	-	-	-
258	Utilization Charges	6125000	4,708	RevReq	673	535	2,387	1,113	-	4,708
259	**Total Other Non-Operating Revenue:**		**$ 83,680**		**$ 11,968**	**$ 9,515**	**$ 42,423**	**$ 19,774**	**$ -**	**$ 83,680**
260										
261	**Interest income**		240,088	Cust Serv	-	-	240,088	-	-	240,088
262										
263	**Wholesale sales**		-	N/A	-	-	-	-	-	-
264										
265	**Transmission revenue**		-	N/A	-	-	-	-	-	-
266										
267	**Total Other Income**		**$ 3,802,802**		**$ 28,436**	**$ 22,608**	**$ 3,704,775**	**$ 46,982**	**$ -**	**$ 3,802,802**
268										
269										
270	**Total Retail Revenue Requirement**		**$ 11,883,568**		**$ 1,699,625**	**$ 1,351,291**	**$ 6,024,544**	**$ 2,808,108**	**$ -**	**$ 11,883,568**
271	Check		-		14%	11%	51%	24%	0%	
272										
273	Revenue From Current Retail Rates									
274	Residential									
275	Commercial-Flat									
276	Commercial-Demand									
277	Industrial-TOU									
278	City Contract									
279	Other									
280	**Total Revenue From Current Retail Rates**		**$ -**							

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Meter Reading	Customer Accounting	Customer Service	Sales	Blank	Total
281										
282										
283										
284	PLANT IN SERVICE									
285										
286	Gross Plant in Service									
287	**Intangible Plant**									
288	Organization	301	$ -	N/A	-	-	-	-	-	-
289	Franchises and Consents	302	-	N/A	-	-	-	-	-	-
290	Misc. Intangible Plant	303	-	Total Labor	-	-	-	-	-	-
291	Misc. Computer Software	3030	-	N/A	-	-	-	-	-	-
292	**Total Intangible Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
293										
294	**Production Plant**									
295	**Steam Production**									
296	Land and Land Rights	310	$ -	N/A	-	-	-	-	-	-
297	Structures & Improvements	311	-	N/A	-	-	-	-	-	-
298	Boiler Plant Equipment	312	-	N/A	-	-	-	-	-	-
299	Engines and Engine Generators	313	-	N/A	-	-	-	-	-	-
300	Turbo-Generator Units	314	-	N/A	-	-	-	-	-	-
301	Accessory Electric Equipment	315	-	N/A	-	-	-	-	-	-
302	Misc. Power Plant Equipment	316	-	N/A	-	-	-	-	-	-
303	**Total Steam Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
304										
305	**Hydraulic Production**									
306	Land and Land Rights	330	$ -	N/A	-	-	-	-	-	-
307	Structures & Improvements	331	-	N/A	-	-	-	-	-	-
308	Reservoirs, Dams and Water Ways	332	-	N/A	-	-	-	-	-	-
309	Water Wheel, Turbine and Generator	333	-	N/A	-	-	-	-	-	-
310	Accessory Electric Equipment	334	-	N/A	-	-	-	-	-	-
311	Misc. Power Plant Equipment	335	-	N/A	-	-	-	-	-	-
312	Roads, Railroads and Bridges	336	-	N/A	-	-	-	-	-	-
313	**Total Hydraulic Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
314										
315	**Combustion Turbine & Other Production**									
316	Land and Land Rights	340	$ -	N/A	-	-	-	-	-	-
317	Structures & Improvements	341	-	N/A	-	-	-	-	-	-
318	Fuel Holders, Prod & Acc	342	-	N/A	-	-	-	-	-	-
319	Prime Movers	343	-	N/A	-	-	-	-	-	-
320	Generators & Other Production	344	-	N/A	-	-	-	-	-	-
321	Accessory Electric Equipment	345	-	N/A	-	-	-	-	-	-
	Misc. Production Plant	2000	-	N/A	-	-	-	-	-	-
322	**Total Combustion Turbine & Other Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
322										
323	**Total Production Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
324										
325	**Transmission Plant**									
326	Land and Land Rights	350	$ -	N/A	-	-	-	-	-	-
327	Reserved	351	-	N/A	-	-	-	-	-	-
328	Structures & Improvements	352	-	N/A	-	-	-	-	-	-
329	Station Equipment - System	353	-	N/A	-	-	-	-	-	-
330	Towers and Fixtures	354	-	N/A	-	-	-	-	-	-
331	Poles and Fixtures	355	-	N/A	-	-	-	-	-	-
332	Overhead Conductor	356	-	N/A	-	-	-	-	-	-
333	Underground Conductor	357	-	N/A	-	-	-	-	-	-
334	Underground Conduit	358	-	N/A	-	-	-	-	-	-
335	Misc. Transmission Plant	359	-	N/A	-	-	-	-	-	-
336	**Total Transmission Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
337										
338	**Distribution Plant**									
339	Land and Land Rights	360	$ -	N/A	-	-	-	-	-	-
340	Structures & Improvements	361	-	N/A	-	-	-	-	-	-
341	Station Equipment	362	-	N/A	-	-	-	-	-	-
342	Misc. Plant	363	-	N/A	-	-	-	-	-	-
343	Towers and Fixtures	364	-	N/A	-	-	-	-	-	-
344	Overhead Conductor	365	-	N/A	-	-	-	-	-	-
345	Underground Conduit	366	-	N/A	-	-	-	-	-	-
346	Underground Conductor	367	-	N/A	-	-	-	-	-	-
347	Line Transformers	368	-	N/A	-	-	-	-	-	-
348	Services	369	-	N/A	-	-	-	-	-	-
349	Meters	370	-	N/A	-	-	-	-	-	-
350	Inst. on Customer Premises	371	-	N/A	-	-	-	-	-	-
351	Street Light / Signal Systems	373	-	N/A	-	-	-	-	-	-
352	**Total Distribution Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
353										
354	**Subtotal Plant Before General**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
355										

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Meter Reading	Customer Accounting	Customer Service	Sales	Blank	Total
356	**General Plant**									
357	Land and Land Rights	389	$ -	Labor Exc A&G	-	-	-	-	-	-
358	Structures & Improvements	390	-	Labor Exc A&G	-	-	-	-	-	-
359	Structures & Improvements - Other	3900	-	N/A	-	-	-	-	-	-
360	Office Furniture & Equipment	391	-	Labor Exc A&G	-	-	-	-	-	-
361	Info System Computers	3910	-	N/A	-	-	-	-	-	-
362	Transportation Equipment	392	-	Labor Exc A&G	-	-	-	-	-	-
363	Stores Equipment	393	-	Labor Exc A&G	-	-	-	-	-	-
364	Tools, Shop & Garage Equip.	394	-	Labor Exc A&G	-	-	-	-	-	-
365	Laboratory Equipment	395	-	Labor Exc A&G	-	-	-	-	-	-
366	Power Operated Equipment	396	-	Labor Exc A&G	-	-	-	-	-	-
367	Communication Equipment	397	-	Labor Exc A&G	-	-	-	-	-	-
368	Miscellaneous Equipment	398	-	Labor Exc A&G	-	-	-	-	-	-
369	Other Tangible Property	399	-	N/A	-	-	-	-	-	-
370	**Total General Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
371										
372	**Total Gross Plant in Service**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
373	Check		-							
374										
375	Accumulated Depreciation									
376	**Intangible Plant**									
377	Organization	301	$ -	N/A	-	-	-	-	-	-
378	Franchises and Consents	302	-	N/A	-	-	-	-	-	-
379	Misc. Intangible Plant	303	-	Labor Exc A&G	-	-	-	-	-	-
380	Misc. Computer Software	3030	-	N/A	-	-	-	-	-	-
381	**Total Intangible Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
382										
383	**Production Plant**									
384	**Steam Production**									
385	Land and Land Rights	310	$ -	N/A	-	-	-	-	-	-
386	Structures & Improvements	311	-	N/A	-	-	-	-	-	-
387	Boiler Plant Equipment	312	-	N/A	-	-	-	-	-	-
388	Engines and Engine Generators	313	-	N/A	-	-	-	-	-	-
389	Turbo-Generator Units	314	-	N/A	-	-	-	-	-	-
390	Accessory Electric Equipment	315	-	N/A	-	-	-	-	-	-
391	Misc. Power Plant Equipment	316	-	N/A	-	-	-	-	-	-
392	**Total Steam Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
393										
394	**Hydraulic Production**									
395	Land and Land Rights	330	$ -	N/A	-	-	-	-	-	-
396	Structures & Improvements	331	-	N/A	-	-	-	-	-	-
397	Reservoirs, Dams and Water Ways	332	-	N/A	-	-	-	-	-	-
398	Water Wheel, Turbine and Generator	333	-	N/A	-	-	-	-	-	-
399	Accessory Electric Equipment	334	-	N/A	-	-	-	-	-	-
400	Misc. Power Plant Equipment	335	-	N/A	-	-	-	-	-	-
401	Roads, Railroads and Bridges	336	-	N/A	-	-	-	-	-	-
402	**Total Hydraulic Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
403										
404	**Combustion Turbine & Other Production**									
405	Land and Land Rights	340	$ -	N/A	-	-	-	-	-	-
406	Structures & Improvements	341	-	N/A	-	-	-	-	-	-
407	Fuel Holders, Prod & Acc	342	-	N/A	-	-	-	-	-	-
408	Prime Movers	343	-	N/A	-	-	-	-	-	-
409	Generators & Other Production	344	-	N/A	-	-	-	-	-	-
410	Accessory Electric Equipment	345	-	N/A	-	-	-	-	-	-
411	Misc. Production Plant	2000	-	N/A	-	-	-	-	-	-
412	**Total Combustion Turbine & Other Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
413										
414	**Total Production Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
415										
416	**Transmission Plant**									
417	Land and Land Rights	350	$ -	N/A	-	-	-	-	-	-
418	Reserved	351	-	N/A	-	-	-	-	-	-
419	Structures & Improvements	352	-	N/A	-	-	-	-	-	-
420	Station Equipment - System	353	-	N/A	-	-	-	-	-	-
421	Towers and Fixtures	354	-	N/A	-	-	-	-	-	-
422	Poles and Fixtures	355	-	N/A	-	-	-	-	-	-
423	Overhead Conductor	356	-	N/A	-	-	-	-	-	-
424	Underground Conductor	357	-	N/A	-	-	-	-	-	-
425	Underground Conduit	358	-	N/A	-	-	-	-	-	-
426	Misc. Transmission Plant	359	-	N/A	-	-	-	-	-	-
427	**Total Transmission Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
428										
429	**Distribution Plant**									
430	Land and Land Rights	360	$ -	N/A	-	-	-	-	-	-
431	Structures & Improvements	361	-	N/A	-	-	-	-	-	-
432	Station Equipment	362	-	N/A	-	-	-	-	-	-

Customer Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Meter Reading	Customer Accounting	Customer Service	Sales	Blank	Total
433	Misc. Plant	363	-	N/A	-	-	-	-	-	-
434	Towers and Fixtures	364	-	N/A	-	-	-	-	-	-
435	Overhead Conductor	365	-	N/A	-	-	-	-	-	-
436	Underground Conduit	366	-	N/A	-	-	-	-	-	-
437	Underground Conductor	367	-	N/A	-	-	-	-	-	-
438	Line Transformers	368	-	N/A	-	-	-	-	-	-
439	Services	369	-	N/A	-	-	-	-	-	-
440	Meters	370	-	N/A	-	-	-	-	-	-
441	Inst. on Customer Premises	371	-	N/A	-	-	-	-	-	-
442	Street Light / Signal Systems	373	-	N/A	-	-	-	-	-	-
443	**Total Distribution Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
444										
445	**Subtotal Plant Before General**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
446										
447	**General Plant**									
448	Land and Land Rights	389	$ -	N/A	-	-	-	-	-	-
449	Structures & Improvements	390	-	Labor Exc A&G	-	-	-	-	-	-
450	Structures & Improvements - Other	3900	-	N/A	-	-	-	-	-	-
451	Office Furniture & Equipment	391	-	Labor Exc A&G	-	-	-	-	-	-
452	Info System Computers	3910	-	N/A	-	-	-	-	-	-
453	Transportation Equipment	392	-	Labor Exc A&G	-	-	-	-	-	-
454	Stores Equipment	393	-	Labor Exc A&G	-	-	-	-	-	-
455	Tools, Shop & Garage Equip.	394	-	Labor Exc A&G	-	-	-	-	-	-
456	Laboratory Equipment	395	-	Labor Exc A&G	-	-	-	-	-	-
457	Power Operated Equipment	396	-	Labor Exc A&G	-	-	-	-	-	-
458	Communication Equipment	397	-	Labor Exc A&G	-	-	-	-	-	-
459	Miscellaneous Equipment	398	-	Labor Exc A&G	-	-	-	-	-	-
460	Other Tangible Property	399	-	N/A	-	-	-	-	-	-
461	**Total General Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
462										
463	**Total Accumulated Depreciation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
464	Check		-							
465										
466	Net Plant in Service									
467	**Intangible Plant**									
468	Organization	301	$ -		-	-	-	-	-	-
469	Franchises and Consents	302	-		-	-	-	-	-	-
470	Misc. Intangible Plant	303	-		-	-	-	-	-	-
471	Misc. Computer Software	3030	-		-	-	-	-	-	-
472	**Total Intangible Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
473										
474	**Production Plant**									
475	**Steam Production**									
476	Land and Land Rights	310	$ -		-	-	-	-	-	-
477	Structures & Improvements	311	-		-	-	-	-	-	-
478	Boiler Plant Equipment	312	-		-	-	-	-	-	-
479	Engines and Engine Generators	313	-		-	-	-	-	-	-
480	Turbo-Generator Units	314	-		-	-	-	-	-	-
481	Accessory Electric Equipment	315	-		-	-	-	-	-	-
482	Misc. Power Plant Equipment	316	-		-	-	-	-	-	-
483	**Total Steam Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
484										
485	**Hydraulic Production**									
486	Land and Land Rights	330	$ -		-	-	-	-	-	-
487	Structures & Improvements	331	-		-	-	-	-	-	-
488	Reservoirs, Dams and Water Ways	332	-		-	-	-	-	-	-
489	Water Wheel, Turbine and Generator	333	-		-	-	-	-	-	-
490	Accessory Electric Equipment	334	-		-	-	-	-	-	-
491	Misc. Power Plant Equipment	335	-		-	-	-	-	-	-
492	Roads, Railroads and Bridges	336	-		-	-	-	-	-	-
493	**Total Hydraulic Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
494										
495	**Combustion Turbine & Other Production**									
496	Land and Land Rights	340	$ -		-	-	-	-	-	-
497	Structures & Improvements	341	-		-	-	-	-	-	-
498	Fuel Holders, Prod & Acc	342	-		-	-	-	-	-	-
499	Prime Movers	343	-		-	-	-	-	-	-
500	Generators & Other Production	344	-		-	-	-	-	-	-
501	Accessory Electric Equipment	345	-		-	-	-	-	-	-
502	Misc. Production Plant	2000	-		-	-	-	-	-	-
503	**Total Combustion Turbine & Other Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
504										
505	**Total Production Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
506										
507	**Transmission Plant**									
508	Land and Land Rights	350	$ -		-	-	-	-	-	-
509	Reserved	351	-		-	-	-	-	-	-

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Meter Reading	Customer Accounting	Customer Service	Sales	Blank	Total
510	Structures & Improvements	352	-		-	-	-	-	-	-
511	Station Equipment - System	353	-		-	-	-	-	-	-
512	Towers and Fixtures	354	-		-	-	-	-	-	-
513	Poles and Fixtures	355	-		-	-	-	-	-	-
514	Overhead Conductor	356	-		-	-	-	-	-	-
515	Underground Conductor	357	-		-	-	-	-	-	-
516	Underground Conduit	358	-		-	-	-	-	-	-
517	Misc. Transmission Plant	359	-		-	-	-	-	-	-
518	**Total Transmission Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
519										
520	**Distribution Plant**									
521	Land and Land Rights	360	$ -		-	-	-	-	-	-
522	Structures & Improvements	361	-		-	-	-	-	-	-
523	Station Equipment	362	-		-	-	-	-	-	-
524	Misc. Plant	363	-		-	-	-	-	-	-
525	Towers and Fixtures	364	-		-	-	-	-	-	-
526	Overhead Conductor	365	-		-	-	-	-	-	-
527	Underground Conduit	366	-		-	-	-	-	-	-
528	Underground Conductor	367	-		-	-	-	-	-	-
529	Line Transformers	368	-		-	-	-	-	-	-
530	Services	369	-		-	-	-	-	-	-
531	Meters	370	-		-	-	-	-	-	-
532	Inst. on Customer Premises	371	-		-	-	-	-	-	-
533	Street Light / Signal Systems	373	-		-	-	-	-	-	-
534	**Total Distribution Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
535										
536	**Subtotal Plant Before General**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
537										
538	**General Plant**									
539	Land and Land Rights	389	$ -		-	-	-	-	-	-
540	Structures & Improvements	390	-		-	-	-	-	-	-
541	Structures & Improvements - Other	3900	-		-	-	-	-	-	-
542	Office Furniture & Equipment	391	-		-	-	-	-	-	-
543	Info System Computers	3910	-		-	-	-	-	-	-
544	Transportation Equipment	392	-		-	-	-	-	-	-
545	Stores Equipment	393	-		-	-	-	-	-	-
546	Tools, Shop & Garage Equip.	394	-		-	-	-	-	-	-
547	Laboratory Equipment	395	-		-	-	-	-	-	-
548	Power Operated Equipment	396	-		-	-	-	-	-	-
549	Communication Equipment	397	-		-	-	-	-	-	-
550	Miscellaneous Equipment	398	-		-	-	-	-	-	-
551	Other Tangible Property	399	-		-	-	-	-	-	-
552	**Total General Plant**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
553										
554	**Total Net Plant in Service**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
555	Check		-							
556										
557										
558	LABOR									
559										
560	Production Labor									
561	**Steam Production Operation**									
562	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-
563	Fuel (Transportation & Handling)		-	N/A	-	-	-	-	-	-
564	Steam Expense		-	N/A	-	-	-	-	-	-
565	Electric Expense		-	N/A	-	-	-	-	-	-
566	Miscellaneous		-	N/A	-	-	-	-	-	-
567	Rent		-	N/A	-	-	-	-	-	-
568	**Total Steam Production Operation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
569										
570	**Steam Production Maintenance**									
571	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-
572	Structures		-	N/A	-	-	-	-	-	-
573	Boilers		-	N/A	-	-	-	-	-	-
574	Electric Plant		-	N/A	-	-	-	-	-	-
575	Miscellaneous Labor		-	N/A	-	-	-	-	-	-
576	**Total Steam Production Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
577										
578	**Hydro Production Operation**									
579	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-
580	Water for Power		-	N/A	-	-	-	-	-	-
581	Hydraulic Expense		-	N/A	-	-	-	-	-	-
582	Electric Expense		-	N/A	-	-	-	-	-	-
583	Miscellaneous		-	N/A	-	-	-	-	-	-
584	Rent		-	N/A	-	-	-	-	-	-
585	**Total Hydro Production Operation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -

Customer Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Meter Reading	Customer Accounting	Customer Service	Sales	Blank	Total
586										
587	**Hydro Production Maintenance**									
588	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-
589	Structures		-	N/A	-	-	-	-	-	-
590	Reservoirs & Dams		-	N/A	-	-	-	-	-	-
591	Electric Plant		-	N/A	-	-	-	-	-	-
592	Miscellaneous Plant		-	N/A	-	-	-	-	-	-
593	**Total Hydro Production Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
594										
595	**Combined Cycle Operation**									
596	Labor		$ -	N/A	-	-	-	-	-	-
597	Fuel Handling		-	N/A	-	-	-	-	-	-
598	Generation Expense		-	N/A	-	-	-	-	-	-
599	Miscellaneous		-	N/A	-	-	-	-	-	-
600	**Total Combined Cycle Operation**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
601										
602	**Combined Cycle Maintenance**									
603	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-
604	Structures		-	N/A	-	-	-	-	-	-
605	Electric Plant		-	N/A	-	-	-	-	-	-
606	Miscellaneous Plant		-	N/A	-	-	-	-	-	-
607	**Total Combined Cycle Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
608										
609	**Other Production**									
610	RERC/Acorn Gen. Plant	612013	$ -	N/A	-	-	-	-	-	-
611	Clearwater Generating Plant	612014	-	N/A	-	-	-	-	-	-
612	PU Elec Power Supply Operations	612000	-	N/A	-	-	-	-	-	-
613	**Total Other Production**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
614										
615	**Total Production Labor**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
616										
617	Transmission Labor									
618	**Transmission Operations**									
619	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-
620	Load Dispatch		-	N/A	-	-	-	-	-	-
621	Station Equipment		-	N/A	-	-	-	-	-	-
622	Overhead Lines		-	N/A	-	-	-	-	-	-
623	Underground Lines		-	N/A	-	-	-	-	-	-
624	General Labor		-	N/A	-	-	-	-	-	-
625	Miscellaneous		-	N/A	-	-	-	-	-	-
626	Rents		-	N/A	-	-	-	-	-	-
627	**Total Transmission Operations**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
628										
629	**Transmission Maintenance**									
630	Supervision & Engineering		$ -	N/A	-	-	-	-	-	-
631	Structures		-	N/A	-	-	-	-	-	-
632	Station Equipment		-	N/A	-	-	-	-	-	-
633	Overhead Lines		-	N/A	-	-	-	-	-	-
634	Underground Lines		-	N/A	-	-	-	-	-	-
635	Miscellaneous		-	N/A	-	-	-	-	-	-
636	**Total Transmission Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
637										
638	**Wheeling**									
639	Wheeling		$ -	N/A	-	-	-	-	-	-
640	Wheeling		-	N/A	-	-	-	-	-	-
641	**Total Wheeling**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
642										
643	**Total Transmission Labor**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
644										
645	Distribution Labor									
646	**Distribution Operations**									
647	Electric Operations	610000	$ -	N/A	-	-	-	-	-	-
648	PU Electric Field Operations	610500	-	N/A	-	-	-	-	-	-
649	Energy Deliv Engineering	611000	-	N/A	-	-	-	-	-	-
650	Customer Engineering-GIS	611500	-	N/A	-	-	-	-	-	-
651	Underground Lines		-	N/A	-	-	-	-	-	-
652	Street Lighting		-	N/A	-	-	-	-	-	-
653	Metering		-	N/A	-	-	-	-	-	-
654	Customer Installations		-	N/A	-	-	-	-	-	-
655	Miscellaneous		-	N/A	-	-	-	-	-	-
656	Rents		-	N/A	-	-	-	-	-	-
657	**Total Distribution Operations**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
658										
659	**Distribution Maintenance**									
660	Supervision		$ -	N/A	-	-	-	-	-	-
661	Structures		-	N/A	-	-	-	-	-	-
662	Station Equipment		-	N/A	-	-	-	-	-	-

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Meter Reading	Customer Accounting	Customer Service	Sales	Blank	Total
663	Overhead Lines		-	N/A	-	-	-	-	-	-
664	Underground Lines		-	N/A	-	-	-	-	-	-
665	Transformers		-	N/A	-	-	-	-	-	-
666	Street Lighting		-	N/A	-	-	-	-	-	-
667	Metering		-	N/A	-	-	-	-	-	-
668	Miscellaneous		-	N/A	-	-	-	-	-	-
669	**Total Distribution Maintenance**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
670										
671	**Total Distribution Labor**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
672										
673	Customer Labor									
674	**Customer Accounting Expense**									
675	Pub Util Business Support	600400	$ 730,534	Cust Serv	-	-	730,534	-	-	730,534
676	Pub Util Admin-Utility Billing	600500	823,026	Billing Exp	-	823,026	-	-	-	823,026
677	Pub Util Admin-Customer Service	601500	4,243,613	Cust Serv	-	-	4,243,613	-	-	4,243,613
678	Pub Util Adm-Marketing Service	602000	2,066,236	Cust Serv	-	-	2,066,236	-	-	2,066,236
679	Miscellaneous		-	N/A	-	-	-	-	-	-
680	**Total Customer Accounting Expense**		**$ 7,863,409**		**$ -**	**$ 823,026**	**$ 7,040,383**	**$ -**	**$ -**	**$ 7,863,409**
681										
682	**Customer Service Expense**									
683	Customer Engineering-GIS		$ -	Cust Serv	-	-	-	-	-	-
684	Customer Assistance		-	Cust Serv	-	-	-	-	-	-
685	Advertisement / Marketing		-	Sales	-	-	-	-	-	-
686	Miscellaneous		-	N/A	-	-	-	-	-	-
687	**Total Customer Service Expense**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
688										
689	**Sales Expense**									
690	Sales Expense		$ -	N/A	-	-	-	-	-	-
691	Demonstrations & Selling		-	N/A	-	-	-	-	-	-
692	Miscellaneous Sales Expense		-	N/A	-	-	-	-	-	-
693	**Total Sales Expense**		$ -		$ -	$ -	$ -	$ -	$ -	$ -
694										
695	**Total Customer Labor**		**$ 7,863,409**		**$ -**	**$ 823,026**	**$ 7,040,383**	**$ -**	**$ -**	**$ 7,863,409**
696										
697	**Total Labor Expense excluding A&G**		**$ 7,863,409**		**$ -**	**$ 823,026**	**$ 7,040,383**	**$ -**	**$ -**	**$ 7,863,409**
698										
699	Administrative & General Labor									
700	Pub Util Admin-Mgmt Service	600000	$ -	N/A	-	-	-	-	-	-
701	Pub Util Admin-Field Services	601000	3,127,327	RevReq	447,280	355,611	1,585,443	738,993	-	3,127,327
702	Legislative & Regulator Risk	602500	-	N/A	-	-	-	-	-	-
703	Outside Services		-	N/A	-	-	-	-	-	-
704	Outside Services		-	N/A	-	-	-	-	-	-
705	Property Insurance		-	N/A	-	-	-	-	-	-
706	Injuries and Damages		-	N/A	-	-	-	-	-	-
707	Electric Utility Communication Labor		-	N/A	-	-	-	-	-	-
708	Miscellaneous		-	N/A	-	-	-	-	-	-
709	Rents		-	N/A	-	-	-	-	-	-
710	Transportation Pool General Labor		-	N/A	-	-	-	-	-	-
711	Maintenance of General Plant		-	N/A	-	-	-	-	-	-
712	N/A		-	N/A	-	-	-	-	-	-
713	**Total Administrative & General Labor**		**$ 3,127,327**		**$ 447,280**	**$ 355,611**	**$ 1,585,443**	**$ 738,993**	**$ -**	**$ 3,127,327**
714										
715	**Total Labor Expense**		**$ 10,990,736**		**$ 447,280**	**$ 1,178,637**	**$ 8,625,826**	**$ 738,993**	**$ -**	**$ 10,990,736**
716	Check		-							
717										
718	**Allocation Factors**									
719	Meter Reading			Mtr Read Exp	100%	0%	0%	0%	0%	100%
720					1	-	-	-	-	1
721	Billing & Cashiering			Billing Exp	0%	100%	0%	0%	0%	100%
722					-	1	-	-	-	1
723	Labor w/o A&G			Labor Exc A&G	0%	10%	90%	0%	0%	100%
724					-	823,026	7,040,383	-	-	7,863,409
725	Revenue Related			Revenue	14%	11%	51%	24%	0%	100%
726					1,699,625	1,351,291	6,024,544	2,808,108	-	11,883,568
727	Plant In Service - General			Net Plant	0%	0%	0%	0%	0%	0%
728					-	-	-	-	-	-
729	Plant In Service - Total			Gross Plant	0%	0%	0%	0%	0%	0%
730					-	-	-	-	-	-
731	Customer Accounting - Supervision			Cust Acctng - Super	0%	100%	0%	0%	0%	100%
732					-	1	-	-	-	1
733	Not Applicable			N/A	0%	0%	0%	0%	0%	0%
734					-	-	-	-	-	-
735	Customer Accounting Supervision			Cust Acct Supervision	0%	100%	0%	0%	0%	100%
736					-	1	-	-	-	1
737	Revenue Requirement			RevReq	14%	11%	51%	24%	0%	100%
738					1,699,625	1,351,291	6,024,544	2,808,108	-	11,883,568
739	Sales			Sales	0%	0%	0%	100%	0%	100%

Customer Function

Line No.	Item	Account/ID	Adjusted Test Year	Allocation Factor	Meter Reading	Customer Accounting	Customer Service	Sales	Blank	Total
740					-	-	-	1	-	1
741	Capital			CIP	33%	33%	33%	0%	0%	100%
742					141,451	141,451	141,451	-	-	424,352
743	MR-CS-Sales			MR-CS-Sales	33%	0%	33%	33%	0%	100%
744					1	-	1	1	-	3
745	EQUAL (Temp)			EQUAL (Temp)	25%	25%	25%	25%	0%	100%
746					1	1	1	1	-	4
747	Total Labor			Total Labor	4%	11%	78%	7%	0%	100%
748					447,280	1,178,637	8,625,826	738,993	-	10,990,736
741	Customer Service			Cust Serv	0%	0%	100%	0%	0%	100%
749					-	-	1	-	-	1
750	Blank			MR-CA-CS	33%	33%	33%	0%	0%	100%
751					1	1	1	-	-	3
752	Blank			Blank	0%	0%	0%	0%	0%	0%
753					-	-	-	-	-	-
754	Blank			Blank	0%	0%	0%	0%	0%	0%
755					-	-	-	-	-	-

Line No.	Item		Test Year	Factor		Residential		Commercial Flat		Commercial Demand		Industrial TOU		City Contract		Street Lights Cust. Owned
1	**Class Cost of Service**															
2	**Production**															
3	Demand Related															
4	Production Demand	$	78,610,556	4 CP	$	35,250,996	$	9,406,971	$	5,287,900	$	26,531,716	$	2,071,802	$	-
5	Blank		-	N/A		-		-		-		-		-		-
6	Energy Related															
7	Fuel & Energy		156,155,952	DCR w Losses		49,942,501		20,500,743		11,767,570		68,834,117		3,505,956		22,687
8	Blank		-	N/A		-		-		-		-		-		-
9	Direct Assignment															
10	Direct Assign A		-	N/A		-		-		-		-		-		-
11	Blank		-	N/A		-		-		-		-		-		-
12	**Total Production**	**$**	**234,766,507**		**$**	**85,193,497**	**$**	**29,907,714**	**$**	**17,055,471**	**$**	**95,365,833**	**$**	**5,577,757**	**$**	**22,687**
13	Check		-													
14	**Transmission**															
15	Demand Related															
16	Transmission Demand	$	36,524,410	4 NCP	$	14,621,397	$	4,877,586	$	2,591,666	$	13,056,220	$	990,636	$	3,911
17	Blank		-	N/A		-		-		-		-		-		-
18	Energy Related															
19	Transmission Energy		(10,241,222)	DCR w Losses		(3,275,394)		(1,344,506)		(771,756)		(4,514,368)		(229,932)		(1,488)
20	Blank		-	N/A		-		-		-		-		-		-
21	Direct Assignment															
22	Direct Assign A		-	N/A		-		-		-		-		-		-
23	Blank		-	N/A		-		-		-		-		-		-
24	**Total Transmission**	**$**	**26,283,187**		**$**	**11,346,003**	**$**	**3,533,080**	**$**	**1,819,910**	**$**	**8,541,852**	**$**	**760,704**	**$**	**2,423**
25	Check		-													
26	**Distribution**															
27	Demand Related															
28	Distribution Demand	$	49,904,727	4 NCP	$	19,977,786	$	6,664,436	$	3,541,095	$	17,839,224	$	1,353,545	$	5,343
29	Substations		10,464,961	4 NCP		4,189,318		1,397,524		742,563		3,740,864		283,837		1,120
	Contribution from Hi Voltage Discount			N/A		363,803		121,362		64,485		(583,925)		24,649		97
30	Customer Related															
31	Distribution Customer		10,595,196	W Cust - Cust Acct - No L		6,918,618		2,264,609		296,230		682,480		432,486		-
32	Blank		-	N/A		-		-		-		-		-		-
33	Direct Assignment															
34	Lighting		2,386,505	Lighting - kWh Sales		-		-		-		-		-		34,963
35	Blank		-	N/A		-		-		-		-		-		-
36	**Total Distribution**	**$**	**73,351,390**		**$**	**31,449,525**	**$**	**10,447,932**	**$**	**4,644,373**	**$**	**21,678,642**	**$**	**2,094,516**	**$**	**41,524**
37	Check		-													
38	**Customer**															
39	Meter Reading	$	1,699,625	No. Cust Mo - Ex SL	$	1,508,620	$	164,601	$	12,919	$	7,832	$	4,963	$	-
40	Customer Accounting		1,351,291	W Cust Mo -Exl Light		882,387		288,824		37,781		87,042		55,158		-
41	Customer Service		6,024,544	W Cust Mo -Exl Light		3,934,002		1,287,682		168,440		388,066		245,916		-
42	Sales		2,808,108	No. Cust Mo - Ex SL		2,492,531		271,953		21,344		12,941		8,200		-
43	Blank		-	N/A		-		-		-		-		-		-
44	**Total Customer**	**$**	**11,883,568**		**$**	**8,817,540**	**$**	**2,013,059**	**$**	**240,483**	**$**	**495,881**	**$**	**314,238**	**$**	**-**
45	Check		-													
46	**Direct Assignments Other**															
47	General Government Charges		-	12 NCP (excluding city)		-		-		-		-		-		-

Line No.	Item	Test Year	Factor	Residential	Commercial Flat	Commercial Demand	Industrial TOU	City Contract	Street Lights Cust. Owned
48	Direct Assigned City Contract	(740,000)	City Contract	-	-	-	-	(740,000)	-
49	Direct Assigned Misc Income (Contract Customers)	$ -	Industrial TOU	$ -	$ -	$ -	$ -	$ -	$ -
50	**Total Direct Assignments Other**	**$ (740,000)**		**$ -**	**$ -**	**$ -**	**$ -**	**$ (740,000)**	**$ -**
51									
52	**Total Cost of Service**	**$ 345,544,652**		**$ 136,806,565**	**$ 45,901,785**	**$ 23,760,237**	**$ 126,082,208**	**$ 8,007,215**	**$ 66,633**
53	**Average COS ($/kWh)**	**$ 0.1566**		**$ 0.1965**	**$ 0.1606**	**$ 0.1449**	**$ 0.1302**	**$ 0.1157**	**$ 0.2107**
54	Check	-							
55	**Rate Revenue**								
56	Base Rate Revenue (excluding Reliability Revenue)	$ 283,916,246		$ 100,213,791	$ 43,070,119	$ 24,025,603	$ 105,224,294	$ 6,624,755	$ 37,923
57	Reliability Revenue	$ 25,331,319		$ 13,342,197	$ 4,082,803	$ 853,830	$ 6,470,200	$ 547,489	$ -
58	**Total Rate Revenue**	**$ 309,247,565**		**$ 113,555,988**	**$ 47,152,922**	**$ 24,879,433**	**$ 111,694,494**	**$ 7,172,245**	**$ 37,923**
59	Check	-		-	-	-	-	-	-
60									
61	**Rate Change to Meet COS - $ Increase / (Decrease)**	**$ 36,297,087**		**$ 23,250,577**	**$ (1,251,137)**	**$ (1,119,196)**	**$ 14,387,714**	**$ 834,971**	**$ 28,711**
62									
63									
64	**Cost Classification Unit Summary**		Units						
65	**Production**								
66	Demand Related	10.25	kW (Sum of Max D)	9.12	10.06	10.19	12.58	11.68	-
67	Energy Related	0.0708	kWh	0.0717	0.0717	0.0717	0.0711	0.0507	0.0717
68	Direct Assignment	(0.0003)	kWh	-	-	-	-	(0.0107)	-
69	**Transmission**								
70	Demand Related	4.76	kW (Sum of Max D)	3.7828	5.2145	4.9924	6.1888	5.5845	6.1184
71	Energy Related	(0.0046)	kWh	(0.0047)	(0.0047)	(0.0047)	(0.0047)	(0.0033)	(0.0047)
72	Direct Assignment	-	kW	-	-	-	-	-	-
73	**Distribution**						10.229		
74	Demand Related	7.88	kW (Sum of Max D)	6.35	8.75	8.38	9.95	9.37	10.27
	Demand Hi Voltage						8.8071		
	Demand Low Voltage						10.1064		
75	Customer Related	6.20	Meters	5.85	17.56	29.27	111.21	111.21	-
76	Direct Assignment	1.40	Meters	-	-	-	-	-	8.01
77	**Customer**								
78	Customer Related	6.95	Meters	7.46	15.61	23.76	80.80	80.80	-
79	**Total System**								
80	Demand Related	22.89	kW (Sum of Max D)	19.25	24.02	23.55	28.72	26.63	16.38
81	Production & Transmission Demand Related*		kW (Sum of Max D)			15.18	18.77		
82	Energy Related								
83	Energy Only	0.0658	kWh	0.06704	0.06704	0.06704	0.06640	0.03664	0.06704
	Energy Hi Voltage								
	Energy Low Voltage								
84	Combined Energy and Demand	0.1454	kWh	0.17392	0.14566	0.14158	0.12895	0.11558	0.10015
85	Production and Trans Combined Energy and Demand*		kWh	0.13868	0.11703				
86	Customer Related	14.55	Meters	13.31	33.17	53.02	192.01	192.01	8.01
87	Check	-		-	-	-	-	-	-
88									
89	**Allocation Factors**								
90	Demand (1 CP)		1 CP	45%	12%	7%	33%	2%	0%

Line No.	Item	Test Year	Factor	Residential	Commercial Flat	Commercial Demand	Industrial TOU	City Contract	Street Lights Cust. Owned
91				208	56	31	152	11	0
92	Demand (4 CP)		4 CP	45%	12%	7%	34%	3%	0%
93				757	202	114	570	44	-
94									
95									
96	12 NCP- High Voltage		12 NCP- High Voltage	36%	13%	7%	39%	3%	0%
97				1,790	668	370	1,932	136	1
98	Demand (12 CP)		12 CP	40%	12%	7%	37%	3%	0%
99				1,659	511	291	1,523	110	0
100	Demand (1 NCP)		1 NCP	41%	13%	7%	35%	3%	0%
101				222	71	38	191	14	0
102	12 NCP (excluding city)		12 NCP (excluding city)	37%	14%	8%	40%	0%	0%
103				1,790	668	370	1,937		1
104	4 NCP		4 NCP	40%	13%	7%	36%	3%	0%
105				802	268	142	716	54	0
106									
107									
108	Sum of Max Demands		Sum of Max Demands	50%	12%	7%	28%	2%	0%
109				3,865	935	519	2,110	177	1
110	Demand (12 NCP)		12 NCP	36%	13%	7%	39%	3%	0%
111				1,790	668	370	1,937	136	1
112									
113									
114									
115									
116	City Contract		City Contract	0%	0%	0%	0%	100%	0%
117				-	-	-	-	1.00	-
118	Ralph's Credit		Ralph's Credit	0%	0%	0%	0%	0%	0%
119				-	-	-	-	-	-
120	kWh Sales - w/Losses * DCR		DCR w Losses	31.98%	13.13%	7.54%	44.08%	2.25%	0.01%
121				45,381,500	18,628,512	10,692,896	62,547,837	3,185,774	20,615
122	kWh Sales		kWh Sales	31.55%	12.95%	7.44%	43.91%	3.14%	0.01%
123				696,137,017	285,755,139	164,025,450	968,600,635	69,219,011	316,226
124	Generation Cost - Dedicated City Resources		Gen Cost - DCR	31.85%	13.07%	7.50%	44.31%	2.24%	0.01%
125				42,812,735.56	17,574,068	10,087,638	59,569,369	3,005,447.20	19,448.04
126	No. Cust Mo		No. Cust Mo	69%	8%	1%	0%	0%	0%
127				1,182,059	128,971	10,122	6,137	3,889	4,367
128	No. Cust Mo - Ex SL		No. Cust Mo - Ex SL	89%	10%	1%	0%	0%	0%
129				1,182,059	128,971	10,122	6,137	3,889	
130	Avg Cust Mo - Incrmtal Light		Avg Cust Mo - Incrmtal Ligh	69%	8%	1%	0%	0%	0%
131				98,505	10,748	844	511	324	364
132	W Cust Mo -Exl Light		W Cust Mo -Exl Light	65%	21%	3%	6%	4%	0%
133				1,182,059	386,913	50,611	116,603	73,891	-
134	Weighted Customers		Weighted Customers	62%	20%	3%	6%	4%	0%
135				1,182,059	386,913	50,611	116,603	73,891	1,092
136	City SL		City SL	0%	0%	0%	0%	0%	50%
137				-	-	-	-	-	1
138	Lighting (Street and Traffic)		Lighting - kWh Sales	0%	0%	0%	0%	0%	1.47%

Line No.	Item	Test Year	Factor	Residential	Commercial Flat	Commercial Demand	Industrial TOU	City Contract	Street Lights Cust. Owned
139				-	-	-	-	-	316,226
140	N/A		N/A	0%	0%	0%	0%	0%	0%
141				-	-	-	-	-	-
142	Cust Accounting - Cust Weighting		W Cust - Cust Acct - No L	65%	21%	3%	6%	4%	0%
143				1,182,059	386,913	50,611	116,603	73,891	-
144	Revenue Req		Revenue Req	40%	13%	7%	36%	2%	0%
145				136,806,565	45,901,785	23,760,237	126,082,208	8,007,215	66,633
146	Industrial TOU		Industrial TOU	0%	0%	0%	100%	0%	0%
147				-	-	-	1	-	-
148									
149									
150	4 NCP (High Voltage)		4 NCP (High Voltage)	40%	13%	7%	36%	3%	0%
151				802	268	142	714	54	0
152									
153									
154									
155									
156									
157									

Line No.	Item	Street Lights Dept. Owned	Traffic Signals	Ag Pumping	Misc. Lighting	Total
1	**Class Cost of Service**					
2	**Production**					
3	Demand Related					
4	Production Demand	$ -	$ 27,057	$ 26,431	$ 7,682	$ 78,610,556
5	Blank	-	-	-	-	-
6	Energy Related					
7	Fuel & Energy	1,423,328	91,389	56,496	11,164	156,155,952
8	Blank	-	-	-	-	-
9	Direct Assignment					
10	Direct Assign A	-	-	-	-	-
11	Blank	-	-	-	-	-
12	**Total Production**	**$ 1,423,328**	**$ 118,446**	**$ 82,927**	**$ 18,847**	**$ 234,766,507**
13	Check					
14	**Transmission**					
15	Demand Related					
16	Transmission Demand	$ 334,447	$ 31,779	$ 12,255	$ 4,512	$ 36,524,410
17	Blank	-	-	-	-	-
18	Energy Related					
19	Transmission Energy	(93,347)	(5,994)	(3,705)	(732)	(10,241,222)
20	Blank	-	-	-	-	-
21	Direct Assignment					
22	Direct Assign A	-	-	-	-	-
23	Blank	-	-	-	-	-
24	**Total Transmission**	**$ 241,101**	**$ 25,785**	**$ 8,550**	**$ 3,780**	**$ 26,283,187**
25	Check					
26	**Distribution**					
27	Demand Related					
28	Distribution Demand	$ 456,969	$ 43,421	$ 16,744	$ 6,165	$ 49,904,727
29	Substations	95,826	9,105	3,511	1,293	10,464,961
	Contribution from Hi Voltage Discount	8,322	791	305	112	(0)
30	Customer Related					
31	Distribution Customer	-	-	773	-	10,595,196
32	Blank	-	-	-	-	-
33	Direct Assignment					
34	Lighting	2,193,497	140,840	-	17,205	2,386,505
35	Blank	-	-	-	-	-
36	**Total Distribution**	**$ 2,754,613**	**$ 194,157**	**$ 21,333**	**$ 24,776**	**$ 73,351,390**
37	Check					
38	**Customer**					
39	Meter Reading	$ -	$ -	$ 674	$ 15	$ 1,699,625
40	Customer Accounting	-	-	99	-	1,351,291
41	Customer Service	-	-	439	-	6,024,544
42	Sales	-	-	1,113	25	2,808,108
43	Blank	-	-	-	-	-
44	**Total Customer**	**$ -**	**$ -**	**$ 2,325**	**$ 41**	**$ 11,883,568**
45	Check					
46	**Direct Assignments Other**					
47	General Government Charges	-	-	-	-	-

Line No.	Item	Street Lights Dept. Owned	Traffic Signals	Ag Pumping	Misc. Lighting	Total
48	Direct Assigned City Contract	-	-	-	-	(740,000)
49	Direct Assigned Misc Income (Contract Customers)	$ -	$ -	$ -	$ -	$ -
50	**Total Direct Assignments Other**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (740,000)**
51						
52	**Total Cost of Service**	**$ 4,419,042**	**$ 338,388**	**$ 115,135**	**$ 47,443**	**$ 345,544,652**
53	**Average COS ($/kWh)**	**$ 0.2227**	**$ 0.2656**	**$ 0.1462**	**$ 0.3049**	**$ 0.1566**
54	Check					
55	**Rate Revenue**					
56	Base Rate Revenue (excluding Reliability Revenue)	$ 4,488,768	$ 120,588	$ 89,381	$ 21,024	$ 283,916,246
57	Reliability Revenue	$ -	$ -	$ 34,800	$ -	$ 25,331,319
58	**Total Rate Revenue**	**$ 4,488,768**	**$ 120,588**	**$ 124,181**	**$ 21,024**	**$ 309,247,565**
59	Check	-	-	-	-	
60						
61	**Rate Change to Meet COS - $ Increase / (Decrease)**	**$ (69,726)**	**$ 217,800**	**$ (9,046)**	**$ 26,419**	**$ 36,297,087**
62						
63						
64	**Cost Classification Unit Summary**					Check
65	**Production**					
66	Demand Related	-	15.52	18.74	15.52	-
67	Energy Related	0.0717	0.0717	0.0717	0.0717	-
68	Direct Assignment	-	-	-	-	-
69	**Transmission**					
70	Demand Related	6.1184	18.2323	8.6897	9.1171	-
71	Energy Related	(0.0047)	(0.0047)	(0.0047)	(0.0047)	-
72	Direct Assignment	-	-	-	-	-
73	**Distribution**					
74	Demand Related	10.27	30.59	14.58	15.30	-
	Demand Hi Voltage					
	Demand Low Voltage					
75	Customer Related	-	-	1.46	-	-
76	Direct Assignment	5.87	11,736.69	-	1,433.77	-
77	**Customer**					
78	Customer Related	-	-	4.40	3.38	-
79	**Total System**					-
80	Demand Related	16.38	64.34	42.01	39.94	-
81	Production & Transmission Demand Related*					
82	Energy Related					
83	Energy Only	0.06704	0.06704	0.06704	0.06704	-
	Energy Hi Voltage					
	Energy Low Voltage					
84	Combined Energy and Demand	0.11218	0.15508	0.14227	0.19405	-
85	Production and Trans Combined Energy and Demand*					
86	Customer Related	5.87	11,736.69	5.87	1,437.16	-
87	Check	-	-	-	-	-
88						
89	**Allocation Factors**					
90	Demand (1 CP)	1%	0%	0%	0%	100%

Line No.	Item	Street Lights Dept. Owned	Traffic Signals	Ag Pumping	Misc. Lighting	Total
91		5	0	0	0	462
92	Demand (4 CP)	0%	0%	0%	0%	100%
93		-	1	1	0	1,688
94						
95						
96	12 NCP- High Voltage	1%	0%	0%	0%	100%
97		55	2	1	0	4,956
98	Demand (12 CP)	0%	0%	0%	0%	100%
99		18	2	1	0	4,115
100	Demand (1 NCP)	1%	0%	0%	0%	100%
101		5	0	0	0	541
102	12 NCP (excluding city)	1%	0%	0%	0%	100%
103		55	2	1	0	4,824
104	4 NCP	1%	0%	0%	0%	100%
105		18	2	1	0	2,003
106						
107						
108	Sum of Max Demands	1%	0%	0%	0%	100%
109		55	2	1	0	7,666
110	Demand (12 NCP)	1%	0%	0%	0%	100%
111		55	2	1	0	4,961
112						
113						
114						0%
115						-
116	City Contract	0%	0%	0%	0%	100%
117		-	-	-	-	1
118	Ralph's Credit	0%	0%	0%	0%	0%
119		-	-	-	-	-
120	kWh Sales - w/Losses * DCR	0.91%	0.06%	0.04%	0.01%	100%
121		1,293,343	83,043	51,337	10,145	141,895,001
122	kWh Sales	0.90%	0.06%	0.04%	0.01%	100%
123		19,839,445	1,273,854	787,485	155,616	2,206,109,878
124	Generation Cost - Dedicated City Resources	0.91%	0.06%	0.04%	0.01%	100%
125		1,220,134.66	78,342.57	48,431	9,570	134,425,184
126	No. Cust Mo	22%	0%	0%	0%	100%
127		373,436	12	528	12	1,709,532
128	No. Cust Mo - Ex SL	0%	0%	0%	0%	100%
129				528	12	1,331,718
130	Avg Cust Mo - Incrmtal Light	22%	0%	0%	0%	100%
131		31,120	1	44	1	142,461
132	W Cust Mo -Exl Light	0%	0%	0%	0%	100%
133		-	-	132	-	1,810,209
134	Weighted Customers	5%	0%	0%	0%	100%
135		93,359	3	132	3	1,904,665
136	City SL	50%	0%	0%	0%	100%
137		1	-	-	-	2
138	Lighting (Street and Traffic)	91.9%	5.90%	0%	0.7%	100%

Line No.	Item	Street Lights Dept. Owned	Traffic Signals	Ag Pumping	Misc. Lighting	Total
139		19,839,445	1,273,854	-	155,616	21,585,141
140	N/A	0%	0%	0%	0%	0%
141		-	-	-	-	-
142	Cust Accounting - Cust Weighting	0%	0%	0%	0%	100%
143		-	-	132	-	1,810,209
144	Revenue Req	1%	0%	0%	0%	100%
145		4,419,042	338,388	115,135	47,443	345,544,652
146	Industrial TOU	0%	0%	0%	0%	100%
147		-	-	-	-	1
148						
149						
150	4 NCP (High Voltage)	1%	0%	0%	0%	100%
151		18	2	1	0	2,002
152						
153						
154						
155						
156						
157						

Operating Expense

Line No.	Acct	Acct Desc[1]	Projected FY 2017/18	Projected FY 2018/19	Projected FY 2019/20	Projected FY 2020/21	Projected FY 2021/22	TY 2018-2022	TY Adjustment
		Escalation Factors ->	4.23%	7.17%	7.35%	7.95%	2.89%		
3	0500	Operation Supervision and Engineering	-	-	-	-	-	-	-
8	0517	Operation Supervision and Engineering	-	-	-	-	-	-	-
9	0518	Nuclear Fuel Expense (SONGS)	-	-	-	-	-	-	-
10	0523	Electric Exp - Turbine Generators	-	-	-	-	-	-	-
11	0524	Miscellaneous Power Expenses- SONGS OP EXP-FIXED	2,050,000	2,050,000	2,050,000	2,050,000	2,050,000	2,050,000	1,252,462
16	0528	Maintenance Supervision and Engineering	-	-	-	-	-	-	-
17	0530	532 Maintenance of Misc. Nuclear Plant -SONGS MAINT EXP	800,000	800,000	800,000	800,000	800,000	800,000	388,978
22	0546	Intermountain Power (take or pay)	44,325,000	48,361,000	50,072,000	51,409,000	41,145,000	47,062,400	11,472,941
23	0547	Fuel expense	848,000	1,232,000	1,557,000	2,006,000	1,904,000	1,509,400	(2,785,150)
24	0548	Hoover (take or Pay)	867,000	865,000	866,000	868,000	870,000	867,200	(116,632)
25	0549	Misc Other Power Gen	-	-	-	-	-	-	-
26	0550	Palo Verde Power (take or pay)	3,941,000	4,065,000	4,198,000	4,322,000	4,464,000	4,198,000	521,355
27	0552	Deseret Power (take or pay)	-	-	-	-	-	-	-
28	0553	Maint/Generating & Elec Equip	4,764,586	5,106,044	5,481,086	5,917,014	6,088,086	5,471,363	1,000,496
29	0555	Purchased Power	91,677,000	97,184,000	102,518,000	106,983,000	120,623,000	103,797,000	22,017,318
30	0556	System Control and Load Dispatching	4,064,487	4,355,772	4,675,707	5,047,580	5,193,516	4,667,413	853,485
31	0557	Other Expenses	2,836,000	2,994,000	2,037,000	1,787,000	3,128,000	2,556,400	1,292,423
39	0560	Operation Supervision and Engineering	-	-	-	-	-	-	-
40	0561	Load Dispatching	-	-	-	-	-	-	-
41	0562	Station Expenses	119,835	128,424	137,856	148,820	153,123	137,612	25,164
42	0563	Overhead Line Expenses	-	-	-	-	-	-	-
43	0564	Underground Line Expenses	-	-	-	-	-	-	-
44	0565	Transmission of Electricity by Others	59,736,000	61,038,000	63,892,000	66,160,000	64,869,000	63,139,000	7,050,850
45	0566	Miscellaneous Transmission Expenses	235,176	252,030	270,542	292,059	300,503	270,062	49,384
46	0567	Rents	-	-	-	-	-	-	-
58	0568	Maintence Supervision and Engineering	-	-	-	-	-	-	-
59	0569	Maintenance of Structures	-	-	-	-	-	-	-
60	0570	Maintenance of Station Equipment	299,858	321,348	344,951	372,386	383,152	344,339	62,966
61	0571	Maintenance of Overhead Lines	3,654	3,916	4,204	4,538	4,669	4,196	767
62	0572	Maintenance of Underground Lines	-	-	-	-	-	-	-
63	0573	Maintence of Misc. Transmission Plant	1,532,022	1,641,816	1,762,408	1,902,578	1,957,585	1,759,282	321,703
71	0580	Operation Maintenance and Engineering	3,960,712	4,244,560	4,556,326	4,918,704	5,060,914	4,548,243	831,694
72	0581	Load Dispatching	2,255,957	2,417,632	2,595,209	2,801,614	2,882,614	2,590,605	473,719
73	0582	Station Expenses	31,732	34,006	36,504	39,407	40,546	36,439	6,663
74	0583	Overhead Line Expenses	10,207	10,938	11,741	12,675	13,042	11,721	2,143
75	0584	Underground Line Expenses	748	802	861	929	956	859	157
76	0585	Street Lighting and Signal Expenses	-	-	-	-	-	-	-
77	0586	Meter Expenses	135,706	145,432	156,114	168,530	173,403	155,837	28,496
78	0587	Customer Installation Expenses	21,877	23,445	25,167	27,168	27,954	25,122	4,594
79	0588	Miscellaneous Distribution Expenses	347,217	372,101	399,432	431,200	443,667	398,723	72,911
80	0589	Rents	-	-	-	-	-	-	-
85	0590	Maintenance Supervision and Engineering	-	-	-	-	-	-	-
86	0591	Maintenance of Structures	56,569	60,623	65,076	70,251	72,282	64,960	11,879
87	0592	Maintenance of Station Equipment	1,249,562	1,339,113	1,437,471	1,551,798	1,596,663	1,434,921	262,390
88	0593	Maintenance of Overhead Lines	5,027,980	5,388,314	5,784,090	6,244,116	6,424,646	5,773,829	1,055,805
89	0594	Maintenance of Underground Lines	2,377,807	2,548,214	2,735,382	2,952,936	3,038,311	2,730,530	499,306
90	0595	Maintenance of Line Transformers	69,348	74,318	79,777	86,121	88,611	79,635	14,562
91	0596	Maintenance of Street Light and Signals	775,466	831,040	892,081	963,031	990,874	890,498	162,837
92	0597	Maintenance of Meters	292,945	313,940	336,999	363,801	374,319	336,401	61,514
93	0598	Maintenance of Misc. Distribution Equipment	594,328	636,921	683,703	738,080	759,419	682,490	124,800
101	0901	Supervision	174,833	187,363	201,125	217,121	223,398	200,768	36,712
102	0902	Meter Reading Expenses	987,260	1,058,013	1,135,725	1,226,053	1,261,500	1,133,710	207,311

Line No.	Acct	Acct Desc[1]	Projected FY 2017/18	Projected FY 2018/19	Projected FY 2019/20	Projected FY 2020/21	Projected FY 2021/22	TY 2018-2022	TY Adjustment
103	0903	Customer Records and Collection Expenses	5,422,351	5,810,948	6,237,766	6,733,875	6,928,564	6,226,701	1,138,618
104	0904	Uncollectible Accounts*	919,000	982,301	1,038,380	1,096,721	1,155,041	1,038,288	275,288
105	0905	Misc. Customer Account Expenses	-	-	-	-	-	-	-
118	0907	Supervision	-	-	-	-	-	-	-
119	0908	Customer Assistance Expenses	1,334,158	1,429,772	1,534,790	1,656,856	1,704,759	1,532,067	280,155
120	0909	Information and Advertising Expenses	1,018,047	1,091,007	1,171,142	1,264,286	1,300,839	1,169,064	213,776
121	0910	Misc. Customer Service Expense	-	-	-	-	-	-	-
127	0911	Supervision	-	-	-	-	-	-	-
128	0912	Demonstration and Selling Expenses	204,120	218,748	234,816	253,491	260,820	234,399	42,862
129	0913	Advertising Expenses	3,596	3,854	4,137	4,466	4,595	4,130	755
130	0916	Miscellaneous Sales Expenses	-	-	-	-	-	-	-
136	0920	Administrative and General Salaries	741,182	794,299	852,641	920,454	947,066	851,129	155,638
137	0921	Office Supplies and Expenses	781,486	837,492	899,006	970,507	998,566	897,411	164,101
138	0922	Administrative Expenses Transferred	(21,191,303)	(22,709,995)	(24,378,061)	(26,316,923)	(27,077,796)	(24,334,816)	(4,449,876)
139	0923	Outside Services Employed	4,179,539	4,479,069	4,808,060	5,190,459	5,340,526	4,799,530	877,644
140	0924	Property Insurance	-	-	-	-	-	-	-
141	0925	Injuries and Damages	-	-	-	-	-	-	-
142	0926	Employee Pensions and Benefits	21,241,001	22,763,255	24,435,232	26,378,642	27,141,299	24,391,886	4,460,312
143	0927	Franchise Requirements	-	-	-	-	-	-	-
144	0928	Regulatory Commission Expenses	24,854	26,635	28,591	30,865	31,758	28,541	5,219
145	0929	Duplicate Charges - Credit	-	-	-	-	-	-	-
146	0930	General Advertising Expenses	24,292	26,033	27,945	30,168	31,040	27,896	5,101
147	0931	Rents	2,095,272	2,245,431	2,410,360	2,602,063	2,677,294	2,406,084	439,978
148	0933	Miscellaneous General Expenses	2,229,588	2,389,373	2,564,874	2,768,866	2,848,920	2,560,324	468,182
153	0932	Maintenance of General Plant	1,032	1,106	1,188	1,282	1,319	1,186	217
168	0701	General Government Charges	10,953,229	11,738,202	12,600,381	13,602,528	13,995,803	12,578,029	2,300,024
169	0702	Expenses Transferred From Electric	3,782,780	4,053,876	4,351,637	4,697,736	4,833,556	4,343,917	794,331
170	0703	IDI Utility Charges	838	898	964	1,041	1,071	962	176
171	0704	Removal Expenses	-	-	-	-	-	-	-
172	0707	Taxes	-	-	-	-	-	-	-
173	0781	Stores Expenses	-	-	-	-	-	-	-
174	0782	Transportation Expenses	1,415,078	1,516,491	1,627,879	1,757,349	1,808,157	1,624,991	297,147
175	0783	787, 789 Tool and Shop Expenses	(613,216)	(657,162)	(705,431)	(761,537)	(783,554)	(704,180)	(128,767)
176	0788	Insurance	569,631	610,454	655,293	707,410	727,863	654,130	119,615
177	0790	795 Non-Operating expenses	-	-	-	-	-	-	-
219	**Grand Total**		**$ 271,606,428**	**$ 287,737,209**	**$ 302,201,122**	**$ 316,474,117**	**$ 322,284,259**	**$ 300,060,627**	**$ 54,726,501**
220	.								

Plant in Service

Line No.	Acct	Acct Desc	Gross Plant	Accumulated Depreciation	Net Plant (6/30/2016)
3	303	303 TOTAL INTANGIBLES - 167000	10,651,084	-	10,651,084
6	310	310 SOURCE SUPPLY/LAND&RTS	17,142	-	17,142
7	320	320 PROD. PLANT	-	-	-
8	340	340 LAND & LAND RIGHTS	1,036,916	-	1,036,916
9	350	350 TRANS. PLANT	1,711,343	-	1,711,343
10	360	360 DIST. PLANT	10,553,496	-	10,553,496
11	389	389 GENERAL PLANT	8,119,611	-	8,119,611
15	341	341 TREATMNT/STRUCT&IMP	149,894	21,235	128,659
16	352	352 TRANS. PLT	980,750	641,394	339,356
17	361	361 DIST. PLT	10,678,983	2,514,219	8,164,764
18	390	390 GENERAL PLT	48,373,400	4,575,262	43,798,139
22	321	321 PROD. PLT SONGS Unit 2 - dep	-	-	-
23	321	321 PROD. PLT SONGS Unit 3 - non dep	-	-	-
24	322	322 PROD. PLT	-	-	-
25	323	323 PROD. PLT	-	-	-
26	324	324 PROD. PLT	-	-	-
27	325	325 PROD. PLT	-	-	-
28	344	344 PROD. PLT	266,433,602	70,437,931	195,995,671
29	353	353 TRANS. PLT	4,863,356	4,385,910	477,446
30	354	354 TRANS. PLT	3,532,104	808,468	2,723,636
31	355	355 TRANS. PLT	18,659,015	6,310,350	12,348,665
32	356	356 TRANS. PLT	8,592,606	2,681,443	5,911,163
33	357	357 TRANS. PLT	5,727,571	1,283,113	4,444,457
34	358	358 TRANS. PLT	2,058,122	880,098	1,178,024
35	359	359 TRANS. PLT	-	-	-
36	362	362 DIST. PLT	119,656,124	39,375,584	80,280,540
37	363	363 DIST. PLT	-	-	-
38	364	364 DIST. PLT	31,980,198	13,510,816	18,469,382
39	365	365 DIST. PLT	38,718,492	18,402,517	20,315,975
40	366	366 DIST. PLT	109,279,967	26,031,289	83,248,679
41	367	367 DIST. PLT	126,112,503	48,413,025	77,699,479
42	368	368 DIST. PLT	53,163,303	27,607,645	25,555,658
43	369	369 DIST. PLT	26,592,360	10,963,449	15,628,911
44	370	370 DIST. PLT	15,232,659	4,308,301	10,924,357
45	371	371 DIST. PLT	839,555	713,846	125,709
46	372	372 DIST. PLT	-	-	-
47	373	373 DIST. PLT	47,962,902	29,554,194	18,408,708

WATER | ENERGY | LIFE
CITY OF RIVERSIDE
PUBLIC UTILITIES

Plant in Service

Line No.	Acct	Acct Desc	Gross Plant	Accumulated Depreciation	Net Plant (6/30/2016)
48	390	390 GENERAL PLT	10,276,623	1,508,600	8,768,022
49	391	391 OFC FURN & EQUIP	2,079,311	407,682	1,671,629
50	397	397 COMM IMP	11,445,827	7,991,280	3,454,547
55	344	344 GENERATORS	729,331	364,235	365,096
56	362	362 DISTRIBUTION/STRUCTURES	3,793,451	664,822	3,128,629
57	390	390 GEN. PLT	5,746,417	876,731	4,869,686
58	391	391 OFFICE FURNITURE	7,357,430	4,817,823	2,539,608
59	392	392 VEHICLE EQUIP.	11,707,771	6,318,952	5,388,819
60	392	392 VEHICLE EQUIP (FUND 511)	26,897	11,207	15,690
61	393	393 STORES EQUIPMENT	45,523	45,523	-
62	394	394 SHOP EQUIP.	519,337	442,411	76,926
63	395	395 LAB EQUIP.	933,333	915,690	17,643
64	396	396 POWER EQUIP.	1,462,581	1,023,696	438,884
65	397	397 COMM. EQUIP.	5,695,791	2,759,062	2,936,728
66	398	398 MISC. EQUIP.	1,076,588	773,205	303,383
70	303	303 TOTAL INTANGIBLES - 168000	18,960,760	1,825,287	17,135,474
82	**Grand Total**		**$1,053,534,029**	**$344,166,295**	**$709,367,733**
83	.				

