Report on the

ELECTRIC COST-OF-SERVICE AND RATE DESIGN STUDY

Pasadena Water & Power
City of Pasadena, California

Project No. 67757

June 2013

Electric Cost-of-Service
And Rate Design Study

prepared for

Pasadena Water & Power
Pasadena, California

June 2013

Project No. 67757

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

Burns & McDonnell
SINCE 1898

June 28, 2013

Ms. Shari M. Thomas
Assistant General Manager
City of Pasadena, California
150 South Los Robles Avenue, Suite 200
Pasadena, California 91101

Re: Pasadena Water & Power
Electric Cost-of-Service and Rate Design Study
Project Number 67757

Dear Ms. Thomas:

Burns & McDonnell is pleased to present this report on the Electric Cost-of-Service and Rate Design Study (the Study) completed on behalf of the City of Pasadena, California (the City) for the Pasadena Water & Power (PWP) electric utility.

This report presents the results of the Study, including the proposed new retail electric rates. The report also provides an explanation of the analyses performed to develop the seven-year financial forecast, the test period revenue requirement, and the allocated, unbundled cost-of-service for each of PWP's current and proposed electric rate classifications. It describes, in detail, the data, assumptions, and methodology used in completing the Study. The report also provides Burns & McDonnell's recommendations for PWP for new retail electric rates.

Throughout each phase of the Study, Burns & McDonnell worked closely with PWP staff to gather the utility staff's opinions and input. We greatly appreciate the opportunity to work with the City, PWP and its staff. We specifically wish to thank you, Tunji, and Clarence for your guidance and input throughout the study process. Please call us with any questions or comments you may have regarding this report.

Sincerely,
Burns & McDonnell

Ted J. Kelly
Principal and Project Manager

Gerron Blackwell
Project Analyst

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LIST OF ABBREVIATIONS AND ACRONYMS

AB 32	Assembly Bill 32, California Global Warming Solutions Act of 2006
AMI	Advanced Metering Infrastructure
AMR	Advanced Meter Reading
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CAISO	California Independent System Operator
CHP	Combined Heat and Power
City	City of Pasadena, California
D&C	Distribution and Customer Charge
DG	Distributed Generation
DOE	US Department of Energy
DR	Demand Response
EDR	Economic Development Rider
EEI	Edison Electric Institute
ESC	Energy Services Charge
FIT	Feed-in Tariff
FY	Fiscal Year
HSS	Hourly Supply Service
IPP	Intermountain Power Project
IRP	Integrated Resource Plan
kV	kilovolt
kVA	kilovolt-ampere
kVAr	kilovolt-ampere reactive
kVArh	kilovolt-ampere reactive hour
kW	kilowatt

kWh	kilowatt-hour
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory (*The DOE's primary laboratory for renewable energy and energy efficiency research and development)*
PBC	Public Benefits Charge
PCA	Power Cost Adjustment
PTO	Participating Transmission Owner
PWP	Pasadena Water & Power
Study	Cost-of-Service and Rate Design Study
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
RTP	Real-Time Pricing
TOU	Time-of-Use
TRR	Transmission Revenue Requirement
TSC	Transmission Services Charge

* * * * *

Statement of Limitations

In preparation of the Cost-of-Service and Rate Design Study (the Study), Burns & McDonnell has relied upon information provided by Pasadena Water & Power of the City of Pasadena, California (PWP). The information included various analyses, computer-generated information and reports, audited financial reports, and other financial and statistical information, as well as other documents such as operating budgets and current retail electric rate schedules. In addition, input to key assumptions regarding expected future levels of revenue, sales, and expenditures was provided by PWP staff to Burns & McDonnell. While Burns & McDonnell has no reason to believe that the information provided, and upon which Burns & McDonnell has relied, is inaccurate or incomplete in any material respect, Burns & McDonnell has not independently verified such information and cannot guarantee its accuracy or completeness.

Estimates and projections prepared by Burns & McDonnell relating to performance and costs are based on Burns & McDonnell's experience, qualifications, and judgment as a professional consultant. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, contractors' procedures and methods, unavoidable delays, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding, and market conditions or other factors affecting such estimates or projections, Burns & McDonnell does not guarantee the accuracy of its estimates or predictions.

Revision History

Revision	Issue Date	Author	Reviewer	Notes
0	14 - Dec. - 2012	Blackwell	Kelly	Revenue Requirements and COS. Original release.
1	17 - Jan. - 2013	Blackwell	Kelly	Revenue Requirements and COS. General revisions.
2	28 - Feb. - 2013	Blackwell	Kelly	Revised Rev. Requirements Analysis. Added Rate Design sections.
3	8 - Apr. - 2013	Blackwell	Kelly	Revised Rate Recommendations and Executive Summary
4	3 - May - 2013	Blackwell	Kelly	Picked up PWP comments. Revised ES and Billing Demand Sections. Other general revisions.
5	31 - May - 2013	Blackwell	Kelly	Revisions based on 5/23 discussion in PWP offices.
6	20 - June - 2013	Blackwell	Kelly	Revised ES and Intro. Other general revisions.
7	28 - June - 2013	Blackwell	Kelly	Final Report.
7	28 – Feb. - 2014	Blackwell	Kelly	Final Report. Watermark removed.

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1.0 EXECUTIVE SUMMARY

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In April 2012, the City of Pasadena, California (the City) retained Burns & McDonnell Engineering Company (Burns & McDonnell) of Kansas City, Missouri to prepare a Cost-of-Service and Rate Design Study (the Study) on behalf of the Pasadena Water & Power (PWP) electric utility. This report describes the approach followed and the assumptions made in the completion of the analyses for PWP and presents the results of the Study, including the proposed new retail electric rates.

PWP reviews and updates electric rates on a regular basis. The Power Cost Adjustment (PCA) was last increased in October 2010. The most recent increase in Customer and Distribution rates took place in July 2012. Transmission rates were lowered in July 2006 as a result of PWP joining Participating Transmission Owner (PTO) with California Independent System Operator (CAISO). The previous electric cost-of-service and rate study for the PWP electric utility was completed in 2000 and implemented in 2001.

1.1 PURPOSE

Numerous changes have occurred in the electric industry since the last cost-of-service and rate restructuring was performed. The objective in the last cost-of-service and rate design study was to unbundle rates in anticipation of deregulation of California's energy market. As part of this cost-of-service and rate structure design process, rates were designed to address the ongoing changes taking place in the electric industry. PWP's directive was to design rates that, when implemented, meet the following goals:

- Recover the electric system's cost-of-service
- Support the development and purchase of renewable resources
- Promote conservation and demand-side management objectives
- Reflect the impacts of Greenhouse Gas and other regulations, and new initiatives such as Distributed Generation, Feed-in-Tariff, Smart Metering, Smart Grid, and Electric Vehicle programs
- Provide economic development incentive rate recommendations
- Facilitate Distributed Generation policy objectives while providing adequate cost recovery for PWP's distribution services; and
- Accurately reflect the time differentiated cost of providing service

For the Study, PWP desired to analyze historical costs of providing electric service to its customers and to incorporate projections of future costs into its annual system revenue requirement. In addition, PWP is looking to add several rate classifications so the electric utility can begin offering electric vehicle (EV), feed-in tariff, and net metering services associated with its ongoing advanced technology build-out.

1.2 ELECTRIC RATE CLASSIFICATIONS

PWP bills its retail electric customers based on rate schedules last updated July 2012. The current rate schedule classifications are as follows:

- Residential Single Family
- Residential Multi-Family
- Small Commercial and Industrial
- Medium Commercial and Industrial – Secondary
- Medium Commercial and Industrial – Primary
- Large Commercial and Industrial – Secondary
- Large Commercial and Industrial – Primary
- Street Lighting and Traffic Signals
- Pilot Time-of-Use Electric Vehicle Rate 1
- Pilot Time-of-Use Electric Vehicle Rate 2

Currently, the Light & Power Rate Ordinance sets rates and charges for electric customers. The current electric rate structures are comprised of the following:

- Distribution & Customer (D&C) Charge, *Residential customers only*
- Distribution Charge
- Customer Charge
- Energy Services Charge (ESC)
- Power Cost Adjustment
- Transmission Services Charge (TSC)
- Public Benefits Charge (PBC)

1.3 APPROACH

The Study performed by Burns & McDonnell consisted of the development of a load forecast, a revenue requirements analysis, a cost-of-service analysis, and a rate design analysis. Summary descriptions of each phase of the Study are provided herein.

The load forecast developed, and on which all subsequent analyses of the Study were based, forecasts demand and energy requirements for each rate classification of the electric utility. Load projections were developed for each month of the seven-year forecast to form the basis for the financial forecast. Section 3.0 of this report explains the analysis conducted and the considerations taken in the development of the load forecast.

The annual revenue requirement to be used in the subsequent phases of the Study was determined based on a seven-year financial forecast of PWP's revenues, expenses, capital requirements, and other income and expenses. This financial forecast included projections of known changes in annual costs of large dollar items, i.e. power cost projections, and was based on known increases in costs due to climate change legislation, the renewable portfolio standard and rates from wholesale power supply contracts with multiple electric generating facilities. Other categories of expenses were forecast using historical trends or assumed annual rates of inflation. For the Study, the annual revenue requirement was based on the forecast results for FY 2013. Section 4.0 of this report presents and explains the seven-year financial forecast and annual revenue requirement.

The cost-of-service analysis included the assignment, or unbundling, of the various costs and return included in the test period net revenue requirement. These costs were assigned to the electric utility's functional services (i.e. power supply, distribution, transmission, etc.). The unbundled cost components of the net revenue requirement were then allocated to the various electric rate classifications. The resulting allocated cost-of-service for each rate classification was compared to the estimated annual service revenues for each class to assess the adequacy of the projected cost recovery provided by the existing retail rates. These steps and the corresponding results are detailed in Section 5.0 of this report.

The results of the cost-of-service analysis provided a basis for PWP to consider whether revisions to its electric rates might be necessary. Sections 6.0 and 7.0 of this report discuss the implications of the cost-of-service results on PWP's current electric rates and describe the proposed modifications to retail rates. Comparisons of sample monthly bills based on the current and proposed standard and Time-of-Use (TOU) rates for each customer classification are also presented.

Section 8.0 of the report addresses additional rate design considerations examined as part of the Study. Among these considerations are the power factor adjustment, net metering, self-generation, demand response, distributed generation, feed-in-tariffs, green power, power cost adjustment, transmission services charge, public benefits charge, and smart metering. Burns & McDonnell also discusses the formulas used to calculate these rates and provides recommendations for associated adjustments, as appropriate.

The Summary and Recommendations section, included as Section 9.0 of this report, summarizes key points from the Study and presents Burns & McDonnell's recommendations for the PWP electric utility. The recommendations are also provided below.

1.4 STUDY RECOMMENDATIONS

Burns & McDonnell recommends a number of actions be taken by PWP based on the analyses conducted during the Study. The Study recommendations include the following:

1.4.1 Revenue Adjustments

It is recommended PWP increase the Distribution, Customer, and ESC rates by 10.0 percent for FY 2014. This will allow PWP to meet its outstanding debt service obligations and its required City Transfer. Moving forward, PWP should increase its distribution, customer, and ESC rates in subsequent years by the percentages shown in Table 1-1.

Table 1-1: Proposed Revenue Adjustments

Fiscal Year	# of Months Effective	Adjustment
FY 2013	12	0.0%
FY 2014	12	10.0%
FY 2015	12	4.0%
FY 2016	12	0.0%
FY 2017	12	1.0%

1.4.2 Residential Billing

PWP should bill Residential customers separately for distribution and customer service associated costs. This approach will allow PWP to recover costs from Residential consumers more appropriately, as opposed to the combined Distribution & Customer charge currently being billed to Residential customers.

PWP should eliminate the $2.00 per month credit given to Residential Multi-Family customers as the cost-of-service for the class was calculated and rates were designed to recover appropriate levels of revenue.

1.4.3 Billing Demand Ratchet

Billing demand is the demand upon which billing to a customer is based, as specified in a rate schedule or contract. A demand ratchet sets the level of demand for computing a customer's monthly demand charge equal to the highest level of demand utilized at any point during a preceding time period.[1] Analysis was conducted to develop an alternative to the current 12-month billing demand ratchet. The billing demand ratchet options closely examined included the following:

- Current 12-month demand ratchet
- Four-month demand ratchet
- Seasonal four-month demand ratchet
- No ratchet

Table 1-2 compares estimates of each of these options' relative impact on test year demand billing prior to rate adjustments.

Table 1-2: Demand Average Cost Summary

Description	12-Month *Current Rates*	4-Month *Option*	4-Month Seasonal *Winter Option*	*Summer Option*	1-Month *Option*
	$/kW-month	$/kW-month	$/kW-month	$/kW-month	$/kW-month
Seondary Service	10.89	11.72	10.50	14.09	16.72
Primary Service	10.76	11.53	11.10	12.36	16.34

Based on its detailed demand billing cost analysis, Burns & McDonnell recommends the adoption of a four-month billing demand ratchet. Section 6.2.2 of the report provides a billing cost comparison to demonstrate the impact the recommended change will have on a customer. A four-month ratchet approach to determining billing demand will simultaneously provide rate relief to winter peaking customers, when distribution infrastructure is burdened the least, while maintaining PWP's mechanism to recover costs for distribution assets built to enable adequate power delivery for all customers during the summer months, when system load is greatest and when investment in distribution infrastructure is most critical.

1.4.4 Power Cost Adjustment

PWP should maintain the use of the PCA as a mechanism to recover power supply or energy related cost. On the occasion that revenue exceeds the theoretical ESC fund balance target, PWP should credit

[1]EEI, E. E. (2005). Glossary of Electric Industry Terms. Edison Electric Institute (EEI).

customers appropriately. The PCA revenue requirement and rate formulas appear reasonable. No formula modifications are recommended or required at this time.

1.4.5 Transmission Services Charge

Burns & McDonnell recommends that PWP continue to utilize the TSC to recover the Transmission Revenue Requirement. The TSC revenue requirement and rate formula appears reasonable. No changes are recommended to those formulas. Moving forward, PWP should adjust its TSC to the rates shown in Table 1-3.

Table 1-3: Proposed TSC Rate Adjustments

Fiscal Year	TSC Secondary	TSC Primary
	$/kWh	$/kWh
FY 2013 [1]	0.00821	0.00802
FY 2014	0.00885	0.00866
FY 2015	0.00931	0.00912
FY 2016	0.00998	0.00979
FY 2017	0.01069	0.01050

[1] Current TSC rates.

1.4.6 Current and Proposed Electric Rates

Distribution, Customer, and ESC rate recommendations were prepared based on the Residential billing, billing demand and PCA proposals. It is expected that revised rate recommendations will be implemented for FY 2014. Table 1-4 through Table 1-10 present side-by-side comparisons of the current and proposed electric rates by customer classification.

Table 1-4: Current and Proposed Residential Single Family Rates

	Current Rates		Recommended Rates	
Rate Component	Flat	TOU	Flat	TOU
D&C Charge - $/month				
0 to 250	6.02	6.02	Recommendation: Bill Distribution and Customer Charges Separately. See Below	
251 to 350	12.32	12.32		
351 to 450	24.94	24.94		
451 to 550	35.97	35.97		
551 to 650	45.43	45.43		
651 to 750	56.47	56.47		
751 to 1,000	67.5	67.5		
> 1,000	89.57	89.57		
Customer Charge - $/month	---	---	7.53	7.53
Minimum Charge - $/month	6.02	6.02	7.53	7.53
Distribution Charge - $/kWh	---	---	0.05848	0.05848
Energy Services Charge - $/kWh				
winter on-peak	0.08397	0.08892	0.08671	0.09720
winter off-peak		0.07891		0.07665
summer on-peak	0.09323	0.12454	0.10037	0.13702
summer off-peak		0.08132		0.08831
Transmission Services Charge - $/kWh	0.00821	0.00821	0.00885	0.00885

Table 1-5: Current and Proposed Residential Multi-Family Rates

Rate Component	Current Rates		Recommended Rates	
	Flat	TOU	Flat	TOU
D&C Charge - $/month			Recommendation: Bill Distribution and Customer Charges Separately. See Below	
0 to 250	6.02	6.02		
251 to 350	12.32	12.32		
351 to 450	24.94	24.94		
451 to 550	35.97	35.97		
551 to 650	45.43	45.43		
651 to 750	56.47	56.47		
751 to 1,000	67.5	67.5		
> 1,000	89.57	89.57		
Customer Charge - $/month	---	---	7.53	7.53
Minimum Charge - $/month	6.02	6.02	7.53	7.53
Distribution Charge - $/kWh	---	---	0.05848	0.05848
Energy Services Charge - $/kWh				
winter on-peak	0.08397	0.08892	0.08671	0.09720
winter off-peak		0.07891		0.07665
summer on-peak	0.09323	0.12454	0.10037	0.13702
summer off-peak		0.08132		0.08831
Transmission Services Charge - $/kWh	0.00821	0.00821	0.00885	0.00885

Table 1-6: Current and Proposed Small Commercial Rates

Rate Component	Current Rates		Recommended Rates	
	Flat	TOU	Flat	TOU
Customer Charge - $/month				
Single-Phase	14.16	14.16	7.85	7.85
Three-Phase	19.07	19.07	10.57	10.57
Minimum Charge - $/month				
Single-Phase	14.16	14.16	7.85	7.85
Three-Phase	19.07	19.07	10.57	10.57
Distribution Charge - $/kWh	0.04475	0.04475	0.05641	0.05641
Energy Services Charge - $/kWh				
winter on-peak	0.0828	0.08681	0.0869	0.09741
winter off-peak		0.07861		0.07682
summer on-peak	0.09151	0.12713	0.10049	0.13719
summer off-peak		0.07956		0.08842
Transmission Services Charge - $/kWh	0.00821	0.00821	0.00885	0.00885

Table 1-7: Current and Proposed Medium Commercial – Secondary Rates

Rate Component	Current Rates		Recommended Rates	
	Flat	TOU	Flat	TOU
Customer Charge - $/month	60.22	60.22	19.49	19.49
Minimum Charge - $/month	362.32	362.32	495.90	495.90
Distribution Charge - $/kW [1]	10.89	10.89	15.88	15.88
Energy Services Charge - $/kWh				
winter on-peak	0.08463	0.08828	0.08665	0.09713
winter off-peak		0.08035		0.07660
summer on-peak	0.09588	0.12468	0.10019	0.13678
summer off-peak		0.08313		0.08816
Transmission Services Charge - $/kWh	0.00821	0.00821	0.00885	0.00885

[1] Recommended Distribution Charge includes consideration for revenue adjustments and proposed four-month ratchet.

Table 1-8: Current and Proposed Medium Commercial – Primary Rates

Rate Component	Current Rates		Recommended Rates	
	Flat	TOU	Flat	TOU
Customer Charge - $/month	83.92	83.92	24.81	24.81
Minimum Charge - $/month	376.72	376.72	358.40	358.40
Distribution Charge - $/kW [1]	10.54	10.54	11.12	11.12
Energy Services Charge - $/kWh				
winter on-peak	0.08371	0.08731	0.08600	0.09640
winter off-peak		0.07963		0.07603
summer on-peak	0.09404	0.12378	0.09938	0.13567
summer off-peak		0.08220		0.08744
Transmission Services Charge - $/kWh	0.00802	0.00802	0.00866	0.00866

[1] Recommended Distribution Charge includes consideration for revenue adjustments and proposed four-month ratchet.

Table 1-9: Current and Proposed Large Commercial – Secondary Rates

Rate Component	Current Rates	Recommended Rates
Customer Charge - $/month	160.21	39.64
Minimum Charge - $/month	3181.21	4773.65
Distribution Charge - $/kW [1]	10.86	15.78
Energy Services Charge - $/kWh		
winter on-peak	0.08829	0.09584
winter off-peak	0.07909	0.07558
summer on-peak	0.12644	0.13496
summer off-peak	0.08093	0.08698
Transmission Services Charge - $/kWh	0.00821	0.00885

[1] Recommended Distribution Charge includes consideration for revenue adjustments and proposed four-month ratchet.

Table 1-10: Current and Proposed Large Commercial – Primary Rates

Rate Component	Current Rates	Recommended Rates
Customer Charge - $/month	183.93	44.94
Minimum Charge - $/month	3111.93	3359.95
Distribution Charge - $/kW [1]	10.51	11.05
Energy Services Charge - $/kWh		
winter on-peak	0.08867	0.09512
winter off-peak	0.07879	0.07502
summer on-peak	0.12102	0.13388
summer off-peak	0.07830	0.08629
Transmission Services Charge - $/kWh	0.00802	0.00866

[1] Recommended Distribution Charge includes consideration for revenue adjustments and proposed four-month ratchet.

As part of the Study, a Street Lighting and Traffic Signals Service cost analysis was prepared and rate adjustments were developed for implementation with the rate adjustments for the other classes. The cost-of-service analysis established the allocated cost recovery requirement for the Lighting classes. Based on the allocated costs, there is a need for significant rate adjustments for some lighting types. Much of the adjustment is driven by a reduction in allocated distribution cost. For unmetered lamp lighting, a cost buildup was completed for each lamp type the utility offers. Consideration was made for each lamp's demand, ballast losses, estimated useful life, and average power supply cost. The lighting cost analysis indicated, in some instances, that significant changes should be made to rates to be more reflective of the costs for providing the service. Table 1-11 and Table 1-12 present the current and proposed monthly rates for the class.

Table 1-11: Current and Proposed Street Lighting and Traffic Signals Rates

Description	Current Rates	Recommended Rates
	- $/kWh -	- $/kWh -
Street Lighting - Metered Distribution Rate		
Street Lighting	0.03646	0.02946
Traffic Signals and Signs	0.05397	0.02946
Street Lighting - Unmetered Distribution Rate		
Street Lighting	0.05397	0.02946
Traffic Signals and Signs	0.05397	0.02946
Energy Services Charge	0.06500	0.08130
Transmission Services Charge	0.00821	0.00885

Table 1-12: Current and Proposed Monthly Unmetered Lamp Rates

Description	Current Rates	Recommended Rates	Description	Current Rates	Recommended Rates
	- $/month -	- $/month -		- $/month -	- $/month -
Incandescent			High Pressure Sodium (HPS)		
1,000 Lumen	1.00	1.42	70 Watts	1.37	1.49
1,500 Lumen	1.19	2.07	100 Watts	1.91	2.07
2,500 Lumen	2.10	3.31	150 Watts	2.61	2.99
4,000 Lumen	3.36	5.16	200 Watts	3.33	3.92
6,000 Lumen	4.82	7.61	250 Watts	4.24	4.84
10,000 Lumen	7.38	12.55	310 Watts	5.18	5.95
67 Watts	0.91	1.42	400 Watts	6.44	7.61
69 Watts	0.93	1.47			
100 Watts	1.39	2.07	Induction Lamps		
103 Watts	1.39	2.12	50 Watts	0.71	1.06
150 Watts	2.03	2.99	65 Watts	0.90	1.38
202 Watts	2.73	3.95	85 Watts	1.18	1.79
303 Watts	4.10	5.82	135 Watts	1.88	2.72
			150 Watts	2.00	2.99
Mercury Vapor (MV)					
3,500 lumens	1.72	2.07	Light Emitting Diode (LED)		
7,000 lumens	2.84	3.46	26 Watts	0.37	0.50
11,000 lumens	3.95	4.84	27 Watts	0.37	0.52
20,000 lumens	6.23	7.61			
35,000 lumens	10.56	13.16	Bus Stop		
54,000 lumens	14.92	18.71	4-60 w att unit bus Stop	5.20	1.28
			2-40 w att unit bus Stop	0.00	0.85
Fluorescent					
213 Watts	2.88	4.16	Metal Halide (MH)		
248 Watts	3.36	4.81	400 Watts	6.14	7.61
18 Watts	0.00	0.38	100 Watts	1.54	2.07
27 Watts	0.00	0.57			

1.4.7 TOU Pricing Periods

There is an opportunity to encourage customers' selection of TOU rate schedules by reducing potential barriers. One of the limiting factors of participation may be the timing and number of hours in the on-peak pricing periods. It is recommended that the winter on-peak pricing period be reduced from sixteen hours to twelve hours and the summer on-peak pricing period be reduced from eight hours to six. The reduction of on-peak hours is a step in the right direction; however, PWP should consider reducing its on-peak periods even more to encourage participation in the TOU program. Shorter on-peak timeframes during hours when customers are more likely to respond combined with greater pricing signals would likely encourage selection of TOU rate schedules. This can be done while managing system load and associated costs. Another limiting factor may be placing the up-front metering installation cost burden on the customer. Without specifics on costs, customers may choose not to research, select a contractor and have metering equipment installed independently. To encourage participation, the electric utility should consider funding the installation cost of metering equipment and recouping the cost through a TOU metering charge.

1.4.8 Power Factor Adjustment

Power factor is the ratio of real power (kW) to apparent power (kVA) at any given point and time in an electrical circuit. Generally, it is expressed as a percentage ratio. A power factor adjustment is a clause in a rate schedule that provides for an adjustment in the billing if the customer's power factor varies from a specified percentage or range of percentages.[1]

It is recommended PWP implement a power factor adjustment to billing demand to recover cost for investments in power factor correction rather than adjusting the actual $/kW-month demand rate, as it does today. The adjustment should be made to the maximum metered demand to determine billing demand for customers whose power factors at their metered billing period peaks are not at least 85 percent. It is also recommended that the adjusted billing demand be no more than two times the maximum metered demand utilized as the dividend in the adjustment calculation.

1.4.9 Net Metering

Burns & McDonnell recommends that PWP lower its net metering premium from 6.6¢/kWh to 6.329¢/kWh. The proposed rate is the difference between the proposed winter Residential Single Family Service Option A ESC, which is the lowest proposed flat Residential ESC, and the internally developed estimated average cost of wind and solar generation in southern California. In addition, Burns & McDonnell recommends PWP lower its payment for renewable energy credits (RECs) or attributes purchased from net metering customers. Table 1-13 presents side-by-side comparisons of the current and proposed net metering rates.

The recommended REC rebate reduction is due in part to the fact that those RECs are not used by PWP to meet RPS goals. In addition, the proposed rebate for net metering RECs would match the proposed Green Power premium as it does today. If a distributed generation rate tariff is implemented, Burns & McDonnell recommends that the maximum generating capacity for any solar or wind net metering customer be capped at 30 kW as opposed to the current 1-MW limit.

Table 1-13: Proposed Net Metering Premium and REC Compensation

Description	Current Rates	Recommended Rates
	- $/kWh -	- $/kWh -
Retail Energy Services Charge Rate	As Applicable	As Applicable
Net Energy Metering Compensation	0.06600	0.06329
Net Energy Metering Compensation for Credits/Attributes	0.02500	0.02000

1.4.10 Distributed Generation

Burns & McDonnell recommends that when PWP establishes a Distributed Generation (DG) rate tariff, service should be made available to customers with a minimum monthly demand of 30 kW and a maximum demand of 1.0 MW. DG customers should utilize bi-directional demand meters and maintain a power factor of at least 85 percent. It is proposed that the energy credit for non-renewable distributed generation for any day shall equal the published California Independent System Operator (CAISO) market price per MWh minus the calculated power supply return on rate base. For renewable DG, Burns & McDonnell recommends the energy credits presented in Table 1-14.

Table 1-14: Proposed Renewable Distributed Generation Rates

Description	Avoided Cost
	- $/kWh -
Wind:	
Winter On-Peak	0.13452
Winter Off-Peak	0.10608
Summer On-Peak	0.16382
Summer Off-Peak	0.10559
Solar:	
Winter On-Peak	0.16814
Winter Off-Peak	0.13260
Summer On-Peak	0.20478
Summer Off-Peak	0.13198

The energy credits are based on internal estimates for renewable power in southern California at each technology's respective avoided cost. The avoided cost of wind generation was estimated to be $120/MW based on the cost of a small scale wind project. The avoided cost of solar generation was estimated to be $150/MW based on the cost of a 1-MW, rooftop photovoltaic system. The avoided cost of renewable generation technologies should be recalculated by the utility no less than once per year. The DG rates should be appropriately adjusted based on these updated cost calculations. The ownership of associated DG RECs would be transferred from the customer to PWP for each kWh produced.

1.4.11 Demand Response

PWP currently has a Demand Response (DR) program in place, but the program is underutilized. The utility should review the strategies on which its current program was based and solidify the program's goals by utilizing the strategies outlined previously as guidelines. It is the opinion of Burns & McDonnell that the utility should initially focus on a peak load reduction strategy in order to reduce PWP's exposure the market during the peak hours of the day, when power is most expensive.

A demand response 'event' occurs at a specific time when a utility calls for load curtailment from program participants. If 10 percent of the approximately 56,000 Residential customers are able to reduce their respective loads by 1.25 kW during an event, the utility would reduce its load requirement by 7 MW. The estimated demand reduction of 1.25 kW per customer is based on the estimated impact of cycling off a four-ton 13 Seasonal Energy Efficiency Ratio air conditioning unit; a typical sized unit for a four person home.

The estimated target reimbursement amount for participating in a DR program should be based on PWP's estimated power supply demand cost savings from reducing electrical load during the system peak hour of the month. For the Study, internal estimates for the installed cost of four peaking capacity technologies were developed. The average cost for these technologies was $1,175/kW. This avoided cost of capacity should serve as the basis for the DR pricing program.

1.4.12 Feed-in Tariff

A PWP Feed-in Tariff (FIT) program should be made available for customers capable of generating between 100 kW and 1,000 kW of renewable power. The summation of contract subscriptions should not exceed 10 MW. The program should offer contract lengths of 10, 15, or 20 years. Burns & McDonnell recommends the 2014 energy credits average 15.0¢/kWh. The energy credits are based on internally-developed estimates for the avoided cost of solar power in southern California.

The recommended compensation amount reflects the average rate PWP would pay for FIT distributed generation. Analysis should be completed to develop seasonal time-based rates for the program. The rates would not vary over the term of the purchase power agreement. However, the rates should be recalibrated no less than each year for the program to reflect varying costs of power. Detailed analysis should be completed to further solidify program scope and pricing.

1.4.13 Green Power Service

Burns & McDonnell recommends PWP lower the premium required to participate in the Green Power Service program from 2.5¢/kWh to no more than 2.0¢/kWh. The combination of a lower premium and increased focus and resources on advertising the program, to increase visibility, should help spur voluntary participation. This recommendation is based on data available in the California market for green power programs.

1.4.14 Real-time Pricing

Burns & McDonnell is not currently recommending that PWP offer a real-time pricing (RTP) tariff. Through RTP customers would be incentivized to monitor electrical usage during high priced, peak usage hours. This will provide customers the opportunity to, at times, achieve an average energy rate lower than the flat rate offered to the customers' normal rate class. RTP would also offer billing flexibility to customers, but there are investments PWP would need to make as well. Significant infrastructure spending for metering associated costs is necessary to support a system-wide roll-out. Offering an RTP option would also likely result in decreased energy sales and a corresponding reduction in revenues. In addition, PWP would likely see increased recurring costs to administer the program.

At such time that PWP implements an RTP tariff, it should be available to all customers with TOU metering infrastructure and be applicable to the ESC portion of the bill. The day-ahead CAISO market price per MWh plus the calculated power supply return on rate base, up to nine percent, should be utilized as the ESC.

1.4.15 Economic Development Rider

Burns & McDonnell recommends that PWP offer an economic development rider (EDR). The program should be made available to customers bringing at minimum 100 kW of new load to the system. The overall program should be capped at 5 MW. The EDR tariff should be available to either new PWP customers meeting demand and load factor requirements, or existing customers who meet the load factor requirements and are increasing their maximum demand by at least the minimum qualifying threshold of

100 kW. The proposed EDR offers a three-year discount on Total Electric Services, as currently designated in PWP's billing system. Eligible customers would receive a 25 percent discount in year 1, followed by discounts of 15, and 5 percent in year two and year three, respectively. EDR contracts are offered by utilities to stimulate job growth, add new customers and promote system expansion.

1.4.16 Advanced Metering

To achieve operational effectiveness, interval metering, two-way communication with customers, and advanced distribution system awareness, many utilities are implementing advanced metering networks. PWP should consider investment in advanced metering technology for all its customers over a reasonable time period based on program costs, achievable benefits, and internal rate of return analysis. If desired, PWP could undertake a business planning study to determine an appropriate strategy for moving forward with an advanced metering implementation program.

1.4.17 Conclusion

PWP should monitor the financial position of the PWP electric utility, including adequacy of cost recovery and cash balances on an on-going basis to confirm that the implementation of the proposed rates is maintaining its financial requirements. Burns & McDonnell recommends the reexamination of the utility's financial plan, costs of service, and electric rates every five years.

* * * * *

2.0 INTRODUCTION

2.0 INTRODUCTION

In April 2012, the City of Pasadena, California (the City) retained Burns & McDonnell Engineering Company (Burns & McDonnell) of Kansas City, Missouri to prepare a Cost-of-Service and Rate Design Study (the Study) on behalf of the Pasadena Water & Power (PWP) electric utility. This report describes the approach followed and the assumptions made in the completion of the analyses for PWP and presents the results of the Study, including the proposed new retail electric rates.

PWP reviews and updates electric rates on a regular basis. The Power Cost Adjustment (PCA) was last increased in October 2010. The most recent increase in Customer and Distribution rates took place in July 2012. Transmission rates were lowered in July 2006 as a result of PWP joining Participating Transmission Owner (PTO) with California Independent System Operator (CAISO). The previous electric cost-of-service and rate study for the PWP electric utility was completed in 2000 and implemented in 2001.

2.1 PURPOSE

Numerous changes have occurred in the electric industry since the last cost-of-service and rate restructuring was performed. The objective in the last cost-of-service and rate design study was to unbundle rates in anticipation of deregulation of California's energy market. As part of this cost-of-service and rate structure design process, PWP desired to create new rates that address the ongoing changes taking place in the electric industry. PWP's desire was to have rates developed and implemented that:

- Recover the electric system's cost-of-service
- Support the development and purchase of renewable resources
- Promote conservation and demand-side management objectives
- Reflect the impacts of Greenhouse Gas and other regulations, and new initiates such as Distributed Generation, Feed-in-Tariff, Smart Metering, Smart Grid, and Electric Vehicle programs
- Facilitate Distributed Generation policy objectives while providing adequate cost recovery for PWP's distribution services; and
- Accurately reflect the time differentiated cost of providing service

For the Study, PWP desired to analyze historical costs of providing electric service to its customers and to incorporate projections of future costs into its annual system revenue requirement. In addition, PWP is looking to add several rate classifications so the electric utility can begin offering electric vehicle (EV), feed-in tariff, and net metering services associated with its ongoing advanced technology build-out.

2.2 RELEVANT TERMS AND CONCEPTS

The following are definitions of technical terms and concepts used throughout the report.

Advanced Metering

A system of meter technologies that adds computer and communications technology to the existing electricity grid so it can operate more efficiently and reliably. For example, the local utility will be able to immediately pinpoint a power outage without having to be called by a customer.

Billing Demand

The demand upon which billing to a customer is based, as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and therefore does not necessarily coincide with the actual measured demand of the billing period.[1]

Cost of Service

The total costs incurred by a company in providing utility services. Usually refers to annual costs unless otherwise specified. This amount, which consists of estimated operating expenses, depreciation, taxes, a return on the rate base (investment), and possibly other costs, is used to design and establish regulated "cost-based" rates.[1]

Cost of Service Analysis

An analysis of the costs incurred by the utility in producing, transmitting, and distributing electricity to its customers, by customer class, in relation to revenues collected from each class or projected to be collected under average historical embedded cost of the existing plant and expenses in a test year, past or future; or they may be the long-run incremental costs of the utility's service, that is, the cost per year of the capacity and customer load planned for a future period of time expressed in constant current dollars. This analysis is used as a step in setting rates.[1]

Demand Ratchet

A method of establishing the level of demand that a customer must pay for through a demand charge. The ratchet sets the level of demand for computing a customer's monthly demand charge equal to the highest level of demand (kw) utilized at any point during a preceding time period (e.g., one year).[1]

Demand Response (DR)

Load Response called for by others and price response managed by end-use customers. Load response includes direct load control such as residential air conditioners, partial or curtailable load reductions, and complete load interruptions. Price response includes real-time pricing, dynamic pricing, coincident peak pricing, time-or-use rates, and demand bidding or buyback programs.[1]

Demand-Side Management (DSM)

The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.[1]

Distributed Generation (DG)

A term referring to a small generator, typically 10 megawatts or smaller, that is sited at or near load, and that is attached to the distribution grid. Distributed generation can serve as a primary or backup energy source, and can use various technology, including combustion turbines, reciprocating engines, fuel cells, wind generators, and photovoltaics.[1]

Economic Development Rider

A rate or rate discount that is designed to induce specific development actions by customers that brings new or significantly increased loads. For example, utilities have offered rate discounts for industrial customers that expand employment or locate significant activities in their service territories.[1]

Feed-in Tariff (FIT)

A feed-in tariff is a policy mechanism designed to accelerate investment in renewable energy technologies. It achieves this by offering long-term contracts to renewable energy producers, typically based on the cost of generation of each technology. Technologies such as wind power, for instance, are awarded a lower per-kWh price, while technologies such as solar PV are offered a higher price, reflecting higher costs.

Functionalization

The procedural step in a cost of service study that categorizes the supply costs related to the operating functions (e.g., generation, transmission, customer, and distribution). The next step is to classify the functionalized costs to categories reflecting cost incurrence. These categories are generally demand, energy, and customer costs.[1]

Load Factor

The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. Load factor, in percent, also may be derived by multiplying the kilowatt-hours in the period by 100 and dividing by the product of the maximum demand in kilowatts and the number of hours in the period.[1]

Load Forecast

Predicted demand for electric power. A load forecast may be short-term (e.g., 15 minutes) for system operation purposes, long-term (e.g., 5 to 20 years) for generation planning purposes, or for any range in between. Load forecasts may include peak demand (kW), energy (kWh), reactive power (kVAr), and/or load profile. Forecasts may be made of total system load, transmission load, substation/feeder load, individual customers' loads, and/or appliance loads.[1]

Net Metering

A utility metering practice in which utilities measure and bill for the net electricity consumption or generation of their customers with small generators. Net metering can be accomplished through two means: (1) A single, bi-directional electric meter that turns backward when the customer’s generator is producing energy in excess of his demand and forward when the customer’s demand exceeds the energy generated or (2) By separately metering the flows of electricity into and out of the customer’s facility. Net metering provisions vary by state and utility, but usually apply only to very small generators that typically use solar or wind energy.[1]

Power Factor

The ratio of real power (kW) to apparent power (kVA) at any given point and time in an electrical circuit. Generally, it is expressed as a percentage ratio.[1]

Power Factor Adjustment

A clause in a rate schedule that provides for an adjustment in the billing if the customer's power factor varies from a specified percentage or range of percentages.[1]

Real-Time Pricing

A method of charging for energy that changes the price at irregular times as the marginal cost of generation changes. It is accompanied by some form of communications system that informs customers of the current price as that price is changing, so that the customers have the opportunity to change their usage in response to price changes.[1]

Revenue Requirement

The sum total of the revenues required to pay all operating and capital costs of providing service.[1]

Time-of-Use (TOU) Pricing

A method of electricity pricing where prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year. Prices paid for energy consumed during these periods are pre-established and known to consumers in advance, allowing them to vary their usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall.

Unbundling

Selling various component parts of a product or service separately, usually at a price that reflects costs for only that component of the product or service.[1]

2.3 APPROACH

The Study performed by Burns & McDonnell consisted of the development of a load forecast, a revenue requirements analysis, a cost-of-service analysis, and a rate design analysis. Throughout each phase of the Study, Burns & McDonnell worked closely with PWP staff to gather the utility staff’s opinions and input. Summary descriptions of each phase of the Study are provided herein.

2.3.1 Load Forecast

The initial phase of the Study was the preparation of the load forecast. The load forecast developed for the Study is a seven-year forecast of class-specific energy sales and peak demand for the PWP electric utility. The forecast took into consideration three years of historical data through fiscal year (FY) 2012 and budget year estimations for FY 2013 in order to develop annual projections through FY 2020.

Through the load forecast analysis, projections were made for each year of the analysis period for customer accounts, energy sales, and billing demand by customer class. When combined, these components formed system-level projections for load distribution and energy requirements. System loss percentages are projected to total 6.3 percent in each year of the forecast. Section 3.0 of this report explains the analysis conducted and the considerations taken in the development of the load forecast.

2.3.2 Revenue Requirements Analysis

The second phase of the Study determined the annual revenue requirements of the electric utility. A financial forecast was developed based on seven-year projections of PWP’s revenues, expenses, capital requirements, and other income and expenses. This financial forecast included projections of known changes in annual costs of large dollar items, i.e. power cost projections, and was based on known increases in costs due to climate change legislation, the renewable portfolio standard and rates from wholesale power supply contracts with multiple electric generating facilities. Other categories of expenses were forecast using historical trends or assumed annual rates of inflation. Financial forecast projections were summarized in pro forma statements of net income and comparisons of net revenue requirements.

The annual net revenue requirement is equal to the annual cost-of-service minus other revenue. The cost-of-service consists of total operating expenses, including depreciation and interest expenses, plus the return on rate base. To comply with Proposition 26, established in 2010 to require a two-thirds majority vote of the State Legislature to raise taxes or fees, General Fund transfer requirements were excluded from the net revenue requirements calculations. For the Study, the test period net revenue requirement was based on the forecast results for FY 2013.

Based on the analysis completed and specific discussion regarding proposed rate adjustments, Burns & McDonnell proposed the electric utility should take gradual steps in adjusting rates to meet its financial targets and to mitigate customer rate shock. The proposed rate adjustments involve a combination of increases of the Distribution Charge, Customer Charge, Energy Services Charge (ESC), and Transmission Services Charge (TSC) rates. By implementing the proposed rate adjustments, PWP will meet its annual debt service and transfer requirements while gradually building to meet its rate base return requirements. Section 4.0 of this report presents and explains the seven-year financial forecast and development of the test period net revenue requirement.

2.3.3 Cost-of-Service Analysis

The third phase of the Study was the development of the cost-of-service analysis. The net revenue requirement for FY 2013 developed from the financial forecast was used as the basis for the cost-of-service analysis.

Nine functional services were identified while analyzing PWP's five cost categories: Energy, Transmission, Distribution, Customer, and Public Benefits. The test period value for each component of the revenue requirement was assigned to one or more of the functional services. The unbundled assignment of each amount was based on the utilization of specific data to estimate the portions of each item attributable to the various functional services.