Labor Expense

Line No.	Section ID	Code	Name	Budget 2017/18
1	600000	41	Pub Util Admin-Mgmt Service	$ 6,082,346
2	600400	41	Pub Util Business Support	1,070,458
3	600500	41	Pub Util Admin-Utility Billing	1,018,613
4	601000	41	Pub Util Admin-Field Services	3,983,609
5	601500	41	Pub Util Admin-Customer Service	5,002,805
6	602000	41	Pub Util Adm-Marketing Service	1,262,555
7	602500	41	Legislative & Regulator Risk	377,676
8	610000	41	Electric Operations	8,766,229
9	610500	41	PU Electric Field Operations	12,563,370
10	611000	41	Energy Deliv Engineering	8,855,010
11	611500	41	Customer Engineering-GIS	-
12	612000	41	PU Elec Power Supply Operations	6,589,249
13	612012	41	SPRINGS Power & Energy Purch	-
14	612013	41	RERC/Acorn Gen. Plant	2,538,448
15	612014	41	Clearwater Generating Plant	1,015,100
16	**Grand Total**			**$59,125,468**
17				

Other Revenue

Line No.	Acct	Acct Desc	Projected 2018	Projected 2019	Projected 2020	Projected 2021	Projected 2022	TY 2018-2022	TY Adjustment
1	Other Operating Revenue:								
2	344400	Diversion	-	-	-	-	-	-	-
3	344410	Service Connect Charges-Elec	371,000	378,420	385,988	393,708	401,582	386,140	(539,653)
4	344491	Misc Service Revenues-Electric	2,861,000	2,918,220	2,976,584	3,036,116	3,096,838	2,977,752	848,574
5	344492	Misc Operating Revenues-Elec	17,800	17,800	17,800	17,800	17,800	17,800	(9,824)
6	344493	Corona Fees- Rev	-	-	-	-	-	-	-
7	344511	Cap and Trade Auction	5,000,000	5,000,000	5,000,000	-	-	3,000,000	(697,889)
		REC Sale	2,944,000	5,235,000	5,043,000	-		3,305,500	3,305,500
8		RPS Sale						-	-
9	344513	Non Energy Recpts ABC Admin OH	749,100	760,337	771,742	783,318	795,067	771,913	127,842
10									
11	Other Non-Operating Revenue:								
12	344493	Corona Fees- Rev	20,000	20,000	20,000	20,000	20,000	20,000	18,746
13	344494	Misc Settlement Reimb	-	-	-	-	-	-	-
14	353400	Late Payment Penalties	-	-	-	-	-	-	-
15	373100	Land and Building Rental	1,821,000	1,821,000	1,821,000	1,821,000	1,821,000	1,821,000	91,696
16	373120	Other Property Rental	74,000	75,480	76,990	78,529	80,100	77,020	(110,410)
17	373125	Pole Attachments	216,900	221,238	225,663	230,176	234,780	225,751	(13,038)
18	373126	Substation Operation & Maint	325,833	-	-	-	-	65,167	(358,641)
19	373127	Substation Leasing	289,500	-	-	-	-	57,900	(613,031)
20	373128	Communication Services	268,200	268,200	268,200	268,200	268,200	268,200	5,901
21	373132	CIS User Fee	688,600	688,600	688,600	688,600	688,600	688,600	17,301
22	374000	Refunds and Reimbursements	-	-	-	-	-	-	-
23	374200	Miscellaneous Receipts	115,000	115,000	115,000	115,000	115,000	115,000	(11,384)
24	374207	Cash Over/Shortage	-	-	-	-	-	-	352
25	374500	Asset Forfeiture Revenue	-					-	(945)
26	374800	Bad Debt Recovery						-	(6,169)
27	374801	Settlement Recovery	-	-	-	-	-	-	(1,676,027)
28	374802	Settlement Recovery - SONGS						-	(9,457,186)
29	374810	Liquidated Damages						-	(2,327,892)
30	985650	Operating Transfer from 650 Fund	-	-	-	-	-	-	-
31	6125000	Utilization Charges	409,400	218,559	19,269	19,412	19,377	137,203	(272,196)
32	**Grand Total**		**$ 16,171,333**	**$ 17,737,854**	**$ 17,429,836**	**$ 7,471,859**	**$ 7,558,345**	**$ 13,934,945**	**$ (11,678,374)**
33									

Proforma Revenue Requirement

Line No.	Line Item from Proforma	Excel Row from Proforma	Projected FY 2017/18	Projected FY 2018/19	Projected FY 2019/20	Projected FY 2020/21	Projected FY 2021/22	TY 2018-2022	TY Adjustment
1	**Required revenues:**								
2	Generation-Power costs	445	146,684,000	157,049,378	163,564,951	169,861,110	173,734,733	162,178,834	32,995,834
3	Generation-prepaid and amort of prepaids and regulatory assets	446	(2,137,000)	(1,966,000)	(1,027,000)	657,000	661,000	(762,400)	(6,005,400)
4	Transmission costs	447	59,736,000	61,037,910	63,891,924	66,159,896	64,868,685	63,138,883	4,993,883
5	Power Supply Reduction Due to Rate Increases	448	(467,064)	(914,212)	(1,540,219)	(1,765,600)	(2,381,780)	(1,413,775)	(1,413,775)
6	Personnel costs including PERS, net of interfund svcs	449	47,544,903	51,821,931	55,141,247	57,968,455	60,994,875	54,694,282	18,301,282
7	Other operating and maintenance costs	450	16,977,589	16,896,901	17,234,839	17,579,536	17,931,126	17,323,998	2,466,998
8	Decommissioning expense	451	1,500,000	1,500,000	1,500,000	1,500,000	853,578	1,370,716	620,716
9	Nuclear fuel purchase	452	-	-	-	-	-	-	-
10	Additional O&M for CIP, advanced tech, smart grid	453	849,000	1,329,000	2,397,000	3,417,000	4,467,000	2,491,800	2,491,800
11	Debt service requirements	454	40,687,000	44,592,000	49,706,000	49,728,000	54,554,000	47,853,400	4,219,400
12	General fund transfer	326	39,831,497	40,018,802	42,514,697	44,740,668	47,033,249	42,827,783	4,467,783
13	Capital outlay financed by rates	456	4,186,000	4,571,000	5,452,000	5,826,000	5,834,000	5,173,800	2,712,800
14	**Total**		355,391,925	375,936,711	398,835,439	415,672,065	428,550,467		
15									
16	**Revenue offsets:**								
17	Interest income	461	(4,679,000)	(7,391,000)	(8,188,000)	(7,344,000)	(7,378,578)	(6,996,116)	(1,853,116)
18	Wholesale sales	462	-	-	-	-	-	-	3,000
19	Transmission revenue	463	(38,643,000)	(39,167,000)	(39,809,000)	(40,277,000)	(40,679,770)	(39,715,154)	(6,791,154)
20	Miscellaneous income	464	(11,653,000)	(13,219,854)	(12,911,836)	(7,953,859)	(8,040,345)	(10,755,779)	11,324,221
21	**Total**		(54,975,000)	(59,777,854)	(60,908,836)	(55,574,859)	(56,098,693)		
13									
22	**Other Items**								
23	Gain (Loss) on retirement of utility plant	178	482,000	482,000	482,000	482,000	482,000	482,000	58,000
24	Reserve for Uncoll (net of recovery)	144	919,000	982,301	1,038,380	1,096,721	1,155,041	1,038,288	275,288
25	Use of/(Contributions to) Reserves	472	(4,930,657)	(10,292,384)	(7,161,572)	(4,379,629)	(11,406,710)	(7,634,190)	27,975,668
26									
27	**Total O&M**		**271,606,428**	**287,737,209**	**302,201,122**	**316,474,117**	**322,284,258**	**300,060,627**	**54,726,627**
28									
29	**Total Retail Revenue Requirement**	477	**306,266,582**	**327,433,541**	**346,126,555**	**365,573,555**	**385,013,525**	**346,082,752**	**40,833,894**
30	Check		-	-	-	-	-		

Capital Improvement Program Allocator

Line No.	Item[1]	Function	2017/18	2018/19	2019/20	2020/21	2021/22
1	**CIP Scenario**	Option 3					
2							
3	**Infrastructure CIP**						
4	Overhead Options	Distribution	$ 7,182,545	$ 9,088,817	$ 12,685,726	$ 11,896,412	$ 12,235,460
5	Underground Options	Distribution	5,500,624	8,395,787	12,085,960	15,663,168	17,295,592
6	Substation Options	Distribution	4,829,971	5,205,888	4,143,534	5,236,401	8,194,456
7	Technology Options	See Allocation	4,453,390	3,993,901	8,899,143	8,507,137	8,749,591
8	Subtotal		$ 21,966,530	$ 26,684,393	$ 37,814,363	$ 41,303,118	$ 46,475,099
9							
10	**Other CIP**						
11	Remainder of CIP (Obligation to Serve Projects)	See Allocation	$ 10,440,607	$ 10,738,164	$ 11,044,202	$ 11,358,962	$ 11,682,692
12	EV Stations	N/A	528,906	543,980	559,483	575,429	591,828
13	LED Street Light Retrofit	N/A	7,933,592	4,079,850	-	-	-
14	RTRP	N/A	8,462,498	10,879,599	8,951,734	9,206,858	17,754,851
15	CIS	Customer	-	-	-	-	-
16	Additional CIP - Performance Audit and Security Assess	N/A	1,262,500	-	-	-	-
17	Facilities	N/A	-	-	-	-	-
18	Other carryovers from FY 14 - rolling carryovers	N/A	-	-	-	-	-
19	Subtotal		$ 28,628,103	$ 26,241,593	$ 20,555,419	$ 21,141,249	$ 30,029,372
20							
21	**Total CIP**		$ 50,594,633	$ 52,925,986	$ 58,369,782	$ 62,444,367	$ 76,504,471
22	**less non-Allocated**	N/A	$ (18,187,496)	$ (15,503,429)	$ (9,511,217)	$ (9,782,287)	$ (18,346,680)
23	**Total CIP less non-Allocated**		$ 32,407,137	$ 37,422,557	$ 48,858,565	$ 52,662,080	$ 58,157,791
24							
25	**Technology Options Allocation**						
26	Production	Production	$ -	$ -	$ -	$ -	$ -
27	Transmission	Transmission	-	-	-	-	-
28	Distribution	Distribution	2,729,753	2,448,104	5,454,824	5,214,540	5,363,155
29	Customer	Customer	1,723,637	1,545,797	3,444,319	3,292,597	3,386,436
30							
31	**Remainder of CIP Allocation**						
32	Production	Production	$ -	$ -	$ -	$ -	$ -
33	Transmission	Transmission	-	-	-	-	-
34	Distribution	Distribution	10,559,305	9,688,671	9,964,798	10,248,795	10,540,885
35	Customer	Customer	1,143,802	1,049,494	1,079,404	1,110,167	1,141,807
36							
37	**CIP by Function**						
38	Production	Production	$ -	$ -	$ -	$ -	$ -
39	Transmission	Transmission	-	-	-	-	-
40	Distribution	Distribution	30,802,198	34,827,267	44,334,842	48,259,316	53,629,548
41	Customer	Customer	2,867,439	2,595,290	4,523,723	4,402,764	4,528,243
42	Total Allocated CIP		33,669,637	37,422,557	48,858,565	52,662,080	58,157,791
43							
44	**CIP Allocation %**						
45	Production		0.00%	0.00%	0.00%	0.00%	0.00%
46	Transmission		0.00%	0.00%	0.00%	0.00%	0.00%
47	Distribution		91.48%	93.06%	90.74%	91.64%	92.21%
48	Customer		8.52%	6.94%	9.26%	8.36%	7.79%
49							

Line No.	Item[1]	Function	2017/18	2018/19	2019/20	2020/21	2021/22
50							
51	**GL Object[2]**	**Project Description**	**$ Applicable**	**Allocation**	**Production**	**Transmission**	**Distribution**
52							
53	**Remainder of CIP - 2016/17**						
54	470603	Lines Rebuilds / Relocate	(2,150,000)	Distribution	-	-	(2,150,000)
55	470612	Capacitors-Regulators	(50,000)	Distribution	-	-	(50,000)
56	470601	Distribution Line Extensions	(2,000,000)	Distribution	-	-	(2,000,000)
57	470611	Transformers	(2,100,000)	Distribution	-	-	(2,100,000)
58	470613	Meters	(350,000)	Customer	-	-	-
59	470615	Services	(405,000)	Customer	-	-	-
	470608	System Substation Modifica	(180,000)	Distribution	-	-	(180,000)
60	470607	Street Lighting	(300,000)	Distribution	-	-	(300,000)
61	Total Remainder of CIP		**(7,535,000)**		-	-	(6,780,000)
62	**Remainder of CIP Allocation - 2015/16**				**0%**	**0%**	**90%**
63							
64	**Remainder of CIP - TY Average**						
65	470603	Lines Rebuilds / Relocate	(2,150,000)	Distribution	-	-	(2,150,000)
66	470612	Capacitors-Regulators	(50,000)	Distribution	-	-	(50,000)
67	470601	Distribution Line Extensions	(2,250,000)	Distribution	-	-	(2,250,000)
68	470611	Transformers	(2,250,000)	Distribution	-	-	(2,250,000)
69	470613	Meters	(350,000)	Customer	-	-	-
70	470615	Services	(427,750)	Customer	-	-	-
	470608	System Substation Modifica	(180,000)	Distribution	-	-	(180,000)
71	470607	Street Lighting	(300,000)	Distribution	-	-	(300,000)
72	Total Remainder of CIP		**(7,957,750)**		-	-	(7,180,000)
73	**Remainder of CIP Allocation - Test Year**				**0%**	**0%**	**90%**
74							
75	**Project[3]**		**Customer**				
76							
77	**Project Management and Technology Governance**						
78	RPU Operational Technology (OT) Office						
79	Technology Governance (Cybersecurity Measures)		1.36				
80	**Customer-Focused Technologies (IT Realm)**						
81	Customer Information System (CIS)						
82	Customer Relationship Management (CRM)						
83	Interactive Voice Response (IVR)		11.32				
84	Customer Web Portal (CWP)		3.69				
85	**Information-Based Technologies (IT Realm)**						
86	Asset Management System (AMS)						
87	Work Management System (WMS)						
88	Warehouse Inventory System (WIS)						
89	Geographic Information System (GIS)						
90	Mobile Applications (Mobile Apps)		0.92				
91	Operational Data Management System (ODMS)						
92	**Operational Technologies (OT Realm)**						
93	Network Communications System (NCS)						
94	Land Mobile Radio (LMR)						
95	Advanced Metering Infrastructure (AMI)						
96	Meter Data Management System (MDMS)		10.00				
97	Automatic Vehicle Location (AVL)						
98	**Distribution Automation (DA)- Electric**						
99	Distribution Automation (DA)- Water						
100	Substation Automation (SA)						
101	Outage Management System (OMS)		1.00				
102	Supervisory Control and Data Acquisition (SCADA)- Elec						
103	Advanced Distribution Management System (ADMS)- Elec						
104	Supervisory Control and Data Acquisition (SCADA)- Wtr						
105	Advanced Distribution Management System (ADMS)- Wtr						
106	Total Technology		$ 28.28	$ 73.08			
107	**Technology Allocation**		**39%**				
108							

Debt by Function

Line No.	Bond Issue[1]	Sum of Construction and Refunding Escrow Funds			
		Generation	Transmission	Distribution	Total
1	2008A (Var.) (B)	52,992,955	318,269	15,217,427	68,528,651
2	2008C (Var.)	17,542,598	1,942,403	26,173,396	45,658,397
3	2008D (Fixed)	123,792,186	19,626,792	70,704,058	214,123,036
4	2009A (Fixed)	9,989,056	1,573,134	26,661,054	38,223,245
5	2010A (BAB)	622,615	19,602,777	115,341,592	135,566,984
6	2010B (Fixed)	-	1,067,815	6,544,010	7,611,825
7	2011A (Var.)	17,408,563	1,927,562	29,266,784	48,602,908
8	2013A (Fixed)	64,308,601	1,047,878	17,189,245	82,545,724
9	1993	113,040,875	-	4,609,658	117,650,533
10	1986	101,615,000	-	3,085,000	104,700,000
11	1998	2,943,460	5,925,891	100,430,400	109,299,751
12	2004B	57,334,754	344,346	16,464,215	74,143,315
13	2005A	20,214,061	2,238,201	30,159,193	52,611,454
14	2005B	20,214,061	2,238,201	30,159,193	52,611,454
15	2008B	22,057,208	2,442,283	32,909,152	57,408,643
16	2011A	21,692,996	2,401,956	36,469,652	60,564,604
17	**Grand Total**	**$645,768,988**	**$0**	**$624,081,536**	**$1,269,850,523**
18	%	51%	0%	49%	100%
19					

A&G Allocator

Line No.	Acct	Acct Desc	Function	Projected FY 2017/18	Projected FY 2018/19	Projected FY 2019/20	Projected FY 2020/21	Projected FY 2021/22
1	0553	Maint/Generating & Elec Equip	Production	4,764,586	5,106,044	5,481,086	5,917,014	6,088,086
2	0556	System Control and Load Dispatching	Production	4,064,487	4,355,772	4,675,707	5,047,580	5,193,516
3	0557	Other Expenses	Production	2,836,000	2,994,000	2,037,000	1,787,000	3,128,000
4	0560	Operation Supervision and Engineering	Distribution	-	-	-	-	-
5	0561	Load Dispatching	Distribution	-	-	-	-	-
6	0562	Station Expenses	Distribution	119,835	128,424	137,856	148,820	153,123
7	0563	Overhead Line Expenses	Distribution	-	-	-	-	-
8	0564	Underground Line Expenses	Distribution	-	-	-	-	-
9	0566	Miscellaneous Transmission Expenses	Distribution	235,176	252,030	270,542	292,059	300,503
10	0568	Maintence Supervision and Engineering	Distribution	-	-	-	-	-
11	0569	Maintenance of Structures	Distribution	-	-	-	-	-
12	0570	Maintenance of Station Equipment	Distribution	299,858	321,348	344,951	372,386	383,152
13	0571	Maintenance of Overhead Lines	Distribution	3,654	3,916	4,204	4,538	4,669
14	0572	Maintenance of Underground Lines	Distribution	-	-	-	-	-
15	0573	Maintence of Misc. Transmission Plant	Distribution	1,532,022	1,641,816	1,762,408	1,902,578	1,957,585
16	0580	Operation Maintenance and Engineering	Distribution	3,960,712	4,244,560	4,556,326	4,918,704	5,060,914
17	0581	Load Dispatching	Distribution	2,255,957	2,417,632	2,595,209	2,801,614	2,882,614
18	0582	Station Expenses	Distribution	31,732	34,006	36,504	39,407	40,546
19	0583	Overhead Line Expenses	Distribution	10,207	10,938	11,741	12,675	13,042
20	0584	Underground Line Expenses	Distribution	748	802	861	929	956
21	0585	Street Lighting and Signal Expenses	Distribution	-	-	-	-	-
22	0586	Meter Expenses	Distribution	135,706	145,432	156,114	168,530	173,403
23	0587	Customer Installation Expenses	Distribution	21,877	23,445	25,167	27,168	27,954
24	0588	Miscellaneous Distribution Expenses	Distribution	347,217	372,101	399,432	431,200	443,667
25	0589	Rents	Distribution	-	-	-	-	-
26	0590	Maintenance Supervision and Engineering	Distribution	-	-	-	-	-
27	0591	Maintenance of Structures	Distribution	56,569	60,623	65,076	70,251	72,282
28	0592	Maintenance of Station Equipment	Distribution	1,249,562	1,339,113	1,437,471	1,551,798	1,596,663
29	0593	Maintenance of Overhead Lines	Distribution	5,027,980	5,388,314	5,784,090	6,244,116	6,424,646
30	0594	Maintenance of Underground Lines	Distribution	2,377,807	2,548,214	2,735,382	2,952,936	3,038,311
31	0595	Maintenance of Line Transformers	Distribution	69,348	74,318	79,777	86,121	88,611
32	0596	Maintenance of Street Light and Signals	Distribution	775,466	831,040	892,081	963,031	990,874
33	0597	Maintenance of Meters	Distribution	292,945	313,940	336,999	363,801	374,319
34	0598	Maintenance of Misc. Distribution Equipment	Distribution	594,328	636,921	683,703	738,080	759,419
35	0901	Supervision	Distribution	174,833	187,363	201,125	217,121	223,398
36	0902	Meter Reading Expenses	Distribution	987,260	1,058,013	1,135,725	1,226,053	1,261,500
37	0903	Customer Records and Collection Expenses	Distribution	5,422,351	5,810,948	6,237,766	6,733,875	6,928,564
38	0904	Uncollectible Accounts*	Distribution	919,000	982,301	1,038,380	1,096,721	1,155,041
39	0905	Misc. Customer Account Expenses	Distribution	-	-	-	-	-
40	0907	Supervision	Distribution	-	-	-	-	-
41	0908	Customer Assistance Expenses	Distribution	1,334,158	1,429,772	1,534,790	1,656,856	1,704,759
42	0909	Information and Advertising Expenses	Distribution	1,018,047	1,091,007	1,171,142	1,264,286	1,300,839
43	0910	Misc. Customer Service Expense	Distribution	-	-	-	-	-
44	0911	Supervision	Distribution	-	-	-	-	-
45	0912	Demonstration and Selling Expenses	Distribution	204,120	218,748	234,816	253,491	260,820
46	0913	Advertising Expenses	Distribution	3,596	3,854	4,137	4,466	4,595
47	0916	Miscellaneous Sales Expenses	Distribution	-	-	-	-	-
52	**Grand Total**			**$ 41,127,145**	**$ 44,026,752**	**$ 46,067,565**	**$ 49,295,207**	**$ 107,818,876**
53	.							
54	.		**Production**	**11,665,073**	**12,455,816**	**12,193,793**	**12,751,594**	**14,409,602**
55	.							
56	.		**Transmission**	**-**	**-**	**-**	**-**	**-**
57	.							
58	.		**Distribution**	**29,462,072**	**31,570,936**	**33,873,772**	**36,543,613**	**37,626,770**
59	.							
60	.							

Purchased Power

Line No.	Acct	Type	Acct Desc	FY 2015/16
1	422917	1	ARB	105,831
2	422914	2	Anaheim WSPP & Non-Firm Energy	480
3	422914	2	BP Energy	6,150,510
4	422914	2	Burbank	43,472
5	422915	1	Azusa	-
6	422914	2	Cabazon Wind - Nextera	3,337,825
7	422912	3	California ISO Transmission	25,694,494
8	422912	3	California ISO- NERC/WECC	-
9	422914	2	California ISO Energy -Clearwater	-
10	422914	2	California ISO Energy	21,745,131
11	422915	1	California ISO Capacity	(26,110)
12	422915	1	Calpine Energy	675,000
13	422912	3	California Power Exchange	3,611
14	422914	2	Citigroup Energy	-
15	422914	2	Covanta Energy Marketing LLC	-
16	422914	2	Columbia 2 Solar (SCPPA)	1,143,248
17	422915	2	Columbia 2 Solar (SCPPA) Scheduling Coordinator3	(15,834)
18	422914	2	EDF Trading North America Energy	1,563,100
19	422915	1	EDF Trading North America Capacity	-
20	422915	1	Dynegy Marketing & Trade	13,500
21	422914	2	Evolution Marketing	-
22	422914	2	Exelon Generation	1,206,413
23	422914	2	First Solar Kingbird (SCPPA)	715,040
24	422915	2	First Solar Kingbird (SCPPA) Scheduling Coordinator	(9,800)
25	422915	1	Genon Energy	10,500
26	422915	1	Hoover Capacity (SCPPA)	449,058
27	422915	1	Hoover Capacity (SCPPA) - Amortization	495,718
28	422914	2	Hoover Energy	328,220
29	422914	2	Hoover Energy Prepaid Adjustment	(26,661)
30	422914	2	Iberdrola Renewables	-
31	422915	1	ICE Energy	-
32	422915	1	ICE Installation	-
33	422915	1	ICE O&M	-
34	422915	1	IPA Minimum	35,589,459
35	422914	2	IPA Variable	1,555,228
36	422915	1	Inland Empire Energy	159,968
37	422912	3	LADWP Transmission	1,311,832
38	422912	3	Thompson Corburn RE LADWP	11,483
39	422914	2	Macquarie Energy	407,770
40	422912	3	Mead-Adelanto Transmission (SCPPA)	3,369,725
41	422912	3	Mead-Phoenix Transmission (SCPPA)	308,608
42	422914	1	Mead-Phoenix DOE (WAPA) WSPP Energy	-
43	422914	1	Mead-Phoenix Energy Losses DOE (WAPA)	-
44	422914	2	MidAmerican Energy Holdings (Salton Sea)	28,317,769
45	422914	2	MidAmerican Energy Holdings (Salton Sea) - Amortization	(2,412,995)
46	422914	2	Morgan Stanley Capital Group	1,380,657
47	422915	1	Elk Hills Power	-
48	422912	3	Northern Transmission (UAMPS)	1,402,049
49	422914	2	Pacificorp	-
50	422915	1	Palo Verde Minimum	3,551,592
51	422914	2	Palo Verde Variable	647,022
52	422915	1	Palo Verde Adjustments (Resolutions)	193,298
53	422914	2	PowerEx Corp	391,040
54	422914	1	Recurrent Solar	-
55	422915	1	RRI (Reliant Energy Services) - Capacity	-
56	422914	1	Riverside County (Waste)	-
57	422914	2	Salt River Project	-
58	422914	2	San Diego Gas & Electric	-
59	422914	2	Sempra Energy Trading Co	-
60	422915	1	Sempra Energy Trading Co Capacity	-
61	422915	1	Sempra Generation	53,500
62	422912	3	SCE W/S Distribution Access-WDAT	1,297,863

Purchased Power

Line No.	Acct	Type	Acct Desc	FY 2015/16
63	422912	3	SCE Firm Transmission	12,318,187
64	422912	3	SCE Facilities Charge	77,177
65	422914	2	Shell Energy North America	1,501,548
66	422915	1	Shell Energy North America Capacity	-
67	422914	2	Solar Star California (SunPower)	1,042,323
68	422912	3	Southern Transmission System (STS)	11,683,255
69	422914	2	SunEdison (AP North Lake)	3,413,752
70	422914	2	TransAlta Energy Inc.	572,400
71	422914	2	WAPA (US Dept)	3,898
72	422915	1	WAPA	17,364
73	422914	2	Wagner Wind (formerly WKN Wagner)	1,251,962
74	422914	2	Wintec	234,668
75	422914	2	Deferred Regulatory Costs - Energy	-
76	422914	2	Cap & Trade Inventory Surrender	105,000
77	422914	2	Deferred Regulatory Costs - Energy	7,160,000
78	422915	2	Deferred Regulatory Costs - Capacity	-
79	011-424130	1	SONGS O&M Estimated-424130	-
80	011-424130	1	SONGS O&M Adjustment-424130	84,244
81	011-428420	1	SONGS Insurance Charges-428420	(17,624)
82	011-442100	1	SONGS Decommission Expense-442100	749,593
83	011-422910	1	SONGS Decommission Operations	-
84	011-465000	1	SONGS Nuclear Fuel Purchases	-
85	422914	1	SONGS Deviations	-
86	011-424130	1	SONGS Mesa	-
87	011-447100	1	SONGS Taxes & Assessments-447100	108
88	011-421000	1	SONGS Professional Services	10,000
89	011-421100	1	SONGS Outside Legal	351,328
90	011-424130	1	SONGS-Nuclear	30,912
91	012-41XXXX	1	SPRINGS - Personnel Costs	-
92	012-42XXXX	1	SPRINGS - Non-Personnel Costs	268,739
93	010-422925	2	SPRINGS - EDF	-
94	010-422925	2	SPRINGS - So Calif Gas Co	1,027
95	010-422925	2	SPRINGS - Occ Energy Marketing Inc-Gas	17,653
96	010-422925	2	SPRINGS - Shell	8,084
97	010-422925	2	SPRINGS - Shell Gas Sales	(2,058)
98	010-422925	2	SPRINGS - Pacific Summit	-
99	010-422925	2	SPRINGS - Macquarie	1,365
100	422917	1	SPRINGS - ARB	-
101	013-41XXX	1	RERC- Personnel Costs	2,491,755
102	013-42XXX	1	RERC - Non-Personnel Costs	1,972,048
103	010-422926	2	RERC - EDF	-
104	010-422926	2	RERC - Occ Energy Marketing Inc-Gas	1,961,080
105	010-422926	2	RERC - Shell	964,232
106	010-422926	2	RERC - Shell Gas Sales	-
107	010-422926	2	RERC - Pacific Summit	-
108	010-422926	2	RERC - Macquarie	394,083
109	010-422926	2	RERC - So Calif Gas Co	77,642
110	422917	1	RERC - ARB	-
111	010-422927	2	CLEARWATER - EDF	-
112	010-422927	2	CLEARWATER - So Cal Gas Co.	20,044
113	010-422927	2	CLEARWATER - Occ Energy Marktg Inc-Gas	563,113
114	010-422927	2	CLEARWATER - Shell	235,032
115	010-422927	2	CLEARWATER - Pacific Summit	-
116	010-422927	2	CLEARWATER - Macquarie	53,252
117	014-41XXXX	1	CLEARWATER - Personnel Costs	933,985
118	014-42XXXX	1	CLEARWATER - Non-Personnel Costs	963,373
119	422912	3	CLEARWATER - SCE Facilities Charge	62,539
120	422914	4	NEM Net Surplus Energy Compensation	864
146	**Grand Total**			**$192,716,561**
147				
148	**Total Generation**			**135,175,738**
149	Demand			49,127,140
150	Energy			86,048,598
151				
152	**Total Transmission**			**57,540,823**

Transmission Costs

Line No.	Acct	Acct Desc	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
1	Transmission Cost (FIXED)						
2	5650	Mead-Adelanto	3,252	3,242	2,507	335	345
3	5650	Mead-Phoenix	392	394	332	145	149
4	5650	STS	12,000	11,000	12,000	14,000	11,000
5	5650	NTS	1,681	1,681	1,681	1,681	1,681
6	5650	SCE	13,300	13,800	14,300	14,900	15,496
7	5650	SCE WDAT	1,400	1,500	1,600	1,700	1,800
8	5650	LADWP Service Agreements	1,500	1,600	1,700	1,800	1,900
9							
10	Transmission Cost (VARIABLE)						
11	5650	ISO TAC Load	24,111	25,621	27,472	29,199	29,998
12	5650	ISO Transmission Charges	2,100	2,200	2,300	2,400	2,500
13							
14	**Grand Total**		**$59,736**	**$61,038**	**$63,892**	**$66,160**	**$64,869**
15							
16	**Total Fixed**		**33,525**	**33,217**	**34,120**	**34,561**	**32,371**
17	% Fixed		56%	54%	53%	52%	50%
18							
19	**Total Variable**		**26,211**	**27,821**	**29,772**	**31,599**	**32,498**
20	% Variable		44%	46%	47%	48%	50%
21							

Minimum System Analysis

Line No.	Transformers[1] Transformer Size (kVA)	Count	Unit Cost New	Inventory Value New	Estimated Value @ Min	Meters[3] Meter Description	Class	Count	Unit Cost New	Inventory Value New	Estimated Value @ Min
1	5	17	$ 887	$ 15,078	$ 39,602	Residential factor of 1 (RF)	Domestic	86,846	50	4,337,958	4,337,958
2	7	2	1,085	2,171	4,659	Residential factor of 1 (Non RF)	Domestic	9,280	160	1,484,800	463,536
3	10	431	1,344	579,397	1,004,015	Residential factor > 1 (RF)	Domestic	102	280	28,529	5,095
4	15	672	1,715	1,152,186	1,565,424	Residential factor > 1 (Non RF)	Domestic	20	325	6,500	999
5	25	3,700	2,330	8,619,150	8,619,150	D TOU (old rate)	Domestic	234	205	47,970	11,688
6	37.5	957	2,971	2,843,344	2,229,332	D TOU Tiered (new rate)	Domestic	11	205	2,255	549
7	45	45	3,315	149,155	104,828	NET	Domestic	1,535	176	269,715	76,673
8	50	3,981	3,531	14,056,361	9,273,740	NET TOU (old)	Domestic	15	205	3,075	749
9	75	2,505	4,503	11,280,886	5,835,398	NET TOU Tiered (new)	Domestic	1	205	205	50
10	100	1,037	5,352	5,549,802	2,415,692	PV production meters All RF	Domestic	1,320	50	65,934	65,934
11	112	1	5,728	5,728	2,330	Single phase demand factor 1 (R	Commercial	2,191	175	383,644	383,644
12	112.5	66	5,744	379,083	153,747	Single phase demand factor 1 (N	Commercial	1,558	136	211,389	272,806
13	150	394	6,826	2,689,365	917,823	Single phase demand factor > 1	Commercial	88	340	29,920	15,409
14	167	190	7,280	1,383,191	442,605	Single phase demand factor >1 (	Commercial	186	205	38,171	32,569
15	225	108	8,706	940,225	251,586	Three phaseDMD/KWH factor 1	Commercial	231	257	59,252	40,448
16	250	8	9,274	74,191	18,636	Three phase DMD/KWH factor :	Commercial	5,360	169	904,071	938,536
17	300	331	10,346	3,424,518	771,065	Three phase DMD/KWH factor :	Commercial	195	757	147,518	34,145
18	333	8	11,015	88,116	18,636	Three phase DMD/KWH factor :	Commercial	1,936	681	1,317,874	338,994
19	500	245	14,057	3,443,870	570,728	TOU	Commercial	470	774	399,640	82,297
20	750	121	17,928	2,169,306	281,870	NET demand	Commercial	54	774	41,818	9,455
21	1000	75	21,306	1,597,938	174,713	NET TOU (two TOU meters)	Commercial	32	1,049	33,562	5,603
22	1500	51	27,174	1,385,874	118,805	PV production meters (RF)	Commercial	14	257	3,592	2,451
23	2000	20	32,294	645,872	46,590	PV production meters (Non RF)	Commercial	20	169	3,373	3,502
24	2500	42	36,920	1,550,644	97,839	Primary metered services	Commercial	33	5,174	170,755	5,778
25	3000	6	41,188	247,128	13,977	Services billed by MV90	Commercial	9	6,100	54,900	1,576
26	-	13	4,281	55,655	30,284						
27	Blank	110	4,281	470,924	256,245						
28											
36											
37	**Grand Total**	**15,136**		**$64,799,158**	**$35,259,312**			**111,741**		**$10,046,419**	**$7,130,445**

Minimum System Analysis

	Transformers	Meters	Average
Customer	**54%**	**71%**	**63%**
Demand	**46%**	**29%**	**37%**

Meters	Avg Cost	Weight	Class
Residential	**$ 62.87**	**1**	Residential
Small Commercial	**$ 164.83**	**3**	Commercial Flat
Medium Commercial	**$ 314.04**	**5**	Commercial Demand, UCR, City Contract
Large Commercial	**$ 1,171.70**	**19**	Industrial TOU, ROHR, Ralphs, Kaiser
Other		**0.25**	Street Lights Cust. Owned, Street Lights Dept. Owned, Traffic Signals, Ag Pumping, Misc. Cal-Trans

Line Miles		
Miles of 4 kV	**137**	**10%**
Miles of 12 kV	**1,192**	**90%**
Miles of overhead	**512**	**39%**
Miles of underground	**817**	**61%**

Demand Results

Line No.	Data	Residential	Commercial Flat	Commercial Demand	Industrial TOU	City Contract	Street Lights Cust. Owned
1							1.16%
2	1 CP	208.14	55.86	30.56	151.51	11.30	0.05
3	4 CP	756.95	202.00	113.55	569.72	44.49	-
4	12 CP	1,658.59	511.39	290.82	1,522.77	109.98	0.21
5	1 NCP	222.07	70.54	37.78	191.31	13.97	0.05
6	4 NCP	801.95	267.52	142.15	716.10	54.33	0.21
7	12 NCP	1,790.40	668.33	370.17	1,936.51	136.35	0.64
8	Sum of Max Demands	3,865.21	935.38	519.12	2,109.65	177.39	0.64
9							
10	Energy @ Meter	696,137,017	285,755,139	164,025,450	968,600,635	69,219,011	316,226
11	Load Factor	25%	42%	43%	63%	53%	68%
12	NCP Coincidence Factor	0.46	0.71	0.71	0.92	0.79	1.00
13	CP Coincidence Factor	0.92	0.77	0.78	0.79	0.81	0.33
12							

Demand Results

Line No.	Data	Street Lights Dept. Owned	Traffic Signals	Ag Pumping	Misc. Cal-Trans	Blank	Total
1		98.84%					
2	1 CP	4.58	0.15	0.16	0.04	-	462
3	4 CP	-	0.58	0.57	0.16	-	1,688
4	12 CP	18.24	1.74	1.12	0.49	-	4,115
5	1 NCP	4.59	0.15	0.19	0.04	-	541
6	4 NCP	18.34	1.74	0.67	0.25	-	2,003
7	12 NCP	54.66	1.74	1.41	0.49	-	4,961
8	Sum of Max Demands	54.66	1.74	1.41	0.49	-	7,666
9							
10	Energy @ Meter	19,839,445	1,273,854	787,485	155,616		2,206,109,878
11	Load Factor	50%	100%	76%	43%		
12	NCP Coincidence Factor	1.00	1.00	1.00	1.00		
13	CP Coincidence Factor	0.33	1.00	0.77	1.00		
12							

Street Lighting

Line No.	Tariff	Lamp Type	Customer Class	# of Lamps	kW/Unit	Total kW	kWh/Yr	Charge per Unit	Revenue/Yr
1	LS-1	Incandescent - 1	Street and OD Lights - Dept. Owned	86	0.092	7.91	32,819	$ 6.82	$ 7,038
2	LS-1	Incandescent - 2.8	Street and OD Lights - Dept. Owned	312	0.189	58.97	244,599	$ 10.12	$ 37,889
3	LS-1	Incandescent - 4	Street and OD Lights - Dept. Owned	44	0.295	12.98	53,841	$ 13.44	$ 7,096
4	LS-1	Mercury Vapor - 3.5	Street and OD Lights - Dept. Owned	446	0.133	59.32	246,051	$ 10.77	$ 57,641
5	LS-1	Mercury Vapor - 7	Street and OD Lights - Dept. Owned	1,251	0.208	260.21	1,079,343	$ 12.76	$ 191,553
6	LS-1	Mercury Vapor - 10	Street and OD Lights - Dept. Owned	12	0.29	3.48	14,435	$ 15.68	$ 2,258
7	LS-1	LED Lighting - 4.1	Street and OD Lights - Dept. Owned	97	0.088	8.54	35,407	$ 10.51	$ 12,234
8	LS-1	LED Lighting - 5.34	Street and OD Lights - Dept. Owned	158	0.088	13.90	57,674	$ 10.51	$ 19,927
9	LS-1	LED Lighting - 5	Street and OD Lights - Dept. Owned	7	0.088	0.62	2,555	$ 10.51	$ 883
10	LS-1	LED Lighting - 5.571	Street and OD Lights - Dept. Owned	233	0.088	20.50	85,051	$ 10.51	$ 29,386
11	LS-1	LED Lighting - 10.68	Street and OD Lights - Dept. Owned	187	0.124	23.19	96,184	$ 11.85	$ 26,591
12	LS-1	LED Lighting - 10.5	Street and OD Lights - Dept. Owned	2	0.202	0.40	1,676	$ 13.88	$ 333
13	LS-1	LED Lighting - 14.1	Street and OD Lights - Dept. Owned	7	0.254	1.78	7,375	$ 13.88	$ 1,166
14	LS-1	LED Lighting - 9.6	Street and OD Lights - Dept. Owned	18	0.202	3.64	15,082	$ 13.88	$ 2,998
15	LS-1	LED Lighting - 13.62	Street and OD Lights - Dept. Owned	436	0.202	88.07	365,323	$ 13.88	$ 72,620
16	LS-1	LED Lighting - 15.5	Street and OD Lights - Dept. Owned	7	0.202	1.41	5,865	$ 13.88	$ 1,166
17	LS-1	High Pressure Sodium - 5.8	Street and OD Lights - Dept. Owned	2,467	0.088	217.10	900,514	$ 10.51	$ 311,138
18	LS-1	High Pressure Sodium - 9.5	Street and OD Lights - Dept. Owned	18,514	0.124	2,295.74	9,522,713	$ 11.85	$ 2,632,691
19	LS-1	High Pressure Sodium - 16	Street and OD Lights - Dept. Owned	989	0.202	199.78	828,679	$ 13.88	$ 164,728
20	LS-1	High Pressure Sodium - 22	Street and OD Lights - Dept. Owned	4,421	0.254	1,122.93	4,657,930	$ 15.75	$ 835,569
21	LS-1	High Pressure Sodium - 25	Street and OD Lights - Dept. Owned	647	0.307	198.63	823,913	$ 17.39	$ 135,016
22	LS-1	High Pressure Sodium - 40	Street and OD Lights - Dept. Owned	102	0.482	49.16	203,932	$ 21.84	$ 26,732
23	LS-2	INC. - 1000 (O221)	Street Lights - Cust. Owned	1	0.092	0.09	382	$ 4.52	$ 54
24	LS-2	M.V. - 7000 (O225)	Street Lights - Cust. Owned	103	0.208	21.37	88,660	$ 9.66	$ 11,912
25	LS-2	M.V. - 10000 (O226)	Street Lights - Cust. Owned	1	0.29	0.29	1,203	$ 12.92	$ 155
26	LS-2	M.V. - 20000 (O227)	Street Lights - Cust. Owned	5	0.46	2.30	9,540	$ 19.77	$ 1,186
27	LS-2	S.V. - 9500 (O231)	Street Lights - Cust. Owned	105	0.124	13.02	54,007	$ 6.53	$ 8,228
28	LS-2	S.V. - 16000 (O232)	Street Lights - Cust. Owned	31	0.202	6.36	26,386	$ 9.05	$ 3,420
29	LS-2	S.V. - 22000 (O233)	Street Lights - Cust. Owned	14	0.254	3.56	14,750	$ 11.27	$ 1,893
30	LS-2	S.V. - 40000 (O235)	Street Lights - Cust. Owned	-	0.482	-	-	$ 20.36	$ -
31	LS-2	M.V. - 7000 (O245)	Street Lights - Cust. Owned	51	0.208	10.52	43,657	$ 7.96	$ 4,833
32	LS-2	M.V. - 20000 (O247)	Street Lights - Cust. Owned	4	0.46	1.84	7,632	$ 17.47	$ 839
33	LS-2	M.V. - 55000 (O249)	Street Lights - Cust. Owned	3	1.102	3.31	13,713	$ 42.35	$ 1,525
34	LS-2	S.V. - 16000 (O252)	Street Lights - Cust. Owned	8	0.202	1.62	6,703	$ 7.71	$ 740
35	LS-2	S.V. - 22000 (O253)	Street Lights - Cust. Owned	8	0.254	2.03	8,429	$ 9.94	$ 954
36	LS-2	S.V. - 40000 (O255)	Street Lights - Cust. Owned	2	0.482	0.96	3,999	$ 18.30	$ 439
37	LS-2	INC. - 6000 (O330)	Street Lights - Cust. Owned	28	0.295	8.27	34,293	$ 5.19	$ 1,744
38	Outdoor Lighting	M.V. - 7000 (O181)	Street and OD Lights - Dept. Owned	228	0.208	47.36	196,430	$ 10.33	$ 28,222
39	Outdoor Lighting	M.V. - 20000 (O182)	Street and OD Lights - Dept. Owned	137	0.46	63.02	261,407	$ 18.25	$ 30,003
40	Outdoor Lighting	S.V. - 9500 (O183)	Street and OD Lights - Dept. Owned	100	0.124	12.40	51,453	$ 10.39	$ 12,472
41	Outdoor Lighting	S.V. - 16000 (O184)	Street and OD Lights - Dept. Owned	187	0.202	37.76	156,631	$ 14.55	$ 32,639
42	Outdoor Lighting	M.V. - 7000 (O331)	Street and OD Lights - Dept. Owned	24	0.208	4.99	20,707	$ 5.03	$ 1,449
43	Outdoor Lighting	M.V. - 20000 (O360)	Street and OD Lights - Dept. Owned	1	0.46	0.46	1,908	$ 11.60	$ 139
44									
45	**LS-1**			30,443		4,648	19,280,962		4,383,844
46	**Outdoor Lighting**			677		166	688,535		104,924
47	**Total - Street and OD Lights - Dept. Owned**			31,120		4,814	19,969,497		4,488,768
48									
49	**LS-2**			364		76	313,355		37,923
50	**Total - Street Lights - Cust. Owned**			364		76	313,355		37,923
51									
52	**Total - All Street Lighting**			**31,484**		**4,890**	**20,282,852**		**4,526,690**

Generation Costs - DCR

Line No.	Resource	RERC & Clearwater Adjusted; Reduced IPP, PV, Hoover									
		2018		2019		2020		2021		2022	
		$/MWh	MWh	$/MWh	MWh	$/MWh	MWh	$/MWh	MWh	$/MWh	MWh
1	CalEnergy Portfolio Units (Renewable)	$ 74.46	144,177	$75.79	222,288	$76.77	335,021	$77.86	647,774	$79.03	647,465
2	Clearwater - MultiMonths	$ 68.05	124,830	$40.50	124,830	$40.61	124,830	$41.13	124,830	$42.43	124,830
3	Hoover	$ 28.56	15,363	$28.82	15,005	$28.88	15,002	$28.94	15,005	$28.99	15,005
4	IPP Detail - Emissions	$ 46.15	1,072,132	$50.32	1,070,177	$51.75	1,073,213	$53.09	1,070,010	$43.39	1,086,630
5	Palo Verde - MultiMonths	$ 42.50	62,740	$43.68	63,056	$45.08	63,117	$46.75	62,450	$47.94	63,120
6	RERC	$ 79.34	232,800	$89.48	232,800	$87.63	232,800	$88.22	232,800	$89.65	232,800
7	Salton Sea (Renewable) - MultiMonths	$ 74.03	318,512	$75.14	317,978	$76.17	291,133		-		-
8	Cabazon Wind	$ 59.30	71,220	$59.30	71,220	$59.30	71,395	$59.30	71,220	$59.30	71,220
9	DVL 20MW Solar Historical Gen	$ 81.17	55,231	$82.39	54,669	$83.62	54,307	$84.87	53,858	$86.15	53,483
10	First Solar 14MW (no sim)	$ 68.75	41,348	$68.75	41,141	$68.75	41,046	$68.75	40,730	$68.75	40,527
11	Recurrent Columbia II Solar 11MW (no sim)	$ 69.98	32,759	$69.98	32,595	$69.98	32,502	$69.98	32,270	$69.98	32,108
12	Silverado 20MW (no sim)	$ 71.25	44,473	$71.25	44,248	$71.25	44,133	$71.25	43,800	$71.25	43,572
13	sPower Antelope DSR Solar 25MW (no sim)	$ 53.75	71,037	$53.75	70,681	$53.75	70,456	$53.75	69,976	$53.75	69,627
14	Tequesquite Solar 7.5MW (no sim)	$ 83.15	15,870	$84.39	15,791	$85.66	15,744	$86.94	15,634	$88.25	15,555
15	WinTec	$ 60.48	4,663	$61.13	2,131		-		-		-
16	WKN	$ 69.62	21,519	$71.29	21,519	$73.00	21,519	$74.75	21,519	$76.54	21,519

Line No.							
17							
18		2018	2019	2020	2021	2022	Average 2018-22
19	Weighted Average	$59.17	$61.43	$62.71	$63.94	$60.25	$61.50
20	20/40/40 weighted average of Hoover|IPP|PV	$41.17	$43.36	$44.51	$45.72	$42.33	$43.42
21							

Hourly Supply Costs

TOU Costs - Hourly Supply Costs for Calculation of TOU charges

	TOU	Total	Variable	Fixed	TOU	Total	Variable	Fixed
0	Off	49%	69%	32%	Off	$ 17,399	$ 11,418	$ 5,982
1	Mid	70%	94%	49%	Mid	$ 24,739	$ 15,423	$ 9,317
2	Peak	100%	100%	100%	Peak	$ 35,396	$ 16,455	$ 18,941

	Proposed	Existing	Cost	P-C	P-E	
Demand On-Peak						
Demand Mid-Peak	50%	40%	49%	1%	10%	Same as COS, Increase from Existing
Demand Off-Peak	25%	19%	32%	-7%	6%	Approximately half-way to COS, Increase from Existing
Energy On-Peak						
Energy Mid-Peak	82%	80%	94%	-12%	2%	Slight increase to existing, approxiamtely 1/6 the delta from COS
Energy Off-Peak	70%	70%	69%	1%	0%	Same as COS and existing

High Voltage Adjustment

Line No.	Item	Service Level		
		Secondary	Primary (4KV, 12 KV)	Primary (>69 KV)
1				
2	Proposed Adjustment for High Voltage			
3	Demand Adjust ($/kW)	$ -	$ (1.15)	$ (9.47)
4	Energy Adjust ($/kWh)	$ -	$ (0.0007)	$ (0.0007)
5				
6	Revenue Impact ($)			
7	On-Peak Demand (kW) for HV Customers		699,443	
8	Adjustment ($/kW)		$ (1.15)	
9	Revenue Impact ($)		$ (801,079)	$ -

Primary Service Customers

Line No.	Account Name	Customer #	Customer Class	Service	FY 2014/15 Total On Peak KW	Total Mid Peak KW	Total Off Peak KW	Total Max KW	KWH	$
1			CONTRACT	12kV	33,552	34,152	34,992	35,640	18,796,800	$ 1,398,276.91
2			TOU	12kV	73,180	76,751	73,522	76,806	43,857,680	$ 4,117,429.31
3			TOU	12kV	24,752	24,624	20,896	25,312	11,422,400	$ 1,203,784.64
4			RESIDENTIAL MULTI F	12kV	3,487	3,487	3,487	3,487	2,592,000	$ 304,615.81
5			TOU	12kV	5,140	5,088	5,376	5,388	2,656,400	$ 282,961.20
6			CONTRACT	12kV	1,496	1,572	1,384	1,580	900,400	$ 101,462.52
7			TOU	2-12kV	14,424	14,676	13,812	14,760	9,156,000	$ 901,959.48
8			TOU	4kV	17,525	19,392	13,776	19,848	4,704,000	$ 593,539.10
9			TOU	12kV	7,256	7,800	5,776	7,928	1,963,200	$ 261,550.08
10			TOU	69 kV to 4kV	35,016	35,712	33,024	33,000	20,349,600	$ 1,643,841.12
11			TOU	69 kV to 4kV	8,736	8,880	7,728	60,104	4,856,000	$ 411,624.80
12			TOU	12kV	5,280	6,640	9,200	9,680	1,816,000	$ 215,059.28
13			TOU	12kV	8,064	9,216	7,728	9,216	3,619,200	$ 367,347.44
14			TOU	12kV	3,402	3,270	3,438	3,492	1,180,200	$ 133,741.86
15			TOU	69 kV to 12kV	201,581	225,216	220,032	235,296	111,580,800	$ 11,158,080.00
16			TOU	69 kV to 12kV	3,840	3,888	3,408	4,080	1,968,000	$ 213,323.52
17			CONTRACT	69 kV to 12kV	61,491	62,365	60,090	62,914	30,140,584	$ 3,098,865.17
18			TOU	4kV	6,432	8,624	11,936	11,936	3,232,000	$ 355,154.21
19			TOU	4kV	7,920	8,160	7,880	8,480	4,444,000	$ 454,281.73
20			TOU	12kV	8,928	12,384	9,168	12,576	2,793,600	$ 351,581.25
21			TOU	12kV	23,688	25,776	24,048	25,776	7,473,600	$ 902,921.01
13			TOU	12kV	7,260	7,140	6,020	7,540	2,584,000	$ 299,535.40
22			TOU	4kV	14,512	14,928	14,176	15,152	7,383,364	$ 766,807.20
23			TOU	4kV	1,084	1,052	1,036	1,000	73,439	$ 73,438.59
24			TOU	4kV	2,238	2,228	2,228	1,092	529,200	$ 129,105.00
25			TOU	4kV	6,688	6,816	7,008	7,360	3,043,600	$ 347,299.38
26										
27		**# Customers**	**On-Peak Demands**							
28	**CONTRACT**	**3**	96,539		586.97	629.84	601.17	699.44	303,116,066.59	30,087,586.00
29	**TOU**	**22**	486,946	2,019,518						
30	**RESIDENTIAL MULTI FAMILY**	**1**	3,487							

Billing Determinants

Line No.	Data	Residential	Small Commercial	Medium Commercial	Large TOU Commercial	Contract 1	Contract 2	Contract 3	Contract 4	City Contract	Street Lights Cust. Owned
1		Residential	Commercial Flat	Commercial Dema	Industrial TOU					City Contract	Street Lights - Cus
2	kWh										
5	2018	694,264,573	277,058,939	159,107,816	911,184,222	-	25,502,856	-	-	69,219,011	316,226
6	2019	695,035,157	281,114,465	161,401,185	951,565,727	-	-	-	-	69,219,011	316,226
7	2020	696,409,688	285,622,070	163,950,201	968,128,763	-	-	-	-	69,219,011	316,226
8	2021	697,528,181	290,092,865	166,478,401	984,480,113	-	-	-	-	69,219,011	316,226
9	2022	697,447,486	294,887,356	169,189,648	1,002,141,495	-	-	-	-	69,219,011	316,226
10											
11	kWh (adjusted for elasticity)										
14	2018	693,538,240	276,893,338	159,012,746	910,321,091	-	25,502,856	-	-	69,155,190	316,226
15	2019	690,063,397	280,084,829	160,810,298	946,298,813	-	-	-	-	68,834,965	316,226
16	2020	687,939,742	283,860,948	162,939,582	959,134,688	-	-	-	-	68,575,394	316,226
17	2021	685,556,224	287,579,243	165,036,166	971,644,035	-	-	-	-	68,315,823	316,226
18	2022	682,294,849	291,662,343	167,339,555	985,668,299	-	-	-	-	68,081,146	316,226
19											
20	Meter Months										
23	2018	1,172,763	124,200	9,759	6,127	-	10	-	-	3,889	4,367
24	2019	1,177,381	126,485	9,933	6,137	-	-	-	-	3,889	4,367
25	2020	1,182,028	128,896	10,117	6,137	-	-	-	-	3,889	4,367
26	2021	1,186,706	131,369	10,305	6,137	-	-	-	-	3,889	4,367
27	2022	1,191,415	133,904	10,498	6,137	-	-	-	-	3,889	4,367
28											
29	Revenues (no change to rates)										
32	2018	$ 113,116,038	$ 45,672,725	$ 24,153,677	$ 106,213,130	$ -	$ 2,002,005	$ -	$ -	$ 7,172,245	$ 37,923
33	2019	$ 113,313,767	$ 46,366,185	$ 24,492,414	$ 110,255,280	$ -	$ -	$ -	$ -	$ 7,172,245	$ 37,923
34	2020	$ 113,590,397	$ 47,130,069	$ 24,868,235	$ 111,781,714	$ -	$ -	$ -	$ -	$ 7,172,245	$ 37,923
35	2021	$ 113,835,763	$ 47,892,441	$ 25,241,623	$ 113,295,070	$ -	$ -	$ -	$ -	$ 7,172,245	$ 37,923
36	2022	$ 113,923,977	$ 48,703,189	$ 25,641,218	$ 114,925,272	$ -	$ -	$ -	$ -	$ 7,172,245	$ 37,923
37											
38	Revenues (with proposed rate changes)										
41	2018	$ 114,405,899	$ 46,112,308	$ 24,373,450	$ 107,665,806	$ -	$ 2,002,005	$ -	$ -	$ 7,222,263	$ 38,378
42	2019	$ 120,993,248	$ 49,063,790	$ 25,865,895	$ 119,425,817	$ -	$ -	$ -	$ -	$ 7,548,006	$ 40,697
43	2020	$ 126,202,060	$ 51,718,403	$ 27,244,572	$ 128,245,375	$ -	$ -	$ -	$ -	$ 7,948,322	$ 42,650
44	2021	$ 132,527,479	$ 54,069,205	$ 28,707,915	$ 136,830,806	$ -	$ -	$ -	$ -	$ 8,393,061	$ 44,697
45	2022	$ 139,622,736	$ 56,170,051	$ 30,432,491	$ 144,906,844	$ -	$ -	$ -	$ -	$ 8,849,112	$ 46,843
46											
47	KW (Billing Demand)										
50	2018	-	-	514,265	6,058,836	-	157,908	-	-	336,444	-
48	2019	-	-	520,578	6,277,434	-	-	-	-	336,444	-
51	2020	-	-	527,595	6,344,848	-	-	-	-	336,444	-
52	2021	-	-	534,555	6,411,824	-	-	-	-	336,444	-
53	2022	-	-	542,019	6,483,451	-	-	-	-	336,444	-
54											

Billing Determinants

Line No.	Data	Street Lights Dept. Owned		Traffic Lights		Ag Pumping		Misc. Lighting		
1		Street and OD Ligh		Traffic Signals		Ag Pumping				
2	kWh									
5	2018		19,839,445		1,273,854		787,485		155,616	
6	2019		19,839,445		1,273,854		787,485		155,616	
7	2020		19,839,445		1,273,854		787,485		155,616	
8	2021		19,839,445		1,273,854		787,485		155,616	
9	2022		19,839,445		1,273,854		787,485		155,616	
10										
11	kWh (adjusted for elasticity)									
14	2018		19,839,445		1,273,854		787,485		155,616	
15	2019		19,839,445		1,273,854		787,485		155,616	
16	2020		19,839,445		1,273,854		787,485		155,616	
17	2021		19,839,445		1,273,854		787,485		155,616	
18	2022		19,839,445		1,273,854		787,485		155,616	
19										
20	Meter Months									
23	2018		373,436		12		528		12	
24	2019		373,436		12		528		12	
25	2020		373,436		12		528		12	
26	2021		373,436		12		528		12	
27	2022		373,436		12		528		12	
28										
29	Revenues (no change to rates)									
32	2018	$	4,488,768	$	120,588	$	124,181	$	21,024	$ 303,122,302
33	2019	$	4,488,768	$	120,588	$	124,181	$	21,024	$ 306,392,374
34	2020	$	4,488,768	$	120,588	$	124,181	$	21,024	$ 309,335,142
35	2021	$	4,488,768	$	120,588	$	124,181	$	21,024	$ 312,229,624
36	2022	$	4,488,768	$	120,588	$	124,181	$	21,024	$ 315,158,383
37										
38	Revenues (with proposed rate changes)									
41	2018	$	4,490,027	$	122,213	$	127,145	$	21,276	$ 306,580,769
42	2019	$	4,496,443	$	129,597	$	138,405	$	22,562	$ 327,724,460
43	2020	$	4,501,848	$	135,818	$	147,913	$	23,645	$ 346,210,605
44	2021	$	4,507,512	$	142,337	$	156,074	$	24,780	$ 365,403,866
45	2022	$	4,513,448	$	149,169	$	162,903	$	25,969	$ 384,879,567
46										
47	KW (Billing Demand)									
50	2018		-		-		-		-	
48	2019		-		-		-		-	
51	2020		-		-		-		-	
52	2021		-		-		-		-	
53	2022		-		-		-		-	
54										

Network Access Charge

Line No.	Item			Year 1	Year 2	Year 3	Year 4	Year 5
1	**NAC - Cost of Service**		Residential	Commercial-Flat	Commercial-Demanc	Industrial TOU		
2	Distribution - Demand Related		$20.75	$63.45	$8.38	$9.95		
3	less Reliability Charge Revenues		$1.24	$3.78	$0.42	$0.48		
4	Net Distribution - Demand Related		$19.51	$59.67	$7.96	$9.47		
5			$/Meter	$/Meter	$/kW	$/kW		
6		2022	$21.71					
7	**RESIDENTIAL**							
8	**NAC Phase-In**			14.0%	28.0%	42.0%	56.0%	71.0%
9	$/Meter			2.73	5.46	8.19	10.93	13.85
10								
11	**Proposed Tiering**		**Tier Increment**					
12	NAC - Tier 1		39%	$ 1.08	$ 2.16	$ 3.23	$ 4.31	$ 5.47
13	NAC - Tier 2		100%	$ 2.73	$ 5.46	$ 8.19	$ 10.93	$ 13.85
14	NAC - Tier 3		209%	$ 5.72	$ 11.43	$ 17.15	$ 22.86	$ 28.98
15								
16	**NAC Tier Increment Calculation**		**kWh per Tier**	**Avg Bill (kWh)**	**Approx kW**	**Ratio**		
17	Summer - Tier 1		0-750	401.4	1.06	1.00		
18	Summer - Tier 2		751-1500	1039.8	2.76	2.59		
19	Summer - Tier 3		> 1500	2069.7	5.48	5.16		
20	Winter - Tier 1		0-350	208.3	0.55	1.00		
21	Winter - Tier 2		351-750	516.6	1.37	2.48		
22	Winter - Tier 3		> 750	1134.0	3.01	5.44		
23	Average - Tier 1			272.7	0.7	1.00		
24	Average - Tier 2			691.0	1.83	2.52		
25	Average - Tier 3			1445.9	3.83	5.35		
26								
27	**Billing Det. (% of Residential Meters)**		**Summer**	**Winter**	**Average**			
28	Tier 1		61%	40%	47%			
29	Tier 2		30%	41%	38%			
30	Tier 3		9%	19%	16%			
31								
32	**COMMERCIAL-FLAT**				0.3	0.4	0.6	1
33	**NAC Phase-In**			15%	30.0%	45.0%	50.0%	55.0%
34	$/Meter			8.95	17.90	26.85	29.83	32.82
35						45%	50%	55%
36	**Proposed Rates - Commercial Flat**		**Tier Increment**			26.85	29.83	32.82
37	NAC - Tier 1		20%	$ 1.77	$ 3.55	$ 5.32	$ 5.91	$ 6.50
38	NAC - Tier 2		56%	$ 5.03	$ 10.06	$ 15.09	$ 16.77	$ 18.45
39	NAC - Tier 3		100%	$ 8.95	$ 17.90	$ 26.85	$ 29.83	$ 32.82
40	NAC - Tier 4		241%	$ 21.53	$ 43.06	$ 64.59	$ 71.77	$ 78.95
41								
42	**NAC Tier Increment Calculation - Commercial Flat**		**Avg Bill (kWh)**	**Approx kW**	**Ratio**		**LF**	
43	Average - Tier 1		199.4	2.3	1.00		0.5	
44	Average - Tier 2		918.2	6.4	2.84			
45	Average - Tier 3		2133.7	11.4	5.05			
46	Average - Tier 4		7715.0	27.5	12.14			
47								
48	**Billing Det. (% of Commercial Flat Meters)**		**Average/Yr**					
49	Tier 1		33%					
50	Tier 2		28%					
51	Tier 3		16%					
52	Tier 4		22%					
53								
	COMMERCIAL-DEMAND							
	NAC Phase-In			20%	40.0%	60.0%	80.0%	100.0%
	$/Meter			1.59	3.18	4.77	6.37	7.96
54	**INDUSTRIAL TOU**							
55	**NAC Phase-In**			20%	40.0%	60.0%	80.0%	100.0%
56	$/Meter			1.89	3.79	5.68	7.58	9.47
57								
58	Sum of Class Demands		2012	2013	2014	Average		
59	Max Demand		2,072,417	2,109,576	2,128,940			
60	On-Peak Demand		1,802,632	1,849,767	1,891,060			
61	Mid-Peak Demand		1,958,445	2,018,593	2,040,443			
62	Off-Peak Demand		1,867,836	1,896,127	1,915,160			
63								
64	On-Peak Demand (% of Max Demand)		87%	88%	89%	88%		
65	Mid-Peak Demand (% of Max Demand)		95%	96%	96%	95%		
66	Off-Peak Demand (% of Max Demand)		90%	90%	90%	90%		
67								

Line No.		Residential NAC Scenario					
8	0	Low	7.5%	16.0%	25.5%	36.0%	47.5%
9		Highlow	37.5%	40.00%	42.50%	45.00%	47.5%
10		LowMid	14.0%	28.0%	42.0%	56.0%	71.0%
11		Medium	55.0%	59.00%	63.00%	67.00%	71.0%
12		High	75.0%	80.0%	85.0%	90.0%	95.00%
14				4.00%	4.00%	4.00%	4.00%

Line No.					
37	Very Small	$ 1.77	$ 1.77	$ 0.59	$ 0.59
38	Small	$ 5.03	$ 5.03	$ 1.68	$ 1.68
39	Average	$ 8.95	$ 8.95	$ 2.98	$ 2.98
40	Large	$ 21.53	$ 21.53	$ 7.18	$ 7.18

Reliability Funds Cash

Line No.		Projected 2018	Projected 2019	Projected 2020	Projected 2021	Projected 2022
1						
2	**Operating revenues:**					
3	Reliability Charge Revenue	$ 25,687,804	$ 25,827,698	$ 25,969,430	$ 26,113,065	$ 26,258,655
	Check: Reliability Charge Revenue (COSA Model)	$ 25,825,121	$ 25,990,180	$ 26,157,047	$ 26,326,758	$ 26,491,730
4	Less: General Fund Transfer (11.5%)	2,954,098	2,970,185	2,986,484	3,003,003	3,019,745
5	**Net Reliability Charge Revenue**	**$ 22,733,707**	**$ 22,857,512**	**$ 22,982,946**	**$ 23,110,063**	**$ 23,238,909**
6						
7	**Operating expenses:**					
8	***RERC 1 & 2 Debt Service***					
9	2004 Debt Service (77.3%)	$ -	$ -	$ -	$ -	$ -
10	2005 A & B Bond issues	-	-	-	-	-
11	2008 A Debt Service (77.3%)	1,696,348	5,150,308	5,191,281	5,208,571	5,240,526
12	2008 C & 2011 A Debt Service (3.4%)	100,577	160,159	215,102	215,014	215,604
13	2013 A Debt Service (Refunded 2008 A) (17.2%) (77.3%)	3,454,109	-	-	-	-
14	2013 A Debt Service (Refunded 2008 C & 2011A) (29.0%) (3.	60,439	-	-	-	-
15	**Subtotal RERC 1 & 2 Debt Service**	**$ 5,311,473**	**$ 5,310,467**	**$ 5,406,383**	**$ 5,423,585**	**$ 5,456,129**
16						
17	***RERC 3 & 4 Debt Service***					
18	2005 A & B Bond issues	$ -	$ -	$ -	$ -	$ -
19	2008 C & 2011 A Debt Service (15.0%)	443,723	706,583	948,979	948,592	951,193
20	2008 D Debt Service (46.2%)	6,302,011	6,285,738	6,261,466	6,241,553	6,202,750
21	2013 A Debt Service (Refunded 2008 C & 2011A) (29.0%) (1	266,643	-	-	-	-
22	**Subtotal RERC 3 & 4 Debt Service**	**$ 7,012,377**	**$ 6,992,321**	**$ 7,210,445**	**$ 7,190,146**	**$ 7,153,943**
23						
24	**Total RERC 1-4 Debt Service**	**$ 12,323,850**	**$ 12,302,788**	**$ 12,616,828**	**$ 12,613,731**	**$ 12,610,072**
25						
26	***Debt Service - RTRP/STP***					
27	2005 A & B Bond issues	$ -	$ -	$ -	$ -	$ -
28	2008 C & 2011 A Debt Service (2.7%)	79,870	127,185	170,816	170,747	171,215
29	2013 A Debt Service (Refunded 2008 C & 2011A) (29.0%) (2.	45,911	-	-	-	-
30	2008 D Debt Service (9.0%)	1,227,664	1,224,494	1,219,766	1,215,887	1,208,328
31	2010 B Bond issue	359,117	357,337	311,080	-	-
32	2010 A Bond issue - spent portion	898,172	896,769	895,366	1,192,895	1,185,654
33	2018 New Bond issue	-	-	-	-	-
34	2021 New Bond issue				-	-
35	**Total RTRP/STP Debt Service**	**$ 2,610,735**	**$ 2,605,786**	**$ 2,597,028**	**$ 2,579,529**	**$ 2,565,196**
36						
37	**Total Debt Service Payments**	**$ 14,934,585**	**$ 14,908,574**	**$ 15,213,856**	**$ 15,193,259**	**$ 15,175,268**
38						
39						
40	**Reserves/Rates - Reliability Fund - RTRP CIP**	**$ 8,462,498**	**$ 10,879,599**	**$ 8,951,734**	**$ 9,206,858**	**$ 17,754,851**
41						
42						
43	**Net Cash Flow**	**$ (663,376)**	**$ (2,930,660)**	**$ (1,182,645)**	**$ (1,290,055)**	**$ (9,691,210)**
44						
45	**Reliabilty Fund Reserve**	**$ 49,885,081**	**$ 46,954,420**	**$ 45,771,776**	**$ 44,481,721**	**$ 34,790,511**
46						

Contribution by Customer Class
2010 Calculation

Electric Cost of Service Summary
Class Over/(Under Collection)

		Total	Residential	Commercial	Commercial - Demand	Industrial-TOU
Revenue Requirement- Internal 2010 Cost of Service						
Total Costs from 2010 Cost of Service		$ 304,845,105	$ 128,033,463	$ 42,966,366	$ 18,062,865	$ 80,193,799
Less Other Revenues		$ (51,229,463)	$ (19,664,704)	$ (7,774,321)	$ (3,499,237)	$ (14,715,647)
		$ 253,615,642	$ 108,368,759	$ 35,192,045	$ 14,563,628	$ 65,478,152
			42.73%	13.88%	5.74%	25.82%
Additional Reserves *		$ 21,873,877	$ 9,186,922	$ 3,083,012	$ 1,296,084	$ 5,754,231
Revenue Requirement with Reserves	**A**	$ 275,489,519	$ 117,555,681	$ 38,275,057	$ 15,859,712	$ 71,232,383
Retail Revenues- 2010	**B**	$ 275,489,519	$ 107,305,581	$ 45,559,756	$ 19,531,475	$ 75,789,749
			38.95%	16.54%	7.09%	27.51%
Retail Revenues less Revenue Requirement	**B-A**	$ -	$ (10,250,100)	$ 7,284,699	$ 3,671,763	$ 4,557,366
	(B-A) /A	0.00%	-8.72%	19.03%	23.15%	6.40%
				$ 7,284,699	$ 3,671,763	$ 4,557,366
				46.96%	23.67%	29.38%

*- Additional Reserves determined by the difference between Retail Revenues and Cost of Service less Other Revenues. Additional Reserves allocated to customer class by percentage of costs allocate to customer class.

Contribution by Customer Class
2010 Calculation

Electric Cost of Service Summary
Class Over/(Under Collection)

		Contract 1	Contract 2	Contract 3	Contract 4	City Contract	Street Lights - Cust. Owned
Revenue Requirement- Internal 2010 Cost of Service							
Total Costs from 2010 Cost of Service		$ 3,668,338	$ 3,686,081	$ 2,596,201	$ 13,519,654	$ 7,728,557	
Less Other Revenues		$ (563,322)	$ (542,380)	$ (401,338)	$ (2,077,083)	$ (1,305,680)	
		$ 3,105,016	$ 3,143,701	$ 2,194,863	$ 11,442,571	$ 6,422,877	$ -
		1.22%	1.24%	0.87%	4.51%	2.53%	0.00%
Additional Reserves *		$ 263,218	$ 264,491	$ 186,288	$ 970,090	$ 554,555	$ -
Revenue Requirement with Reserves	**A**	$ 3,368,234	$ 3,408,192	$ 2,381,151	$ 12,412,661	$ 6,977,432	$ -
Retail Revenues- 2010	**B**	$ 2,274,192	$ 2,251,178	$ 1,792,180	$ 8,477,124	$ 6,873,675	$ -
		0.83%	0.82%	0.65%	3.08%	2.50%	0.00%
Retail Revenues less Revenue Requirement	**B-A**	$ (1,094,042)	$ (1,157,014)	$ (588,971)	$ (3,935,537)	$ (103,757)	$ -
	(B-A) /A	-32.48%	-33.95%	-24.73%	-31.71%	-1.49%	#DIV/0!
		$ 15,513,828					

*- Additional Reserves determined by the difference between Retail Revenues and Cost of Service less Other Revenues. Additional Reserves allocated to customer class by percentage of costs allocate to customer class.

Contribution by Customer Class
2010 Calculation

Electric Cost of Service Summary
Class Over/(Under Collection)

		Street and OD Lights - Dept. Owned	Traffic Signals	Ag Pumping	Miscellaneous-Lighting	Total
Revenue Requirement- Internal 2010 Cost of Service						
Total Costs from 2010 Cost of Service		$ 3,115,940	$ 195,067	$ 1,007,867	$ 70,905	$ 304,845,103
Less Other Revenues		$ (475,146)	$ (32,259)	$ (166,237)	$ (12,110)	$ (51,229,464)
		$ 2,640,794	$ 162,808	$ 841,630	$ 58,795	$ 253,615,639
		1.04%	0.06%	0.33%	0.02%	100.00%
Additional Reserves *		$ 223,581	$ 13,997	$ 72,319	$ 5,088	$ 21,873,877
Revenue Requirement with Reserves	**A**	$ 2,864,375	$ 176,805	$ 913,949	$ 63,883	$ 275,489,516
Retail Revenues- 2010	**B**	$ 4,457,079	$ 168,419	$ 895,998	$ 113,113	$ 275,489,519
		1.62%	0.06%	0.33%	0.04%	100.00%
Retail Revenues less Revenue Requirement	**B-A**	$ 1,592,704	$ (8,386)	$ (17,951)	$ 49,230	$ 3
	(B-A) /A	55.60%	-4.74%	-1.96%	77.06%	0.00%

*- Additional Reserves determined by the difference between Retail Revenues and Cost of Service less Other Revenues. Additional Reserves allocated to customer class by percentage of costs allocate to customer class.

Streetlight - LED Replacement (LS-1)

Streetlighting - LED Replacement

TYPE	SIZE	Lumens	UNITS	Spec Wattage	Lumen Per Intenet Search	Per Lamp/Mo Rates - Existing	Total Revenue	LED Lights Replacement Watts	Units	Rate	$/yr	No Change	Equivlaent Lumens			
INCANDESCENT	1	1,000	88	100	1600	$ 6.82	$ 7,202	42	88	6.82	$ 7,202		1,000	1,000	5,800	
Induction (No Change)	2.8	2,800	312	55	800	$ 10.12	$ 37,889					$ 37,889				
	4	4,000	44	300	3600	$ 13.44	$ 7,096	58	44	13.44	$ 7,096		4,000	4,000	3,500	9,500
MERCURY VAPOR	3.5	3,500	446	100	4000	$ 10.77	$ 57,641	58	446	10.77	$ 57,641		3,500			
	7	7,000	1251	175	7300	$ 12.76	$ 191,553	93	1251	12.76	$ 191,553		7,000	7,000	9,500	
	10	10,000	12	400	23000	$ 15.68	$ 2,258	139	12	15.68	$ 2,258		10,000	10,000	22,000	
HIGH PRESSURE SODIUM	5.8	5,800	2453	70	6500	$ 10.51	$ 309,372	42	2453	10.51	$ 309,372		5,800			
	9.5	9,500	18801	100	9500	$ 11.85	$ 2,673,502	58	18801	11.85	$ 2,673,502		9,500			
	16	16,000	949	150	1600	$ 13.88	$ 158,065	93	949	13.88	$ 158,065		16,000			
	22	22,000	4498	200	22,000	$ 15.75	$ 850,122	139	4498	15.75	$ 850,122		22,000			
	25	25,000	804	250	25,000	$ 17.39	$ 167,779	185	804	17.39	$ 167,779		25,000			
	40	40,000	294	400	40,000	$ 21.84	$ 77,052	275	294	21.84	$ 77,052		40,000			

Adjustment Factor 1

Rate Tariff LED Watt			# of Lamps	LED Per Lamp / Mo	No change
0	$ 37,889				$ 10.12
42	$ 309,372				
42	$ 7,202	$ 316,574	2541	$ 10.38	
58	$ 7,096				
58	$ 57,641				
58	$ 2,673,502	$ 2,738,240	19291	$ 11.83	
93	$ 191,553				
93	$ 158,065	$ 349,619	2200	$ 13.24	
139	$ 850,122				
139	$ 2,258	$ 852,380	4510	$ 15.75	
185	$ 167,779	$ 167,779	804	$ 17.39	
275	$ 77,052	$ 77,052	294	$ 21.84	

Streetlight - LED Replacement (LS-2)

Streetlighting - LED Replacement

TYPE	SIZE	Lumens	Spec Watts	Per Lamp/Yr Energy Only	Energy & Mainte	Energy Rate $ 0.0658	Demand Cost (Remaining)	LED Lights Replacement Watts	Cost of Energy	Energy Only	Maintence Adder	Energy + Maint	Lumen Per internet search
INCANDESCENT	1	1,000	100	$ 42.52	$ 54.19	$ 6.58	$ 35.94	42	$ 2.76	$ 38.70	$ 11.67	$ 50.37	1,600
Induction (No Change)	2.5	2,500	55	$ 88.83	$ 103.43	$ 3.62	$ 85.21	42	$ 2.76	$ 87.97	$ 14.60	$ 102.57	800
	4	4,000	300	$ 135.72	$ 156.13	$ 19.74	$ 115.98	58	$ 3.82	$ 119.80	$ 20.41	$ 140.21	3,600
	6	6,000	433	$ 156.13	$ 196.96	$ 28.52	$ 127.61	93	$ 6.12	$ 133.73	$ 40.83	$ 174.56	
MERCURY VAPOR	7	7,000	175	$ 95.46	$ 115.88	$ 11.52	$ 83.94	93	$ 6.12	$ 90.06	$ 20.42	$ 110.48	7,300
	10	10,000	400	$ 131.66	$ 155.00	$ 26.32	$ 105.34	139	$ 9.15	$ 114.48	$ 23.34	$ 137.82	23,000
	20	20,000	1150	$ 209.59	$ 237.29	$ 75.68	$ 133.91	139	$ 9.15	$ 143.06	$ 27.70	$ 170.76	
	35	35,000	2275	$ 361.49	$ 399.38	$ 149.71	$ 211.78	275	$ 18.10	$ 229.88	$ 37.89	$ 267.77	
	55	55,000	3775	$ 508.17	$ 559.21	$ 248.42	$ 259.75	432	$ 28.44	$ 288.19	$ 51.04	$ 339.23	
HIGH PRESSURE SODIUM	5.8	5,800	70	$ 40.37	$ 53.50	$ 4.61	$ 35.76	42	$ 2.76	$ 38.53	$ 13.13	$ 51.66	6,500
	9.5	9,500	100	$ 63.74	$ 78.32	$ 6.58	$ 57.16	58	$ 3.82	$ 60.98	$ 14.58	$ 75.56	9,500
	16	16,000	150	$ 92.56	$ 108.61	$ 9.87	$ 82.69	93	$ 6.12	$ 88.81	$ 16.05	$ 104.86	1,600
	22	22,000	200	$ 119.23	$ 135.28	$ 13.16	$ 106.07	139	$ 9.15	$ 115.22	$ 16.05	$ 131.27	22,000
	25	25,000	250	$ 143.81	$ 161.30	$ 16.45	$ 127.36	185	$ 12.17	$ 139.53	$ 17.49	$ 157.02	25,000
	40	40,000	400	$ 219.57	$ 244.36	$ 26.32	$ 193.25	275	$ 18.10	$ 211.34	$ 24.79	$ 236.13	40,000

Adjustment Factor 1

Rate Tariff LED Watt	Data Points Equivalent Lume	Energy Only	Energy + Maint	Rate Equivalent Lume	Energy Only	Energy + Maint
42	1,000	$ 38.70	$ 50.37			
42	2,500	$ 87.97	$ 102.57			
42	5,800	$ 38.53	$ 51.66	3,100	$ 55.07	$ 68.20
58	$ 4,000	$ 119.80	$ 140.21			
58	$ 9,500	$ 60.98	$ 75.56	6,750	$ 90.39	$ 107.88
93	$ 6,000	$ 133.73	$ 174.56			
93	$ 7,000	$ 90.06	$ 110.48			
93	$ 16,000	$ 88.81	$ 104.86	9,667	$ 104.20	$ 129.97
139	$ 10,000	$ 114.48	$ 137.82			
139	$ 20,000	$ 143.06	$ 170.76			
139	$ 22,000	$ 115.22	$ 131.27	17,333	$ 124.25	$ 146.62
185	$ 25,000	$ 139.53	$ 157.02	25,000	$ 139.53	$ 157.02
275	$ 35,000	$ 229.88	$ 267.77			
275	$ 40,000	$ 211.34	$ 236.13	37,500	$ 220.61	$ 251.95
432	$ 55,000	$ 288.19	$ 339.23	55,000	$ 288.19	$ 339.23

Streetlight - LED Offer for Outdoor LIghts

Streetlighting - Existing and LED Offer for Outdoor Lights

	Class	Total KWh	Total Revenue	$/kWh
Outdoor Lighting OL	LS-1	19,112,668	$ 4,383,844	0.23
Department Owned & Maintained	OL	693,142	$ 104,924	0.15

Month		Existing (Mo)	Proposed FY18	Proposed FY19	Proposed FY20	Proposed FY21	Proposed FY22
MV 7000		$ 10.33	$ 10.83	$ 11.35	$ 11.89	$ 12.46	$ 13.06
MV 20000		$ 18.25	$ 19.13	$ 20.05	$ 21.01	$ 22.02	$ 23.08
HPS 9500		$ 10.39	$ 10.89	$ 11.41	$ 11.96	$ 12.53	$ 13.13
HPS 16000		$ 14.55	$ 15.25	$ 15.98	$ 16.75	$ 17.55	$ 18.39
% Increse	4.8%	2016	2018	2019	2020	2021	2022
			April 1	Jan 1	Jan 1	Jan 1	Jan 1
Current / Projcted Revenue		$ 104,924	$ 109,960	$ 115,238	$ 120,770	$ 126,567	$ 132,642
Partial Year			$ 106,183	$ 112,599	$ 118,004	$ 123,668	$ 129,604
Incremental Revenue	Annual		$ 1,259	$ 6,416	$ 5,405	$ 5,664	$ 5,936
	Cummulative		$ 1,259	$ 7,675	$ 13,080	$ 18,744	$ 24,680

LED Equivalent

TYPE	**SIZE**	**Lumens**	**Spec Wattage**	**Per Month**	**LED Lights Replacement Watts**	**SL-1 Rate**	**Proposed Rate**
MERCURY VAPOR	7	7,000	175	$ 10.33	93	$ 13.24	$ 13.24
	20	20,000	1,150	$ 18.25	139	$ 15.75	$ 15.75
HIGH PRESSURE SODIUM	9.5	9,500	100	$ 10.39	58	$ 11.83	$ 11.83
	16	16,000	150	$ 14.55	93	$ 13.24	$ 13.24

City Owned EV Charging Station Analysis

January Average Energy		Std. Devia	Peak per E	Std. Dev F	Daily Max	Ave Dema	Std. Dev D	Cumulativ	Events/day
	7.96	5.06	19.68	10.59	29.85	20.83	10.87	139	4.48
February Average Energy									
	14.67	11.66	24.97	10.75	35.42	23.88	10.32	116	4.00
March Average Energy									
	16.4	12.9	24.1	12.1	37.6	24.3	12.1	174	5.6
April Average Energy									
	17.45322382	13.68866	25.44376	12.23911	42.27067	25.25586	11.81014	181	6.033333
May Average Energy									
	17.44248447	13.00869	25.75495	11.27462	42.02133	28.08573	12.098	190	6.129032
June Average Energy									
	18.42021505	13.67269	28.50909	10.52331	37.15429	28.80328	10.78873	33	4.714286
Total Average Energy									
	16.19	12.75	24.32	11.65	37.45	24.91	11.77	834	5.25

$	0.07		22.89	$/ Demanc	10.19		
$	1.124		597.78	Total Demand			
		$ 0.2061	$ 6.23	Demand + Energy / Event			139
			$ 6.44	Demand + Energy + Customer / Event			116
							174
							181
			67% of Da	12.67			190
				35.98			141.43
							157
						Std	29

EV Public Charging Data	Avg	Std Dev	Low Range	High Range
# of Charging Events	222	75.87	146.30	298.04
Peak Demand Day (kW)	26.11	11.63	14.48	37.74
Duration (min)	26.00	16.17	9.83	42.17
Energy (kWh)	10.56	6.59	3.96	17.15

Collected from January 1, 2016 to December, 2016

Water Cost of Service Study

PROJECT MEMORANDUM

WATER COST OF SERVICE AND RATE DESIGN

City of Riverside Public Utilities

Date:	03/30/2018
Project No.:	9938B.00

Subject:	**Development of Scaled Rates Calculation**

Purpose

This project memorandum describes the methodology and results of the rate scaling analysis. Carollo assisted Riverside Public Utilities (RPU) with the analysis in order to adjust the rates proposed in the 2017 Cost of Service Analysis (COSA) Report based on RPU's updated 10-Year Financial Pro Forma (Pro Forma).

Background

Beginning in 2015, Carollo worked with RPU to complete a comprehensive water cost of service and rate design analysis, the analysis and report were finalized in August 2017. After the finalization of the COSA, RPU began a public outreach campaign with presentations to several stakeholder groups, the RPU Board of Directors, and the Riverside City Council. RPU subsequently received direction from the Board and Council to modify the plan and adjust the rates to lessen overall rate increases. Carollo assisted RPU in adjusting the rates proposed in the 2017 COSA to reflect the updated Pro Forma's projected rate revenue requirements and water sales.

Methodology and Results

Rate Implementation Timing

When the COSA study was completed, RPU anticipated implementing rate adjustments starting on April 1, 2018 followed by adjustments on January 1 of each of the following 4 years. Due to the delay driven by the Council's request to reevaluate the rates, the implementation dates were pushed back. As planned, the first adjustment will now take place on July 1, 2018, followed by adjustments on July 1 of the following 4 years.