Following the unbundling of the various components of the annual revenue requirement to the functional utility services, the unbundled revenue requirement was allocated to PWP's retail rate classifications. Cost allocation factors were developed to reflect the relative impact each rate class has on the level of each component of the test period revenue requirement. The peak responsibility methodology for allocating a substantial portion of the demand related costs is based on the electric system's average twelve monthly coincident peak demands (12-CP). This methodology apportions peak demand costs on the basis of each customer class's demand contribution at the time of the twelve monthly system peaks.

The resulting allocated cost-of-service for each rate classification was compared to the estimated annual service revenues for each class to assess the adequacy of the projected cost recovery provided by the existing retail rates. These steps and the corresponding results are detailed in Section 5.0 of this report.

2.3.4 Rate Design Analysis

As part of the rate design analysis, multiple approaches to determining billing demand were evaluated. The four billing demand options closely examined were the current 12-month demand ratchet, four-month ratchet for both winter and summer seasons, seasonal four-month ratchet, and no ratchet monthly metered demand.

TOU pricing periods were formulated that more closely align with the average system peak and offer a typical customer a greater opportunity to respond to pricing signals by reducing the hours in the pricing periods. The revised pricing periods will recover costs during the hours where the market pricing remains relatively high and the system demand remains relatively strong.

Based on the cost-of-service analysis, billing demand evaluation, and TOU pricing period analysis, flat and TOU rate revisions were developed. It is expected that revised rate recommendations will be implemented for FY 2014.

Sections 6.0 and 7.0 of this report discuss the implications of the cost-of-service results on PWP's current electric rates and describe the proposed modifications to retail rates. Comparisons of sample monthly bills based on the current and proposed standard and TOU rates for each customer classification are also presented.

2.3.5 Additional Rate Design Considerations

Additional rate design considerations were examined as part of the Study. Some initiatives are expected to be implemented with the proposed rates. Recommendations for specific rates associated with these supplemental considerations are detailed in Section 8.0. The additional rate design considerations include the following:

- Power Factor Adjustment
- Reactive Power Billing
- Self-Generation
- Net Metering
- Distributed Generation
- Demand Response
- Feed-In Tariffs
- Green Power Service
- Power Cost Adjustment
- Transmission Services Charge
- Public Benefit Charge
- Economic Development Rider
- Advanced Metering

2.3.6 Summary and Recommendations

The Summary and Recommendations section, included as Section 9.0 of this report, summarizes key points from the Study and presents Burns & McDonnell's recommendations for the PWP electric utility.

* * * * *

3.0 LOAD FORECAST

3.0 LOAD FORECAST

3.1 OVERVIEW

The load forecast developed for the Study is a seven-year forecast of class-specific energy sales and peak demand for the PWP electric utility. The forecast includes three years of historical data through FY 2012, budget year estimations for FY 2013, and annual projections through FY 2020.

The load forecast was prepared in a bottom-up fashion. Class-specific data was acquired from PWP and used for class-specific forecasts. These were then combined to develop the forecast of total energy sales at the system level. A forecast of system peak demand was developed separately and compared to historical annual load factors for reasonableness.

The load forecast forms the basis for the subsequent analyses for the Study. This section of the report explains the analysis conducted and the considerations taken in the development of the load forecast.

3.2 FORECASTING APPROACH

The basic premise of load forecasting for the Study was that the historical average relationship between energy sales and number of customers will continue into the future. Thus, the underlying hypothesis of the load forecast was that PWP's future energy sales growth, in general, is likely to be determined by the same factors that have influenced its growth in the past.

Once the projections were developed, assumptions based from the newly instituted EV pilot program were used to modify the customer and sales projections for the Residential classes. These modifications were due to the institution of new electric services billed from the EV-1 and EV-2 rate tariffs.

A number of EV assumptions correlate with the addition of the new rate classes and were applied to the projected annual customers and monthly energy sales to develop more accurate projections of annual number of customers and sales by class. The assumptions included penetration rates, mileage, capacity, and load assumptions for EV customers.

The subsequent sections in Section 3.0 provide additional detail on the bases for the load projections for each class. Summary tables are provided.

3.3 SEASONAL PERIODS

Sufficiency of the current winter and summer seasonal periods were examined as part of the load forecast development. The winter season and associated billing spans from October 1 through May 31 each year, while the summer season and associated billing spans from June 1 through September 30. PWP provided full years of weather-adjusted and metered hourly load data for the system from FY 2009 through FY 2011. The maximum weekday load by month and the average weekday load by month were extracted from each data type for each year. Each month was compared to the preceding and following months to determine if an adjustment should be made. Load data utilized to complete the analysis is summarized in Table 3-1.

Table 3-1: Historical System Peaks by Month

Weather-Adjusted Data

Max Weekday Load by Month - MW

Month	Season	2009	2010	2011	Max
1	Winter	175	185	173	185
2	Winter	182	172	176	182
3	Winter	186	177	177	186
4	Winter	249	169	202	249
5	Winter	233	181	216	233
6	**Summer**	**224**	**209**	**242**	**242**
7	**Summer**	**293**	**296**	**284**	**296**
8	**Summer**	**287**	**294**	**285**	**294**
9	**Summer**	**291**	**320**	**302**	**320**
10	Winter	222	233	226	233
11	Winter	192	217	177	217
12	Winter	177	179	173	179
Max		293	320	302	320

Average Weekday Load by Month - MW

Month	Season	2009	2010	2011	Avg.
1	Winter	137	142	133	138
2	Winter	144	136	140	140
3	Winter	141	131	136	136
4	Winter	135	129	130	131
5	Winter	150	131	134	139
6	**Summer**	**143**	**143**	**146**	**144**
7	**Summer**	**177**	**160**	**167**	**168**
8	**Summer**	**168**	**168**	**169**	**168**
9	**Summer**	**176**	**155**	**163**	**164**
10	Winter	142	138	134	138
11	Winter	134	135	128	132
12	Winter	136	136	130	134

Actual Metered Data

Max Weekday Load by Month - MW

Month	Season	2009	2010	2011	Max
1	Winter	175	185	171	185
2	Winter	182	172	176	182
3	Winter	186	177	199	199
4	Winter	249	169	202	249
5	Winter	233	181	218	233
6	**Summer**	**224**	**209**	**220**	**224**
7	**Summer**	**293**	**296**	**272**	**296**
8	**Summer**	**287**	**294**	**284**	**294**
9	**Summer**	**291**	**320**	**307**	**320**
10	Winter	222	233	246	246
11	Winter	192	217	164	217
12	Winter	177	179	172	179
Max		293	320	307	320

Average Weekday Load by Month - MW

Month	Season	2009	2010	2011	Avg.
1	Winter	137	142	134	138
2	Winter	144	136	141	140
3	Winter	141	131	138	137
4	Winter	135	129	129	131
5	Winter	150	131	131	138
6	**Summer**	**143**	**143**	**138**	**141**
7	**Summer**	**177**	**160**	**161**	**166**
8	**Summer**	**168**	**168**	**164**	**166**
9	**Summer**	**176**	**155**	**157**	**163**
10	Winter	142	138	136	139
11	Winter	134	135	127	132
12	Winter	136	136	130	134

Based on the analysis, Burns & McDonnell recommended PWP maintain its current seasonal months due to insufficient statistical defense to support a shift. The subsequent phases of the Study were conducted with assumption that the current seasonal months would remain.

3.4 CUSTOMER CLASSES

3.4.1 Projected Customers

Table 3-2 presents the projected number of customers for each customer class from FY 2013 through FY 2020. Modest customer growth is projected for each class over the seven-year analysis period.

Table 3-2: Projected Customers by Class

Customer Class	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
Residential Single-Family Service	46,936	46,964	46,992	47,020	47,048	47,076	47,104	47,132
Residential Multi-Family Service	8,974	8,979	8,984	8,989	8,994	8,999	9,004	9,009
Small Commercial and Industrial Service	7,567	7,572	7,577	7,582	7,587	7,593	7,598	7,603
Medium Comm. and Ind. Service - Secondary	860	861	862	863	864	872	873	874
Medium Comm. and Ind. Service - Primary	1	1	1	1	1	2	2	2
Large Comm. and Ind. Service - Secondary	131	131	131	131	131	142	142	142
Large Comm. and Ind. Service - Primary	16	16	16	16	16	19	19	19
Street Lighting and Traffic Signals	220	222	223	225	226	227	229	230
Total Customers	64,705	64,746	64,786	64,827	64,867	64,930	64,971	65,011
Percentage Growth		0.06%	0.06%	0.06%	0.06%	0.10%	0.06%	0.06%

3.4.2 EV Pilot Customers

On May 1, 2012, PWP commenced its EV pilot program which offers TOU ESC rates to qualifying Residential Single Family and Residential Multi-Family customers. The program currently features two schedule options: Time-of-Use Electric Vehicle Rate 1(EV-1) and Time-of-Use Electric Vehicle Rate 2 (EV-2). The purpose of the pilot program is to track and evaluate the new load's impact on the system and determine how to accommodate additional load of this type while encouraging users to charge during off-peak periods. The program is expected to end April 30, 2015. Electrical service for EV customers is metered through City installed metering and electrical infrastructure.

Table 3-3 presents the annual energy sales and supporting assumptions for the Residential EV classes from FY 2013 through FY 2020. For the purposes of the Study, the Residential customer group was assumed to be the only class supporting EVs for the load forecast. Several existing commercial and industrial customers have already indicated that they are considering the installation of charging stations for EVs sometime in the near future or have already done so. Assuming daily total energy usage per car does not change from the forecasted amounts, it is probable that some of the energy sales currently projected for the Residential EV class will shift to the commercial and industrial charging stations.

For the purposes of this analysis, EVs are projected to start migrating from standard rate classes beginning in FY 2013 coinciding with the three-year pilot program. While some light penetration may have occurred in FY 2012, no significant impact has been included in this analysis. The number of cars, and ultimately, class energy usage is projected to grow each year of the forecast.

Table 3-3: EV Pilot Program Customers

Customer Class	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
Customers								
Residential Single-Family Service	14	29	43	58	72	86	101	115
Residential Multi-Family Service	1	1	2	2	4	5	5	6
Total Customers	15	30	45	60	76	91	106	121
Percentage Growth		100.0%	50.0%	33.3%	26.7%	19.7%	16.5%	14.2%
Energy Usage - kWh								
Residential Single-Family Service	130,410	274,554	412,904	564,962	711,533	862,366	1,027,795	1,187,780
Residential Multi-Family Service	7,853	7,993	16,240	16,501	33,538	42,609	43,314	52,843
Total Energy	138,263	282,547	429,144	581,464	745,071	904,976	1,071,109	1,240,623
Percentage Growth		104.4%	51.9%	35.5%	28.1%	21.5%	18.4%	15.8%

3.5 SYSTEM LOAD

3.5.1 Energy Sales

PWP provided Burns & McDonnell the historical monthly energy sales by class for FY 2010 through FY 2012. PWP also provided projections for annual system-level energy sales. Annual sales projections by class were based on the historical proportion of a class's annual usage to total system sales multiplied by the projected total system sales for each year of the forecast.

Table 3-4 presents the projected energy sales, including EV consumption, from FY 2013 through FY 2020. As illustrated, the energy sales are projected to grow steadily from FY 2013. Energy sales are projected to increase at an average annual rate of 0.6 percent per year from FY 2014 and FY 2020 in the Residential, Small, Medium, and Large Commercial, and Street Lighting customer classes.

Table 3-4: Projected Energy Sales by Class

Customer Class	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
Residential Single-Family Service	280,308,381	282,985,215	284,710,248	286,452,019	288,203,550	289,968,580	291,751,296	293,544,074
Residential Multi-Family Service	40,549,183	40,928,759	41,174,283	41,417,831	41,670,349	41,920,929	42,169,251	42,423,177
Small Commercial and Industrial Service	153,649,486	155,087,423	156,003,989	156,926,054	157,853,652	158,786,816	159,725,579	160,669,976
Medium Comm. and Ind. Service - Secondary	268,888,650	271,412,469	273,021,177	274,639,537	276,267,609	277,905,449	279,553,118	281,210,673
Medium Comm. and Ind. Service - Primary	709,114	715,750	719,980	724,236	728,517	732,823	737,156	741,514
Large Comm. and Ind. Service - Secondary	314,801,230	317,747,291	319,625,159	321,514,296	323,414,768	325,326,645	327,249,993	329,184,883
Large Comm. and Ind. Service - Primary	67,583,345	68,372,428	68,875,044	69,380,673	69,889,333	70,401,041	70,915,816	71,433,677
Street Lighting	16,847,992	17,005,664	17,106,167	17,207,272	17,308,984	17,411,307	17,514,244	17,617,798
Total Energy	1,143,337,382	1,154,255,000	1,161,236,047	1,168,261,919	1,175,336,763	1,182,453,590	1,189,616,454	1,196,825,772
Percentage Growth		1.0%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%

3.5.2 Peak Demand

FY 2011 hourly load data from PWP formed the basis for projecting class demands and system peak demands by month from FY 2013 through FY 2020. The hourly load by customer class for the projected years was calculated by scaling the previously calculated annual forecasted energy sales to weather adjusted hourly customer class load shapes from FY 2011. The load shape data was based on hourly load data provided by PWPs third party load analyst. The hourly load data from each class was then combined for each respective year to determine the annual system-level load by hour. Table 3-5 summarizes the annual peak demand by class and the annual system peak for each year of the analysis. The FY 2013 system hourly load profile is presented in Figure 3.1.

Table 3-5: Projected System Peak Demand

Customer Class	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
	kW	kW	kW	kW	kW	kW	kW	kW
Non-Coincident Peak								
Residential Single-Family Service	111,466	112,510	113,175	113,844	114,517	115,194	115,875	116,560
Residential Multi-Family Service	14,844	14,983	15,072	15,161	15,250	15,341	15,431	15,522
Small Commercial and Industrial Service	45,679	46,107	46,379	46,653	46,929	47,205	47,484	47,765
Medium Comm. and Ind. Service - Secondary	80,261	81,015	81,496	81,980	82,467	82,778	83,269	83,764
Medium Comm. and Ind. Service - Primary	223	225	226	227	229	230	231	233
Large Comm. and Ind. Service - Secondary	69,049	69,695	70,107	70,521	70,938	71,357	71,779	72,204
Large Comm. and Ind. Service - Primary	21,292	21,541	21,699	21,859	22,019	22,180	22,342	22,506
Street Lighting	5,916	5,971	6,006	6,042	6,078	6,113	6,150	6,186
Non-Coincident Peak	348,730	352,047	354,161	356,287	358,426	360,398	362,562	364,739
Contribution to Coincident Peak								
Residential Single-Family Service	105,061	106,044	106,671	107,302	107,936	108,575	109,217	109,863
Residential Multi-Family Service	12,304	12,420	12,493	12,567	12,641	12,716	12,791	12,867
Small Commercial and Industrial Service	41,233	41,619	41,865	42,113	42,361	42,610	42,862	43,116
Medium Comm. and Ind. Service - Secondary	71,943	72,619	73,050	73,483	73,919	74,215	74,656	75,099
Medium Comm. and Ind. Service - Primary	114	115	115	116	117	118	118	119
Large Comm. and Ind. Service - Secondary	68,770	69,413	69,823	70,236	70,651	71,069	71,489	71,912
Large Comm. and Ind. Service - Primary	12,593	12,740	12,834	12,928	13,023	13,118	13,214	13,311
Street Lighting	-	-	-	-	-	-	-	-
Coincident Peak	312,018	314,970	316,852	318,745	320,650	322,421	324,348	326,286

3.5.3 System Load Summary

Table 3-6 summarizes the projected system energy requirements for the forecast period. PWP provided the monthly system energy requirements for the budget year and annual totals for each year of the forecast. System loss percentages are projected to total 6.3 percent in FY 2013. The power supply forecast provided by PWP projects distribution losses to vary significantly from year to year. The system peak was projected to grow for each year of the analysis while the annual system load factor percentage was projected to remain in the low forties.

Figure 3.2 and Figure 3.3 illustrate the FY 2013 projected average day load shapes of the electric system for the winter and summer seasons, respectively. The figures feature the current TOU pricing periods.

Figure 3.1: Budget Year 2013 Hourly System Load Profile

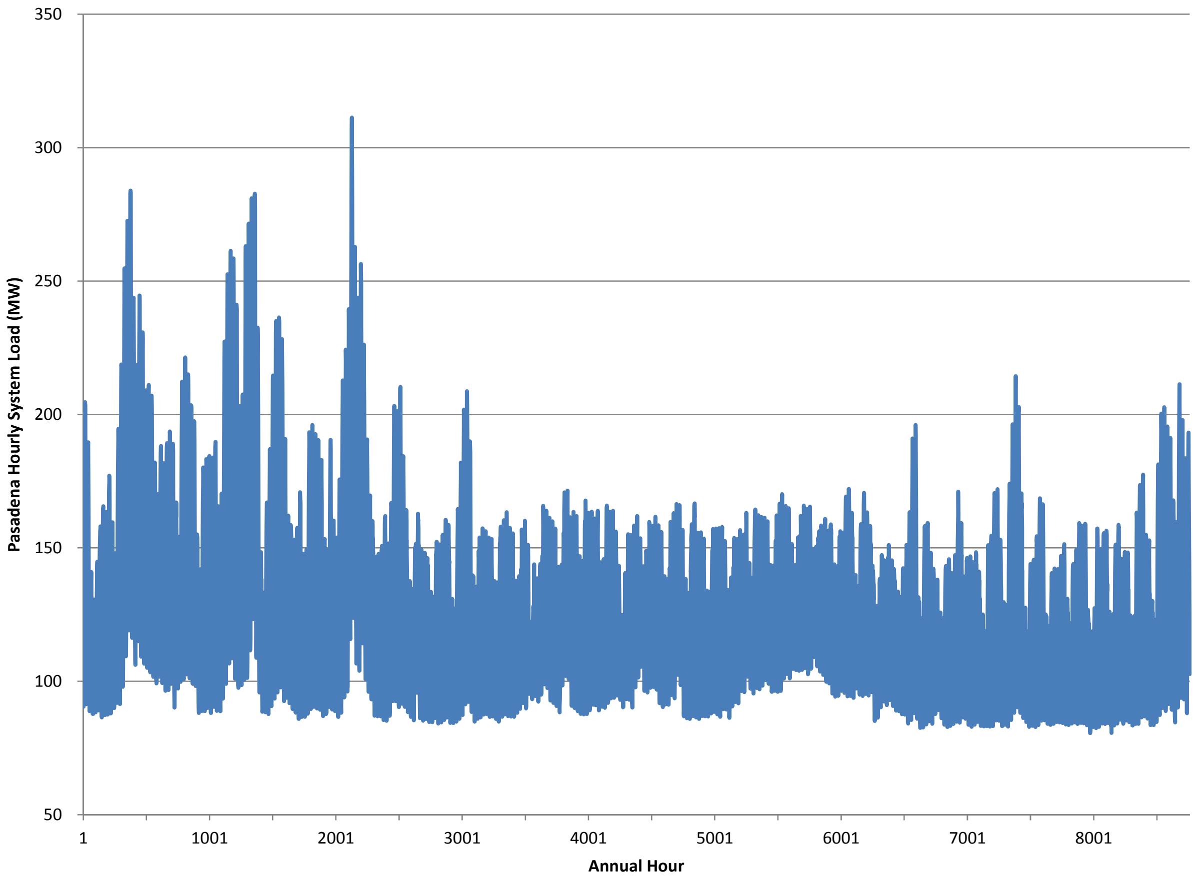


Table 3-6: Projected System Energy Requirements

Description	Budget 2013	Forecast 2014	2015	2016	2017	2018	2019	2020
Net System Energy Sales - kWh	1,143,337,382	1,154,255,000	1,161,236,047	1,168,261,919	1,175,336,763	1,182,453,590	1,189,616,454	1,196,825,772
System Energy Losses - kWh	77,352,611	77,047,302	77,513,291	77,982,273	78,454,524	78,929,577	79,407,703	79,888,929
Loss Percentage	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%	6.3%
Net Energy Requirements - kWh	1,220,689,993	1,231,302,302	1,238,749,338	1,246,244,192	1,253,791,286	1,261,383,167	1,269,024,156	1,276,714,701
System Peak Demand - kW	312,018	314,970	316,852	318,745	320,650	322,421	324,348	326,286
Annual Load Factor	44.7%	44.6%	44.6%	44.6%	44.6%	44.7%	44.7%	44.7%

Figure 3.2: System Daily Load Shape - Winter

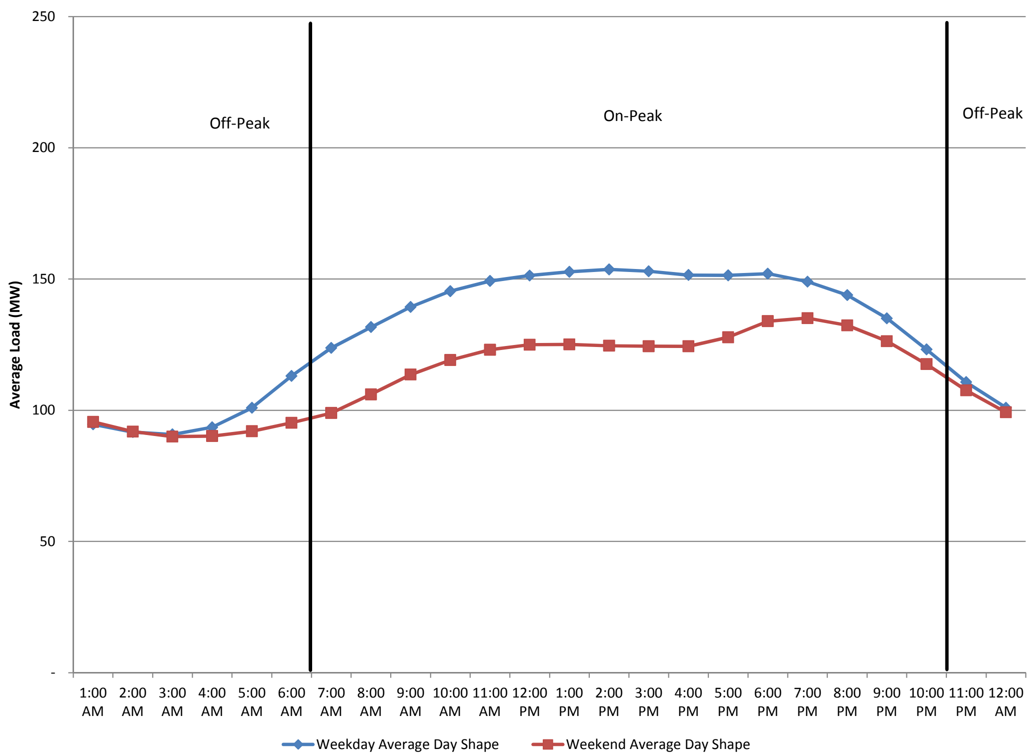
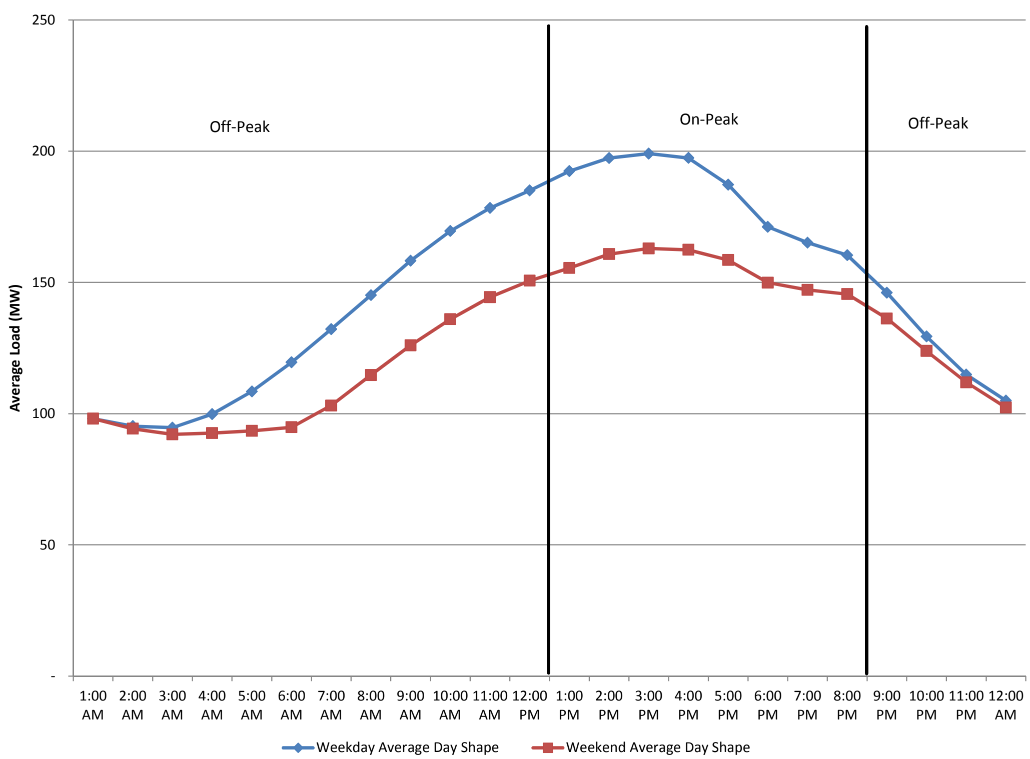


Figure 3.3: System Daily Load Shape - Summer



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4.0 REVENUE REQUIREMENTS ANALYSIS

4.0 REVENUE REQUIREMENTS ANALYSIS

4.1 OVERVIEW

The second phase of the Study involved the determination of the annual revenue requirements of the PWP electric utility. The annual revenue requirements analysis was used as the basis for the subsequent phases of the project, namely the cost-of-service analysis and rate design. In order to determine the annual revenue requirements, a seven-year financial forecast of the operations of the PWP electric utility was developed. This section of the report explains the analysis conducted and the considerations taken in the development of the financial forecast.

4.2 FINANCIAL FORECAST

The financial forecast was developed to estimate PWP's annual revenue requirement and included projections of annual operating revenues, operating expenses, net non-operating income, and the resulting net income, as well as projections of plant investment, debt service, and other cash flows from budget FY 2013 and forecast FY 2014 through FY 2020. The forecast included consideration of annual levels of internally generated funds from operations and PWP's projected capital expenditure requirements. These estimates are typically used to forecast the need for additional funds through retail rate adjustments, transfers from reserves, and/or external capital financing. The evaluation of whether any required additional funds would be derived from revenue increases or externally through debt financing, was based PWP's five-year plan.

The projections developed were summarized in pro forma statements of projected net income. The annual revenue requirements were determined from these pro forma financial statements. The bases of the projections and the assumptions used in the development of each component of the forecast are described herein.

4.3 OPERATING REVENUES

4.3.1 Customer Rate Revenues

Burns & McDonnell projected annual customer rate revenues under existing rates based on the existing retail rate schedules for each class and annual billing determinants from the load forecast. Total customer rate revenues are comprised of D&C revenue, Distribution Charge Revenue, Customer Charge Revenue, ESC revenue, PCA revenue, green power revenue, TSC revenue, and PBC revenue. The FY 2013 rate revenue expected to be generated by the current rates is $171.2 million. This assumes the current D&C, Distribution, Customer and ESC rates are in place throughout the forecast and the PCA is rolled into current ESC rates. Projected PCA and TSC adjustments are reflected in the projections, the basis for these projections were provided in the PWP five-year plan. Total customer rate revenues are expected to increase in FY 2014 and continue to increase each year after FY 2014 due to a rise in energy sales and the aforementioned PCA and TSC adjustments. Table 4-1 presents projected customer rate revenue for each year of the analysis period. D&C, Distribution Charge, and Customer Charge revenues are collectively summarized as D&C Revenue.

Table 4-1: Projected Customer Rate Revenue at Current Rates

Description	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
D&C Revenue								
Residential Single-Family Service	$ 17,665,666	$ 17,682,700	$ 17,699,400	$ 17,716,300	$ 17,732,900	$ 17,749,500	$ 17,766,600	$ 17,783,300
Residential Multi-Family Service	2,365,840	2,367,300	2,369,000	2,370,400	2,372,300	2,374,100	2,375,400	2,377,200
Small Commercial and Industrial Service	8,323,920	8,389,300	8,431,100	8,473,500	8,515,900	8,558,900	8,601,800	8,645,000
Medium Comm. and Ind. Service - Secondary	11,390,732	11,492,100	11,557,000	11,622,100	11,687,800	11,758,800	11,825,300	11,892,100
Medium Comm. and Ind. Service - Primary	39,186	39,500	39,800	40,000	40,200	41,500	41,700	41,900
Large Comm. and Ind. Service - Secondary	10,635,231	10,732,400	10,794,300	10,856,600	10,919,300	11,003,500	11,067,000	11,130,800
Large Comm. and Ind. Service - Primary	3,894,123	3,919,900	3,936,200	3,952,800	3,969,500	3,992,800	4,009,700	4,026,600
Street Lighting	88,042	88,900	89,400	89,900	90,500	91,000	91,500	92,100
Total D&C Revenues	$ 54,402,741	$ 54,712,100	$ 54,916,200	$ 55,121,600	$ 55,328,400	$ 55,570,100	$ 55,779,000	$ 55,989,000
ESC Revenue								
Residential Single-Family Service	$ 24,442,746	$ 24,673,600	$ 26,245,600	$ 26,403,500	$ 29,444,500	$ 29,622,600	$ 29,801,900	$ 29,982,600
Residential Multi-Family Service	3,537,019	3,570,000	3,797,300	3,819,900	4,259,300	4,284,600	4,309,900	4,336,000
Small Commercial and Industrial Service	13,217,956	13,341,700	14,200,500	14,284,400	15,947,400	16,041,700	16,136,500	16,231,900
Medium Comm. and Ind. Service - Secondary	23,786,584	24,010,700	25,518,400	25,670,000	28,585,300	28,754,900	28,925,600	29,097,700
Medium Comm. and Ind. Service - Primary	62,070	62,600	66,600	67,000	74,700	75,200	75,500	76,000
Large Comm. and Ind. Service - Secondary	27,740,410	28,000,100	29,763,700	29,939,700	33,350,600	33,547,700	33,746,000	33,945,600
Large Comm. and Ind. Service - Primary	5,854,411	5,922,800	6,310,700	6,356,900	7,102,400	7,154,500	7,206,800	7,259,500
Street Lighting	1,905,524	1,918,600	2,007,900	2,016,800	2,189,700	2,199,600	2,209,600	2,219,700
Total ESC Revenue	$ 100,546,721	$ 101,500,100	$ 107,910,700	$ 108,558,200	$ 120,953,900	$ 121,680,800	$ 122,411,800	$ 123,149,000
Green Power Revenue	$ 345,732	$ 349,000	$ 351,100	$ 353,300	$ 355,400	$ 357,600	$ 359,700	$ 361,900
Total TSC Revenue Revenue								
Residential Single-Family Service	$ 2,302,297	$ 2,324,300	$ 2,338,400	$ 2,352,700	$ 2,367,200	$ 2,381,600	$ 2,396,200	$ 2,410,900
Residential Multi-Family Service	332,934	336,100	338,000	340,000	342,200	344,200	346,300	348,400
Small Commercial and Industrial Service	1,261,472	1,273,300	1,280,800	1,288,400	1,296,000	1,303,600	1,311,400	1,319,100
Medium Comm. and Ind. Service - Secondary	2,214,032	2,234,800	2,247,900	2,261,200	2,274,600	2,288,100	2,301,600	2,315,200
Medium Comm. and Ind. Service - Primary	5,687	5,700	5,800	5,800	5,800	5,900	5,900	5,900
Large Comm. and Ind. Service - Secondary	2,584,518	2,608,700	2,624,100	2,639,600	2,655,200	2,670,900	2,686,700	2,702,600
Large Comm. and Ind. Service - Primary	542,018	548,400	552,400	556,400	560,500	564,600	568,700	572,900
Street Lighting	138,322	139,600	140,400	141,300	142,100	142,900	143,800	144,600
Total TSC Revenue	$ 9,381,281	$ 9,470,900	$ 9,527,800	$ 9,585,400	$ 9,643,600	$ 9,701,800	$ 9,760,600	$ 9,819,600
Total PBC Revenue Revenue	$ 6,551,037	$ 6,831,400	$ 6,885,700	$ 6,941,700	$ 6,999,800	$ 7,059,700	$ 7,121,600	$ 7,185,500
Total Customer Rate Revenue	$ 171,227,512	$ 172,863,500	$ 179,591,500	$ 180,560,200	$ 193,281,100	$ 194,370,000	$ 195,432,700	$ 196,505,000
Percentage Growth		1.0%	3.9%	0.5%	7.0%	0.6%	0.5%	0.5%

4.3.2 Other Operating Revenues

PWP generates other operating revenues in addition to customer rate revenue. In FY 2013, these other revenues include sales to other utilities and CAISO reimbursements totaling $20.2 million. Table 4-2 presents the projected operating revenues for the PWP electric utility through FY 2020.

Table 4-2: Other Operating Revenues

Description	Budget 2013	Forecast 2014	2015	2016	2017	2018	2019	2020
Total Customer Rate Revenue	$ 171,204,627	$ 172,840,500	$ 179,568,400	$ 180,536,900	$ 193,257,600	$ 194,346,500	$ 195,408,900	$ 196,481,100
Other Operating Revenues								
Sales to Other Utilities	$ 5,891,314	$ 6,017,700	$ 9,647,000	$ 13,349,200	$ 13,625,700	$ 13,908,200	$ 14,196,800	$ 14,491,500
ISO-PTO	14,264,576	14,816,100	15,389,000	15,984,000	16,602,000	17,243,900	17,910,600	18,603,100
Total Other Operating Revenues	$ 20,155,890	$ 20,833,800	$ 25,036,000	$ 29,333,200	$ 30,227,700	$ 31,152,100	$ 32,107,400	$ 33,094,600
Total Operating Revenue	$ 191,360,517	$ 193,674,300	$ 204,604,400	$ 209,870,100	$ 223,485,300	$ 225,498,600	$ 227,516,300	$ 229,575,700

4.4 OPERATING EXPENSES

4.4.1 Power Supply Expense

Purchased power projections were developed based on projected energy and transmission costs provided by PWP. PWP is projected to generate 54,000 MW annually, while purchasing the remainder of its supply from a number of electric generating facilities. For the Budget year, PWP is expected to purchase approximately 63 percent of its load from IPP, costing $40.5 million. The IPP allocation drops throughout the forecast until FY 2020 when approximately 32 percent of the system load is projected to be provided by IPP at $29.9 million. This decrease is made up by annual increases in spot purchases, the largest year over year increase in costs throughout the analysis period.

A relatively new driver for increased costs for the analysis period was due to the requirements established pursuant to AB 32, The California Global Warming Solutions Act of 2006. AB 32 established guidelines for greenhouse gas emissions reduction. As a result, a carbon cap and trade system was established in California and was fully instituted on January 1, 2013. Costs associated with this program are off-set by income from emission credits from the program, and are expected to be a net cost to the electric utility $4.0 million in FY 2013. Net gains from the program are projected for each successive year of the forecast.

Table 4-3 presents an annual forecast of purchased power expenses. The cost of purchased power was projected by month for the budget year and by year for each of the subsequent years in the forecast. The cost of purchased power is projected to grow from $91.7 million in FY 2013 to $115.4 million in FY 2020.

4.4.2 Operation and Maintenance Expense

In addition to purchased power expenses, the PWP electric utility incurs General Managers Office & Legal, Public Benefit Charge, Power Supply Business Unit, Power Production, Power Delivery Business Unit, Customer Service, Finance & Administrative Business Unit, and Finance & Administrative General expenses on an annual basis. Burns & McDonnell developed non-power supply O&M expenses through FY 2020. Including purchased power, O&M expenses are projected to increase from $172.1 million in FY 2013 to $214.1 million in FY 2020 as illustrated in Table 4-4.

Table 4-3: Projected Power Supply Expenses

Description	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
Pow er Supply by Source - MWh								
Local Generation	54,000	87,000	54,000	54,000	54,000	54,000	54,000	54,000
Intermountain (IPP)	762,966	740,381	677,448	619,865	567,177	518,967	474,855	407,170
Palo Verde Nuclear (PV)	73,786	73,700	73,700	73,700	73,700	70,015	66,514	63,733
Hoover	50,349	51,641	51,641	51,641	51,641	50,092	48,589	45,842
LT Energy Contract Spot Sale	-	-	-	-	-	-	-	-
Magnolia-Nat Gas	82,149	333	350	367	367	367	367	367
Magnolia-Bio Gas	-	122,976	129,125	135,581	135,581	135,581	135,581	135,581
Spot Purchases	115,262	49,893	130,432	205,788	266,054	327,121	383,905	471,643
Purchased Pow er-LT Renew able	138,616	121,900	138,616	121,900	121,900	121,900	121,900	97,849
Subtotal Pow er Supply for Load	1,277,128	1,247,824	1,255,312	1,262,843	1,270,420	1,278,043	1,285,711	1,276,186
BPA Net	(56,491)	(16,632)	(16,732)	(16,832)	(16,933)	(17,035)	(17,137)	-
Net Pow er Supply for Load	1,220,637	1,231,192	1,238,580	1,246,011	1,253,487	1,261,008	1,268,574	1,276,186
Pow er Supply Cost by Source								
Intermountain (IPP) - 8213	$40,459,572	$40,717,900	$ 41,875,400	$ 39,657,100	$ 37,556,200	$ 35,566,700	$ 33,682,600	$ 29,892,400
Palo Verde Nuclear (PV) - 8213	4,131,994	4,200,900	4,347,900	4,500,100	4,657,600	4,579,600	4,502,900	4,465,600
Hoover - 8213	805,584	867,600	897,900	929,400	961,900	965,700	969,500	946,700
Magnolia - Bio & Nat Gas - 8213	3,318,252	2,913,000	3,015,000	3,120,500	3,229,700	3,342,800	3,459,800	3,580,800
Magnolia O&M and Natural Gas - 8229	3,362,041	4,206,500	4,417,300	4,638,600	4,639,000	4,639,500	4,640,000	4,640,500
Local Gen & Gas Trans & Prepay Cred & Std	4,033,329	5,816,700	3,970,600	4,169,800	4,378,400	4,596,800	4,825,300	5,064,600
Spot Purchases - 8222	4,896,166	2,194,700	6,024,300	9,980,000	13,547,800	17,490,300	21,552,700	27,802,400
LT Renew able (energy) - 8291	8,316,056	7,357,600	8,617,500	7,805,700	8,039,900	8,281,100	8,529,500	7,052,000
LT Renew able (recs) and Mag. Bio-gas Pren	5,851,528	5,615,500	6,102,800	6,120,200	6,174,400	6,230,300	6,287,800	5,945,700
ST Renew able (recs) OTC - 8270	3,330,540	1,652,000	4,934,900	6,106,000	7,590,200	9,221,700	11,012,400	15,051,100
RES REC (OTC) - 8270	105,007	-	-	-	-	-	-	-
CARB Cap & Trade - 8283 and 8263 (Pow er	9,745,155	5,499,000	5,554,000	5,609,600	5,665,700	5,722,300	5,779,500	5,837,300
CARB Cap & Trade - 8283 and 8263(Pow er	50,000	50,500	51,000	51,500	52,000	52,600	53,100	53,600
Ancillary Services - 8224	988,737	822,300	863,400	906,600	951,900	999,500	1,049,500	1,101,900
ISO GMC - 8292	299,285	293,300	308,000	323,400	339,600	356,600	374,400	393,100
ISO Energy Services - 8293	649,625	1,322,600	1,388,700	1,458,200	1,531,100	1,607,600	1,688,000	1,772,400
UUT - Gas Burned for Retail - 8159	115,748	377,700	246,200	258,500	271,400	285,000	299,200	314,200
Gas & Fuel - Long Term - 8229	1,236,348	1,139,600	1,196,500	1,256,400	1,319,200	1,385,100	1,454,400	1,527,100
Total Pow er Supply Cost	$91,694,967	$85,047,400	$ 93,811,400	$ 96,891,600	$100,906,000	$105,323,200	$110,160,600	$115,441,400
Average Pow er Cost $/MWh	$ 75.12	$ 69.08	$ 75.74	$ 77.76	$ 80.50	$ 83.52	$ 86.84	$ 90.46

Table 4-4: Projected O&M Expense

Description	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
General Manager's Office & Legal	$ 2,314,277	$ 2,313,800	$ 2,314,800	$ 2,317,100	$ 2,320,400	$ 2,324,900	$ 2,330,800	$ 2,337,900
Public Benefit Charge	6,778,827	6,831,400	6,885,700	6,941,700	6,999,800	7,059,700	7,121,600	7,185,500
Pow er Supply Business Unit	119,696,215	114,069,600	123,894,000	128,075,400	133,233,600	138,837,800	144,908,200	151,469,500
Pow er Production (Pow er Plant)	11,572,003	11,819,400	13,575,600	15,393,600	15,775,600	16,171,000	16,580,200	17,003,600
Pow er Delivery Business Unit	20,649,809	20,940,000	21,240,100	21,550,500	21,871,800	22,203,700	22,546,500	22,900,900
Customer Service	5,738,279	5,892,200	6,051,100	6,215,100	6,383,900	6,557,700	6,736,900	6,921,500
Finance & Administrative Business Unit	4,337,360	4,471,300	4,608,500	4,749,600	4,894,100	5,042,500	5,194,600	5,351,200
Finance & Administrative General Expenses	1,038,367	1,028,100	1,018,100	1,008,200	998,300	988,700	979,300	970,000
Total - Existing Classes	$172,125,136	$167,365,800	$179,587,900	$186,251,200	$192,477,500	$199,186,000	$206,398,100	$214,140,100
Percentage Grow th		-2.8%	7.3%	3.7%	3.3%	3.5%	3.6%	3.8%

4.5 CAPITAL IMPROVEMENTS

4.5.1 Capital Expenditures

A forecast of capital expenditures for the electric system was developed internally by PWP staff. The capital expenditures forecast was incorporated into the financial model and utilized to determine the forecasted annual plant in service as well as the forecasted depreciation expense. PWP funds its capital expenditures through a combination of cash financing, debt financing, operating fund transfers, and private investment. The largest of these capital expenditures is the Local Repowering project. This project includes the installation of a new gas fired combined cycle plant to replace the existing B-3 unit currently in operation. Total estimated costs for the Local Repowering project are $121.7 million.

4.5.2 Plant in Service and Depreciation Expense

Total annual depreciation expense included in the financial forecast was provided by PWP. Plant in service at the end of each year, by type of plant, was determined by adding estimates for specific known plant additions which were provided by PWP. The average gross plant in service balances of each plant category were multiplied by the corresponding depreciation rates, which were developed based on historical depreciation expense. Table 4-5 presents a summary of projected net plant in service for the forecast period. As illustrated, annual depreciation expense is projected to grow from $20.3 million in FY 2013 to $26.6 million in FY 2020.