To account for the delay, the rate scaling calculations compare the FY 2017/18 results from the COSA to the FY 2018/19 results from the updated Pro Forma and so forth for subsequent years. Table 1 below shows the COSA and Pro Forma fiscal years that correspond to each of the rate plan years (1 through 5).

Table 1. Scaling Analysis Years

	Year 1	Year 2	Year 3	Year 4	Year 5
COSA	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Updated Pro Forma	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22	FY 2022/23

Water Sales

RPU's Pro Forma includes price elasticity adjustments to account for changes in water sales driven by rate increases. The lowered rate increases of the updated Pro Forma lessen the impact of price elasticity on

RPU's sales projections, leading to higher overall sales. The rate scaling calculation is based on the higher level of sales in the updated Pro Forma. Table 2 shows the projected sales from the COSA analysis compared to those in the Updated Pro Forma. By year 5, RPU expects to have annual sales of nearly 1 million ccf higher than those projected in the COSA.

Table 2. Projected Sales Comparison

	Year 1	Year 2	Year 3	Year 4	Year 5
COSA Retail Sales (ccf)	26,572,000	26,035,000	25,604,000	25,176,000	24,744,000
Updated Pro Forma Retail Sales (ccf)	26,629,000	26,422,000	26,216,000	26,007,000	25,738,000
Increase from COSA (ccf)	57,000	387,000	612,000	831,000	994,000
Note: Sales shown in this table do not include sales to Totals may be imprecise due to rounding.					

In order to complete the rate scaling calculation, the sales projection from the updated Pro Forma was used to develop matching sales projections by rate class. Increases in sales for each of the major customer types (Residential, Commercial and Industrial, and Other) were applied to the detailed projections from the COSA to project the sales by rate class with the lowered rate increases of the updated Pro Forma. Table 3 shows the projected sales by rate class used in the rate scaling calculations.

Table 3. Projected Sales by Class

	Year 1	Year 2	Year 3	Year 4	Year 5
WA-2 Temporary Service	54,000	54,200	54,400	54,500	54,600
WA-4 Riverside Water Company Irrigators	29,100	28,700	28,400	28,000	27,600
Commercial and Industrial	7,874,000	7,898,300	7,923,500	7,947,900	7,960,800
WA-7 Interruptible	962,900	965,900	968,900	971,900	973,500
SFR	15,712,000	15,479,900	15,248,300	15,014,700	14,736,800
MFR	469,200	462,200	455,300	448,300	440,000
Landscape	1,527,500	1,532,200	1,537,100	1,541,900	1,544,300
Total Sales	**26,629,000**	**26,422,000**	**26,216,000**	**26,007,000**	**25,738,000**
Note: Totals may be imprecise due to rounding.					

Revenue Requirements

The updated revenue requirements set the basis for adjusting the proposed rates from the COSA. Table 4 shows a summary of the updated revenue requirements. This table can be compared to Table 4-9 in the COSA report.

Table 4. Updated Revenue Requirements

Revenues	Year 1 FY 2018/19	Year 2 FY 2019/20	Year 3 FY 2020/21	Year 4 FY 2021/22	Year 5 FY 2022/23
Revenue before rate and demand increase[1]	$57.74	$60.25	$63.29	$66.48	$69.83
Offsetting Revenues					
Interest income	1.45	1.69	1.30	1.54	1.79
Miscellaneous income	10.06	10.18	10.30	10.43	10.55
Outside City Surcharge	1.55	1.59	1.64	1.69	1.73
Other Charges for Service	0.63	0.64	0.66	0.67	0.68
Total Revenues Before Increase	**$71.43**	**$74.35**	**$77.19**	**$80.80**	**$84.60**
Expenditures					
Production costs	$4.85	$4.92	$5.00	$5.07	$5.13
Personnel costs	18.21	19.51	20.59	21.69	22.73
Other O&M costs	20.17	20.57	20.98	21.40	21.82
Additional O&M for CIP and Tech	0.99	1.47	1.95	2.34	2.98
Debt service requirements	15.42	17.54	17.21	18.56	21.47
General fund transfer	6.71	7.00	7.36	7.73	8.12
Capital outlay financed by rates	10.79	5.62	6.70	4.46	4.83
Total Expenditures	**$77.13**	**$76.62**	**$79.78**	**$81.25**	**$87.08**
Allocation to (Use of) Reserves Prior to Increases	**($5.70)**	**($2.27)**	**($2.59)**	**($0.45)**	**($2.49)**
Revenue Increase due to Demand and Growth Increases[2]	0.99%	0.80%	0.81%	0.83%	0.84%
Rate Revenue Increase	4.50%	5.75%	5.75%	5.75%	6.50%
Month of Rate Increase	July	July	July	July	July
Revenues from Demand and Rate Increases	$2.57	$3.10	$3.25	$3.41	$3.95
Total Revenues	**$73.99**	**$77.45**	**$80.44**	**$84.21**	**$88.55**
Allocation to (Use of) Reserves After to Increases	**($3.13)**	**$0.83**	**$0.66**	**$2.96**	**$1.46**
Unrestricted Undesignated Reserves	*$33.60*	*$33.41*	*$33.47*	*$33.67*	*$33.97*
Debt Service Coverage Ratio[3]	2.05x	1.86x	1.96x	1.91x	1.75x

Notes:

(1) Projected revenues prior to each fiscal year's demand and rate increases, includes the impact of increases from previous years.
(2) Prior to inclusion price elasticity adjustment.
(3) Net of BABs treasury credit.
(4) Totals may be off due to rounding.

Agricultural and Cemetery Rates

Based on direction from the City Council, agricultural customers in the Special Irrigation (WA-3) and Grove Preservation (WA-9) rate classes will not transition to otherwise applicable tariffs as proposed in the COSA. Rather, an Agricultural Rate Task Force is being assembled to assess options for the agricultural customers. For this analysis, it was assumed that the agricultural customers would receive the system average rate increases with a one-year delay to allow the Task Force to complete its study.

Similarly, cemeteries currently assessed the WA-7 rates will not be transitioned to the Landscape or Commercial classes. For this analysis, it was assumed that the cemetery customers would receive the system average rate increases beginning on July 1, 2018.

The proposed rates in the COSA report were calculated with the assumption that agricultural and cemetery customers would be transitioned into the other rate classes. The revenue impacts associated with the transition were incorporated into the rate revenue requirements and offset using non-rate revenues from interest earnings to avoid revenue shortfalls. The Council's new direction to create the Task Force and the change to the cemetery transition, as well as the scaled rates change the revenue impacts from those shown in the COSA.

Resulting Rate Revenue Requirements

Table 5 on the following page shows the rate revenue requirements used to calculate the scaled rates. The rate revenue requirements are determined by subtracting any offsetting revenues from the total annual requirements (expenditures) and adding adjustments for the rate increase delays (mid-year increases) and the agricultural and cemetery rates revenue impacts. Because the rates will be implemented on July first of each year, no adjustment for rate increase delays is needed in the updated rate revenue requirements. Table 5 can be compared to Table 4-10 in the COSA report.

Table 5. Updated Rate Revenue Requirements

	Year 1 FY 2018/19	Year 2 FY 2019/20	Year 3 FY 2020/21	Year 4 FY 2021/22	Year 5 FY 2022/23
Total Expenditures	$77.13	$76.62	$79.78	$81.25	$87.08
Allocation to (Use of) Reserves After Increases	(3.13)	0.83	0.66	2.96	1.46
Less Offsetting Revenues:					
Interest Income	($1.45)	($1.69)	($1.30)	($1.54)	($1.79)
Miscellaneous income	(10.06)	(10.18)	(10.30)	(10.43)	(10.55)
Outside City Surcharge	(1.55)	(1.59)	(1.64)	(1.69)	(1.73)
Other Charges for Service	(0.63)	(0.64)	(0.66)	(0.67)	(0.68)
Required Rate Revenue	**$60.30**	**$63.35**	**$66.54**	**$69.89**	**$73.78**
Plus: Anticipated Adjustment for Agricultural and Cemetery Rates[1]	$0.75	$0.75	$0.74	$0.72	$0.71
Revenue Requirements For Scaled Rates	**$61.05**	**$64.10**	**$67.28**	**$70.61**	**$74.49**
Notes:					
(1) The revenue shortfalls associated with Agricultural and Cemetery rates will be offset using Interest Income.					

Rate Scaling

The rate scaling calculation applies a scaling factor to the COSA rates to adjust them such that they generate the rate revenue requirements shown in Table 5.

Revenues with COSA Rates

Because the updated Pro Forma includes a higher sales projection than that of the COSA report due to decreased price elasticity, the rate revenue requirements from the COSA cannot be directly compared to those in the updated Pro Forma. Rather, the rate scaling calculation considers the amount of revenue that would be generated by applying the COSA's proposed rates to the updated sales projections. Table 6 shows the amount of rate revenues that would be expected with the COSA rates and the updated sales projection.

Table 6. Revenues with COSA Rates and Updated Sales Projection

	Year 1 FY 2018/19	Year 2 FY 2019/20	Year 3 FY 2020/21	Year 4 FY 2021/22	Year 5 FY 2022/23
Variable Revenue	$45,707,700	$47,229,200	$48,558,000	$49,959,400	$50,967,500
Fixed Revenue	17,680,000	20,909,400	24,504,600	28,472,500	32,802,800
Total Revenues with COSA Rates	**$63,388,000**	**$68,139,000**	**$73,063,000**	**$78,432,000**	**$83,770,000**
Note: Totals may be imprecise due to rounding.					

Scaling and Proposed Rates

The rate scaling factor for each year is equal to the Total Revenues with COSA Rates from Table 6 divided by the Revenue Requirements for Scaled Rates from Table 5. Table 7 shows the scaling factors for each year in the analysis.

Table 7. Rate Scaling Factor

	Year 1	Year 2	Year 3	Year 4	Year 5
Total Revenues with COSA Rates	$63,388,000	$68,139,000	$73,063,000	$78,432,000	$83,770,000
Updated Revenue Requirements	61,052,000	64,099,000	67,281,000	70,615,000	74,493,000
Rate Scaling Factor	**0.963**	**0.941**	**0.921**	**0.900**	**0.889**

The proposed rates from the COSA report are multiplied by the rate scaling factor for the corresponding year to calculate the scaled rates. Due to the phase-in of increased fixed charges, the calculated volumetric rates for certain rate classes decrease slightly year-to-year. In these cases, the rates were overridden to hold rates constant for the 5-year period. The overrides will result in a slight under collection of revenue in years 1 through 3 and a corresponding slight over collection in years 4 and 5. Table 8 and Table 9 show the scaled volumetric rates and fixed service charges.

Table 8. Scaled Volumetric Rates

Single Family Residential (SFR) WA-1A							
Winter Rates	Existing	CCF Allotment	Year 1	Year 2	Year 3	Year 4	Year 5
Tier 1	$1.13	First 9	$1.16	$1.19	$1.22	$1.26	$1.30
Tier 2	1.64	10-35	1.45	1.50	1.54	1.58	1.64
Tier 3	2.26	>35	2.67	2.76	2.84	2.91	3.01
Tier 4	2.75						
Summer Rates	Existing	CCF Allotment	Year 1	Year 2	Year 3	Year 4	Year 5
Tier 1	$1.14	First 9	$1.16	$1.19	$1.22	$1.26	$1.30
Tier 2	1.83	10-35	1.45	1.50	1.54	1.58	1.64
Tier 3	2.85	>35	3.26	3.37	3.46	3.55	3.66
Tier 4	4.10						
Multi-Family Residential (MFR) WA-1B							
Winter Rates	Existing	CCF Allotment	Year 1	Year 2	Year 3	Year 4	Year 5
Tier 1	$1.13	First 7 per DU[1]	$1.16	$1.19	$1.22	$1.25	$1.30
Tier 2	1.64	>7 per DU[1]	1.66	1.71	1.76	1.81	1.87
Tier 3	2.26						
Tier 4	2.75						
Summer Rates	Existing	CCF Allotment	Year 1	Year 2	Year 3	Year 4	Year 5
Tier 1	$1.14	First 7 per DU[1]	$1.16	$1.19	$1.22	$1.25	$1.30
Tier 2	1.83	>7 per DU[1]	1.88	1.95	2.00	2.05	2.12
Tier 3	2.85						
Tier 4	4.10						
Commercial and Industrial WA-6							
Winter Rates	Existing		Year 1	Year 2	Year 3	Year 4	Year 5
Tier 1	Varies	All Usage	$1.58	$1.58	$1.58	$1.58	$1.58
Summer Rates	Existing		Year 1	Year 2	Year 3	Year 4	Year 5
Tier 1	Varies	All Usage	$1.84	$1.84	$1.84	$1.84	$1.84
Landscape Volumetric Rates (New Rate Schedule)							
Winter Rates	Existing		Year 1	Year 2	Year 3	Year 4	Year 5
Tier 1	Varies	All Usage	$1.67	$1.67	$1.67	$1.67	$1.67
Summer Rates	Existing		Year 1	Year 2	Year 3	Year 4	Year 5
Tier 1	Varies	All Usage	$2.14	$2.14	$2.14	$2.14	$2.14
Temporary Service WA-2							
	Existing		Year 1	Year 2	Year 3	Year 4	Year 5
All Usage	$2.71	All Usage	$2.39	$2.39	$2.39	$2.39	$2.39

Riverside Water Company Irrigators WA-4							
Winter Rates	Existing	CCF Allotment	Year 1	Year 2	Year 3	Year 4	Year 5
Tier 1	$1.14	First 15	$1.21	$1.22	$1.26	$1.29	$1.32
Tier 2	1.75	16-70	1.45	1.48	1.52	1.55	1.58
Tier 3	1.77	>70	2.26	2.29	2.36	2.40	2.46
Summer Rates	Existing	CCF Allotment	Year 1	Year 2	Year 3	Year 4	Year 5
Tier 1	$1.14	First 15	$1.21	$1.22	$1.26	$1.29	$1.32
Tier 2	1.76	16-70	1.45	1.48	1.52	1.55	1.58
Tier 3	1.87	>70	2.91	2.94	3.04	3.10	3.17
Interruptible and Recycled Water (New Rate Schedule- Previously WA-7 and WA-10)							
	Existing		Year 1	Year 2	Year 3	Year 4	Year 5
All Usage	$0.80 to $1.14		$1.57	$1.57	$1.57	$1.57	$1.57
Notes:							
(1) Dwelling Unit							

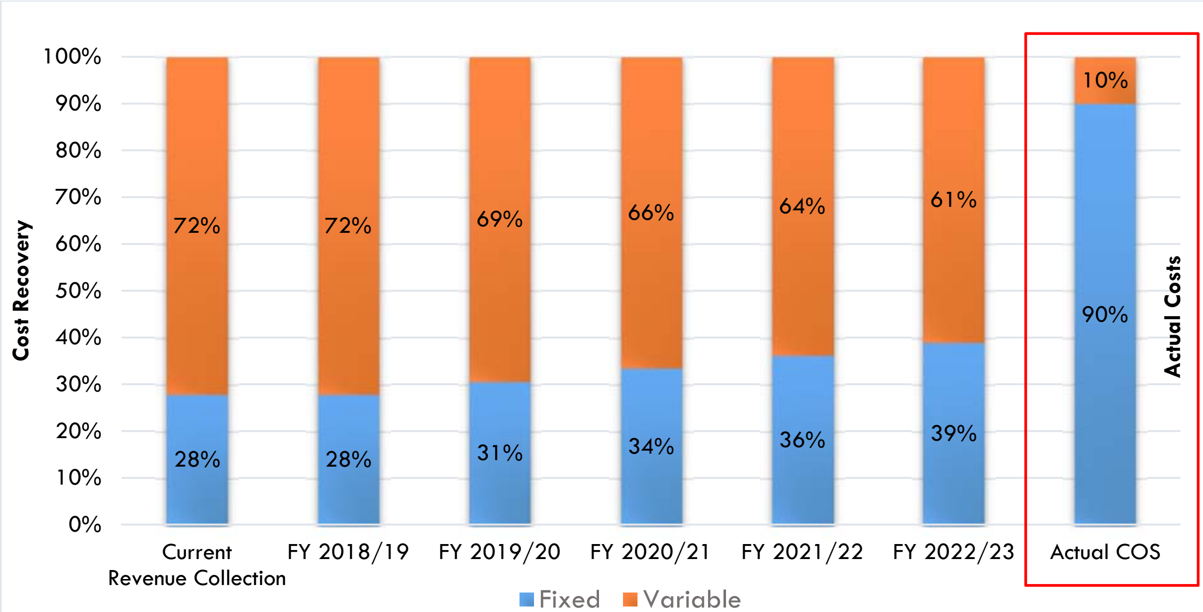
Table 9. Scaled Monthly Fixed Charges

Meter Size	Existing Residential	Existing Commercial/ Industrial	Year 1	Year 2	Year 3	Year 4	Year 5
3/4" & 5/8"	$13.99	$11.57	$15.80	$18.07	$20.53	$23.08	$26.00
1"	23.29	19.22	25.08	28.69	32.58	36.63	41.26
1.5"	46.60	38.46	48.08	55.00	62.45	70.22	79.08
2"	74.49	61.51	75.80	86.70	98.45	110.68	124.64
3"		142.52	140.51	160.72	182.49	205.16	231.03
4"		237.57	232.95	266.44	302.52	340.10	382.97
6"		475.19	510.10	583.43	662.43	744.72	838.59
8"		760.29	833.40	953.19	1,082.28	1,216.71	1,370.06
10"		1092.85	1,295.28	1,481.47	1,682.08	1,891.02	2,129.34
12"		1330.40	1,849.59	2,115.45	2,401.91	2,700.26	3,040.57

Fixed and Variable Revenues

Figure 1 on the next page shows the percentage of rate revenue in each year that is expected from the fixed and variable components of the rates. By the last year in the rate plan, 39 percent of total rate revenues will be generated by the fixed service charges. In the COSA, fixed service charge revenues in the last year of the rate plan were expected to comprise 40 percent of total rate revenues. However, the increased level of sales as compared to the projections in the COSA study leads to an increased portion of overall rate revenues being generated by the volumetric rates.

Figure 1. Fixed and Variable Revenues



Outside City Surcharge

The outside city surcharge calculation has been updated to reflect the scaling. Because (1) the scaled rates are lower than those proposed in the COSA, but (2) the amount of surcharge revenue to be collected is based on infrastructure needs that are not subject to scaling, the updated surcharge is slightly higher than that presented in the COSA report. Table 10 shows a summary of the outside city surcharge calculation, the updated surcharge amount will be 47 percent.

Table 10. Outside City Surcharge Calculation

	Year 1	Year 2	Year 3	Year 4	Year 5	Five Year Sum
Variable Revenue Without Surcharge	$2,240,000	$2,269,000	$2,290,000	$2,313,000	$2,340,000	$11,452,000
Annual Fixed Revenue Without Surcharge	874,000	1,008,000	1,154,000	1,308,000	1,485,000	$5,829,000
Total Revenue Without Surcharge	**$3,114,000**	**$3,277,000**	**$3,444,000**	**$3,621,000**	**$3,825,000**	**$17,281,000**
Surcharge Costs to Collect	**$1,550,000**	**$1,595,000**	**$1,640,000**	**$1,687,000**	**$1,735,000**	**$8,207,000**
					Calculated Surcharge	**47%**
Notes:						
(1) Totals may be off due to rounding.						

Memorandum Source Material

The information discussed and presented in this document is based on the "*Water 10 Yr Pro Forma 1-23-2018 - With Rate Scaling 3-30-2018.xlsm*" spreadsheet.

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WATER COST OF SERVICE AND RATE DESIGN STUDY

AUGUST 2017

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GLOSSARY

TERM	DESCRIPTION
AF	Acre foot / Acre feet, 1 AF = 435.6 CCF, 326,000 gallons
AWWA	American Water Works Association
Carollo	Carollo Engineers, Inc.
CCF	One hundred cubic feet, 1 CCF = 748 gallons
CIP	Capital Improvement Plan
CY	Calendar Year
Domestic	Potable Water
Fixed Costs	Expenses that are not dependent on the level water production or water sold
FY	Fiscal Year
GPCD	Gallons per capita per day
GPD	Gallons per day
M1 Manual	"Principles of Water Rates, Fees, and Charges: Manual of Water Supply Practices M1" published by AWWA
MEU	Meter Equivalent Units – relate the capacity required to serve each connection to the system based on the expected maximum flow from meters of each size
MGD	Million gallons per day
O&M	Operations and Maintenance
PAYGO	Pay-As-You-Go
Potable Water	Water suitable to be consumed for drinking and other uses.
Raw Water	Water in its natural state, prior to any treatment for drinking.
Recycled Water or Reclaimed Water	Sewage that is treated to remove solids and impurities, and used for non-potable irrigation and commercial and industrial water needs
R-GPCD	Residential gallons per capita per day
RPU	Riverside Public Utilities
SWRCB	State Water Resources Control Board
Variable Cost	Costs that change in proportion to volume of water sold or produced

1 EXECUTIVE SUMMARY

1.1 STUDY PURPOSE

The City of Riverside, California's (City) Strategic Plan seeks to advance the mission of providing high-quality municipal services to ensure a safe, inclusive, and livable community. As the *City of Arts & Innovation*, the City's leaders aim towards a prosperous future in which the City builds on its assets to implement intelligent growth, and to be a location of choice that drives innovation, provides a high quality of life, and is united in pursuing the common good. In the Riverside 2.0 Strategic Plan, a wide-reaching set of objectives address challenges ranging from uncertain economic conditions, to climate change, to aging infrastructure. Guided by the Riverside 2.0 Strategic Plan, Riverside Public Utilities (RPU) developed the Utility 2.0 Strategic Plan (Utility 2.0 Plan). The Utility 2.0 Plan focuses on providing safe, reliable, affordable, and financially responsible water and electric services for the benefit of the residences and businesses it serves. Specific challenges that RPU is facing include:

- Ensuring water supply remains resilient and sustainable.
- Replacing aging water and electric infrastructure while balancing cost impacts.
- Developing its workforce and addressing the need for changing skill sets.
- Employing advanced technology in all areas of its business to provide more efficient and better customer service, both behind, and in front of, the meter.
- Thriving financially by ensuring costs are recovered and developing a new business model to adapt for the future.

To thrive financially, RPU must balance operating costs, capital expenditures, operating income, and reserves. Spending too much on operations and capital investments requires more revenue from customers, while spending too little degrades safety, reliability, and customer service. If operating income falls short of budgets, reserves can deplete causing borrowing costs to increase. RPU has effective tools to strike the right balance between these competing objectives including its 10-year Financial Pro Forma Model (pro forma) and new fiscal policies, which includes an updated reserves policy. However, RPU needs to develop a business model that is sustainable into the future.

RPU provides safe and reliable water to over 65,000 service connections in an environmentally and financially responsible manner. RPU's water service area is approximately 75 square miles, which includes approximately five square miles of land outside of the City limits. RPU's potable water system consists of groundwater basins, groundwater wells, a supply transmission system, water treatment plants, and a water distribution system. This report and the specific information that is presented relates specifically to RPU's Water Utility.

RPU funds its operations using water rate revenue, wholesale water revenue, water conveyance revenue (wheeling fees), and other miscellaneous revenue. The primary source of funding are the water rates charged to residential, commercial, industrial, and other users, which account for over 86 percent of annual operating revenues.

Within the State of California, water agencies must establish rates in conformance with the substantive requirements defined by California Constitution article XIII D, section 6 (commonly referred to as Proposition 218), while taking into consideration the constitutional mandate to conserve the water resources of the State set forth in California Constitution article X, section 2.

Prudent financial planning and responsible use of reserves has allowed RPU to avoid increasing rates since 2010. To maintain a high level of service, RPU has undertaken the development of a cost-of-service and rate design study (study). This study incorporates and builds upon the projections in RPU's pro forma and consumption forecasts, and draws on several other sources including, but not limited to, historical billing data, cost of water analyses, and engineering data related to RPU's water systems. The goals of this study are to determine revenue requirements to operate the water utility, update the cost of providing water service to various customer classes, and develop water rates that are adequate to fund RPU's water operations in compliance with the requirements of proposition 218.

Though the wet winter in Fiscal Year (FY) 2016/17 has alleviated drought conditions for much of the state, it has resulted in ongoing challenges for water agencies. At the peak of the drought in FY 2015/16, RPU's customers were using over 20 percent less water than historic levels. Since the lifting of the State mandated usage curtailments RPU has realized a rebound in demands. However, it is expected that demand hardening due to conservation will result in continuing demand reductions, though not as severe as those in FY 2015/16.

RPU's current rates recover costs primarily through volumetric charges. However, approximately 90% of RPU's costs are fixed. As water demand decreases, RPU loses income needed to pay for its fixed costs related to providing water service. With ideally designed rates, the fixed charges are designed to recover fixed costs and variable charges are designed to recover variable costs, and eliminating the risk of under-collection of fixed costs. RPU's current residential and commercial rate structures also include inclining tiered pricing which increases revenue risk when customers in the higher tiers conserve or reduce their demand. These factors have significantly increased the level of uncertainty with regards to RPU's operational and financial planning. Reducing the number of tiers will allow RPU to mitigate the revenue risk associated with reduced revenue resulting from reduced demand.

These uncertainties underscore the need for integrated financial planning and flexible rate design. At the outset of the study, Carollo Engineers (Carollo) and RPU discussed and summarized key study goals. Several key issues and challenges that were considered during the cost-of-service analysis and rate design project included:

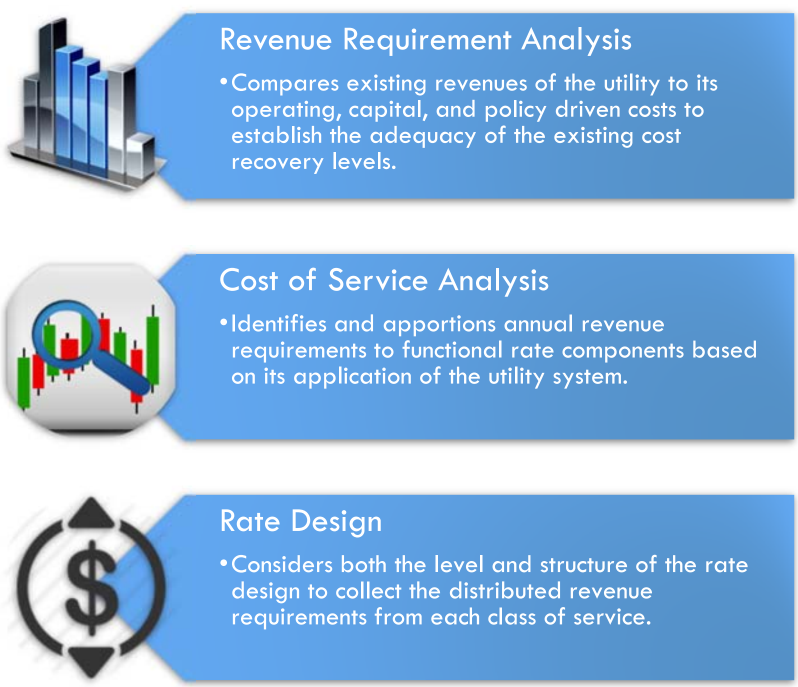
- Review implications of ongoing water conservation.
- Implement cost-of-service-based demand reduction rates that comply with Proposition 218, and are adaptable to changing water demands.
- Maintain financial stability while incentivizing efficient water usage.

- Better align fixed and variable revenue collection with costs.
- Evaluate and consider reducing the number of tiers in the residential and commercial classes
- Achieve customer equity under continued changes to consumption. Review customer demand impacts from implementing a new rate structure.
- Identify future fiscal, operational, and capital impacts and considerations.

1.2 COST OF SERVICE STUDY

RPU retained Carollo Engineers to conduct a five-year cost of service study starting with its FY 2017/18 water rate structure. Like many California water agencies, the drought and its now lifted mandatory water use reduction requirements has had lasting implications for RPU. Continued conservation has resulted in some revenue instability due to decreased revenues resulting from lower water sales and uncertainty of future water demands. The cost of service study addresses the need for RPU to adapt to this “new normal” level of demand as it continues to fund its operations and system investment.

The cost of service rate analysis presented within this report consists of the following three interconnected processes:



The processes presented above are advocated by the American Water Works Association (AWWA) for cost of service rate setting. While the process is described in a linear step by step approach, it is better understood as an iterative process where the ultimate objective is to balance revenues with costs in an equitable manner for customers. These three processes will form the basis for the rate analyses presented within this report.

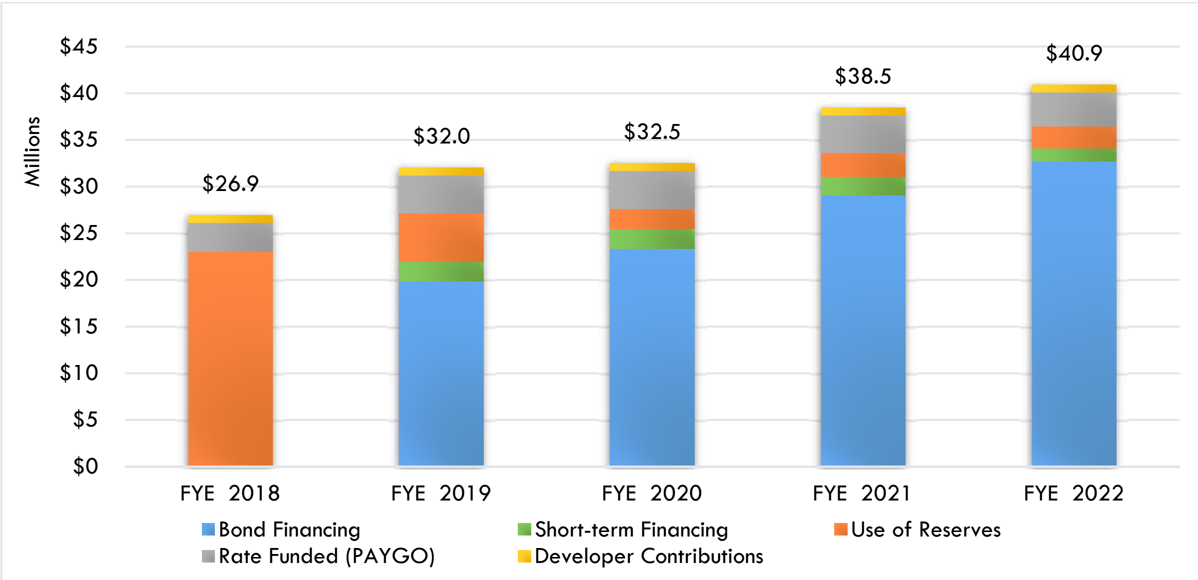
1.2.1 Revenue Requirements

The revenue requirements analysis compares the forecasted revenues of the utility to its forecasted operating and capital costs less offsetting revenues including interest income, lease revenues, water conveyance revenue, wholesale water sales revenues, capacity charge revenues, settlement revenues, interest earnings, and other operating and non-operating revenues, to determine the adequacy of the existing rates to recover the utility's costs of providing service. If any shortfalls exist, rates might need to be increased. Through its annual budgeting process, RPU performs a detailed review of its costs, including operations expenditures, capital needs, and funding requirements. RPU developed and maintains a financial pro forma that defines its annual rate revenue requirements based on projected expenditures and as prescribed by its fiscal, cash reserve, and debt management policies. The pro forma serves as the basis for this rate analysis.

Capital Improvement Plan

In October 2015, RPU's governing Board and City Council conceptually approved a new plan called Utility 2.0. Utility 2.0 includes a ten year Capital Improvement Plan with several options that relate to rehabilitation and replacement of existing infrastructure, enhancements to existing water supply, development of new sources of supply, expansion of the recycled water system, and employing advanced technologies to provide more efficient and better customer service. The results discussed within the body of this report are based on Option 3 in the Utility 2.0 Plan which was conceptually approved by City Council on October 6, 2015. The Utility 2.0 CIP will be funded through a combination of reserve funds, rate revenues, debt financing, and other sources as shown in Figure 1-1 below.

FIGURE 1-1 CIP FUNDING SOURCES



Reserve Policy

To accompany the Utility 2.0 CIP, RPU has developed a robust reserve policy, which is designed to promote fiscal sustainability, minimize borrowing costs, and provide a source of emergency funds for unforeseen events. The reserve policy defines the restricted reserves, unrestricted designated reserves, and unrestricted undesignated reserves, while also setting the overall minimum and maximum unrestricted undesignated reserve levels. Detailed information on each specific risk category is provided in Section 4.4 of this report. Table 1-1 below shows the projected unrestricted undesignated reserve minimum and maximum levels for each year of the study period.

As part of the Five Year Rate Plan, RPU will propose updating the reserve policy to securing a line of credit (LOC) from a third party as available reserves to meet unrestricted undesignated reserve targets. A LOC is a low cost mechanism that allows RPU to draw upon cash when needed, thus reducing required cash reserve levels, minimizing rate increases to maintain reserve levels, and increasing liquidity. Unrestricted undesignated reserve projections were developed to include the LOC and remain above the target minimum levels.

TABLE 1-1 UNRESTRICTED, UNDESIGNATED RESERVE LEVELS

Target Reserve Level	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Minimum	$43,647,000	$47,915,000	$52,101,000	$55,734,000	$62,907,000
Maximum	$67,226,000	$72,686,000	$79,257,000	$84,457,000	$93,807,000
Proposed Line of Credit	$34,222,000	$34,222,000	$34,222,000	$34,222,000	$34,222,000

Financial Projection

Overall, RPU must raise rate revenues in order to account for reduced water demands, increases in operating costs, and to fund future capital reinvestments. While the water utility will recover some additional revenue from the projected increases in water demands as the restrictions are lifted, these increased sales alone are not sufficient to fund RPU's needs. Table 1-2 presents a summarized financial projection including revenues, expenditures, and overall rate revenue increases for the forecast period beginning in FY 2017/18 through FY 2021/22. A system wide rate revenue increase of 8.75 percent will be required starting on April 1, 2018, with 8.50 percent increases occurring on January 1 of each subsequent year through FY 2021/22. Actual rate increases may vary by customer class and consumptions levels as reflected in Appendices G and H.

TABLE 1-2 REVENUE REQUIREMENTS FORECAST (MILLIONS)

Revenues	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Rate Revenue before annual rate and demand increase[1]	$55.61	$59.60	$65.26	$69.85	$74.64
Offsetting Revenues	11.32	12.56	13.03	12.67	13.38
Total Revenues Before Increase	**$66.93**	**$72.16**	**$78.29**	**$82.52**	**$88.01**
Expenditures					
O&M Expenditures	40.77	44.25	46.58	48.67	50.65
Debt service requirements	13.82	15.40	18.78	18.79	21.10
General fund transfer	6.64	7.11	7.76	8.30	8.86
Capital outlay financed by rates	5.07	9.79	6.70	7.10	6.52
Total Expenditures	**$66.30**	**$76.54**	**$79.82**	**$82.86**	**$87.12**
Allocation to (Use of) Reserves Prior to Increases	**$0.63**	**($4.37)**	**($1.53)**	**($0.34)**	**$0.89**
Demand and Growth Increase[2]	6.56%	0.99%	0.80%	0.81%	0.83%
Rate Revenue Increase	8.75%	8.50%	8.50%	8.50%	8.50%
Month of Rate Increase	April	January	January	January	January
Revenue from Demand and Rate Increases	$4.01	$5.67	$4.60	$4.81	$5.10
Total Revenues	**$70.94**	**$77.84**	**$82.89**	**$87.32**	**$93.12**
Allocation to (Use of) Reserves After Increases	**$4.64**	**$1.30**	**$3.06**	**$4.46**	**$6.00**
Unrestricted Undesignated Reserves	*$40.22*	*$38.41*	*$40.19*	*$43.85*	*$45.64*
Debt Service Coverage Ratio[3]	2.29x	2.27x	2.00x	2.13x	2.07x

Notes:
(1) Projected revenues prior to each fiscal year's demand and rate increases with Outside City Surcharge, includes the impact of increases from previous years.
(2) Prior to inclusion of price elasticity adjustments.
(3) Net of BABs treasury credit.
(4) Totals may be off due to rounding

1.2.2 Cost of Service Analysis

After determining the utility's revenue requirements, the next step in the analysis is to outline the cost to deliver each unit of water to serve each customer. This process takes each item in RPU's budget and reviews how and why those costs are incurred to serve water customers. For example, some cost items support the ability to deliver basic water service, while other costs are incurred in order to provide water during the summer when outside irrigation demands are the highest. These high summer demands drive the need for oversizing of infrastructure and system capacity to serve the peak demand. Organizing the budget in terms of end function allows direct correlation between each budget item and the rate, coupling the cost incurred by RPU and the benefit delivered to the customer or the demand and burden that the customer places on RPU's system and/or water resources.

1.2.3 Rate Design Analysis

The final component of the analysis is the rate design analysis. The rate design involves developing a rate structure that proportionally recovers costs between customer classes (i.e., single-family residential and commercial), as well as from customers within their designated customer class. For example water supply costs are recovered based on the units of water sold (demand), while capital costs are recovered based on the size of a customer's meter, which accounts for the capacity needs of that customer or potential demand that customer can place on the system. This step allows RPU to develop unit costs that can then be layered based on customer characteristics. This is a critical process for establishing tiered rates, as increasing usage incurs additional costs that make each unit of water more expensive to provide. This process creates a fair and equitable foundation for establishing each charge and rate that RPU levies in order to proportionally recover system costs from its customers.

Forecasting water sales and purchases is also a critical component in the rate setting process. RPU's forecast process includes a multi-year evaluation of system demands on a customer class and system-wide basis. RPU currently has enough local supplies to meet all of its demands, as well as has the ability to purchase imported water from Western Municipal Water District, a member agency of the Metropolitan Water District of Southern California. RPU's water demand forecast is used as the basis for setting commodity rates for this rate plan.

With this approach, Carollo has taken into consideration not only industry accepted standards issued by the AWWA and RPU's specific water system and customer characteristics, but also California's unique legal framework as discussed later within this study.

Current Rate Structure

Table 1-3 below shows a list of RPU's current water customer classes and a brief description of the rate structure and consumption characteristics of each. The rate design analysis reviewed the characteristics and consumption patterns of each rate to verify the appropriateness of the current structure, and to identify potential enhancements and simplifications that could be made.

TABLE 1-3 CURRENT CUSTOMER CLASSES AND RATES

Customer Class		Rate Structure and Consumption Characteristics
Residential	WA-1	Meters serve both single and multiple unit residences; consumption peaks in summer months due to increased outdoor usage. Seasonal rates with a 4-tier inclining block structure.
Flat Rate Temporary Service	WA-2	Flat rate for temporary usage for construction, fire hydrant use, and bulk permit delivery. Consumption peaks heavily in summer.
Irrigation Metered Service w/ Residence	WA-3.1	Two tiered inclining block structure with very large tier 1 block (100 CCF). Consumption peaks marginally in summer. Closed to new customers as of May 31, 2003.
Irrigation Metered Service w/o Residence	WA-3.2	Flat rate for all usage. Consumption peaks during the summer months. Closed to new customers as of May 31, 2003.
Riverside Water Company Irrigators	WA-4	Three tiered inclining block structure for residential and commercial customers. Consumption peaks marginally in summer. RPU is contractually bound to serve these customers under a unique rate structure, resulting from the acquisition of the Riverside Water Company.
General Metered Service - Commercial	WA-6.1	Two tiered inclining block structure for meters from 5/8" to 2" serving commercial customers. Consumption peaks marginally in summer.
General Metered Service - Industrial	WA-6.2	Three tiered inclining block structure for meters from 3" to 12" serving industrial and institutional customers. Consumption peaks marginally in summer.
Special Metered Service	WA-7	Flat rate for all usage by City of Riverside for irrigation of public facilities. Consumption peaks heavily in summer.
Greenbelt Irrigation Service	WA-8	Pass-through rate for customers who are able to take Gage Canal water and have installed a pressurized system. Used only for outdoor irrigation; consumption peaks heavily in summer.
Grove Preservation Service with Residence and Nominal Ornamental Landscaping	WA-9.1	Three tiered structure with declining tier 3 rate. Meters serve both indoor (residential) and outdoor usage; consumption peaks in summer due to increased outdoor usage.
Grove Preservation Service without residence or with separately metered Residence and more than Nominal Ornamental Landscaping	WA-9.2	Flat rate for all usage. Meters may serve outdoor usage; consumption peaks in summer due to increased outdoor usage.
Recycled Water Service	WA-10	Flat Rate for all usage. Meters serve outdoor usage; consumption peaks heavily in summer due to increased irrigation demands.

1.3 RESULTS AND RECOMMENDATIONS

While the existing rate structure was found to be appropriate, Carollo recommends that RPU update its water rates based on its forecasted budget, water demands and on the analysis as presented within this Cost of Service Study (Study). The rate structure updates and enhancements center on providing increased revenue stability from both fixed and variable charges, simplifying specific rate structures, and creating new customer classes for distinct user groups.

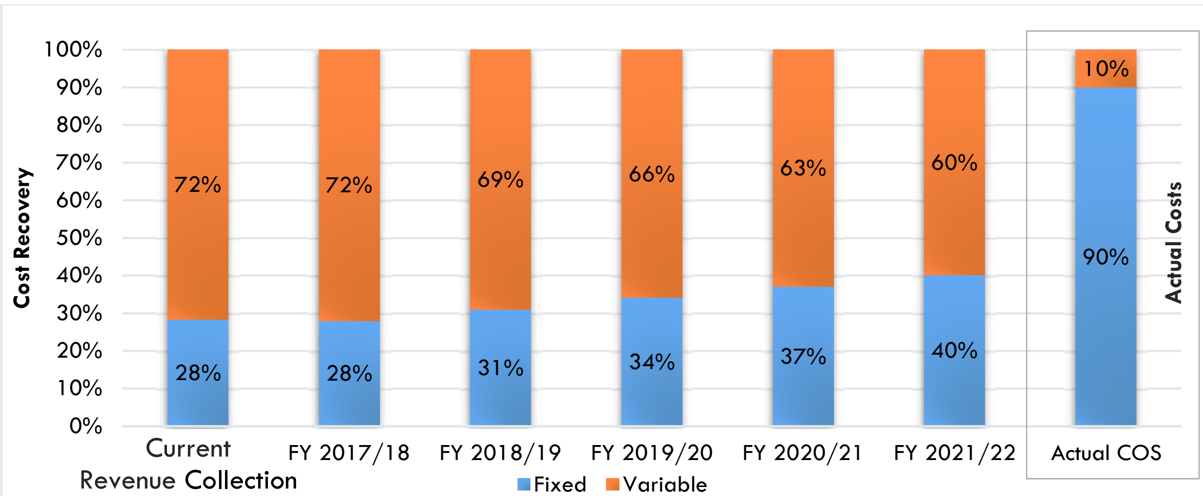
Based on discussion with RPU staff and careful review of the cost of service analysis, Carollo recommends that RPU implement the following rate design modifications:

- Increase the percentage of costs recovered by the fixed charge to better reflect how actual costs are incurred. The adjustments helps RPU meet its objective of increased revenue stability and predictability.
- Implement a uniform fixed monthly service charge for each meter size.
- Separate Single Family Residential (SFR) and Multi-Family Residential (MFR) customers into different rates.
- Implement a three-tier rate structure for SFR customers with seasonally adjusted rates.
- Revise SFR tier 1 allotment from 15 CCF to 9 CCF per month, which assumes 55 gallons per day at four persons per SFR dwelling.
- Implement a two-tier rate structure for MFR customers with two, three, or four dwelling units with tier allocations based on the number of dwelling units served by each account. MFR accounts with more than 4 dwelling units will be assessed the Commercial and Industrial Rate.
- The MFR tier 1 allotment will be set at 7 CCF based on 3 persons per household and 55 gallons per person per day.
- Combine Commercial (WA-6.1) and Industrial (WA-6.2) accounts into one rate class with a uniform, seasonally adjusted rate.
- Implement a uniform landscape rate which is seasonally adjusted and separate from the Commercial and Industrial Rates.
- Combine Special Metered Service (WA-7) accounts, which are used by the City for irrigation of public facilities, with Recycled Water (WA-10).
- Transition Irrigation Metered Service (WA-3) and Grove Preservation Service (WA-9) customers to the otherwise applicable rate classes. Services with residences (WA-3.1 and WA-9.1) will be transitioned to the SFR rate class as they serve residences, while services without residences (WA-3.2 and WA-9.2) will be transitioned to the commercial and industrial rate class as they serve primarily commercial nursery operations.
- Transition cemeteries that have historically been charged under the Special Metered Service (WA-7) rate to the otherwise applicable rate classes. Meters that serve offices or other structures will transition to the Commercial and Industrial rate, while those that serve exclusively irrigation will transition to the Landscape rate.

Revenue Stability

RPU's current rates are structured to recover costs primarily through volumetric charges while most of its costs are fixed. As water demand decreases, RPU loses income needed to pay for its fixed costs related to providing water service. As fixed charges are increased to better collect fixed costs, RPU increases revenue stability and predictability. The proposed rates will increase fixed revenue to about 40% of retail revenues by FY 2021/22 and reduce the number of tiers in the residential and commercial classes. The proposed rate structures reduce revenue volatility and maintain financial stability. Figure 1-2 shows the percentage of overall rate revenue to be collected through the fixed charges and the volumetric rates for each year of the study period.

FIGURE 1-2 FIXED COST RECOVERY



Revenue stability enhancements will also be achieved through the modifications to the volumetric rates for SFR and Commercial and Industrial customers. The move to a three tiered structure rather than a four tiered structure for SFR customers decreases volatility in revenues from the highest users. Additionally, the differential in the rate for usage within each tier have been reduced based on RPU's supply characteristics to further reduce volatility. Migration to a seasonally adjusted uniform rate for commercial and industrial users will reduce volatility driven by the changes among the highest users in those classes.

Rate Structure Simplifications

Simplifications will be made to the fixed charges paid by all classes, and to the volumetric rates for specific classes. The shift to monthly fixed service charges that are consistent for all customer classes will simplify the overall rate structure and promote better customer understanding while accurately reflecting the capacity burden placed on the system by each customer. Implementation of a seasonally adjusted uniform rate structure will allow commercial and industrial customers to be combined into a single class.

New Customer Classes

New customer classes will be created to separate distinct user groups that are currently charged under more general rate classes. The Residential customer class will be separated into SFR and MFR classes, and landscape irrigation rates will be separated from the commercial and industrial classes.

MFR customers with two, three, or four dwelling units will be placed into a distinct rate class with a two tiered structure and allotments that are set based on the number of dwelling units served by each account. This structure better reflects the indoor usage needs and overall usage pattern of MFR accounts. All MFR accounts with more than four dwelling units will be charged under the commercial and industrial rate, since those complexes typically exhibit consumption patterns similar to those of commercial customers.

Landscape irrigation customers are currently served under the commercial and industrial rates depending on the size of the water meter. However, analysis of billing data has shown that the consumption patterns of landscape irrigation customers are distinct from those of other non-landscape commercial and industrial users, in that they exhibit a much larger seasonal peak. The proposed rates address this discrepancy by providing a separate seasonally adjusted uniform rate for landscape irrigation customers.

Variable Rates

The variable rates are developed for each customer class and are designed to recover the costs proportionate to water demands. The variable rates recover the costs of producing water from RPU's groundwater basins, treating water to potable standards, and transporting it to each customer. They also recover the costs to operate and maintain the system, a portion of engineering costs, and the portion of capital costs (debt service and rate funded capital) that is associated with projects that develop, maintain, or enhance RPU's water supplies. Supply related capital projects include groundwater recharge, recycled water, storm water capture, and treatment plant projects.

Costs that are associated with providing a basic level of service, base costs, are equal for each unit of water provided. Differences in rates between each customer class and between each tier are based on the water supplies required to provide water to each customer class, and to cover demand in each tier (in classes with tiered rates.) Supply related costs are recovered from each customer class based on each class's consumption patterns, users who place a greater burden on the system during the summer months are responsible for a greater share of the higher cost sources of supply.

For classes with tiered rates, supply costs are allocated to each tier starting with the lowest cost sources for usage in Tier 1 and applying the higher cost supplies to usage in the upper tiers. For example, the Proposed Tier I rate for single family includes base costs, plus the single family class's share of supply costs for water produced from the Gage supply, RPU's lowest cost water source, and a portion of existing debt service. Tier 2 rate includes the class's share of costs to produce water from the Riverside North/South supply, a portion of those from Waterman supply (the next highest cost sources of supply), and a portion of supply related capital costs. The Tier 3 rate includes the class's remaining portion of Waterman costs, the class's share of costs for the Flume system costs (the highest cost source of supply) as well as portion of supply related capital costs. The proposed volumetric rates are presented in Table 1-4.

TABLE 1-4 VOLUMETRIC RATES

Single Family Residential (SFR) WA-1							
Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.13	First 9	$1.20	$1.27	$1.33	$1.40	$1.46
Tier 2	1.64	10-35	1.51	1.59	1.67	1.76	1.84
Tier 3	2.26	>35	2.77	2.93	3.08	3.23	3.38
Tier 4	2.75						
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 9	$1.20	$1.27	$1.33	$1.40	$1.46
Tier 2	1.83	10-35	1.51	1.59	1.67	1.76	1.84
Tier 3	2.85	>35	3.38	3.58	3.76	3.94	4.12
Tier 4	4.10						
Multi-Family Residential (MFR) WA-1							
Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.13	First 7 per DU[1]	$1.20	$1.27	$1.33	$1.39	$1.46
Tier 2	1.64	>7 per DU[1]	1.72	1.82	1.91	2.01	2.10
Tier 3	2.26						
Tier 4	2.75						
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 7 per DU[1]	$1.20	$1.27	$1.33	$1.39	$1.46
Tier 2	1.83	>7 per DU[1]	1.95	2.07	2.17	2.28	2.38
Tier 3	2.85						
Tier 4	4.10						
Commercial and Industrial WA-6							
Winter Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$1.66	$1.69	$1.72	$1.75	$1.77
Summer Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$1.93	$1.97	$2.00	$2.03	$2.05
Landscape Volumetric Rates (New Rate Schedule)							
Winter Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$1.75	$1.78	$1.81	$1.84	$1.86
Summer Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$2.24	$2.28	$2.32	$2.36	$2.38
Temporary Service WA-2							
	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$2.50	$2.56	$2.60	$2.64	$2.67
Riverside Water Company Irrigators WA-4							
Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 15	$1.26	$1.30	$1.37	$1.43	$1.48
Tier 2	1.75	16-70	1.51	1.57	1.65	1.72	1.78
Tier 3	1.77	>70	2.35	2.43	2.56	2.67	2.77
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 15	$1.26	$1.30	$1.37	$1.43	$1.48
Tier 2	1.76	16-70	1.51	1.57	1.65	1.72	1.78
Tier 3	1.87	>70	3.02	3.13	3.30	3.44	3.56
Interruptible and Recycled Water (New Rate Schedule- Previously WA-7 and WA-10)							
	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$0.80 to $1.14	All Usage	$1.63	$1.67	$1.70	$1.72	$1.74
Notes:							
(1) Dwelling Unit							

Fixed Charges

The fixed charge is intended to provide a stable revenue source that that recovers the costs allocated based on customer accounts and the amount of capacity reserved by each customer. The customer account component recovers costs that apply to all accounts in the system, regardless of usage or the size of the connection to the system. Specifically, these costs include billing and administrative costs that are independent of each customer's capacity share and therefore equal for each account.

The amount of capacity reserved by each customer is based on the size of their connection to the system, thus, the capacity component of the fixed charge is different for each meter size. In the proposed fixed charge, the capacity component is designed to collect costs associated with capital expenditures that are not related to water supply enhancements. These costs include a portion of existing and projected debt service, a portion of rate funded capital, and a portion of engineering costs.

Table 1-5 presents the proposed fixed charges for each year of the rate plan.

TABLE 1-5 FIXED MONTHLY SERVICE CHARGES

Meter Size	Existing Residential	Existing Commercial/ Industrial	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
3/4" & 5/8"	$13.99	$11.57	$16.40	$19.21	$22.29	$25.64	$29.24
1"	23.29	19.22	26.04	30.50	35.38	40.69	46.40
1.5"	46.60	38.46	49.92	58.47	67.82	77.99	88.93
2"	74.49	61.51	78.70	92.16	106.91	122.93	140.16
3"		142.52	145.89	170.85	198.17	227.87	259.80
4"		237.57	241.86	283.23	328.52	377.75	430.67
6"		475.19	529.61	620.20	719.36	827.16	943.03
8"		760.29	865.28	1,013.27	1,175.29	1,351.40	1,540.69
10"		1,092.85	1,344.83	1,574.84	1,826.63	2,100.35	2,394.54
12"		1,330.40	1,920.34	2,248.78	2,608.32	2,999.17	3,419.25

1.4 TRANSITIONAL RATES

As a component of the cost of service analysis, RPU's rate classes were reviewed and customer data was analyzed to test the nexus between rate class and account and usage characteristics. As a result of this analysis, it was determined that several rate classes that have historically been treated as distinct classes, would be more appropriately placed within RPU's general SFR, Commercial and Industrial, or Landscape rate classes. The effected customers include all customers in Irrigation Metered Service (WA-3.1, WA-3.2), Grove Preservation Rate (WA-9.1, WA-9.2), and cemetery customers in Special Metered Service (WA-7).

Under direction from RPU, and in order to mitigate the rate impacts to effected customers, this study migrates the customers to the appropriate rate classes over the rate projection period. As a result, transitional rates for each of the classes were developed to smooth the increases over five years. All of the effected rate classes are or will be closed to new users going forward.

The proposed monthly transitional rates are set forth in the tables of this report as well as in in Appendix H.

1.5 RATE ADJUSTMENTS

In light of the current water demand uncertainty and need for financial resiliency, RPU has explored multiple approaches to increase revenue stability. Two rate adjustment mechanisms were explored as part of this study, if used collectively, can help to create revenue stability for RPU.

1.5.1 Demand Reduction Rates

Demand Reduction Rates are charges that may be imposed by RPU following levels of extreme water demand reductions. The objective of these rates is to maintain sufficient revenue levels if customers' potable water usage declines as a result of expanded or future water shortage conditions. The rates are important in that many of RPU's costs are fixed and do not fluctuate with changes in water demands.

RPU is forecasted to have water sales of roughly 26.7 million CCF in FY 2017/18. Based on an extreme water curtailment period, RPU estimated three potential demand reduction scenarios as follows:

- Demand Reduction Stage 1 would equate to a slight reduction in demands (15 percent).
- Demand Reduction Stage 2 would equate to a larger reduction in demands (20 percent).
- Demand Reduction Stage 3 would equate to the maximum expected reduction in demands (30 percent).

The demand reduction rates would be implemented through a council action and would be lifted once there are no longer reduced water sales.

1.5.2 Pass-Through Cost Adjustments

In 2008, the California legislature adopted California Assembly Bill 3030 (AB 3030), which allows agencies to adopt rates that include automatic adjustments that either pass through increases in wholesale charges for water or include increases for inflation. As part of its Proposition 218 rate noticing process, RPU may notice its cost escalation assumptions and subsequently make specific pass-through cost adjustments if costs escalation, such as for the price of energy, exceed the noticed cost assumptions. These adjustments require a written notice to RPU's customers before the automatic increase is implemented, and gives RPU flexibility to adapt to changes in costs that could occur within the Five Year Rate Plan.

1.6 RPU WITHOUT RATE ADJUSTMENTS

RPU is going through a challenging period of change over the next five years as it takes action to achieve the strategic visions of the City. The Utility 2.0 Plan includes updating and modernizing operations through technology; replacing aging infrastructure; enhancements to existing water supply; development of new sources of supply; expansion of the recycled water system; and setting new standards for excellence in operations, safety, efficiency, and reliability; all while maintaining long-term financial strength.

RPU's operations and needed investments cannot be sustained without rate adjustments. Rates must be adjusted to more accurately reflect the high fixed costs relative to variable cost structure. If rates are not adjusted, RPU will not be able to fund its Utility 2.0 investments, its increased operating costs, and will fail to maintain its strong financial metrics. RPU's existing reserves are not sufficient to pay for the planned investments. Additionally, drawing down on its reserves will also lead to higher borrowing costs for the City, as a result of anticipated negative impacts to its credit rating. RPU has deferred its investments for as long as practical; without rate adjustments, these delays will impact utility operations and customer service.

2 INTRODUCTION

2.1 STUDY PURPOSE

The City of Riverside (City) Public Utilities Department (RPU) provides safe and reliable water to over 65,000 service connections in an environmentally and financially responsible manner. To maintain this level of service in light of water conservation requirements and needed implementation of Utility 2.0, RPU has undertaken the development of a cost-of-service and rate design study. This study incorporates and builds upon the projections in the pro forma and consumption forecasts, and draws on several other sources including, but not limited to, historical billing data, cost of water analyses, and engineering data related to RPU's water systems.

Though the wet winter in FY 2016/17 has alleviated drought conditions for much of the state, it has resulted in ongoing challenges for water agencies. At the peak of the drought in FY 2015/16, RPU's customers were using over 20 percent less water than historic levels. Since the lifting of the State mandated usage curtailments RPU has realized a rebound in demands. However, it is expected that demand hardening due to conservation will result in continuing demand reductions, though not as severe as the reductions in FY 2015/16. Continued conservation has resulted in some revenue instability due to decreased revenues resulting from lower water sales and uncertainty of future water demands. These factors have significantly increased the level of uncertainty with regards to RPU's operational and financial planning.

This uncertainty underscores the need for integrated financial planning and flexible rate design. At the outset of the study, Carollo Engineers (Carollo) and RPU discussed and summarized key study goals. Several key issues and challenges that were considered during the cost-of-service analysis and rate design project included:

- Review implications of ongoing water conservation.
- Implement cost-of-service-based demand reduction rates that comply with Proposition 218 and are adaptable to changing water demands.
- Maintain financial stability while incentivizing efficient water usage.
- Achieve customer equity under continued changes to consumption. Review customer demand impacts from implementing a new rate structure.
- Identify future fiscal, operational, and capital impacts and considerations.

The purpose of this report is to address each of these key issues as part of the systematic evaluation and development of the cost-of-service analysis and RPU rate design.

The study was divided into three main phases in order to address these issues and prepare the rate design:

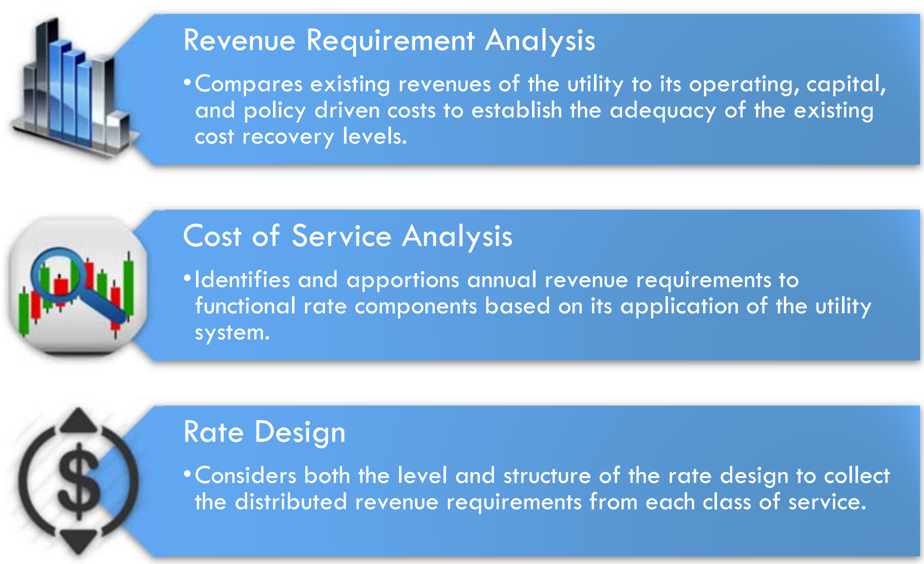
1. Water Utility Rate Trends Analysis
2. Cost of Service Analysis at Current Rates
3. Rate Design Recommendations

This Cost of Service Analysis Report (COSA) addresses the cost of service analysis and the rate design recommendations. Earlier in the study process, water utility rate trends were reviewed to explore industry rate trends present alternatives that might be appropriate for RPU to consider.

2.2 OVERVIEW OF THE RATE SETTING PROCESS

Rate analyses should be performed periodically so that revenues from rates adequately fund utility operations, maintenance, and capital investments. Additionally, in California, water rates must adhere to the cost of service requirements imposed by Proposition 218 and the State Constitution. Proposition 218 requires that property related fees and charges, including water rates, do not exceed the reasonable cost of providing the service. In additional to Proposition 218 requirements, Article X (2) of the State Constitution establishes the need to preserve the State's water supplies and discourage the wasteful or unreasonable use of water by encouraging conservation. The proposed rate plan accounts for both the proportionality requirement of Proposition 218, as well as encourages efficient use of water.

The cost of service rate analysis presented within this report consists of the following three interconnected processes:



The processes presented above are advocated by the American Water Works Association (AWWA) for cost of service rate setting. While the process is described in a linear step by step approach, it is better understood as an iterative process where the ultimate objective is to balance revenues with costs in an equitable manner for customers. These three processes will form the basis for the rate analyses presented within this report.

2.3 FORWARD-LOOKING STATEMENT

The rate calculations presented within this report are based on the reasonable projections of existing service costs, water demands, system operations with information available, and on existing legal requirements. Moreover, RPU developed the pro forma and water demand forecast that serve as the basis for all rate calculations. Significant changes in RPU's operations or costs or the Utility 2.0 Capital Improvement Plan discussed in Section 4, changes occurring in California law, deviation from the projected water demands, or further regulatory actions by the Governor or the SWRCB in regard to water use may result in the projected rate revenues deviating from Carollo's projections, and will require RPU to revisit the cost of service analysis.

2.4 RPU BACKGROUND

The current RPU service area is approximately 75 square miles and includes about 65,000 water service connections. The service area is primarily within the City limits and includes approximately five square miles of land served by RPU outside of the City limits as shown on Figure 2-1 (Figure 2.1 from master plan). RPU’s potable water system consists of groundwater basins, groundwater wells, a supply transmission system, water treatment plants, and a water distribution system. As discussed later within this report, these water supplies are used to meet both ongoing, year-round and peak summer demands, as well as provide a level of resiliency for drought conditions.

RPU has facilities to extract groundwater from five groundwater basins: Bunker Hill, Rialto-Colton, Riverside North, Riverside South, and Arlington Basins. RPU’s groundwater supply production is based on the 1969 Western-San Bernardino Judgment that regulates basin extraction amounts. The location of these groundwater basins, the City boundaries, and RPU’s groundwater wells are depicted on Figure 2-2 (Figure 2.3 from master plan).

Groundwater pumped from RPU’s wells is conveyed to the Linden-Evans Reservoir for blending and temporary storage through a network of water supply transmission lines. This supply system consists of four transmission mains: Gage Pipeline, Waterman Pipeline, North Orange Pipeline, and the Flume Pipeline. Prior to reaching the Linden-Evans Reservoir, groundwater from several wells is treated at one of RPU’s six water treatment facilities. See Figure 2-3 (Figure 2.4 from master plan) for a diagram of the supply system.

From Linden-Evans Reservoir, water is distributed to RPU's customers. The distribution system includes approximately 65,000 connections and consists of 46 pressure zones, 921 miles of pipelines, 16 storage reservoirs, 41 booster pump stations, and 29 pressure regulating stations. Figure 2-4 (Figure 2.5 from master plan) for a diagram of the distribution system.

RPU also distributes a small amount of recycled water (about 200 acre-feet-per-year (AFY)) from the City's Regional Water Quality Control Plant (RWQCP). Current deliveries are to nine meters located near the RWQCP. Based on current effluent flows, the RWQCP has the potential to deliver approximately 5,400 AFY, after subtracting a 25,000 AFY environmental commitment. As part of the proposed capital improvement plan, RPU will begin expanding its recycled water distribution system.

FIGURE 2-1 RPU SERVICE AREA

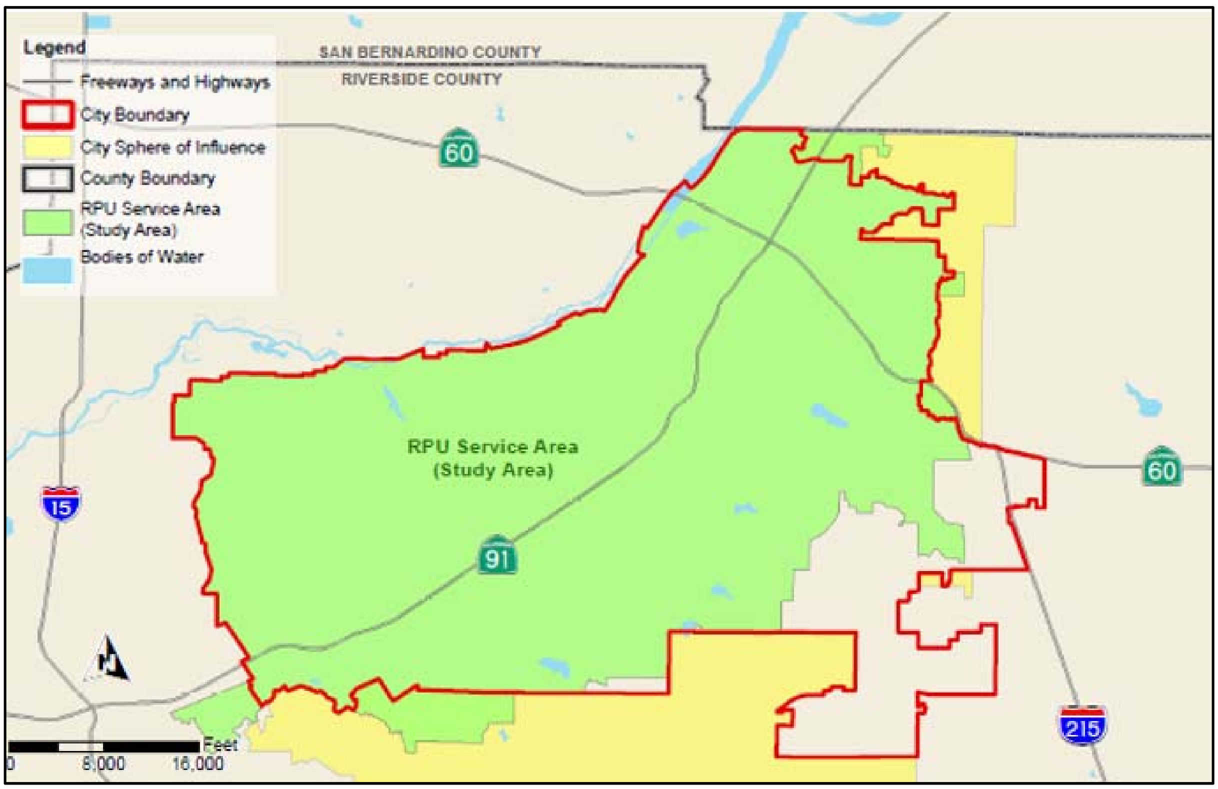


FIGURE 2-2 GROUNDWATER BASINS

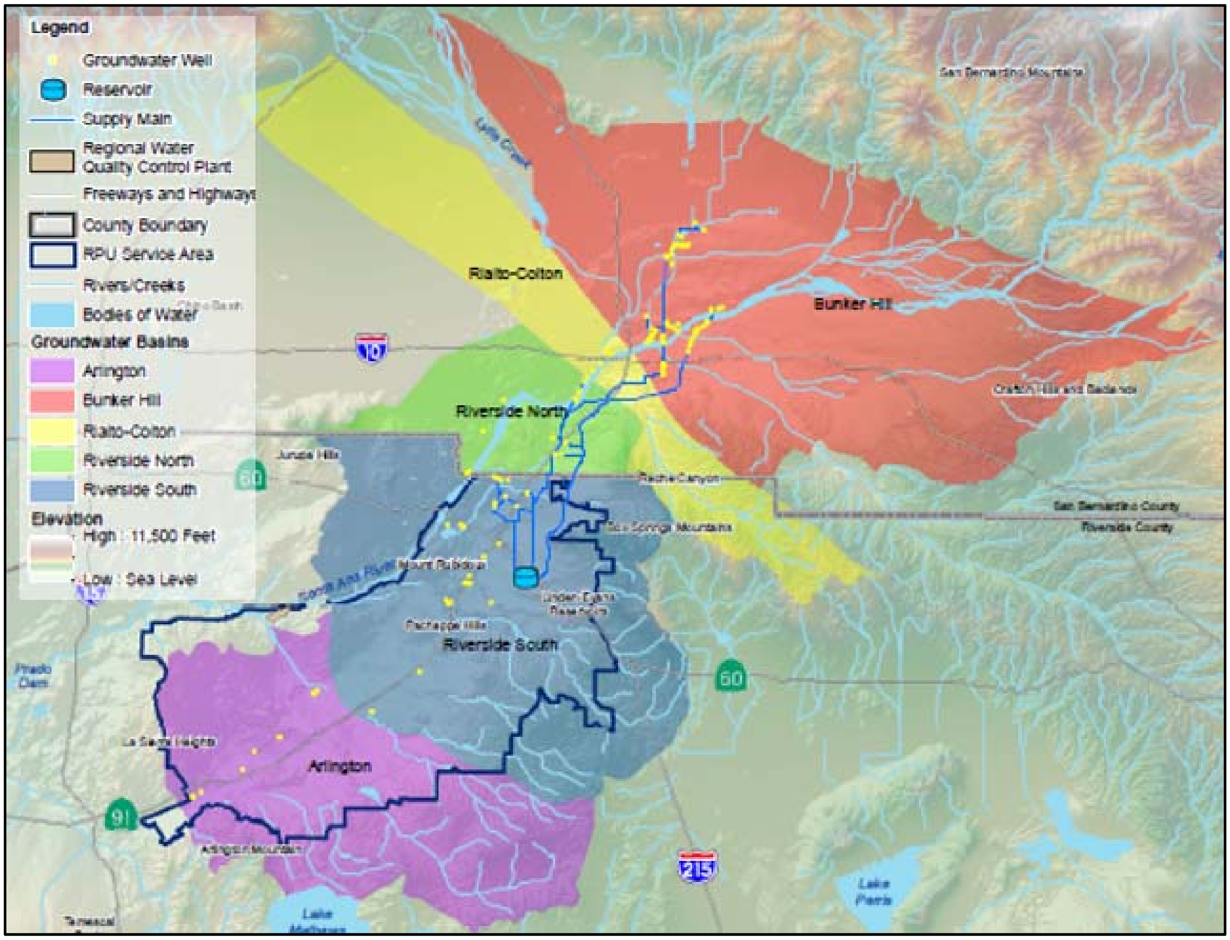


FIGURE 2-3 TREATMENT AND TRANSMISSION FACILITIES

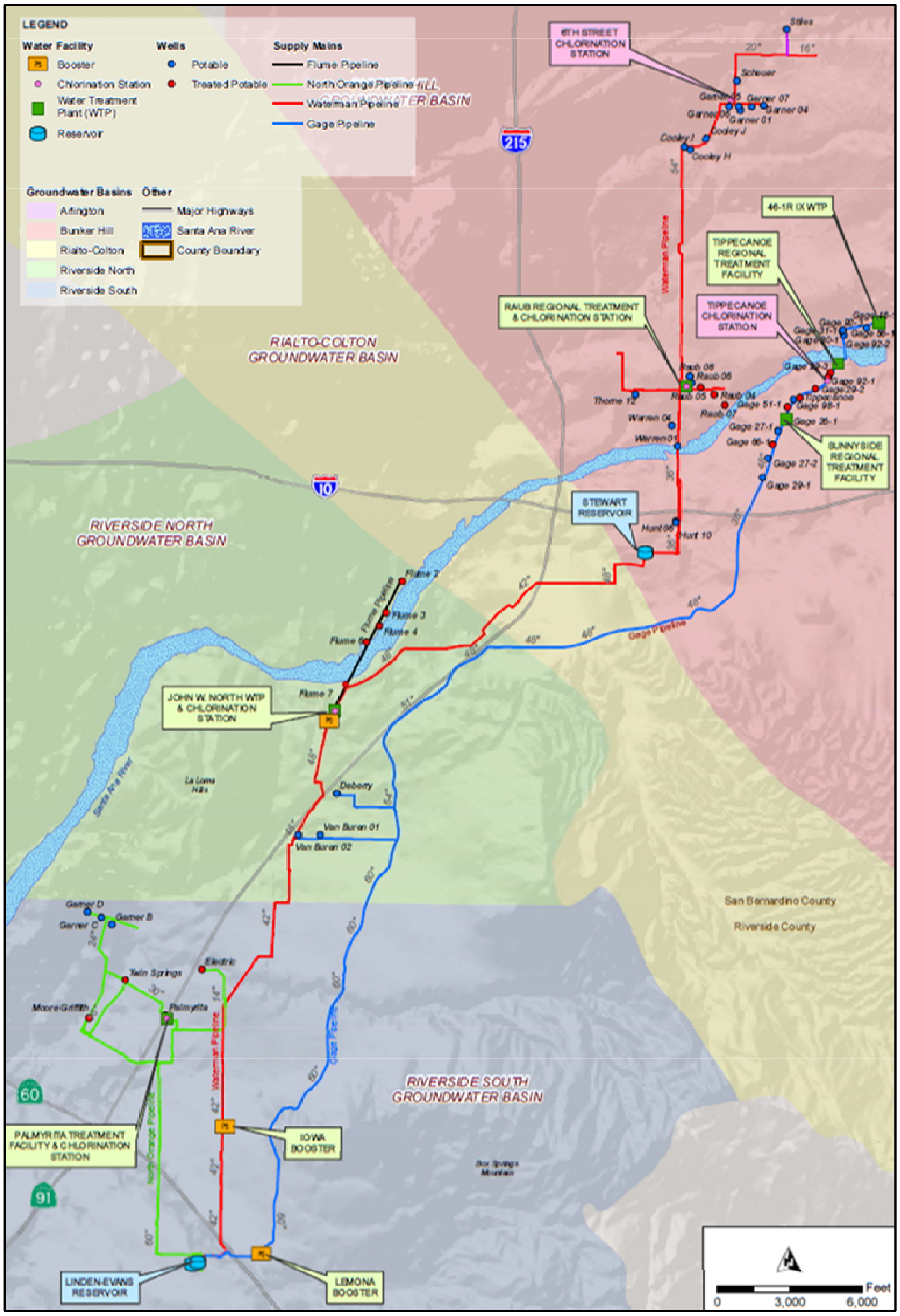
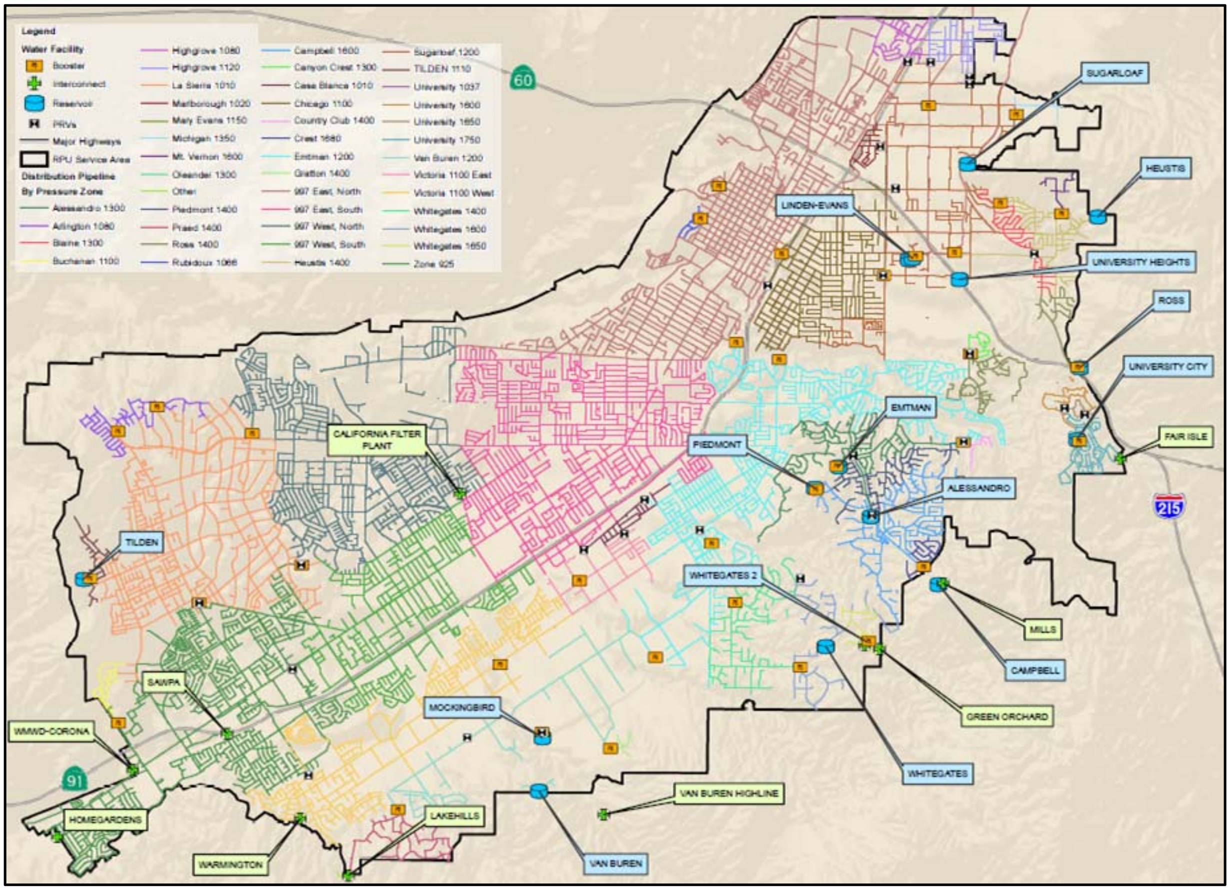


FIGURE 2-4 DISTRIBUTION SYSTEM



2.4.1 Impact of Recent Drought

The recent drought in the Western US has had profound impacts on municipalities and water agencies across the State of California. In order to cope with the effects of the drought, the State instituted mandatory restrictions to achieve a total conservation target of 25 percent compared to 2013 levels of consumption for municipal water agencies. Under the requirements of the State Water Boards Emergency Regulations (SWRCB), RPU was required to curtail water demands by 28 percent as compared to the base year of 2013. In February of 2016, the SWRCB voted to extend the conservation mandate through October 2016; however, they applied new rules to account for growth and alternatives supplies. Based on those changes, RPU's target for March through October 2016 was set at 25 percent.