Table 4-5: Projected Net Plant in Service

Description	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
Gross Plant In Service								
Gross Plant in Service as of July 1	$653,110,536	$693,631,900	$730,927,900	$766,758,200	$782,292,100	$797,408,700	$812,525,300	$827,641,900
Plant in Service Additions	82,524,750	75,956,000	72,971,000	31,636,000	30,786,000	30,786,000	30,786,000	30,786,000
Plant in Service Retirements	42,003,400	38,660,000	37,140,700	16,102,100	15,669,400	15,669,400	15,669,400	15,669,400
Gross Plant in Service as of June 30	$693,631,900	$730,927,900	$766,758,200	$782,292,100	$797,408,700	$812,525,300	$827,641,900	$842,758,500
Accumulated Depreciation								
Accumulated Depreciation as of July 1	$300,217,465	$315,053,200	$330,975,800	$348,172,200	$366,744,300	$386,802,200	$405,140,700	$424,086,500
Depreciation Expense	20,293,286	21,780,100	23,522,500	25,404,300	27,436,700	25,084,800	25,915,400	26,643,500
Deletions	5,457,600	5,857,500	6,326,100	6,832,200	7,378,800	6,746,300	6,969,600	7,165,500
Accumulated Depreciation as of June 30	$315,053,200	$330,975,800	$348,172,200	$366,744,300	$386,802,200	$405,140,700	$424,086,500	$443,564,500
Net Plant in Service Balance as of April 30	$378,578,700	$399,952,100	$418,586,000	$415,547,800	$410,606,500	$407,384,600	$403,555,400	$399,194,000

4.6 DEBT SERVICE

4.6.1 Outstanding Debt

Currently the electric utility pays annual principal and interest on four series of general obligation bonds issued by the City. The bonds were for the electric utility's obligations for miscellaneous projects and debt refunding issuances over the years. The projections of outstanding debt service obligations from FY

2013 through FY 2020 are based on debt service schedules provided by PWP. Table 4-6 presents annual projections of outstanding debt service obligations for the electric utility.

Table 4-6: Outstanding Debt Service Obligations

Description	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
1998 Electric Revenue/Refunding Bonds								
Principal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interest	238	238	238	238	238	238	238	238
Total Debt Service	$ 238	$ 238	$ 238	$ 238	$ 238	$ 238	$ 238	$ 238
2002 Power Revenue Bonds								
Principal	$ 3,620,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interest	407,713	262,913	262,913	262,913	262,913	262,913	262,913	262,913
Total Debt Service	$ 4,027,713	$ 262,913	$ 262,913	$ 262,913	$ 262,913	$ 262,913	$ 262,913	$ 262,913
2003 Power Revenue Bonds 2003 series								
Principal	$ 495,000	$ 515,000	$ 535,000	$ 535,000	$ 535,000	$ 605,000	$ 635,000	$ 665,000
Interest	272,025	252,225	230,981	228,244	228,963	157,863	130,033	100,188
Total Debt Service	$ 767,025	$ 767,225	$ 765,981	$ 763,244	$ 763,963	$ 762,863	$ 765,033	$ 765,188
2008 Power Revenue Bonds								
Principal	$ 1,260,000	$ 1,315,000	$ 1,420,000	$ 1,485,000	$ 1,545,000	$ 1,545,000	$ 1,605,000	$ 1,670,000
Interest	2,361,079	2,310,679	2,203,079	2,138,479	2,079,579	2,080,179	2,018,379	1,954,179
Total Debt Service	$ 3,621,079	$ 3,625,679	$ 3,623,079	$ 3,623,479	$ 3,624,579	$ 3,625,179	$ 3,623,379	$ 3,624,179
2009 Electric Revenue Refunding Bonds								
Principal	$ 2,955,000	$ 3,035,000	$ 3,205,000	$ 3,510,000	$ 3,015,000	$ 3,015,000	$ 3,135,000	$ 3,260,000
Interest	1,506,950	1,359,200	1,237,800	1,077,550	937,150	876,850	753,850	625,950
Total Debt Service	$ 4,461,950	$ 4,394,200	$ 4,442,800	$ 4,587,550	$ 3,952,150	$ 3,891,850	$ 3,888,850	$ 3,885,950
2010 A Electric Revenue Refunding Bonds								
Principal	$ 185,000	$ 3,950,000	$ 4,070,000	$ 4,230,000	$ 4,365,000	$ 4,490,000	$ 4,625,000	$ 4,810,000
Interest	1,204,950	1,201,250	1,082,750	919,950	793,050	662,100	527,400	342,400
Total Debt Service	$ 1,389,950	$ 5,151,250	$ 5,152,750	$ 5,149,950	$ 5,158,050	$ 5,152,100	$ 5,152,400	$ 5,152,400
Outstanding Debt Summary								
Total Annual Principal	$ 8,515,000	$ 8,815,000	$ 9,230,000	$ 9,760,000	$ 9,460,000	$ 9,655,000	$10,000,000	$10,405,000
Total Annual Interest	5,752,954	5,386,504	5,017,760	4,627,373	4,301,891	4,040,141	3,692,811	3,285,866
Total Outstanding Debt Service	$14,267,954	$14,201,504	$14,247,760	$14,387,373	$13,761,891	$13,695,141	$13,692,811	$13,690,866

4.6.2 Proposed Debt

Based on its five-year plan, PWP expects to issue revenue bonds to finance capital expenditures in each year from FY 2013 through FY 2016. The issuance parameters for the bonds include 30-year terms, issuance expenses between 9.2 and 10.0 percent, and annual interest rates of 5.0 percent. Table 4-7 presents annual projections of new debt service obligations of the electric utility.

4.7 PROJECTED NET INCOME

The projection of net income for each year provided the basis for determining the cash generated from operations. Ultimately, annual net income was used to establish PWP's test period rate revenue requirement for FY 2013.

Table 4-7: Proposed Debt Amortization

Description	Budget 2013	Forecast 2014	2015	2016	2017	2018	2019	2020
Series FY 2014 Electric Revenue Bonds								
Interest Rate	0%	5%	5%	5%	5%	5%	5%	5%
Beginning Year Balance	$ -	$ -	$85,250,000	$83,966,900	$82,619,600	$81,205,000	$79,719,700	$78,160,100
Amount to Finance	-	85,250,000	-	-	-	-	-	-
Principal	-	-	1,283,100	1,347,300	1,414,600	1,485,300	1,559,600	1,637,600
Interest	-	2,131,300	4,262,500	4,198,300	4,131,000	4,060,300	3,986,000	3,908,000
Annual Debt Payment	-	2,131,300	5,545,600	5,545,600	5,545,600	5,545,600	5,545,600	5,545,600
End of Year Balance	$ -	$85,250,000	$83,966,900	$82,619,600	$81,205,000	$79,719,700	$78,160,100	$76,522,500
Series FY 2015 Electric Revenue Bonds								
Interest Rate	0%	0%	5%	5%	5%	5%	5%	5%
Beginning Year Balance	$ -	$ -	$ -	$60,500,000	$59,589,400	$58,633,300	$57,629,400	$56,575,300
Amount to Finance	-	-	60,500,000	-	-	-	-	-
Principal	-	-	-	910,600	956,100	1,003,900	1,054,100	1,106,800
Interest	-	-	1,512,500	3,025,000	2,979,500	2,931,700	2,881,500	2,828,800
Annual Debt Payment	-	-	1,512,500	3,935,600	3,935,600	3,935,600	3,935,600	3,935,600
End of Year Balance	$ -	$ -	$60,500,000	$59,589,400	$58,633,300	$57,629,400	$56,575,300	$55,468,500
Series FY 2016 Electric Revenue Bonds								
Interest Rate	0%	0%	0%	5%	5%	5%	5%	5%
Beginning Year Balance	$ -	$ -	$ -	$ -	$33,000,000	$32,503,300	$31,981,800	$31,434,200
Amount to Finance	-	-	-	33,000,000	-	-	-	-
Principal	-	-	-	-	496,700	521,500	547,600	575,000
Interest	-	-	-	825,000	1,650,000	1,625,200	1,599,100	1,571,700
Annual Debt Payment	-	-	-	825,000	2,146,700	2,146,700	2,146,700	2,146,700
End of Year Balance	$ -	$ -	$ -	$33,000,000	$32,503,300	$31,981,800	$31,434,200	$30,859,200
Series FY 2017 Electric Revenue Bonds								
Interest Rate	0%	0%	0%	0%	5%	5%	5%	5%
Beginning Year Balance	$ -	$ -	$ -	$ -	$ -	$33,000,000	$32,503,300	$31,981,800
Amount to Finance	-	-	-	-	33,000,000	-	-	-
Principal	-	-	-	-	-	496,700	521,500	547,600
Interest	-	-	-	-	825,000	1,650,000	1,625,200	1,599,100
Annual Debt Payment	-	-	-	-	825,000	2,146,700	2,146,700	2,146,700
End of Year Balance	$ -	$ -	$ -	$ -	$33,000,000	$32,503,300	$31,981,800	$31,434,200
New Debt Summary								
Total Annual Principal	$ -	$ -	$ 1,283,100	$ 2,257,900	$ 2,867,400	$ 3,507,400	$ 3,682,800	$ 3,867,000
Total Annual Interest	-	2,131,300	5,775,000	8,048,300	9,585,500	10,267,200	10,091,800	9,907,600
Total New Debt Service	$ -	$ 2,131,300	$ 7,058,100	$10,306,200	$12,452,900	$13,774,600	$13,774,600	$13,774,600

4.7.1 Operating Revenues

4.7.1.1 Customer Rate Revenues

Annual customer rate revenues under existing rates were projected based on the existing retail rate schedules for each class and annual billing determinants from the load forecast. Annual customer rate revenue is generated from the following classes: Residential Service, Small Commercial and Industrial Service, Medium Commercial and Industrial Service, Large Commercial and Industrial Service, and Street Lighting and Traffic Signal Service. These classes each offer multiple services including, but not limited to TOU rates, Net Metering, EV, and green energy rates. Customer rate revenues are also generated by the TSC and PBC. In total, customer rate revenues are projected to total $171.2 million in FY 2013 and reach $196.5 in FY 2020, if only the projected PCA and TSC rate adjustments are implemented.

4.7.1.2 Other Operating Revenues

Other types of electric operating revenues include charges for Accrued Unbilled, Sales to Other Utilities, ISO-PTO, and miscellaneous other revenues. These other revenues represent just over one percent of PWP's total operating revenue in FY 2013 at $20.2 million. Other operating revenues are projected to increase each year of the forecast and reach $33.1 million in FY 2020.

4.7.2 Operating Expenses

4.7.2.1 Operating Expense

Electric operating expenses were included in the financial forecast. Expenses were broken out by FERC accounts. Aside from annual purchased power expense and non-cash expenses, annual projections were developed by Burns & McDonnell for each year of the forecast period. Operating expenses were projected to increase from $192.2 million in FY 2013 to $240.6 million in FY 2020.

4.7.3 Non-Operating Income and Expenses

Net non-operating income is projected to decrease from $5.3 million in FY 2013 to ($1.8) million in FY 2020. The decrease is primarily a result of increased interest expense resulting from future debt issuances. Notwithstanding, earnings from IPP defeasance, investment income, capital fees, and gain/loss on disposal of assets were projected to remain constant throughout the forecast period.

4.7.3.1 City Transfer

Section 1407 of the City Charter states that:

> *"Each fiscal year the City Council shall transfer from the Light and Power Fund an amount equal to eight percent (8%) of the gross income of the electric works received during the immediately preceding fiscal year from the sale of electric energy at rates and charges fixed by ordinance."*

Additionally, Section 1408 states:

> *"Each fiscal year the City Council shall transfer from the Light and Power Fund an amount equal to eight percent (8%) of the gross income of the electric works… Said amounts shall be in addition to the amount authorized to be transferred by Section 1407."*

From FY 2009 through FY 2011, the PWP transferred an annual average of 8.9 percent from the Light and Power Fund to the City's General Fund. In FY 2012, after a budgeted transfer of 8.0 percent was passed, the City authorized an additional $3.5 million to be transferred to the General Fund in FY 2012. The total transferred that year equaled $15.9 million. In the same November 2011 authorization, the City informed the electric utility that transfers would equal 9.0 percent for the foreseeable future. The FY 2013 transfer was calculated to be $14.8 million prior to additional rate increases. Based on the customer rate revenue projections, and no additional rate increases, the annual transfer was projected to reach $17.0 million in FY 2020.

4.7.4 Net Income

Projected net income for each year of the financial forecast was determined by deducting the estimated net non-operating expense estimates from the net operating income, plus net transfers, for each respective year. Based on the projections presented in Table 4-8, PWP is projected to suffer an operating income loss and a negative net change in assets in FY 2013.

Table 4-8: Projected Net Income Prior to Adjustments

Description	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
Customer Rate Revenue	$ 171,227,512	$ 172,863,500	$ 179,591,500	$ 180,560,200	$ 193,281,100	$ 194,370,000	$ 195,432,700	$ 196,505,000
Other Operating Revenues	20,155,890	20,833,800	25,036,000	29,333,200	30,227,700	31,152,100	32,107,400	33,094,600
Total Operating Revenue	$ 191,383,401	$ 193,697,300	$ 204,627,500	$ 209,893,400	$ 223,508,800	$ 225,522,100	$ 227,540,100	$ 229,599,600
Operating Expense	$ 192,209,357	$ 188,936,800	$ 202,901,300	$ 211,446,400	$ 219,705,100	$ 224,061,700	$ 232,104,400	$ 240,574,500
Operating Income (Loss)	$ (825,955)	$ 4,760,500	$ 1,726,200	$ (1,553,000)	$ 3,803,700	$ 1,460,400	$ (4,564,300)	$ (10,974,900)
Non-Operating Revenue (Expense)								
Interest Expense	$ (7,026,661)	$ (7,517,800)	$ (10,792,800)	$ (12,675,700)	$ (13,887,400)	$ (14,307,300)	$ (13,784,600)	$ (13,193,500)
Other Non-Op. Revenue (Expense)	12,372,697	12,725,000	12,510,300	12,290,700	12,062,300	11,822,300	11,624,300	11,426,600
Total Non-Operating Revenue (Expense)	$ 5,346,036	$ 5,207,200	$ 1,717,500	$ (385,000)	$ (1,825,100)	$ (2,485,000)	$ (2,160,300)	$ (1,766,900)
Net Income (Loss) Before Transfers	$ 4,520,081	$ 9,967,700	$ 3,443,700	$ (1,938,000)	$ 1,978,600	$ (1,024,600)	$ (6,724,600)	$ (12,741,800)
Capital Contributions	$ 1,500,000	$ 3,500,000	$ 3,750,000	$ 4,000,000	$ 4,000,000	$ 1,754,700	$ 1,754,700	$ 1,754,700
Transfers In - General Fund	-	-	-	-	-	-	-	-
Transfers Out - General Fund	(14,820,900)	(14,942,900)	(15,543,500)	(15,625,700)	(16,765,300)	(16,857,900)	(16,948,000)	(17,038,800)
Change in Net Assets	**$ (8,800,819)**	**$ (1,475,200)**	**$ (8,349,800)**	**$ (13,563,700)**	**$ (10,786,700)**	**$ (16,127,800)**	**$ (21,917,900)**	**$ (28,025,900)**
Total Net Assets, July 1	$ 520,349,700	$ 511,548,881	$ 510,073,681	$ 501,723,881	$ 488,160,181	$ 477,373,481	$ 461,245,681	$ 439,327,781
Total Net Assets, June 30	$ 511,548,881	$ 510,073,681	$ 501,723,881	$ 488,160,181	$ 477,373,481	$ 461,245,681	$ 439,327,781	$ 411,301,881

Beginning in FY 2014, purchased power expenses are projected to increase annually on a dollars-per-megawatt-hour basis by 4.6 percent per year. Without corresponding rate adjustments to offset increased in purchased power costs, annual rate revenue will not be sufficient to cover PWP's requirements resulting in negative net income.

4.7.5 Debt Service Coverage

A debt service coverage ratio of 1.50 was the target for the revenue requirements analysis. Net income before General Fund transfers is the key variable in the coverage calculation. As illustrated in Table 4-9, the debt service coverage ratio is projected to exceed the coverage target through 2017. The coverage ratio is projected to fall below the 1.50 threshold each year thereafter.

Table 4-9: Projected Debt Service Coverage Prior to Adjustments

Description	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
Net Income (Loss) Before Transfers	$ 6,020,081	$ 13,467,700	$ 7,193,700	$ 2,062,000	$ 5,978,600	$ 730,100	$ (4,969,900)	$ (10,987,100)
Add Interest	7,026,661	7,517,800	10,792,800	12,675,700	13,887,400	14,307,300	13,784,600	13,193,500
Add Depreciation	20,293,286	21,780,100	23,522,500	25,404,300	27,436,700	25,084,800	25,915,400	26,643,500
Net Income Available for Debt Service	$ 33,340,028	$ 42,765,600	$ 41,509,000	$ 40,142,000	$ 47,302,700	$ 40,122,200	$ 34,730,100	$ 28,849,900
Annual Debt Service	$ 15,541,700	$ 16,332,800	$ 21,305,900	$ 24,693,600	$ 26,214,800	$ 27,469,700	$ 27,467,400	$ 27,465,500
Debt Service Coverage	2.15	2.62	1.95	1.63	1.80	1.46	1.26	1.05
Debt Service Coverage Target	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50

4.8 RATE BASE

In addition to debt service coverage, rate base return was a key variable in determining whether PWP's currently defined revenue generation mechanisms were sufficient to sustain financial health of the utility for the analysis period. PWP desires to maintain a rate base return of 9.0 percent to maintain reserves and sustain a prudent debt to cash ratio while continuing to invest in the electric system.

4.8.1 Rate Base Return Requirement

For the analysis, the rate base was calculated by adding the net utility plant in service and construction work in progress to a working capital allowance of 60 cash days of operations and maintenance expenses, and subtracting capital contributions. The 60-day allowance is due to fact that many PWP customers are billed on a bi-monthly basis. At a return of 9.0 percent, the budget year rate base return requirement was $36.5 million.

Once the required return was calculated, the dollars were allocated to the production, transmission, and distribution functional services. The initial allocation calculation multiplied the percentage of the proportional investment of the production, transmission, and distribution plant in service to the required return. From here an adjustment was taken to allocate more of the transmission return requirement to distribution due to the fact two-thirds of the transmission plant in service assets are actually distribution assets, as defined by PWP. Table 4-10 summarizes the rate base calculation and the plant specific allocated rate base return requirements.

Table 4-10: Rate Base Return Requirement

Description	Budget 2013	Forecast 2014	2015	2016	2017	2018	2019	2020
Net Utility Plant in Service	$308,136,714	$329,510,100	$348,144,100	$345,105,800	$340,164,600	$336,942,500	$333,113,400	$328,751,800
Construction Work in Progress	$ 70,442,021	$ 70,442,000	$ 70,442,000	$ 70,442,000	$ 70,442,000	$ 70,442,000	$ 70,442,000	$ 70,442,000
Capital Contributions	(1,500,000)	(3,500,000)	(3,750,000)	(4,000,000)	(4,000,000)	(1,754,700)	(1,754,700)	(1,754,700)
Working Capital	28,181,402	27,399,000	29,408,200	30,503,500	31,527,000	32,629,800	33,815,300	35,088,000
Total Rate Base	$405,260,137	$423,851,100	$444,244,300	$442,051,300	$438,133,600	$438,259,600	$435,616,000	$432,527,100
Return on Rate Base Target (WACC=9%)	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Return on Rate Base Target	$ 36,473,412	$ 38,146,600	$ 39,982,000	$ 39,784,600	$ 39,432,000	$ 39,443,400	$ 39,205,400	$ 38,927,400
Allocated Return on Rate Base - Adjusted								
Production	$ 9,522,168	$ 11,690,900	$ 11,656,700	$ 10,392,700	$ 10,303,100	$ 10,324,400	$ 10,275,200	$ 10,210,700
Transmission	1,919,851	2,015,000	2,211,700	2,305,300	2,352,300	2,415,900	2,467,500	2,519,600
Distribution	25,031,393	24,440,700	26,113,600	27,086,600	26,776,600	26,703,100	26,462,700	26,197,100
Total Return on Rate Base Target	$ 36,473,412	$ 38,146,600	$ 39,982,000	$ 39,784,600	$ 39,432,000	$ 39,443,400	$ 39,205,400	$ 38,927,400

4.8.2 Calculated Rate Base Return

Once the rate base return requirements were established, calculated rate base returns from current rates were projected. Table 4-11 summarizes projected rate base returns from current rates for the analysis period. As illustrated, the utility is expected to generate an overall return of 2.29 percent in FY 2013. Negative returns are projected in FY 2019 through FY 2020 if no rate adjustments are implemented prior to those years.

Table 4-11: Rate Base Return Prior to Rate Adjustments

Description	Budget 2013	Forecast 2014	2015	2016	2017	2018	2019	2020
Allocated Return on Rate Base								
Production	$ 9,522,168	$ 11,690,900	$ 11,656,700	$ 10,392,700	$ 10,303,100	$ 10,324,400	$ 10,275,200	$ 10,210,700
Transmission	1,919,851	2,015,000	2,211,700	2,305,300	2,352,300	2,415,900	2,467,500	2,519,600
Distribution	25,031,393	24,440,700	26,113,600	27,086,600	26,776,600	26,703,100	26,462,700	26,197,100
Total Return on Rate Base Target	$ 36,473,412	$ 38,146,600	$ 39,982,000	$ 39,784,600	$ 39,432,000	$ 39,443,400	$ 39,205,400	$ 38,927,400
Rate Base Return before Adjustments								
Production	$ 1,707,146	$ 9,231,900	$ 5,852,600	$ 3,207,500	$ 10,102,500	$ 6,604,300	$ (254,800)	$ (3,580,700)
Transmission	(1,054,268)	(1,373,800)	(1,747,400)	(2,139,600)	(2,551,000)	(2,860,100)	(3,271,500)	(3,697,900)
Distribution	8,632,203	7,119,600	4,623,500	2,559,100	277,100	1,381,200	991,700	716,800
Total Return on Rate Base Target	$ 9,285,081	$ 14,977,700	$ 8,728,700	$ 3,627,000	$ 7,828,600	$ 5,125,400	$ (2,534,600)	$ (6,561,800)
Rate Base Return before Adjustments								
Production	0.42%	2.18%	1.32%	0.73%	2.31%	1.51%	-0.06%	-0.83%
Transmission	-0.26%	-0.32%	-0.39%	-0.48%	-0.58%	-0.65%	-0.75%	-0.85%
Distribution	2.13%	1.68%	1.04%	0.58%	0.06%	0.32%	0.23%	0.17%
Total Return on Rate Base Target	2.29%	3.53%	1.96%	0.82%	1.79%	1.17%	-0.58%	-1.52%
Return Surplus (Deficit) before Adjustments								
Production	$ (7,815,022)	$ (2,459,000)	$ (5,804,100)	$ (7,185,200)	$ (200,600)	$ (3,720,100)	$ (10,530,000)	$ (13,791,400)
Transmission	(2,974,119)	(3,388,800)	(3,959,100)	(4,444,900)	(4,903,300)	(5,276,000)	(5,739,000)	(6,217,500)
Distribution	(16,399,190)	(17,321,100)	(21,490,100)	(24,527,500)	(26,499,500)	(25,321,900)	(25,471,000)	(25,480,300)
Total Return on Rate Base Target	$ (27,188,332)	$ (23,168,900)	$ (31,253,300)	$ (36,157,600)	$ (31,603,400)	$ (34,318,000)	$ (41,740,000)	$ (45,489,200)

4.9 PROPOSED REVENUE ADJUSTMENTS

In order to maintain adequate operating income, maintain adequate operating fund cash balances, meet debt service coverage requirements, and meet rate base return requirements, PWP requires rate adjustments. Based on the analysis completed and specific discussion regarding proposed rate adjustments, Burns & McDonnell recommends PWP take gradual steps in adjusting rates to meet its financial targets to mitigate customer rate shock. The proposed rate adjustments involve a combination of increases of the Distribution, Customer, ESC, and TSC rates.

PWP should increase its Distribution, Customer, and ESC revenue by 10.0 percent. This will allow the utility to meet its outstanding debt service obligations and its required City Transfer. Moving forward, PWP should increase its Distribution, Customer, and ESC rates in subsequent years by the following percentages:

- FY 2015 – 4.0 percent
- FY 2017 – 1.0 percent
- FY 2018 – 1.9 percent
- FY 2019 – 3.25 percent
- FY 2020 – 1.75 percent

PWP has the option of adjusting its Power Cost Adjustment (PCA) to recover cost for energy due to supply cost fluctuations. PWP's five-year plan projected PCA increases of 0.50¢/kWh each year from FY 2013 through FY 2018. It is Burns & McDonnell's recommendation that PWP roll the projected PCA increases into the ESC, for each year an ESC increase is proposed, upon adopting this financial plan. Since there are no ESC adjustments proposed for FY 2016, Burns & McDonnell recommends PWP implement the PCA adjustment as initially planned. The utility should consider PCA adjustments as an alternative to ESC rate adjustments if power markets remain volatile or as an alternative to adjusting the base ESC if overall cost oscillation is chiefly due to fluctuating underlying power supply costs.

As part of its five-year plan, PWP provided a TSC revenue forecast for the Study. Currently, secondary voltage customers are billed a TSC rate of 0.821¢/kWh while primary voltage customers are billed a TSC rate of 0.802¢/kWh. Based on the TSC revenue projections in five-year plan, PWP should increase its TSC rates in FY 2014 through 2017 to the following:

- FY 2014 – secondary 0.885¢/kWh; primary 0.866¢/kWh
- FY 2015 – secondary 0.931¢/kWh; primary 0.912¢/kWh
- FY 2016 – secondary 0.998¢/kWh; primary 0.979¢/kWh
- FY 2017 – secondary 1.069¢/kWh; primary 1.050¢/kWh

By implementing the preceding revenue adjustments, PWP will meet its annual debt service and transfer requirements while gradually building to meet its rate base return requirements. Table 4-12 and Table 4-13 illustrate the impact of the prescribed adjustments on the electric utility.

Table 4-12: Net Income with Rate Adjustments

Description	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
Customer Rate Revenue	$186,722,412	$189,224,000	$204,317,000	$212,128,300	$223,599,500	$228,747,900	$236,813,600	$241,919,100
Other Operating Revenues	20,155,890	20,833,800	25,036,000	29,333,200	30,227,700	31,152,100	32,107,400	33,094,600
Total Operating Revenue	$206,878,301	$210,057,800	$229,353,000	$241,461,500	$253,827,200	$259,900,000	$268,921,000	$275,013,700
Operating Expense	$192,209,357	$188,936,800	$202,901,300	$211,446,400	$219,705,100	$224,061,700	$232,104,400	$240,574,500
Operating Income (Loss)	$ 14,668,945	$ 21,121,000	$ 26,451,700	$ 30,015,100	$ 34,122,100	$ 35,838,300	$ 36,816,600	$ 34,439,200
Non-Operating Revenue (Expense)								
Interest Expense	$ (7,026,661)	$ (7,517,800)	$ (10,792,800)	$ (12,675,700)	$ (13,887,400)	$ (14,307,300)	$ (13,784,600)	$ (13,193,500)
Other Non-Op. Revenue (Expense)	12,372,697	12,725,000	12,510,300	12,290,700	12,062,300	11,822,300	11,624,300	11,426,600
Total Non-Operating Revenue (Expense)	$ 5,346,036	$ 5,207,200	$ 1,717,500	$ (385,000)	$ (1,825,100)	$ (2,485,000)	$ (2,160,300)	$ (1,766,900)
Net Income (Loss) Before Transfers	$ 20,014,981	$ 26,328,200	$ 28,169,200	$ 29,630,100	$ 32,297,000	$ 33,353,300	$ 34,656,300	$ 32,672,300
Capital Contributions	$ 1,500,000	$ 3,500,000	$ 3,750,000	$ 4,000,000	$ 4,000,000	$ 1,754,700	$ 1,754,700	$ 1,754,700
Transfers In - General Fund	-	-	-	-	-	-	-	-
Transfers Out - General Fund	(16,215,400)	(16,415,300)	(17,768,800)	(18,466,800)	(19,494,000)	(19,951,900)	(20,672,300)	(21,126,000)
Change in Net Assets	**$ 5,299,581**	**$ 13,412,900**	**$ 14,150,400**	**$ 15,163,300**	**$ 16,803,000**	**$ 15,156,100**	**$ 15,738,700**	**$ 13,301,000**
Total Net Assets, July 1	$520,349,700	$525,649,281	$539,062,181	$553,212,581	$568,375,881	$585,178,881	$600,334,981	$616,073,681
Total Net Assets, June 30	$525,649,281	$539,062,181	$553,212,581	$568,375,881	$585,178,881	$600,334,981	$616,073,681	$629,374,681

Table 4-13: Debt Service Coverage with Rate Adjustments

Description	Budget	Forecast						
	2013	2014	2015	2016	2017	2018	2019	2020
Net Income (Loss) Before Transfers	$ 21,514,981	$ 29,828,200	$ 31,919,200	$ 33,630,100	$ 36,297,000	$ 35,108,000	$ 36,411,000	$ 34,427,000
Add Interest	7,026,661	7,517,800	10,792,800	12,675,700	13,887,400	14,307,300	13,784,600	13,193,500
Add Depreciation	20,293,286	21,780,100	23,522,500	25,404,300	27,436,700	25,084,800	25,915,400	26,643,500
Net Income Available for Debt Service	$ 48,834,928	$ 59,126,100	$ 66,234,500	$ 71,710,100	$ 77,621,100	$ 74,500,100	$ 76,111,000	$ 74,264,000
Annual Debt Service	$ 15,541,700	$ 16,332,800	$ 21,305,900	$ 24,693,600	$ 26,214,800	$ 27,469,700	$ 27,467,400	$ 27,465,500
Debt Service Coverage	3.14	3.62	3.11	2.90	2.96	2.71	2.77	2.70
Debt Service Coverage Target	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50

4.10 PROJECTED REVENUE REQUIREMENTS

A summary of the test period FY 2013 rate revenue requirement is presented in Table 4-14. The revenue requirement is equal to the annual cost-of-service minus other revenue. The annual cost-of-service consists of total operating expenses, including depreciation and interest expenses, plus the rate base return.

To comply with Proposition 26, established in 2010 to require a two-thirds majority vote of the State Legislature to raise taxes or fees, General Fund transfer requirements were excluded from the net revenue requirements calculations. For the Study, the test period net revenue requirement was based on the financial forecast results for FY 2013 and totaled $203.9 million.

Table 4-14: Projected Revenue Requirements with Rate Adjustments

Description	Budget 2013	Forecast 2014	2015	2016	2017	2018	2019	2020
Revenue & Income								
Customer Rate Revenue - w/Adjustments	$186,722,412	$189,224,000	$204,317,000	$212,128,300	$223,599,500	$228,747,900	$236,813,600	$241,919,100
Investment Earnings	5,389,297	5,507,200	5,232,500	4,952,300	4,662,700	4,360,900	4,100,500	3,839,800
IPP Defeasance Principal	4,765,000	5,010,000	5,285,000	5,565,000	5,850,000	6,150,000	4,190,000	6,180,000
Other Non-Op. Revenues (Expenses)	1,222,650	1,222,700	1,222,700	1,222,700	1,222,700	1,222,700	1,222,700	1,222,700
Energy Emission Credits	5,760,750	5,995,100	6,055,100	6,115,700	6,176,900	6,238,700	6,301,100	6,364,100
Net Revenue & Income	$203,860,109	$206,959,000	$222,112,300	$229,984,000	$241,511,800	$246,720,200	$252,627,900	$259,525,700
Revenue Requirements								
Operations and Maintenance Expense	$168,861,370	$163,995,100	$174,606,500	$179,602,800	$185,603,700	$192,078,900	$199,049,600	$206,541,700
Fuel Burned for Wholesale Sales	3,054,701	3,161,600	4,772,300	6,439,300	6,664,700	6,898,000	7,139,400	7,389,300
Depreciation	20,293,286	21,780,100	23,522,500	25,404,300	27,436,700	25,084,800	25,915,400	26,643,500
Interest Expense	7,026,661	7,517,800	10,792,800	12,675,700	13,887,400	14,307,300	13,784,600	13,193,500
Return on Rate Base	24,779,981	31,338,200	33,454,200	35,195,100	38,147,000	39,503,300	38,846,300	38,852,300
Total Cost of Service	$224,015,999	$227,792,800	$247,148,300	$259,317,200	$271,739,500	$277,872,300	$284,735,300	$292,620,300
Less Other Revenue Sources:								
Wholesale Energy Sales-ISO	$ (3,332,473)	$ (3,399,100)	$ (6,967,100)	$ (10,606,400)	$ (10,818,500)	$ (11,034,900)	$ (11,255,600)	$ (11,480,700)
Other Wholesale Sales	(2,131,624)	(2,174,300)	(2,217,800)	(2,262,200)	(2,307,400)	(2,353,500)	(2,400,600)	(2,448,600)
ISO-PTO	(14,691,793)	(15,260,400)	(15,851,100)	(16,464,600)	(17,101,800)	(17,763,700)	(18,451,200)	(19,165,300)
Unbilled/Miscellaneous	-	-	-	-	-	-	-	-
Net Revenue Requirement	$203,860,109	$206,959,000	$222,112,300	$229,984,000	$241,511,800	$246,720,200	$252,627,900	$259,525,700
Return on Rate Base Target	$ 36,473,412	$ 38,146,600	$ 39,982,000	$ 39,784,600	$ 39,432,000	$ 39,443,400	$ 39,205,400	$ 38,927,400
Return on Rate Base	24,779,981	31,338,200	33,454,200	35,195,100	38,147,000	39,503,300	38,846,300	38,852,300
Return on Rate Base Surplus (Deficit)	$ (11,693,432)	$ (6,808,400)	$ (6,527,800)	$ (4,589,500)	$ (1,285,000)	$ 59,900	$ (359,100)	$ (75,100)
Return on Rate Base Target (WACC=9%)	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Return on Rate Base with Adjustments	6.11%	7.39%	7.53%	7.96%	8.71%	9.01%	8.92%	8.98%
General Fund Transfer	$ 16,215,400	$ 16,415,300	$ 17,768,800	$ 18,466,800	$ 19,494,000	$ 19,951,900	$ 20,672,300	$ 21,126,000
Principal Payment	8,515,000	8,815,000	10,513,100	12,017,900	12,327,400	13,162,400	13,682,800	14,272,000
Total (Minimum Required Return)	$ 24,730,400	$ 25,230,300	$ 28,281,900	$ 30,484,700	$ 31,821,400	$ 33,114,300	$ 34,355,100	$ 35,398,000
Rate Base Return less Minimum Req. Return	$ 49,581	$ 6,107,900	$ 5,172,300	$ 4,710,400	$ 6,325,600	$ 6,389,000	$ 4,491,200	$ 3,454,300

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5.0 COST-OF-SERVICE ANALYSIS

5.0 COST-OF-SERVICE ANALYSIS

5.1 OVERVIEW

The third phase of the Study involved the development of the cost-of-service analysis. The annual revenue requirement for FY 2013 developed from the financial forecast, described in Section 4.0 of this report, was used as the basis for the cost-of-service analysis. Section 5.0 explains the bases of the functionalization, classification and allocation efforts of the cost-of-service analysis. Tables showing the assignment of the annual revenue requirement among functional services, as well as the development of allocation factors and the allocation of the annual revenue requirement to PWP's rate classifications, are presented in the following subsections.

5.2 REVENUE REQUIREMENT UNBUNDLING

The first step in the development of the cost-of-service analysis was the assignment, or unbundling, of the various components of the annual revenue requirement by functional utility service. To a certain degree, the electric service PWP provides its customers is sold as a bundled product. However, this bundled product actually involves the provision of multiple functional services. Utilities such as PWP have a need to unbundle the costs of providing the component services making up this bundled product. PWP will benefit from this separation of the costs of providing its services at a functional level. New information will be available to aid PWP in the overall management of its costs and in communicating with its key customers regarding the costs of providing services to them. The unbundling of PWP's costs also facilitates future implementation of separate pricing of individual services, if desired.

5.2.1 Unbundled Services

Nine functional services were identified while analyzing PWP's five cost categories: Energy/Power Supply, Transmission, Distribution/Power Delivery, Customer, and Public Benefits. Each cost category and its subordinate functional services are summarized below.

- Energy/Power Supply
  - Energy Service (PS)
- Transmission
  - Transmission Service (TDEL)
- Distribution/Power Delivery
  - Primary Distribution Service (DIST-P)
  - Secondary Distribution Service (DIST-S)

- Customer Services
  - Customer Service – Metering (MT)
  - Customer Service – Billing (BL)
  - Customer Service – Call Center (CC)
  - Customer Service – Customer Services (CS)
- Public Benefits Charge
  - Public Benefits Charge (PBC)

5.2.2 Test Period Revenue Requirement Assignment

The test period value for each component of the revenue requirement was assigned to one or more of the unbundled services. The unbundled assignment of each amount was based on the utilization of specific data to estimate the portions of each item attributable to the various functional services. The amount for each item was assigned using one of the following approaches:

- Direct Assignment – to one or more specific functional services due to the nature of the account/element. For example, energy purchases were assigned to the PS service based on the projected cost of purchased energy in the test period.
- Percentage Utilization – based on estimated level of activities within the account/element, costs were assigned to multiple functional service categories. For example, some administrative and general salaries were allocated amongst the Distribution Delivery – Primary and Distribution Delivery – Secondary, and Customer Related Costs services based on the a ratio of primary to secondary costs for the system and an estimated customer service contribution.
- Composite Ratio Assignment – involves the assignment of costs based on the ratio of costs by functional service, whose percentage allocations have already been established, to the associated cost totals for the test period. For example, bad debt expense was assigned to each service based on the percentage distribution of all other system costs.

The manner in which each component was assigned to the functional services varied based on the nature of the item. Burns & McDonnell developed the proposed unbundling of the components of the FY 2013 revenue requirement based on its understanding of the types of associated costs. A summary of the assignment of each detailed component of the annual revenue requirement is shown in Table 5-1.

Table 5-1: Revenue Requirement Unbundled Assignment Summary

Description	Budget Yr. FY 2013	PS	TDEL	DIST-P	DIST-S	PBC	MT	BL	CC	CS
Total Operating Expenses	$ 199,236,018	$ 117,436,650	$ 25,087,586	$ 38,692,281	$ 5,179,136	$ 6,807,906	$ 1,386,079	$ 2,231,626	$ 636,009	$ 1,778,746
Return on Rate Base (6.11% Return)	24,779,981	6,469,347	1,304,344	14,998,653	2,007,637	-	-	-	-	-
Total Cost of Service	$ 224,015,998	$ 123,905,997	$ 26,391,929	$ 53,690,935	$ 7,186,773	$ 6,807,906	$ 1,386,079	$ 2,231,626	$ 636,009	$ 1,778,746
Total Other Revenue Deduction	$ (20,155,890)	$ (5,464,097)	$ (14,691,793)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue Requirement	$ 203,860,108	$ 118,441,900	$ 11,700,136	$ 53,690,935	$ 7,186,773	$ 6,807,906	$ 1,386,079	$ 2,231,626	$ 636,009	$ 1,778,746
Functional Service Distribution	100.0%	58.1%	5.7%	26.3%	3.5%	3.3%	0.7%	1.1%	0.3%	0.9%

In Table 5-1, the assignment of the components of the annual revenue requirement for FY 2013 shows that $118.4 million, or 58.1 percent, of PWP's test year revenue requirement was related to the power supply energy (PS) functional service.

5.3 REVENUE REQUIREMENT ALLOCATION

Following the unbundling of the various components of the annual revenue requirement to the functional utility services, the unbundled annual revenue requirement was allocated to PWP's retail rate classifications. These allocations were developed to reflect the relative impact each rate class will have on the level of each component of the test period revenue requirement.

PWP currently bills its retail electric customers based on rate schedules that became effective July 1, 2012. There are currently eight main types of service. In FY 2013, PWP will offer an expanded set of electric services and classifications. The test period revenue requirement was allocated based on the new classifications that would likely be utilized in FY 2013. The test period FY 2013 rate classifications are as follows:

- Residential Single Family
- Residential Multi-Family
- Small Commercial and Industrial
- Medium Commercial and Industrial – Secondary
- Medium Commercial and Industrial – Primary
- Large Commercial and Industrial – Secondary
- Large Commercial and Industrial – Primary
- Street Lighting and Traffic Signals

5.3.1 Allocation Factors

Burns & McDonnell utilized detailed billing history data from FY 2012 and projections of future sales and loads to develop a series of allocation factors. The allocation factors were developed based on statistical billing determinants, estimates of the contributions of each rate classification to PWP's total annual system energy requirements, average monthly coincident system peak demand, and average monthly non-coincident system peak demand. In addition, the total number of customers in each rate category was determined. Ratios were calculated of each class's contribution for each statistic to the corresponding total. These ratios were used as cost allocation factors to allocate each unbundled component of the annual revenue requirement to the rate classes. These allocation factors are presented in Table 5-2 and the bases for their development are provided in the following sections.