In May of 2016, the State modified the emergency regulations to allow agencies to self-certify that sufficient supply is available, and thus to modify their mandatory curtailments. Based on RPU's water supplies exceeding projected water demands for the next three years, the City Council self-certified to a zero conservation standard in June 2016. However, the adopted zero conservation standard only applies to the extraordinary conservation requirements of the State and does not reduce Riverside's need to conserve water to comply with State Senate bill SBX7-7 (2009). In addition, conservation is the centerpiece of Riverside's water supply plan. With an ongoing drought, the City Council deemed it appropriate to remain within a drought stage at this time, and Water Conservation Stage 1 was declared. While Water Conservation Stage 1 does not include mandatory outdoor water restriction, it does encourage customers to use water efficiently and reflects changes to state regulations.

The water demand analyses completed for the cost of service study center on comparing usage on a fiscal year basis, since this method is in line with RPU's accounting practices. Significant voluntary conservation began in May 2015 (part of FY 2014/15) with the announcement of the mandatory curtailments that began in July 2015. FY 2015/16 included the height of the drought, and the highest levels of conservation, resulting in the lowest fiscal year water consumption of the analyzed fiscal years. The wet winter in FY 2016/17 has led to the lifting of the State's mandatory usage curtailments. Water usage has rebounded during FY 2016/17, though it remains below historical levels due to demand hardening from conservation, as well as decreased irrigation demands due to the wet winter. The demand analyses within the cost of service study use past data from FY 2013/14 and FY 2015/16 along with RPU's water sales forecasts to project usage for each customer class and tier (where applicable).

2.5 UTILITY 2.0 PLAN

The Utility 2.0 Plan has been designed to facilitate and advance the strategic goals adopted by the City Council in the Riverside 2.0 Strategic Plan, as well as the strategic goals adopted by the Board. In developing the Utility 2.0 Plan, a number of "roadmaps" have been presented to the City Council and Board, including Utility Infrastructure and Supply, Workforce Development, and Thriving Financially. The Utility 2.0 Plan provides 10-year financial projections for revenue requirements needed to fund various paces of implementation for the Utility 2.0 Plan. In conceptually selecting the Option 3 strategy of proactive implementation, the Board and City Council recognize that business as usual will fall far short of both the RPU's vision and the City's vision for the future. A summary of each of the utility Infrastructure and Supply roadmaps, as applicable to RPU's water utility, follows.

2.5.1 Water Supply

RPU's future water supply will be met through a combination of conservation and efficiency, recycled water, and storm water capture. Water conservation activities will continue as RPU enhances its programs. The proposed Jackson Street alignment of the future first phase of recycled water infrastructure will be introduced. Storm water capture projects including Riverside's continued participation in the Seven Oaks Dam infrastructure improvements, the proposed Santa Ana River rubber dam project, and smaller scale urban storm water capture projects are expected to yield 16,000 acre feet of new water supply annually. Recommended water supply projects have been arranged in three tiers to allow execution of new projects as future demand materializes.

2.5.2 Water Infrastructure

RPU's investment in the Safe WATER Plan beginning in 2006 yielded significant improvements to the water utility infrastructure, including replacement of 68 miles of water pipelines, replacement of three storage reservoirs, and construction of the John W. North Water Treatment Plant. With these investments, Riverside has moved ahead of many agencies in infrastructure management. However, as acknowledged at the time of its adoption, the Safe WATER Plan did not address all of the infrastructure needs.

2.5.3 Technology

On July 10, 2015 and August 7, 2015, the Board received updates on the Strategic Technology Plan which outlines 19 recommended projects to be completed over the next 10 years. Many of those projects are embedded within the recommendations outlined in the infrastructure roadmaps. All of the costs associated with the technology projects are outlined in the pro forma and financial plan. The Strategic Technology Plan includes 19 projects categorized as customer focused, information based, and real-time operational technologies. Three additional technology projects were added after the Strategic Technology Plan was issued. All of the costs associated with the projects are outlined in the ten-year pro forma.

2.6 EXISTING RATE STRUCTURE

The existing water rates are based on industry accepted, cost of service structures. The rate program incorporates a number of different features, such as tiers and seasonal rates in order to account for the increase cost of water delivery during peak periods. The current rate program includes ten rate categories (and thirteen total rate codes) as shown in Table 2-1.

TABLE 2-1 EXISTING RATE CLASS DESCRIPTIONS

Rate Class Number and Name		Rate Structure Description
WA-1	Residential Metered Service Inside City	1. For single and multi-family units. 2. Different seasonal rates June through October and November through May 3. Four inclining rate tiers (CCF) Tier 1: 0 to 15, Tier 2: 16 to 35, Tier 3: 36 to 60, Tier 4: Over 60
WA-2	Flat Rate - Temporary Service	Flat rate for construction water, fire hydrant use, and bulk permit delivery.
WA-3	Irrigation Metered Service	1. Closed to new customers as of May 31, 2003. 2. With Residence two inclining tiers (CCF) Tier 1: 0 to 100, Tier 2: Over 100 3. Without Residence per CCF
WA-4	Riverside Water Company Irrigators	1. Three inclining tiers (CCF) Tier 1: 0 to 15, Tier 2: 16 to 70, Tier 3: Over 70 2. Different seasonal rates June through October and November through May 3. Open only to former shareholders in Riverside Water Company.
WA-6	General Metered Service	1. Commercial two inclining tiers (CCF) Tier 1: 0 to 550, Tier 2: Over 550 2. Industrial three inclining tiers (CCF) Tier 1: 0 to 550, Tier 2: 551 to 5500, Tier 3: Over 5500 3. Seasonal rates using WA-1 seasons.
WA-7	Special Metered Service	Flat rate structure for two cemeteries and City irrigation.
WA-8	Greenbelt Irrigation Service	1. Properties in greenbelt able to take service from Gage Canal facilities. 2. Flat rate plus Gage Canal pass-through charge. 3. Pass-through has three inclining tiers (CCF). Tier 1: 0 to 156, Tier 2: 157 to 312, Tier 3: Over 312
WA-9	Grove Preservation Service	1. With residence and nominal landscaping - three inclining tiers (CCF). Tier 1: 0 to 15, Tier 2: 16 to 60, Tier 3: Over 60 2. With residence and more than nominal landscaping requires 2 meters. a. Residence and landscape area - WA-1. b. All other water flat rate. 3. Without residence - flat rate structure.
WA-10	Recycled Water Service	Flat rate structure.

Table 2-2 presents the current rates for the majority of the customers in the City: residential (WA-1), commercial (WA-6.1), and industrial (WA-6.2).

TABLE 2-2 RPU RATES BY CUSTOMER CATEGORY

Category	Summer Rates Jun to Oct -	Winter Rates - Nov to May -	Fixed Charges: Per meter/month		
WA-1: Residential Metered Service			**Meter Size**	**Residential**	**Commercial/ Industrial**
First 15 CCF	$1.14	$1.13	5/8 & 3/4"	$13.99	$11.57
16-35 CCF	1.83	1.64	1"	23.29	19.22
36-60 CCF	2.85	2.26	1.5"	46.60	38.46
>60 CCF	4.10	2.75	2"	74.49	61.51
WA-6.1: General Metered Service - Commercial			3"		142.52
First 550 CCF	$1.77	$1.42	4"		237.57
>550 CCF	2.32	1.99	6"		475.19
WA-6.2: General Metered Service - Industrial			8"		760.29
First 550 CCF	$1.77	$1.42	10"		1,092.85
551- 5500 CCF	1.89	1.54	12"		1,330.40
>5500 CCF	2.32	1.99			
(1) One CCF is equivalent to 748 gallons					

3 WATER USAGE AND SUPPLY

As noted in the report above, RPU maintains a diversified portfolio of water sources and has invested in redundant supplies to create a highly localized and resilient system. To this end, RPU will also be expanding the recycled water distribution system and deliveries, and looking to conservation as a "new" source of supply. In addition to these localized supplies, RPU also has the ability to purchase water from Western Municipal Water District. These supplemental, imported supplies are significantly more expensive than RPU's local supplies and supply is not guaranteed.

3.1 GROWTH AND WATER DEMAND

3.1.1 Customer Account Growth

A moderate level of customer account growth is expected over the projection period from FY 2017/18 through FY 2021/22. Annual growth in the total number of accounts is expected at about 0.8 percent per year through the projection period. Growth for specific customer classes is expected to vary from 0 percent to about 2.1 percent per year, with the highest level of growth in commercial accounts. Table 3-1 below presents the projected accounts for each customer class.

TABLE 3-1 ACCOUNT GROWTH

Growth ID	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Residential	0.5%	0.6%	0.6%	0.6%	0.6%
Commercial & Industrial	1.9%	2.1%	2.1%	2.1%	2.1%
Other	0.0%	0.0%	0.0%	0.0%	0.0%
Customer Category					
Temporary Service	70	71	72	73	74
Riverside Water Company Irrigators	38	38	38	38	38
Commercial & Industrial	4,620	4,718	4,818	4,920	5,025
City Irrigation	489	499	509	519	529
Single Family	58,931	59,280	59,639	60,009	60,390
Multi-family	1,217	1,224	1,231	1,238	1,245
Landscape	663	676	690	704	718
Total	**66,028**	**66,506**	**66,997**	**67,501**	**68,019**

3.1.2 Water Usage

Water sales are RPU's primary source of water revenues. Consequently, it is critical to examine and analyze potential shifts in short- and long-term water demands. Carollo evaluated several years of billing data to examine historical water demand patterns and potential developing trends. RPU also maintains an internal demand forecast used for system and financial planning. This forecast accounts for these changing demand patterns, type of future development, price elasticity, and, due to the State mandated water restrictions, the reduction, and subsequent bounce-back in water demands.

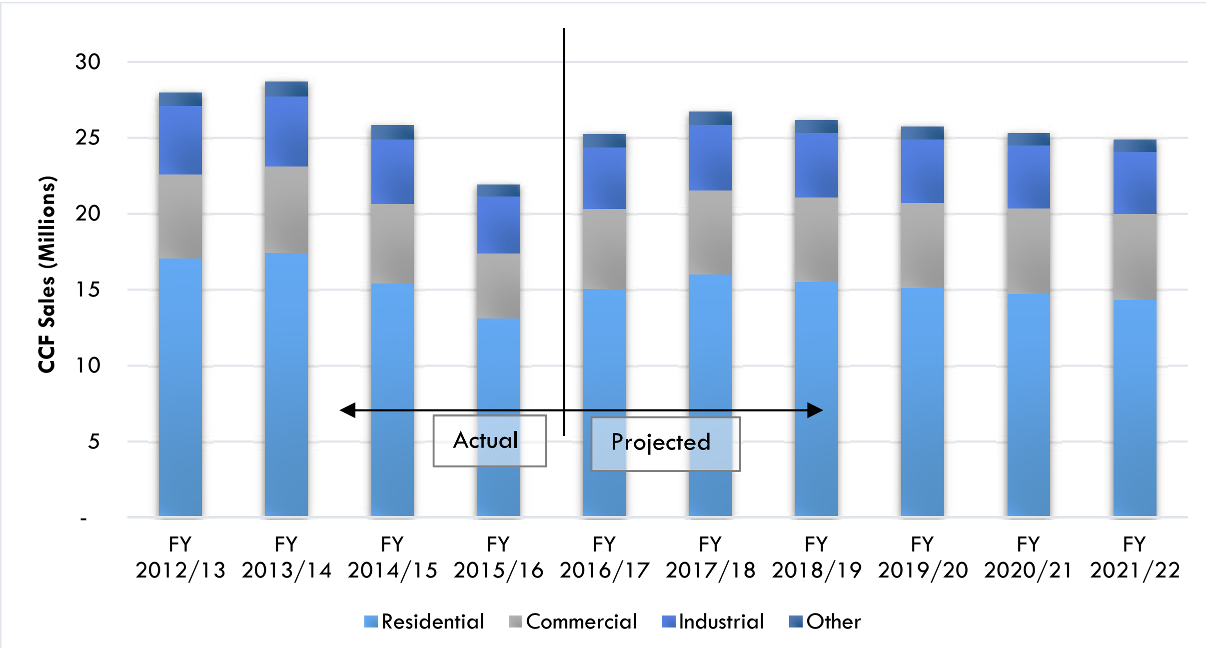
Mandatory and voluntary reductions in water usage caused by the ongoing drought have driven significant reductions in water demands. Conservation associated with the current drought began in FY 2014/15 as RPU's customers voluntarily curtailed usage. The total usage in FY 2014/15 of 25.8 million CCF of water represented a 10 percent decrease from the previous year (FY 2013/14) total of 28.7 million CCF. With the onset of State mandated conservation in July of 2015, RPU continued to see significant conservation through the end of FY 2015/16, with total sales in that year of only 21.9 million CCF. It is expected that a portion of that conservation will be permanent.

Based on RPU's water supplies exceeding projected water demands for the next three years, the City Council self-certified to a zero conservation standard in June 2016. Demand has rebounded through FY 2016/17, and RPU updated its usage forecasts accordingly. Based on discussion with RPU, Carollo used this forecast as the basis for calculating the proposed rate plan.

The rebound in consumption began in FY 2016/17 and is expected to last through FY 2017/18. It is expected that demand hardening, permanent conservation, and price elasticity will result in some permanent reductions to retail water demands. Retail sales are expected to reach a peak of about 26.7 million CCF in FY 2017/18, about 7 percent below FY 2013/14 demands. Retail sales are expected to decrease slightly in FY 2018/19, FY 2019/20, FY 2020/21, and FY 2021/22 due to price elasticity associated with future rate increases.

Figure 3-1 below shows the historical and projected demands that serve as the basis of the cost of service analysis. This forecast includes the State's modifications to the emergency regulations, self-certification to a zero conservation standard, and price elasticity to reflect the effects of the recommended rate increases. The 2015 Urban Water Master Plan forecasts differ slightly from these forecasts due to being developed when the State mandatory emergency drought regulations were implemented and includes a slightly higher retention of conservation. The current forecasts also differ from those submitted for self-certification due to the specific self-certification calculation requirements of the State.

FIGURE 3-1 WATER SALES FORECAST



Monthly water usage data for the past three fiscal years was analyzed in order to develop a reasonable projection of water demands for FY 2017/18 and subsequent years for each rate class. The projected increases in consumption were applied to each rate class and tier (where applicable) based on the amount of conservation that was realized form FY 2013/14 to FY 2015/16. Thus, the detailed projections assume that water use form each class and tier will rebound in proportion to the conservation that was realized in each class and tier.

3.2 WATER RATE CODES

RPU's water customers are currently each assigned to one of thirteen rate codes. Each rate code was analyzed independently to determine, and account for, distinct consumption patterns. Monthly and seasonal demand patterns were analyzed to establish overall consumption characteristics and each rate code's use of the system.

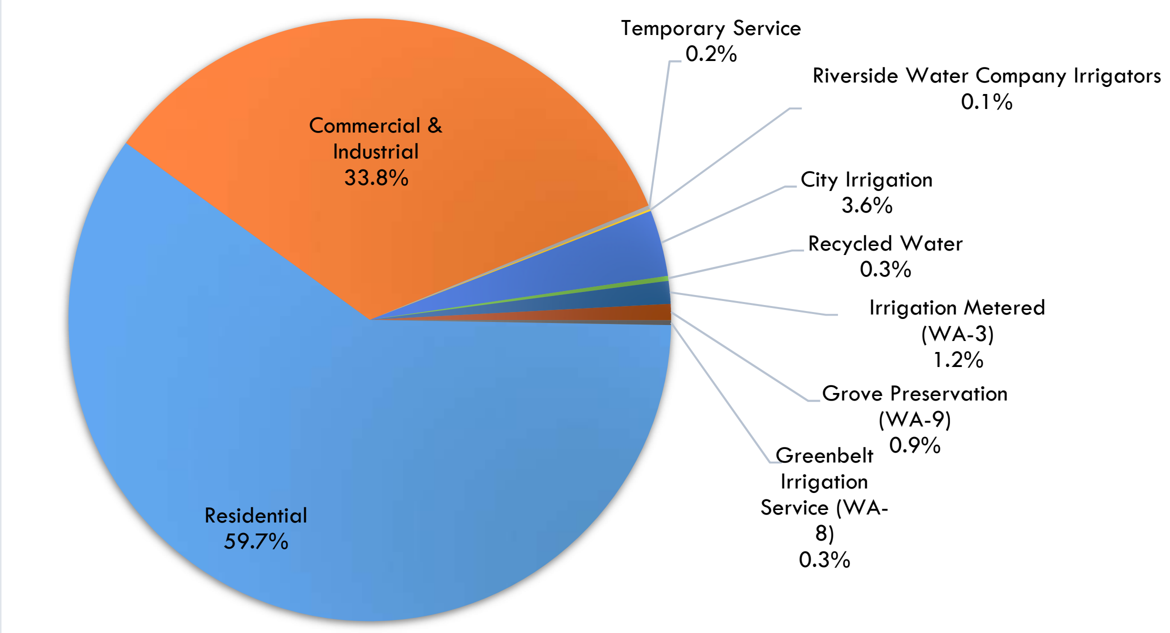
TABLE 3-2 RATE CLASS CHARACTERISTICS

Customer Class		Rate Structure and Consumption Characteristics
Residential	WA-1	Meters serve both single and multiple unit residences; consumption peaks in summer months due to increased outdoor usage. Seasonal rates with a 4-tier inclining block structure.
Flat Rate Temporary Service	WA-2	Flat rate for temporary usage for construction, fire hydrant use, and bulk permit delivery. Consumption peaks heavily in summer.
Irrigation Metered Service w/ Residence	WA-3.1	Two tiered inclining block structure with very large tier 1 block (100 CCF). Consumption peaks marginally in summer. Closed to new customers as of May 31, 2003.
Irrigation Metered Service w/o Residence	WA-3.2	Flat rate for all usage. Consumption peaks during the summer months. Closed to new customers as of May 31, 2003.
Riverside Water Company Irrigators	WA-4	Three tiered inclining block structure for residential and commercial customers. Consumption peaks marginally in summer. RPU is contractually bound to serve these customers under a unique rate structure, resulting from the acquisition of the Riverside Water Company.
General Metered Service - Commercial	WA-6.1	Two tiered inclining block structure for meters from 5/8" to 2" serving commercial customers. Consumption peaks marginally in summer.
General Metered Service - Industrial	WA-6.2	Three tiered inclining block structure for meters from 3" to 12" serving industrial and institutional customers. Consumption peaks marginally in summer.
Special Metered Service - City Irrigation	WA-7	Flat rate for all usage by City of Riverside for irrigation of public facilities. Consumption peaks heavily in summer.
Greenbelt Irrigation Service	WA-8	Pass-through rate for customers who are able to take Gage Canal water and have installed a pressurized system. Used only for outdoor irrigation; consumption peaks heavily in summer.
Grove Preservation Service with Residence and Nominal Ornamental Landscaping	WA-9.1	Three tiered structure with declining tier 3 rate. Meters serve both indoor (residential) and outdoor usage; consumption peaks in summer due to increased outdoor usage.
Grove Preservation Service without residence or with separately metered Residence and more than Nominal Ornamental Landscaping	WA-9.2	Flat rate for all usage. Meters may serve outdoor usage; consumption peaks in summer due to increased outdoor usage.
Recycled Water Service	WA-10	Flat Rate for all usage. Meters serve outdoor usage; consumption peaks heavily in summer due to increased irrigation demands.

RPU also provides service to two other customers through special contracts: the University of California at Riverside (UCR) and the American Youth Soccer Organization (AYSO). UCR owns its own water rights in the Bunker Hill Basin, and under the current agreement is charged at the industrial rate for any water delivered in excess of their water rights. AYSO receives untreated irrigation water from an adjacent well and under the agreement RPU recovers all production costs.

Figure 3-2 shows the percent of annual consumption from each customer rate code excluding the special contract classes based on FY 2015/16 billing data. Residential accounts from WA-1 are the primary users of water making up roughly 60 percent of annual water usage. The remaining 40 percent is split between commercial, industrial, irrigation, and other accounts.

FIGURE 3-2 PERCENT OF CONSUMPTION PER RATE CODE FY 2015/16



Note: Sum of percentages may be off due to rounding.

4 REVENUE REQUIREMENTS

4.1 INTRODUCTION

The revenue requirement analysis is a test of a utility's fiscal health, which evaluates the adequacy of current revenues and establishes rate revenue needs that are used to develop RPU's rate plan. The analysis accounts for RPU's revenues, expenses, debt, and reserve policies. As system revenues and reserve balances are insufficient, the revenue requirement analysis calculates the needed additional cash flows to meet RPU's funding goals.

The revenue requirement forecast is derived from RPU's financial pro forma, including major cost components: production costs, personnel costs, other operations and maintenance (O&M), debt service requirements; and rate funded capital outlays. Policy requirements are also considered in RPU's financial pro forma and used to derive the revenue requirement. The revenue requirements forecast of the pro forma incorporates RPU's FY 2017/18 adopted budget with adjustments based on actual performance to project costs thereafter. Additionally, applicable costs savings have been included based on actual costs in prior years. The relevant financial information for this analysis was provided by RPU including: current reserve ending balances, budgeted capital improvement plan expenditures, other future expenses, other future revenues, and other miscellaneous financial information.

The revenue requirement analysis is comprised of two tests:

- The **cash flow sufficiency test** compares projected system revenues to the cost to operate, maintain, and improve the water system. This test evaluates whether revenues meet expenses; when they do not, this test calculates the amount of rate revenue that must be raised to fund the projected expenditures.
- The second test is the **debt service coverage test**. Utility bond issuances regularly include a stipulation that the agency maintain sufficient cash flows to fund annual operating expenses and the annual debt service, plus an additional percent of that debt service. If cash flow falls below this ratio, this test calculates the additional revenue required.

The revenue requirement analysis determines if RPU must increase system revenues in order to meet its ongoing obligations. In the event that revenues are found to be deficient to meet ongoing expenses (cash flow test) and/or debt obligation (debt service coverage test), revenues must be increased to achieve the higher of the two needs.

The cash-flow sufficiency test compares projected cash requirements in each given year necessary to operate, maintain, and improve the utility systems. Cash requirements include O&M expenses, miscellaneous capital outlays, replacement funding, rate-funded capital expenditures, and policy-driven additions to reserves. RPU must maintain certain reserve targets for working capital, rate stabilization, capital emergency, capital system improvements, and debt service as outlined in the reserve policy.

The debt service coverage test measures the ability of the water utility to meet its debt obligations on an annual basis. When a municipality issues a bond, the bond Official Statement defines the financial obligations that must be met in order to remain in legal compliance. As part of the bond covenant as set forth in the Official Statement, the utility must collect a defined amount of annual revenue to illustrate that it has the financial capacity to repay bondholders. More specifically, annual net revenues, in excess of operations and maintenance, must equal to a minimum of 1.25 times the annual debt service payments for senior lien debt. However, as is the case for RPU's water utility that has maintained a AAA rating from Standard and Poor's, this coverage factor can be set at a higher level than is legally required in order to assist in maintaining or achieving a higher bond rating. For the purposes of this analysis, the pro forma targets a coverage factor of 2.0 times while maintaining a target minimum coverage factor of 1.75 times for financial planning purposes.

The pro forma recommendations presented within this report were developed by RPU staff based on best known information as of the writing of this report.

4.2 ONGOING COSTS AND OFFSETTING REVENUES

4.2.1 Operating and Maintenance Costs

Operation and maintenance costs (O&M) are expenditures that RPU incurs in the day-to-day operations of its water system - e.g., employee salaries and benefits, fuel, chemicals, power, supplies, and debt service. Other costs in the operating budget include indirect costs for services provided to RPU by other City departments or funds. The water O&M costs projected in the pro forma are the backbone of the revenue requirements analysis.

Table 4-1 summarizes the projected water O&M costs for FY 2017/18 through FY 2021/22.

Production Costs

Production costs are variable O&M costs incurred by RPU to provide water service. Specific items included in this category are electricity, gas, other utilities, and water production charges associated with each of RPU's groundwater sources.

Electricity costs account for the majority of production costs. In an effort to control production costs, RPU will be constructing solar power generating facilities that will be used to power wells, pumps, and other equipment at several of the production sites. The solar generating facilities are expected to lower annual production costs by nearly $0.8 million in FY 2017/18 with annual savings increasing to over $0.9 million per year by FY 2021/22.

Personnel Costs

Personnel costs include all of the direct and overhead costs associated with RPU staff. These costs are considered to be fixed costs, as staffing requirements generally do not change based on fluctuations in water demands.

Other O&M Costs

Other O&M costs include materials, supplies, and services, as well as services from other funds. Some of these costs are offset by services that RPU provides to other funds. In all, Other O&M costs are generally not impacted by water demands and are therefore considered to be fixed.

Additional O&M for CIP and Advanced Technology

Several of the CIP projects will be accompanied by annual O&M costs as projects are completed or programs are initiated. Estimated O&M costs associated with CIP projects were provided by RPU engineering staff and those associated with the Advanced Technology program were provided using estimated project implementation costs from the Strategic Technology Plan. Annual costs for this category are expected to increase from about $1.2 million in FY 2017/18 to about $2.7 million in FY 2021/22.

O&M costs associated with recycled water are included as a component of the additional O&M for CIP. Recycled water costs are expected to be about $140 thousand in each year of the projection. After that time, recycled water costs are expected to increase as the system is built-out and additional users come on-line.

General Fund Transfer

The Riverside City Charter requires RPU to annually transfer to the general fund an amount not to exceed to 11.5 percent of the previous year's gross operating revenues (the Water GFT). Riverside voters reaffirmed the Water GFT in June of 2013. Because the Water GFT is based upon revenues, the annual amount fluctuates with water demands.

TABLE 4-1 PROJECTED WATER O&M EXPENDITURES

Expenditures	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Production costs	$4,753,000	$4,757,000	$4,780,000	$4,802,000	4,819,000
Personnel costs	15,073,000	18,208,000	19,506,000	20,587,000	21,691,000
Other operating and maintenance costs	19,777,000	20,170,000	20,570,000	20,979,000	21,395,000
Additional O&M for CIP and Advanced Tech	1,165,000	1,117,000	1,719,000	2,306,000	2,745,000
Debt service requirements(1)	13,817,000	15,396,000	18,783,000	18,792,000	21,095,000
General fund transfer	6,639,000	7,105,000	7,763,000	8,298,000	8,858,000
Capital outlay financed by rates	5,074,000	9,787,000	6,702,000	7,098,000	6,516,000
Total Expenditures	**$66,298,000**	**$76,540,000**	**$79,823,000**	**$82,862,000**	**$87,119,000**

Notes:

(1) Debt service requirements include the amount due in any given year for current and future Revenue Bonds as well as the existing Pension Obligation Bonds, and General Fund Allocation and Debt Related Fiscal Charges (which are not included in the Total Annual Debt Service in Table 4-2).

Debt Service

In addition to O&M expenditures, RPU holds several outstanding debt obligations that provided funding for past capital projects and acquisitions. Table 4-2 shows RPU's outstanding water debt obligations and associated debt service for each year of the projection period. Additional debt that will be required to fund CIP expenditures is discussed in Section 4.3 of this report.

TABLE 4-2 OUTSTANDING WATER DEBT OBLIGATIONS AND DEBT SERVICE

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
2008B ($58.235M Fixed)	$3,952,000	$4,222,000	$3,852,000	$3,827,000	$3,851,000
2009A ($31.895M Fixed)	2,889,000	2,888,000	2,427,000	2,416,000	0
2009B ($67.790M Fixed BABs)	4,181,000	4,181,000	4,181,000	4,181,000	6,592,000
2009B Treasury Credit	(1,463,000)	(1,463,000)	(1,463,000)	(1,463,000)	(1,441,000)
2011A ($59.000M Variable)	3,435,000	3,159,000	3,989,000	4,008,000	3,976,000
Total Annual Debt Service[1]	**$12,994,000**	**$12,987,000**	**$12,986,000**	**$12,969,000**	**$12,978,000**
Notes: (1) Net of Treasury credit for Build America Bonds (BABs)					

4.2.2 Offsetting Revenues

The rate revenue needs are defined as the amount of revenues that must be recovered through water rates in order to cover expenditures, less any offsetting revenues. Offsetting revenues include water conveyance revenue, wholesale water sales revenues, capacity charge revenues, settlement revenues, interest earnings, lease revenues, and other operating and non-operating revenues. Table 4-3 identifies the projected offsetting revenues for the upcoming five years.

TABLE 4-3 PROJECTED OFFSETTING REVENUES

Offsetting Revenues	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Interest income	$801,000	$1,660,000	$1,992,000	$1,495,000	$2,057,000
Miscellaneous income	9,898,000	10,269,000	10,390,000	10,517,000	10,647,000
Outside City Surcharge	1,507,000	1,550,000	1,595,000	1,640,000	1,687,000
Non-Rate Revenues in Sales Statistics	620,000	632,000	645,000	657,000	671,000
Total Offsetting Revenues	**$12,826,000**	**$14,111,000**	**$14,622,000**	**$14,309,000**	**$15,062,000**

RPU is able to take advantage of surplus local water supplies and sell an increased amount of water to other agencies in order to help offset rate increases for RPU retail customers.

4.3 CAPITAL IMPROVEMENT PLAN

4.3.1 Utility 2.0 CIP

Over the past several years, RPU has undertaken an effort to develop a detailed Capital Improvement Plan (CIP). Beginning with the Integrated Water Management Plan in 2013, RPU identified necessary improvements related to rehabilitation and replacement of existing infrastructure, enhancements to existing water supply, development of new sources of supply, expansion of the recycled water system, and rollout of new technologies. RPU staff has continued to refine the proposed projects, expenditures, and implementation schedule. The total cost of the CIP for FY 2017/18 through FY 2021/22, with capital costs assumed to escalate at 2.85 percent annually, is $171 million.

4.3.2 CIP Funding

Completion of the CIP will require RPU to utilize funding from several different sources. The pro forma has been developed to strike a balance between debt financing, use of reserves, and rate funding in order to minimize impacts to ratepayers while promoting financial sustainability. Figure 4-1 below shows the projected funding sources for each year of the CIP.

FIGURE 4-1 CIP FUNDING SOURCES

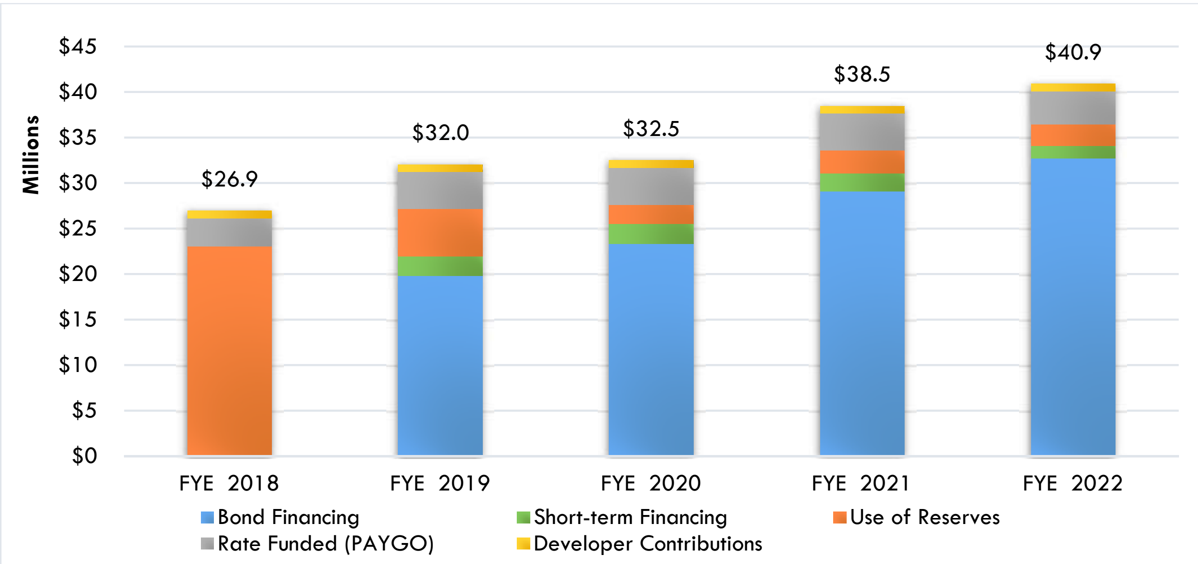


Table 4-4 shows the funding from each source by fiscal year of the rate projection period as well as the total funding from each source.

TABLE 4-4 CIP FUNDING BY SOURCE (MILLIONS)

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22	Five-Year Total
Bond Financing	$0.00	$19.84	$23.34	$29.10	$32.71	$105.00
Short-term Financing	0.00	2.10	2.16	1.96	1.37	7.60
Use of Reserves	23.04	5.20	2.10	2.56	2.39	35.28
Rate Funded (PAYGO)	3.10	4.09	4.10	4.04	3.63	18.95
Developer Contributions	0.80	0.80	0.80	0.80	0.80	4.00
Total Annual CIP Funding	**$26.93**	**$32.03**	**$32.51**	**$38.46**	**$40.90**	**$170.83**
Notes:						
(1) Totals may be off due to rounding.						

4.3.3 Projected Debt Issuances

As shown in the table above, RPU anticipates issuing additional debt to fund the capital improvement program over the next 5 years. Based on the pro forma developed for this study, RPU will require a total of nearly $113 million in financing proceeds to fund capital projects from FY 2017/18 through FY 2021/22.

Debt service associated with projected bond issuances and short term financing has been estimated based on typical financing assumptions and incorporated in to the cost of service analysis. Bond issuances and short-term financing are projected to fund capital projects for a three year period. The projected bond issuances and short term financing in FY2021/22 is in anticipation of the continuation of the 10 year plan and will fund projected capital projects over a 3 year period from FY 2021/22 through FY2023/24. Table 4-5 shows the anticipated bond issuances, short-term financing, and associated debt service.

TABLE 4-5 PROJECTED BOND AND SHORT-TERM ISSUANCES (MILLIONS)

Year of Issuance	Issuance Amounts (Millions)	Annual Debt Service (Millions)[1]
Revenue Bonds		
2019	$72.00	$4.16
2022	$108.00	$6.25
Short Term Financing		
2019	$6.22	$0.77
2022	$5.61	$0.69
Notes (1) Maximum annual debt service starting one fiscal year after the year of issuance.		

4.4 RESERVE REQUIREMENTS

To accompany the Utility 2.0 CIP, RPU has developed a robust reserve policy, which is designed to promote fiscal sustainability, minimize borrowing costs, and providing a source of emergency funds to rapidly respond to market volatility, emergencies, demand reductions, or regulatory changes. The reserve policy guidelines were adopted by City Council on March 22, 2016 and later incorporated into the fiscal policy which was adopted by City Council on July 26, 2016.

The overall reserve target will be met by combining five risk categories that each have a target based on specific metrics. Table 4-6 provides a summary of the metrics that are used to calculate the unrestricted undesignated target minimum and maximum reserve levels for each risk category.

TABLE 4-6 UNRESTRICTED UNDESIGNATED RESERVE LEVEL METRICS

COMPONENT AND DESCRIPTION	MINIMUM TARGET	MAXIMUM LEVEL
Operating (Working Capital): maintain sufficient resources to pay budgeted operating and maintenance expenses recognizing the timing differences between payment of expenditures and receipt of revenues.	60 Days of Operating Expenses	90 Days of Operating Expenses
Rate Stabilization: mitigates rate shock due to temporary and transitional regulatory changes, loss of a major resource, sharp demand reduction, or market volatility.	7 Percent of Operating Revenues	15 Percent of Operating Revenues
Emergency Capital: provides funds to maintain ability to repair system after an emergency or natural disaster such as a flood, earthquake, or major storm.	1 Percent of Depreciable Assets	2 Percent of Depreciable Assets
System Improvements Capital: provide funds to maintain continuity of construction over fiscal years to be reimbursed by bond proceeds or other resources.	6 Months of Annual CIP	9 Months of Annual CIP
Debt Service: maintain ability to make debt service payments in an extreme event that may impact RPU's ability to provide services, thus impacting revenues at a time critical infrastructure repairs are needed to restore systems. The Debt Service Reserve is intended to prevent an event where RPU would be unable to pay its debt service obligations during such emergencies, or extreme market disruptions.	Maximum Annual Debt Service in Upcoming Fiscal Year	Maximum Annual Debt Service in Upcoming Fiscal Year

As part of the Five-Year Rate Plan, RPU will propose updating the reserve policy to include a line of credit (LOC) as available reserves to meet unrestricted undesignated reserve targets. An LOC is a low-cost mechanism that allows RPU to draw upon cash when needed, thus reducing required cash reserve levels, minimizing rate increases to maintain reserve levels, and increasing liquidity. The LOC is currently projected as the highest of the five-year maximum system improvements capital to provide for capital funding if bond proceeds or other resources are not available.

The reserve levels vary in each year based on the expenditures or revenues used to calculate each component. Table 4-7 shows the projected target minimum and maximum reserve levels for each year of the five year rate projection. The revenue requirements in the pro forma were set to include unrestricted undesignated reserves combined with the LOC to remain above the minimum targets identified.

TABLE 4-7 PROJECTED UNRESTRICTED UNDESIGNATED MIN & MAX RESERVE CALCULATIONS (MILLIONS)

Component	Target	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Working Capital	Minimum	$6.70	$7.27	$7.66	$8.00	$8.33
	Maximum	$10.05	$10.91	$11.48	$12.00	$12.49
Rate Stabilization	Minimum	$4.77	$5.18	$5.50	$5.85	$6.21
	Maximum	$10.23	$11.09	$11.79	$12.53	$13.31
Capital- Emergency	Minimum	$6.77	$7.09	$7.42	$7.81	$8.23
	Maximum	$13.53	$14.18	$14.85	$15.63	$16.46
Capital- System Improvements	Minimum	$16.02	$16.25	$19.23	$20.45	$22.81
	Maximum	$24.02	$24.38	$28.84	$30.68	$34.22
Debt Service (Max Annual Debt Service in upcoming FY)	Minimum	$9.39	$12.12	$12.29	$13.62	$17.32
	Maximum	$9.39	$12.12	$12.29	$13.62	$17.32
Total	**Minimum**	**$43.65**	**$47.92**	**$52.10**	**$55.73**	**$62.91**
	Maximum	**$67.23**	**$72.69**	**$79.26**	**$84.46**	**$93.81**
Proposed Line of Credit		**$34.22**	**$34.22**	**$34.22**	**$34.22**	**$34.22**
Notes:						
(1) Totals may be off due to rounding.						

4.5 REVENUE REQUIREMENT FORECAST

Overall, RPU must raise rate revenues in order to recover from the revenue losses occurring due to the State imposed water restrictions, as well as to fund future capital reinvestments. While the water utility will recover some additional revenue from the projected increases in water demands as the restrictions are lifted, these increased sales alone are not sufficient to fund RPU's needs. Table 4-8 presents the revenues, expenditures, and overall rate revenue increases for the forecast period beginning in FY 2017/18 through FY 2021/22.

TABLE 4-8 RESULTS OF REVENUE REQUIREMENT ANALYSIS (MILLIONS)

Revenues	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Revenue before annual rate and demand increase[1]	$54.10	$58.05	$63.67	$68.21	$72.95
Offsetting Revenues					
Interest income	0.80	1.66	1.99	1.50	2.06
Miscellaneous income	9.90	10.27	10.39	10.52	10.65
Outside City Surcharge	1.51	1.55	1.60	1.64	1.69
Other Charges for Service	0.62	0.63	0.64	0.66	0.67
Total Revenues Before Increase	**$66.93**	**$72.17**	**$78.29**	**$82.52**	**$88.01**
Expenditures					
Production costs	$4.75	$4.76	$4.78	$4.80	$4.82
Personnel costs	15.07	18.21	19.51	20.59	21.69
Other O&M costs	19.78	20.17	20.57	20.98	21.40
Additional O&M for CIP and Tech	1.17	1.12	1.72	2.31	2.75
Debt service requirements	13.82	15.40	18.78	18.79	21.10
General fund transfer	6.64	7.11	7.76	8.30	8.86
Capital outlay financed by rates	5.07	9.79	6.70	7.10	6.52
Total Expenditures	**$66.30**	**$76.54**	**$79.82**	**$82.86**	**$87.12**
Allocation to (Use of) Reserves Prior to Increases	**$0.63**	**($4.37)**	**($1.53)**	**($0.34)**	**$0.89**
Demand and Growth Increase[2]	6.56%	0.99%	0.80%	0.81%	0.83%
Rate Revenue Increase	8.75%	8.50%	8.50%	8.50%	8.50%
Month of Rate Increase	April	January	January	January	January
Revenues from Demand and Rate Increases	$4.01	$5.67	$4.60	$4.81	$5.10
Total Revenues	**$70.94**	**$77.84**	**$82.89**	**$87.32**	**$93.12**
Allocation to (Use of) Reserves After Increases	**$4.64**	**$1.30**	**$3.06**	**$4.46**	**$6.00**
Unrestricted Undesignated Reserves	*$40.22*	*$38.41*	*$40.19*	*$43.85*	*$45.64*
Debt Service Coverage Ratio[3]	2.29x	2.27x	2.00x	2.13x	2.07x

Notes:
(1) Projected revenues prior to each fiscal year's demand and rate increases, includes the impact of increases from previous years.
(2) Prior to inclusion of price elasticity adjustments.
(3) Net of BABs treasury credit.
(4) Totals may be off due to rounding.

The amount of revenue to be collected from user rates is defined by the total revenue requirements less any offsetting revenues. Table 4-9 presents the revenue required from user rates that provides the basis for the cost of service analysis and rate design. As of the completion of this analysis, RPU anticipates to implement rate increases in April of 2018, and in January of each following year. Because the rate increases will be implemented in the middle of each fiscal year, the rate revenue requirements for each year include an "Adjustment for Mid-year Increase." This line item adjusts the required rate revenue to reflect a full year increase to match the full year of projected usage that is used to calculate the rates for each year.

TABLE 4-9 REQUIRED RATE REVENUE (MILLIONS)

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Total Expenditures	$66.30	$76.54	$79.82	$82.86	$87.12
Allocation to (Use of) Reserves After Increases	4.64	1.30	3.06	4.46	6.00
Less Offsetting Revenues:					
Interest Income	($0.80)	($1.66)	($1.99)	($1.50)	($2.06)
Miscellaneous income	(9.90)	(10.27)	(10.39)	(10.52)	(10.65)
Outside City Surcharge	(1.51)	(1.55)	(1.59)	(1.64)	(1.69)
Other Charges for Service	(0.62)	(0.63)	(0.64)	(0.66)	(0.67)
Required Rate Revenue	**$58.11**	**$63.72**	**$68.26**	**$73.01**	**$78.05**
Plus: Adjustment for Mid-Year Increase	$4.30	$2.98	$3.10	$3.31	$3.53
Plus: Adjustment for Transitional Rates[1]	$0.72	$0.62	$0.48	$0.31	$0.00
Revenue Requirements For Rate Design	**$63.13**	**$67.33**	**$71.85**	**$76.63**	**$81.58**

Notes:

(1) Line-item reflects a full fiscal year impact of the transition amount. For FY 2017/18, the actual impact will only reflect 3 months of transitional impacts, about $0.18 million, due to the timing of the proposed rate increases. The revenue impact associated with transitional rates will be offset using Interest Income. Projected impacts in millions for each fiscal year are as follows.

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Fiscal Year Transitional Impacts	$0.18	$0.67	$0.55	$0.39	$0.15

(2) Totals may be off due to rounding.

In addition to the adjustment to account for the mid-year rate increases, the required rate revenue for the rate design is adjusted to account for transitional rates. In order to mitigate the rate impacts to customers in rate classes that will be closed, RPU has proposed to transition Irrigation Metered Service (WA-3), Grove Preservation Service (WA-9), and WA-7 cemetery customers to the otherwise applicable rate classes in the fifth year of the rate plan. This transition will result in revenue impacts for FY 2017/18 through FY 2021/22 that will be offset using non-rate revenues from interest income. The adjustment shown in Table 4-9 above is included so that the revenue requirements for rate design reflect the use of interest income to offset the impact of the transitional rates.

5 WATER COST OF SERVICE ANALYSIS

With RPU's water utility's revenue requirements outlined—including needed rate increases—the next step is to link each cost item with a specific service to the system that it supports. This is commonly referred to as the cost of service analysis, or the functional cost allocation, because it connects each cost of the utility with a functional category or purpose that it funds. For instance, expenses related to the billing system are allocated under the umbrella of the customer service function, while baseline water purchases go to support the base demand function.

The costs incurred are generally responsive to the specific service requirements or cost drivers imposed on the system and its water resources by its customers. The principal service requirements that drive costs include the annual volume of water consumed, the peak water demands incurred, and the number of customers or meter equivalents in the system. Accordingly, these service requirements are the basis for the selection of the categories utilized in the functional allocation process.

The AWWA M1 Manual outlines the two most widely used methods for allocation of costs— the base-extra capacity method and the commodity demand methodology. Both methods recognize that the cost of serving a customer depends not only on the total volume of water used, but also on the rate of use or peak-demand requirements.

The proposed rates presented within this report are developed using a base-extra capacity method. In using this approach, costs are typically separated into three cost components: (1) Base (average), (2) Extra Capacity (related to sources of supply), (3) Customer. As noted in the AWWA M1 Manual, in detailed rate studies, such as the one performed for this study, some of these elements might be broken down further into two or more subcomponents.

Based on the City's expenditures and system characteristics, the Customer (or fixed monthly) component was separated into two subcomponents: (1) Customer (accounts) and (2) Capacity (meter equivalents). This bifurcation of the Customer component is done to better identify and allocate costs that vary based on capacity needs (as defined by the size of the meter) from those that should be equally shared by each customer account. Similarly, water supply costs were split into the four sources of supplies. These are designed to better distinguish that not all demand (and peaking) is equal. These calculated peaking factors are used as a proxy for determining and allocating the cost of providing extra-capacity in the system needed to serve those who use more. Different facilities, such as distribution and storage facilities, and the operation and maintenance costs associated with those facilities, are designed to meet the peaking demands of customers. Therefore, extra capacity costs[1] include the operations and maintenance costs and capital costs associated with meeting peak customer demand.

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[1] The terms extra capacity, peaking, and capacity costs are used interchangeably.

5.1 FUNCTIONAL COST COMPONENTS

The objective of this cost-of-service study is to develop rate structures that proportionally recover costs from RPU's customers. RPU's budget was analyzed line-item by line-item and expenditures were distributed between the following system functions:

> ***Customer:*** Fixed expenditures that relate to operational support activities including accounting, billing, customer service, and administrative and technical support. These expenditures are essentially common-to-all customers and are reasonably uniform across the different customer classes.
>
> ***Capacity:*** Meter and capacity related costs, such as meter maintenance and peaking charges, that are included based on the meter's hydraulic capacity (measured in gallons per minute). Additionally, as the system's facilities are designed to meet peak demand, a portion of the infrastructure related costs are allocated to Capacity.
>
> ***Base:*** Operating and capital costs incurred by the water system to provide a basic level of service to each customer.
>
> ***Supply 1:*** Operating costs associated with the lowest cost source of water supply, Gage.
>
> ***Supply 2:*** Operating costs associated with the second lowest cost source of supply, the Riverside North and South basins.
>
> ***Supply 3:*** Operating costs associated with the second most expensive source of supply, Waterman.
>
> ***Supply 4:*** Operating costs associated with the most expensive source of supply, Flume.
>
> ***Outside City:*** Additional capital costs incurred to meet demands for water from the City's customers who reside outside of the City and who require additional infrastructure to receive water service. These costs have been excluded from the rate calculation as the Outside City surcharge will continue to be assessed as a percentage adjustment to the In-City rates. The percentage adjustment has been recalculated based on information provided by RPU engineering and operations staff as discussed later in this report.

In order to perform the functional allocation, the cost of service analysis combines information from the pro forma, RPU's detailed operating budget, historical billing data, and additional operational and system information provided by RPU. The allocation to each functional component was calculated based on the detailed budget and cost information, and applied to the revenue requirements calculated in the pro forma.

Table 5-1 below presents the overall allocation by expense category and division to each functional component. A table showing the line item detail of the functional allocation is included in Appendix B.

TABLE 5-1 FUNCTIONAL ALLOCATION SUMMARY

Division/Category	Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base	As all Other	Total
Water Production and Operations	0.0%	0.0%	28.8%	20.8%	39.1%	11.3%	0.0%	0.0%	**100%**
Water Field Operations	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	**100%**
Water Engineering	0.0%	41.8%	9.6%	8.4%	18.0%	6.1%	16.2%	0.0%	**100%**
Existing Debt Service	0.0%	72.2%	6.3%	5.5%	11.9%	4.1%	0.0%	0.0%	**100%**
Rate-Funded Capital and New Debt Service	0.0%	61.2%	0.0%	0.0%	19.1%	6.5%	13.2%	0.0%	**100%**
Charges From Other Funds	16.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	83.8%	**100%**
Notes:									
(1) Totals may be off due to rounding.									

5.1.1 Water Production and Operations

The first set of costs to allocate amongst the functional cost components are the Water Production and Operations costs. This allocation defines how RPU's water supply costs, which include the production, purchasing, storage, and distribution of water, are distributed among each of RPU's sources of supply.

Due to the abnormally low water demands in FY 2015/16 resulting from the State water restrictions, water supply allocations and associated cost allocations have been developed based on FY 2013/14 and FY 2014/15 supply and cost data. This methodology provided a more accurate representation of the total supply available to RPU retail customers, including both utilized and resilient supply. The allocations developed are then applied to the projected costs for each year of the projection period in the cost of service analysis.

Water Supply

All potable water produced by RPU is pumped from RPU's five groundwater basins and is treated at one of six treatment facilities, then blended and stored in the Linden-Evans Reservoir. This system provides a majority of RPU's potable water needs. RPU also has the ability to take imported water from the Metropolitan Water District in excess of these local supplies. Consequently, a significant portion of RPU's costs are related to the production and distribution of water from its groundwater resources. An allocation has been developed for the "Water Production and Distribution" division of RPU's operating budget to allocate those costs.

Available Supply

RPU pumps groundwater from several groundwater basins that underlie or are nearby the City. The sources are grouped into four distinct supply sources referred to as Gage, Riverside North and South, Waterman, and Flume. The amount of water available from each supply is governed by the adjudicated pumping rights held by RPU. The average production levels by source for FY 2013/14 and FY 2014/15 serve as the basis of supply availability for the cost of service analysis. Table 5-2 shows the total production from each source for FY 2013/14 and FY 2014/15, water used for purposes other than RPU retail, water losses, and the amount available for RPU retail customers. Based on the projected levels of demand, RPU's existing water supplies will continue to meet the demands of RPU's projected customer base.

TABLE 5-2 WATER PRODUCTION BY SOURCE

Source/Function	Gage	Riverside South/ North	Waterman	Flume	Distribution (After Linden Reservoir)
Total Production, AF					
FY 2013/14	27,514	17,019	26,022	6,041	76,596
FY 2014/15	27,495	15,319	23,680	3,642	70,136
Loss Above Linden Evans					
FY 2013/14	(597)	(369)	(565)	(131)	(1,662)
FY 2014/15	(634)	(353)	(546)	(84)	(1,617)
Potable Wheeled to WMWD					
FY 2013/14	(1,702)	(1,053)	(1,610)	(374)	(4,739)
FY 2014/15	(1,912)	(1,065)	(1,646)	(253)	(4,876)
Potable Wholesale to Western					
FY 2013/14	0	0	0	0	0
FY 2014/15	0	0	0	0	0
Potable to Home Garden					
FY 2013/14	(166)	(103)	(157)	(37)	(463)
FY 2014/15	(158)	(88)	(136)	(21)	(402)
Delivered to UCR					
FY 2013/14	(328)	(203)	(311)	(72)	(914)
FY 2014/15	(352)	(196)	(303)	(47)	(897)
Water Loss Below Linden					
FY 2013/14	(1,393)	(862)	(1,318)	(306)	(3,879)
FY 2014/15	(1,558)	(868)	(1,342)	(206)	(3,975)
Potable to RPU Customers					
FY 2013/14	23,327	14,429	22,062	5,122	64,939
FY 2014/15	22,882	12,749	19,707	3,031	58,369

Water Supply and Production Costs

In FY 2013/14 and FY 2014/15 and through the projection period, RPU produced and anticipates continuing to produce all of its water needs locally from the groundwater basins to which it owns pumping and export rights. Each basin has a specific cost associated with water production. Costs associated with water supply are tracked in the Water Production and Operations Division of RPU's water operating budget. Those costs are then allocated to each source of supply as well as distribution by operations and engineering staff based on several factors including pumping charges or dues for each basin, the amount of water produced from each basin, the level of treatment required for water from each basin, and the amount of maintenance required for facilities in each basin. Table 5-3 below presents a summary of the cost of water allocation for based on the average of FY 2013/14 and FY 2014/15.

TABLE 5-3 SOURCE OF SUPPLY COST ALLOCATION AND UNIT COSTS

FY 2013/14	Gage + Rialto/Colton Supply 1	Riverside South/ North Supply 2	Waterman Supply 3	Flume Supply 4	Distribution (After Linden Reservoir)
Total Allocated Costs (Millions)	**$2.871**	**$2.906**	**$3.534**	**$1.381**	**$5.089**
Less:					
LMC paid labor, Lab, Elec, etc.	($0.782)	$0.000	($0.207)	$0.000	$0.000
DBCP (Shell) paid GAC, Legal fees, O & M	0.000	(0.561)	0.000	0.000	0.000
Adjusted Production Cost (Millions)	**$2.089**	**$2.345**	**$3.327**	**$1.381**	**$5.089**
Total Allocation	**15%**	**16%**	**23%**	**10%**	**36%**
					RPU Retail
Production (AF)	34,095	25,279	26,022	7,165	**65,854**
Unit Cost (per AF)	**$61.26**	**$92.77**	**$127.85**	**$192.80**	**$77.27**
FY 2014/15	Gage + Rialto/Colton Supply 1	Riverside South/ North Supply 2	Waterman Supply 3	Flume Supply 4	Distribution (After Linden Reservoir)
Total Allocated Costs (Millions)	**$3.017**	**$2.809**	**$3.527**	**$1.256**	**$4.375**
Less:					
LMC paid labor, Lab, Elec, etc.	($0.784)	$0.000	($0.180)	$0.000	$0.000
DBCP (Shell) paid GAC, Legal fees, O & M	0.000	(0.538)	0.000	0.000	0.000
Adjusted Production Cost (Millions)	**$2.233**	**$2.271**	**$3.347**	**$1.256**	**$4.375**
Total Allocation	**17%**	**17%**	**25%**	**9%**	**32%**
					RPU Retail
Production (AF)	33,024	22,730	23,680	4,130	**59,265**
Unit Cost (per AF)	**$67.61**	**$99.91**	**$141.35**	**$304.06**	**$73.82**

Notes:
(1) Includes water Wheeled to UCR.
(2) Totals may be off due to rounding.

The available water supplies have been prioritized based on unit costs. Water from Gage, the lowest cost source, is considered priority 1 supply (Supply 1), water from Riverside North and South is priority 2 supply (Supply 2), water from Waterman is priority 3 supply (Supply 3), and water from Flume (the most expensive source) is priority 4 supply (Supply 4). Costs associated with distribution (after the Linden-Evans reservoir) are considered to be a base cost, and are therefore distributed to each supply in proportion to the total amount of water available from that supply. Table 5-4 below shows the calculated costs associated with each source of supply and the resulting allocation of costs to Supply 1 through Supply 4. Water Production and Operations costs are allocated based on the "Total Cost, Supply and Distribution" allocation since that division includes costs for both producing and treating water from RPU's groundwater basins, and distributing it to customers.

TABLE 5-4 SOURCE OF SUPPLY ALLOCATIONS

Source of Supply	Supply 1 Gage	Supply 2 Riverside South/North	Supply 3 Waterman	Supply 4 Flume	Base Distribution
Supply Source Unit Cost (per AF)					
FY 2013/14	$61.26	$92.77	$127.85	$192.80	$77.27
FY 2014/15	67.61	99.91	141.35	304.06	73.82
Distribution Unit Cost					
FY 2013/14	$77.27	$77.27	$77.27	$77.27	$77.27
FY 2014/15	73.82	73.82	73.82	73.82	73.82
Total Unit Cost With Distribution					
FY 2013/14	$138.53	$170.04	$205.12	$270.07	$154.54
FY 2014/15	141.43	173.73	215.17	377.88	147.64
Available for RPU Retail[1]					
FY 2013/14	23,327	14,429	22,062	5,122	64,939
FY 2014/15	22,882	12,749	19,707	3,031	58,369
Supply Source Costs					Total
FY 2013/14	$1,429,000	$1,339,000	$2,821,000	$987,000	$6,576,000
FY 2014/15	1,547,000	1,274,000	2,786,000	922,000	6,529,000
Combined	**$2,976,000**	**$2,613,000**	**$5,607,000**	**$1,909,000**	**$13,105,000**
Percent	**23%**	**20%**	**43%**	**15%**	**100%**
Total Cost, Supply and Distribution					Total
FY 2013/14	$3,232,000	$2,454,000	$4,525,000	$1,383,000	$11,594,000
FY 2014/15	3,236,000	2,215,000	4,240,000	1,145,000	10,836,000
Combined	**$6,468,000**	**$4,669,000**	**$8,765,000**	**$2,528,000**	**$22,430,000**
Percent	**29%**	**21%**	**39%**	**11%**	**100%**

Notes:
(1) Does not include water Wheeled to UCR.

Continued water conservation has led to a surplus in the amount of water supply available to RPU. Though the entirety of RPU's available supply is not currently being used to serve retail customers, those customers benefit from the resiliency provided by that supply. However, in an effort to offset the need for rate increases, RPU has elected to increase wholesale water sales to other agencies. Revenues from these sales will help to support RPU operations and capital expenditures in light of the decreased retail demands and revenues. In the event that demands bounce back, or one of the supply sources is lost or reduced, the surplus supply will be used to serve retail customers.

5.1.2 Water Field Operations

RPU's expenses related to its Water Field Operations are allocated as a Base cost and recovered proportionally from each unit of water sold. The costs included in this category are not related to water production or distributions, and are therefore considered to be equal for every unit of water sold regardless of its source of supply.

5.1.3 Water Engineering

Staff in RPU's water engineering group split their time between supporting the capital program and supporting operations. Engineering staff working on capital projects charge their time directly to those projects, administrative staff costs within the Water Engineering category are budgeted as O&M expenditures. According to RPU, 51 percent of administrative staff time is spent on the CIP, 19.7 percent is spend on distribution, and 29.3 percent is spent on production and supply. Thus personnel costs in the Water Engineering category have been allocated at 51 percent to Capacity, 19.7 percent to Base to recover distribution costs, and the remaining 29.3 percent is split based on the water supply allocation. Non-personnel costs within the Water Engineering include consultant services, equipment and software purchases, insurance, and other operational expenses. As these costs are associated primarily with water supply and usage beyond the baseline level, they have been layered onto the supply costs and allocated at 22.7 percent to Supply 1, 19.9 percent to Supply 2, 42.8 percent to Supply 3, and 14.6 percent to Supply 4. These allocation factors are based on the amount of water available for retail from each source. Appendix E shows the calculations used to develop the allocations.

5.1.4 Debt Service

RPU has five outstanding debt obligations as well as pension obligations that are, for the purposes of the model, combined into one expense referred to as Debt Service. An analysis was completed to allocate the existing debt service obligations to supply related debt and non-supply related debt based on the types of projects that were funded by each debt issue. Based on that analysis, 28 percent of outstanding debt service costs are allocated based on the water supply allocations, with the remaining 72 percent of debt service costs allocated to Capacity. An additional benefit of this methodology is that revenue to cover the majority of debt service is reliable as it is collected entirely through the fixed charge.

5.1.5 General Fund Transfer

The City's General Fund Transfer is based on the total amount of gross operating revenue collected by RPU, thus it is allocated As All Others, meaning that it will be allocated between the functional cost components in the same proportion as the aggregate of all other expenses. This allocation effectively matches the general fund transfer allocation to the overall rate revenue allocation.

5.1.6 Charges from Other Funds

Charges from Other Funds are associated primarily administrative services provided to RPU's water division from other funds within RPU or the City general fund. Of those costs, about 16 percent are related to utility billing. Because billing costs do not relate to the amount of water consumed or the capacity required to serve each customer, they are allocated to the Customer component, and collected equally from all customers. The remaining 84 percent of costs are allocated As All Others.

5.1.7 Additional O&M for CIP and Advanced Tech

Additional O&M expenses will be required to operate a variety of soon to be built capital projects and for the advanced technology program. Costs associated with CIP projects are related primarily to water supply enhancements and are therefore allocated to the highest cost water in the Supply 4 category.

Advanced Technology expenditures will be incurred primarily to operate the water production and distribution systems, therefore the O&M costs will be allocated as supply and distribution at 29 percent to Supply 1, 21 percent to Supply 2, 39 percent to Supply 3, and 11 percent to Supply 4.

5.1.8 Rate-Funded Capital and New Debt Service

Rate Funded Capital and New Debt Service expenditures have been based on assigning each CIP project to the Capacity, Supply 3 and Supply 4, or Base categories.

Projects allocated to Capacity include distribution, transmission projects, and reservoir projects as well as technology projects. These projects make up about 61 percent of the proposed CIP through FY 2021/22.

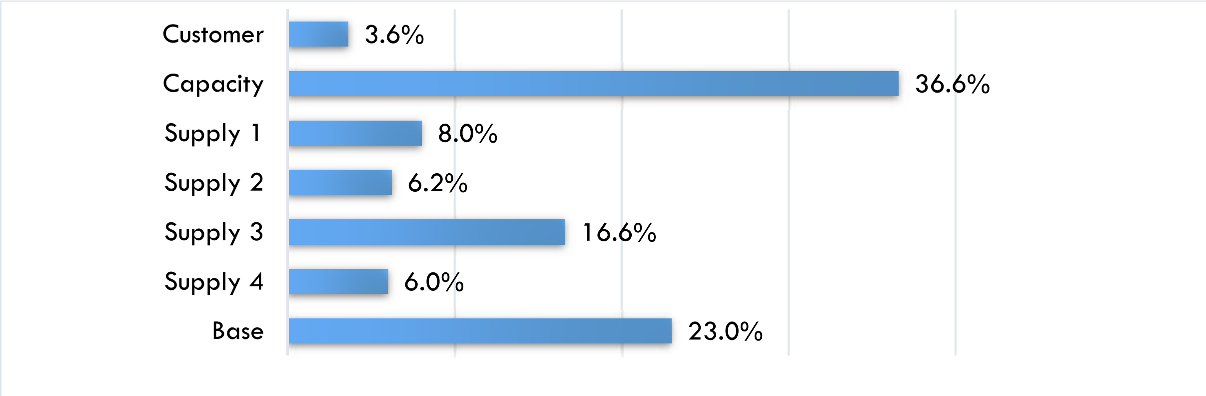
Projects allocated to Supply 3 and Supply 4 are projects that are intended to enhance water supplies and reliability. Specific projects include groundwater recharge, recycled water, and treatment plant projects and make up about 26 percent of the proposed CIP through FY 2021/22. The costs of these projects is split between the Supply 3 and Supply 4 Categories based on the supply allocation.

Projects allocated to Base include booster station and pressure reducing station rehabilitation, meter replacements, and well rehabilitation projects. These projects make up about 13 percent of the proposed CIP through FY 2021/22.

5.1.9 Final Allocation

Once each cost is allocated, a single allocation of each of RPU's expenses is used as the basis for allocating costs amongst customer classes. This is presented in the results of the functional allocation in Figure 5-1. The Capacity and Customer components collectively represent approximately 40 percent of RPU's costs that will comprise the fixed charge. The combined 60 percent of costs are allocated to the Base and Supply components and will be the basis for the variable rates.

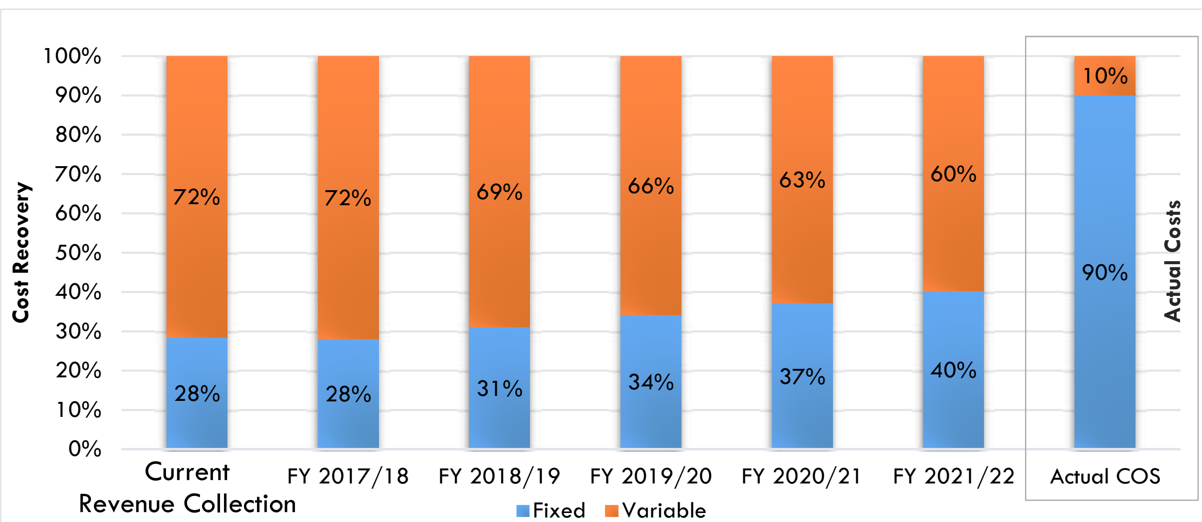
FIGURE 5-1 FUNCTIONAL ALLOCATION RESULTS



Note: Totals in figure may be off due to rounding.

The functional allocation results discussed above represent a shift toward collecting a greater share of revenues through the fixed charge in an effort to stabilize revenues and better match RPU's water costs, which are approximately 90 percent fixed. Any time costs or revenues are shifted from variable to fixed components, low volume customers may see a higher rate impact on a percentage basis. In an effort to mitigate impacts to low volume users, the shift to increased fixed revenue recovery will be phased in over the 5 year rate plan. Fixed charges will account for roughly 28 percent of revenues in year 1 (FY 2017/18) and ramp up to about 40 percent of revenues by year 5 (FY 2021/22). Figure 5-2 below shows the percentage of fixed and variable revenue recovery for each year of the projection period under the proposed rates.

FIGURE 5-2 FIXED AND VARIABLE COST RECOVERY



5.2 ALLOCATION OF COSTS TO CUSTOMER RATE CODES

The next step in the cost of service analysis is the allocation of costs to each rate class. This step utilizes the results of the functional allocation and the customer usage and account data, to proportionally allocate costs based on the level of service provided to each rate class.

5.2.1 Rate Class Updates

RPU's existing rate structure, as previously mentioned, has 10 rate classes with 13 individual rate codes. As a component of the cost of service analysis, the existing rate codes were evaluated and updated to provide an enhanced nexus between rate class and customer characteristics. The analysis identified three key updates to RPU's rate classes.

Residential Accounts

Currently, WA-1 is the rate code that encapsulates a majority of RPU's residential customers. It is often difficult for a single rate code to adequately address both Single-Family Residences (SFR) and Multi-Family Residences (MFR) whose consumption patterns and account characteristics differ greatly. Taking this into consideration, this study splits WA-1 and makes a distinction between SFR and MFR customers.

Landscape Irrigation Accounts

Additionally, RPU provides service to a number of accounts that function as Landscape Irrigation accounts. Currently, these customers are found in three different rate codes (WA-1, WA-6.1, and WA-6.2) despite providing a similar benefit to customers and requiring a similar cost to RPU. As a result, RPU intends to reclassify all Landscape accounts as such and create a new rate code that properly recovers the costs of providing them with commercial landscape irrigation services.

Commercial and Industrial Accounts

Lastly, Commercial and Industrial accounts, which have historically been treated as separate rate codes WA-6.1 and WA-6.2, will be combined into a single class with a uniform seasonal rate. These classes provide a similar level of service, and although total usage per account varies based on meter size, the annual consumption profile is consistent.

The allocations and rates discussed throughout this report are based on the proposed updates to RPU's rate classes discussed above.

5.2.2 Water Supply Allocation

The available supply from each priority and the allocation of supply costs to each priority is used to allocate costs to each customer class, and to usage in each tier where applicable. Allocations are based on the five year average projected consumption from each customer class for FY 2017/18 through FY 2021/22. The allocation of available supply to each customer class was performed using the five step process described below:

1. **Allocate first increment of demand as dedicated Supply 1 for essential usage.**
Indoor residential demands are given top priority for water in Supply 1 as these demands are considered to be essential for public health and safety. The amount of Supply 1 water dedicated to cover these demands is based on the tier 1 consumption for WA-1 single family and WA-1 multi-family customers, and estimated based on 9 CCF per month per account for WA-4 customers. This step exhausts about 6.00 million CCF of the available 10.60 million CCF of Supply 1 water. The remaining Supply 1 water (4.60 million CCF) is available to be allocated to all customers in step two of the supply allocation.

2. **Allocate supply to the second increment of demand to all classes based on annualized three month minimum usage.**
The annualized 3 month minimum demand is assumed to represent the basic minimum level of usage for each customer class. For classes that were allocated a designated share of Supply 1 that dedicated share is subtracted from the annualized 3 month minimum demand prior to the allocation of supply. Step two of the allocation exhausts all remaining Supply 1 water (4.60 million CCF), all available Supply 2 water (6.24 million CCF), and a portion of Supply 3 water (1.97 million CCF).

3. **Allocate supply to the third increment of needed supply based on annualized winter consumption.**
Annualized winter demand represents the next increment of demand from each customer class. It represents annual demands associated with usage levels using RPU's seven-month winter (November through May). The supply allocated to each class in step one and step two is subtracted from the annualized winter demand prior to the allocation of remaining supply 3 water. Step 3 of the allocation exhausts 3.00 million CCF of Supply 3 water, leaving 4.63 million CCF to be allocated in step four.

4. **Allocate supply to the remaining demand based on total usage.**
Step four supplies to cover the remaining demand from each customer class based on total usage. The supply allocated to each class in step one, step two, and step three is subtracted from the total annual demand prior to the allocation of remaining supply 3 water and Supply 4. Step 4 of the allocation exhausts the majority of remaining Supply 3 water (3.84 million CCF). The Supply 3 water remaining after step 4 (0.79 million CCF) and all of the Supply 4 water (1.87 million CCF), is considered resilient supply and is reallocated in step five.

5. **Spread unallocated Supply 4 water over Supply 3 and Supply 4 to account for supply resiliency.**
The remaining supply 4 water is reallocated to each customer class based on each's allocation of Supply 3 and Supply 4 water. This reallocation is intended to reflect the supply resiliency afforded to each class by the excess supply 4 water. Resilient supply is not allocated to WA-7 accounts since they are considered to be interruptible and would be cut off in the event that supplies became limited.

Supply Resiliency

Holding a basis in available water from each source and the amount of usage from each class, the supply allocations used to allocate production and operations costs to each customer class are intended to reflect the strain that each class places on RPU's available sources of supply. The resiliency component discussed in step 5 of the allocation represents the amount of excess supply that is available to serve increased peak usage within each class. The costs that are ultimately allocated using these factors are projected based only on the amount of usage expected, rather than the total potential usage from each supply source. The costs associated with resilient supplies are only those to maintain access to those supplies, and do not include costs for water that is not produced. Table 5-5 shows a summary of the water supply allocated to cover demand in each step of the allocation. A detailed table showing the allocation of supplies in each step to each customer class is included for reference in Appendix F.