Table 5-2: Allocation Factors by Type

Description		Total System	Res. Single Family	Res. Multi-Family	Small Com. & Industrial	Ind. Secondary	Med. Com. & Ind. Primary	Ind. Secondary	Large Com. & Ind. Primary	Street Lighting & Traffic
Cost Allocation Factors	Allocation Code									
Winter Energy	A	1.000	0.2495	0.0361	0.1332	0.2352	0.0006	0.2758	0.0538	0.0157
Summer Energy	B	1.000	0.2385	0.0344	0.1370	0.2360	0.0006	0.2756	0.0648	0.0130
Total Energy	C	1.000	0.2455	0.0355	0.1346	0.2355	0.0006	0.2757	0.0578	0.0148
12-CP	D	1.000	0.2039	0.0253	0.1318	0.2191	0.0004	0.2287	0.0407	0.1500
12-NCP	E	1.000	0.2678	0.0408	0.1440	0.2422	0.0007	0.2415	0.0549	0.0082
12-NCP Primary	F	1.000	0.2678	0.0408	0.1440	0.2422	0.0007	0.2415	0.0549	0.0082
12-NCP Secondary	G	1.000	0.2835	0.0432	0.1524	0.2565	0.0000	0.2557	0.0000	0.0086
1-NCP Winter	H	1.000	0.2503	0.0391	0.1429	0.2315	0.0008	0.2523	0.0618	0.0212
1-NCP Summer	I	1.000	0.3196	0.0426	0.1310	0.2302	0.0006	0.1980	0.0611	0.0170
1-NCP Total	J	1.000	0.3196	0.0426	0.1310	0.2302	0.0006	0.1980	0.0611	0.0170
Metering	K	1.000	0.7161	0.1369	0.1154	0.0262	0.0001	0.0040	0.0012	-
Billing	L	1.000	0.7167	0.1370	0.1155	0.0263	0.0000	0.0040	0.0005	-
Call Center	M	1.000	0.8085	0.1546	0.0326	0.0037	0.0000	0.0006	0.0001	-
Customer Services	N	1.000	0.6362	0.1216	0.1539	0.0583	0.0001	0.0266	0.0033	-

5.3.2 Energy Allocation

Seasonal and total energy allocation factors were developed for use in the distribution of all energy-related expenses. Based on the billing data provided, the historical energy sales to each of PWP's rate classes were determined. The seasonal and total energy sales for each class were factored up to the system level. System losses were assumed to occur between three voltage levels, from power supply to transmission, from transmission voltage to primary distribution voltage, and from primary distribution voltage to secondary distribution voltage. All customer classes that receive service at secondary distribution voltage shared proportionally equal losses based on energy sales. Primary service customer classes do not share in the losses at the secondary level. The ratios of the resulting estimated contributions of each class to the total system energy requirements represented the energy allocation factors.

5.3.3 Demand Allocation

The determination of system demand contributions for each rate class was more complex than the development of the energy allocation factors for two reasons. First, the normal operation of an electric utility does not require collecting the same amount of demand-related data as it does energy-related data. The second reason is that there are a variety of methodologies that may be used in allocating the demand costs of an electric utility. The Burns & McDonnell load forecast prepared as part of this study provided substantial amounts of statistically valid data from which demand allocations were derived. The various demand allocation factors were developed utilizing the results of the load forecast.

The peak responsibility methodology for allocating a substantial portion of the demand related costs was based on the electric system's average 12 monthly coincident peak demands (12-CP). This methodology apportions peak demand costs on the basis of each customer class's demand contribution at the time of the 12 monthly system peaks. The use of 12-CP methodology recognizes each customer class's contribution to system demands during each month of the year.

In addition to the average 12-CP demand, the average annual demand for each customer class was also determined and used in determining the peak demand allocation factors for each class. The 12-CP demand was assigned a weighting of 12/13th and the average demand was assigned a weighting of 1/13th. This weighting assigns some cost responsibility to customers who usually have little or no coincident peak responsibility such as lighting customers.

The average monthly non-coincident peak (12-NCP) demand of the various classes was also developed for the test period based on the results of the load forecast. The 12-NCP demand allocation factor was utilized in the Study to allocate distribution related costs to the various customer classes. Annual non-coincident peak factors were developed as well.

5.3.4 Customer Allocation

The customer allocation factors for metering, billing, call center, and other customer service costs were developed to allocate the costs of customer services among the various rate classifications. The allocation factors were based on relative weighting of the number of customers included in each rate class. Relative weights were estimated to reflect differences in the effort required and the cost incurred to provide customer services to customers in the different rate classes. The numbers of customers for each classification were multiplied by the relative weight factor to calculate the weighted number of customers in each class. The ratios of the weighted customer counts for each class to the total weighted number of customers represented the customer allocation factor.

5.3.5 Cost Allocation

Each component item of the annual revenue requirement, which was unbundled and assigned to the various functional utility services, was allocated to the appropriate customer rate classifications using the corresponding allocation factors. The allocated amounts were summarized for each rate class. Table 5-3 presents a summary of the allocation of the annual revenue requirement to the rate classifications by the unbundled functional services. The total amounts in Table 5-3 for each unbundled service within each component of the annual revenue requirement were carried forward from Table 5-1.

Table 5-3: Functional Cost Allocation Summary

Description		Test Period FY 2013	Res. Single Family	Res. Multi-Family	Small Com. & Industrial	Med. Com. & Ind. Secondary	Med. Com. & Ind. Primary	Large Com. & Ind. Secondary	Large Com. & Ind. Primary	Street Lighting & Traffic
PS	Winter Energy	$ 74,566,436	$ 18,605,032	$ 2,694,743	$ 9,932,399	$ 17,539,550	$ 44,790	$ 20,564,642	$ 4,011,084	$ 1,174,195
PS	Summer Energy	49,339,561	11,769,499	1,698,689	6,758,691	11,645,483	30,399	13,599,005	3,195,046	642,749
TDEL		26,391,929	7,067,053	1,077,709	3,799,257	6,393,282	17,876	6,373,047	1,448,383	215,323
DIST-P		53,690,935	14,376,997	2,192,458	7,729,092	13,006,298	36,366	12,965,132	2,946,547	438,046
DIST-S		7,186,773	2,037,630	310,734	1,095,433	1,843,363	-	1,837,529	-	62,084
PBC		6,807,906	1,671,448	241,790	916,199	1,603,359	4,128	1,877,131	393,389	100,462
MT		1,386,079	992,570	189,776	160,022	36,373	106	5,541	1,692	-
BL		2,231,626	1,599,310	305,782	257,840	58,608	68	8,927	1,090	-
CC		636,009	514,208	98,315	20,725	2,355	3	359	44	-
CS		1,778,746	1,131,715	216,380	273,682	103,681	121	47,380	5,787	-
Total Cost of Service		$ 224,015,998	$ 59,765,463	$ 9,026,376	$ 30,943,339	$ 52,232,353	$ 133,856	$ 57,278,693	$ 12,003,062	$ 2,632,858
Less Other Revenues										
PS	Winter Energy	$ (3,288,285)	$ (820,458)	$ (118,835)	$ (438,006)	$ (773,472)	$ (1,975)	$ (906,875)	$ (176,884)	$ (51,781)
PS	Summer Energy	(2,175,812)	(519,020)	(74,910)	(298,050)	(513,551)	(1,341)	(599,699)	(140,897)	(28,344)
TDEL		(14,691,793)	(3,934,069)	(599,936)	(2,114,961)	(3,558,996)	(9,951)	(3,547,732)	(806,282)	(119,865)
DIST-P		-	-	-	-	-	-	-	-	-
DIST-S		-	-	-	-	-	-	-	-	-
PBC		-	-	-	-	-	-	-	-	-
MT		-	-	-	-	-	-	-	-	-
BL		-	-	-	-	-	-	-	-	-
CC		-	-	-	-	-	-	-	-	-
CS		-	-	-	-	-	-	-	-	-
Total		$ (20,155,890)	$ (5,273,548)	$ (793,681)	$ (2,851,016)	$ (4,846,019)	$ (13,267)	$ (5,054,305)	$ (1,124,064)	$ (199,990)
Net Revenue Requirement		$ 203,860,108	$ 54,491,915	$ 8,232,695	$ 28,092,322	$ 47,386,334	$ 120,589	$ 52,224,388	$ 10,878,999	$ 2,432,868

5.4 COST-OF-SERVICE SUMMARY

The results of the cost-of-service analysis and the allocation of the annual revenue requirement to PWP's rate classes are presented on Table 5-4. The results are broken out into energy-related costs, expressed in both dollars and cents per kWh; distribution-related costs, expressed in both dollars and dollars per kW of system power supply billing demand per month; and customer-related costs, expressed in dollars per customer per month. The total cost-of-service is expressed in both dollars and cents per kWh.

PWP's rate revenue requirement of $203.9 million and the total projected system sales of 1,143,337 MWh translate to an average cost of 17.83¢/kWh. Table 5.4 also shows the net requirement of providing service to each class. For example, the cost allocated to the Residential-Single Family rate classes in FY 2013 totals $54.5 million. Based on the total energy sales from Residential-Single Family customers of 280,308 MWh, the average requirement to provide service to the Residential-Single Family customer class is 19.44¢/kWh.

Table 5-4: Cost-of-Service Summary

Description	Test Period FY 2013	Res. Single Family	Res. Multi-Family	Small Com. & Industrial	Ind. Secondary	Med. Com. & Ind. Primary	Ind. Secondary	Large Com. & Ind. Primary	Street Lighting & Traffic
Power Supply									
Winter Energy									
Net Revenue Requirement	$ 71,278,151	$ 17,784,574	$ 2,575,908	$ 9,494,393	$ 16,766,078	$ 42,815	$ 19,657,768	$ 3,834,201	$ 1,122,415
Energy Sales - kWh	727,044,932	181,165,078	26,239,849	96,715,974	170,790,025	446,741	200,246,629	40,007,002	11,433,635
¢/kWh	9.80	9.82	9.82	9.82	9.82	9.58	9.82	9.58	9.82
Summer Energy									
Net Revenue Requirement	$ 47,163,749	$ 11,250,479	$ 1,623,779	$ 6,460,641	$ 11,131,932	$ 29,059	$ 12,999,306	$ 3,054,148	$ 614,405
Energy Sales - kWh	416,292,450	99,143,302	14,309,334	56,933,513	98,098,626	262,374	114,554,601	27,576,343	5,414,357
¢/kWh	11.33	11.35	11.35	11.35	11.35	11.08	11.35	11.08	11.35
Total Energy									
Net Revenue Requirement	$ 118,441,900	$ 29,035,053	$ 4,199,687	$ 15,955,034	$ 27,898,010	$ 71,873	$ 32,657,074	$ 6,888,349	$ 1,736,819
Energy Sales - kWh	1,143,337,382	280,308,381	40,549,183	153,649,486	268,888,650	709,114	314,801,230	67,583,345	16,847,992
¢/kWh	10.36	10.36	10.36	10.38	10.38	10.14	10.37	10.19	10.31
Public Benefits Charge									
PBC									
Net Revenue Requirement	$ 6,807,906	$ 1,671,448	$ 241,790	$ 916,199	$ 1,603,359	$ 4,128	$ 1,877,131	$ 393,389	$ 100,462
Energy Sales - kWh	1,143,337,382	280,308,381	40,549,183	153,649,486	268,888,650	709,114	314,801,230	67,583,345	16,847,992
¢/kWh	0.60	0.60	0.60	0.60	0.60	0.58	0.60	0.58	0.60
Transmission									
Transmission Delivery									
Net Revenue Requirement	$ 11,700,136	$ 3,132,984	$ 477,773	$ 1,684,296	$ 2,834,286	$ 7,925	$ 2,825,315	$ 642,101	$ 95,457
Non-Coincident Peak - kW	252,025	67,486	10,291	36,280	61,051	171	60,858	13,831	2,056
$/kW-mo.	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87	3.87
Distribution									
Total Distribution Cost									
Net Revenue Requirement	$ 60,877,707	$ 16,414,627	$ 2,503,191	$ 8,824,524	$ 14,849,661	$ 36,366	$ 14,802,661	$ 2,946,547	$ 500,129
Non-Coincident Peak - kW	252,025	67,486	10,291	36,280	61,051	171	60,858	13,831	2,056
$/kW-mo.	20.13	20.27	20.27	20.27	20.27	17.75	20.27	17.75	20.27
Customer Service									
Net Revenue Requirement	$ 6,032,459	$ 4,237,803	$ 810,253	$ 712,269	$ 201,018	$ 297	$ 62,207	$ 8,613	$ -
Number of Customers	64,705	46,936	8,974	7,567	860	1	131	16	220
$/cust.-mo.	7.77	7.52	7.52	7.84	19.48	24.77	39.57	44.86	-
Summary									
Net Revenue Requirement	$ 203,860,108	$ 54,491,915	$ 8,232,695	$ 28,092,322	$ 47,386,334	$ 120,589	$ 52,224,388	$ 10,878,999	$ 2,432,868
Energy Sales - kWh	1,143,337,382	280,308,381	40,549,183	153,649,486	268,888,650	709,114	314,801,230	67,583,345	16,847,992
¢/kWh	17.83	19.44	20.30	18.28	17.62	17.01	16.59	16.10	14.44
Dist., Cust. and ESC Revenue Comparison									
Dist., Cust. and ESC Revenue Requirement	$ 170,444,361	$ 46,151,215	$ 7,021,251	$ 23,612,256	$ 39,554,614	$ 100,480	$ 43,084,945	$ 8,965,694	$ 1,953,907
Gen. by Existing Rates	154,949,461	42,108,411	5,902,859	21,541,876	35,177,316	101,256	38,375,642	9,748,534	1,993,566
Dollar Difference	$ 15,494,900	$ 4,042,804	$ 1,118,392	$ 2,070,380	$ 4,377,298	$ (777)	$ 4,709,303	$ (782,840)	$ (39,659)
Revenue Adjustment Required	10.00%	9.60%	18.95%	9.61%	12.44%	-0.77%	12.27%	-8.03%	-1.99%

Table 5-4 also provides a comparison of the total Distribution, Customer, and ESC revenue requirement to the projected revenue that would be generated by current rates. In addition, the analysis indicates the extent to which the projected annual revenues generated from these existing rates for each class would either exceed or fall short of the corresponding revenue requirement.

The line labeled Revenue Adjustment Required on the summary table shows some cross subsidization between the rate classes. The Residential Multi-Family class is receiving the largest benefit mainly due to the current D&C rate being tied to the Residential Single-Family D&C rate. Based on the analysis, PWP is not recovering sufficient distribution cost from the Residential Multi-Family D&C rate. Conversely, the Large Commercial and Industrial – Primary class is appears to be recovering more distribution cost than it has been allocated. This class subsidizes more cost than any other class.

The cost-of-service analysis served as one input into the process of developing revised electric rates. Study efforts to design standard rates are described in Section 6.0 of this report. Time-of-use rate design is discussed in Section 7.0.

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6.0 STANDARD RATE DESIGN ANALYSIS

6.0 STANDARD RATE DESIGN ANALYSIS

6.1 OVERVIEW

Once the test period cost-of-service was established for each rate classification, standard retail rates were developed with the goal of recovery of the appropriate amount of cost for the utility. The cost-of-service analysis described in Section 5.0 of this report served as one input into the standard rate analysis and design of revised retail electric rates. Input from PWP was also taken into consideration in the development of the proposed standard rates and structures.

As discussed in Section 4.0, the financial forecast indicated that PWP requires Distribution Charge, Customer Charge and ESC test period revenue adjustments. It is expected that revised rate recommendations will be implemented for FY 2014. Rate revenue adjustment recommendations for the remainder of the analysis period, beginning in FY 2015, remain appropriate if the FY 2014 rate recommendations are implemented July 1, 2013. In addition, the cost-of-service results indicated some imbalance in the cost recovery of the electric rates currently employed by PWP. To combat this, some rate structures were modified to more appropriately recover costs. Section 6.0 provides a discussion on the rate design considerations taken and modifications made to each rate structure from which standard rates are billed. Time-of-use pricing rates are discussed in Section 7.0.

6.1.1 Rate Design Objectives

The proposed electric rates and structures developed and submitted to PWP for consideration and adoption were developed in order to continue to meet the following electric utility rate criteria for service provided by municipally owned utilities:

- Electric rates should be based on a policy which calls for the lowest possible price consistent with customer requirements, quality service efficiently rendered, and a return to the City
- Electric rates should be simple and understandable
- Electric rates should be equitable among classes of customers and individuals within classes, taking into consideration the cost-of-service analysis
- Electric rates should be designed to encourage the most efficient use of the utility plant and discourage unnecessary or wasteful use of electricity
- Electric rates should comply with the applicable orders and requirements of local, state and federal regulatory authorities that have jurisdiction

6.1.2 Customer Classes

PWP has billed the current D&C and standard ESC charges to each rate payer since July 1, 2012. PWP will likely offer modified rate structures and an expanded set of electric services and classifications beginning in FY 2014. The standard electric rate classifications to be offered by PWP beginning FY 2014 are as follows:

- Residential Single Family
- Residential Multi-Family
- Small Commercial and Industrial
- Medium Commercial and Industrial – Secondary
- Medium Commercial and Industrial – Primary
- Large Commercial and Industrial – Secondary
- Large Commercial and Industrial - Primary
- Street Lighting and Traffic Signals

6.2 STANDARD RATE DESIGN ANALYSIS

6.2.1 Residential D&C Charge

Based on the results of the analyses conducted, it was determined that the most reasonable approach to recover cost from customers currently billed from the current Residential Single Family and Residential Multi-Family rate schedule was to bill separately for distribution and customer service and associated costs. This approach will address one of the utility's concerns by allowing it recover distribution costs from large Residential consumers, likely over 30 maximum kW per month, more appropriately without requiring the installation of demand metering equipment. The current rates only allow the utility to recover a maximum of $89.57 per month for distribution and customer service related costs. The proposed kWh billing structure does not limit how much the utility can bill customers for distribution cost recovery based on usage.

6.2.2 Billing Demand Ratchet

One of the primary points of analysis conducted for the Study was examination of the currently billed annual demand ratchet. Billing demand and the ratchet are defined in the Ordinance as follows:

> *"…the greater of (i) the kilowatts of measured maximum demand occurring during the current month or (ii) the highest demand recorded in the last twelve months, including the current billing month."*

PWP requested Burns & McDonnell develop an alternative to the current 12-month billing demand ratchet to provide rate relief to customers who, for example, reach an extraordinarily high peak once per year, yet are billed for that recorded demand for that month and the subsequent 11 months. The project team evaluated multiple approaches to determining billing demand including the current 12-month demand ratchet, three and four month demand ratchets, seasonal monthly demand billing with ratchets at varying percentages, no ratchet seasonal monthly demand billing, and no ratchet monthly metered demand billing.

The four billing demand options closely examined were the current 12-month demand ratchet, four-month ratchet for both winter and summer seasons, seasonal four-month ratchet, and no ratchet monthly metered demand. Table 6-1 compares estimates of each of these options' relative impact on demand billing. Summer season estimates were scaled from the winter estimate based on the test period summer NCP for each class. The analysis was based on costs before proposed revenue adjustments.

Table 6-1: Demand Analysis

Description	Units	All Seasons	Winter	Summer
12-Month Billing Demand Ratchet				
Residential Service	$/kW-mo.	$ 10.89	N/A	N/A
Small Com. Industrial Service	$/kW-mo.	$ 10.89	N/A	N/A
Medium Com. Industrial Service	$/kW-mo.	$ 10.89	N/A	N/A
Large Com. and Industrial Service	$/kW-mo.	$ 10.76	N/A	N/A
4-Month Billing Demand Ratchet				
Residential Service	$/kW-mo.	$ 11.72	N/A	N/A
Small Com. Industrial Service	$/kW-mo.	$ 11.72	N/A	N/A
Medium Com. Industrial Service	$/kW-mo.	$ 11.72	N/A	N/A
Large Com. and Industrial Service	$/kW-mo.	$ 11.53	N/A	N/A
4-Month Seasonal Billing Demand Ratchet				
Residential Service	$/kW-mo.	N/A	$ 10.50	$ 14.09
Small Com. Industrial Service	$/kW-mo.	N/A	$ 10.50	$ 14.09
Medium Com. Industrial Service	$/kW-mo.	N/A	$ 10.50	$ 14.09
Large Com. and Industrial Service	$/kW-mo.	N/A	$ 11.10	$ 12.36
1-Month Billing Demand (No Ratchet)				
Residential Service	$/kW-mo.	$ 16.72	N/A	N/A
Small Com. Industrial Service	$/kW-mo.	$ 16.72	N/A	N/A
Medium Com. Industrial Service	$/kW-mo.	$ 16.72	N/A	N/A
Large Com. and Industrial Service	$/kW-mo.	$ 16.34	N/A	N/A

As illustrated, the current 12-month demand ratchet would be the least cost billing demand option for customers on a dollars per kW basis. The tradeoff is customers are billed 12 consecutive months for their highest peak. This is particularly concerning to a number of Large Commercial customers that reach extraordinarily high peaks, relative to their average demand requirements, only a few times per year. Both seasonal and non-seasonal four-month billing demand options were evaluated closely. Both offer rate relief for infrequent yet extraordinarily high peaking customers, but still encourage customers to manage their loads with a ratchet. The ratchet also creates a more stable cost recovery mechanism for the utility. Elimination of the ratchet was examined. This would create less stable cost recovery for the utility while increasing the billed demand cost per kW more than the 12-month and four-month ratchet options.

Based on its analysis, Burns & McDonnell recommends the adoption of a four-month billing demand ratchet. The revised billing demand description would become: the greater of (i) the kilowatts of measured maximum demand, after necessary power factor adjustments, occurring during the current month or (ii) the highest demand recorded, after necessary power factor adjustments, in the last four months, including the current billing month.

Table 6-2 presents a comparison demonstrating the potential impact of the recommended four-month demand ratchet. The table compares the revenue impact from current rates when utilizing the current billing demand ratchet or the recommended four-month ratchet.

Table 6-2: Billing Demand Ratchet Impact Comparison

		Billing Demand		Billing Demand Revenue [1]		Billing Demand Impact	
Month	Metered Demand	Current 12-Month Ratchet	Recommended 4-Month Ratchet	Current 12-Month Ratchet	Recommended 4-Month Ratchet	Dollar Difference	Percentage Difference
	- kW -	- kW -	- kW -	- kW -	- kW -		
July	90	90	90	$ 980	$ 980	$ -	0.0%
August	105	105	105	1,143	1,143	-	0.0%
September	110	110	110	1,198	1,198	-	0.0%
October	95	110	110	1,198	1,198	-	0.0%
November	85	110	110	1,198	1,198	-	0.0%
December	85	110	110	1,198	1,198	-	0.0%
January	80	110	95	1,198	1,035	(163)	-13.6%
February	90	110	90	1,198	980	(218)	-18.2%
March	85	110	90	1,198	980	(218)	-18.2%
April	95	110	95	1,198	1,035	(163)	-13.6%
May	90	110	95	1,198	1,035	(163)	-13.6%
June	100	110	100	1,198	1,089	(109)	-9.1%
12-Month Total	1,110	1,295	1,200	$ 14,103	$ 13,068	$ (1,035)	-7.3%

[1] Revenue calculated w ith current monthly $10.89/kW Medium Commercial Secondary Distribution Charge.