TABLE 5-5 SUPPLY ALLOCATION SUMMARY

Class Allocation		Supply 1	Supply 2	Supply 3	Supply 4	Total
Total Available for RPU Retail	**CCF**	**10,600,000**	**6,235,000**	**9,582,000**	**1,870,000**	**28,287,000**
Step 1: Dedicated Supply	**Allocated**	**6,003,000**	**0**	**0**	**0**	**6,003,000**
Remaining Available After Step 1		4,597,000	6,235,000	9,582,000	1,870,000	22,284,000
Step 2: Annualized 3-Month Minimum	**Allocated**	**4,597,000**	**6,235,000**	**1,971,000**	**0**	**12,803,000**
Remaining Available After Step 2		0	0	7,611,000	1,870,000	9,481,000
Step 3: Annualized Winter	**Allocated**	**0**	**0**	**2,986,000**	**0**	**2,986,000**
Remaining Available After Step 3		0	0	4,626,000	1,870,000	6,496,000
Step 4: Remaining Usage	**Allocated**	**0**	**0**	**3,835,000**	**0**	**3,835,000**
Remaining Available After Step 4		0	0	791,000	1,870,000	2,661,000
Allocation to Each Supply		**10,600,000**	**6,235,000**	**8,791,000**	**0**	
Reallocation of Remaining Supply 4		0	0	791,000	1,870,000	
Final Allocation		**10,600,000**	**6,235,000**	**9,582,000**	**1,870,000**	**28,287,000**

Table 5-6 shows the results of the supply allocation with allocated supplies for each customer class, as well as each class's percentage share of each supply. The percentage shares shown are used to allocate the costs associated with each supply to each customer class.

TABLE 5-6 SUPPLY ALLOCATION RESULTS

Total With Reallocation of Remaining Supply 4				
Rate Code[1]	Supply 1	Supply 2	Supply 3	Supply 4
Temporary Service	3,000	4,000	52,000	11,000
Riverside Water Company Irrigators	8,000	5,000	16,000	3,000
Commercial & Industrial	2,243,000	3,042,000	2,849,000	590,000
City Irrigation	177,000	240,000	547,000	0
Single Family	7,550,000	2,442,000	5,188,000	1,074,000
Multi-family	292,000	57,000	100,000	21,000
Landscape	328,000	445,000	830,000	172,000
Total[2]	**10,600,000**	**6,235,000**	**9,582,000**	**1,870,000**
Percentage Allocation			Includes Resiliency Component	
Rate Code[1]	Supply 1	Supply 2	Supply 3	Supply 4
Temporary Service	0.0%	0.1%	0.5%	0.6%
Riverside Water Company Irrigators	0.1%	0.1%	0.2%	0.2%
Commercial & Industrial	21.2%	48.8%	29.7%	31.5%
City Irrigation	1.7%	3.9%	5.7%	0.0%
Single Family	71.2%	39.2%	54.1%	57.4%
Multi-family	2.8%	0.9%	1.0%	1.1%
Landscape	3.1%	7.1%	8.7%	9.2%
Total[2]	**100%**	**100%**	**100%**	**100%**

Notes:
(1) WA-1 accounts are included in SFR and MFR rate codes, WA-10 accounts are included in WA-7. WA-3.1 and WA-9.1 accounts are included with SFR. WA-3.2 and WA-9.2 accounts are included with WA-6.1. WA-5 has no normal usage and is therefore not allocated a share of supply. WA-8 accounts are not supplied with RPU water and are therefore not allocated a share of supply.
(2) Totals may be off due to rounding.

5.2.3 Rate Code Characteristics

Table 5-7 presents the total service units, otherwise known as the customer class characteristics, of each rate code. These totals are used to proportionally allocate the functional cost components between each rate code. The accounts and MEUs presented are the five year average of expected accounts for FY 2017/18 through FY 2021/22. The supply allocations are shown in CCF are those discussed above in Section 5.2.2 and include each class's share of resilient supply. Lastly, estimated total usage shows each class's share of annual retail demands.

TABLE 5-7 RATE CODE CHARACTERISTICS

Allocation Factor	Accounts	%	MEUs[3]	%	Supply 1	%	Supply 2	%
Temp. Service	72	0.1%	674	0.7%	3,000	0.0%	4,000	0.1%
Riv. Water Co.	38	0.1%	75	0.1%	8,000	0.1%	5,000	0.1%
Com. & Ind.	4,820	7.2%	22,931	24.1%	2,243,000	21.2%	3,042,000	48.8%
City Irrigation	509	0.8%	1,632	1.7%	177,000	1.7%	240,000	3.8%
Single Family	59,650	89.0%	65,354	68.7%	7,550,000	71.2%	2,442,000	39.2%
Multi-family	1,231	1.8%	1,459	1.5%	292,000	2.8%	57,000	0.9%
Landscape	690	1.0%	2,975	3.1%	328,000	3.1%	445,000	7.1%
Total	**67,010**	**100.0%**	**95,101**	**100.0%**	**10,601,000**	**100.0%**	**6,235,000**	**100.0%**
Allocation Factor	Supply 3	%	Supply 4	%	Estimated Total Usage	%		
Temp. Service	52,000	0.5%	11,000	0.6%	51,000	0.2%		
Riv. Water Co.	16,000	0.2%	3,000	0.2%	29,000	0.1%		
Com. & Ind.	2,849,000	29.7%	590,000	31.5%	7,488,000	29.8%		
City Irrigation	547,000	5.7%	0	0.0%	916,000	3.6%		
Single Family	5,188,000	54.1%	1,074,000	57.4%	14,746,000	58.7%		
Multi-family	100,000	1.0%	21,000	1.1%	440,000	1.8%		
Landscape	830,000	8.7%	172,000	9.2%	1,453,000	5.8%		
Total	**9,582,000**	**100.0%**	**1,871,000**	**100.0%**	**25,123,000**	**100.0%**		

Notes:

(1) WA-1 and WA-10 are no longer distinct rate classes and have been absorbed by the other rate classes.

(2) Meter Equivalent Units – relate the capacity required to serve each connection to the system based on the expected maximum flow from meters of each size

(3) Totals may be off due to rounding.

5.2.4 Customer Rate Code Allocation

To allocate costs of service to the different customer rate codes, each functional cost component must be split and divided appropriately amongst the rate codes. Each functional cost component is divided amongst the rate codes in proportion to each rate code's share of the total annual service units of the respective component. For the fixed components, the Customer component unit cost is based on the number of accounts and the Capacity component is based on meter equivalent units. The Base component is allocated based on the total sales volume. The Supply 1, 2, 3, and 4 components are allocated based on each class's respective supply allocations and adjusted to account for the interruptible rates that will be charged to City Irrigation and recycled water customers. No interruptible adjustments are made for the Customer, Capacity, or Base allocations.

The adjustment for interruptible customers is based on debt service and capital costs. Interruptible users are only responsible for the portion of debt service costs allocated to Capacity, and the portion of new debt service and rate funded capital costs that are allocated to Capacity or Base. These users are not considered to benefit from investments in water supply resiliency because they will be required to stop using water in the event that system wide usage must be curtailed, or if a system failure or other event leads to a decrease in available supplies. Thus, the allocation of supply costs is adjusted to remove the debt service and capital costs that are associated with developing or enhancing water supply sources from the interruptible users' share of costs.

Table 5-8 shows the percentage allocation adjustments that are made to the each of the supply costs for due to the interruptible rates. The costs allocated to the interruptible customers are lowered based on the percentages and the reduction amount is reallocated to the non-interruptible rate classes who benefit from the past and future water supply projects. Detail showing the items that are applied to the interruptible rates and the calculation of the percentage adjustments is included for reference in Appendix B.

TABLE 5-8 INTERRUPTIBLE SERVICE ALLOCATION ADJUSTMENTS

	Supply 1	Supply 2	Supply 3	Supply 4
Percentage Adjustment for Interruptible Service	-2.9%	-3.7%	-9.1%	-8.3%

Table 5-9 shows the effective supply cost allocations after the interruptible service adjustment is made for the City Irrigation customers. These adjusted allocations are used to allocate supply costs to each customer class. Additional details of this calculation can be found in Appendix C.

TABLE 5-9 SUPPLY ALLOCATIONS WITH INTERRUPTIBLE SERVICE ADJUSTMENTS

	Supply 1		Supply 2	
	Baseline Allocation	Adjusted Allocation	Baseline Allocation	Adjusted Allocation
Temporary Service	0.0%	0.0%	0.1%	0.1%
Riverside Water Company Irrigators	0.1%	0.1%	0.1%	0.1%
Commercial & Industrial	21.2%	21.2%	48.8%	48.9%
City Irrigation	1.7%	1.6%	3.8%	3.7%
Single Family	71.2%	71.3%	39.2%	39.2%
Multi-family	2.8%	2.8%	0.9%	0.9%
Landscape	3.1%	3.1%	7.1%	7.1%
Total	100%	100%	100%	100%
	Supply 3		Supply 4	
	Baseline Allocation	Adjusted Allocation	Baseline Allocation	Adjusted Allocation
Temporary Service	0.5%	0.5%	0.6%	0.6%
Riverside Water Company Irrigators	0.2%	0.2%	0.2%	0.2%
Commercial & Industrial	29.7%	29.9%	31.5%	31.5%
City Irrigation	5.7%	5.2%	0.0%	0.0%
Single Family	54.1%	54.4%	57.4%	57.4%
Multi-family	1.0%	1.0%	1.1%	1.1%
Landscape	8.7%	8.7%	9.2%	9.2%
Total	100%	100%	100%	100%
Notes:				
(1) Totals may be off due to rounding.				

Table 5-10 shows the allocation of the functional cost components to each of the rate codes in FY 2017/18. This process is repeated for each year of the rate projection period to calculate rates for each fiscal year. Appendix E shows the allocation of costs to each customer class for each year of the rate projection period.

TABLE 5-10 ALLOCATION OF COSTS TO CUSTOMER CLASS

Function	Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base
Allocation Factor	Accounts	MEUs	Supply 1	Supply 2	Supply 3	Supply 4	Total Usage
Temporary Service	$2,000	$114,000	$2,000	$3,000	$68,000	$26,000	$36,000
Riverside Water Company Irrigators	1,000	13,000	4,000	4,000	22,000	8,000	20,000
Commercial & Industrial	114,000	3,878,000	1,289,000	2,307,000	3,772,000	1,438,000	5,205,000
City Irrigation	12,000	276,000	99,000	175,000	655,000	0	637,000
Single Family	1,415,000	11,055,000	4,340,000	1,853,000	6,867,000	2,618,000	10,252,000
Multi-family	29,000	247,000	168,000	43,000	132,000	50,000	306,000
Landscape	16,000	503,000	188,000	337,000	1,098,000	419,000	1,010,000
Total	**$1,589,000**	**$16,086,000**	**$6,090,000**	**$4,722,000**	**$12,614,000**	**$4,559,000**	**$17,466,000**
Notes:							
(1) Totals may be off due to rounding.							

The allocations of functional cost components to each rate code shown in the above Table 5-10 are then recovered over each customer class's projected accounts, MEUs, and usage to derive the variable and fixed rates for each rate code. The functional cost components allocated to the customer classes for each fiscal year are recovered over the various service units from for that specific year.

5.3 TYPES OF COST ALLOCATION

Not only are costs proportionately allocated between customer rate codes, but it is important to design rates that are proportionate at various demand levels within a customer class. Once the costs are allocated to rate codes, the next step is to equitably allocate the variable rate components (Base, Peak, and Max) to users within the group. In meeting Proposition 218 requirements, Carollo analyzed how these services vary between rate codes and within rate codes. Additionally, RPU's water costs were aligned to promote water use efficiency while placing a greater share of the costs on those customer who proportionately place greater demands on the water system and its water resources.

5.3.1 Water Use Characteristics

Both the design of water system (capacity & infrastructure) and the cost of the City's overall water portfolio are governed by peaking

As RPU pays different prices to pump water from each of its sources, water use at inefficient or excessive levels costs the agency significantly more than water used at efficient levels. Under RPU's existing structure, the cost of water is separated and the costs of producing water from more expensive sources are allocated to those customers who consume water at levels in excess of basic needs essential for public health and safety and above minimal living needs and thus place a greater demand on the system. Through a tiered rate structure, customers who consume above efficient levels are charged progressively more for each CCF of water they consume. If RPU's rate structure did not include a tiered structure, then the costs of producing water from each source would be uniformly blended and increased usage would increase the cost to all users.

However, this update to the rate structure largely maintains RPU's existing rate structure where a number of the existing rate codes charge different prices in different tiers. In order to maintain this structure and update the rates so as to apportion the cheapest source of water to those users who use the least amount of water, Carollo analyzed water use across rate codes as well as within each rate code. The peaking factors provided below in Table 5-11 illustrate that each customer class uses water differently. Some customer rate codes tend to consume more during the peak season (summer) or only during a peak month in comparison to their average usage.

TABLE 5-11 PEAKING FACTORS

Ratio of Consumption	Max Month/ Annual Average	Max Month/ Winter Average	Max Month/ Min Month
Temporary Service	263%	291%	3112%
Riverside Water Company Irrigators	197%	248%	441%
Commercial & Industrial	124%	140%	174%
City Irrigation	160%	214%	439%
Single Family	130%	155%	191%
Multi-family	125%	138%	162%
Landscape	142%	177%	276%

In RPU's existing rate structure, some rate codes are charged a different rate during summer in order to more accurately charge those customers whose consumption drives the need for oversizing of infrastructure and the additional transmission of water from the Linden-Evans Reservoir. This study updates these existing seasonal rates, as well as develops seasonal rates for the three new rate codes: SFR, MFR, and Landscape. The rate codes that are charged a higher seasonal summer rate are assumed, based on historic billing data, to have a larger portion of their consumption occur during peak periods relative to other rate codes. Consequently, these rate codes are responsible for a larger share of the oversized capacity built into the system to serve peak users.

6 WATER RATE DESIGN ANALYSIS

The rate design analysis links the rate code costs identified in Section 5 with the water rates necessary to achieve cost recovery. The focus of this process is to achieve full cost recovery and substantiate that each rate code is paying their fair and proportionate share of system costs.

6.1 SELECTING RATE STRUCTURES

Once costs have been equitably allocated to each customer class, RPU does have some flexibility in designing the rate structure in order to meet its policy objectives. In determining the appropriate rate level and structure, Carollo analyzed various rate design alternatives and the corresponding customer and utility implications. Beyond the identified study objectives, Carollo identified additional criteria for considerations and discussed them at length with RPU staff. Listed below are RPU's ratemaking principles:

Ratemaking Principles

RPU rate structures will be designed to provide a transition to rates that align with the transformational changes occurring in the electric and water industries. RPU's rates shall be designed to achieve the following goals:

- Achieve full recovery of costs.
- Equitably allocate costs across and within customer classes.
- Encourage efficient use of water and electricity.
- Provide rate stability.
- Offer flexibility and options.
- Maintain rate competitiveness in region.
- Be simple and easy to understand.

Given the numerous and, at times, competing elements, selection of an appropriate rate structure is complex. There is no single structure that meets all objectives equally, nor are all objectives or elements valued the same by the utility or customers. Each criteria or element has merit and plays an important role in the rates implementation and overall effectiveness. These elements and competing objectives were discussed and evaluated at length throughout the financial and rate study process.

6.2 PROPOSED WATER RATES

Based on discussion with RPU staff and careful review of the cost of service analysis, Carollo recommends that RPU implement the following rate design modifications:

- Increase the percentage of costs recovered by the fixed charge to better reflect how actual costs are incurred. This adjustment helps RPU meet its objective of increased revenue stability and predictability.
- Implement a uniform fixed monthly service charge for each meter size. This charge will be assessed to all rate codes including Irrigation Metered Service (WA-3.1, WA-3.2) and Special Metered Service (WA-7), who have historically been subject to a minimum monthly charge rather than a fixed service charge.
- Separate SFR and MFR customers that are currently tracked together in Residential (WA-1).
- Implement a three-tier rate structure for SFR customers with seasonally adjusted rates.
- Revise SFR Tier 1 allotment from 15 CCF to 9 CCF per month, which assumes 55 gallons per day per person at four persons per SFR dwelling.
- Implement a two-tier rate structure for MFR customers with two, three, or four dwelling units with tier allocations based on the number of dwelling units served by each account. MFR accounts with more than 4 dwelling units will be assessed the Commercial and Industrial Rate.
- The MFR Tier 1 allotment will be set at 7 CCF based on 3 persons per household and 55 gallons per person per day.
- Combine Commercial (WA-6.1) and Industrial (WA-6.2) accounts into one rate class with a uniform, seasonally adjusted rate.
- Implement a uniform landscape rate which is seasonally adjusted and separate from the Commercial and Industrial Rates.
- Combine Special Metered Service (WA-7) accounts, which are used by the City for irrigation of public facilities, with Recycled Water (WA-10).
- Transition Irrigation Metered Service (WA-3) and Grove Preservation Metered Service (WA-9) customers to the otherwise applicable rate classes. Services with residences (WA-3.1 and WA-9.1) will be transitioned to the SFR rate class, while services without residences (WA-3.2 and WA-9.2) will be transitioned to the commercial and industrial rate class as they serve primarily commercial nursery operations.
- Transition cemeteries that have historically been charged under the Special Metered Service (WA-7) rate to the otherwise applicable rate classes. Meters that serve offices or other structures will transition to the Commercial and Industrial rate, while those that serve exclusively irrigation will transition to the Landscape rate.

6.3 FIXED CHARGES

The fixed charge is intended to provide a stable revenue source that is related to how customers use the system. The proposed fixed charge is a combination of the Customer and Capacity functional components. The Customer component recovers costs that apply to all accounts in the system, regardless of usage or the size of the connection to the system. The proposed fixed charge is designed to collect costs associated with capital expenditures (debt service, rate funded capital, and a portion of engineering) based on each customer's capacity share as measured by MEUs. The customer share accounts for billing and administrative costs that are independent of each customer's capacity share and therefore equal for each account.

6.3.1 Fixed Monthly Service Charges

To determine the fixed charge, the meter unit cost is multiplied by the meter capacity ratios previously developed by RPU to calculate the meter capacity cost. These ratios are based on ratios identified in the AWWA M6 Manual 'Water Meters - Selection, Installation, Testing, and Maintenance' and represent the types of meters used by Riverside. The ratios are calculated using the average of maximum flow for meters of each size.

The meter Capacity cost is then added to the Customer cost to calculate the cost based fixed charges. Historically, the fixed expenses associated with Irrigation (WA-3.1 and WA-3.2) and Special (WA-7) Metered Services have been recovered through the variable rate and the associated minimum monthly charge. As proposed, Irrigation (WA-3.1 and WA-3.2) and Special (WA-7) Metered Services customers will pay the fixed monthly service charge, rather than the minimum monthly charge. Table 6-1 presents the results of this calculation for FY 2017/18.

While an increased fixed charge provides a stable source of revenues for the utility, increasing the fixed charge reduces the amount allocated to the commodity rates, and thus has the incidental effect of reducing incentives for conservation. The proposed revenue adjustments, as a percentage, do not equal or necessarily correlate to an equivalent percentage increase to rates or monthly bills. The results of the cost of service analysis and rate redesign will affect users differently based on their meter size and water consumptions habits.

This calculation is repeated for each year based on the allocated Customer and Capacity Costs, and the projected number of accounts and MEUs to calculate the charges for each year of the rate projection period. As discussed in Section 5 the increased allocation of costs to fixed components, and therefore the increase in fixed charges will be phased in over the Five Year Rate Plan.

TABLE 6-1 COMPONENTS TO PROPOSED FIXED CHARGE

Meter Size	Capacity Ratio	Customer Component	Capacity Component	Total Monthly Charge[1]
3/4" & 5/8"	1.00	$2.01	$14.39	$16.40
1"	1.67	2.01	24.03	26.04
1.5"	3.33	2.01	47.91	49.92
2"	5.33	2.01	76.69	78.70
3"	10.00	2.01	143.88	145.89
4"	16.67	2.01	239.85	241.86
6"	36.67	2.01	527.60	529.61
8"	60.00	2.01	863.27	865.28
10"	93.33	2.01	1,342.82	1,344.83
12"	133.33	2.01	1,918.33	1,920.34
Notes	(1) Totals may be off due to rounding.			

Table 6-2 presents the proposed fixed charges for each year of the rate plan.

TABLE 6-2 PROPOSED MONTHLY FIXED CHARGES

Meter Size	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
3/4" & 5/8"	$16.40	$19.21	$22.29	$25.64	$29.24
1"	26.04	30.50	35.38	40.69	46.40
1.5"	49.92	58.47	67.82	77.99	88.93
2"	78.70	92.16	106.91	122.93	140.16
3"	145.89	170.85	198.17	227.87	259.80
4"	241.86	283.23	328.52	377.75	430.67
6"	529.61	620.20	719.36	827.16	943.03
8"	865.28	1,013.27	1,175.29	1,351.40	1,540.69
10"	1,344.83	1,574.84	1,826.63	2,100.35	2,394.54
12"	1,920.34	2,248.78	2,608.32	2,999.17	3,419.25

6.4 VARIABLE RATES

The variable rates are developed for each customer class group and are designed to recover the costs proportionate to water demands. Cost of service based rates were developed for each customer class based on the principle of maintaining vertical and horizontal customer-class equity. Customer classes, such as single-family residential or commercial, only pay for their assigned share of costs of service, and within each customer class, each account will pay a fair share of the costs assigned to that customer class. The water commodity rate for each customer class group is calculated based on the customer class' cost (required revenues) and the forecasted water demands.

Seasonally Adjusted Rates

Like RPU's current rate structure, the proposed variable rates for several customer classes will be seasonally adjusted. Rates are increased in the summer months in order to reflect the increased costs associated with providing water during times of peak usage. The seasonal adjustment also provides the additional benefit of promoting efficient usage throughout the year.

Under the existing rate structure, summer months include June through October and winter months include November through May. Based on current water usage patterns these seasonal definitions were found to be in alignment with customer usage patterns, and were therefore maintained for the proposed rates. The seasonal adjustment to the rates was made by allocating a greater share of costs to the tier three summer rate based on the annualized summer to annual average usage peak factor. This peak factor is calculated for each of the seasonally adjusted classes by dividing the average summer consumption by the average annual consumption as shown in Table 6-3 below.

TABLE 6-3 SEASONAL PEAK FACTORS

Rate Class	Summer	Winter	Annual	
Number of Months	5	7	12	
Total Seasonal Usage (FY 2017/18)	**CCF**	**CCF**	**CCF**	
SFR	7,978,000	7,701,000	15,679,000	
MFR	221,000	247,000	468,000	
Commercial and Industrial	3,801,000	4,057,000	7,858,000	
Landscape	814,000	711,000	1,525,000	
Riverside Water Company Irrigators	15,580	13,460	29,100	
Average Monthly Usage	**CCF**	**CCF**	**CCF**	**Peak Factor[1]**
SFR	1,596,000	1,100,000	1,307,000	**1.22**
MFR	44,000	35,000	39,000	**1.13**
Commercial and Industrial	760,000	580,000	655,000	**1.16**
Landscape	163,000	102,000	127,000	**1.28**
Riverside Water Company Irrigators	3,120	1,920	2,420	**1.29**
Notes:				
(1) Annualized summer to annual average peak factor calculated by dividing 'Summer: Average Monthly Usage' by 'Annual: Average Monthly Usage'.				
(2) Totals may be off due to rounding.				

6.4.1 Single Family Residential Rates

Given ongoing drought and calls for conservation, and RPU's continued investment in supply resiliency, it is important that the proposed water rate structure promotes efficient water usage and passes the true cost of providing water service on to the customers who utilize that service. The continuation of a seasonally adjusted tiered rate structure for single-family customers is to maintain those objectives. The study reviewed the appropriateness and applicability of several rate structure alternatives for the Single Family residential customer class.

Maintaining the Current Structure – The current single family rates are fixed tiered rates with a four-block inclining structure and seasonally adjusted rates. While this four tier structure, which is intended to proportionally recover the cost to provide peak water demands, also promotes conservation through the increasing price structure, it has resulted in a high level of revenue variability due to the large difference in rates between Tier four and Tiers one, two, and three, most notable in the summer. Additionally, it was found that only a very small percentage of total SFR usage was within Tiers 3 and 4, about 7 percent and 5 percent respectively.

Modifying the Structure, Three Tiers – Several fixed tier, three tiered rate structure alternatives were developed and reviewed. These options included seasonal and non-seasonal rates, various methods to set tier breaks, and various methods to allocate costs to each tier.

Proposed Rate Structure

The proposed single-family rate structure is designed to proportionately allocate a greater share of the costs of service to those whose higher water usage generates additional costs to the water utility. The proposed rate structure is an inclining block rate structure designed to reflect RPU's various sources of supply coupled with the typical usage patterns and needs of a SFR customer.

The proposed rates have been developed with a three-tiered inclining block structure, with rates that vary seasonally. The CCF allotments for each tier will remain constant throughout the course of the year. The proposed tier allotments have been set based on water needs for each customer and on the actual usage patterns observed in the customer billing data.

Tier 1 Allotment – Indoor Usage: The proposed tier one allotment is 9 CCF per account per month. This allotment was calculated based on an assumed 4 persons per household and 55 gallons per capita per day.

Tier 2 Allotment – Efficient Outdoor Usage: The tier two allotment is an additional 26 CCF per month above the tier one allotment. This allotment maintains RPU's existing tier two breakpoint of 35 CCF per month, and is in alignment with the average maximum month consumption per SFR account.

Tier 3 – High Usage: Any usage above 35 CCF will be charged the tier three rate.

Seasonal adjustment of the tier three rates helps to reflect the additional cost of seasonal peaking on the system.

Proposed Single Family Rates

Volumetric rates for each tier are calculated by allocating the variable costs to be collected from the SFR rate class to each tier based on usage per tier, and supply available in each tier. Base costs are allocated equally to all usage as they are considered to be independent of source of supply costs. Costs for each priority of supply (Supply 1, Supply 2, Supply 3, and Supply 4) are allocated to each tier based on exhausting the lowest cost source of supply to each tier before allocating costs associated with the next source of supply. Supply cost allocation to each tier were developed based on the five year average consumption per tier, and the five year average supply allocated to single family residential customers to maintain consistency.

Based on current demand levels, RPU has some available, unused supplies. These supplies provide a critical level of resiliency for the water system and are available to meet high-level, peak demands as other supply sources become restricted. As noted in the report above, RPU is able to sell some of these supplies to offset its operational costs and rate impacts. However, because these supplies provide the greatest level of benefit to high volume users, costs associated with supply resiliency are allocated into tier 3, to reflect the supply available for high volume users and the peak strain that they place on the system. But for the fact that RPU's customers peak on the system, new local supplies and the associated facilities would not have been developed. A direct example of these cost investments is the John W. North Water Treatment Plant.

Table 6-4 below shows the development of the allocation of each supply cost to each tier based on the five year average consumption over the rate planning period. The allocations are based on the five year average to correspond to the allocation of available supplies to each customer class discussed in Section 5.2.2. Though the resilient supply allocated into tier 3 shows an excess of available supply, the costs allocated into each tier reflect only costs that RPU will actually incur. The resilient supply costs considered in the analysis include only those that will be incurred based on the projected usage, and the fixed costs incurred to maintain access to those supplies. Variable costs associated with resilient supplies such as electricity or chemicals are not included in the analysis.

TABLE 6-4 SINGLE FAMILY RESIDENTIAL SUPPLY ALLOCATION

		Tier 1	Tier 2	Tier 3
Cons per Tier	**Five Year Average**	**5,678,000**	**6,642,000**	**2,406,000**
Allocated Supply		**Tier 1**	**Tier 2**	**Tier 3**
Supply 1	7,550,000	5,678,000	1,872,000	0
Supply 2	2,442,000	0	2,442,000	0
Supply 3	5,188,000	0	2,328,000	2,860,000
Supply 4	1,074,000	0	0	1,074,000
Supply Cost Allocation Per Tier		Tier 1	Tier 2	Tier 3
Supply 1		75%	25%	0%
Supply 2		0%	100%	0%
Supply 3		0%	45%	55%
Supply 4		0%	0%	100%
Base	All Usage	39%	45%	16%

The allocations shown in Table 6-5 above are then used to allocate supply costs to each tier. Table 6-5 below shows an example of the allocation for FY 2017/18.

TABLE 6-5 SINGLE FAMILY SUPPLY COST PER TIER (FY 2017/18)

	Allocated Costs	Tier 1	Tier 2	Tier 3
Supply 1	$4,340,000	$3,264,000	$1,076,000	$0
Supply 2	1,853,000	0	1,853,000	0
Supply 3	6,867,000	0	3,081,000	3,786,000
Supply 4	2,618,000	0	0	2,618,000
Base	10,252,000	3,953,000	4,624,000	1,675,000
Total Allocated Costs Per Tier[1]	**$25,930,000**	**$7,217,000**	**$10,634,000**	**$8,079,000**
Notes:				
(1) Totals may be off due to rounding.				

After costs have been allocated to each tier, they are split between winter and summer based upon the projected usage per tier in each season. The seasonal rate adjustment for tier three is created by allocating costs for summer consumption in tier three using the annualized summer to annual average peak factor. A corresponding allocation is made to the allocated winter tier three costs to maintain revenue neutrality over the entire year. The allocation results in a seasonal differential in the tier three rate that is equal to the peak factor, thus the tier three rate in summer is 1.22 times the tier 3 rate in winter. The costs allocated to each tier in each season are then divided by the projected usage for the corresponding tier and season to calculate the volumetric rates. The single family rate calculation for FY 2017/18 is shown in Table 6-6 below.

TABLE 6-6 SINGLE FAMILY RATE CALCULATION (FY 2017/18)

Projected Usage		Summer	Winter	Total[1]
Tier 1		2,598,000	3,447,000	6,045,000
Tier 2		3,763,000	3,309,000	7,072,000
Tier 3		1,617,000	945,000	2,562,000
Total		**7,978,000**	**7,701,000**	**15,679,000**
Projected Costs		Summer	Winter	Total
Tier 1		$3,102,000	$4,115,000	$7,216,000
Tier 2		5,658,000	4,975,000	10,634,000
Tier 3	Peak: 1.22	5,463,000	2,616,000	8,079,000
Total		**$14,223,000**	**$11,706,000**	**$25,929,000**
Volumetric Rates		Summer	Winter	
Tier 1		**$1.20**	**$1.20**	
Tier 2		**$1.51**	**$1.51**	
Tier 3		**$3.38**	**$2.77**	
Notes:				
(1) Totals may be off due to rounding.				

The calculation is repeated for each year of the analysis based on each years' projected usage and allocated costs to develop the rate presented in Table 6-7. Appendix H provides additional detail of the SFR rate calculations.

TABLE 6-7 PROPOSED SFR RATES

Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.13	First 9	$1.20	$1.27	$1.33	$1.40	$1.46
Tier 2	1.64	10-35	1.51	1.59	1.67	1.76	1.84
Tier 3	2.26	>35	2.77	2.93	3.08	3.23	3.38
Tier 4	2.75						
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 9	$1.20	$1.27	$1.33	$1.40	$1.46
Tier 2	1.83	10-35	1.51	1.59	1.67	1.76	1.84
Tier 3	2.85	>35	3.38	3.58	3.76	3.94	4.12
Tier 4	4.10						
Notes:							
(1) Existing residential customers are currently charged WA-1 rates.							
(2) WA-1 had four tiers. Tier 1: First 15. Tier 2: 16 to 35. Tier 3: 36-60. Tier 4: >60.							

Single Family Revenue Volatility

As discussed previously, one of the goals of the rate design analysis was to create a rate structure that decreases revenue volatility, while conforming to the requirements of Proposition 218, and RPU's other rate setting principles. Under the existing rates, the most volatile source of revenue is variable revenue from high usage single family customers, particularly those whose consumption falls within tier four. With the current rates, and based on projected usage for FY 2017/18, customers using over 70 CCF (about 3 percent of accounts) would be responsible for about 20.4 percent of SFR revenues. The proposed rate structure mitigates volatility by reducing the number of tiers from tiers from 4 to 3, and decreasing the pricing differential between tiers to match supply related costs.

Figure 6-1 shows the percent of customers within each usage block as well as the projected usage by each block for FY 2017/18. The left axis corresponds to the green bars which show the total annual usage expected from accounts falling within each monthly usage group. The right axis corresponds to the blue line showing the percent of accounts within each monthly usage group.

FIGURE 6-1 SFR USAGE GROUPS

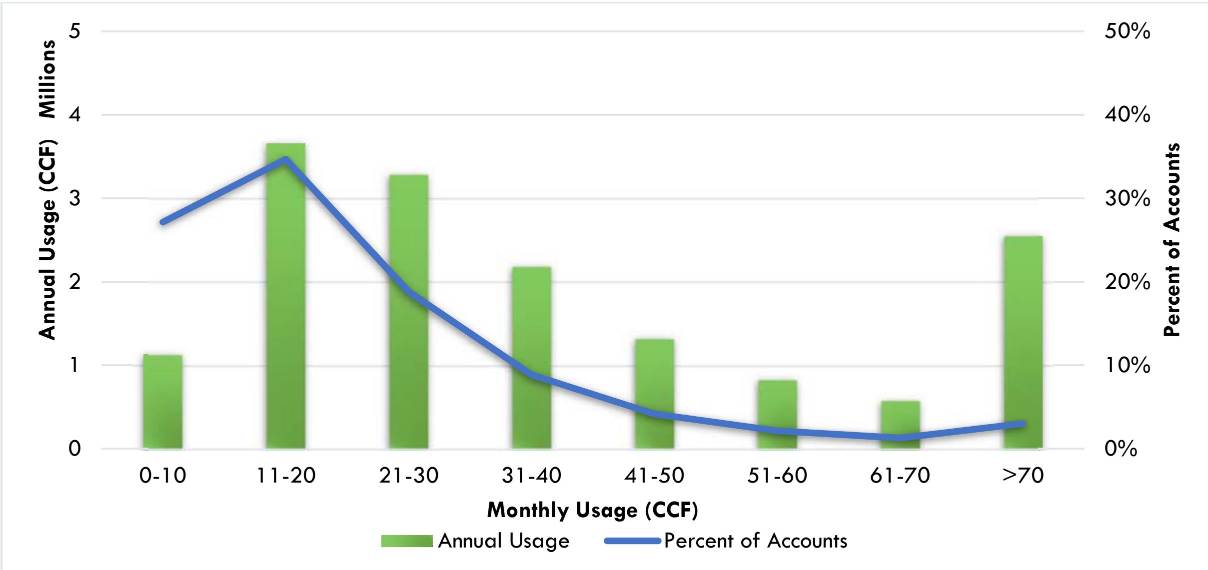
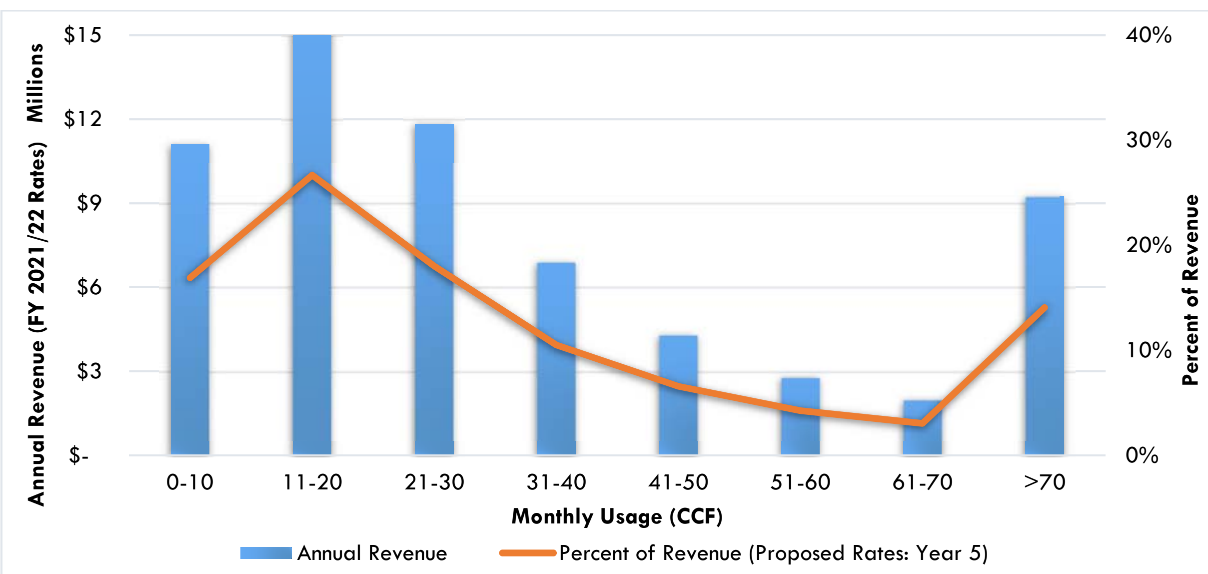


Figure 6-2 shows the revenue generated by single family users at varying levels of consumption for FY 2017/18. The left axis corresponds to the blue bars that show the annual revenue expected from users within each usage group. The right axis corresponds to the orange line that shows the percent of annual revenues from users within each group.

FIGURE 6-2 SFR REVENUE BY USAGE GROUP



As shown, the highest users, those above 70 CCF per month, account for 14.1 percent of SFR revenues under the proposed structure.

Single Family Bill Impact Analysis

Due to the changes in the rate structure, monthly bill impacts will vary for specific customers based on their level of usage, seasonal peaking, and meter size. The primary rate structure updates, and their impact on customer bills is discussed below. Note that the calculated bills and impacts presented within this report do not include RPU's Water Conservation Surcharge.

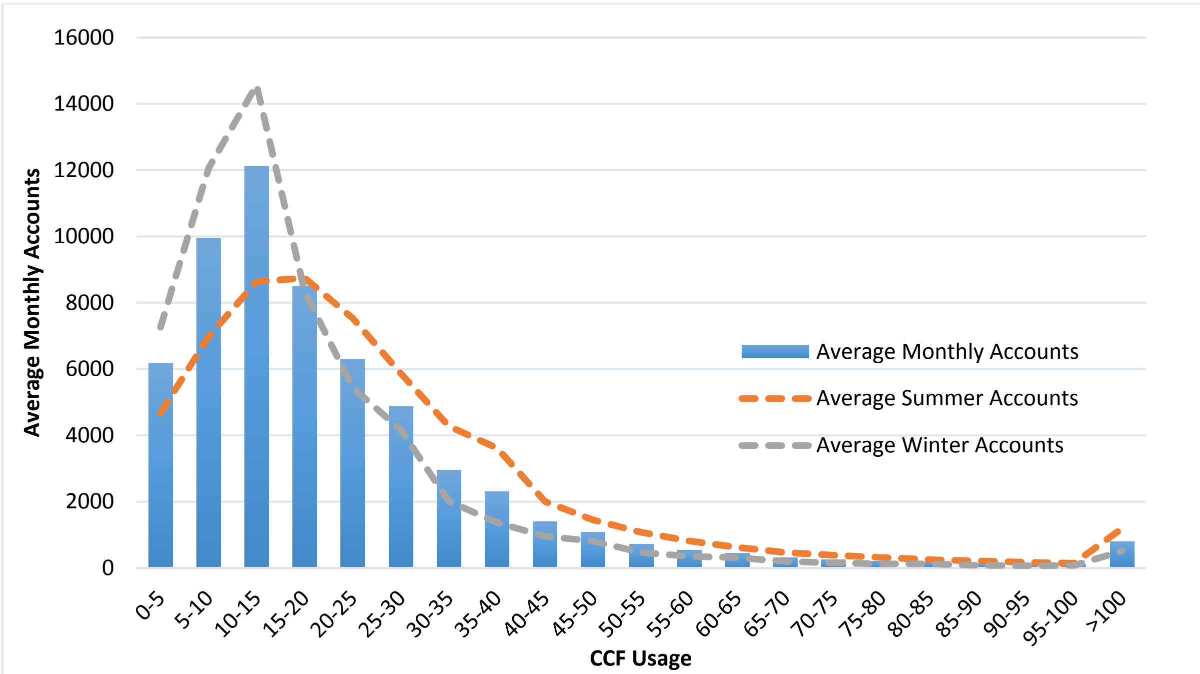
Phase-in of Increased Fixed Charges: The phase-in of increased fixed revenue recovery over the rate plan period will result in slightly higher percentage increases for low usage customers, however on a dollar basis, the lower usage customers will see a lower increase than higher usage customers.

Decreased Tier 1 Allotment: The decrease of the Tier 1 breakpoint from 15 CCF to 9 CCF will impact customers whose usage typically falls above 9 CCF per month. Due to the lowered breakpoint, more of their usage will be charged at the higher Tier 2 rate rather than the Tier 1 rate. A portion of this increase will be offset by the change in the Tier 2 rate, with will drop to $1.51 in FY 2017/18 from the current rates of $1.64 (winter) and $1.83 (summer).

Change to Three-tiered Structure: The change to a three-tiered structure from the current rate's four-tiered structure aims to decrease revenue volatility by decreasing the amount of revenues from the largest users. It also allows the tiered rates to be better tied to RPU's water supplies. As a result of this change, the highest users will no longer be subject to the Tier 4 rate, all usage above 35 CCF will be charged at the Tier 3 rate. Due to the combining of Tiers 3 and 4, along with the other cost of service updates, the Tier 3 rate is will increase from the current rates of $2.26 (winter) and $2.85 (summer) to $2.77 (winter) and $3.38 (summer).

An analysis was completed in order to assess and understand the impact of the rate structure updates across a wide variety of customers with differing usage levels and meter sizes. Figure 6-3 below shows the average distribution of the number of customer accounts at each usage level. On an annual average basis, the majority of customers, about 89 percent, use less than 40 CCF per month. About one percent of customers have an average use of more than 100 CCF per month. The usage distribution varies based on the season with more accounts at higher levels of monthly consumption in the summer, and more accounts at lower levels of consumption in the winter.

FIGURE 6-3 SINGLE FAMILY MONTHLY USAGE DISTRIBUTION



Further analysis of billing data and projected consumption for FY 2017/18 was completed to determine winter and summer usage at various consumption percentiles, and the bill impacts were calculated for each percentile. For this analysis the percentiles define the levels of consumption at which a given percentage of the customers fall at or below. For example, the 10th percentile corresponds to monthly usage of 5 CCF or below in the winter and 8 CCF or below in the summer. The customer attributes for each percentile are shown below in Table 6-8.

TABLE 6-8 SINGLE FAMILY TEST CUSTOMERS

Percentile	Winter CCF	Summer CCF	Average Annual Use	Assumed Meter Size
10th	5	8	6	3/4"
25th	9	15	12	3/4"
50th (Median)	15	24	19	3/4"
75th	24	36	29	1"
90th	37	54	44	1"

Figure 6-4 below shows the average monthly bill increase for each percentile in FY 2017/18 (Year 1) and the average monthly bill increase from FY 2018/19 through FY 2021/22 (Years 2 to 5). The average monthly bill for a 50th percentile (median) customer will increase by $4.06 per month in FY 2017/18, with an average monthly increase of $4.60 for years 2 through 5.

FIGURE 6-4 SINGLE FAMILY AVERAGE MONTHLY BILL INCREASES

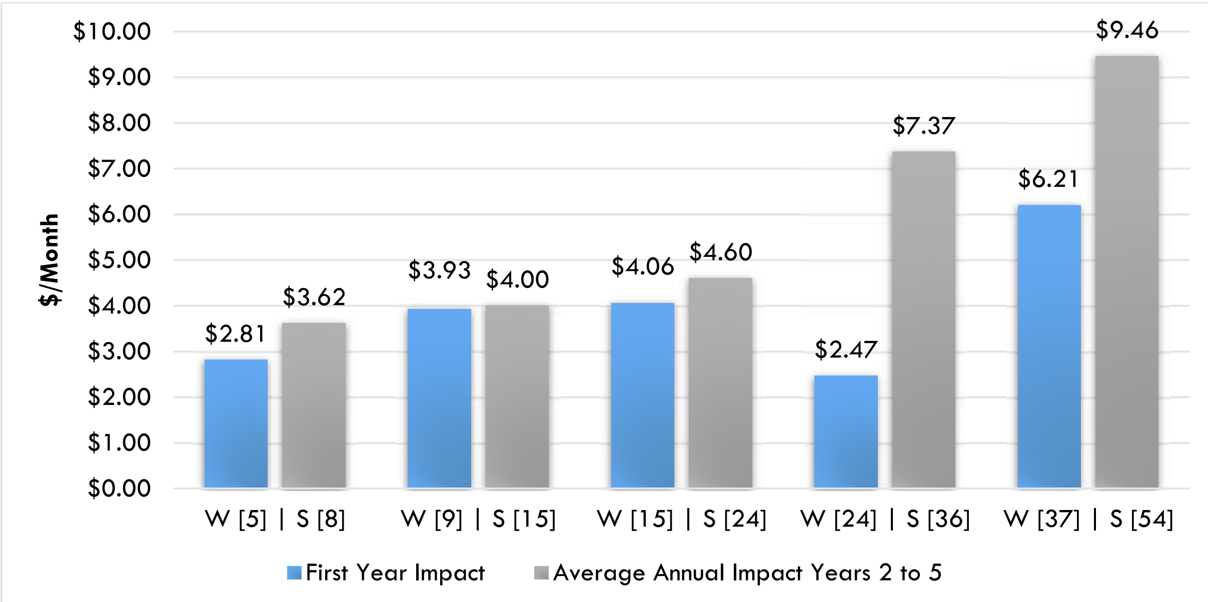


Table 6-9 below presents the average monthly bills for each user under the current rates and under the proposed rates in FY 2017/18 (Year 1) and in FY 2021/22 (Year 5). Also shown are the percentage increases in Year 1 and the average percentage increases for Years 2 through 5. As discussed previously, the lower users will see higher percentage increases due to the phase-in of increased fixed revenue recovery, and the modification of the tier structure. However, as shown in the last column, the overall dollar change from the current rates to the proposed rates in Year 5 increases incrementally as consumption levels rise.

TABLE 6-9 SINGLE FAMILY MONTHLY BILL IMPACTS

Percentile	CCF Usage Win | Sum	Avg Monthly Current Bill	Avg Monthly New Bill - Yr 1	Annual Avg % Yr 1	Avg Monthly New Bill - Yr 5	Annual Avg % Yr 2 to 5	5-Year Increase Current to Yr 5
10th	5 | 8	$21.09	$23.90	13.35%	$38.37	12.56%	$17.28
25th	9 | 15	$27.05	$30.98	14.52%	$46.98	10.98%	$19.93
50th	15 | 24	$37.87	$41.92	10.72%	$60.32	9.52%	$22.46
75th	24 | 36	$65.35	$67.82	3.78%	$97.29	9.44%	$31.94
90th	37 | 54	$99.89	$106.09	6.21%	$143.94	7.93%	$44.06

6.4.2 Multi-Family Residential Rates

Due to the high variance in account characteristics among individual customers, traditional tiered rate structures are often not a good fit for multi-family accounts. While multi-family usage is relatively homogeneous per dwelling unit, the number of units per complex varies widely. Relying only on account total information to develop and impose rates would penalize large complexes rather than excessive use or peaking. Therefore, tiered rate structures for multi-family accounts are typically developed based on allotments per dwelling unit rather than allotments per account.

Larger complexes, those with five or more dwelling units, exhibit consumption patterns that are more closely matched to commercial customers rather than other residential customers. In the absence of rates per dwelling unit, these customers are best served by a uniform volumetric rate.

Under the existing rate structure, multi-family accounts are charges under varying rate codes, some under the SFR WA-1 residential rate, and other under the Commercial and Industrial (WA-6.1 or WA-6.2) rate. The cost of service analysis and rate design aimed to identify all multi-family accounts regardless of their current rate class, and analyze the account and usage characteristics to develop multi-family specific rates, or find the most appropriate rate class to group the accounts.

Through billing system and property data analysis, RPU was able to identify the multi-family accounts and the number of dwelling units associated with each. The tiered multi-family rates will be limited to accounts with two, three, or four dwelling units. All larger accounts with five or more dwelling units will be migrated to the proposed Commercial and Industrial rate, as the usage for these properties better aligns with this class of user - more stable month or month water demands that vary by property size rather than based on seasonal peak usage.

Proposed Multi-Family Rates

The proposed rates have been developed with a two-tiered inclining block structure, with rates that vary seasonally. The per dwelling unit CCF allotments for each tier will remain constant throughout the course of the year. The proposed tier allotments have been set based on water needs for each customer and on the actual usage patterns observed in the customer billing data. Of the customers to be included in the multi-family rates, average monthly consumption per multi-family account for FY 2015/16 was 29 CCF; while the average monthly consumption per dwelling unit was 11 CCF. Setting tier allotments on a per dwelling unit basis helps to place all accounts on an even playing field, and enables tiered rates to appropriately standardize multi-family accounts to target efficiency and peaking, rather than demand alone.

- Tier 1 Allotment – Indoor Usage: The proposed tier one allotment is 7 CCF per account per month. This allotment was calculated based on an assumed 3 persons per household and 55 gallons per capita per day.
- Tier 2: Any usage above 7 CCF per dwelling unit will be charged the tier two rate.

Similar to SFR rates, seasonal adjustment of the tier two rates helps to promote year-round efficient water usage. The seasonal adjustment to the rates was made by allocating a greater share of costs to the tier three summer rate based on the annualized summer to annual average usage peak factor.

The rate calculation for the multi-family rates follows a process nearly identical to that outlined for the SFR rates above, but with only two tiers rather than three. Detailed calculations for the multi-family rates are included for reference in Appendix H. Table 6-10 below shows the proposed multi-family rates.

TABLE 6-10 PROPOSED MULTI-FAMILY RATES

Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.13	First 7 per DU	$1.20	$1.27	$1.33	$1.39	$1.46
Tier 2	1.64	>7 per DU	1.72	1.82	1.91	2.01	2.10
Tier 3	2.26						
Tier 4	2.75						
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 7 per DU	$1.20	$1.27	$1.33	$1.39	$1.46
Tier 2	1.83	>7 per DU	1.95	2.07	2.17	2.28	2.38
Tier 3	2.85						
Tier 4	4.10						
Notes:							
(1) Most applicable multi-family customers are currently charged WA-1 rates, though a small number are charged the WA-6.1 rate.							
(2) WA-1 had four tiers. Tier 1: First 15. Tier 2: 16 to 35. Tier 3: 36-60. Tier 4: >60.							

Multi-Family Bill Impact Analysis

Monthly bill impacts will vary for specific customers based on their level of usage, seasonal peaking, and meter size. Overall, the implementation of per dwelling unit rates in FY 2017/18 will result in lower increases and possible decreases for accounts that provide service to 3 or 4 dwelling units. The lowered increases or decreases are due to the accounts with more dwelling units no longer being subject to the current Tier 2, Tier 3, and Tier 4 rates simply because they serve a greater number of dwelling units and therefore use more water. Note that the calculated bills and impacts presented within this report do not include RPU's Water Conservation Surcharge.

After the initial structure change, increases are expected to be relatively proportional for accounts with different numbers of dwelling units but with similar consumption per dwelling unit. Figure 6-5 below shows the average monthly bill increases for multi-family customers currently on the SFR rate with two, three, and 4 dwelling units and average usage levels of 10 CCF and 12 CCF per month in winter and summer respectively.

FIGURE 6-5 MULTI-FAMILY AVERAGE MONTHLY BILL INCREASES

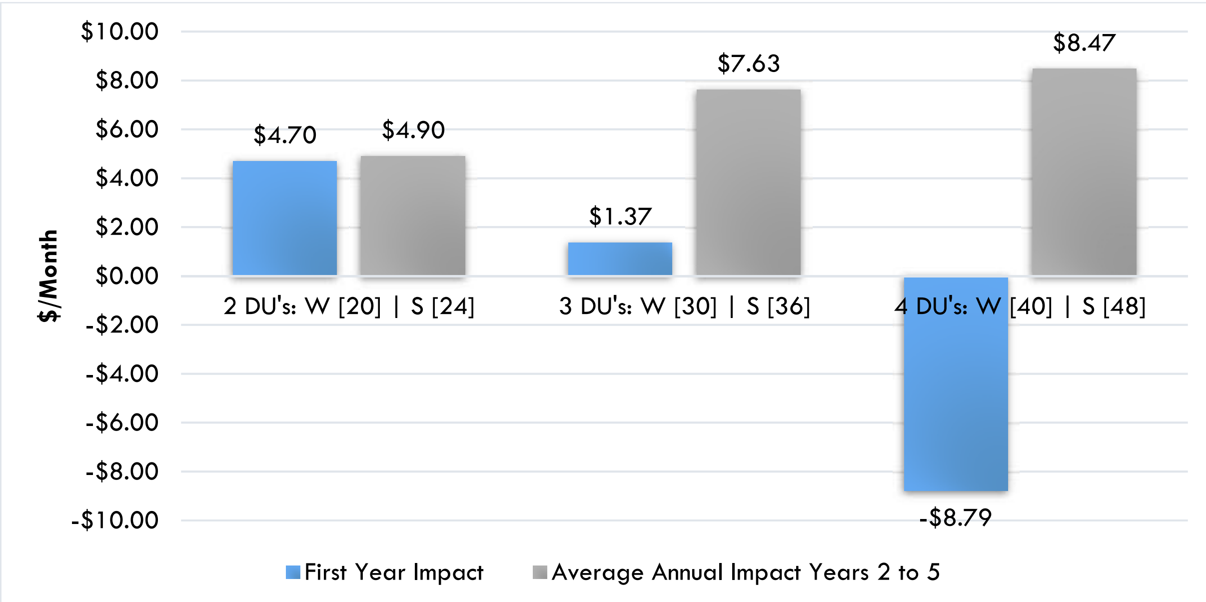


Table 6-11 below presents the average monthly bills for each user under the current rates and under the proposed rates in FY 2017/18 (Year 1) and in FY 2021/22 (Year 5). Also shown are the percentage increases in Year 1 and the average percentage increases for Years 2 through 5. As discussed previously, larger accounts will see smaller percentage increases or decreases in Year 1 due to the change to the per dwelling unit rate structure. After the initial change, increases for each user are expected to normalize.

TABLE 6-11 MULTI-FAMILY MONTHLY BILL IMPACTS

Customer Size	CCF Usage	Avg Monthly	Avg Monthly	Annual Avg %	Avg Monthly	Annual Avg %	5-Year Increase
	Win | Sum	Current Bill	New Bill - Yr 1	Yr 1	New Bill - Yr 5	Yr 2 to 5	
2 DU's	20 | 24	$42.65	$47.35	11.01%	$66.95	9.05%	$24.30
3 DU's	30 | 36	$71.09	$72.46	1.92%	$102.96	9.18%	$31.87
4 DU's	40 | 48	$96.72	$87.93	-9.08%	$121.81	8.49%	$25.10

6.4.3 Commercial and Industrial Rates

Under the existing rate structure, commercial and industrial users are each charged under distinct rate codes with fixed usage tiers. Non-residential users with meter sizes from 5/8-inch through 2-inch fall into the Commercial rate class (WA-6.1), and are subject to a two tiered, seasonally adjusted rates. The tier one allotment for commercial users is set at 550 CCF per month. Users with meter sizes of 3-inches or greater are placed in the Industrial rate class (WA-6.2) and are subject to a three tiered rate with Tier

1 from 0 to 550 CCF, Tier 2 from 551 to 5500 CCF, and any usage above 5500 CCF charged at the Tier 3 rate.

Though the difference in tier allotments between the commercial and industrial rate classes does afford some level of refinement, a high degree of variation does still exists between users with each class. For example, in FY 2015/16, average monthly consumption ranged from less than 15 CCF for 5/8-inch meters to almost 140 CCF for 2 inch meters. For Industrial WA-6.2 customers, average usage varied from about 440 CCF to over 1,800 CCF. This variation in usage illustrates the heterogeneity of accounts within the commercial and industrial classes, and points to the conclusion that the traditional tiers structure is not the best fit for commercial and industrial users. Unlike multi-family customers, there is no readily available methodology for creating appropriately sized tiered rates. As such, the proposed rates consist of a seasonally adjusted uniform rate structure that covers both the Commercial WA 6.1 and Industrial WA-6.2 accounts.

Proposed Commercial and Industrial Rates

The proposed Commercial and Industrial rates are calculated in a manner similar to the SFR rates shown above, however the calculation can be simplified because the proposed rates are a uniform rather than tiered. As an example, Table 6-12 below shows the calculation of the Commercial and Industrial rates for FY 2017/18. The total volumetric costs allocated to the commercial and industrial customers are split between summer and winter based on the annualized summer to annual average peak factor. Those seasonal costs are then divided by the projected consumption for each season to calculate the volumetric rates. Detailed calculations of the Commercial and Industrial rates are provided for reference in Appendix H.

TABLE 6-12 COMMERCIAL AND INDUSTRIAL RATE CALCULATION (FY 2017/18)

Projected Usage		Summer	Winter	Total
Total (WA-6.1 and WA-6.2 Combined)		3,801,000	4,057,000	**7,858,000**
Projected Costs		Summer	Winter	Total
Total Costs	Peak: 1.16	$7,299,000	$6,712,000	**$14,011,000**
Volumetric Rates		**Summer**	**Winter**	
Rate for All Usage		$1.93	$1.66	

Table 6-13 below shows the proposed Commercial and Industrial rates for each year of the rate plan. Existing rates are included for reference in Appendix H.

TABLE 6-13 PROPOSED COMMERCIAL AND INDUSTRIAL RATES

Winter Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$1.66	$1.69	$1.72	$1.75	$1.77
Summer Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$1.93	$1.97	$2.00	$2.03	$2.05
(1) WA-6.1 had two tiers. Tier 1: First 550. Tier 2: >550.							
(2) WA-6.2 had three tiers. Tier 1: First 550. Tier 2: 551 to 5500. Tier 3: >5500.							

Commercial and Industrial Bill Impact Analysis

Due to the changes in the rate structure, monthly bill impacts will vary for specific customers based on their level of usage, seasonal peaking, and meter size. The primary rate structure updates, and their impact on customer bills is discussed below. Note that the calculated bills and impacts presented within this report do not include RPU's Water Conservation Surcharge.

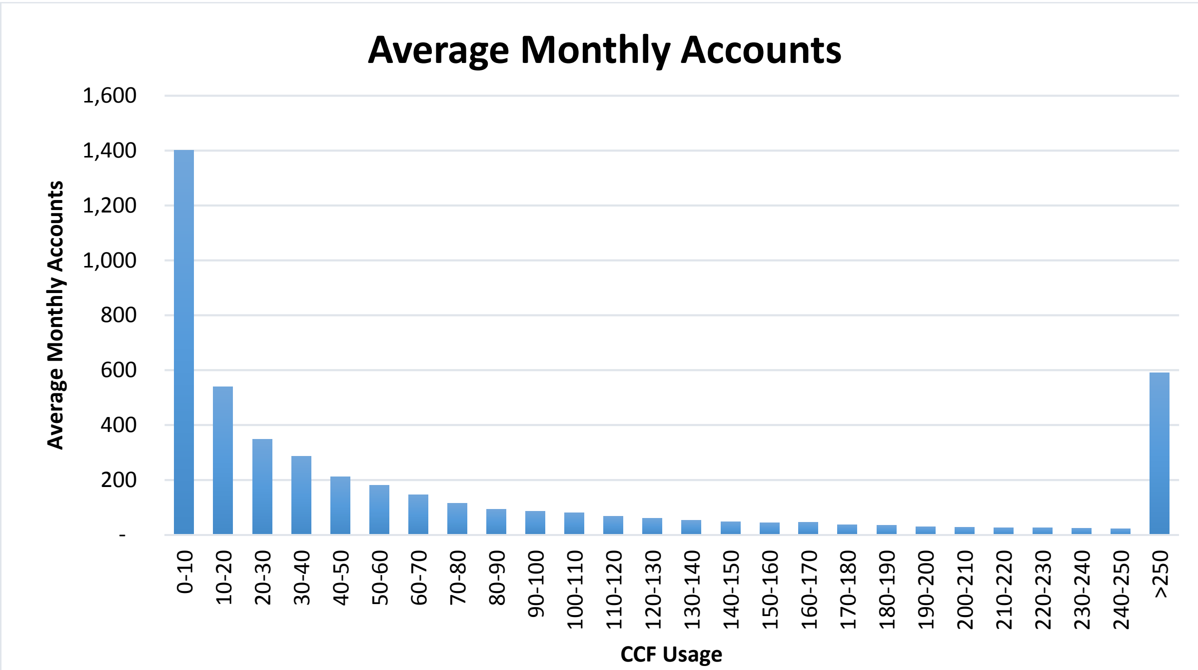
Uniform Fixed Charges: Historically, commercial and industrial users paid fixed charges that were lower than those assessed to residential customers. Under the proposed rate structure, fixed charges for each meter size will be the same for all customer classes. For most commercial users, this change will result in a higher increase in FY 2017/18 as compared to the expected increases for FY 2018/19 through FY 2021/22. This change will have more of an impact to the lowest usage commercial and industrial customers because the fixed charge is a greater proportion of their bill.

Phase-in of Increased Fixed Charges: The phase-in of increased fixed revenue recovery over the rate plan period will result in slightly higher percentage increases for low usage customers, however on a dollar basis, the lower usage customers will see a lower increase than higher usage customers.

Change to Uniform Seasonally Adjusted Rates: The change to a seasonally adjusted uniform rate from the current rate's two-tiered (commercial) or three-tiered (industrial) structure better suits the widely varied characteristics and usage patterns of commercial and industrial customers. Further, it will help to decrease revenue volatility by decreasing the amount of revenues from the largest and most variable users. As a result of this change, the highest users will no longer be subject to Tier 2 or Tier 3 rates.

An analysis was completed in order to assess and understand the impact of the rate structure updates across a wide variety of customers with differing usage levels and meter sizes. Figure 6-6 below shows the average distribution of the number of customer accounts at each usage level. As shown, the commercial and industrial class exhibits greater variability in its usage distribution as compared to the SFR class due to the wide array of business types and sizes that it encompasses. The usage distribution varies based on the season with more accounts at higher levels of monthly consumption in the summer, and more accounts at lower levels of consumption in the winter.

FIGURE 6-6 COMMERCIAL AND INDUSTRIAL MONTHLY USAGE DISTRIBUTION



Further analysis of billing data and projected consumption for FY 2017/18 was completed to determine winter and summer usage at various consumption percentiles, and the bill impacts were calculated for each percentile. The customer attributes for each percentile are shown below in Table 6-14.

TABLE 6-14 COMMERCIAL AND INDUSTRIAL TEST CUSTOMERS

Percentile	Winter CCF	Summer CCF	Average Annual Use	Assumed Meter Size
10th	2	3	2	3/4"
25th	9	12	10	3/4"
50th (Median)	33	43	37	1"
75th	100	146	119	2"
90th	318	415	358	3"

Figure 6-7 below shows the average monthly bill increase for each percentile in FY 2017/18 (Year 1) and the average monthly bill increase from FY 2018/19 through FY 2021/22 (Years 2 to 5). The average monthly bill for a 50th percentile (median) customer will increase by $14.31 per month in FY 2017/18, with an average monthly increase of $6.16 for years 2 through 5.

FIGURE 6-7 COMMERCIAL AND INDUSTRIAL AVERAGE MONTHLY BILL INCREASES

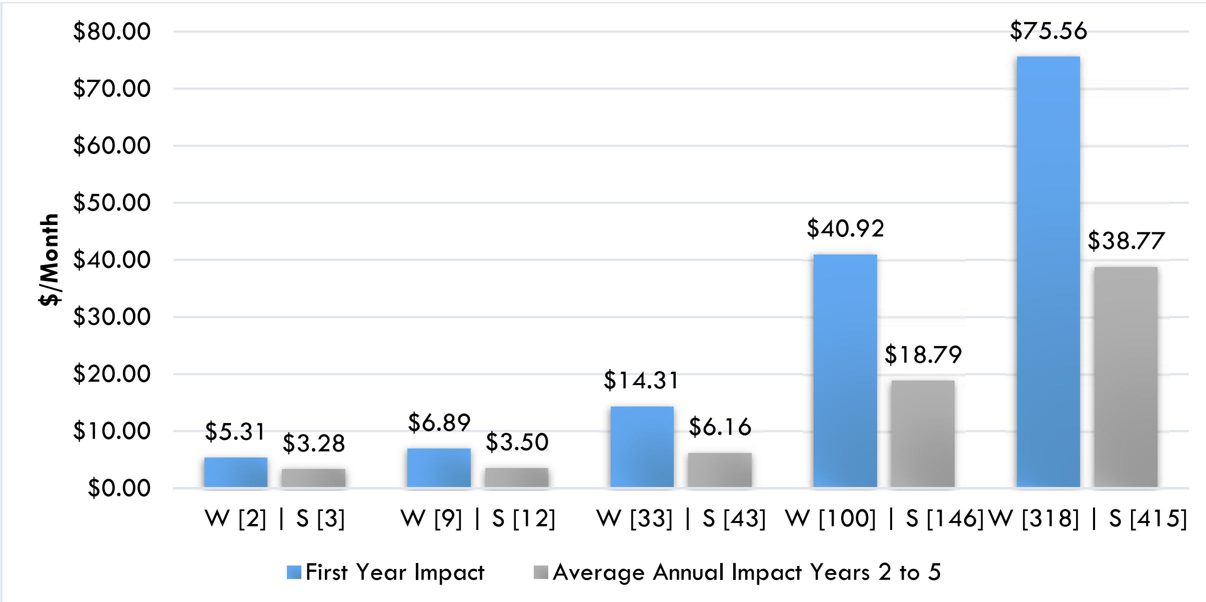


Table 6-15 below presents shows the average monthly bills for each user under the current rates and under the proposed rates in FY 2017/18 (Year 1) and in FY 2021/22 (Year 5). Also shown are the percentage increases in Year 1 and the average percentage increases for Years 2 through 5. As discussed previously, the Year 1 percentage increase is greater than the percentage increase for years 2 through 5 due to the implementation of fixed charges that are uniform among the customer classes. Further, the smaller users will see higher percentage increases in Years 2 to 5 due to the phase-in of increased fixed revenue recovery, and the modification of the tier structure. However, as shown in the last column, the overall dollar change from the current rates to the proposed rates in Year 5 increases incrementally as consumption levels rise.

TABLE 6-15 COMMERCIAL AND INDUSTRIAL MONTHLY BILL IMPACTS

Percentile	CCF Usage	Avg Monthly	Avg Monthly	Annual Avg %	Avg Monthly	Annual Avg %	5-Year Increase
	Win | Sum	Current Bill	New Bill - Yr 1	Yr 1	New Bill - Yr 5	Yr 2 to 5	
10th	2 | 3	$15.44	$20.75	34.39%	$33.87	13.03%	$18.43
25th	9 | 12	$27.88	$34.77	24.72%	$48.78	8.84%	$20.91
50th	33 | 43	$78.27	$92.57	18.28%	$117.20	6.07%	$38.93
75th	100 | 146	$252.02	$292.94	16.24%	$368.12	5.88%	$116.10
90th	318 | 415	$711.99	$787.55	10.61%	$942.61	4.60%	$230.62

6.4.4 Landscape Irrigation Rates

Under the existing rate structure, landscape irrigation users are placed into varying rate classes. Most users with meter sizes from 5/8-inch through 2 inch fall into the Commercial rate class (WA-6.1) and most users with meter sizes of 3-inches or greater are placed in the Industrial rate class (WA-6.2). A small number of users flagged as Landscape irrigation accounts are currently in the WA-1 (Residential) class. Landscape users typically place a higher peak burden on the water system as they use water heavily in the hottest and driest summer months, with significantly less usage in the winter. Thus, it is appropriate to separate Landscape users into a unique rate class that reflects the increased burden that they place on the system.

Proposed Landscape Irrigation Rates

The proposed Landscape rates are calculated using the same methodology as the Commercial and Industrial rates above. As an example, Table 6-16 below shows the calculation of the landscape rates for FY 2017/18. Detailed calculations of the Landscape rates are provided for reference in Appendix H.

TABLE 6-16 LANDSCAPE IRRIGATION RATE CALCULATION (FY 2017/18)

Projected Usage		Summer	Winter	Total
Usage		814,000	711,000	**1,525,000**
Projected Costs		Summer	Winter	Total
Total Costs	Peak: 1.28	$1,815,000	$1,238,000	**$3,053,000**
Volumetric Rates		**Summer**	**Winter**	
Rate for All Usage		$2.24	$1.75	

Table 6-17 below shows the proposed Landscape rates for each year of the rate plan. Existing rates are included for reference in Appendix H.

TABLE 6-17 PROPOSED LANDSCAPE IRRIGATION RATES

Winter Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tiered	Varies	All Usage	$1.75	$1.78	$1.81	$1.84	$1.86
Summer Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tiered	Varies	All Usage	$2.24	$2.28	$2.32	$2.36	$2.38

Landscape Irrigation Bill Impact Analysis

Due to the changes in the rate structure, monthly bill impacts will vary for specific customers based on their level of usage, seasonal peaking, and meter size. The primary rate structure updates, and their impact on customer bills is discussed below. Note that the calculated bills and impacts presented within this report do not include RPU's Water Conservation Surcharge.

Unique Rate Class for Landscape Irrigation: Under the existing rate structure landscape irrigation customers have been combined with commercial and industrial customers. However, due the unique demands that landscape irrigation customers place on the system, the proposed rate structure includes a specific landscape irrigation rate. Because the landscape users exhibit a greater seasonal peak, their volumetric rates will be higher than those proposed for the commercial and industrial class and the overall increase in FY 2017/18 will be greater for landscape irrigation customers.

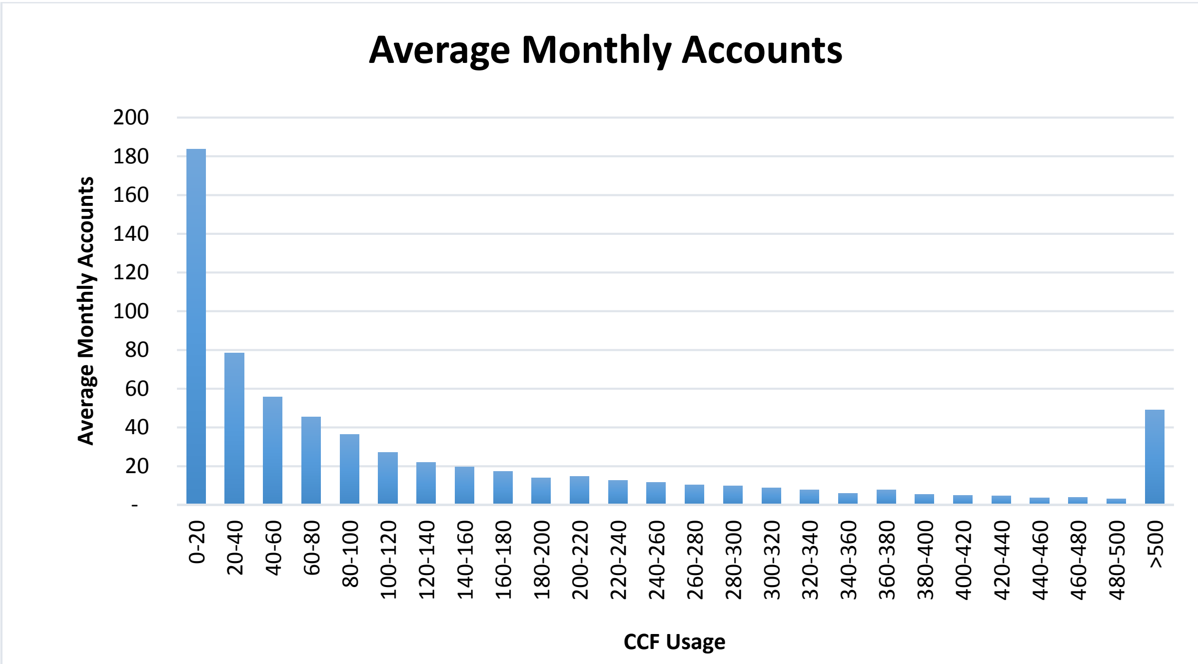
Uniform Fixed Charges: Historically, landscape irrigation customers paid fixed charges that were lower than those assessed to residential customers. Under the proposed rate structure, fixed charges for each meter size will be the same for all customer classes. For most users, this change will result in a higher increase in FY 2017/18 as compared to the expected increases for FY 2018/19 through FY 2021/22. This change will have more of an impact to the lowest usage landscape customers because the fixed charge is a greater proportion of their bill.

Phase-in of Increased Fixed Charges: The phase-in of increased fixed revenue recovery over the rate plan period will result in slightly higher percentage increases for low usage customers, however on a dollar basis, the lower usage customers will see a lower increase than higher usage customers.

Change to Uniform Seasonally Adjusted Rates: The change to a seasonally adjusted uniform rate from the current rate's two-tiered (commercial) or three-tiered (industrial) structure better suits the widely varied characteristics and usage patterns of landscape irrigation customers. Further, it will help to decrease revenue volatility by decreasing the amount of revenues from the largest and most variable users. As a result of this change, the highest users will no longer be subject to Tier 2 or Tier 3 rates.

An analysis was completed in order to assess and understand the impact of the rate structure updates across a wide variety of customers with differing usage levels and meter sizes. Figure 6-8 below shows the average distribution of the number of customer accounts at each usage level. As shown, the landscape irrigation class exhibits a large degree of variability in monthly usage. The usage distribution varies based on the season with more accounts at higher levels of monthly consumption in the summer, and more accounts at lower levels of consumption in the winter.

FIGURE 6-8 LANDSCAPE IRRIGATION MONTHLY USAGE DISTRIBUTION



Further analysis of billing data and projected consumption for FY 2017/18 was completed to determine winter and summer usage at various consumption percentiles, and the bill impacts were calculated for each percentile. The customer attributes for each percentile are shown below in Table 6-18.

TABLE 6-18 LANDSCAPE IRRIGATION TEST CUSTOMERS

Percentile	Winter CCF	Summer CCF	Average Annual Use	Assumed Meter Size
10th	6	8	7	3/4"
25th	19	32	24	3/4"
50th (Median)	63	106	81	1.5"
75th	165	285	215	2"
90th	356	555	439	3"

Figure 6-9 below shows the average monthly bill increase for each percentile in FY 2017/18 (Year 1) and the average monthly bill increase for FY 2018/19 through FY 2021/22 (Years 2 to 5).

FIGURE 6-9 LANDSCAPE IRRIGATION AVERAGE MONTHLY BILL INCREASES

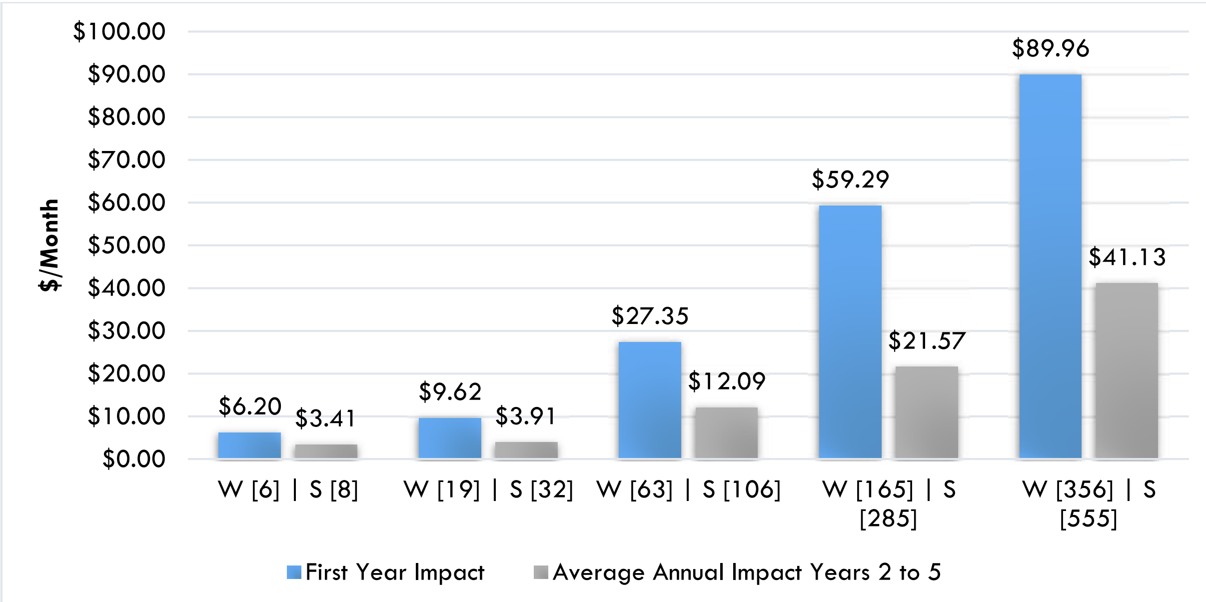


Table 6-19 below presents shows the average monthly bills for each user under the current rates and under the proposed rates in FY 2017/18 (Year 1) and in FY 2021/22 (Year 5). Also shown are the percentage increases in Year 1 and the average percentage increases for Years 2 through 5. As discussed previously, the year 1 percentage increase is greater than the percentage increase for years 2 through 5 due to the implementation of fixed charges that are uniform among the customer classes and due to the landscape irrigation customers being separated into a unique rate class. Further, the smaller users will see higher percentage increases due to the phase-in of increased fixed revenue recovery, and the modification of the tier structure. However, as shown in the last column, the overall dollar change from the current rates to the proposed rates in Year 5 increases incrementally as consumption levels rise.

TABLE 6-19 LANDSCAPE IRRIGATION MONTHLY BILL IMPACTS

Percentile	CCF Usage	Avg Monthly	Avg Monthly	Annual Avg %	Avg Monthly	Annual Avg %	5-Year Increase
	Win | Sum	Current Bill	New Bill - Yr 1	Yr 1	New Bill - Yr 5	Yr 2 to 5	
10th	6 | 8	$22.44	$28.64	27.64%	$42.27	10.22%	$19.83
25th	19 | 32	$50.91	$60.53	18.90%	$76.19	5.92%	$25.28
50th	63 | 106	$168.82	$196.17	16.20%	$244.52	5.66%	$75.70
75th	165 | 285	$408.37	$467.66	14.52%	$553.96	4.32%	$145.59
90th	356 | 555	$846.97	$936.93	10.62%	$1,101.43	4.13%	$254.46

6.4.5 Temporary Service Rates WA-2

The Temporary Service WA-2 rate class is primarily used by developers or contractors to provide water service for construction sites and by agricultural customers to fill spraying trucks for grove maintenance. The current rate structure consists of a daily meter rental fee of $9.02 per day, with a maximum rental charge of $271.20 per month. The rate for all usage is $2.71 per CCF, there is no monthly fixed charge. Under the proposed rate structure, Temporary Service users would continue to pay a meter rental fee and volumetric charge.

Fees and Charges for Fire Hydrant Meters

Temporary service customers at construction sites are served via a metered connection to a fire hydrant. The daily rental fee that they pay includes a component to cover the cost of the 3-inch meter and backflow prevention unit that is connected to serve each customer, as well as a daily fixed service charge component based on the proposed fixed service charges.

The meter cost component is calculated by dividing the annualized cost of the meter by the estimated annual days in service, then applying an adjustment to account for the 11.5 percent general fund transfer. The meter cost component is escalated each year based on the capital escalation factor of 2.85 percent per year. The daily fixed service charge component is calculated by multiplying the proposed monthly charge for a 3-inch meter by 12 and dividing by 360. Table 6-20 below shows the calculation of the daily rental fee for FY 2017/18.

TABLE 6-20 TEMPORARY SERVICE DAILY RENTAL FEE CALCULATION (FY 2017/18)

Daily Rental Fee	FY 2017/18
Meter Cost	$2,500
Depreciable Life (Years)	5
Annualized Cost	$500
Utilization	25%
Annual Days in Service	90
Daily Meter Cost	$5.56
General Fund Transfer (GFT)	11.5%
Daily Meter Cost With GFT	**$6.19**
3" Meter Charge	$145.89
Daily Fixed Charge	**$4.86**
Daily Meter Cost With GFT	$6.19
Daily Fixed Charge	$4.86
Total Daily Rental Fee	**$11.06**

Table 6-21 shows the calculation of the maximum monthly charge for FY 2017/18. The maximum monthly charge is calculated by adding 30 days of the daily meter cost with the general fund transfer to the proposed monthly fixed service charge for a 3-inch meter.

TABLE 6-21 TEMPORARY SERVICE MAXIMUM MONTHLY CHARGE CALCULATION

Maximum Monthly Charge	FY 2017/18
Daily Meter Cost With GFT (30 Days)	$185.84
3" Meter Charge (Monthly)	$145.89
Annualized Cost	**$331.73**

Table 6-22 below shows the proposed daily rental fees and maximum monthly charges for each year of the rate plan. Detailed calculations of the daily rental fee and maximum monthly charge are included for reference in Appendix H.

TABLE 6-22 PROPOSED TEMPORARY SERVICE DAILY RENTAL FEES AND MAXIMUM MONTHLY CHARGES

	Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Daily Rental Fee	$9.02	$11.06	$11.89	$12.81	$13.80	$14.86
Maximum Monthly Charge	$271.20	$331.73	$356.69	$384.01	$413.71	$445.64

Proposed Temporary Service Rates

The proposed Temporary Service rates are calculated using a similar methodology as the Commercial and Industrial rates above, however the calculation is simplified because the rates are not seasonally adjusted. As an example, Table 6-23 below shows the calculation of the Temporary Service rates for FY 2017/18. Detailed calculations of the Temporary Service rates are provided for reference in Appendix H.

TABLE 6-23 TEMPORARY SERVICE RATE CALCULATION (FY 2017/18)

Projected Usage	
Total CCF	54,000
Projected Costs	
Total Costs	$135,000
Volumetric Rates	
Rate for All Usage	$2.50

Table 6-24 below shows the proposed Temporary Service rates for each year of the rate plan. Though the volumetric charge represents a decrease as compared to the existing rates, imposition of a prorated daily fixed charge will result in an increase overall for most Temporary Service Users.

TABLE 6-24 PROPOSED TEMPORARY SERVICE RATES

	Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
All Usage	$2.71	$2.50	$2.56	$2.60	$2.64	$2.67

6.4.6 Riverside Water Company Irrigators WA-4

The Irrigation metered service WA-4 rates provide service to primarily residential customers located in a specific region of RPU's service area who were shareholders in the Riverside Water Company. When RPU acquired Riverside Water Company and as a condition of acquisition, these customers transferred water rights from the Riverside Water Company to RPU. This rate class is closed to new users and RPU intends to phase it out in accord with the acquisition agreement. The current rate structure is a three tiered volumetric rate with a tier one allotment of 15 CCF per month, and a tier two allotment of 55 CCF per month. All usage over 70 CCF per month is charges at the tier three rate. The rates are seasonally adjusted.

Proposed Riverside Water Company Irrigators WA-4 Rates

Based on the customer data analysis, the existing tier breaks are appropriate, the proposed rates maintain the current structure and update the volumetric rates based on the cost of service analysis. Volumetric rates for each tier are calculated using the same methodology as that used to calculate the SFR rates described previously. Detailed calculations for the rates are included for reference in Appendix H. Table 6-25 below shows the proposed Riverside Water Company Irrigators rates.

TABLE 6-25 PROPOSED RIVERSIDE WATER COMPANY IRRIGATORS WA-4 RATES

Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 15	$1.26	$1.30	$1.37	$1.43	$1.48
Tier 2	1.75	16-70	1.51	1.57	1.65	1.72	1.78
Tier 3	1.77	>70	2.35	2.43	2.56	2.67	2.77
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 15	$1.26	$1.30	$1.37	$1.43	$1.48
Tier 2	1.76	16-70	1.51	1.57	1.65	1.72	1.78
Tier 3	1.87	>70	3.02	3.13	3.30	3.44	3.56

6.4.7 Interruptible City Irrigation and Recycled Water WA-7

In general, interruptible service and rates are most appropriate for customers whose service can be reliably curtailed or service can be shut off without implication for public health and safety. For RPU the accounts that fall into that category are the City irrigation accounts, primarily those for parks and medians irrigation, and recycled water accounts, because the water consumed is used exclusively for irrigation. Equally as important, because the City is the customer, RPU has certainty that service can be shut off on demand for extended periods of time without breaching service requirements or agreements.

The rates for WA-7 users are developed to reflect the interruptible nature of the service, and therefore do not include costs associated with supply resiliency. In the event that system wide usage must be curtailed, or if a system failure or other event leads to a decrease in available supplies, the interruptible accounts can be shut off, leaving their share of supply available to serve other users.

Recycled water users have historically been charged for service under a unique rate code, WA-10. Moving forward, recycled water users will be combined with Interruptible WA-7 users as the usage patterns, customer characteristics, and the level of service provided is similar among each class.

An additional modification to the Interruptible WA-7 rate structure is the inclusion of the fixed monthly service charge. Previously, Special WA-7 accounts paid a minimum monthly charge calculated based on a minimum level of usage for each account based on meter size.

Proposed WA-7 Rates

The proposed Interruptible WA-7 rates are calculated using the same methodology as that discussed above for Temporary Service WA-2. As an example, Table 6-26 below shows the calculation of the Interruptible WA-7 rates for FY 2017/18. Detailed calculations of the Interruptible WA-7 rates are provided for reference in Appendix H.

TABLE 6-26 INTERRUPTIBLE CITY IRRIGATION RATE CALCULATION WA-7 (FY 2017/18)

Projected Usage	
Total CCF	961,000
Projected Costs	
Total Costs	$1,565,000
Volumetric Rates	
Rate for All Usage	$1.63

Table 6-27 below shows the proposed WA-7 rates for each year of the rate plan.

TABLE 6-27 INTERRUPTIBLE CITY IRRIGATION WA-7 PROPOSED RATES

	Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
All Usage	$0.80 to $1.14	$1.63	$1.67	$1.70	$1.72	$1.74

Interruptible City Irrigation Bill Impact Analysis

Due to the changes in the rate structure, monthly bill impacts will vary for specific customers based on their level of usage, seasonal peaking, and meter size. The primary rate structure updates, and their impact on customer bills is discussed below. Note that the calculated bills and impacts presented within this report do not include RPU's Water Conservation Surcharge.

<u>Increased Volumetric Rates:</u> The costs of service analysis showed that the volumetric rates for interruptible city irrigation users needed to be increased significantly. The proposed plan adjusts the rates to the updated cost of service level in FY 2017/18, resulting in large first year increases.

<u>Uniform Fixed Charges:</u> Under the current rate structure, interruptible city irrigation customers paid a minimum monthly charge rather than a monthly fixed charge. Under the proposed rate structure, fixed charges for each meter size will be the same for all customer classes.

Phase-in of Increased Fixed Charges: The phase-in of increased fixed revenue recovery over the rate planning period will result in slightly higher percentage increases for low usage customers, however on a dollar basis, the lower usage customers will see a lower increase than higher usage customers.

An analysis was completed in order to assess and understand the impact of the rate structure updates across a wide variety of customers with differing usage levels and meter sizes. Billing data and projected consumption for FY 2017/18 was analyzed to determine winter and summer usage at various consumption percentiles, and the bill impacts were calculated for each percentile. The customer attributes for each percentile are shown below in Table 6-28.

TABLE 6-28 INTERRUPTIBLE CITY IRRIGATION TEST CUSTOMERS

Percentile	Winter CCF	Summer CCF	Average Annual Use	Assumed Meter Size
10th	4	5	4	3/4"
25th	10	12	11	3/4"
50th (Median)	31	31	31	1"
75th	106	123	113	1.5"
90th	381	529	443	2"

Figure 6-10 below shows the average monthly bill increase for each percentile in FY 2017/18 (Year 1) and the average monthly bill increase for FY 2018/19 through FY 2021/22 (Years 2 to 5).

FIGURE 6-10 INTERRUPTIBLE CITY IRRIGATION AVERAGE MONTHLY BILL INCREASES

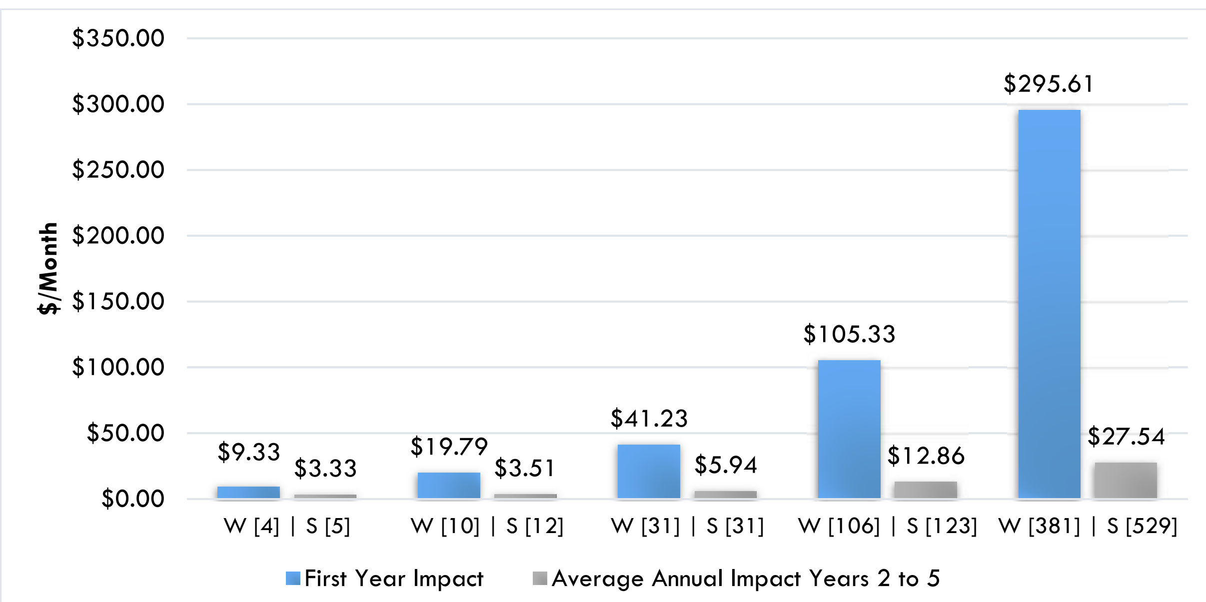


Table 6-29 below presents shows the average monthly bills for each user under the current rates and under the proposed rates in FY 2017/18 (Year 1) and in FY 2021/22 (Year 5). Also shown are the percentage increases in Year 1 and the average percentage increases for Years 2 through 5. Year 1 increases are significant due to the large increase in the volumetric rate and the switch to fixed charges rather than minimum charges. During years 2 to 5, smaller users will see higher percentage increases due to the phase-in of increased fixed revenue recovery. However, as shown in the last column, the overall dollar change from the current rates to the proposed rates in Year 5 increases incrementally as consumption levels rise.

TABLE 6-29 INTERRUPTIBLE CITY IRRIGATION MONTHLY BILL IMPACTS

Percentile	CCF Usage	Avg Monthly	Avg Monthly	Annual Avg %	Avg Monthly	Annual Avg %	5-Year Increase
	Win | Sum	Current Bill	New Bill - Yr 1	Yr 1	New Bill - Yr 5	Yr 2 to 5	
10th	4 | 5	$14.27	$23.60	65.38%	$36.93	11.84%	$22.66
25th	10 | 12	$14.27	$34.06	138.67%	$48.09	9.01%	$33.82
50th	31 | 31	$35.34	$76.57	116.67%	$100.34	6.99%	$65.00
75th	106 | 123	$128.92	$234.25	81.71%	$285.70	5.09%	$156.78
90th	381 | 529	$504.64	$800.25	58.58%	$910.40	3.28%	$405.76

6.5 TRANSITIONAL RATES

As a component of the cost of service analysis, RPU's rate classes were reviewed and customer data was analyzed to test the nexus between rate class and account and usage characteristics. As a result of this analysis, it was determined that several rate classes that have historically been treated as distinct classes, would be more appropriately placed within RPU's general SFR, Commercial, or Landscape rate classes. The effected customers include all customers in the Irrigation Metered Service (WA-3.1 and WA-3.2), Grove Preservation Service (WA-9.1 and WA-9.2), and cemetery customers in Special Metered Service WA-7.

In order to mitigate the rate impacts to effected customers, RPU has decided to migrate the customers to the appropriate rate classes over the rate projection period. As a result, transitional rates for each of the classes were developed to smooth the increases over four or five years depending on the rate class. All of the affected rate classes are or will be closed to new users going forward.

6.5.1 Irrigation WA-3.1 Transition to SFR

The Irrigation WA-3.1 rates provide service to residential customers that have historically consumed large amounts of water for irrigation. The current rate structure is a two tiered volumetric rate with a minimum monthly charge rather than the fixed service charge. The tier one allotment is 100 CCF per month and the rates are not seasonally adjusted.

Based on the customer data analysis, Irrigation WA-3.1 users would be most appropriately served by the SFR rate class, as their account characteristics are in line with those of large SFR customers. Table 6-17 below shows the transitional rates for customers currently included in Irrigation WA-3.1, these customers will be fully transitioned in FY 2021/22, at which point they will be assessed the SFR rates.

Irrigation WA-3.1 customers currently pay a minimum monthly charge rather than the monthly fixed service charge. The customers will begin to pay the monthly fixed service charge starting in year 1 (FY 2017/18). Table 6-30 shows the transitional rates for Irrigation WA-3.1 customers.

TABLE 6-30 TRANSITIONAL IRRIGATION WA-3.1 RATES

	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$0.81	First 100	$0.90	$1.14	$1.45	$1.84	SFR Rates
Tier 2	1.26	>100	1.71	2.17	2.76	3.50	

6.5.2 Grove Preservation WA-9.1 Transition to SFR

The Grove Preservation Service WA-9.1 rates provide service to residential customers that have historically consumed large amounts of water for irrigation. The current rate structure is a three tiered volumetric rate with a tier one allotment of 15 CCF per month, and a tier two allotment of 45 CCF per month. All usage over 60 CCF per month is charged at the tier three rate. The rates are not seasonally adjusted.

Based on the customer data analysis, Grove Preservation WA-9.1 users would be most appropriately served by the SFR rate class, as their account characteristics and usage patterns are in line with those of large SFR customers. Table 6-18 below shows the transitional rates for customers currently included in Grove Preservation WA-9.1, these customers will be fully transitioned in FY 2021/22, at which point they will be assessed the SFR rates.

Grove Preservation WA-9.1 customers currently pay a monthly fixed service charge that is significantly lower than that of SFR customers. The customers will begin to pay the updated monthly fixed service charge starting in year 1 (FY 2017/18). Table 6-31 shows the transitional rates for Grove Preservation WA-9.1 customers.

TABLE 6-31 TRANSITIONAL GROVE PRESERVATION WA-9.1 RATES

	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$0.91	First 15	$1.10	$1.33	$1.62	$1.97	SFR Rates
Tier 2	1.58	16-60	1.12	1.37	1.66	2.03	
Tier 3	1.07	>60	1.50	1.88	2.36	2.97	

6.5.3 Irrigation WA-3.2 Transition to Commercial and Industrial

The Irrigation WA-3.2 service rates provide service to non-residential customers for irrigation of commercial nurseries or groves. This rate class is closed to new users. The current rate structure is a uniform volumetric rate with a minimum monthly charge rather than the fixed service charge. The rates are not seasonally adjusted.

Based on the customer data analysis, Irrigation WA-3.2 users would be most appropriately served by the Commercial and Industrial rate class, as their account characteristics and usage patterns are in line with those of non-residential customers. Table 6-19 below shows the transitional rates for customers currently included in Irrigation WA-3.2, these customers will be fully transitioned in FY 2021/22, at which point they will be assessed the Commercial and Industrial rates.

Irrigation WA-3.2 customers currently pay a minimum monthly charge rather than the monthly fixed service charge. The customers will begin to pay the monthly fixed service charge starting in year 1 (FY 2017/18). Table 6-32 shows the transitional rates for Irrigation WA-3.2 customers.

TABLE 6-32 TRANSITIONAL IRRIGATION WA-3.2 TRANSITIONAL RATES

	Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
All Usage	$1.26	$1.35	$1.48	$1.63	$1.79	Commercial & Industrial Rates

6.5.4 Grove Preservation WA-9.2 Transition to Commercial and Industrial

The Grove Preservation WA-9.2 service rates provide service non-residential customers for irrigation of commercial nurseries or groves. Grove Preservation WA-9.2 customers require 2 meters, one to serve residential needs, and one to serve outdoor needs. RPU has indicated that several of the Grove Preservation WA-9.2 customers operate commercial nurseries. The current rate structure is a uniform volumetric rate that is not seasonally adjusted.

Based on the customer data analysis, Grove Preservation WA-9.2 users would be most appropriately served by the Commercial and Industrial rate class, as their account characteristics and usage patterns are in line with those of non-residential customers. Table 6-20 below shows the transitional rates for customers currently included in Grove Preservation WA-9.2, these customers will be fully transitioned in FY 2021/22, at which point they will be assessed the Commercial and Industrial rates.

Grove Preservation WA-9.1 customers currently pay a monthly fixed service charge that is significantly lower than that of SFR customers. The customers will begin to pay the updated monthly fixed service charge starting in year 1 (FY 2017/18). Table 6-33 shows the transitional rates for WA-9.2 customers.

TABLE 6-33 TRANSITIONAL GROVE PRESERVATION WA-9.2 RATES

	Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
All Usage	$1.07	$1.18	$1.34	$1.53	$1.74	Commercial & Industrial Rates

6.5.5 Special Service WA-7 Cemeteries Transition to Commercial or Landscape

Two cemeteries, with a total of 7 meters, are currently charged under the Special WA-7 rates, which are intended to provide interruptible service to City Irrigation accounts. Because the cemeteries are not owned or operated by the City, RPU does not have certainty to immediately curtail or interrupt usage. Thus, these accounts are not eligible for the interruptible rate.

Meters that serve exclusively irrigation will be transitioned to the Landscape rate class, those that serve both structures and irrigation will be transitioned to the Commercial and Industrial rate class. These customers will be fully transitioned in FY 2021/22, at which point they will be assessed the Landscape or the Commercial and Industrial rates. As Special WA-7 customers, these cemeteries currently pay a minimum monthly charge rather than the monthly fixed service charge. The customers will begin to pay the monthly fixed service charge starting in year 1 (FY 2017/18). Table 6-34 and Table 6-35 show the transitional rates for cemetery customers.

TABLE 6-34 TRANSITIONAL SPECIAL SERVICE WA-7 CEMETERIES RATES TO COMMERCIAL AND INDUSTRIAL

	Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
All Usage	$1.14	$1.19	$1.35	$1.53	$1.74	Commercial & Industrial Rates

TABLE 6-35 TRANSITIONAL SPECIAL SERVICE WA-7 CEMETERIES RATES TO LANDSCAPE

	Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
All Usage	$1.14	$1.21	$1.39	$1.61	$1.87	Landscape Rates

6.6 OUTSIDE CITY SURCHARGE

Along with customers within the City of Riverside, RPU provides water service to about 4,000 residential, commercial, industrial, and landscape accounts that are located outside of City limits. Because these customers lie outside City limits, RPU incurs additional capital and operating costs to provide them with water service. In order to recover those costs, the rates charged to outside City users include a percentage surcharge based on the incremental capital and operational costs that they require. The current Outside City Surcharge is 50 percent, thus users pay 1.5 times the In-City rate for comparable service.

Proposed Outside City Surcharge

The Outside City Surcharge was updated as a component of the cost of service analysis. The calculation of the updated surcharge includes three main steps: (1) determine the incremental costs associated with providing service to outside City users, (2) determine the amount of revenue generated by outside City users without applying the surcharge, and (3) divide the incremental costs (step 1) by the revenue without the surcharge (step 2) to determine the required Outside City Surcharge.

Incremental Costs

The incremental capital and O&M costs were determined based on information provided by RPU's engineering and operations departments. The Outside City user's share of capital assets (facilities and pipelines), energy needs, and flow was determined based on RPU's hydraulic model and system schematic. Capital costs are annualized based on accounting depreciation assuming a 50 year life for pipelines and a 30 year life for facilities. The annual cost was then escalated at 2.85 percent per year, consistent with the capital escalation factor used throughout the pro forma and COSA.

Energy costs are estimated based on the amount of energy required to serve outside City users annually (KWh) and an assumed energy cost. Energy costs are escalated at 2 percent per year consistent with the O&M escalation factors in the pro forma. Table 6-36 summarizes the costs associated with serving outside City users. Detailed calculations of the capital and energy costs are included for reference in Appendix D.

TABLE 6-36 PROJECTED OUTSIDE CITY COSTS

Outside City Costs	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Capital Costs	$1,437,000	$1,478,000	$1,520,000	$1,563,000	$1,608,000
Energy Costs	71,000	73,000	75,000	77,000	79,000
Total Outside City Costs	**$1,508,000**	**$1,551,000**	**$1,595,000**	**$1,640,000**	**$1,687,000**

Revenues without Surcharge

The estimated revenues from outside City users without the surcharge were calculated by applying the proposed inside City volumetric rates presented within this report to the projected outside City usage, and adding the expected fixed revenues based on the number of accounts and MEUs. Table 6-37 below summarizes the projected revenues, detailed calculations are included for reference in Appendix D.

Surcharge Calculation

The proposed outside City surcharge of 43 percent has been calculated by dividing the total incremental costs for FY 2017/18 through FY 2021/22 by the projected revenues without the surcharge for the same period. Using this five year approach mitigates year-over-year changes to the surcharge, while recovering cost equitably from outside City users. Table 6-38 below presents the calculation of the proposed Outside City Surcharge, detailed calculations are included for reference in Appendix D.

TABLE 6-37 OUTSIDE CITY REVENUES WITHOUT SURCHARGE

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Variable Revenues					
Landscape	$210,000	$213,000	$218,000	$222,000	$225,000
MFR	11,000	11,000	12,000	12,000	12,000
SFR	1,723,000	1,759,000	1,792,000	1,828,000	1,851,000
WA-4	1,000	1,000	1,000	1,000	1,000
Commercial and Industrial	381,000	389,000	396,000	404,000	409,000
Total Variable Revenues	**$2,326,000**	**$2,374,000**	**$2,419,000**	**$2,467,000**	**$2,498,000**
Fixed Revenues					
All Outside City Users	**$908,000**	**$1,071,000**	**$1,253,000**	**$1,453,000**	**$1,670,000**
Total Outside City Revenues Without Surcharge	**$3,234,000**	**$3,445,000**	**$3,672,000**	**$3,920,000**	**$4,168,000**
Notes:					
(1) Totals may be off due to rounding.					

TABLE 6-38 OUTSIDE CITY SURCHARGE CALCULATION

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22	Five Year Sum
Variable Revenue Without Surcharge	$2,326,000	$2,374,000	$2,419,000	$2,467,000	$2,498,000	$12,084,000
Annual Fixed Revenue Without Surcharge	908,000	1,071,000	1,253,000	1,453,000	1,670,000	$6,355,000
Total Revenue Without Surcharge	**$3,234,000**	**$3,445,000**	**$3,672,000**	**$3,920,000**	**$4,168,000**	**$18,439,000**
Surcharge Costs to Collect	**$1,507,000**	**$1,550,000**	**$1,595,000**	**$1,640,000**	**$1,687,000**	**$7,979,000**
					Calculated Surcharge	**43%**
Notes:						
(1) Totals may be off due to rounding.						

6.7 DEMAND REDUCTION RATES AND PASS THROUGH ADJUSTMENTS

The proposed rates contain several components aimed at enhancing revenue stability for RPU's water operations including increased fixed charges and restructuring of variable rates. To accompany and augment those components, additional rate structure elements are proposed to give RPU the flexibility to adapt to changes in usage, revenues, and costs.

Demand reduction rates will allow RPU to react to revenue shortfalls driven by sustained decreases in sales due to drought, supply limitations, or other circumstances. Pass through costs adjustments will allow RPU to more easily adapt to unforeseen changes in operating or capital costs.

6.7.1 Demand Reduction Rates

In light of the current water demand uncertainty and need for financial resiliency, the COSA developed rates for demand reduction surcharges. Demand Reduction Surcharges are charges that may be imposed by RPU during levels of extreme water demand reductions. The objective of these rates is to provide cost recovery to the agency if customers' potable water usage declines as a result of expanded or future water shortage conditions. As discussed previously, many of RPU's costs are fixed, in that they do not fluctuate with changes in water demands.

As presented previously, RPU is forecasted to have water sales of roughly 26.7 million CCF in FY 2017/18. Based on an extreme water curtailment period, the RPU estimated three potential demand reduction scenarios. Because the ongoing drought has led to projected water usage that is much lower than historic norms, additional cutbacks in the drought scenarios have been capped to 30 percent.

Demand Reduction Stage 1 would equate to a slight reduction in demands (15 percent).

Demand Reduction Stage 2 would equate to a larger reduction in demands (20 percent).

Demand Reduction Stage 3 would equate to the maximum expected reduction in demands (30 percent).

To safeguard against these significant financial implications, RPU is proposing to implement the following Demand Reduction Surcharge rates. Once in effect, these surcharges will help to provide revenues needed to continue to meet RPU's expenditures and debt obligations, despite significant reductions in demand/sales.

Proposed Demand Reduction Rates

The Proposed Demand Reduction rates are designed to recover revenues through both RPU's fixed monthly service charge and the water commodity charges. For example, in scenario 1 (15 percent reduction), 10 percent of the forecasted shortfall would be funded through a fixed surcharge on a meter equivalent basis. The remaining costs would be collected by increases to the volumetric rates. This approach recovers a portion of RPU's fixed expenditures in proportion to each customer's reserved capacity within the system and the remaining portion based on each customer's usage of the system and water purchases.

The tables below present the proposed Demand Reduction rates for each reduction scenario. The rates presented are for the specified usage reduction. Additionally, the rate calculations are based on assumed water demand reductions by customer class and class tier. Because it is not possible to exactly predict how customer demands might change across customer classes and tiers, it is important for RPU to monitor revenues and adjust if and as necessary. The usage reductions by tier are reasonable, based on usage pattern changes, but cannot be guaranteed.

Stage 1 Demand Reduction: 15 Percent

The Stage 1 demand reduction rates have been calculated assuming a 15 percent departure from the sales forecast in each year of the projection. Ten percent of the reduction in revenues will be recovered through the fixed service charge on a per MEU basis, the remaining 90 percent will be recovered through increases to the volumetric rates.

TABLE 6-39 FIXED SERVICE CHARGES FOR 15 PERCENT REDUCTION

Meter Size	Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
3/4" & 5/8"	$13.99	$17.09	$19.91	$22.99	$26.35	$29.95
1"	23.29	27.19	31.67	36.56	41.88	47.60
1.5"	46.60	52.23	60.80	70.17	80.37	91.31
2"	74.49	82.39	95.89	110.67	126.73	143.98
3"	142.52	152.81	177.84	205.23	235.00	266.96
4"	237.57	253.40	294.89	340.29	389.64	442.61
6"	475.19	555.00	645.86	745.27	853.32	969.29
8"	760.29	906.82	1,055.26	1,217.67	1,394.20	1,583.66
10"	1,092.85	1,409.44	1,640.14	1,892.56	2,166.91	2,461.38
12"	1,330.40	2,012.65	2,342.07	2,702.51	3,094.27	3,514.74

TABLE 6-40 VOLUMETRIC RATES FOR 15 PERCENT REDUCTION

SFR Volumetric Rates							
Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.13	First 9	$1.29	$1.36	$1.43	$1.50	$1.57
Tier 2	1.64	10-35	1.76	1.86	1.97	2.07	2.17
Tier 3	2.26	>35	3.62	3.85	4.07	4.29	4.52
Tier 4	2.75						
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 9	$1.29	$1.36	$1.43	$1.50	$1.57
Tier 2	1.83	10-35	1.76	1.86	1.97	2.07	2.17
Tier 3	2.85	>35	4.29	4.55	4.81	5.07	5.33
Tier 4	4.10						
MFR Volumetric Rates							
Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.13	First 7 per DU	$1.41	$1.49	$1.57	$1.65	$1.72
Tier 2	1.64	>7 per DU	1.81	1.92	2.02	2.13	2.23
Tier 3	2.26						
Tier 4	2.75						
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 7 per DU	$1.41	$1.49	$1.57	$1.65	$1.72
Tier 2	1.83	>7 per DU	2.07	2.20	2.32	2.44	2.55
Tier 3	2.85						
Tier 4	4.10						
Commercial and Industrial Volumetric Rates							
Winter Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$1.97	$2.01	$2.03	$2.06	$2.07
Summer Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$2.22	$2.26	$2.29	$2.32	$2.33

Landscape Volumetric Rates							
Winter Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$1.87	$1.91	$1.93	$1.95	$1.97
Summer Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$2.61	$2.66	$2.70	$2.73	$2.75
WA-2 Temporary Service Volumetric Rates							
		Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
All Usage		Varies	$2.98	$3.03	$3.08	$3.11	$3.14
WA-4 Riverside Water Co Volumetric Rates							
Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 15	$1.41	$1.45	$1.54	$1.61	$1.67
Tier 2	1.75	16-70	1.92	1.99	2.11	2.21	2.29
Tier 3	1.77	>70	2.81	2.90	3.08	3.21	3.34
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 15	$1.41	$1.45	$1.54	$1.61	$1.67
Tier 2	1.76	16-70	1.92	1.99	2.11	2.21	2.29
Tier 3	1.87	>70	4.14	4.28	4.53	4.72	4.91
WA-7 Interruptible Volumetric Rates							
	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
All Usage	$0.80 to $1.14		$1.90	$1.93	$1.96	$1.98	$2.00

Stage 2 Demand Reduction: 20 Percent

The Stage 2 demand reduction rates have been calculated assuming a 20 percent departure from the sales forecast in each year of the projection. Fifteen percent of the reduction in revenues will be recovered through the fixed service charge on a per MEU basis, the remaining 85 percent will be recovered through increases to the volumetric rates.

TABLE 6-41 FIXED SERVICE CHARGES FOR 20 PERCENT REDUCTION

Meter Size	Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
3/4" & 5/8"	$13.99	$17.78	$20.61	$23.70	$27.06	$30.67
1"	23.29	28.35	32.83	37.74	43.07	48.79
1.5"	46.60	54.53	63.12	72.52	82.74	93.69
2"	74.49	86.07	99.62	114.43	130.53	147.79
3"	142.52	159.73	184.83	212.29	242.13	274.11
4"	237.57	264.92	306.54	352.05	401.51	454.53
6"	475.19	580.36	671.48	771.14	879.44	995.52
8"	760.29	948.31	1,097.19	1,260.00	1,436.94	1,626.58
10"	1,092.85	1,473.98	1,705.37	1,958.41	2,233.40	2,528.13
12"	1,330.40	2,104.85	2,435.25	2,796.58	3,189.25	3,610.11

TABLE 6-42 VOLUMETRIC RATES FOR 20 PERCENT REDUCTION

SFR Volumetric Rates							
Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.13	First 9	$1.33	$1.41	$1.48	$1.55	$1.62
Tier 2	1.64	10-35	1.85	1.97	2.08	2.19	2.30
Tier 3	2.26	>35	3.98	4.24	4.50	4.76	5.02
Tier 4	2.75						
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 9	$1.33	$1.41	$1.48	$1.55	$1.62
Tier 2	1.83	10-35	1.85	1.97	2.08	2.19	2.30
Tier 3	2.85	>35	4.66	4.97	5.26	5.56	5.87
Tier 4	4.10		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
MFR Volumetric Rates							
Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.13	First 7 per DU	$1.45	$1.53	$1.61	$1.70	$1.78
Tier 2	1.64	>7 per DU	1.89	2.01	2.12	2.23	2.34
Tier 3	2.26						
Tier 4	2.75						
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 7 per DU	$1.45	$1.53	$1.61	$1.70	$1.78
Tier 2	1.83	>7 per DU	2.16	2.29	2.42	2.54	2.67
Tier 3	2.85						
Tier 4	4.10						
Commercial and Industrial Volumetric Rates							
Winter Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$2.06	$2.10	$2.12	$2.14	$2.15
Summer Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$2.32	$2.36	$2.38	$2.41	$2.42
Landscape Volumetric Rates							
Winter Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$1.93	$1.97	$1.99	$2.01	$2.03
Summer Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$2.67	$2.72	$2.76	$2.79	$2.81
WA-2 Temporary Service Volumetric Rates							
		Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
All Usage		Varies	$3.04	$3.10	$3.14	$3.17	$3.19
WA-4 Riverside Water Co Volumetric Rates							
Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 15	$1.49	$1.54	$1.64	$1.71	$1.77
Tier 2	1.75	16-70	2.16	2.23	2.38	2.49	2.59
Tier 3	1.77	>70	2.94	3.04	3.23	3.37	3.50
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 15	$1.49	$1.54	$1.64	$1.71	$1.77
Tier 2	1.76	16-70	2.16	2.23	2.38	2.49	2.59
Tier 3	1.87	>70	4.22	4.37	4.63	4.83	5.02
WA-7 Interruptible Volumetric Rates							
	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
All Usage	$0.80 to $1.14		$1.98	$2.01	$2.03	$2.05	$2.07

Stage 3 Demand Reduction: 30 Percent

The Stage 3 demand reduction rates have been calculated assuming a 30 percent departure from the sales forecast in each year of the projection. 25 percent of the reduction in revenues will be recovered through the fixed service charge on a per MEU basis, the remaining 75 percent will be recovered through increases to the volumetric rates.

TABLE 6-43 FIXED SERVICE CHARGES FOR 30 PERCENT REDUCTION

Meter Size	Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
3/4" & 5/8"	$13.99	$19.86	$22.70	$25.81	$29.20	$32.81
1"	23.29	31.81	36.33	41.27	46.64	52.37
1.5"	46.60	61.43	70.10	79.57	89.85	100.83
2"	74.49	97.12	110.79	125.71	141.92	159.22
3"	142.52	180.46	205.79	233.44	263.49	295.56
4"	237.57	299.49	341.47	387.32	437.12	490.28
6"	475.19	656.39	748.32	848.71	957.76	1,074.16
8"	760.29	1,072.71	1,222.92	1,386.93	1,565.09	1,755.26
10"	1,092.85	1,667.49	1,900.94	2,155.84	2,432.74	2,728.29
12"	1,330.40	2,381.29	2,714.64	3,078.63	3,474.02	3,896.05

TABLE 6-44 VOLUMETRIC RATES FOR 30 PERCENT REDUCTION

SFR Volumetric Rates							
Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.13	First 9	$1.43	$1.51	$1.59	$1.67	$1.75
Tier 2	1.64	10-35	2.05	2.19	2.32	2.46	2.59
Tier 3	2.26	>35	4.93	5.30	5.68	6.07	6.48
Tier 4	2.75						
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 9	$1.43	$1.51	$1.59	$1.67	$1.75
Tier 2	1.83	10-35	2.05	2.19	2.32	2.46	2.59
Tier 3	2.85	>35	5.62	6.05	6.47	6.90	7.36
Tier 4	4.10						
MFR Volumetric Rates							
Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.13	First 7 per DU	$1.55	$1.64	$1.73	$1.81	$1.90
Tier 2	1.64	>7 per DU	2.04	2.17	2.30	2.42	2.55
Tier 3	2.26						
Tier 4	2.75						
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 7 per DU	$1.55	$1.64	$1.73	$1.81	$1.90
Tier 2	1.83	>7 per DU	2.31	2.46	2.60	2.74	2.89
Tier 3	2.85						
Tier 4	4.10						
Notes:							
Commercial and Industrial Volumetric Rates							
Winter Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$2.24	$2.26	$2.28	$2.29	$2.29
Summer Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$2.51	$2.54	$2.56	$2.57	$2.57

Landscape Volumetric Rates							
Winter Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$2.04	$2.07	$2.09	$2.10	$2.11
Summer Rates	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	Varies	All Usage	$2.76	$2.80	$2.83	$2.86	$2.87
WA-2 Temporary Service Volumetric Rates							
		Existing	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
All Usage		Varies	$3.11	$3.16	$3.19	$3.21	$3.23
WA-4 Riverside Water Co Volumetric Rates							
Winter Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 15	$1.70	$1.76	$1.87	$1.95	$2.03
Tier 2	1.75	16-70	2.55	2.65	2.80	2.91	3.02
Tier 3	1.77	>70	3.14	3.25	3.46	3.61	3.76
Summer Rates	Existing	CCF Allotment	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	$1.14	First 15	$1.70	$1.76	$1.87	$1.95	$2.03
Tier 2	1.76	16-70	2.55	2.65	2.80	2.91	3.02
Tier 3	1.87	>70	4.29	4.44	4.72	4.92	5.12
WA-7 Interruptible Volumetric Rates							
	Existing		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
All Usage	$0.80 to $1.14		$2.13	$2.15	$2.17	$2.18	$2.19

6.7.2 Pass-Through Cost Adjustments

The revenue requirements projection and the proposed rates developed for the cost of service analysis rate design are based on best known information and projections. This report and its appendices identify and delineate the underlying assumptions including demands, projected costs, cost escalation factors, and other information used to develop the projections. Though the projections are based on the best information available, changes to costs outside of RPU's control such as power or chemicals can occur, causing operating expenditures to differ from those projected. The cost adjustment is a mechanism used by utilities to allow for the recovery of non-budgeted or unanticipated changes in costs like power or chemical costs. If implemented, the cost adjustment will be applied to CCF sold and will be reviewed and revised annually.

In 2008, the California legislature adopted California Assembly Bill 3030 (AB 3030), which allows agencies to modify the adopted rate program based upon inflation or increases to costs of wholesale water. As part of its Proposition 218 rate noticing process, RPU may notice its formula for such cost escalations and subsequently make specific pass-through cost adjustments if cost escalation, such as for the price of energy, exceeds the noticed cost assumptions. These adjustments do require a re-noticing of RPU's customers, but gives RPU some flexibility to adapt to changing costs without opening the adopted rate plan to another Proposition 218 protest process.

Pass-through costs adjustments will reflect only the incremental increase between the applicable cost increases that were assumed to develop the proposed rates, and the actual cost increases realized by RPU.

7 LEGAL REQUIREMENTS

7.1 INTRODUCTION

Carollo's analysis provides the record illustrating how RPU develops rates in conformance with cost of service principles. The discussion below sets forth the legal framework under which Carollo evaluated RPU's rates.

RPU's water rates and rate setting process must adhere to California constitutional and statutory requirements. Procedural requirements apply to the rate-setting process. The principal substantive requirements governing the rates are that revenues recovered through the rates do not exceed costs, and that the costs recovered from users do not exceed the cost for such service. The cost of service principles used for this analysis include these substantive requirements.

RPU's water rate structure includes tiered rates for some customer classes. The use of tiered water rates has been determined to be consistent with constitutional requirements pertaining to reasonable cost of service. The 2015 opinion in Capistrano Taxpayers Association, Inc. v. City of San Juan Capistrano ("*San Juan*") upheld tiered water rates under California Constitution Article XIII D (enacted by Proposition 218), noting that the tiers must correspond to the actual cost of furnishing service at a given level of usage. However, the *San Juan* Court held that the City of San Juan Capistrano did not attempt to calculate the actual costs of providing water at various tier levels. In reaching its conclusions, the *San Juan* Court treated all of the tiers as property-related services subject to Article XIII D, as interpreted by the California Supreme Court in its 2006 decision in *Bighorn-Desert View Water Agency v. Verjil*, 39 Cal. 4th 205 (2006) ("*Bighorn*"), that charges for domestic water delivery are charges for a property-related service. On the facts and arguments presented in San Juan, the Court found no basis for altering its application of Article XIII D in either Article XIII C ("Proposition 26") or Article X, Section 2 ("Article X").

Further judicial and legislative interpretation may provide additional guidance in the use of tiered water rates, including the application of Proposition 26's provisions concerning levies, charges and exactions other than property-related fees and the application of Article X. For the purposes of this cost of service analysis, it has been assumed that RPU's tiered water and recycled water rate structures are to be analyzed under the requirements of Article XIIID and implementing statutory provisions, described below.

7.2 ARTICLE XIII D

In November 1996, California voters approved Proposition 218, which amended the California Constitution by adding Article XIII C and Article XIII D. Article XIII D placed substantive limitations on the use of the revenue collected from property-related fees and on the amount of the fee that may be imposed on each parcel. The substantive requirements, contained in Article XIII D, Section 6, include that the amount of a fee "shall not exceed the proportional cost of the service attributable to the parcel," and that revenues from the rates "shall not exceed the funds required to provide the service" and "shall not be used for any purpose other than that for which the fee was imposed." Additionally, Proposition 218 established procedural requirements for imposing new, or increasing existing, property-related fees.

Following the passage of Proposition 218, there have been a number of court rulings interpreting and applying its language, and implementing statutes have also been enacted. In *City of Palmdale v. Palmdale Water District*, the court recognized that California Constitution Article X, Section 2 may be harmonized with Article XIII D, section 6 to allow for budget based and tiered rates that promote water conservation, provided conservation is attained in a manner that "shall not exceed the proportional cost of the service attributable to the parcel". As noted in *San Juan*, the 2011 *Palmdale* decision recognized that budget based water rates on their own do not violate Proposition 218. In *Palmdale*, the district failed to demonstrate a basis for the more restrictive tiered budgets and progression through the tiers in the irrigation customer class as compared to the other customer classes.

The *San Juan* decision rejected the argument that for purposes of the proportional cost allocation required by Article XIII D, the agency's calculation is a matter within legislative or quasi-legislative discretion shielded from judicial review. It did recognize some degree of latitude in making such calculations. The *San Juan* Court notes, for example, that it is not necessary to figure a rate for each parcel and it is permissible to allocate cost within tiers, as long as tiers are based on usage and not budgets. The opinion also explains that the time frame for the calculation of true water cost, particularly capital cost, may be long and calculation on a billing-cycle by billing-cycle basis is not required.

Cost and revenue projections are necessarily based on the best available information, and demand and consumption will be affected by weather and other factors that cannot be predicted. See *San Juan*, fn 11 (acknowledging projections of Metropolitan Water District rates as included in rate-setting process). Projections such as this may result in operating surplus and carryover, maintaining cost of service standards on a year over year basis through the inclusion of these amounts in subsequent years' budget processes.

7.3 CALIFORNIA ASSEMBLY BILL 2882

Among the legislative enactments implementing Proposition 218 is California Assembly Bill (AB) 2882, which became law at the beginning of 2009. AB 2882 (Sections 370-374 of the California Water Code) defined the elements of allocation-based conservation pricing under Proposition 218, including the appropriate property characteristics (i.e., number of occupants, land use, irrigable area, and local climate data) to establish a reasonable basic use allocation. While rates for all water used within the basic allocation must be established following cost causation principles, AB 2882 provides authority for higher charges on increments of water used in excess of the basic use allocation.

This statute creates a framework under which water agencies may establish cost-of-service based rates while simultaneously allowing for the deterrence of wasteful water use. Under AB 2882, the elements of an allocation-based conservation water rate structure compliant with the mandates of both Article X and Proposition 218 are:

1. Water bills must be based on metered water use.
2. A water allocation of “basic use” must be established, providing a reasonable amount of water for each customer’s basic needs based on property characteristics. Allocation factors may include, but are not limited to, number of occupants, type of land use, size of irrigated area, and local climate data.
3. All water used within the basic use allocation must be a basic volumetric unit rate that is established following cost causation principles for the cost of water service.
4. A “conservation charge” can be imposed on all increments of water use in excess of the basic use allocation. The conservation charge must also be a volumetric charge and should be designed to encourage water conservation and efficiency.

The cost of service analysis of RPU’s water rate structures is performed within the requirements of Article XIII D. While RPU is not recommending a water budget based rate structure at this time, the cost of service allocation as presented within this report does consider the framework of AB 2882, allowing the City to more easily transition to that type of rate structure in the future as and if desired. RPU's water rates are designed to both recover costs proportionally from system users as well as encourage conservation. RPU’s cost of service approach thereby conforms to the requirements of Article XIII D.

7.4 ARTICLE XIII C

The application of Proposition 26 in the structuring of water rates is presently undetermined. The *San Juan* decision briefly touched upon one aspect of the Article XIII C provisions enacted by Proposition 26, finding that tiered water charges would not appropriately be characterized as penalties. Other aspects of the application of Proposition 26 to tiered rate structures may be addressed in future judicial decisions and legislative enactments.

The voters in the State approved Proposition 26 on November 2, 2010. Proposition 26 amended Article XIII C of the State Constitution to expand the definition of “tax” to include “any levy, charge, or exaction of any kind imposed by a local government” with listed exceptions. By means of these exceptions, Article XIII C classifies several types of charges, in addition to property-related charges, that are not taxes, such as charges for specific services or benefits, regulatory charges and penalties.

Article XIII C’s definition of “tax” lists the following exceptions: (1) a charge imposed for a specific benefit conferred or privilege granted directly to the payor that is not provided to those not charged, and which does not exceed the reasonable costs to the local government of conferring the benefit or granting the privilege; (2) a charge imposed for a specific government service or product provided directly to the payor that is not provided to those not charged, and which does not exceed the reasonable costs to the local government of providing the service or product; (3) a charge imposed for the reasonable regulatory costs to a local government for issuing licenses and permits, performing investigations, inspections, and audits, enforcing agricultural marketing orders, and the administrative enforcement and adjudication thereof; (4) a charge imposed for entrance to or use of local government property, or the purchase, rental, or lease of local government property; (5) a fine, penalty, or other monetary charge imposed by the judicial branch of government or a local government, as a result of a violation of law; (6) a charge imposed as a condition of property development; and (7) assessments and property-related fees imposed in accordance with the provisions of Article XIII D.

Proposition 26 also provides that the local government bears the burden of proving by a preponderance of the evidence that a levy, charge, or other exaction is not a tax, that the amount is no more than necessary to cover the reasonable costs of the governmental activity, and that the manner in which those costs are allocated to a payor bear a fair or reasonable relationship to the payor's burdens on, or benefits received from, the governmental activity. Like the proportionality requirements of Article XIII D, assessment of rates under these requirements, if applicable, would be supported by the cost of service approach.

7.5 ARTICLE X

Article X, enacted as an amendment to the California Constitution in 1928 pursuant to an electoral initiative, provides that:

> *"It is hereby declared that because of the conditions prevailing in this State the general welfare requires that the water resources of the State be put to beneficial use to the fullest extent of which they are capable, and that the waste or unreasonable use or unreasonable method of use of water be prevented, and that the conservation of such waters is to be exercised with a view to the reasonable and beneficial use thereof in the interest of the people and for the public welfare."*

Article X conveys further that the right to water does not "extend to the waste or unreasonable use" of water. California Water Code Section 100 restates the policy that the waste of water shall be prevented. As indicated above, judicial interpretation in the *Palmdale* and *San Juan* decisions analyzed tiered water rates as property-related charges and, as such, found them to be compliant with Article XIII D provided that the tiers correspond to the actual cost of furnishing service at a given level of usage. Pricing signal was assumed to result from this manner of design. The use of tiered structures in compliance with Article XIII D restrictions was found to work in harmony with Article X. Further refinement through judicial and legislative interpretation may provide more specific guidance in this area, such as on the use of pricing signals.

APPENDIX

The following pages present details of the calculations completed for the Cost of Service and Rate Design Study.

Appendix A – REVENUE REQUIREMENT AND FINANCIAL INFORMATION

City of Riverside - Water Utility

PROJECTED STATEMENT OF OPERATIONS AND RETAINED EARNINGS

For the Fiscal Years Ending

	Projected 2018	Projected 2019	Projected 2020	Projected 2021	Projected 2022
	(In Thousands)	(In Thousands)	(In Thousands)	(In Thousands)	(In Thousands)
Operating revenues:					
Residential	$ 38,532	$ 42,003	$ 44,650	$ 47,346	$ 50,169
Commercial	10,650	11,869	12,974	14,176	15,488
Industrial	9,278	10,114	10,845	11,625	12,458
Other sales	1,776	1,920	2,035	2,162	2,298
Water Conveyance	3,127	3,170	3,214	3,258	3,304
Water Conservation	853	989	1,058	1,130	1,206
Other	4,986	5,056	5,127	5,199	5,273
Total operating revenues	69,202	75,121	79,903	84,897	90,196
Reserve for uncollectible	(181)	(198)	(212)	(226)	(241)
Total operating revenue, net of allowance	69,021	74,923	79,691	84,671	89,955
Operating expenses:					
Production costs	5,540	5,580	5,641	5,702	5,761
Electrical savings	(787)	(823)	(861)	(900)	(942)
Personnel expense	21,222	24,480	25,903	27,112	28,347
Supplies & services	8,693	8,867	9,044	9,225	9,410
Special projects	144	144	144	144	144
Service from other funds	10,940	11,159	11,382	11,610	11,842
Less charges to other	(6,149)	(6,272)	(6,397)	(6,525)	(6,656)
Additional O&M for CIP and Advanced Tech	1,165	1,117	1,719	2,306	2,745
Water Conservation Programs	1,310	989	1,058	1,130	1,206
Depreciation	13,374	14,894	15,588	16,409	17,283
Total operating expenses	55,452	60,134	63,221	66,212	69,140
Operating income	13,570	14,789	16,470	18,459	20,815
Non-operating revenues (expenses):					
Interest income	801	1,660	1,992	1,495	2,057
Interest expense (inc amort)	(8,503)	(9,400)	(10,689)	(10,227)	(12,277)
Line of Credit	(103)	(103)	(103)	(103)	(103)
Gain on sale of capital assets	132	132	132	132	132
Other (misc. income)	2,050	2,330	2,357	2,390	2,424
Non-operating revenues(expenses)	(5,622)	(5,381)	(6,311)	(6,313)	(7,767)
Income before CIA and operating transfers	7,947	9,408	10,159	12,146	13,048
General fund contribution	(6,639)	(7,105)	(7,763)	(8,298)	(8,858)
Contributions in aid of construction-Cash	1,600	1,600	1,600	1,600	1,600
Net income (Loss)	2,908	3,903	3,996	5,448	5,790
Net position, July 1	308,301	311,210	315,113	319,109	324,557
Net position, June 30	$ 311,210	$ 315,113	$ 319,109	$ 324,557	$ 330,347

CASH RESERVES AND REVENUE REQUIREMENTS

Fiscal Year	2018	2019	2020	2021	2022
Unrestricted cash and reserves:					
Undesignated reserves	$ 40,226	$ 38,405	$ 40,191	$ 43,850	$ 45,637
Water property reserve	5,000	5,000	5,000	5,000	5,000
Customer deposits reserve	433	433	433	433	433
Capital repair/replacement reserve	2,250	2,250	2,250	2,250	2,250
Legally restricted cash and cash equivalents:					
Reserved for debt service - monthly set aside	6,163	8,423	8,575	8,742	11,817
Reserved for bond construction	-	51,978	29,208	105	75,066
Reserved for short term financing construction	-	4,119	1,956	-	4,236
Reserve for Water Conservation	1,426	1,426	1,426	1,426	1,426
Total	$ 55,498	$ 112,034	$ 89,039	$ 61,806	$ 145,865

Revenue Requirements

Fiscal Year	2018	2019	2020	2021	2022
Production costs	$ 4,753	$ 4,757	$ 4,780	$ 4,802	$ 4,819
Personnel costs	15,073	18,208	19,506	20,587	21,691
Other operating and maintenance costs	19,777	20,170	20,570	20,979	21,395
Additional O&M for CIP and Advanced Tech	1,165	1,117	1,719	2,306	2,745
Debt service requirements	13,817	15,396	18,783	18,792	21,095
General fund transfer	6,639	7,105	7,763	8,298	8,858
Capital outlay financed by rates	5,074	9,787	6,702	7,098	6,516
Total Revenue Requirements	$ 66,298	$ 76,539	$ 79,823	$ 82,861	$ 87,120

Available Revenues

Fiscal Year	2018	2019	2020	2021	2022
Revenue at current rates	$ 55,611	$ 59,604	$ 65,262	$ 69,846	$ 74,639
Current year increase	4,006	5,670	4,597	4,805	5,104
Other Charges for Service	620	632	645	657	671
Interest income	801	1,660	1,992	1,495	2,057
Miscellaneous income	9,898	10,269	10,390	10,517	10,647
Total Available Revenues	$ 70,936	$ 77,835	$ 82,886	$ 87,322	$ 93,117
Use of/(Contributions to) Reserves	$ (4,638)	$ (1,296)	$ (3,062)	$ (4,460)	$ (5,998)

RESERVE REQUIREMENTS

All Monetary Values in Thousands of Dollars	2018	2019	2020	2021	Fiscal Year End 2022
Working Capital					
Operating Expenses (exc Deprec & Wtr Cons.)	$ 40,768	$ 44,251	$ 46,575	$ 48,673	$ 50,651
Per day (365 Days)	$ 112	$ 121	$ 128	$ 133	$ 139
60 Days of Operating Expenses	$ 6,702	$ 7,274	$ 7,656	$ 8,001	$ 8,326
90 Days of Operating Expenses	$ 10,052	$ 10,911	$ 11,484	$ 12,002	$ 12,489
Rate Stabilization					
Operating Revenues (exc Wtr Cons.)	$ 68,169	$ 73,934	$ 78,633	$ 83,541	$ 88,749
7%	$ 4,772	$ 5,175	$ 5,504	$ 5,848	$ 6,212
15%	$ 10,225	$ 11,090	$ 11,795	$ 12,531	$ 13,312
Capital- Emergency					
Depreciable Assets	$ 676,734	$ 709,231	$ 742,275	$ 781,385	$ 823,000
1%	$ 6,767	$ 7,092	$ 7,423	$ 7,814	$ 8,230
2%	$ 13,535	$ 14,185	$ 14,846	$ 15,628	$ 16,460
Capital- System Improvments					
Annual CIP for Following Year	$ 32,031	$ 32,508	$ 38,459	$ 40,901	$ 45,630
Less Designated Reserve Funding (Recycled Wtr/Property)	$ -	$ -	$ -	$ -	$ -
Revised Annual CIP for Following Year	$ 32,031	$ 32,508	$ 38,459	$ 40,901	$ 45,630
6 Months of Annual CIP	$ 16,015	$ 16,254	$ 19,229	$ 20,451	$ 22,815
9 Months of Annual CIP	$ 24,023	$ 24,381	$ 28,844	$ 30,676	**$ 34,222**
Debt Service (Max Annual D/S in upcoming FY)					
Principal	$ 5,635	$ 7,667	$ 7,954	$ 8,269	$ 10,955
Semi-Annual Interest	$ 7,232	$ 8,635	$ 8,413	$ 10,461	$ 12,509
/2	$ 3,616	$ 4,318	$ 4,206	$ 5,231	$ 6,254
Monthly Interest	$ 1,684	$ 1,614	$ 1,533	$ 1,451	$ 1,366
/12	$ 140	$ 134	$ 128	$ 121	$ 114
Total **(Includes New Proposed Debt)**	$ 9,391	$ 12,119	$ 12,288	$ 13,620	$ 17,323
Minimum Reserve Requirement	**$ 43,647**	**$ 47,915**	**$ 52,101**	**$ 55,734**	**$ 62,907**
Maximum Reserve Requirement	**$ 67,226**	**$ 72,686**	**$ 79,257**	**$ 84,457**	**$ 93,807**

Functional Allocation

Appendix B, *Functional Allocation,* presents the complete allocation of each of the expenses and offsetting revenues associated with Riverside Public Utilities' operation and maintenance of the water system. The dollar value of each expense and each revenue is associated with a certain process of the system. This process is, in turn, associated with the water system's ability to provide Customer, Capacity, Supply 1, Supply 2, Supply 3, Supply 4, and Base. The dollar value of any expense or revenue is allocated to each of these cost components in the same proportion that it's related process is allocated. The aggregate distribution amongst the cost components of all of the syste m's expenses and revenues combined is calculated at the top of Appendix B *Functional Allocation.*

Allocation Index	Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base	As All Others	Total
								100%	100%
Customer Only	100%	0%	0%	0%	0%	0%	0%	0%	100%
Capacity Only	0%	100%	0%	0%	0%	0%	0%	0%	100%
Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
Supply 4 Only	0%	0%	0%	0%	0%	100%	0%	0%	100%
Customer/Capacity	50%	50%	0%	0%	0%	0%	0%	0%	100%
Customer/Capacity/Base	34%	33%	33%	0%	0%	0%	0%	0%	100%
As All Others	0%	0%	0%	0%	0%	0%	0%	100%	100%
Existing Debt		72.167%	6.322%	5.549%	11.908%	4.055%			
Charges From Other Funds	16.186%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	84%	100%
Supply and Distribution			29%	21%	39%	11%		0%	100%
Supply Only			23%	20%	43%	15%		0%	100%
Engineering Staff Alloc		51%	7%	6%	13%	4%	20%	0%	100%
CIP Allocation		61%			19%	6%	13%	0%	

Rate Revenue Requirement	Applied to Interruptable	Five Year Total	Allocation	Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base	As All Others	Total
Operating Expenses (Less Charges From Other Funds)	100%	$ 167,697,294	As O&M	0%	8%	14%	10%	19%	6%	43%	0%	100%
Existing Debt Service	72%	$ 64,911,700	Existing Debt	0%	72%	6%	6%	12%	4%	0%	0%	100%
New Debt Service	74%	$ 18,629,290	CIP Allocation	0%	61%	0%	0%	19%	6%	13%	0%	100%
General Fund Transfer	100%	$ 38,663,000	As All Others	0%	0%	0%	0%	0%	0%	0%	100%	100%
Charges From Other Funds	100%	$ 54,168,776	Charges From Other Funds	16%	0%	0%	0%	0%	0%	0%	84%	100%
Charges To Other Funds	100%	$ (31,675,400)	Charges to Othr Funds	0%	14%	2%	2%	4%	1%	77%	0%	100%
Recharge Basins, Booster Stations, Wells	100%	$ 660,000	Supply 4 Only	0%	0%	0%	0%	0%	100%	0%	0%	100%
Inflatable Dam, Pipelines, Reservoirs	100%	$ 345,000	Supply 4 Only	0%	0%	0%	0%	0%	100%	0%	0%	100%
Treatment Plant O&M	100%	$ -	Supply 4 Only	0%	0%	0%	0%	0%	100%	0%	0%	100%
Technology Projects	100%	$ 6,730,800	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
Recycled Water O&M	100%	$ 715,000	Supply 4 Only	0%	0%	0%	0%	0%	100%	0%	0%	100%
Rate Funded Capital	74%	$ 35,176,852	CIP Allocation	0%	61%	0%	0%	19%	6%	13%	0%	100%
Transitional Rates Losses	100%	$ 2,122,007	As Variable			16%	12%	30%	10%	32%	0%	100%
Less Offsetting Revenues												
Cashflow	100%	$ 20,055,380	As All Others	0%	0%	0%	0%	0%	0%	0%	100%	100%
Interest income	100%	$ (8,005,000)	As All Others	0%	0%	0%	0%	0%	0%	0%	100%	100%
Miscellaneous income	100%	$ (20,218,475)	As All Others	0%	0%	0%	0%	0%	0%	0%	100%	100%
WMWD - Water Conveyance	100%	$ (14,823,072)	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
UCR - Water Conveyance	100%	$ (1,250,000)	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
Wholesale Sales- WMWD	100%	$ (15,429,979)	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
Outside City Surcharge	100%	$ (7,978,892)	As All Others	0%	0%	0%	0%	0%	0%	0%	100%	100%
WA-5 Fire Service Charges	100%	$ (3,164,745)	As All Others	0%	0%	0%	0%	0%	0%	0%	100%	100%
			As All Others	0%	0%	0%	0%	0%	0%	0%	100%	100%
			As All Others	0%	0%	0%	0%	0%	0%	0%	100%	100%
			As All Others	0%	0%	0%	0%	0%	0%	0%	100%	100%
Total Rate Revenues to be Collected		**$ 307,329,536**		**$ 8,767,723**	**$ 88,744,369**	**$ 19,437,896**	**$ 15,071,721**	**$ 40,261,092**	**$ 14,550,646**	**$ 55,743,768**	**$ 64,752,321**	**$ 307,329,536**
Reallocation of "As All Others"				**$ 2,340,411**	**$ 23,688,968**	**$ 5,188,653**	**$ 4,023,168**	**$ 10,747,090**	**$ 3,884,075**	**$ 14,879,956**	**$ (64,752,321)**	
Total Allocation		**$ 307,329,536**		**$ 11,108,134**	**$ 112,433,337**	**$ 24,626,549**	**$ 19,094,889**	**$ 51,008,182**	**$ 18,434,721**	**$ 70,623,725**	**$ -**	
Percentage Allocation		100.0%		3.6%	36.6%	8.0%	6.2%	16.6%	6.0%	23.0%	0.0%	

Revenue Requirement Adjustment For Interruptable Rates		Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base	As All Others
Total Rate Revenues to be Collected		**$ 8,767,723**	**$ 67,282,563**	**$ 18,295,792**	**$ 14,069,248**	**$ 35,485,710**	**$ 12,924,497**	**$ 53,927,412**	**$ 64,752,321**
Reallocation of "As All Others"		**$ 2,693,820**	**$ 20,672,082**	**$ 5,621,250**	**$ 4,322,675**	**$ 10,902,728**	**$ 3,970,958**	**$ 16,568,808**	**$ (64,752,321)**
Total Allocation	**$ 275,505,267**	**$ 11,461,543**	**$ 87,954,645**	**$ 23,917,042**	**$ 18,391,923**	**$ 46,388,439**	**$ 16,895,455**	**$ 70,496,220**	**$ -**
Percentage Allocation	100.0%	4.2%	31.9%	8.7%	6.7%	16.8%	6.1%	25.6%	0.0%
Calculated Adjustment For Interuptable Rates		**3.2%**	**-21.8%**	**-2.9%**	**-3.7%**	**-9.1%**	**-8.3%**	**-0.2%**	
Adjustment Override		0%	0%					0%	
Applied Adjustment For Interruptable Rates		**0.0%**	**0.0%**	**-2.9%**	**-3.7%**	**-9.1%**	**-8.3%**	**0.0%**	# **0.0%**

Operating Expenditures			Applicablity to Interruptable	Five Year Total	Allocation	Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base	As All Others	Total
[1] **WATER PRODUCTION AND OPERATIONS**														
Object	GL Key	Description												
411100	6200000	Salaries - Regular	100%	$ 14,279,319	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411105	6200000	Salaries - Non-Productive	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411110	6200000	Salaries-Temp & Part Time	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411130	6200000	Compensatory Time	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411210	6200000	Vacation	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411220	6200000	Holidays & Special Days Off	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411225	6200000	Rest Time Pay - IBEW	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411240	6200000	Sick Leave	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411245	6200000	Family Illness Sick Leave	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411250	6200000	Industrial Accident	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411260	6200000	Bereavement Leave	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411280	6200000	Jury Duty	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411292	6200000	Administrative Leave	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411310	6200000	Night Shift Premium	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411320	6200000	Temporary Foreman Pay	100%	$ 5,204	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411410	6200000	Vacation Payoffs	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411420	6200000	Sick Leave Payoff	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411430	6200000	Compensatory Time Payoff	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411510	6200000	Accrued Payroll	100%	$ 82,276	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411521	6200000	Accrued Sick Leave Yr End Only	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411522	6200000	Accrued Vacation Year-End Only	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
411530	6200000	Accrued Comp. Time Earned	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
412210	6200000	Workers Compensation Ins	100%	$ 361,108	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
412220	6200000	Health Insurance	100%	$ 2,113,397	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
412221	6200000	Retiree Health Insurance	100%	$ 74,938	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
412222	6200000	Dental Insurance	100%	$ 96,275	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
412230	6200000	Life Insurance	100%	$ 48,616	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
412240	6200000	Unemployment Insurance	100%	$ 7,978	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
412250	6200000	Disability Insurance	100%	$ 38,177	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
412310	6200000	PERS Retirement	100%	$ 5,148,843	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
412313	6200000	OPEB Annual Req Cont Expense	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
412320	6200000	Medicare OASDI	100%	$ 201,823	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
412400	6200000	Deferred Compensation	100%	$ 78,061	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
413110	6200000	Overtime At Straight Rate	100%	$ 52,040	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
413120	6200000	Overtime At 1.5 Rate	100%	$ 3,122	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
413130	6200000	Overtime At Double Time Rate	100%	$ 1,027,278	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
413230	6200000	Holiday O/T-Strt/Subj To Retir	100%	$ 10,408	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
413250	6200000	Dbl Time Subj To Retirement	100%	$ 104,081	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
413260	6200000	O/T Meal Allowance-IBEW	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
			100%		Supply and Distribution									
			100%		Supply and Distribution									
421000	6200000	Professional Services	100%	$ 7,670,755	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
421001	6200000	Prof Services/Internal	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
421100	6200000	Outside Legal Services	100%	$ 769,678	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
422100	6200000	Telephone	100%	$ 117,976	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
422120	6200000	Telephone - Cellular	100%	$ 106,162	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
422200	6200000	Electric	100%	$ 28,560,220	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
422300	6200000	Gas	100%	$ 31,728	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
422500	6200000	Water	100%	$ 59,326	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
422600	6200000	Other Utilities	100%	$ 475,916	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
422922	6200000	Imported Water	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
422923	6200000	IW Capacity/Standby Charges	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
422924	6200000	Production Costs	100%	$ 1,771,463	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
423400	6200000	Motor Pool Equipment Rental	100%	$ 1,545,314	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
424130	6200000	Maint/Repair of Bldgs & Improv	100%	$ 3,023,547	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
424220	6200000	All Other Equip Maint/Repair	100%	$ 15,612	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
424230	6200000	Central Garage Charges	100%	$ 66,914	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
424240	6200000	Central Communications Chg	100%	$ 26,020	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
425100	6200000	Advertising Expense	100%	$ 5,204	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
425200	6200000	Periodicals & Dues	100%	$ 182,141	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
425300	6200000	Photo & Recording Supplies	100%	$ 2,602	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
425400	6200000	General Office Expense	100%	$ 130,101	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
425500	6200000	Postage	100%	$ 26,020	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
425600	6200000	Central Printing Charges	100%	$ 2,602	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
425610	6200000	Outside Printing Expense	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
425700	6200000	Software Purchase/Licensing	100%	$ 78,061	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
425800	6200000	Computer Equip Purc Undr $5000	100%	$ 104,081	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%

	Operating Expenditures	Applicablity to Interruptable	Five Year Total	Allocation	Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base	As All Others	Total
	426100 6200000 Janitorial Supplies	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
	426200 6200000 Clothing/Linen/Safety Supplies	100%	$ 62,865	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
	426300 6200000 Motor Fuels & Lubricants	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
	426600 6200000 Chemical Supplies	100%	$ 3,329,545	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
	426700 6200000 Maintenance Tools/Supplies	100%	$ 78,061	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
	426710 6200000 Work Boot Reimbursement	100%	$ 31,224	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
	426800 6200000 Special Department Supplies	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
	427100 6200000 Travel & Meeting Expense	100%	$ 78,061	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
	427200 6200000 Training	100%	$ 104,081	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
	428400 6200000 Liability Insurance	100%	$ 298,436	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
	428420 6200000 Insurance Charges - Direct	100%	$ 762,959	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
	447100 6200000 Taxes And Assessments	100%	$ 9,220,914	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
	449100 6200000 Equipment Rental Charges	100%	$ -	Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
		100%											
		100%											
No	462200 6200000 Machine and Equipment	100%		Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
No	462300 6200000 Office Furniture & Equipment	100%		Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
No	462308 6200000 Off Furn & Eq/Computer Acqustn	100%		Supply and Distribution	0%	0%	29%	21%	39%	11%	0%	0%	100%
		100%											
		100%											
	(1) **WATER FIELD OPERATIONS**	100%											
	Object GL Key Description	100%											
	411100 6205000 Salaries - Regular	100%	$ 34,833,097	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411110 6205000 Salaries-Temp & Part Time	100%	$ 692,762	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411130 6205000 Compensatory Time	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411210 6205000 Vacation	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411220 6205000 Holidays & Special Days Off	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411225 6205000 Rest Time Pay - IBEW	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411230 6205000 Military Leave	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411240 6205000 Sick Leave	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411245 6205000 Family Illness Sick Leave	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411250 6205000 Industrial Accident	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411260 6205000 Bereavement Leave	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411280 6205000 Jury Duty	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411292 6205000 Administrative Leave	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411310 6205000 Night Shift Premium	100%	$ 25,073	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411320 6205000 Temporary Foreman Pay	100%	$ 182,141	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411410 6205000 Vacation Payoffs	100%	$ 122,566	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411420 6205000 Sick Leave Payoff	100%	$ 521,362	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411430 6205000 Compensatory Time Payoff	100%	$ 8,691	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411510 6205000 Accrued Payroll	100%	$ 209,884	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411521 6205000 Accrued Sick Leave Yr End Only	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411522 6205000 Accrued Vacation Year-End Only	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	411530 6205000 Accrued Comp. Time Earned	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	412210 6205000 Workers Compensation Ins	100%	$ 1,183,060	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	412220 6205000 Health Insurance	100%	$ 5,969,872	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	412221 6205000 Retiree Health Insurance	100%	$ 259,161	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	412222 6205000 Dental Insurance	100%	$ 289,001	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	412230 6205000 Life Insurance	100%	$ 138,297	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	412240 6205000 Unemployment Insurance	100%	$ 19,926	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	412250 6205000 Disability Insurance	100%	$ 116,029	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	412310 6205000 PERS Retirement	100%	$ 13,182,816	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	412313 6205000 OPEB Annual Req Cont Expense	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	412320 6205000 Medicare OASDI	100%	$ 489,315	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	412330 6205000 City Retirement Plan	100%	$ 25,979	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	412400 6205000 Deferred Compensation	100%	$ 218,570	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	413110 6205000 Overtime At Straight Rate	100%	$ 383,350	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	413120 6205000 Overtime At 1.5 Rate	100%	$ 18,214	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	413130 6205000 Overtime At Double Time Rate	100%	$ 4,916,954	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	413210 6205000 Holiday O/T-Straight/Non-Sched	100%	$ 36,428	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	413250 6205000 Dbl Time Subj To Retirement	100%	$ 32,265	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	413260 6205000 O/T Meal Allowance-IBEW	100%	$ 2,602	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
		100%											
		100%											
	421000 6205000 Professional Services	100%	$ 1,040,808	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	421001 6205000 Prof Services/Internal	100%	$ 2,158,376	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	422100 6205000 Telephone	100%	$ 3,903	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	422120 6205000 Telephone - Cellular	100%	$ 114,489	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	422700 6205000 Refuse/Disposal Fees	100%	$ 130,101	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	423200 6205000 Land and Building Rental	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	423400 6205000 Motor Pool Equipment Rental	100%	$ 6,296,441	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%

	Operating Expenditures			Applicablity to Interruptable	Five Year Total	Allocation	Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base	As All Others	Total
	424130	6205000	Maint/Repair of Bldgs & Improv	100%	$ 4,787,717	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	424220	6205000	All Other Equip Maint/Repair	100%	$ 52,040	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	424230	6205000	Central Garage Charges	100%	$ 450,347	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	424240	6205000	Central Communications Chg	100%	$ 10,408	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	424310	6205000	Software Maintenance/Support	100%	$ 10,928	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	425200	6205000	Periodicals & Dues	100%	$ 39,030	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	425400	6205000	General Office Expense	100%	$ 130,101	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	425500	6205000	Postage	100%	$ 598	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	425600	6205000	Central Printing Charges	100%	$ 5,204	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	425610	6205000	Outside Printing Expense	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	425700	6205000	Software Purchase/Licensing	100%	$ 15,612	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	425800	6205000	Computer Equip Purc Undr $5000	100%	$ 52,040	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	426100	6205000	Janitorial Supplies	100%	$ 10,408	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	426200	6205000	Clothing/Linen/Safety Supplies	100%	$ 312,242	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	426300	6205000	Motor Fuels & Lubricants	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	426600	6205000	Chemical Supplies	100%	$ 2,602	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	426700	6205000	Maintenance Tools/Supplies	100%	$ 520,404	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	426710	6205000	Work Boot Reimbursement	100%	$ 114,489	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	426800	6205000	Special Department Supplies	100%	$ 364,283	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	427100	6205000	Travel & Meeting Expense	100%	$ 52,040	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	427200	6205000	Training	100%	$ 104,081	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	428400	6205000	Liability Insurance	100%	$ 742,585	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
	449100	6205000	Equipment Rental Charges	100%	$ -	Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
				100%											
				100%											
No	462100	6205000	Automotive Equipment	100%		Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
No	462200	6205000	Machine and Equipment	100%		Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
No	462308	6205000	Off Furn & Eq/Computer Acqustn	100%		Base Only	0%	0%	0%	0%	0%	0%	100%	0%	100%
				100%											
	(4) **WATER ENGINEERING**			100%											
	Object	GL Key	Description	100%											
	411100	6210000	Salaries - Regular	100%	$ 20,661,757	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411110	6210000	Salaries-Temp & Part Time	100%	$ 273,951	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411130	6210000	Compensatory Time	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411210	6210000	Vacation	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411220	6210000	Holidays & Special Days Off	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411225	6210000	Rest Time Pay - IBEW	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411240	6210000	Sick Leave	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411245	6210000	Family Illness Sick Leave	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411250	6210000	Industrial Accident	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411260	6210000	Bereavement Leave	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411280	6210000	Jury Duty	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411292	6210000	Administrative Leave	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411310	6210000	Night Shift Premium	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411410	6210000	Vacation Payoffs	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411510	6210000	Accrued Payroll	100%	$ 116,128	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411521	6210000	Accrued Sick Leave Yr End Only	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411522	6210000	Accrued Vacation Year-End Only	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	411530	6210000	Accrued Comp. Time Earned	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	412210	6210000	Workers Compensation Ins	100%	$ 697,164	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	412220	6210000	Health Insurance	100%	$ 2,321,382	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	412222	6210000	Dental Insurance	100%	$ 101,906	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	412230	6210000	Life Insurance	100%	$ 71,675	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	412240	6210000	Unemployment Insurance	100%	$ 11,678	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	412250	6210000	Disability Insurance	100%	$ 17,340	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	412310	6210000	PERS Retirement	100%	$ 7,266,436	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	412311	6210000	PERS - NPA Amortization	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	412313	6210000	OPEB Annual Req Cont Expense	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	412320	6210000	Medicare OASDI	100%	$ 303,572	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	412330	6210000	City Retirement Plan	100%	$ 6,495	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	412400	6210000	Deferred Compensation	100%	$ 140,509	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	413110	6210000	Overtime At Straight Rate	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	413120	6210000	Overtime At 1.5 Rate	100%	$ 121,775	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
	413130	6210000	Overtime At Double Time Rate	100%	$ -	Engineering Staff Alloc	0%	51%	7%	6%	13%	4%	20%	0%	100%
				100%											
				100%											
	421000	6210000	Professional Services	100%	$ 2,149,269	Supply Only	0%	0%	22.7%	19.9%	42.8%	14.6%	0%	0%	100%
	421001	6210000	Prof Services/Internal	100%	$ -	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
	421100	6210000	Outside Legal Services	100%	$ 260,202	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
	422100	6210000	Telephone	100%	$ 18,214	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
	422120	6210000	Telephone - Cellular	100%	$ 79,310	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%

Operating Expenditures		Applicablity to Interruptable	Five Year Total	Allocation	Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base	As All Others	Total
423400	6210000 Motor Pool Equipment Rental	100%	$ 344,965	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
424130	6210000 Maint/Repair of Bldgs & Improv	100%	$ 20,816	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
424220	6210000 All Other Equip Maint/Repair	100%	$ 72,857	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
424230	6210000 Central Garage Charges	100%	$ -	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
424240	6210000 Central Communications Chg	100%	$ -	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
425100	6210000 Advertising Expense	100%	$ 29,143	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
425200	6210000 Periodicals & Dues	100%	$ 114,749	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
425300	6210000 Photo & Recording Supplies	100%	$ 75,459	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
425400	6210000 General Office Expense	100%	$ 182,141	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
425500	6210000 Postage	100%	$ 6,245	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
425600	6210000 Central Printing Charges	100%	$ 2,602	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
425610	6210000 Outside Printing Expense	100%	$ -	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
425700	6210000 Software Purchase/Licensing	100%	$ 166,789	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
425800	6210000 Computer Equip Purc Undr $5000	100%	$ 33,826	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
425806	6210000 Computers-Software	100%	$ 1,376,859	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
426200	6210000 Clothing/Linen/Safety Supplies	100%	$ 10,408	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
426600	6210000 Chemical Supplies	100%	$ 5,204	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
426700	6210000 Maintenance Tools/Supplies	100%	$ 15,612	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
426710	6210000 Work Boot Reimbursement	100%	$ 10,928	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
426800	6210000 Special Department Supplies	100%	$ 28,622	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
427100	6210000 Travel & Meeting Expense	100%	$ 203,478	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
427200	6210000 Training	100%	$ 343,467	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
428400	6210000 Liability Insurance	100%	$ 437,571	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
443300	6210000 Uncollect Accounts-Bad Debts	100%	$ 1,092,848	Supply Only	0%	0%	23%	20%	43%	15%	0%	0%	100%
		100%											
		100%											
457004	6210000 Property Management	100%	$ 1,248,970	As All Others	0%	0%	0%	0%	0%	0%	0%	100%	100%
		100%		Supply Only									
Operating Expenditures Sub Total			**$ 204,311,550**		**$ -**	**$ 16,376,954**	**$ 27,524,364**	**$ 20,450,569**	**$ 39,281,817**	**$ 11,698,468**	**$ 87,730,409**	**$ 1,248,970**	**$ 204,311,550**
Reallocation of "As All Others"					**$ -**	**$ 100,729**	**$ 169,293**	**$ 125,785**	**$ 241,609**	**$ 71,953**	**$ 539,600**	**$ (1,248,970)**	
Total Allocation			**$ 204,311,550**		$ -	$ 16,477,683	$ 27,693,657	$ 20,576,353	$ 39,523,426	$ 11,770,421	$ 88,270,009	$ -	
Percentage Allocation			**100.0%**		0.0%	8.1%	13.6%	10.1%	19.3%	5.8%	43.2%	0.0%	

O&M Adjustment For Interruptable Rates		Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base	As All Others
Total Rate Revenues to be Collected		**$ -**	**$ 16,376,954**	**$ 27,524,364**	**$ 20,450,569**	**$ 39,281,817**	**$ 11,698,468**	**$ 87,730,409**	**$ 1,248,970**
Reallocation of "As All Others"		**$ -**	**$ 100,729**	**$ 169,293**	**$ 125,785**	**$ 241,609**	**$ 71,953**	**$ 539,600**	**$ (1,248,970)**
Total Allocation	**$ 204,311,550**	**$ -**	**$ 16,477,683**	**$ 27,693,657**	**$ 20,576,353**	**$ 39,523,426**	**$ 11,770,421**	**$ 88,270,009**	**$ -**
Percentage Allocation	100.0%	0.0%	8.1%	13.6%	10.1%	19.3%	5.8%	43.2%	0.0%
Calculated Adjustment For Interuptable Rates		**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	
Adjustment Override									
Applied Adjustment For Interuptable Rates	**0.00%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**

Allocation for Charges to Other Funds	For Services from Field Operations Division and by Engineering Staff		Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base
	Total Allocated								
Field Operations	$ 81,398,696	Calculated Allcation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Eng Staff	$ 32,111,768	Calculated Allcation	0.00%	51.00%	6.65%	5.84%	12.53%	4.27%	19.72%
Cost Weighted Average Allocation For Charges to Other Funds			**0.0%**	**14.4%**	**1.9%**	**1.7%**	**3.5%**	**1.2%**	**77.3%**

Appendix C – MULTI-YEAR AND CUSTOMER ALLOCATION

Multi-Year and Customer Allocation

Appendix C, *Multi-Year* and Customer *Allocation,* takes the aggregate distribution of Riverside Public Utilities' expenses and revenues amongst the cost components and forecasts the total dollar-value of each cost component over the next five fiscal years (2017/18 – 2021/22). Additionally, within this appendix each of the cost components is allocated amongst the various customer categories in direct proportion with that category's share of whichever unit (number of accounts, number of MEUs, level of consumption) is associated with each cost component.

Multi-Year Functional Cost Allocation

		Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base
Proposed CoS Results								
% Allocation	100%	3.6%	36.6%	8.0%	6.2%	16.6%	6.0%	23.0%
Starting Alloaction	100%	2.5%	25.5%	9.6%	7.5%	20.0%	7.2%	27.7%

Years to implement adjustment to Cost of Service based Allocation: 4

		Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base
FY 2017/18	100%	2.5%	25.5%	9.6%	7.5%	20.0%	7.2%	27.7%
FY 2018/19	100%	2.8%	28.3%	9.2%	7.2%	19.1%	6.9%	26.5%
FY 2019/20	100%	3.1%	31.0%	8.8%	6.8%	18.3%	6.6%	25.3%
FY 2020/21	100%	3.3%	33.8%	8.4%	6.5%	17.4%	6.3%	24.2%
FY 2021/22	100%	3.6%	36.6%	8.0%	6.2%	16.6%	6.0%	23.0%

	All Customers Allocation	Amount Allocable to Constituent						
FY 2017/18	63,124,885	1,589,231	16,085,737	6,090,029	4,722,075	12,614,081	4,558,819	17,464,912
FY 2018/19	67,325,380	1,879,590	19,024,667	6,220,165	4,822,980	12,883,628	4,656,235	17,838,115
FY 2019/20	71,845,588	2,202,787	22,295,974	6,344,204	4,919,157	13,140,546	4,749,087	18,193,833
FY 2020/21	76,625,831	2,559,459	25,906,102	6,453,201	5,003,671	13,366,308	4,830,679	18,506,412
FY 2021/22	81,584,713	2,948,802	29,846,925	6,537,445	5,068,992	13,540,800	4,893,742	18,748,007

Allocation Adjustment for Interruptable Rates

	Customer	Capacity	Supply 1	Supply 2	Supply 3	Supply 4	Base
	0.0%	0.0%	-2.9%	-3.7%	-9.1%	-8.3%	

Customer Class Allocation

Customer Costs

		Temp Service WA-2	Riv. Water Co. Irr. WA-4	Comm & Ind WA-6.1 and WA-6.2	City Irrigation WA-7 and WA-10	SFR	MFR	Landscape
Allocation Factor	**Accounts**							
Factor Period	**Five Year Average**							
Baseline Allocation		**0.107%**	**0.057%**	**7.192%**	**0.759%**	**89.018%**	**1.837%**	**1.030%**
Interruptable		No	No	No	No	No	No	No
Interruptable Adjustment		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Effective Allocation Adjustment		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Baseline Allocation With Adjustment		**0.107%**	**0.057%**	**7.192%**	**0.759%**	**89.018%**	**1.837%**	**1.030%**
Reallocation to Non-Interruptable		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
	Total Allocation	**WA-2**	**WA-4**	**WA-6.1**	**WA-7**	**SFR**	**MFR**	**Landscape**
Effective Allocation	**100.0%**	0.107%	0.057%	7.192%	0.759%	89.018%	1.837%	1.030%
FY 2017/18	1,589,231	1,707	901	114,294	12,069	1,414,697	29,195	16,366
FY 2018/19	1,879,590	2,019	1,066	135,176	14,275	1,673,168	34,530	19,356
FY 2019/20	2,202,787	2,367	1,249	158,420	16,729	1,960,871	40,467	22,684
FY 2020/21	2,559,459	2,750	1,452	184,071	19,438	2,278,372	47,019	26,357
FY 2021/22	2,948,802	3,168	1,672	212,071	22,395	2,624,957	54,172	30,367

Capacity Costs

		Temp Service WA-2	Riv. Water Co. Irr. WA-4	Comm & Ind WA-6.1 and WA-6.2	City Irrigation WA-7 and WA-10	SFR	MFR	Landscape
Allocation Factor	**MEUs**							
Factor Period	**Five Year Average**							
Baseline Allocation		**0.709%**	**0.079%**	**24.107%**	**1.716%**	**68.727%**	**1.535%**	**3.128%**
Interruptable		No	No	No	No	No	No	No
Interruptable Adjustment		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Effective Allocation Adjustment		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Baseline Allocation With Adjustment		**0.709%**	**0.079%**	**24.107%**	**1.716%**	**68.727%**	**1.535%**	**3.128%**
Reallocation to Non-Interruptable		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
	Total Allocation	**WA-2**	**WA-4**	**WA-6.1**	**WA-7**	**SFR**	**MFR**	**Landscape**
Effective Allocation	**100.0%**	0.709%	0.079%	24.107%	1.716%	68.727%	1.535%	3.128%
FY 2017/18	16,085,737	113,989	12,634	3,877,784	275,992	11,055,264	246,859	503,214
FY 2018/19	19,024,667	134,816	14,943	4,586,271	326,417	13,075,106	291,961	595,153
FY 2019/20	22,295,974	157,997	17,512	5,374,884	382,544	15,323,381	342,164	697,490
FY 2020/21	25,906,102	183,580	20,348	6,245,177	444,485	17,804,518	397,567	810,426
FY 2021/22	29,846,925	211,506	23,443	7,195,190	512,100	20,512,932	458,045	933,708

Supply 1 Costs

Allocation Factor	Supply 1	Temp Service WA-2	Riv. Water Co. Irr. WA-4	Comm & Ind WA-6.1 and WA-6.2	City Irrigation WA-7 and WA-10	SFR	MFR	Landscape
Baseline Allocation		**0.028%**	**0.074%**	**21.157%**	**1.671%**	**71.226%**	**2.752%**	**3.092%**
Interruptable		No	No	No	Yes	No	No	No
Interruptable Adjustment		0.000%	0.000%	0.000%	-2.881%	0.000%	0.000%	0.000%
Effective Allocation Adjustment		0.000%	0.000%	0.000%	-0.048%	0.000%	0.000%	0.000%
Baseline Allocation With Adjustment		**0.028%**	**0.074%**	**21.157%**	**1.623%**	**71.226%**	**2.752%**	**3.092%**
Reallocation to Non-Interruptable		0.000%	0.000%	0.010%	0.000%	0.035%	0.001%	0.002%
	Total Allocation	**WA-2**	**WA-4**	**WA-6.1**	**WA-7**	**SFR**	**MFR**	**Landscape**
Goal Allocation	**100.0%**	**0.028%**	**0.074%**	**21.167%**	**1.623%**	**71.260%**	**2.754%**	**3.094%**

	Total Allocation	WA-2	WA-4	WA-6.1	WA-7	SFR	MFR	Landscape
FY 2017/18	6,090,029	1,726	4,489	1,289,088	98,842	4,339,782	167,694	188,406
FY 2018/19	6,220,165	1,763	4,585	1,316,635	100,954	4,432,517	171,278	192,432
FY 2019/20	6,344,204	1,798	4,677	1,342,890	102,968	4,520,908	174,693	196,270
FY 2020/21	6,453,201	1,829	4,757	1,365,962	104,737	4,598,580	177,695	199,642
FY 2021/22	6,537,445	1,853	4,819	1,383,794	106,104	4,658,613	180,014	202,248

Supply 2 Costs

Allocation Factor	Supply 2	Temp Service WA-2	Riv. Water Co. Irr. WA-4	Comm & Ind WA-6.1 and WA-6.2	City Irrigation WA-7 and WA-10	SFR	MFR	Landscape
Baseline Allocation		**0.065%**	**0.081%**	**48.786%**	**3.854%**	**39.174%**	**0.910%**	**7.130%**
Interruptable		No	No	No	Yes	No	No	No
Interruptable Adjustment		0.000%	0.000%	0.000%	-3.681%	0.000%	0.000%	0.000%
Effective Allocation Adjustment		0.000%	0.000%	0.000%	-0.142%	0.000%	0.000%	0.000%
Baseline Allocation With Adjustment		**0.065%**	**0.081%**	**48.786%**	**3.712%**	**39.174%**	**0.910%**	**7.130%**
Reallocation to Non-Interruptable		0.000%	0.000%	0.072%	0.000%	0.058%	0.001%	0.011%
	Total Allocation	**WA-2**	**WA-4**	**WA-6.1**	**WA-7**	**SFR**	**MFR**	**Landscape**
Goal Allocation	**100.0%**	**0.065%**	**0.081%**	**48.858%**	**3.712%**	**39.232%**	**0.911%**	**7.141%**

	Total Allocation	WA-2	WA-4	WA-6.1	WA-7	SFR	MFR	Landscape
FY 2017/18	$ 4,722,075	3,090	3,813	2,307,130	175,271	1,852,554	43,019	337,198
FY 2018/19	$ 4,822,980	3,156	3,894	2,356,431	179,016	1,892,141	43,938	344,403
FY 2019/20	$ 4,919,157	3,219	3,972	2,403,421	182,586	1,929,873	44,815	351,271
FY 2020/21	$ 5,003,671	3,274	4,040	2,444,713	185,723	1,963,029	45,584	357,306
FY 2021/22	$ 5,068,992	3,317	4,093	2,476,628	188,148	1,988,656	46,180	361,971

Supply 3 Costs

Allocation Factor	Supply 3	Temp Service WA-2	Riv. Water Co. Irr. WA-4	Comm & Ind WA-6.1 and WA-6.2	City Irrigation WA-7 and WA-10	SFR	MFR	Landscape
Baseline Allocation		**0.538%**	**0.171%**	**29.737%**	**5.706%**	**54.146%**	**1.042%**	**8.660%**
Interruptable		No	No	No	Yes	No	No	No
Interruptable Adjustment		0.000%	0.000%	0.000%	-9.057%	0.000%	0.000%	0.000%
Effective Allocation Adjustment		0.000%	0.000%	0.000%	-0.517%	0.000%	0.000%	0.000%
Baseline Allocation With Adjustment		**0.538%**	**0.171%**	**29.737%**	**5.189%**	**54.146%**	**1.042%**	**8.660%**
Reallocation to Non-Interruptable		0.003%	0.001%	0.163%	0.000%	0.297%	0.006%	0.047%
	Total Allocation	**WA-2**	**WA-4**	**WA-6.1**	**WA-7**	**SFR**	**MFR**	**Landscape**
Goal Allocation	**100.0%**	**0.541%**	**0.172%**	**29.900%**	**5.189%**	**54.443%**	**1.047%**	**8.708%**

	Total Allocation	WA-2	WA-4	WA-6.1	WA-7	SFR	MFR	Landscape
FY 2017/18	$ 12,614,081	68,204	21,652	3,771,664	654,584	6,867,464	132,111	1,098,403
FY 2018/19	$ 12,883,628	69,661	22,115	3,852,260	668,571	7,014,213	134,934	1,121,874
FY 2019/20	$ 13,140,546	71,050	22,556	3,929,079	681,904	7,154,087	137,625	1,144,246
FY 2020/21	$ 13,366,308	72,271	22,943	3,996,583	693,619	7,276,998	139,989	1,163,905
FY 2021/22	$ 13,540,800	73,215	23,243	4,048,757	702,674	7,371,996	141,817	1,179,099

Supply 4 Costs

Allocation Factor	Supply 4	Temp Service WA-2	Riv. Water Co. Irr. WA-4	Comm & Ind WA-6.1 and WA-6.2	City Irrigation WA-7 and WA-10	SFR	MFR	Landscape
Baseline Allocation		**0.570%**	**0.181%**	**31.537%**	**0.000%**	**57.423%**	**1.105%**	**9.184%**
Interruptable		No	No	No	Yes	No	No	No
Interruptable Adjustment		0.000%	0.000%	0.000%	-8.350%	0.000%	0.000%	0.000%
Effective Allocation Adjustment		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Baseline Allocation With Adjustment		**0.570%**	**0.181%**	**31.537%**	**0.000%**	**57.423%**	**1.105%**	**9.184%**
Reallocation to Non-Interruptable		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
	Total Allocation	**WA-2**	**WA-4**	**WA-6.1**	**WA-7**	**SFR**	**MFR**	**Landscape**
Goal Allocation	**100.0%**	**0.570%**	**0.181%**	**31.537%**	**0.000%**	**57.423%**	**1.105%**	**9.184%**

	Total Allocation	WA-2	WA-4	WA-6.1	WA-7	SFR	MFR	Landscape
FY 2017/18	$ 4,558,819	25,998	8,253	1,437,714	-	2,617,796	50,359	418,698
FY 2018/19	$ 4,656,235	26,554	8,430	1,468,436	-	2,673,735	51,435	427,645
FY 2019/20	$ 4,749,087	27,084	8,598	1,497,719	-	2,727,053	52,461	436,173
FY 2020/21	$ 4,830,679	27,549	8,746	1,523,450	-	2,773,905	53,362	443,667
FY 2021/22	$ 4,893,742	27,909	8,860	1,543,338	-	2,810,118	54,059	449,459

Base Costs

Allocation Factor	Estimated Total Usage	Temp Service WA-2	Riv. Water Co. Irr. WA-4	Comm & Ind WA-6.1 and WA-6.2	City Irrigation WA-7 and WA-10	SFR	MFR	Landscape
Baseline Allocation		**0.204%**	**0.117%**	**29.804%**	**3.645%**	**58.698%**	**1.750%**	**5.782%**
FY 2017/18	17,464,912	35,713	20,430	5,205,326	636,546	10,251,539	305,556	1,009,803
FY 2018/19	17,838,115	36,476	20,866	5,316,557	650,148	10,470,602	312,086	1,031,381
FY 2019/20	18,193,833	37,203	21,283	5,422,576	663,113	10,679,400	318,309	1,051,948
FY 2020/21	18,506,412	37,842	21,648	5,515,739	674,505	10,862,878	323,778	1,070,021
FY 2021/22	18,748,007	38,336	21,931	5,587,745	683,311	11,004,689	328,004	1,083,990

Summary	Costs	Temp Service WA-2	Riv. Water Co. Irr. WA-4	Comm & Ind WA-6.1 and WA-6.2	City Irrigation WA-7 and WA-10	SFR	MFR	Landscape
Overall Customer All	**100.0%**	0.4%	0.1%	28.5%	2.9%	60.8%	1.5%	5.7%
FY 2017/18	$ 63,124,885	$ 250,428	$ 72,173	$ 18,003,000	$ 1,853,304	$ 38,399,097	$ 974,794	$ 3,572,087
FY 2018/19	$ 67,325,380	$ 274,445	$ 75,899	$ 19,031,765	$ 1,939,381	$ 41,231,483	$ 1,040,162	$ 3,732,245
FY 2019/20	$ 71,845,588	$ 300,718	$ 79,846	$ 20,128,990	$ 2,029,844	$ 44,295,573	$ 1,110,534	$ 3,900,082
FY 2020/21	$ 76,625,831	$ 329,095	$ 83,934	$ 21,275,695	$ 2,122,507	$ 47,558,280	$ 1,184,995	$ 4,071,324
FY 2021/22	$ 81,584,713	$ 359,303	$ 88,061	$ 22,447,524	$ 2,214,731	$ 50,971,961	$ 1,262,291	$ 4,240,841

Summary	Costs	Temp Service WA-2	Riv. Water Co. Irr. WA-4	Comm & Ind WA-6.1 and WA-6.2	City Irrigation WA-7 and WA-10	SFR	MFR	Landscape
Overall Customer All	**100.0%**	0.3%	0.1%	30.8%	3.4%	57.0%	1.5%	6.7%
FY 2017/18	$ 45,449,917	$ 134,731	$ 58,638	$ 14,010,922	$ 1,565,243	$ 25,929,136	$ 698,740	$ 3,052,508
FY 2018/19	$ 46,421,124	$ 137,610	$ 59,891	$ 14,310,318	$ 1,598,690	$ 26,483,208	$ 713,671	$ 3,117,736
FY 2019/20	$ 47,346,827	$ 140,354	$ 61,085	$ 14,595,686	$ 1,630,570	$ 27,011,321	$ 727,902	$ 3,179,908
FY 2020/21	$ 48,160,270	$ 142,766	$ 62,134	$ 14,846,447	$ 1,658,584	$ 27,475,390	$ 740,408	$ 3,234,541
FY 2021/22	$ 48,788,986	$ 144,629	$ 62,946	$ 15,040,263	$ 1,680,236	$ 27,834,072	$ 750,074	$ 3,276,766

Summary	Costs	Temp Service WA-2	Riv. Water Co. Irr. WA-4	Comm & Ind WA-6.1 and WA-6.2	City Irrigation WA-7 and WA-10	SFR	MFR	Landscape
Overall Customer All	**100.0%**	0.7%	0.1%	22.6%	1.6%	70.6%	1.6%	2.9%
FY 2017/18	$ 17,674,968	$ 115,697	$ 13,536	$ 3,992,078	$ 288,061	$ 12,469,961	$ 276,055	$ 519,580
FY 2018/19	$ 20,904,257	$ 136,835	$ 16,009	$ 4,721,447	$ 340,691	$ 14,748,274	$ 326,491	$ 614,509
FY 2019/20	$ 24,498,761	$ 160,364	$ 18,761	$ 5,533,304	$ 399,273	$ 17,284,252	$ 382,631	$ 720,174
FY 2020/21	$ 28,465,561	$ 186,330	$ 21,799	$ 6,429,248	$ 463,923	$ 20,082,891	$ 444,586	$ 836,784
FY 2021/22	$ 32,795,727	$ 214,674	$ 25,115	$ 7,407,262	$ 534,495	$ 23,137,889	$ 512,217	$ 964,075

		$0.3 M WA-2	$0.08 M WA-4	$20.18 M WA-6	$2.03 M WA-7	$44.49 M SFR	$1.11 M MFR	$3.9 M Landscape
Percent Fixed	34.5%	54%	24%	28%	20%	39%	35%	19%
Percent Variable	65.5%	46%	76%	72%	80%	61%	65%	81%
Total	**100.0%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Appendix D – OUTSIDE CITY SUCHARGE CALCULATION

Outside City Costs

Appendix D, *Outside City Costs,* presents a summary of all costs associated with providing service to customers with accounts outside of the City's standard service area boundaries. The costs summarized within the appendix include pipeline capital costs, other facility capital costs, water distribution costs, and energy costs.

Outside City Surcharge

Appendix D, *Outside City Surcharge,* takes the additional costs calculated in Appendix *Outside City Costs* and calculates the overall percent increase in rates to be charged to customers residing outside of the City's standard service area boundaries.

Results - Capital Cost

ORIGINAL SUMMARY FROM RPU - File: "RPU Wheeling Cost - Outside City Customers Summarized for Carollo.xls"

TABLE 1 - Wheeling Costs

Active Interconnections	Praed 1400 Zone	University City 1600 Zone	Homegardens 925 Zone	Highgrove Zones	University City 1650 Zone	Van Buren 1200 Zone	Victoria 1100 Zone	Total
Number of Services	**333**	**115**	**1,601**	**949**	**73**	**238**	**740**	**4,049**
Estimated Flows to Customers (gpm)[1]	394	110	1020	444	10	83	536	2596
Pipeline Associated Capital Costs[2]	**$8,719,460**	**$2,228,267**	**$23,944,933**	**$15,365,326**	**$1,957,947**	**$5,116,324**	**$12,690,105**	**$70,022,362**
Inside City Transmission	$1,202,540	$296,316	$3,144,430	$502,160	$25,996	$168,021	$660,870	$6,000,333
Outside City Distribution	$7,516,920	$1,931,951	$20,800,502	$14,863,166	$1,931,951	$4,948,303	$12,029,235	$64,022,029
Facility Associated Capital Costs[2]	**$3,929,844**	**$1,148,100**	**$9,687**	**$2,017,353**	**$240,735**	**$493,289**	**$150,745**	**$7,989,752**
Inside City Pump/PRV & Resevoir Capital Cost	$2,346,078	$998,100	$9,687	$1,567,353	$90,735	$493,289	$150,745	$5,655,986
Outside City Pump/PRV Capital Cost	$1,583,766	$150,000	$0	$450,000	$150,000	$0	$0	$2,333,766
Total Capital Cost	**$12,649,305**	**$3,376,368**	**$23,954,620**	**$17,382,678**	**$2,198,682**	**$5,609,613**	**$12,840,850**	**$78,012,114**

Total Capital Cost for Outside City Customers $78,012,114

Notes:
1. Delivered flows to Customers obtained from 2013 Draft IWMP and Hydraulic Water Model
2. Capital cost of water facilities is charged to Customer based on proportion of Customer flow rates. Unit costs obtained from 2013 IWMP construction costs with 50% Markup for Engineering, Contract Administration, & Contingency.

O&M Costs (from RPU's FY 14-15 Financial Statement)

Operations	$25,793,000
Maintenance	$4,745,000
Production (AF)	$65,259
Production (CCF)	$28,426,748
O&M/AF	$467.95
O&M/CCF	$1.07

	Total	Applicable to Surcharge	Notes:	Applicable Capital Costs	Annual Cost Calculation	
Number of Services	**4,049**					
Estimated Flows to Customers (gpm)[1]	2596					
					Amortization	**Annualized Cost**
Pipeline Associated Capital Costs[2]	**$70,022,362**					
Inside City Transmission	$6,000,333	0%	Included in Base Rates	$0	(Years)	(2015 Dollars)
Outside City Distribution	$64,022,029	100%	All for Outside City	$64,022,029		
			Total Pipeline Costs	**$64,022,029**	50.00	$1,280,441
Facility Associated Capital Costs[2]	**$7,989,752**					
Inside City Pump/PRV & Resevoir Capita	$5,655,986	0%	Included in Base Rates	$0		
Outside City Pump/PRV Capital Cost	$2,333,766	100%	All for Outside City	$2,333,766		
			Total Facilities Costs	**$2,333,766**	30.00	$77,792
Total Capital Cost	**$78,012,114**					
				Total Annualized Capital Costs		**$1,358,233**

	Capital	Annual
FY 2015/16		$1,358,233
FY 2016/17	2.85%	$1,396,942
FY 2017/18	2.85%	$1,436,755
FY 2018/19	2.85%	$1,477,703
FY 2019/20	2.85%	$1,519,817
FY 2020/21	2.85%	$1,563,132
FY 2021/22	2.85%	$1,607,681

Operational Costs	Praed 1400 Zone	University City 1600	Homegardens 925 Zone	Highgrove Zones	University City 1650	Van Buren 1200 Zone	Victoria 1100 Zone	Total
Usage (GPM) - 2013	394	110	1,020	444	10	83	536	2,596
Energy Reqired (KWhr)	408,286	164,869	-	226,504	15,600	44,399	148,896	1,008,553

RPU Total Water Sales	AFY	Adjustment	Cost
2013 Total Sales	27,977		
FY 2015/16	21,901	-22%	$0.070
FY 2016/17	25,253	-10%	$0.071
FY 2017/18	26,878	-4%	$0.073
FY 2018/19	27,103	-3%	$0.074
FY 2019/20	27,342	-2%	$0.076
FY 2020/21	27,588	-1%	$0.077
FY 2021/22	27,838	0%	$0.079

Adjusted Energy Required	Praed 1400 Zone	University City 1600	Homegardens 925 Zone	Highgrove Zones	University City 1650	Van Buren 1200 Zone	Victoria 1100 Zone	Total
FY 2017/18	392,241	158,389	-	217,602	14,987	42,654	143,044	968,917
FY 2018/19	395,536	159,720	-	219,430	15,113	43,012	144,246	977,057
FY 2019/20	399,025	161,129	-	221,366	15,246	43,392	145,518	985,676
FY 2020/21	402,604	162,574	-	223,351	15,383	43,781	146,823	994,515
FY 2021/22	406,264	164,052	-	225,381	15,523	44,179	148,158	1,003,556

Energy Cost ($)	Praed 1400 Zone	University City 1600	Homegardens 925 Zone	Highgrove Zones	University City 1650	Van Buren 1200 Zone	Victoria 1100 Zone	Total
FY 2017/18	$28,566	$11,535	$0	$15,848	$1,091	$3,106	$10,418	**$70,564**
FY 2018/19	$29,382	$11,865	$0	$16,300	$1,123	$3,195	$10,715	**$72,580**
FY 2019/20	$30,234	$12,209	$0	$16,773	$1,155	$3,288	$11,026	**$74,685**
FY 2020/21	$31,115	$12,565	$0	$17,262	$1,189	$3,384	$11,347	**$76,862**
FY 2021/22	$32,026	$12,932	$0	$17,767	$1,224	$3,483	$11,679	**$79,112**

Projected Outside City Costs Summary

	Capital Costs	Energy Costs	Total Outside City Costs
FY 2017/18	$1,436,755	$70,564	**$1,507,320**
FY 2018/19	$1,477,703	$72,580	**$1,550,283**
FY 2019/20	$1,519,817	$74,685	**$1,594,502**
FY 2020/21	$1,563,132	$76,862	**$1,639,994**
FY 2021/22	$1,607,681	$79,112	**$1,686,793**

Projected Outside City Costs Summary

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Capital Costs	$1,436,755	$1,477,703	$1,519,817	$1,563,132	$1,607,681
Energy Costs	$70,564	$72,580	$74,685	$76,862	$79,112
Total Outside City Costs	**$1,507,320**	**$1,550,283**	**$1,594,502**	**$1,639,994**	**$1,686,793**

Surcharge Calculation — Detailed Calculations Below

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Variable Revenue Without Surcharge	$ 2,326,372	$ 2,374,117	$ 2,418,892	$ 2,466,991	$ 2,497,696
Annual Fixed Revenue Without Surcharge	$ 907,603	$ 1,071,354	$ 1,252,899	$ 1,452,755	$ 1,670,330
Total Revenue Without Surcharge	**$ 3,233,975**	**$ 3,445,471**	**$ 3,671,791**	**$ 3,919,746**	**$ 4,168,026**
Surcharge Costs to Collect	**$1,507,320**	**$1,550,283**	**$1,594,502**	**$1,639,994**	**$1,686,793**
Required Percentage Surcharge	**47%**	**45%**	**43%**	**42%**	**40%**

Five Year Combined Surcharge Calculation

Total Revenue Without Surcharge	FY 2017/18 through FY 2021/22	$ 18,439,009
Surcharge Costs to Collect	FY 2017/18 through FY 2021/22	$7,978,892
Required Percentage Surcharge		**43%**

Outside City Usage And Revenues

Outside City Percent of Consumption

Month	**FY 2015/16**
Landscape	**6.8%**
MFR	**1.6%**
SFR	**6.6%**
WA-4	**1.7%**
WA-6.1 and WA-6.2	**2.7%**

Source: RPU with Tiering Phase 2.xlsx

Projected Usage - Usage From Rate Design X Outside City Percent of Consumption

Landscape		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Winter	Tier 1	48,590	48,600	48,740	48,872	48,987
Winter	Tier 2	-	-	-	-	-
Winter	Tier 3	-	-	-	-	-
Winter	Tier 4	-	-	-	-	-
Summer	Tier 1	55,624	55,635	55,795	55,946	56,078
Summer	Tier 2	-	-	-	-	-
Summer	Tier 3	-	-	-	-	-
Summer	Tier 4	-	-	-	-	-

Projected Usage - Usage From Rate Design X Outside City Percent of Consumption

MFR		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Winter	Tier 1	2,272	2,195	2,130	2,066	2,001
Winter	Tier 2	1,629	1,574	1,528	1,482	1,435
Winter	Tier 3	-	-	-	-	-
Winter	Tier 4	-	-	-	-	-
Summer	Tier 1	1,694	1,637	1,589	1,541	1,492
Summer	Tier 2	1,800	1,739	1,688	1,637	1,585
Summer	Tier 3	-	-	-	-	-
Summer	Tier 4	-	-	-	-	-

Projected Usage - Usage From Rate Design X Outside City Percent of Consumption

SFR		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Winter	Tier 1	228,337	220,722	214,215	207,777	201,317
Winter	Tier 2	219,168	211,859	205,614	199,434	193,233
Winter	Tier 3	62,603	60,515	58,731	56,966	55,195
Winter	Tier 4	-	-	-	-	-
Summer	Tier 1	172,100	166,361	161,457	156,604	151,735
Summer	Tier 2	249,257	240,944	233,841	226,813	219,761
Summer	Tier 3	107,088	103,517	100,465	97,446	94,416
Summer	Tier 4	-	-	-	-	-

WA-4		Projected Usage - Usage From Rate Design X Outside City Percent of Consumption				
		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Winter	Tier 1	57	56	54	53	51
Winter	Tier 2	76	75	73	71	69
Winter	Tier 3	102	100	97	95	93
Winter	Tier 4	-	-	-	-	-
Summer	Tier 1	47	46	44	43	42
Summer	Tier 2	92	91	88	86	84
Summer	Tier 3	133	131	127	124	121
Summer	Tier 4	-	-	-	-	-

WA-6.1 and WA-6.2		Projected Usage - Usage From Rate Design X Outside City Percent of Consumption				
		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Winter	Tier 1	109,984	110,006	110,323	110,621	110,882
Winter	Tier 2					
Winter	Tier 3					
Winter	Tier 4					
Summer	Tier 1	103,036	103,057	103,354	103,633	103,878
Summer	Tier 2					
Summer	Tier 3					
Summer	Tier 4					

Proposed Rates

Landscape		Proposed Rates				
		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Winter	Tier 1	$1.75	$1.78	$1.81	$1.84	$1.86
Winter	Tier 2					
Winter	Tier 3					
Winter	Tier 4					
Summer	Tier 1	$2.24	$2.28	$2.32	$2.36	$2.38
Summer	Tier 2					
Summer	Tier 3					
Summer	Tier 4					

MFR		Proposed Rates				
		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Winter	Tier 1	$1.20	$1.27	$1.33	$1.39	$1.46
Winter	Tier 2	$1.72	$1.82	$1.91	$2.01	$2.10
Winter	Tier 3					
Winter	Tier 4					
Summer	Tier 1	$1.20	$1.27	$1.33	$1.39	$1.46
Summer	Tier 2	$1.95	$2.07	$2.17	$2.28	$2.38
Summer	Tier 3					
Summer	Tier 4					

SFR		Proposed Rates				
		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Winter	Tier 1	$1.20	$1.27	$1.33	$1.40	$1.46
Winter	Tier 2	$1.51	$1.59	$1.67	$1.76	$1.84
Winter	Tier 3	$2.77	$2.93	$3.08	$3.23	$3.38
Winter	Tier 4					
Summer	Tier 1	$1.20	$1.27	$1.33	$1.40	$1.46
Summer	Tier 2	$1.51	$1.59	$1.67	$1.76	$1.84
Summer	Tier 3	$3.38	$3.58	$3.76	$3.94	$4.12
Summer	Tier 4					

WA-4		**Proposed Rates**				
			FY 2017/18	**FY 2018/19**	**FY 2019/20**	**FY 2020/21**	**FY 2021/22**
Winter	Tier 1		$1.26	$1.30	$1.37	$1.43	$1.48
Winter	Tier 2		$1.51	$1.57	$1.65	$1.72	$1.78
Winter	Tier 3		$2.35	$2.43	$2.56	$2.67	$2.77
Winter	Tier 4						
Summer	Tier 1		$1.26	$1.30	$1.37	$1.43	$1.48
Summer	Tier 2		$1.51	$1.57	$1.65	$1.72	$1.78
Summer	Tier 3		$3.02	$3.13	$3.30	$3.44	$3.56
Summer	Tier 4						

WA-6.1 and WA-6.2		**Proposed Rates**					
			FY 2017/18	**FY 2018/19**	**FY 2019/20**	**FY 2020/21**	**FY 2021/22**
Winter	Tier 1		$1.66	$1.69	$1.72	$1.75	$1.77
Winter	Tier 2						
Winter	Tier 3						
Winter	Tier 4						
Summer	Tier 1		$1.93	$1.97	$2.00	$2.03	$2.05
Summer	Tier 2						
Summer	Tier 3						
Summer	Tier 4						

Variable Revenue Under Proposed Rates - Without Surcharge					
	FY 2017/18	**FY 2018/19**	**FY 2019/20**	**FY 2020/21**	**FY 2021/22**
Landscape	$ 209,630	$ 213,356	$ 217,665	$ 221,957	$ 224,583
MFR	11,070	11,330	11,526	11,722	11,888
SFR	1,723,213	1,759,453	1,792,173	1,828,262	1,850,916
WA-4	1,024	1,046	1,065	1,085	1,098
WA-6.1 and WA-6.2	381,434	388,932	396,463	403,963	409,212
Total Variable Revenue Without Surcharge	**$ 2,326,372**	**$ 2,374,117**	**$ 2,418,892**	**$ 2,466,991**	**$ 2,497,696**

Fixed Revenue Under Proposed Rates - Without Surcharge

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Outside City Accounts					
Meter Size	**Projected Outside City Accounts**				
5/8"	391	394	396	399	401
3/4"	2,747	2,764	2,781	2,799	2,817
1"	631	636	641	645	650
1.5"	76	78	79	81	82
2"	23	24	24	25	25
3"	1	1	1	1	1
4"	2	2	2	2	2
6"	1	1	1	1	1
8"	1	1	1	1	1
10"	-	-	-	-	-
Total	**3,875**	**3,901**	**3,927**	**3,955**	**3,983**
Proposed Rates					
Meter Size					
5/8"	$16.40	$19.21	$22.29	$25.64	$29.24
3/4"	$16.40	$19.21	$22.29	$25.64	$29.24
1"	$26.04	$30.50	$35.38	$40.69	$46.40
1.5"	$49.92	$58.47	$67.82	$77.99	$88.93
2"	$78.70	$92.16	$106.91	$122.93	$140.16
3"	$145.89	$170.85	$198.17	$227.87	$259.80
4"	$241.86	$283.23	$328.52	$377.75	$430.67
6"	$529.61	$620.20	$719.36	$827.16	$943.03
8"	$865.28	$1,013.27	$1,175.29	$1,351.40	$1,540.69
10"	$1,344.83	$1,574.84	$1,826.63	$2,100.35	$2,394.54
Total Annual Fixed Revenue Without Surcharge	**$ 907,603**	**$ 1,071,354**	**$ 1,252,899**	**$ 1,452,755**	**$ 1,670,330**

Surcharge Calculation

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Variable Revenue Without Surcharge	$ 2,326,372	$ 2,374,117	$ 2,418,892	$ 2,466,991	$ 2,497,696
Annual Fixed Revenue Without Surcharge	$ 907,603	$ 1,071,354	$ 1,252,899	$ 1,452,755	$ 1,670,330
Total Revenue Without Surcharge	**$ 3,233,975**	**$ 3,445,471**	**$ 3,671,791**	**$ 3,919,746**	**$ 4,168,026**
Surcharge Costs to Collect	**$1,507,320**	**$1,550,283**	**$1,594,502**	**$1,639,994**	**$1,686,793**
Required Percentage Surcharge	**47%**	**45%**	**43%**	**42%**	**40%**

Five Year Combined Surchage Calculation

Total Revenue Without Surcharge	FY 2017/18 through FY 2021/22	$ 18,439,009
Surchage Costs to Collect	FY 2017/18 through FY 2021/22	$7,978,892
Required Percentage Surcharge		**43%**

Allocation By Customer Class

	Five Year Sum	
Variable Revenue Without Surcharge		
Landscape	$ 1,087,191	
MFR	$ 57,537	
SFR	$ 8,954,017	
WA-4	$ 5,319	
Commercial and Industrial	$ 1,980,004	
Fixed Revenue Without Surcharge		
Landscape	$ 235,259	
MFR	$ 33,219	
SFR	$ 5,495,276	
WA-4	$ 4,296	
Commercial and Industrial	$ 586,891	
Total Without Surcharge		
Landscape	$ 1,322,450	7.2%
MFR	$ 90,756	0.5%
SFR	$ 14,449,293	78.4%
WA-4	$ 9,615	0.1%
Commercial and Industrial	$ 2,566,895	13.9%
Total	**$ 18,439,009**	**100.0%**

APPENDIX E – COST OF WATER ALLOCATION

Cost of Water

Appendix E, *Cost of Water Allocation,* summarizes all of the costs associated with supplying any of the four sources of water. Included in the summary are purchase costs, distribution costs, and other costs. The costs associated with each of the four sources are then summarized. In conjunction with the total quantity of water, CCF, to be provided by each source, the unique unit cost of providing water from each source is determined.

	Supply 1	Supply 1	Supply 1	Supply 2	Supply 3	Supply 4	Base
	Gage	Rialto/ Colton	Gage + Rialto/Colton	Riverside South/North	Waterman	Flume	Distribution
Production							**RPU Retail**
FY 2013/14	34,095		34,095	25,279	26,022	7,165	65,854
FY 2014/15	32,580	444	33,024	22,730	23,680	4,130	59,265
2-Year Sum	**66,674**	**444**	**67,118**	**48,009**	**49,702**	**11,294**	**125,119**
Costs							
FY 2013/14	$2,088,698		$2,088,698	$2,345,121	$3,326,882	$1,381,365	$5,088,701
FY 2014/15	$2,218,232	$14,553	$2,232,786	$2,270,867	$3,347,092	$1,255,660	$4,374,944
2-Year Sum	**$4,306,930**	**$14,553**	**$4,321,483**	**$4,615,987**	**$6,673,974**	**$2,637,026**	**$9,463,645**
		Total Allocation	**16%**	**17%**	**24%**	**10%**	**34%**
		Supply Only	**24%**	**25%**	**37%**	**14%**	
Unit Cost							
FY 2013/14			$61.26	$92.77	$127.85	$192.80	$77.27
FY 2014/15			$67.61	$99.91	$141.35	$304.06	$73.82
2-Year Average			**$64.39**	**$96.15**	**$134.28**	**$233.48**	**$75.64**
Potable Production							
FY 2013/14			27,514	17,019	26,022	6,041	76,596
FY 2014/15			27,495	15,319	23,680	3,642	70,136
2-Year Sum			**55,009**	**32,338**	**49,702**	**9,683**	
Water Loss Above Linden-Evans							
FY 2013/14			(597)	(369)	(565)	(131)	(1,662)
FY 2014/15			(634)	(353)	(546)	(84)	(1,617)
2-Year Sum			**(1,231)**	**(722)**	**(1,111)**	**(215)**	

	Supply 1	Supply 2	Supply 3	Supply 4	Base
Potable Adjustments					
Potable Wheeled to WMWD					
FY 2013/14	(1,702)	(1,053)	(1,610)	(374)	(4,739)
FY 2014/15	(1,912)	(1,065)	(1,646)	(253)	(4,876)
2-Year Sum	**(3,614)**	**(2,118)**	**(3,256)**	**(627)**	**(9,615)**
Wholesale to WMWD					
FY 2013/14	-	-	-	-	-
FY 2014/15	-	-	-	-	-
2-Year Sum	**-**	**-**	**-**	**-**	
Sales to Home Gardens					
FY 2013/14	(166)	(103)	(157)	(37)	(463)
FY 2014/15	(158)	(88)	(136)	(21)	(402)
2-Year Sum	**(324)**	**(191)**	**(293)**	**(57)**	
Delivered to UCR					
FY 2013/14	(328)	(203)	(311)	(72)	(914)
FY 2014/15	(352)	(196)	(303)	(47)	(897)
2-Year Sum	**(680)**	**(399)**	**(613)**	**(119)**	
Water Loss Below Linden-Evans					
FY 2013/14	(1,393)	(862)	(1,318)	(306)	(3,879)
FY 2014/15	(1,558)	(868)	(1,342)	(206)	(3,975)
2-Year Sum	**(2,952)**	**(1,730)**	**(2,660)**	**(512)**	
Available For Potable Use (Estimated)					
FY 2013/14	23,327	14,429	22,062	5,122	64,939
FY 2014/15	22,882	12,749	19,707	3,031	58,369
2-Year Sum	**46,209**	**27,178**	**41,769**	**8,153**	

	Supply 1	Supply 2	Supply 3	Supply 4
Potable Supply Costs				
FY 2013/14	$1,429,031	$1,338,580	$2,820,574	$987,453
FY 2014/15	$1,547,088	$1,273,684	$2,785,568	$921,593
2-Year Sum	**$2,976,119**	**$2,612,264**	**$5,606,142**	**$1,909,047**
Distribution Costs				
FY 2013/14	$1,802,506	$1,114,954	$1,704,762	$395,760
FY 2014/15	$1,689,144	$941,116	$1,454,771	$223,745
2-Year Sum	**$3,491,650**	**$2,056,071**	**$3,159,533**	**$619,505**
Calculated Potable Costs				
FY 2013/14	$3,231,538	$2,453,535	$4,525,336	$1,383,213
FY 2014/15	$3,236,232	$2,214,800	$4,240,339	$1,145,338
2-Year Sum	**$6,467,769**	**$4,668,335**	**$8,765,675**	**$2,528,551**
Percentage Allocations				
Supply With Distribution	**29%**	**21%**	**39%**	**11%**
Supply Only	**23%**	**20%**	**43%**	**15%**
Overall Unit Rate	$139.97	$171.77	$209.86	$310.15
Average Available AF	15,403	9,059	13,923	2,718
Average Available CCF	**6,709,503**	**3,946,209**	**6,064,833**	**1,183,755**

Supply Allocation

Appendix F, *Supply Allocation,* presents an estimate of the percent of each water supply that is used by each customer class. This distribution of the water supplies amongst the customer class also incorporates an allocation between each customer class's tiers. The cheapest of the water sources is allocated first to the lower tiers, while each progressively more expensive source is allocated as needed to meet the demands associated with each tier. The distribution of each water source's capacity is later used to calculate the value of water demanded by each tier within each customer class.

Class Allocation		Step 1		Supply 1	Supply 2	Supply 3	Supply 4	Total
Total Available for RPU Retial	**CCF**			**10,600,472**	**6,234,691**	**9,581,946**	**1,870,238**	28,287,348
Dedicated Supply		**Five Year Avg Accounts or DUs**	**Indoor Usage Monthly CCF**					
SFR	Indoor (Tier 1)	59,650	9	5,749,408				5,749,408
MFR	Indoor (Tier 1)	2,975	7	249,932				249,932
WA-4	Indoor	38	9	4,104				4,104
Total Dedicated				**6,003,445**	**0**	**0**	**0**	**6,003,445**

Annualized 3-Month Minimum		Step 2		Supply 1	Supply 2	Supply 3	Supply 4	Total	
Remaining Available Before Allocation				**4,597,028**	**6,234,691**	**9,581,946**	**1,870,238**	**22,283,903**	
Amount to be Allocated				**4,597,028**	**6,234,691**	**1,970,809**	**0**		
Allocated	**Annualized 3 Month Min**	**Less Dedicated Allocation**	**Remaining**						**Subtotal Allocated**
WA-2: Temprorary Service	8,364	0	**8,364**	3,003	4,073	1,288	0	8,364	8,364
WA-4: Riverside Water Company	14,426	-4,104	**10,322**	3,706	5,027	1,589	0	10,322	14,426
WA-6: Commercial and Industria	6,245,894	0	**6,245,894**	2,242,725	3,041,682	961,487	0	6,245,894	6,245,894
WA-7: City Irrigation	493,359	0	**493,359**	177,151	240,260	75,947	0	493,359	493,359
SFR	10,764,668	-5,749,408	**5,015,260**	1,800,839	2,442,377	772,044	0	5,015,260	10,764,668
MFR	366,394	-249,932	**116,462**	41,818	56,716	17,928	0	116,462	366,394
Landscape	912,867	0	**912,867**	327,785	444,556	140,526	0	912,867	912,867
Total	**18,805,972**		**12,802,528**	**4,597,028**	**6,234,691**	**1,970,809**	**0**	**12,802,528**	**18,805,972**
			Remaining to Allocate	**0**	**0**	**7,611,137**	**1,870,238**	**9,481,375**	

Annualized Winter		Step 3		Supply 1	Supply 2	Supply 3	Supply 4	Total	
Remaining Available Before Allocation				**0**	**0**	**7,611,137**	**1,870,238**	**9,481,375**	
Amount to be Allocated				**0**	**0**	**2,985,580**	**0**		
Allocated	**Annualized Winter Usage**	**Less Previously Allocated**	**Remaining**						**Subtotal Allocated**
WA-2: Temprorary Service	48,889	-8,364	**40,525**	0	0	40,525	0	0	48,889
WA-4: Riverside Water Company	22,059	-14,426	**7,632**	0	0	7,632	0	0	22,059
WA-6: Commercial and Industria	6,978,503	-6,245,894	**732,609**	0	0	732,609	0	0	6,978,503
WA-7: City Irrigation	721,992	-493,359	**228,633**	0	0	228,633	0	0	721,992
SFR	12,400,070	-10,764,668	**1,635,402**	0	0	1,635,402	0	0	12,400,070
MFR	397,493	-366,394	**31,099**	0	0	31,099	0	0	397,493
Landscape	1,222,547	-912,867	**309,680**	0	0	309,680	0	0	1,222,547
Total	**21,791,553**		**2,985,580**	**0**	**0**	**2,985,580**	**0**	**0**	**21,791,553**
			Remaining to Allocate	**0**	**0**	**4,625,557**	**1,870,238**	**6,495,795**	

Remaining Usage	Total Usage	Less Previously Allocated	Remaining (Step 4)	Supply 1	Supply 2	Supply 3	Supply 4	Total	Total Allocated	Total Need (5 Year Average)
Remaining Available Before Allocation				**0**	**0**	**4,625,557**	**1,870,238**	**6,495,795**		
Amount to be Allocated				**0**	**0**	**3,834,763**	**0**			
Allocated										
WA-2: Temprorary Service	54,094	-48,889	**5,204**	0	0	5,204	0	5,204	54,094	53,498
WA-4: Riverside Water Company	27,763	-22,059	**5,705**	0	0	5,705	0	5,705	27,763	28,358
WA-6: Commercial and Industria	7,884,440	-6,978,503	**905,938**	0	0	905,938	0	905,938	7,884,440	7,797,654
WA-7: City Irrigation	964,168	-721,992	**242,176**	0	0	242,176	0	242,176	964,168	953,555
SFR	14,726,777	-12,400,070	**2,326,707**	0	0	2,326,707	0	2,326,707	14,726,777	14,911,366
MFR	439,538	-397,493	**42,045**	0	0	42,045	0	42,045	439,538	444,957
Landscape	1,529,536	-1,222,547	**306,988**	0	0	306,988	0	306,988	1,529,536	1,512,699
Total	**25,626,316**		**3,834,763**	**0**	**0**	**3,834,763**	**0**	**3,834,763**	**25,626,316**	**25,702,087**
			Remaining to Allocate	**0**	**0**	**790,794**	**1,870,238**	**2,661,032**		

Allocated Total By Supply (Step 5)	Supply 1	Supply 2	Supply 3	Supply 4	Total	
WA-2: Temprorary Service	3,003	4,073	47,017	0	54,094	0.21%
WA-4: Riverside Water Company Irrigators	7,810	5,027	14,926	0	27,763	0.11%
WA-6: Commercial and Industrial	2,242,725	3,041,682	2,600,033	0	7,884,440	30.77%
WA-7: City Irrigation	177,151	240,260	546,756	0	964,168	3.76%
SFR	7,550,247	2,442,377	4,734,153	0	14,726,777	57.47%
MFR	291,750	56,716	91,072	0	439,538	1.72%
Landscape	327,785	444,556	757,195	0	1,529,536	5.97%
Total	**10,600,472**	**6,234,691**	**8,791,152**	**0**	**25,626,316**	

Total With Reallocation of Remaining Supply 3 and 4	Supply 1	Supply 2	Supply 3 (Include Resiliency Component)	Supply 4 (Include Resiliency Component)	Total		
WA-2: Temprorary Service	3,003	4,073	51,527	10,666	69,269		
WA-4: Riverside Water Company Irrigators	7,810	5,027	16,358	3,386	32,581		
WA-6: Commercial and Industrial	2,242,725	3,041,682	2,849,426	589,817	8,723,649		
WA-7: City Irrigation	177,151	240,260	546,756	0	964,168	No Resiliency Component, Interruptib	
SFR	7,550,247	2,442,377	5,188,248	1,073,941	16,254,813		
MFR	291,750	56,716	99,808	20,660	468,933		
Landscape	327,785	444,556	829,824	171,769	1,773,934	**Total Supply**	*Check*
Total	**10,600,472**	**6,234,691**	**9,581,946**	**1,870,238**	**28,287,348**	**28,287,348**	*TRUE*

Percent By Supply	Supply 1	Supply 2	Supply 3 (Includes Resiliency Component)	Supply 4 (Includes Resiliency Component)	Total
WA-2: Temprorary Service	0.03%	0.07%	0.54%	0.57%	0.24%
WA-4: Riverside Water Company Irrigators	0.07%	0.08%	0.17%	0.18%	0.12%
WA-6: Commercial and Industrial	21.16%	48.79%	29.74%	31.54%	30.84%
WA-7: City Irrigation	1.67%	3.85%	5.71%	0.00%	3.41%
SFR	71.23%	39.17%	54.15%	57.42%	57.46%
MFR	2.75%	0.91%	1.04%	1.10%	1.66%
Landscape	3.09%	7.13%	8.66%	9.18%	6.27%
Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Appendix G – CUSTOMER DATA AND PROJECTIONS

Customer Data and Projections

Appendix G, *Customer Data and Projections,* consolidates the billing data provided by Riverside Public Utilities as performed within the financial model. The billing data is sorted by a number of variables including the month of consumption, the consumption per customer class, and the consumption per meter size. A number of existing customer classes have been re-categorized within the financial model as shown. This consolidated billing data forms the basis of the financial analysis.

Water Demand Factors	Year	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Usage Projection	Based on Overall change in usage in proforma - includes rebound and elasticity adjustments					
Residential		6.33%	-3.00%	-2.52%	-2.61%	-2.70%
Commercial		4.76%	0.41%	0.72%	0.70%	0.68%
Industrial		6.26%	-1.68%	-1.39%	-1.42%	-1.46%
Other		-1.33%	-1.06%	-2.89%	-1.87%	-1.90%
SFR With WA-3.1 and WA-9.1		6.14%	-2.95%	-2.53%	-2.59%	-2.68%
mmercial With WA-3.2 and WA-9.2		4.51%	0.36%	0.57%	0.60%	0.58%

	FY 2013/14 Use		FY 2013/14 Use
WA-3.1	248,086	**WA-3.2**	20,737
WA 9.1	88,004	**WA 9.2**	103,832
SFR	13,118,634	**Commercial**	2,962,370

		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Account Growth	Based on Proforma					
Residential		0.49%	0.60%	0.61%	0.63%	0.64%
Commercial		1.87%	2.13%	2.14%	2.14%	2.14%
Industrial		0.46%	0.45%	0.45%	0.45%	0.45%
Other		0.00%	0.00%	0.00%	0.00%	0.00%
No Growth		0%	0%	0%	0%	0%

Temporary Service (WA-2)	Meter Ratio	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
5/8"	**1.0**	2	2	2	2	2
3/4"	**1.0**	0	0	0	0	0
1"	**1.7**	0	0	0	0	0
1.5"	**3.3**	2	2	2	2	2
2"	**5.3**	6	6	6	6	6
3"	**10.0**	58	59	60	61	62
4"	**16.7**	2	2	2	2	2
6"	**36.7**	0	0	0	0	0
8"	**60.0**	0	0	0	0	0
10"	**93.3**	0	0	0	0	0
Total Accounts		**70**	**71**	**72**	**73**	**74**
Total EDUs		**654**	**664**	**674**	**684**	**694**

Riverside Water Co. Irrigators (WA-4)	Meter Ratio	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
5/8"	**1.0**	4	4	4	4	4
3/4"	**1.0**	14	14	14	14	14
1"	**1.7**	12	12	12	12	12
1.5"	**3.3**	3	3	3	3	3
2"	**5.3**	5	5	5	5	5
3"	**10.0**	0	0	0	0	0
4"	**16.7**	0	0	0	0	0
6"	**36.7**	0	0	0	0	0
8"	**60.0**	0	0	0	0	0
10"	**93.3**	0	0	0	0	0
Total Accounts		**38**	**38**	**38**	**38**	**38**
Total EDUs		**75**	**75**	**75**	**75**	**75**

Commercial and Industrial	Meter Ratio	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
5/8"	**1.0**	285	291	297	303	309
3/4"	**1.0**	1,091	1,114	1,138	1,162	1,187
1"	**1.7**	1,124	1,148	1,172	1,197	1,223
1.5"	**3.3**	690	705	720	735	751
2"	**5.3**	1,020	1,042	1,064	1,087	1,110
3"	**10.0**	153	156	159	162	165
4"	**16.7**	107	109	111	113	115
6"	**36.7**	70	71	73	75	77
8"	**60.0**	71	73	75	77	79
10"	**93.3**	9	9	9	9	9
Total Accounts		**4,620**	**4,718**	**4,818**	**4,920**	**5,025**
Total EDUs		**21,968**	**22,424**	**22,918**	**23,419**	**23,926**

City Irrigation (WA-7)	Meter Ratio	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
5/8"	**1.0**	3	3	3	3	3
3/4"	**1.0**	118	121	124	127	130
1"	**1.7**	149	152	155	158	161
1.5"	**3.3**	84	86	88	90	92
2"	**5.3**	111	113	115	117	119
3"	**10.0**	15	15	15	15	15
4"	**16.7**	7	7	7	7	7
6"	**36.7**	2	2	2	2	2
8"	**60.0**	0	0	0	0	0
10"	**93.3**	0	0	0	0	0
Total Accounts		**489**	**499**	**509**	**519**	**529**
Total EDUs		**1,581**	**1,607**	**1,632**	**1,657**	**1,683**

SFR	Meter Ratio	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
5/8"	**1.0**	9,632	9,689	9,748	9,808	9,870
3/4"	**1.0**	41,871	42,119	42,374	42,637	42,908
1"	**1.7**	7,135	7,177	7,220	7,265	7,311
1.5"	**3.3**	208	209	210	211	212
2"	**5.3**	85	86	87	88	89
3"	**10.0**	0	0	0	0	0
4"	**16.7**	0	0	0	0	0
6"	**36.7**	0	0	0	0	0
8"	**60.0**	0	0	0	0	0
10"	**93.3**	0	0	0	0	0
Total Accounts		**58,931**	**59,280**	**59,639**	**60,009**	**60,390**
Total EDUs		**64,564**	**64,948**	**65,342**	**65,749**	**66,168**
		0.48%	**0.59%**	**0.61%**	**0.62%**	

MFR	Meter Ratio	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
5/8"	**1.0**	227	228	229	230	231
3/4"	**1.0**	682	686	690	694	698
1"	**1.7**	300	302	304	306	308
1.5"	**3.3**	5	5	5	5	5
2"	**5.3**	3	3	3	3	3
3"	**10.0**	0	0	0	0	0
4"	**16.7**	0	0	0	0	0
6"	**36.7**	0	0	0	0	0
8"	**60.0**	0	0	0	0	0
10"	**93.3**	0	0	0	0	0
Total Accounts		**1,217**	**1,224**	**1,231**	**1,238**	**1,245**
Total EDUs		**1,443**	**1,451**	**1,459**	**1,468**	**1,476**

Landscape	Meter Ratio	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
5/8"	**1.0**	4	4	4	4	4
3/4"	**1.0**	97	99	101	103	105
1"	**1.7**	116	118	121	124	127
1.5"	**3.3**	186	190	194	198	202
2"	**5.3**	218	223	228	233	238
3"	**10.0**	21	21	21	21	21
4"	**16.7**	15	15	15	15	15
6"	**36.7**	2	2	2	2	2
8"	**60.0**	3	3	3	3	3
10"	**93.3**	1	1	1	1	1
Total Accounts		**663**	**676**	**690**	**704**	**718**
Total EDUs		**2,883**	**2,928**	**2,975**	**3,022**	**3,069**

Raw Accounts Projection	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Temporary Service (WA-2)	70	71	73	74	75
Riverside Water Co. Irrigators (WA-4)	38	38	38	38	38
Commercial and Industrial	4,620	4,719	4,819	4,921	5,025
City Irrigation (WA-7)	489	499	510	520	530
SFR	58,939	59,285	59,644	60,014	60,396
MFR	1,218	1,224	1,232	1,239	1,246
Landscape	664	677	690	705	719
Projected Accounts	**66,038**	**66,514**	**67,005**	**67,510**	**68,029**
Proforma Accounts	66,039	66,517	67,008	67,513	68,032
Less: Other Usage	-1	-1	-1	-1	-1
Less: WA-8	-8	-8	-8	-8	-8
Adjust to:	66,030	66,508	66,999	67,504	68,023
Adjustment	**-0.0001**	**-0.0001**	**-0.0001**	**-0.0001**	**-0.0001**

Matched to Proforma	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Temporary Service (WA-2)	70	71	72	73	74
Riverside Water Co. Irrigators (WA-4)	38	38	38	38	38
Commercial and Industrial	4,620	4,718	4,818	4,920	5,025
City Irrigation (WA-7)	489	499	509	519	529
SFR	58,931	59,280	59,639	60,009	60,390
MFR	1,217	1,224	1,231	1,238	1,245
Landscape	663	676	690	704	718
Projected Accounts	**66,028**	**66,506**	**66,997**	**67,501**	**68,019**
Proforma Accounts	66,039	66,517	67,008	67,513	68,032
Less: Other Usage	-1	-1	-1	-1	-1
Less: WA-8	-8	-8	-8	-8	-8
	66,030	66,508	66,999	67,504	68,023
Difference due to Rounding	**-2**	**-2**	**-2**	**-3**	**-4**

MEUs Projection	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Temporary Service (WA-2)	654	664	674	684	694
Riverside Water Co. Irrigators (WA-4)	75	75	75	75	75
Commercial and Industrial	21,968	22,424	22,918	23,419	23,926
City Irrigation (WA-7)	1,581	1,607	1,632	1,657	1,683
SFR	64,564	64,948	65,342	65,749	66,168
MFR	1,443	1,451	1,459	1,468	1,476
Landscape	2,883	2,928	2,975	3,022	3,069
Projected EDUs (Fire excluded)	**93,167**	**94,096**	**95,076**	**96,074**	**97,090**

Raw Usage Projection	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Temporary Service (WA-2)	53,817	54,131	54,306	54,453	54,589
Riverside Water Co. Irrigators (WA-4)	28,998	28,739	27,800	27,164	26,533
Commercial and Industrial	7,844,044	7,889,928	7,915,448	7,936,835	7,956,624
City Irrigation (WA-7)	959,228	964,839	967,959	970,575	972,995
SFR	15,652,168	15,215,653	14,772,289	14,328,261	13,884,619
MFR	467,368	454,107	440,916	427,581	414,257
Landscape	1,521,699	1,530,600	1,535,551	1,539,700	1,543,539
Projected Consumption, CCF	**26,527,320**	**26,137,996**	**25,714,268**	**25,284,569**	**24,853,156**
WA-8	54,643	54,063	52,503	51,523	50,543
Other Usage	74,335	73,546	71,424	70,091	68,758
Total Projected	**26,656,299**	**26,265,605**	**25,838,196**	**25,406,182**	**24,972,456**
Proforma Projection	**26,701,476**	**26,162,350**	**25,727,554**	**25,297,467**	**24,862,300**
	0.0017	**-0.0039**	**-0.0043**	**-0.0043**	**-0.0044**

Usage Projection Matched to PROFORMA	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Temporary Service (WA-2)	53,908	53,919	54,074	54,220	54,348
Riverside Water Co. Irrigators (WA-4)	29,047	28,626	27,681	27,048	26,416
Commercial and Industrial	7,857,338	7,858,911	7,881,553	7,902,873	7,921,527
City Irrigation (WA-7)	960,853	961,046	963,815	966,422	968,703
SFR	15,678,695	15,155,838	14,709,033	14,266,949	13,823,372
MFR	468,160	452,321	439,028	425,752	412,430
Landscape	1,524,278	1,524,583	1,528,975	1,533,111	1,536,730
Projected Consumption, CCF	**26,572,279**	**26,035,243**	**25,604,158**	**25,176,374**	**24,743,526**
WA-8	54,735	53,850	52,278	51,302	50,320
Other Usage	74,461	73,257	71,118	69,791	68,454
Total Projected	**26,701,476**	**26,162,350**	**25,727,554**	**25,297,467**	**24,862,300**
Proforma Projection	**26,701,476**	**26,162,350**	**25,727,554**	**25,297,467**	**24,862,300**
Difference From Proforma	**-**	**-**	**-**	**-**	**-**

Summer Usage	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Temporary Service (WA-2)	25,487	25,492	25,566	25,635	25,695
Riverside Water Co. Irrigators (WA-4)	15,584	15,358	14,851	14,512	14,173
Commercial and Industrial	3,800,538	3,801,299	3,812,251	3,822,563	3,831,586
City Irrigation (WA-7)	541,139	541,248	542,807	544,275	545,560
SFR	7,977,766	7,711,721	7,484,374	7,259,429	7,033,725
MFR	221,190	213,707	207,426	201,154	194,860
Landscape	813,577	813,740	816,084	818,292	820,223
Projected Consumption, CCF	**13,395,281**	**13,122,565**	**12,903,359**	**12,685,859**	**12,465,821**

Winter Usage	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Temporary Service (WA-2)	28,421	28,426	28,508	28,585	28,653
Riverside Water Co. Irrigators (WA-4)	13,462	13,267	12,829	12,536	12,243
Commercial and Industrial	4,056,800	4,057,612	4,069,302	4,080,310	4,089,941
City Irrigation (WA-7)	419,714	419,798	421,008	422,146	423,143
SFR	7,700,929	7,444,117	7,224,659	7,007,520	6,789,647
MFR	246,970	238,615	231,602	224,598	217,571
Landscape	710,701	710,843	712,891	714,820	716,507
Projected Consumption, CCF	**13,176,998**	**12,912,678**	**12,700,799**	**12,490,515**	**12,277,705**

Total	**26,572,279**	**26,035,243**	**25,604,158**	**25,176,374**	**24,743,526**
Check to Totals	**26,572,279**	**26,035,243**	**25,604,158**	**25,176,374**	**24,743,526**
Difference	-	-	-	-	-

Uniform Fixed Rates

Appendix H, *Uniform Fixed Rates* details the final calculation of the fixed monthly rates that are charged to all customers in relation to their meter size. Allocation of costs related to providing service to customers regardless of meter size or customer class are projected and included in the appendix. The same is true for costs related to providing system capacity sufficient to serve all customers. The number of accounts and the number of MEUs as projected by the financial model are included. Customer related expenses are evenly recovered over each account. Capacity related expenses are recovered over each MEU, thereby allocating more in costs to those customers with larger meters and thus requiring more system capacity. Appendix H *Uniform Fixed Rates* presents the resulting fixed charge per meter size over the course of the next five fiscal years (2017/18 - 2021/22).

SFR

Appendix H, *SFR* details the final calculation of the winter and summer rates to be charged to any customers designated as Single-Family Residences (SFR). Using the projections calculated within the financial model for the number of accounts, water usage, and budget forecasts, Appendix H, *SFR* presents the calculated rates for each of the next five fiscal years (2017/18 - 2021/22). The rate structure for customers designated as SFR includes three tiers. Based on the consumption inputs towards the bottom of the appendix, each year's consumption forecast is split between the tiers. Additionally, summer consumption and winter consumption are both forecasted. Based on the resulting seasonal and tiered projections of water consumption, the costs associated with serving SFR customers are allocated between the seasons and tiers. These costs are recovered over each CCF of consumption within each season and tier.

MFR

Appendix H, *MFR* details the final calculation of the winter and summer rates to be charged to any customers designated as Multi-Family Residences (MFR). Using the projections calculated within the financial model for the number of accounts, water usage, and budget forecasts, Appendix H, *MFR* presents the calculated rates for each of the next five fiscal years (2017/18 - 2021/22). The rate structure for customers designated as MFR includes two tiers. Based on the consumption inputs towards the bottom of the appendix, each year's consumption forecast is split between the tiers. Additionally, summer consumption and winter consumption are both forecasted. Based on the resulting seasonal and tiered projections of water consumption, the costs associated with serving MFR customers are allocated between the seasons and tiers. These costs are recovered over each CCF of consumption within each season and tier.

Commercial and Industrial

Appendix H, Co*mmercial and Industrial* details the final calculation of the winter and summer rates to be charged to any customers designated as Commercial and Industrial. Using the projections calculated within the financial model for the number of accounts, water usage, and budget forecasts, Appendix H, Co*mmercial and Industrial* presents the calculated rates for each of the next five fiscal years (2017/18 - 2021/22). The rate structure for customers designated as Commercial and Industrial does not include any tier breaks. However, water consumption is allocated between the winter and summer. As a result, the costs associated with serving Commercial and Industrial customers are allocated over the projected seasonal consumption separately. Once split between the seasons all costs are charged to Commercial and Industrial customers at either the winter rate or the summer rate for each year within the projection.

Landscape

Appendix H, L*andscape* details the final calculation of the winter and summer rates to be charged to any customers designated as Landscape. Using the projections calculated within the financial model for the number of accounts, water usage, and budget forecasts, Appendix H, *Landscape* presents the calculated rates for each of the next five fiscal years (2017/18 - 2021/22). The rate structure for customers designated as Landscape does not include any tier breaks. However, water consumption is allocated between the winter and summer. As a result, the costs associated with serving Landscape customers are allocated over the projected seasonal consumption separately. Once split between the seasons all costs are charged to Landscape customers at either the winter rate or the summer rate for each year within the projection.

Temporary Service (WA-2)

Appendix H, Temporary Service (WA-2) details the final calculation of rates to be charged to any customers designated as Temporary Service (WA-2). These customers are charged based on a uniform, non-seasonally adjusted rate. Using the projections calculated within the financial model for the number of accounts, water usage, and budget forecasts, Appendix H, Temporary Service (WA-2) presents the calculated rates for each of the next five fiscal years (2017/18 - 2021/22).

Riverside Water Company Irrigators (WA-4)

Appendix H, Riverside Water Company Irrigators (WA-4) details the final calculation of the winter and summer rates to be charged to any customers designated as Riverside Water Company Irrigators (WA-4). Using the projections calculated within the financial model for the number of accounts, water usage, and budget forecasts, Appendix H, Riverside Water Company Irrigators (WA-4) presents the calculated rates for each of the next five fiscal years (2017/18 - 2021/22). The rate structure for customers in this class includes three tiers. Based on the consumption inputs towards the bottom of the appendix, each year's consumption forecast is split between the tiers. Additionally, summer consumption and winter consumption are both forecasted. Based on the resulting seasonal and tiered projections of water consumption, the costs associated with serving these customers are allocated between the seasons and tiers. These costs are recovered over each CCF of consumption within each season and tier.

Interruptible City Irrigation and Recycled Water (WA-7)

Appendix H, Interruptible City Irrigation and Recycled Water (*WA-7)* details the final calculation of the rates to be charged to any customers designated as Interruptible City Irrigation and Recycled Water (*WA-7*). Using the projections calculated within the financial model for the number of accounts, water usage, and budget forecasts, Appendix H, Interruptible City Irrigation and Recycled Water (*WA-7)* presents the calculated rates for each of the next five fiscal years (2017/18 - 2021/22). The rate structure for customers designated as Interruptible City Irrigation and Recycled Water (*WA-7)* does not include any tier breaks. These customers are charges based on a uniform, non-seasonally adjusted rate.

Transitional Rates

Appendix H also includes calculations for transitional rates for Irrigation Metered Service (WA-3), Grove Preservation Service (WA-9), and cemeteries currently paying the WA-7 rate. Transitional rates for each class were calculated based on moving customers to the otherwise applicable tariff over the course of the rate plan, with all customers being placed into the appropriate class by FY 2021/22.

Irrigation Metered Service WA-3.1 Transition to SFR

Irrigation Metered Service with residence, WA-3.1, customers are currently charged a two-tiered non-seasonal volumetric rate with a tier break at 100 CCF per month, and a minimum monthly charge. Under the transitional rates, these customers will pay the proposed monthly fixed charge corresponding to their installed water meter size, and a two tiered volumetric rate that maintains the 100 CCF breakpoint. Starting in FY 2021/22, these customers will be assessed the SFR rates.

Grove Preservation WA-9.1 Transition to SFR

Grove Preservation with residence, WA-9.1, customers are currently charged a three-tiered non-seasonal volumetric rate with tier breaks at 15 and 60 CCF per month, and a reduced monthly fixed charge. Under the transitional rates, these customers will pay the proposed monthly fixed charge corresponding to their installed water meter size, and a three-tiered volumetric rate that maintains the current tier breaks. Starting in FY 2021/22, these customers will be assessed the SFR rates.

Irrigation Metered Service WA-3.2 Transition to Commercial and Industrial

Irrigation Metered Service without residence, WA-3.2, customers are currently charged a uniform non-seasonal volumetric rate and a minimum monthly charge. Under the transitional rates, these customers will pay the proposed monthly fixed charge corresponding to their installed water meter size, and a uniform volumetric rate. Starting in FY 2021/22, these customers will be assessed the Commercial and Industrial rates.

Grove Preservation WA-9.2 Transition to Commercial and Industrial

Grove Preservation without residence, WA-9.2, customers are currently charged a uniform non-seasonal volumetric rate and a reduced monthly fixed charge. Under the transitional rates, these customers will pay the proposed monthly fixed charge corresponding to their installed water meter size, and a uniform volumetric rate. Starting in FY 2021/22, these customers will be assessed the Commercial and Industrial rates.

WA-7 Cemeteries Transition to Commercial and Industrial or Landscape

WA-7 Cemetery customers are currently charged a uniform non-seasonal volumetric rate, and a minimum monthly charge. Under the transitional rates, these customers will pay the proposed monthly fixed charge corresponding to their installed water meter size and a uniform volumetric rate. Starting in

FY 2021/22, these customers will be assessed the Commercial and Industrial or Landscape rates depending on their connection characteristics. Specific transitional rates are calculated for each case.

Uniform Fixed Rates by Meter Size	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Number of Accounts	66,028	66,506	66,997	67,501	68,019
Number of MEUs	93,167	94,096	95,076	96,074	97,090
Customer Revenue to Recover	$ 1,589,231	$ 1,879,590	$ 2,202,787	$ 2,559,459	$ 2,948,802
Capacity Revenue to Recover	$ 16,085,737	$ 19,024,667	$ 22,295,974	$ 25,906,102	$ 29,846,925
Monthly Component Charge per Account	$ 2.01	$ 2.36	$ 2.74	$ 3.16	$ 3.61
Monthly Component Charge per MEU	14.39	16.85	19.54	22.47	25.62
Annual Per MEU Cost	189.71	222.16	257.68	296.29	337.79

Meter Size	Meter Equivalents		Monthly Fixed Charges					
5/8"	1.0	1.00	$ 13.99	16.39	19.20	22.28	25.63	29.23
3/4"	1.0	1.00	$ 13.99	16.39	19.20	22.28	25.63	29.23
1"	1.7	1.66	$ 23.29	26.03	30.49	35.38	40.69	46.39
1.5"	3.3	3.33	$ 46.60	49.92	58.46	67.82	77.99	88.92
2"	5.3	5.32	$ 74.49	78.69	92.16	106.90	122.93	140.16
3"	10.0	10.19	$ 142.52	145.88	170.84	198.16	227.87	259.79
4"	16.7	16.98	$ 237.57	241.85	283.22	328.51	377.75	430.66
6"	36.7	33.97	$ 475.19	529.61	620.19	719.36	827.16	943.02
8"	60.0	54.35	$ 760.29	865.28	1,013.27	1,175.28	1,351.40	1,540.69
10"	93.3	78.12	$ 1,092.85	1,344.82	1,574.83	1,826.63	2,100.34	2,394.53
12"	133.3	95.10	$ 1,330.40	1,920.34	2,248.77	2,608.32	2,999.17	3,419.25

NOTE: RATES ARE NOT ROUNDED, THE LAST DIGIT MAY VARY FROM THE PROPOSED RATES PRESENTED WITHIN THE REPORT BODY AND APPENDIX

SFR WA-1

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Allocated Base & Peak Water Costs					
Supply 1	$ 4,339,782	$ 4,432,517	$ 4,520,908	$ 4,598,580	$ 4,658,613
Supply 2	$ 1,852,554	$ 1,892,141	$ 1,929,873	$ 1,963,029	$ 1,988,656
Supply 3	$ 6,867,464	$ 7,014,213	$ 7,154,087	$ 7,276,998	$ 7,371,996
Supply 4	$ 2,617,796	$ 2,673,735	$ 2,727,053	$ 2,773,905	$ 2,810,118
Base	$ 10,251,539	$ 10,470,602	$ 10,679,400	$ 10,862,878	$ 11,004,689
Total Allocated Costs	**$25,929,136**	**$26,483,208**	**$27,011,321**	**$27,475,390**	**$27,834,072**
Projected Annual Consumption (CCF)	15,678,695	15,155,838	14,709,033	14,266,949	13,823,372
Base Unit Cost	$0.65	$0.69	$0.73	$0.76	$0.80
ESTIMATED Projected Summer Consumption (51%)	7,977,766	7,711,721	7,484,374	7,259,429	7,033,725

Tier	Revenue Requirement per Tier				
Tier 1	$7,216,483	$7,370,691	$7,517,673	$7,646,830	$7,746,657
Tier 2	$10,633,750	$10,860,979	$11,077,563	$11,267,881	$11,414,979
Tier 3	$8,078,903	$8,251,539	$8,416,086	$8,560,679	$8,672,436
Tier 4	$0	$0	$0	$0	$0
Total	**25,929,136**	**26,483,208**	**27,011,321**	**27,475,390**	**27,834,072**

Projected Consumption per Block (%)

	Tier	Tier Allocation	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
0	Tier 1	39%	39%	39%	39%	39%	39%
1	Tier 2	45%	45%	45%	45%	45%	45%
2	Tier 3	16%	16%	16%	16%	16%	16%
3	Tier 4		0%	0%	0%	0%	0%
	Total		**100%**	**100%**	**100%**	**100%**	**100%**

Tier	Projected Annual Consumption per Block (CCF)				
Tier 1	6,045,269	5,843,670	5,671,394	5,500,939	5,329,908
Tier 2	7,071,660	6,835,832	6,634,307	6,434,911	6,234,842
Tier 3	2,561,766	2,476,336	2,403,332	2,331,099	2,258,622
Tier 4	-	-	-	-	-
Total	**15,678,695**	**15,155,838**	**14,709,033**	**14,266,949**	**13,823,372**

SEASONAL RATES

Tier	Winter Use per Tier	Projected Winter Consumption per Block (CCF)				
Tier 1	45%	3,447,126	3,332,170	3,233,935	3,136,738	3,039,213
Tier 2	43%	3,308,712	3,198,372	3,104,082	3,010,788	2,917,179
Tier 3	12%	945,091	913,574	886,641	859,993	833,255
Tier 4	0%	-	-	-	-	-
Total		**7,700,929**	**7,444,117**	**7,224,659**	**7,007,520**	**6,789,647**

Tier	Summer Use per Tier	Projected Summer Consumption per Block (CCF)				
Tier 1	33%	2,598,144	2,511,500	2,437,459	2,364,201	2,290,695
Tier 2	47%	3,762,948	3,637,460	3,530,225	3,424,123	3,317,663
Tier 3	20%	1,616,675	1,562,761	1,516,690	1,471,106	1,425,367
Tier 4	0%	-	-	-	-	-
Total		**7,977,766**	**7,711,721**	**7,484,374**	**7,259,429**	**7,033,725**

Tier	Annualized Summer/Annual Average				
Tier 1	1.031	1.031	1.031	1.031	1.031
Tier 2	1.277	1.277	1.277	1.277	1.277
Tier 3	1.515	1.515	1.515	1.515	1.515
Tier 4	-	-	-	-	-
Total	**1.221**	**1.221**	**1.221**	**1.221**	**1.221**

Source	Winter Costs				
Tier 1	$4,114,974	$4,202,906	$4,286,718	$4,360,366	$4,417,289
Tier 2	$4,975,355	$5,081,672	$5,183,008	$5,272,054	$5,340,879
Tier 3	$2,615,947	$2,671,846	$2,725,126	$2,771,946	$2,808,132
Tier 4	$0	$0	$0	$0	$0
Total	**$11,706,275**	**$11,956,424**	**$12,194,852**	**$12,404,366**	**$12,566,300**

Source	Seasonal Peak	Summer Costs				
Tier 1	1.0	$3,101,510	$3,167,785	$3,230,955	$3,286,464	$3,329,368
Tier 2	1.0	$5,658,395	$5,779,307	$5,894,555	$5,995,827	$6,074,100
Tier 3	1.0715	$5,462,956	$5,579,693	$5,690,960	$5,788,733	$5,864,303
Tier 4	1.0	$0	$0	$0	$0	$0
Total		**$14,222,860**	**$14,526,785**	**$14,816,470**	**$15,071,024**	**$15,267,771**

Rates Linked to Model

NOTE: RATES ARE NOT ROUNDED, THE LAST DIGIT MAY VARY FROM THE PROPOSED RATES PRESENTED WITHIN THE REPORT BODY AND APPENDIX

Tier	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Winter Rate ($ per CCF)					
Tier 1	$ 1.19	$ 1.26	$ 1.33	$ 1.39	$ 1.45
Tier 2	$ 1.50	$ 1.59	$ 1.67	$ 1.75	$ 1.83
Tier 3	$ 2.77	$ 2.92	$ 3.07	$ 3.22	$ 3.37
Tier 4	$ 2.77	$ 2.92	$ 3.07	$ 3.22	$ 3.37
Summer Rate ($ per CCF)					
Tier 1	$ 1.19	$ 1.26	$ 1.33	$ 1.39	$ 1.45
Tier 2	$ 1.50	$ 1.59	$ 1.67	$ 1.75	$ 1.83
Tier 3	$ 3.38	$ 3.57	$ 3.75	$ 3.93	$ 4.11
Tier 4	$ 3.38	$ 3.57	$ 3.75	$ 3.93	$ 4.11

	Cons per Tier	5,678,236	6,642,310	2,406,231	-
	Total	**Tier 1**	**Tier 2**	**Tier 3**	**Tier 4**
Supply 1	7,550,247	5,678,236	1,872,011		
Supply 2	2,442,377		2,442,377		
Supply 3	5,188,248		2,327,923	2,860,326	
Supply 4	1,073,941		-	1,073,941	

	Tier 1	Tier 2
Supply 1	75%	25%
Supply 2	0%	100%
Supply 3	0%	45%
Supply 4	0%	0%

MFR	WA-1	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
		Allocated Base & Peak Water Costs				
Supply 1		$ 167,694	$ 171,278	$ 174,693	$ 177,695	$ 180,014
Supply 2		$ 43,019	$ 43,938	$ 44,815	$ 45,584	$ 46,180
Supply 3		$ 132,111	$ 134,934	$ 137,625	$ 139,989	$ 141,817
Supply 4		$ 50,359	$ 51,435	$ 52,461	$ 53,362	$ 54,059
Base		$ 305,556	$ 312,086	$ 318,309	$ 323,778	$ 328,004
Total Allocated Costs		**$ 698,740**	**$ 713,671**	**$ 727,902**	**$ 740,408**	**$ 750,074**
Projected Annual Consumption (CCF)		468,160	452,321	439,028	425,752	412,430
Base Unit Cost		$0.65	$0.69	$0.73	$0.76	$0.80
ESTIMATED Projected Summer Consumption	47%	221,190	213,707	207,426	201,154	194,860

Tier	Revenue Requirement per Tier				
Tier 1	$299,364	$305,761	$311,858	$317,216	$321,357
Tier 2	$399,376	$407,910	$416,044	$423,192	$428,717
Tier 3	$0	$0	$0	$0	$0
Tier 4	$0	$0	$0	$0	$0
Total	**698,740**	**713,671**	**727,902**	**740,408**	**750,074**

Projected Consumption per Block (%)

	Tier	Tier Allocation	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
0	Tier 1	54%	54%	54%	54%	54%	54%
1	Tier 2	46%	46%	46%	46%	46%	46%
2	Tier 3	0%	0%	0%	0%	0%	0%
3	Tier 4		0%	0%	0%	0%	0%
	Total		**100%**	**100%**	**100%**	**100%**	**100%**

Tier	Projected Annual Consumption per Block (CCF)				
Tier 1	251,077	242,583	235,453	228,333	221,189
Tier 2	217,083	209,739	203,575	197,419	191,242
Tier 3	-	-	-	-	-
Tier 4	-	-	-	-	-
Total	**468,160**	**452,321**	**439,028**	**425,752**	**412,430**

SEASONAL RATES

Tier	Winter Use per Tier	Projected Winter Consumption per Block (CCF)				
Tier 1	58%	143,821	138,955	134,871	130,793	126,700
Tier 2	42%	103,149	99,659	96,730	93,805	90,870
Tier 3	0%	-	-	-	-	-
Tier 4	0%	-	-	-	-	-
Total		**246,970**	**238,615**	**231,602**	**224,598**	**217,571**

Tier	Summer Use Per Tier	Projected Summer Consumption per Block (CCF)				
Tier 1	48%	107,256	103,627	100,582	97,540	94,488
Tier 2	52%	113,934	110,080	106,844	103,613	100,371
Tier 3	0%	-	-	-	-	-
Tier 4	0%	-	-	-	-	-
Total		**221,190**	**213,707**	**207,426**	**201,154**	**194,860**

Tier	Annualized Summer/Annual Average				
Tier 1	1.025	1.025	1.025	1.025	1.025
Tier 2	1.260	1.260	1.260	1.260	1.260
Tier 3	-	-	-	-	-
Tier 4	-	-	-	-	-
Total	**1.134**	**1.134**	**1.134**	**1.134**	**1.134**

Source	Winter Costs				
Tier 1	$171,481	$175,145	$178,638	$181,707	$184,079
Tier 2	$177,295	$181,084	$184,695	$187,868	$190,320
Tier 3	$0	$0	$0	$0	$0
Tier 4	$0	$0	$0	$0	$0
Total	**$348,776**	**$356,229**	**$363,332**	**$369,575**	**$374,399**

Source	Seasonal Peak	Summer Costs				
Tier 1	1.0	$127,883	$130,616	$133,221	$135,510	$137,279
Tier 2	1.060	$222,081	$226,826	$231,349	$235,324	$238,396
Tier 3	1.0	$0	$0	$0	$0	$0
Tier 4	1.0	$0	$0	$0	$0	$0
Total		**$349,964**	**$357,442**	**$364,570**	**$370,834**	**$375,675**

Tier	Winter Rate ($per CCF)				
Tier 1	$ 1.19	$ 1.26	$ 1.32	$ 1.39	$ 1.45
Tier 2	$ 1.72	$ 1.82	$ 1.91	$ 2.00	$ 2.09
Tier 3	$ -	$ -	$ -	$ -	$ -
Tier 4	$ -	$ -	$ -	$ -	$ -

Tier	Summer Rate				
Tier 1	$ 1.19	$ 1.26	$ 1.32	$ 1.39	$ 1.45
Tier 2	$ 1.95	$ 2.06	$ 2.17	$ 2.27	$ 2.38
Tier 3	$ -	$ -	$ -	$ -	$ -
Tier 4	$ -	$ -	$ -	$ -	$ -

Rates Linked to Model

NOTE: RATES ARE NOT ROUNDED, THE LAST DIGIT MAY VARY FROM THE PROPOSED RATES PRESENTED WITHIN THE REPORT BODY AND APPENDIX

Tier	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
	Winter Rate ($ per CCF)				
Tier 1	$1.19	$1.26	$1.32	$1.39	$1.45
Tier 2	$1.72	$1.82	$1.91	$2.00	$2.09
Tier 3	$0.00	$0.00	$0.00	$0.00	$0.00
Tier 4	$0.00	$0.00	$0.00	$0.00	$0.00

Tier	Full Summer Rate = Winter Rate + Max usage surcharge ($ per C				
Tier 1	$1.19	$1.26	$1.32	$1.39	$1.45
Tier 2	$1.95	$2.06	$2.17	$2.27	$2.38
Tier 3	$0.00	$0.00	$0.00	$0.00	$0.00
Tier 4	$0.00	$0.00	$0.00	$0.00	$0.00

	Cons per Tier	235,727	203,811	-	-
	Total	Tier 1	Tier 2	Tier 3	Tier 4
Supply 1	291,750	235,727	56,024		
Supply 2	56,716		56,716		
Supply 3	99,808		99,808		
Supply 4	20,660		20,660		

	Tier 1	Tier 2
Supply 1	81%	19%
Supply 2	0%	100%
Supply 3	0%	100%
Supply 4	0%	100%

Commercial and Industrial (Formerly WA-6.1 and WA-6.2)

		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
		Allocated Base & Peak Water Costs				
Supply 1		$ 1,289,088	$ 1,316,635	$ 1,342,890	$ 1,365,962	$ 1,383,794
Supply 2		$ 2,307,130	$ 2,356,431	$ 2,403,421	$ 2,444,713	$ 2,476,628
Supply 3		$ 3,771,664	$ 3,852,260	$ 3,929,079	$ 3,996,583	$ 4,048,757
Supply 4		$ 1,437,714	$ 1,468,436	$ 1,497,719	$ 1,523,450	$ 1,543,338
Base		$ 5,205,326	$ 5,316,557	$ 5,422,576	$ 5,515,739	$ 5,587,745
Total Allocated Costs		**$ 14,010,922**	**$ 14,310,318**	**$ 14,595,686**	**$ 14,846,447**	**$ 15,040,263**
ined Usage						
Projected Annual Consumption (CCF)						
Commercial and Industrial		7,857,338	7,858,911	7,881,553	7,902,873	7,921,527
Total		**7,857,338**	**7,858,911**	**7,881,553**	**7,902,873**	**7,921,527**
ESTIMATED Projected Summer Consumption						
Commercial and Industrial	48%	3,800,538	3,801,299	3,812,251	3,822,563	3,831,586
Total		**3,800,538**	**3,801,299**	**3,812,251**	**3,822,563**	**3,831,586**

Projected Consumption per Block (%)

	Tier	Tier Allocation	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
0	Tier 1	100%	100%	100%	100%	100%	100%
1	Tier 2		0%	0%	0%	0%	0%
2	Tier 3		0%	0%	0%	0%	0%
3	Tier 4		0%	0%	0%	0%	0%
	Total		**100%**	**100%**	**100%**	**100%**	**100%**

Tier	Projected Annual Consumption per Block (CCF)				
Tier 1	7,857,338	7,858,911	7,881,553	7,902,873	7,921,527
Tier 2					
Tier 3					
Tier 4					
Total	**7,857,338**	**7,858,911**	**7,881,553**	**7,902,873**	**7,921,527**

SEASONAL RATES

Tier	Winter Use per Tier	Projected Winter Consumption per Block (CCF)				
Tier 1	100%	4,056,800	4,057,612	4,069,302	4,080,310	4,089,941
Tier 2						
Tier 3						
Tier 4						
Total		**4,056,800**	**4,057,612**	**4,069,302**	**4,080,310**	**4,089,941**

Tier	Summer Use Per Tier	Projected Summer Consumption per Block (CCF)				
Tier 1	100%	3,800,538	3,801,299	3,812,251	3,822,563	3,831,586
Tier 2						
Tier 3						
Tier 4						
Total		**3,800,538**	**3,801,299**	**3,812,251**	**3,822,563**	**3,831,586**

Tier	Summer Months	5	Annualized Summer/Annual Average				
Tier 1			1.161	1.161	1.161	1.161	1.161
Tier 2			-	-	-	-	-
Tier 3			-	-	-	-	-
Tier 4			-	-	-	-	-
Total			**1.161**	**1.161**	**1.161**	**1.161**	**1.161**

	Winter Costs				
Tier 1	$6,712,112	$6,855,541	$6,992,251	$7,112,381	$7,205,231
Tier 2					
Tier 3					
Tier 4					
Total	**$6,712,112**	**$6,855,541**	**$6,992,251**	**$7,112,381**	**$7,205,231**

	Seasonal Factor	Summer Costs				
Tier 1	1.077	$7,298,810	$7,454,776	$7,603,435	$7,734,066	$7,835,032
Tier 2						
Tier 3						
Tier 4						
Total		**$7,298,810**	**$7,454,776**	**$7,603,435**	**$7,734,066**	**$7,835,032**

Rates Linked to Model

NOTE: RATES ARE NOT ROUNDED, THE LAST DIGIT MAY VARY FROM THE PROPOSED RATES PRESENTED WITHIN THE REPORT BODY AND APPENDIX

Tier	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
	Winter Rate				
Tier 1	$1.65	$1.69	$1.72	$1.74	$1.76
Tier 2	$0.00	$0.00	$0.00	$0.00	$0.00
Tier 3	$0.00	$0.00	$0.00	$0.00	$0.00
Tier 4	$0.00	$0.00	$0.00	$0.00	$0.00

Tier	Summer Rate				
Tier 1	$1.92	$1.96	$1.99	$2.02	$2.04
Tier 2	$0.00	$0.00	$0.00	$0.00	$0.00
Tier 3	$0.00	$0.00	$0.00	$0.00	$0.00
Tier 4	$0.00	$0.00	$0.00	$0.00	$0.00

Landscape

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Allocated Base & Peak Water Costs					
Supply 1	$ 188,406	$ 192,432	$ 196,270	$ 199,642	$ 202,248
Supply 2	$ 337,198	$ 344,403	$ 351,271	$ 357,306	$ 361,971
Supply 3	$ 1,098,403	$ 1,121,874	$ 1,144,246	$ 1,163,905	$ 1,179,099
Supply 4	$ 418,698	$ 427,645	$ 436,173	$ 443,667	$ 449,459
Base	$ 1,009,803	$ 1,031,381	$ 1,051,948	$ 1,070,021	$ 1,083,990
Total Allocated Costs	**$ 3,052,508**	**$ 3,117,736**	**$ 3,179,908**	**$ 3,234,541**	**$ 3,276,766**
Projected Annual Consumption (CCF)	1,524,278	1,524,583	1,528,975	1,533,111	1,536,730
ESTIMATED Projected Summer Consumption (53%)	813,577	813,740	816,084	818,292	820,223

Projected Consumption per Block (%)

	Tier	Tier Allocation	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
0	Tier 1	100%	100%	100%	100%	100%	100%
1	Tier 2		0%	0%	0%	0%	0%
2	Tier 3		0%	0%	0%	0%	0%
3	Tier 4		0%	0%	0%	0%	0%
	Total		**100%**	**100%**	**100%**	**100%**	**100%**

Tier	Projected Annual Consumption per Block (CCF)				
Tier 1	1,524,278	1,524,583	1,528,975	1,533,111	1,536,730
Tier 2					
Tier 3					
Tier 4					
Total	**1,524,278**	**1,524,583**	**1,528,975**	**1,533,111**	**1,536,730**

SEASONAL RATES

Tier	Winter Use per Tier	Projected Winter Consumption per Block (CCF)				
Tier 1	100%	710,701	710,843	712,891	714,820	716,507
Tier 2	0%					
Tier 3	0%					
Tier 4	0%					
Total		**710,701**	**710,843**	**712,891**	**714,820**	**716,507**

Tier	Summer Use per Tier	Projected Summer Consumption per Block (CCF)				
Tier 1	100%	813,577	813,740	816,084	818,292	820,223
Tier 2						
Tier 3						
Tier 4						
Total		**813,577**	**813,740**	**816,084**	**818,292**	**820,223**

Tier	Summer Month: 5	Annualized Summer/Annual Average				
Tier 1		1.281	1.281	1.281	1.281	1.281
Tier 2		-	-	-	-	-
Tier 3		-	-	-	-	-
Tier 4		-	-	-	-	-
Total		**1.281**	**1.281**	**1.281**	**1.281**	**1.281**

Tier	Winter Costs				
Tier 1	$1,237,509	$1,263,953	$1,289,158	$1,311,306	$1,328,425
Tier 2					
Tier 3					
Tier 4					
Total	**$1,237,509**	**$1,263,953**	**$1,289,158**	**$1,311,306**	**$1,328,425**

Tier	Seasonal Factor	Summer Costs				
Tier 1	1.1140	$1,814,999	$1,853,783	$1,890,750	$1,923,234	$1,948,341
Tier 2						
Tier 3						
Tier 4						
Total		**$1,814,999**	**$1,853,783**	**$1,890,750**	**$1,923,234**	**$1,948,341**

Rates Linked to Model

NOTE: RATES ARE NOT ROUNDED, THE LAST DIGIT MAY VARY FROM THE PROPOSED RATES PRESENTED WITHIN THE REPORT BODY AND APPENDIX

Tier	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Winter Rate ($per CCF)					
Tier 1	$ 1.74	$ 1.78	$ 1.81	$ 1.83	$ 1.85
Tier 2	$ -	$ -	$ -	$ -	$ -
Tier 3	$ -	$ -	$ -	$ -	$ -
Tier 4	$ -	$ -	$ -	$ -	$ -
Summer Rate					
Tier 1	$ 2.23	$ 2.28	$ 2.32	$ 2.35	$ 2.38
Tier 2	$ -	$ -	$ -	$ -	$ -
Tier 3	$ -	$ -	$ -	$ -	$ -
Tier 4	$ -	$ -	$ -	$ -	$ -

WA-2 Temporary Service

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
	Allocated Base & Peak Water Costs				
Supply 1	$ 1,726	$ 1,763	$ 1,798	$ 1,829	$ 1,853
Supply 2	$ 3,090	$ 3,156	$ 3,219	$ 3,274	$ 3,317
Supply 3	$ 68,204	$ 69,661	$ 71,050	$ 72,271	$ 73,215
Supply 4	$ 25,998	$ 26,554	$ 27,084	$ 27,549	$ 27,909
Base	$ 35,713	$ 36,476	$ 37,203	$ 37,842	$ 38,336
Total Allocated Costs	**$ 134,731**	**$ 137,610**	**$ 140,354**	**$ 142,766**	**$ 144,629**
Projected Annual Consumption (CCF)	**53,908**	**53,919**	**54,074**	**54,220**	**54,348**
ESTIMATED Projected Summer Consumption (47%)	**25,487**	**25,492**	**25,566**	**25,635**	**25,695**

Projected Consumption per Block (%)

	Tier	Tier Allocation	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
0	Tier 1	100%	100%	100%	100%	100%	100%
1	Tier 2		0%	0%	0%	0%	0%
2	Tier 3		0%	0%	0%	0%	0%
3	Tier 4		0%	0%	0%	0%	0%
	Total		**100%**	**100%**	**100%**	**100%**	**100%**

Tier	Tier Break	Allotment (CCF)	Projected Annual Consumption per Block (CCF)				
Tier 1			53,908	53,919	54,074	54,220	54,348
Tier 2							
Tier 3							
Tier 4							
Total			**53,908**	**53,919**	**54,074**	**54,220**	**54,348**

Tier	Non- Seasonal Rate ($per CCF)				
Tier 1	$ 2.50	$ 2.55	$ 2.60	$ 2.63	$ 2.66
Tier 2					
Tier 3					
Tier 4					

Rates Linked to Model

Tier	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
	Annual Rates				
Tier 1	$2.50	$2.55	$2.60	$2.63	$2.66
Tier 2	$0.00	$0.00	$0.00	$0.00	$0.00
Tier 3	$0.00	$0.00	$0.00	$0.00	$0.00
Tier 4	$0.00	$0.00	$0.00	$0.00	$0.00

NOTE: RATES ARE NOT ROUNDED, THE LAST DIGIT MAY VARY FROM THE PROPOSED RATES PRESENTED WITHIN THE REPORT BODY AND APPENDIX

WA-4 Riverside Water Company Irrigators

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
	Allocated Base & Peak Water Costs				
Supply 1	$ 4,489	$ 4,585	$ 4,677	$ 4,757	$ 4,819
Supply 2	$ 3,813	$ 3,894	$ 3,972	$ 4,040	$ 4,093
Supply 3	$ 21,652	$ 22,115	$ 22,556	$ 22,943	$ 23,243
Supply 4	$ 8,253	$ 8,430	$ 8,598	$ 8,746	$ 8,860
Base	$ 20,430	$ 20,866	$ 21,283	$ 21,648	$ 21,931
Total Allocated Costs	**$ 58,638**	**$ 59,891**	**$ 61,085**	**$ 62,134**	**$ 62,946**
Projected Annual Consumption (CCF)	29,047	28,626	27,681	27,048	26,416
Base Unit Cost	$0.70	$0.73	$0.77	$0.80	$0.83
ESTIMATED Projected Summer Consumption 54%	15,584	15,358	14,851	14,512	14,173

Tier	Revenue Requirement per Tier				
Tier 1	$7,415	$7,574	$7,725	$7,857	$7,960
Tier 2	$14,563	$14,874	$15,171	$15,431	$15,633
Tier 3	$36,659	$37,443	$38,189	$38,846	$39,353
Tier 4	$0	$0	$0	$0	$0
Total	**$58,638**	**$59,891**	**$61,085**	**$62,134**	**$62,946**

Projected Consumption per Block (%)

	Tier	Tier Allocation	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
0	Tier 1	20%	20%	20%	20%	20%	20%
1	Tier 2	33%	33%	33%	33%	33%	33%
2	Tier 3	46%	46%	46%	46%	46%	46%
3	Tier 4		0%	0%	0%	0%	0%
	Total		**100%**	**100%**	**100%**	**100%**	**100%**

Tier	Projected Annual Consumption per Block (CCF)				
Tier 1	5,919	5,833	5,641	5,512	5,383
Tier 2	9,660	9,520	9,206	8,995	8,785
Tier 3	13,468	13,272	12,834	12,541	12,248
Tier 4	-	-	-	-	-
Total	**29,047**	**28,626**	**27,681**	**27,048**	**26,416**

SEASONAL RATES

Tier	Winter Use per Tier	Projected Winter Consumption per Block (CCF)				
Tier 1	24%	3,246	3,199	3,093	3,022	2,952
Tier 2	32%	4,371	4,308	4,166	4,070	3,975
Tier 3	43%	5,845	5,760	5,570	5,443	5,316
Tier 4	0%	-	-	-	-	-
Total		**13,462**	**13,267**	**12,829**	**12,536**	**12,243**

Tier	Summer Use per Tier	Projected Summer Consumption per Block (CCF)				
Tier 1	17%	2,673	2,635	2,548	2,489	2,431
Tier 2	34%	5,289	5,212	5,040	4,925	4,810
Tier 3	49%	7,622	7,512	7,264	7,098	6,932
Tier 4	0%	-	-	-	-	-
Total		**15,584**	**15,358**	**14,851**	**14,512**	**14,173**

Tier	Annualized Summer/Annual Average				
Tier 1	1.084	1.084	1.084	1.084	1.084
Tier 2	1.314	1.314	1.314	1.314	1.314
Tier 3	1.358	1.358	1.358	1.358	1.358
Tier 4	-	-	-	-	-
Total	**1.288**	**1.288**	**1.288**	**1.288**	**1.288**

	Winter Costs				
Tier 1	$4,066	$4,153	$4,236	$4,309	$4,365
Tier 2	$6,590	$6,731	$6,865	$6,983	$7,074
Tier 3	$13,681	$13,973	$14,252	$14,497	$14,686
Tier 4	$0	$0	$0	$0	$0
Total	**$24,337**	**$24,857**	**$25,353**	**$25,788**	**$26,125**

	Seasonal Peak	Summer Costs				
Tier 1	1.0	$3,349	$3,421	$3,489	$3,549	$3,595
Tier 2	1.0	$7,973	$8,143	$8,306	$8,448	$8,559
Tier 3	1.1075	$22,979	$23,470	$23,938	$24,349	$24,667
Tier 4	1.0	$0	$0	$0	$0	$0
Total		**$34,301**	**$35,034**	**$35,732**	**$36,346**	**$36,821**

Tier	Winter Rate ($per CCF)				
Tier 1	$ 1.25	$ 1.30	$ 1.37	$ 1.43	$ 1.48
Tier 2	$ 1.51	$ 1.56	$ 1.65	$ 1.72	$ 1.78
Tier 3	$ 2.34	$ 2.43	$ 2.56	$ 2.66	$ 2.76
Tier 4	$ 2.34	$ 2.43	$ 2.56	$ 2.66	$ 2.76

Tier	Summer Rate				
Tier 1	$ 1.25	$ 1.30	$ 1.37	$ 1.43	$ 1.48
Tier 2	$ 1.51	$ 1.56	$ 1.65	$ 1.72	$ 1.78
Tier 3	$ 3.01	$ 3.12	$ 3.30	$ 3.43	$ 3.56
Tier 4	$ 3.01	$ 3.12	$ 3.30	$ 3.43	$ 3.56

Rates Linked to Model

NOTE: RATES ARE NOT ROUNDED, THE LAST DIGIT MAY VARY FROM THE PROPOSED RATES PRESENTED WITHIN THE REPORT BODY AND APPENDIX

Tier	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
	Winter Rates				
Tier 1	$1.25	$1.30	$1.37	$1.43	$1.48
Tier 2	$1.51	$1.56	$1.65	$1.72	$1.78
Tier 3	$2.34	$2.43	$2.56	$2.66	$2.76
Tier 4	$2.34	$2.43	$2.56	$2.66	$2.76
	Summer Rates				
Tier 1	$1.25	$1.30	$1.37	$1.43	$1.48
Tier 2	$1.51	$1.56	$1.65	$1.72	$1.78
Tier 3	$3.01	$3.12	$3.30	$3.43	$3.56
Tier 4	$3.01	$3.12	$3.30	$3.43	$3.56

	Cons per Tier	5,658	9,233	12,872	-				
	Total	Tier 1	Tier 2	Tier 3	Tier 4				
Supply 1	7,810	5,658	2,153			7,810	Supply 1	72%	28%
Supply 2	5,027	-	5,027			5,027	Supply 2	0%	100%
Supply 3	16,358		2,054	14,304		16,358	Supply 3	0%	13%
Supply 4	3,386			3,386		3,386	Supply 4	0%	0%

WA-7 Interruptible City Irrigation and Recycled Water

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
			Allocated Base & Peak Water Costs		
Supply 1	$ 98,842	$ 100,954	$ 102,968	$ 104,737	$ 106,104
Supply 2	$ 175,271	$ 179,016	$ 182,586	$ 185,723	$ 188,148
Supply 3	$ 654,584	$ 668,571	$ 681,904	$ 693,619	$ 702,674
Supply 4	$ -	$ -	$ -	$ -	$ -
Base	$ 636,546	$ 650,148	$ 663,113	$ 674,505	$ 683,311
Total Allocated Costs	**$ 1,565,243**	**$ 1,598,690**	**$ 1,630,570**	**$ 1,658,584**	**$ 1,680,236**
Projected Annual Consumption (CCF)	**960,853**	**961,046**	**963,815**	**966,422**	**968,703**
ESTIMATED Projected Summer Consumption (56%)	**536,223**	**536,331**	**537,876**	**539,331**	**540,604**

Projected Consumption per Block (%)

	Tier	Tier Allocation	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
0	Tier 1	100%	100%	100%	100%	100%	100%
1	Tier 2		0%	0%	0%	0%	0%
2	Tier 3		0%	0%	0%	0%	0%
3	Tier 4		0%	0%	0%	0%	0%
	Total		**100%**	**100%**	**100%**	**100%**	**100%**

Tier	Tier Break	Allotment (CCF)	Projected Annual Consumption per Block (CCF) FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1			960,853	961,046	963,815	966,422	968,703
Tier 2							
Tier 3							
Tier 4							
Total			**960,853**	**961,046**	**963,815**	**966,422**	**968,703**

Rates Linked to Model

Tier	Winter Rate ($per CCF) FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	1.63	1.66	1.69	1.72	1.73
Tier 2	-	-	-	-	-
Tier 3	-	-	-	-	-
Tier 4	-	-	-	-	-

NOTE: RATES ARE NOT ROUNDED, THE LAST DIGIT MAY VARY FROM THE PROPOSED RATES PRESENTED WITHIN THE REPORT BODY AND APPENDIX

WA-3.1 - Irrigation Metered Svc. Transition to SFR

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Growth (Other)		-1.06%	-2.89%	-1.87%	-1.90%
Smoothed Growth		-1.931%	-1.931%	-1.931%	-1.931%
Projected Annual Consumption (CCF)	254,394	249,481	244,663	239,939	235,305

Tier Breaks			FY 2017/18 Usage	Percent	Summer With Conservation	Winter With Conservation	Summer Percent	Winter Percent	Total Percent
Tier 1	0	100.00	13,168	5%	5,421	7,747	2%	3%	
Tier 2	101	99999999	35,925	14%	15,210	20,715	6%	8%	14%
Tier 3	100000000	999999999	71,992	28%	33,961	38,031	13%	15%	28%
Tier 4	1000000000	+	133,309	52%	84,687	48,622	33%	19%	52%
			254,394	100%	139,279	115,115	55%	45%	100%

	Summer Jul-17	Summer Aug-17	Summer Sep-17	Summer Oct-17	Winter Nov-17	Winter Dec-17	Winter Jan-18	Winter Feb-18	Winter Mar-18	Winter Apr-18	Winter May-18	Summer Jun-18	Total	Percent
Tier 1	1,035	1,071	1,068	1,127	1,114	1,128	1,026	1,112	1,122	1,130	1,115	1,120	13,168	5%
Tier 2	2,912	3,026	3,000	3,141	3,081	3,080	2,461	2,774	3,101	3,113	3,105	3,131	35,925	14%
Tier 3	6,506	6,818	6,810	6,738	6,320	5,960	3,368	4,495	5,431	5,985	6,472	7,089	71,992	28%
Tier 4	15,868	20,185	16,570	14,348	9,779	8,062	2,392	4,989	5,779	9,328	8,293	17,716	133,309	52%
Total	**26,321**	**31,100**	**27,448**	**25,354**	**20,294**	**18,230**	**9,247**	**13,370**	**15,433**	**19,556**	**18,985**	**29,056**	**254,394**	**100%**

Transitional Rates Calculation

	Current Rates	FY 2017/18 Usage	Rev With Curent Rates
Tier 1	$0.81	121,085	$98,079
Tier 2	$1.26	133,309	$167,969
Minimum Charges			$37,883
TOTAL		254,394	$303,931

Effective Volumetric Rate $1.19 per HCF

		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Effective SFR Volumetric Rate						
Usage Per SFR Tier		254,394	249,481	244,663	239,939	235,305
Winter Tier 1		7,747	7,597	7,451	7,307	7,166
Winter Tier 2		20,715	20,315	19,923	19,538	19,161
Winter Tier 3		38,031	37,297	36,576	35,870	35,177
Winter Tier 4		48,622	47,683	46,762	45,859	44,974
Summer Tier 1		5,421	5,316	5,214	5,113	5,014
Summer Tier 2		15,210	14,916	14,628	14,346	14,069
Summer Tier 3		33,961	33,305	32,662	32,031	31,413
Summer Tier 4		84,687	83,052	81,448	79,875	78,332
Proposed Rates						
Winter Tier 1		$1.20	$1.27	$1.33	$1.40	$1.46
Winter Tier 2		$1.51	$1.59	$1.67	$1.76	$1.84
Winter Tier 3		$2.77	$2.93	$3.08	$3.23	$3.38
Winter Tier 4		$2.77	$2.93	$3.08	$3.23	$3.38
Summer Tier 1		$1.20	$1.27	$1.33	$1.40	$1.46
Summer Tier 2		$1.51	$1.59	$1.67	$1.76	$1.84
Summer Tier 3		$3.38	$3.58	$3.76	$3.94	$4.12
Summer Tier 4		$3.38	$3.58	$3.76	$3.94	$4.12
Volumetric SFR Costs		$711,107	$737,965	$760,279	$781,918	$801,984
Fixed SFR Costs		$47,188	$55,268	$64,112	$73,731	$84,075
Total SFR Costs		**$758,295**	**$793,234**	**$824,391**	**$855,649**	**$886,059**
Transitional Usage		**254,394**	**249,481**	**244,663**	**239,939**	**235,305**
Effective Volumetric Rate		**$2.98**	**$3.18**	**$3.37**	**$3.57**	**$3.77**
Five Year Total Transition to SFR		215%				
Annualized Increase in Effective Volumetric Rate		**26%**				

Projected Fixed Revenues			FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Meter Size	**Accounts**	**Proposed Rates**					
5/8"	0		$16.40	$19.21	$22.29	$25.64	$29.24
3/4"	16		$16.40	$19.21	$22.29	$25.64	$29.24
1"	88		$26.04	$30.50	$35.38	$40.69	$46.40
1.5"	15		$49.92	$58.47	$67.82	$77.99	$88.93
2"	8		$78.70	$92.16	$106.91	$122.93	$140.16
Projected Fixed Revenue			**$47,188**	**$55,268**	**$64,112**	**$73,731**	**$84,075**

	Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Transitional Effective Volumetric Rate	**$1.19**	**$1.51**	**$1.90**	**$2.39**	**$3.01**	**$3.79**
Total Former WA-3.1 Usage		254,394	249,481	244,663	239,939	235,305
Transitional Revenue Generated		**$382,953**	**$473,203**	**$584,722**	**$722,522**	**$892,797**
Less: Fixed Revenue		($47,188)	($55,268)	($64,112)	($73,731)	($84,075)
Amount to Be Collected Through Transitional Volumetric Rate		**$335,765**	**$417,935**	**$520,610**	**$648,791**	**$808,721**
Revenue By Tier Allocation (Based on Current Rates)						
Tier 1		32%	32%	32%	32%	32%
Tier 2		55%	55%	55%	55%	55%
Tier 3		12%	12%	12%	12%	12%
Total		100%	100%	100%	100%	100%
Revenue To Collect in Each Tier						
Tier 1		$108,352	$134,868	$168,001	$209,365	$260,975
Tier 2		$227,414	$283,067	$352,609	$439,425	$547,746
Total		**$335,765**	**$417,935**	**$520,610**	**$648,791**	**$808,721**
Consumption Per Tier						
Tier 1		121,085	118,747	116,454	114,205	111,999
Tier 2		133,309	130,735	128,210	125,734	123,306
Total		**254,394**	**249,481**	**244,663**	**239,939**	**235,305**

Transitional Rates Per Tier		Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	0 to 100 CCF	$0.81	$0.89	$1.14	$1.44	$1.83	SFR
Tier 2	Over 100 CCF	$1.26	$1.71	$2.17	$2.75	$3.49	SFR
Tier 3			N/A	N/A	N/A	N/A	SFR

Transitional Rates Per Tier - Rounded		Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	0 to 100 CCF	$0.81	$0.90	$1.14	$1.45	$1.84	SFR
Tier 2	Over 100 CCF	$1.26	$1.71	$2.17	$2.76	$3.50	SFR
Tier 3			N/A	N/A	N/A	N/A	SFR

WA-9.1 - Grove Preservation — Transition to SFR

		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Growth (Other)	Includes Proforma Elasticity		-1.06%	-2.89%	-1.87%	-1.90%
Smoothed Growth			-1.931%	-1.931%	-1.931%	-1.931%
Projected Annual Consumption (CCF)		96,647	94,781	92,950	91,155	89,395

Tier Breaks			FY 2017/18 Usage	Percent	Summer With Conservation	Winter With Conservation	Summer Percent	Winter Percent	Total Percent
Tier 1	0	15.00	4,923	5%	2,025	2,898	2%	3%	
Tier 2	16	60	3,241	3%	1,347	1,894	1%	2%	3%
Tier 3	100000000	999999999	21,333	22%	9,535	11,798	10%	12%	22%
Tier 4	1000000000	+	67,150	69%	39,164	27,986	41%	29%	69%
			96,647	100%	52,071	44,576	54%	46%	95%

	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Winter	Summer		
Usage Under Proposed SFR Tiers	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Total	Percent
Tier 1	360	405	405	423	423	423	365	418	414	423	432	432	4,923	5%
Tier 2	1,032	1,153	1,151	1,183	1,186	1,176	876	1,104	1,063	1,127	1,200	1,229	13,480	14%
Tier 3	7,756	11,803	8,587	7,317	6,687	6,429	2,696	3,683	3,633	5,487	5,331	8,835	78,244	81%
Total	**9,148**	**13,361**	**10,143**	**8,923**	**8,296**	**8,028**	**3,937**	**5,205**	**5,110**	**7,037**	**6,963**	**10,496**	**96,647**	**100%**

	Summer	Summer	Summer	Summer	Winter	Winter	Winter	Winter	Winter	Winter	Winter	Summer		
Usage Under Current Tiers	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Total	Percent
Tier 1	360	405	405	423	423	423	365	418	414	423	432	432	4,923	5%
Tier 2	240	270	270	279	279	280	228	270	268	281	288	288	3,241	3%
Tier 3	1,767	1,951	1,938	1,906	1,885	1,819	1,306	1,596	1,539	1,735	1,918	1,973	21,333	22%
Tier 4	6,781	10,735	7,530	6,315	5,709	5,506	2,038	2,921	2,889	4,598	4,325	7,803	67,150	69%
Total	**9,148**	**13,361**	**10,143**	**8,923**	**8,296**	**8,028**	**3,937**	**5,205**	**5,110**	**7,037**	**6,963**	**10,496**	**96,647**	**100%**

	Summer	Winter	Total	Summer %	Winter %	Total %
Tier 1	2,025	2,898	4,923	4%	7%	5%
Tier 2	1,347	1,894	3,241	3%	4%	3%
Tier 3	9,535	11,798	21,333	18%	26%	22%
Tier 4	39,164	27,986	67,150	75%	63%	69%
Total	**52,071**	**44,576**	**96,647**	**100%**	**100%**	**100%**

	Minimum Month	Max Month	Average	Summer Average	Winter Average
Tier 1	360	432	410	405	414
Tier 2	228	288	270	269	271
Tier 3	1,306	1,973	1,778	1,907	1,685
Tier 4	2,038	10,735	5,596	7,833	3,998
Total	3,937	13,361	8,054	10,414	6,368

	Max Month/Min Month	Max Month/Winter Average	Max Month/Average Month
0 to 15	1.22	1.05	1.06
16 to 60	1.51	1.17	1.11
60 +	5.27	2.69	1.92
	3.39	**2.10**	**1.66**

WA-9.1 - Grove Preservation — Transition to SFR

Transitional Rates Calculation

FY 2017/18 | FY 2018/19 | FY 2019/20 | FY 2020/21 | FY 2021/22

	Current Rates	FY 2017/18 Usage	Rev With Curent Rates
Tier 1	$0.91	8,164	$7,429
Tier 2	$1.58	21,333	$33,706
Tier 3	$1.07	67,150	$71,851
Variable Charges		96,647	$112,986
Fixed Charges			$7,858
Total			**$120,844**
Effective Volumetric Rate			**$1.25 per HCF**

Meter Size	Exising Charge	Accounts
5/8 and 3/4 inc	$7.35	10
1-inch	$12.21	34
1 1/2 inch	$24.45	2
2 inch	$39.09	3
3-inch	$73.29	
4-inch	$122.15	
6-inch	$244.33	
8-inch	$390.91	

		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Transitional Usage		96,647	94,781	92,950	91,155	89,395
Usage per SFR Tier						
Winter Tier 1	3%	2,898	2,842	2,787	2,733	2,681
Winter Tier 2	8%	7,732	7,583	7,436	7,293	7,152
Winter Tier 3	35%	33,946	33,290	32,648	32,017	31,399
Winter Tier 4		-	-	-	-	-
Summer Tier 1	2%	2,025	1,986	1,948	1,910	1,873
Summer Tier 2	6%	5,748	5,637	5,528	5,421	5,317
Summer Tier 3	46%	44,298	43,443	42,604	41,781	40,974
Summer Tier 4		-	-	-	-	-
Proposed Rates						
Winter Tier 1		$1.20	$1.27	$1.33	$1.40	$1.46
Winter Tier 2		$1.51	$1.59	$1.67	$1.76	$1.84
Winter Tier 3		$2.77	$2.93	$3.08	$3.23	$3.38
Winter Tier 4		$2.77	$2.93	$3.08	$3.23	$3.38
Summer Tier 1		$1.20	$1.27	$1.33	$1.40	$1.46
Summer Tier 2		$1.51	$1.59	$1.67	$1.76	$1.84
Summer Tier 3		$3.38	$3.58	$3.76	$3.94	$4.12
Summer Tier 4		$3.38	$3.58	$3.76	$3.94	$4.12
Effective SFR Volumetric Rate						
Volumetric SFR Costs		$270,020	$280,216	$288,692	$296,909	$304,531
Fixed SFR Costs		$16,624	$19,470	$22,586	$25,976	$29,620
Total SFR Costs		**$286,644**	**$299,686**	**$311,278**	**$322,885**	**$334,151**
Total SFR Usage		**96,647**	**94,781**	**92,950**	**91,155**	**89,395**
Effective Volumetric Rate		**$2.97**	**$3.16**	**$3.35**	**$3.54**	**$3.74**
Five Year Total Transition to SFR		199%				
Annualized Increase in Effective Volumetric Rate		**24%**				

Projected Fixed Revenues			FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Meter Size	**Accounts**	**Proposed Rates**					
5/8 and 3/4 inc	10		$16.40	$19.21	$22.29	$25.64	$29.24
1-inch	34		$26.04	$30.50	$35.38	$40.69	$46.40
1 1/2 inch	2		$49.92	$58.47	$67.82	$77.99	$88.93
2 inch	3		$78.70	$92.16	$106.91	$122.93	$140.16
3-inch	0		$145.89	$170.85	$198.17	$227.87	$259.80
Projected Fixed Revenue			**$16,624**	**$19,470**	**$22,586**	**$25,976**	**$29,620**

	Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Transitional Effective Volumetric Rate	**$1.25**	**$1.55**	**$1.92**	**$2.38**	**$2.96**	**$3.67**
Total Former WA-9.1 Usage		96,647	94,781	92,950	91,155	89,395
Transitional Revenue Generated		**$149,846**	**$182,221**	**$221,590**	**$269,466**	**$327,685**
Less: Fixed Revenue		($16,624)	($19,470)	($22,586)	($25,976)	($29,620)
Amount to Be Collected Through Transitional Volumetric Rate		**$133,222**	**$162,751**	**$199,004**	**$243,490**	**$298,065**
System Wide Base Unit Cost		$0.60	$0.65	$0.69	$0.73	$0.76
Base Costs		$58,294	$61,972	$64,216	$66,183	$68,065
Peak Costs		$74,928	$100,778	$134,788	$177,308	$229,999

Consumption Per Tier	Max Month/Average Month					
Tier 1	1.06	8,164	8,006	7,852	7,700	7,551
Tier 2	1.11	21,333	20,921	20,517	20,121	19,732
Tier 3	1.92	67,150	65,853	64,582	63,334	62,111
Total		**96,647**	**94,781**	**92,950**	**91,155**	**89,395**

Transitional Rates Per Tier		Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	0 to 15 CCF	$0.91	$1.10	$1.33	$1.61	$1.96	SFR
Tier 2	16 to 60 CCF	$1.58	$1.12	$1.36	$1.66	$2.02	SFR
Tier 3	Over 60 CCF	$1.07	$1.50	$1.88	$2.36	$2.96	SFR

Transitional Rates Per Tier - Rounded		Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Tier 1	0 to 15 CCF	$0.91	$1.10	$1.33	$1.62	$1.97	SFR
Tier 2	16 to 60 CCF	$1.58	$1.12	$1.37	$1.66	$2.03	SFR
Tier 3	Over 60 CCF	$1.07	$1.50	$1.88	$2.36	$2.97	SFR

WA-3.2 - Irrigation Metered Svc. Transition to Commercial

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Growth (Other)		-1.06%	-2.89%	-1.87%	-1.90%
Smoothed Growth		-1.931%	-1.931%	-1.931%	-1.931%
Projected Annual Consumption (CCF)	**23,237**	**22,788**	**22,348**	**21,917**	**21,493**

FY 2017/18 Usage	Percent	Summer With Conservation	Winter With Conservation	Summer Percent
23,237	**100%**	13,758	9,479	**100%**
-	**0%**	-	-	**0%**
-	**0%**	-	-	**0%**
-	**0%**	-	-	**0%**
23,237	**100%**	**13,758**	**9,479**	**100%**

	Summer Jul-17	Summer Aug-17	Summer Sep-17	Summer Oct-17	Winter Nov-17	Winter Dec-17	Winter Jan-18	Winter Feb-18	Winter Mar-18	Winter Apr-18	Winter May-18	Summer Jun-18	Total	Percent
Tier 1	3,115	3,341	2,435	2,150	1,577	1,446	700	839	1,199	1,565	2,153	2,717	23,237	**100%**
Tier 2													-	**0%**
Tier 3													-	**0%**
Tier 4													-	**0%**
Total	**3,115**	**3,341**	**2,435**	**2,150**	**1,577**	**1,446**	**700**	**839**	**1,199**	**1,565**	**2,153**	**2,717**	**23,237**	**100%**

Transitional Rates Calculation

FY 2017/18 | FY 2018/19 | FY 2019/20 | FY 2020/21 | FY 2021/22

	Current Rates	FY 2017/18 Usage	Rev With Curent Rates
Tier 1	$1.26	23,237	$29,279
Tier 2			$0
Minimum Charges			$3,153
Variable Charges		23,237	$32,432
Fixed Charges			$0
Total			**$32,432**

Effective Volumetric Rate **$1.40 per HCF**

Meter Size	Exising Charge	Accounts
5/8 and 3/4 inc	$0.00	0
1-inch	$0.00	4
1 1/2 inch	$0.00	1
2 inch	$0.00	3
3-inch	$0.00	0
4-inch	$0.00	0
6-inch	$0.00	0
8-inch	$0.00	0

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Effective Commercial Volumetric Rate					
Usage	23,237	22,788	22,348	21,917	21,493
Winter	9,479	9,296	9,116	8,940	8,768
Summer	13,758	13,492	13,232	12,976	12,726
Proposed Commercial and Industrial Rates					
Winter	$1.66	$1.69	$1.72	$1.75	$1.77
Summer	$1.93	$1.97	$2.00	$2.03	$2.05
Volumetric Comm/Ind Costs	$42,288	$42,290	$42,144	$41,987	$41,606
Fixed Comm/Ind Costs	$4,682	$5,483	$6,361	$7,314	$8,340
Total Comm/Ind Costs	**$46,970**	**$47,773**	**$48,505**	**$49,302**	**$49,947**
Transitional Usage	**23,237**	**22,788**	**22,348**	**21,917**	**21,493**
Effective Volumetric Rate	**$2.02**	**$2.10**	**$2.17**	**$2.25**	**$2.32**
Five Year Total Transition to Comm/Ind	66%				
Annualized Increase in Effective Volumetric Rate	**11.00%**				

Projected Fixed Revenues

Meter Size	Accounts	Proposed Rates FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
5/8"	0	$16.40	$19.21	$22.29	$25.64	$29.24
3/4"	0	$16.40	$19.21	$22.29	$25.64	$29.24
1"	4	$26.04	$30.50	$35.38	$40.69	$46.40
1.5"	1	$49.92	$58.47	$67.82	$77.99	$88.93
2"	3	$78.70	$92.16	$106.91	$122.93	$140.16
Projected Fixed Revenue		**$4,682**	**$5,483**	**$6,361**	**$7,314**	**$8,340**

	Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Transitional Effective Volumetric Rate	**$1.40**	**$1.55**	**$1.72**	**$1.91**	**$2.12**	**$2.35**
Total Former WA-9.2 Usage		23,237	22,788	22,348	21,917	21,493
Transitional Revenue Generated		**$36,000**	**$39,188**	**$42,658**	**$46,436**	**$50,549**
Less: Fixed Revenue		($4,682)	($5,483)	($6,361)	($7,314)	($8,340)
Amount to Be Collected Through Transitional Volumetric Rate		**$31,317**	**$33,704**	**$36,298**	**$39,122**	**$42,209**
Consumption Per Tier						
Tier 1		23,237	22,788	22,348	21,917	21,493
Tier 2		0	0	0	0	0
Tier 3		0	0	0	0	0
Total		**23,237**	**22,788**	**22,348**	**21,917**	**21,493**

Transitional Rates		Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Annual Transitional Rate	All Usage	$1.26	$1.35	$1.48	$1.62	$1.79	$1.96

Transitional Rates Per Tier - Rounded		Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Annual Rate	All Usage	$1.26	$1.35	$1.48	$1.63	$1.79	Comm/Ind

WA-9.2 - Grove Preservation — Transition to Commercial

		FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Growth (Other)	Includes Proforma Elasticity		-1.06%	-2.89%	-1.87%	-1.90%
Smoothed Growth			-1.931%	-1.931%	-1.931%	-1.931%
Projected Annual Consumption (CCF)		125,111	122,695	120,326	118,002	115,723

Tier Breaks			FY 2017/18 Usage	Percent	Summer With Conservation	Winter With Conservation	Summer Percent
Tier 1	0	15.00	125,111	100%	74,024	51,087	100%
Tier 2	16	60	-	0%	-	-	0%
Tier 3	100000000	999999999	-	0%	-	-	0%
Tier 4	1000000000	+	-	0%	-	-	0%

	Summer Jul-17	Summer Aug-17	Summer Sep-17	Summer Oct-17	Winter Nov-17	Winter Dec-17	Winter Jan-18	Winter Feb-18	Winter Mar-18	Winter Apr-18	Winter May-18	Summer Jun-18	Total	Percent
Tier 1	9,068	9,886	23,459	19,690	8,959	6,936	5,330	4,862	6,732	8,561	9,707	11,921	125,111	100%
Tier 2													-	0%
Tier 3													-	0%
Tier 4													-	0%
Total	**9,068**	**9,886**	**23,459**	**19,690**	**8,959**	**6,936**	**5,330**	**4,862**	**6,732**	**8,561**	**9,707**	**11,921**	**125,111**	**100%**

Transitional Rates Calculation

FY 2017/18 | FY 2018/19 | FY 2019/20 | FY 2020/21 | FY 2021/22

	Current Rates	FY 2017/18 Usage	Rev With Curent Rates
Tier 1	$1.07	122,695	$131,284
Tier 2			$0
Tier 3			$0
Variable Charges		122,695	$131,284
Fixed Charges			$4,545
Total			**$135,828**

Effective Volumetric Rate **$1.11 per HCF**

Meter Size	Exising Charge	Accounts
5/8 and 3/4 inc	$7.35	2
1-inch	$12.21	5
1 1/2 inch	$24.45	1
2 inch	$39.09	4
3-inch	$73.29	0
4-inch	$122.15	1
6-inch	$244.33	
8-inch	$390.91	

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Effective Commercial Volumetric Rate					
Usage	125,111	122,695	120,326	118,002	115,723
Winter	51,087	50,100	49,133	48,184	47,254
Summer	74,024	72,594	71,193	69,818	68,469
Proposed Commercial and Industrial Rates					
Winter	$1.66	$1.69	$1.72	$1.75	$1.77
Summer	$1.93	$1.97	$2.00	$2.03	$2.05
Volumetric Comm/Ind Costs	$227,671	$227,681	$226,894	$226,052	$224,001
Fixed Comm/Ind Costs	$10,376	$12,152	$14,096	$16,209	$18,481
Total Comm and Ind Costs	**$238,047**	**$239,832**	**$240,990**	**$242,261**	**$242,483**
Total Comm/Ind Usage	**125,111**	**122,695**	**120,326**	**118,002**	**115,723**
Effective Volumetric Rate	**$1.90**	**$1.95**	**$2.00**	**$2.05**	**$2.10**
Five Year Total Transition to Comm/Ind	89%				
Annualized Increase in Effective Volumetric Rate	**14%**				

Projected Fixed Revenues			FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Meter Size	**Accounts**	**Proposed Rates**					
5/8 and 3/4 inc	3		$16.40	$19.21	$22.29	$25.64	$29.24
1-inch	5		$26.04	$30.50	$35.38	$40.69	$46.40
1 1/2 inch	1		$49.92	$58.47	$67.82	$77.99	$88.93
2 inch	5		$78.70	$92.16	$106.91	$122.93	$140.16
3-inch	0		$145.89	$170.85	$198.17	$227.87	$259.80
4-inch	1		$241.86	$283.23	$328.52	$377.75	$430.67
Projected Fixed Revenue			**$10,376**	**$12,152**	**$14,096**	**$16,209**	**$18,481**

	Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Transitional Effective Volumetric Rate	**$1.11**	**$1.26**	**$1.44**	**$1.64**	**$1.87**	**$2.13**
Total Former WA-9.2 Usage		125,111	122,695	120,326	118,002	115,723
Transitional Revenue Generated		**$157,893**	**$176,522**	**$197,349**	**$220,633**	**$246,665**
Less: Fixed Revenue		($10,376)	($12,152)	($14,096)	($16,209)	($18,481)
Amount to Be Collected Through Transitional Volumetric Rate		**$147,517**	**$164,371**	**$183,253**	**$204,424**	**$228,183**
Consumption Per Tier						
Tier 1		125,111	122,695	120,326	118,002	115,723
Tier 2		0	0	0	0	0
Tier 3		0	0	0	0	0
Total		**125,111**	**122,695**	**120,326**	**118,002**	**115,723**

Transitional Rates			FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Annual Transitional Rate	All Usage	$1.07	$1.18	$1.34	$1.52	$1.73	Comm/Ind

Transitional Rates Per Tier - Rounded		Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Annual Rate	All Usage	$1.07	$1.18	$1.34	$1.53	$1.74	Comm/Ind

WA-7 - Cemeteries

WA-7 - Cemeteries	Transition to Commercial/Industrial	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Growth (Other)	Includes Proforma Elasticity		-1.06%	-2.89%	-1.87%	-1.90%
Smoothed Growth			-1.931%	-1.931%	-1.931%	-1.931%
Projected Annual Consumption (CCF)		**41,540**	**40,737**	**39,951**	**39,179**	**38,423**

Total With Rebound		Summer With Rebound	Winter With Rebound	Summer Percent
41,540	100%	25,997	15,543	100%
-	0%	-	-	0%
-	0%	-	-	0%
-	0%	-	-	0%
41,540	**100%**	**25,997**	**15,543**	**100%**

	Summer Jul-15	Summer Aug-15	Summer Sep-15	Summer Oct-15	Winter Nov-15	Winter Dec-15	Winter Jan-16	Winter Feb-16	Winter Mar-16	Winter Apr-16	Winter May-16	Summer Jun-16	Total	Percent
Tier 1	4,341	3,548	3,971	2,779	2,818	2,527	1,250	114	442	1,555	2,807	4,618	30,770	**100%**
Tier 2	-	-	-	-	-	-	-	-	-	-	-	-	-	**0%**
Tier 3	-	-	-	-	-	-	-	-	-	-	-	-	-	**0%**
Tier 4	-	-	-	-	-	-	-	-	-	-	-	-	-	**0%**
Total	**4,341**	**3,548**	**3,971**	**2,779**	**2,818**	**2,527**	**1,250**	**114**	**442**	**1,555**	**2,807**	**4,618**	**30,770**	**100%**
FY 2017/18 With Rebound													**Total**	**Percent**
Tier 1	5,860	4,790	5,361	3,752	3,719	3,005	1,685	440	817	2,099	3,777	6,234	41,540	**100%**
Tier 2													-	**0%**
Tier 3													-	**0%**
Tier 4													-	**0%**
Total	**5,860**	**4,790**	**5,361**	**3,752**	**3,719**	**3,005**	**1,685**	**440**	**817**	**2,099**	**3,777**	**6,234**	**41,540**	**100%**

Transitional Rates | FY 2017/18 | FY 2018/19 | FY 2019/20 | FY 2020/21 | FY 2021/22

	Current Rates	FY 2017/18 Usage	Rev With Curent Rates
Tier 1	$1.14	41,540	$47,355
Tier 2			$0
Tier 3			$0
Variable Charges		41,540	$47,355
Fixed Charges			$92
Total			**$47,447**

Effective Volumetric Rate **$1.14 per HCF**

Meter Size	Exising Charge	Accounts
5/8 and 3/4 inch		
1-inch		
1 1/2 inch		
2 inch		2
3-inch		
4-inch		1
6-inch		
8-inch		

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Effective Commercial Volumetric Rate					
Usage	41,540	40,737	39,951	39,179	38,423
Winter	15,543	15,242	14,948	14,659	14,376
Summer	25,997	25,495	25,003	24,520	24,046
Proposed Commercial and Industrial Rates					
Winter	$1.66	$1.69	$1.72	$1.75	$1.77
Summer	$1.93	$1.97	$2.00	$2.03	$2.05
Volumetric Comm/Ind Costs	$75,975	$75,985	$75,716	$75,429	$74,741
Fixed Comm/Ind Costs	$4,791	$5,611	$6,508	$7,483	$8,532
Total Comm and Ind Costs	**$80,766**	**$81,595**	**$82,224**	**$82,912**	**$83,273**
Total Comm/Ind Usage	**41,540**	**40,737**	**39,951**	**39,179**	**38,423**
Effective Volumetric Rate	**$1.94**	**$2.00**	**$2.06**	**$2.12**	**$2.17**
Five Year Total Transition to Comm/Ind	90%				
Annualized Increase in Effective Volumetric Rate	**14%**				

Projected Fixed Revenues			FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Meter Size	**Accounts**	**Proposed Rates**					
5/8 and 3/4 inc	0		$16.40	$19.21	$22.29	$25.64	$29.24
1-inch	0		$26.04	$30.50	$35.38	$40.69	$46.40
1 1/2 inch	0		$49.92	$58.47	$67.82	$77.99	$88.93
2 inch	2		$78.70	$92.16	$106.91	$122.93	$140.16
3-inch	0		$145.89	$170.85	$198.17	$227.87	$259.80
4-inch	1		$241.86	$283.23	$328.52	$377.75	$430.67
Projected Fixed Revenue			**$4,791**	**$5,611**	**$6,508**	**$7,483**	**$8,532**

	Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Transitional Effective Volumetric Rate	**$1.14**	**$1.30**	**$1.48**	**$1.69**	**$1.93**	**$2.20**
Total Former WA-7 Usage		41,540	40,737	39,951	39,179	38,423
Transitional Revenue Generated		**$54,090**	**$60,472**	**$67,606**	**$75,583**	**$84,501**
Less: Fixed Revenue		($4,791)	($5,611)	($6,508)	($7,483)	($8,532)
Amount to Be Collected Through Transitional Volumetric Rate		**$49,299**	**$54,861**	**$61,098**	**$68,100**	**$75,969**
Consumption Per Tier						
Tier 1		41,540	40,737	39,951	39,179	38,423
Tier 2		0	0	0	0	0
Tier 3		0	0	0	0	0
Total		**41,540**	**40,737**	**39,951**	**39,179**	**38,423**

Transitional Rates		Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Annual Transitional Rate	All Usage	$1.14	$1.19	$1.35	$1.53	$1.74	Comm/Ind

Transitional Rates Per Tier - Rounded		Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Annual Rate	All Usage	$1.14	$1.19	$1.35	$1.53	$1.74	Comm/Ind

WA-7 - Cemeteries

Transition to Landscape	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22			
Growth (Other) — Includes Proforma Elasticity	-1.06%	-2.89%	-1.87%	-1.90%	-1.94%	-1.95%	-1.93%	
Smoothed Growth	-1.931%	-1.931%	-1.931%	-1.931%				
Projected Annual Consumption (CCF)	**45,310**	**44,435**	**43,577**	**42,735**	**41,910**	**41,910**	**41,910**	**41,910**

Total With Rebound	Percent	Summer With Conservation	Winter With Conservation	Summer Percent
45,310	**100%**	30,344	14,966	**100%**
-	**0%**	-	-	**0%**
-	**0%**	-	-	**0%**
-	**0%**	-	-	**0%**
45,310	**100%**	**30,344**	**14,966**	**100%**

	Summer Jul-15	Summer Aug-15	Summer Sep-15	Summer Oct-15	Winter Nov-15	Winter Dec-15	Winter Jan-16	Winter Feb-16	Winter Mar-16	Winter Apr-16	Winter May-16	Summer Jun-16	Total	Percent
Tier 1	5,378	4,606	5,569	4,064	2,277	2,084	952	2	815	2,213	3,630	4,658	36,248	**100%**
Tier 2	-	-	-	-	-	-	-	-	-	-	-	-	-	**0%**
Tier 3	-	-	-	-	-	-	-	-	-	-	-	-	-	**0%**
Tier 4	-	-	-	-	-	-	-	-	-	-	-	-	-	**0%**
Total	**5,378**	**4,606**	**5,569**	**4,064**	**2,277**	**2,084**	**952**	**2**	**815**	**2,213**	**3,630**	**4,658**	**36,248**	**100%**
FY 2017/18 With Rebound													**Total**	**Percent**
Tier 1	6,723	5,758	6,961	5,080	2,936	2,386	1,221	299	1,107	2,557	4,461	5,823	45,310	**100%**
Tier 2													-	**0%**
Tier 3													-	**0%**
Tier 4													-	**0%**
Total	**6,723**	**5,758**	**6,961**	**5,080**	**2,936**	**2,386**	**1,221**	**299**	**1,107**	**2,557**	**4,461**	**5,823**	**45,310**	**100%**

Transitional Rates

FY 2017/18 | FY 2018/19 | FY 2019/20 | FY 2020/21 | FY 2021/22

	Current Rates	FY 2017/18 Usage	Rev With Curent Rates
Tier 1	$1.14	45,310	$51,653
Tier 2			$0
Tier 3			$0
Variable Charges		45,310	$51,653
Fixed Charges			$238
Total			**$51,891**
Effective Volumetric Rate			**$1.15 per HCF**

Meter Size	Exising Charge	Accounts
5/8 and 3/4 inch		
1-inch		
1 1/2 inch		
2 inch		3
3-inch		
4-inch		1
6-inch		
8-inch		

	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Effective Landscape Volumetric Rate					
Usage	45,310	44,435	43,577	42,735	41,910
Winter	14,966	14,677	14,394	14,116	13,843
Summer	30,344	29,758	29,183	28,620	28,067
Proposed Landscape Rates					
Winter	$1.75	$1.78	$1.81	$1.84	$1.86
Summer	$2.24	$2.28	$2.32	$2.36	$2.38
Volumetric Landscape Costs	$94,161	$93,973	$93,758	$93,515	$92,548
Fixed Landscape Costs	$5,736	$6,717	$7,791	$8,958	$10,214
Total Landscape Costs	**$99,896**	**$100,690**	**$101,549**	**$102,474**	**$102,761**
Total Landscape Usage	**45,310**	**44,435**	**43,577**	**42,735**	**41,910**
Effective Volumetric Rate	**$2.20**	**$2.27**	**$2.33**	**$2.40**	**$2.45**
Five Year Total Transition to Landscape	114%				
Annualized Increase in Effective Volumetric Rate	**16%**				

Projected Fixed Revenues						
Meter Size	**Accounts**	**Proposed Rates** FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
5/8 and 3/4 inc	0	$16.40	$19.21	$22.29	$25.64	$29.24
1-inch	0	$26.04	$30.50	$35.38	$40.69	$46.40
1 1/2 inch	0	$49.92	$58.47	$67.82	$77.99	$88.93
2 inch	3	$78.70	$92.16	$106.91	$122.93	$140.16
3-inch	0	$145.89	$170.85	$198.17	$227.87	$259.80
4-inch	1	$241.86	$283.23	$328.52	$377.75	$430.67
Projected Fixed Revenue		**$5,736**	**$6,717**	**$7,791**	**$8,958**	**$10,214**

	Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Transitional Effective Volumetric Rate	**$1.15**	**$1.33**	**$1.54**	**$1.79**	**$2.07**	**$2.41**
Total Former WA-7 Usage		45,310	44,435	43,577	42,735	41,910
Transitional Revenue Generated		**$60,194**	**$68,476**	**$77,899**	**$88,618**	**$100,811**
Less: Fixed Revenue		($5,736)	($6,717)	($7,791)	($8,958)	($10,214)
Amount to Be Collected Through Transitional Volumetric Rate		**$54,458**	**$61,760**	**$70,108**	**$79,659**	**$90,597**
Consumption Per Tier						
Tier 1		45,310	44,435	43,577	42,735	41,910
Tier 2		0	0	0	0	0
Tier 3		0	0	0	0	0
Total		**45,310**	**44,435**	**43,577**	**42,735**	**41,910**

Transitional Rates		Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Annual Transitional Rate	All Usage	$1.14	$1.20	$1.39	$1.61	$1.86	Landscape

Transitional Rates Per Tier - Rounded		Current	FY 2017/18	FY 2018/19	FY 2019/20	FY 2020/21	FY 2021/22
Annual Rate	All Usage	$1.14	$1.21	$1.39	$1.61	$1.87	Landscape