The four-month ratchet approach to determining billing demand will simultaneously provide rate relief to winter peaking customers, when distribution infrastructure is burdened the least, while maintaining PWP’s mechanism to recover costs for distribution assets built to enable adequate power delivery for all customers during the summer months, when system load is greatest and when investment in distribution infrastructure is most critical.

Amid rate design discussions, PWP disclosed current plans to offer another approach to determining billing demand to provide customers an additional option. PWP will offer, as policy, a demand limit calculation for determining billing demand. The plan will stipulate the following:

- Available to any PWP customer equipped with, and appropriately billed from, demand metering equipment
- PWP and customer will agree upon a monthly billing demand limit based on historical billing information for that customer, or as estimated by PWP if historical information is not available
- The agreed upon demand limit will be re-examined on an annual basis
- Customer will be charged distribution charges under the applicable rate schedule for the agreed to billing demand amount on a monthly basis
- For any month the agreed to billing demand limit is exceeded, customer will be charged a penalty of three times the associated distribution rate
- If the agreed upon billing demand limit is exceeded, customer will billed the penalty for the current billing month and two consecutive months thereafter
- Once the penalty period has past, customer will be again billed the agreed upon billing demand limit
- Customer may opt into this billing demand option a maximum of one time per 12 billing months
- Customer may opt out at any time but will be billed from the level demand rider for the month for which the opt out request is received

It is expected that revised rate recommendations will be implemented for FY 2014. Table 6-3 presents a side-by-side comparison of the current and proposed standard electric rates. Rates for TOU customers, including Large Commercial and Industrial customers, are discussed in Section 7.

6.2.3 Sample Bills

Sample monthly bills were calculated for each class to demonstrate the impact the proposed rates would have on each class. The bills for non-demand rate customers were calculated based on average FY 2014 seasonal energy determinants for each class as developed in the load forecast described in Section 3.0. Bills for demand rate customers were calculated based on average FY 2014 seasonal billing demand and load factor determinants for each class as developed in the load forecast. To provide larger sample sizes, bills were prepared with determinants incrementally deviating 25 percent from the average.

Table 6-3: Current and Proposed Electric Rates Summary

Description	Units	Current	Proposed	Description	Units	Current	Proposed
Residential Single-Family Service				**Residential Multi-Family Service**			
Distribution and Customer Charge				Distribution and Customer Charge			
0 to 250	$/month	$ 6.02	$ -	0 to 250	$/month	$ 6.02	$ -
251 to 350	$/month	$ 12.32	$ -	251 to 350	$/month	$ 12.32	$ -
351 to 450	$/month	$ 24.94	$ -	351 to 450	$/month	$ 24.94	$ -
451 to 550	$/month	$ 35.97	$ -	451 to 550	$/month	$ 35.97	$ -
551 to 650	$/month	$ 45.43	$ -	551 to 650	$/month	$ 45.43	$ -
651 to 750	$/month	$ 56.47	$ -	651 to 750	$/month	$ 56.47	$ -
751 to 1,000	$/month	$ 67.50	$ -	751 to 1,000	$/month	$ 67.50	$ -
> 1,000	$/month	$ 89.57	$ -	> 1,000	$/month	$ 89.57	$ -
Customer Charge	$/kWh	$ -	$ 7.53	Customer Charge	$/kWh	$ -	$ 7.53
Minimum Charge	$/month	$ 6.02	$ 7.53	Minimum Charge	$/month	$ 6.02	$ 7.53
Distribution Charge	$/kWh	$ -	$ 0.05848	Distribution Charge	$/kWh	$ -	$ 0.05848
Transmission Services Charge	$/kWh	$ 0.00821	$ 0.00885	Transmission Services Charge	$/kWh	$ 0.00821	$ 0.00885
Energy Services Charge - Option A				Energy Services Charge - Option A			
Winter	$/kWh	$ 0.08397	$ 0.08671	Winter	$/kWh	$ 0.08397	$ 0.08671
Summer	$/kWh	$ 0.09323	$ 0.10037	Summer	$/kWh	$ 0.09323	$ 0.10037
Small Commercial and Industrial Service							
Customer Charge							
Single-Phase	$/month	$ 14.16	$ 7.85				
Three-Phase	$/month	$ 19.07	$ 10.57				
Minimum Charge							
Single-Phase	$/month	$ 14.16	$ 7.85				
Three-Phase	$/month	$ 19.07	$ 10.57				
Distribution Charge	$/kWh	$ 0.04475	$ 0.05641				
Transmission Services Charge	$/kWh	$ 0.00821	$ 0.00885				
Energy Services Charge - Option A							
Winter	$/kWh	$ 0.08280	$ 0.08690				
Summer	$/kWh	$ 0.09151	$ 0.10049				
Medium Commercial and Industrial Service – Secondary				**Medium Commercial and Industrial Service – Primary**			
Customer Charge	$/month	$ 60.22	$ 19.49	Customer Charge	$/month	$ 83.92	$ 24.81
Minimum Charge	$/month	$ 362.32	$ 495.90	Minimum Charge	$/month	$ 376.72	$ 358.40
Distribution Charge	$/kW-mo.	$ 10.89	$ 15.88	Distribution Charge	$/kW-mo.	$ 10.54	$ 11.12
Transmission Services Charge	$/kWh	$ 0.00821	$ 0.00885	Transmission Services Charge	$/kWh	$ 0.00802	$ 0.00866
Energy Services Charge - Option A				Energy Services Charge - Option A			
Winter	$/kWh	$ 0.08463	$ 0.08665	Winter	$/kWh	$ 0.08371	$ 0.08600
Summer	$/kWh	$ 0.09588	$ 0.10019	Summer	$/kWh	$ 0.09404	$ 0.09938

6.2.3.1 Residential Single Family Service

The current Residential Single Family Service rates consist of a combined D&C charge, an ESC, a PCA, a TSC, and a PBC. The distribution and customer costs would be recovered independently of one another and the PCA would be reset to 0.00¢/kWh if the proposed rate were implemented. Table 6-4 demonstrates the expected impact of the rate recommendations in the form of sample monthly bill calculations. Based on average winter monthly consumption of 487 kWh, the proposed rates would generate a monthly bill of $85.34, compared to a bill of $83.65 calculated with current rates; a difference of $1.69 or 2.0 percent. Average summer monthly consumption of 534 kWh, would generate a monthly bill of $100.14 with proposed rates, compared to a bill of $93.20 calculated with current rates; a difference of $6.94 or 7.4 percent.

Table 6-4: Residential Single-Family Sample Bill Comparison

	Energy Usage - kWh -	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates - $/kWh -	Bill Total Proposed Rates - $/kWh -
Winter	280	$ 39.73	$ 52.27	$ 12.53	31.54%	$ 0.14191	$ 0.18666
	370	$ 61.17	$ 66.64	$ 5.48	8.96%	$ 0.16532	$ 0.18012
	487	**$ 83.65**	**$ 85.34**	**$ 1.69**	**2.02%**	**$ 0.17177**	**$ 0.17523**
	610	$ 105.16	$ 104.99	$ (0.17)	-0.16%	$ 0.17239	$ 0.17211
	760	$ 141.91	$ 128.96	$ (12.96)	-9.13%	$ 0.18673	$ 0.16968
	950	$ 160.51	$ 159.31	$ (1.20)	-0.75%	$ 0.16896	$ 0.16770

	Energy Usage - kWh -	Bill Total Current Rates	Bill Total Existing Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates - $/kWh -	Bill Total Proposed Rates - $/kWh -
Summer	300	$ 44.47	$ 59.56	$ 15.09	33.93%	$ 0.14824	$ 0.19853
	400	$ 67.81	$ 76.90	$ 9.09	13.41%	$ 0.16952	$ 0.19226
	534	**$ 93.20**	**$ 100.14**	**$ 6.94**	**7.45%**	**$ 0.17453**	**$ 0.18753**
	670	$ 128.27	$ 123.73	$ (4.55)	-3.54%	$ 0.19145	$ 0.18467
	840	$ 157.52	$ 153.21	$ (4.31)	-2.74%	$ 0.18753	$ 0.18239
	1,050	$ 202.10	$ 189.63	$ (12.47)	-6.17%	$ 0.19247	$ 0.18060

6.2.3.2 Residential Multi-Family Service

The current Residential Multi-Family rates consist of a combined D&C charge, an ESC, a PCA, a TSC, and a PBC. Distribution and customer costs would be recovered independently of one another and the PCA would be reset to 0.00¢/kWh if the proposed rate were implemented. Table 6-5 shows the expected impact of the rate recommendations in the form of sample monthly bill calculations. Based on average winter monthly consumption of 369 kWh, the proposed rates would generate a monthly bill of $66.49, compared to a bill of $59.07 calculated with current rates; a difference of $7.42 or 12.6 percent. Average summer monthly consumption of 402 kWh, would generate a monthly bill of $77.25 with proposed rates, compared to a bill of $66.02 calculated with current rates; a difference of $11.23 or 17.0 percent.

6.2.3.3 Small Commercial and Industrial Service

The current Small Commercial and Industrial Service rates consist of a customer charge, a distribution charge, an ESC, a PCA, a TSC, and a PBC. Table 6-6 demonstrates the expected impact of the rate recommendations in the form of sample monthly bill calculations. Based on average winter monthly consumption of 1,612 kWh, the proposed rates would generate a monthly bill of $262.37, compared to a bill of $242.24 calculated with current rates; a difference of $20.13 or 8.3 percent. Average summer monthly consumption of 1,898 kWh, would generate a monthly bill of $333.32 with proposed rates, compared to a bill of $299.24 calculated with current rates; a difference of $34.08 or 11.4 percent.

Table 6-5: Residential Multi-Family Sample Bill Comparison

Winter

Energy Usage - kWh -	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates - $/kWh -	Bill Total Proposed Rates - $/kWh -
210	$ 24.58	$ 41.08	$ 16.50	67.13%	$ 0.11705	$ 0.19563
280	$ 37.73	$ 52.27	$ 14.53	38.51%	$ 0.13477	$ 0.18666
369	**$ 59.07**	**$ 66.49**	**$ 7.42**	**12.56%**	**$ 0.16008**	**$ 0.18018**
460	$ 79.01	$ 81.02	$ 2.02	2.55%	$ 0.17176	$ 0.17614
580	$ 100.22	$ 100.20	$ (0.02)	-0.02%	$ 0.17279	$ 0.17275
730	$ 125.94	$ 124.16	$ (1.78)	-1.42%	$ 0.17253	$ 0.17009

Summer

Energy Usage - kWh -	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates - $/kWh -	Bill Total Proposed Rates - $/kWh -
230	$ 28.67	$ 47.42	$ 18.75	65.40%	$ 0.12465	$ 0.20617
300	$ 42.47	$ 59.56	$ 17.09	40.23%	$ 0.14157	$ 0.19853
402	**$ 66.02**	**$ 77.25**	**$ 11.23**	**17.00%**	**$ 0.16423**	**$ 0.19216**
500	$ 87.56	$ 94.25	$ 6.69	7.64%	$ 0.17511	$ 0.18849
630	$ 110.95	$ 116.79	$ 5.84	5.27%	$ 0.17611	$ 0.18538
790	$ 150.16	$ 144.54	$ (5.62)	-3.75%	$ 0.19008	$ 0.18296

Table 6-6: Small Com. and Ind. Sample Bill Comparison

Winter

Energy Usage - kWh -	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates - $/kWh -	Bill Total Proposed Rates - $/kWh -
910	$ 142.92	$ 151.53	$ 8.61	6.03%	$ 0.15705	$ 0.16652
1,210	$ 185.36	$ 198.90	$ 13.53	7.30%	$ 0.15319	$ 0.16438
1,612	**$ 242.24**	**$ 262.37**	**$ 20.13**	**8.31%**	**$ 0.15027**	**$ 0.16276**
2,020	$ 299.97	$ 326.79	$ 26.82	8.94%	$ 0.14850	$ 0.16178
2,530	$ 372.13	$ 407.31	$ 35.18	9.45%	$ 0.14709	$ 0.16099
3,160	$ 461.27	$ 506.78	$ 45.51	9.87%	$ 0.14597	$ 0.16037

Summer

Energy Usage - kWh -	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates - $/kWh -	Bill Total Proposed Rates - $/kWh -
1,070	$ 174.87	$ 191.33	$ 16.46	9.41%	$ 0.16343	$ 0.17882
1,420	$ 227.44	$ 251.35	$ 23.91	10.51%	$ 0.16017	$ 0.17701
1,898	**$ 299.24**	**$ 333.32**	**$ 34.08**	**11.39%**	**$ 0.15766**	**$ 0.17562**
2,370	$ 370.13	$ 414.26	$ 44.12	11.92%	$ 0.15617	$ 0.17479
2,960	$ 458.75	$ 515.43	$ 56.68	12.35%	$ 0.15498	$ 0.17413
3,700	$ 569.90	$ 642.33	$ 72.43	12.71%	$ 0.15403	$ 0.17360

6.2.3.4 Medium Commercial Secondary Service

The current Medium Commercial and Industrial Service - Secondary rates consist of a customer charge, a kW distribution charge, an ESC, a PCA, a TSC, and a PBC. Table 6-7 demonstrates the expected impact of the rate recommendations in the form of sample monthly bill calculations. Based on average winter monthly billing demand of 63 kW and a 55 percent load factor, the proposed rates would generate a monthly bill of $3,551 compared to a bill of $3,211 calculated with current rates; a difference of $340 or 10.6 percent. Average summer monthly billing demand of 78 kW and a 51percent load factor would generate a monthly bill of $4,552 with proposed rates, compared to a bill of $4,061 calculated with current rates; a difference of $491 or 12.1 percent.

Table 6-7: Medium Com. and Ind. - Secondary Sample Bill Comparison

	Billing Demand	Load Factor	Energy Usage	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates	Bill Total Proposed Rates
	- kW -	- % -	- kWh -					- $/kWh -	- $/kWh -
Winter	30	45%	9,800	$ 1,352.91	$ 1,487.94	$ 135.04	9.98%	$ 0.13805	$ 0.15183
	63	45%	20,500	$ 2,766.98	$ 3,095.15	$ 328.17	11.86%	$ 0.13497	$ 0.15098
	299	45%	97,200	$ 12,897.33	$ 14,607.17	$ 1,709.83	13.26%	$ 0.13269	$ 0.15028
	30	55%	11,900	$ 1,559.90	$ 1,700.53	$ 140.62	9.01%	$ 0.13108	$ 0.14290
	63	**55%**	**25,000**	**$ 3,210.54**	**$ 3,550.68**	**$ 340.14**	**10.59%**	**$ 0.12842**	**$ 0.14203**
	299	55%	118,700	$ 15,016.59	$ 16,783.61	$ 1,767.02	11.77%	$ 0.12651	$ 0.14140
	30	65%	14,100	$ 1,776.76	$ 1,923.23	$ 146.48	8.24%	$ 0.12601	$ 0.13640
	63	65%	29,500	$ 3,654.11	$ 4,006.22	$ 352.11	9.64%	$ 0.12387	$ 0.13580
	299	65%	140,200	$ 17,135.84	$ 18,960.06	$ 1,824.21	10.65%	$ 0.12222	$ 0.13524

	Billing Demand	Load Factor	Energy Usage	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates	Bill Total Proposed Rates
	- kW -	- % -	- kWh -					- $/kWh -	- $/kWh -
Summer	30	41%	8,900	$ 1,364.32	$ 1,517.34	$ 153.03	11.22%	$ 0.15329	$ 0.17049
	78	41%	23,000	$ 3,435.50	$ 3,897.84	$ 462.34	13.46%	$ 0.14937	$ 0.16947
	299	41%	88,200	$ 13,002.45	$ 14,890.32	$ 1,887.87	14.52%	$ 0.14742	$ 0.16882
	30	51%	11,000	$ 1,594.94	$ 1,758.36	$ 163.42	10.25%	$ 0.14499	$ 0.15985
	78	**51%**	**28,700**	**$ 4,061.47**	**$ 4,552.03**	**$ 490.56**	**12.08%**	**$ 0.14151**	**$ 0.15861**
	299	51%	109,700	$ 15,363.58	$ 17,357.88	$ 1,994.30	12.98%	$ 0.14005	$ 0.15823
	30	61%	13,200	$ 1,836.54	$ 2,010.85	$ 174.31	9.49%	$ 0.13913	$ 0.15234
	78	61%	34,200	$ 4,665.48	$ 5,183.26	$ 517.78	11.10%	$ 0.13642	$ 0.15156
	299	61%	131,300	$ 17,735.70	$ 19,836.91	$ 2,101.22	11.85%	$ 0.13508	$ 0.15108

6.2.3.5 Medium Commercial Primary Service

The current Medium Commercial and Industrial Service - Primary rates consist of a customer charge, a kW distribution charge, an ESC, a PCA, a TSC, and a PBC. Table 6-8 demonstrates the expected impact of the rate recommendations in the form of sample monthly bill calculations. Based on average winter monthly billing demand of 162 kW and a 48 percent load factor, the proposed rates would generate a monthly bill of $7,488, compared to a bill of $7,288 calculated with current rates; a difference of $200 or 2.8 percent. Average summer monthly billing demand of 177 kW and a 52 percent load factor would generate a monthly bill of $9,525 with proposed rates, compared to a bill of $9,085 calculated with current rates; a difference of $439 or 4.8 percent.

6.2.4 Street Lighting and Traffic Signals

PWP offers Street Lighting and Traffic Signals Service throughout the service area where the poles, electrolier standards and lighting equipment are owned by the customer. As part of the Study, a Street Lighting and Traffic Signals Service cost analysis was prepared and rate adjustments were developed for implementation with the rate adjustments for the other classes. The cost-of-service analysis established the allocated cost recovery requirement for the Lighting classes. Based on the allocated costs, there is a need for significant rate adjustments for some lighting types. Much of the adjustment is driven by a reduction in allocated distribution cost. For unmetered lamp lighting, a cost buildup was completed for each lamp type the utility offers. Consideration was made for each lamp's demand, ballast losses, estimated useful life, and average power supply cost. The lighting cost analysis indicated, in some instances, that significant changes should be made to rates to be more reflective of the costs for providing the service. Table 6-10 and Table 6-10: Current and Proposed Unmetered Lamp Rates

Description	Units	Current	Proposed	Description	Units	Current	Proposed
Incandescent				High Pressure Sodium (HPS)			
1,000 Lumen	$/lamp-mo.	$ 1.00	$ 1.42	70 Watts	$/lamp-mo.	$ 1.37	$ 1.49
1,500 Lumen	$/lamp-mo.	$ 1.19	$ 2.07	100 Watts	$/lamp-mo.	$ 1.91	$ 2.07
2,500 Lumen	$/lamp-mo.	$ 2.10	$ 3.31	150 Watts	$/lamp-mo.	$ 2.61	$ 2.99
4,000 Lumen	$/lamp-mo.	$ 3.36	$ 5.16	200 Watts	$/lamp-mo.	$ 3.33	$ 3.92
6,000 Lumen	$/lamp-mo.	$ 4.82	$ 7.61	250 Watts	$/lamp-mo.	$ 4.24	$ 4.84
10,000 Lumen	$/lamp-mo.	$ 7.38	$ 12.55	310 Watts	$/lamp-mo.	$ 5.18	$ 5.95
67 Watts	$/lamp-mo.	$ 0.91	$ 1.42	400 Watts	$/lamp-mo.	$ 6.44	$ 7.61
69 Watts	$/lamp-mo.	$ 0.93	$ 1.47				
100 Watts	$/lamp-mo.	$ 1.39	$ 2.07	Induction Lamps			
103 Watts	$/lamp-mo.	$ 1.39	$ 2.12	50 Watts	$/lamp-mo.	$ 0.71	$ 1.06
150 Watts	$/lamp-mo.	$ 2.03	$ 2.99	65 Watts	$/lamp-mo.	$ 0.90	$ 1.38
202 Watts	$/lamp-mo.	$ 2.73	$ 3.95	85 Watts	$/lamp-mo.	$ 1.18	$ 1.79
303 Watts	$/lamp-mo.	$ 4.10	$ 5.82	135 Watts	$/lamp-mo.	$ 1.88	$ 2.72
				150 Watts	$/lamp-mo.	$ 2.00	$ 2.99
Mercury Vapor (MV)							
3,500 lumens	$/lamp-mo.	$ 1.72	$ 2.07	Light Emitting Diode (LED)			
7,000 lumens	$/lamp-mo.	$ 2.84	$ 3.46	26 Watts	$/lamp-mo.	$ 0.37	$ 0.50
11,000 lumens	$/lamp-mo.	$ 3.95	$ 4.84	27 Watts	$/lamp-mo.	$ 0.37	$ 0.52
20,000 lumens	$/lamp-mo.	$ 6.23	$ 7.61				
35,000 lumens	$/lamp-mo.	$ 10.56	$ 13.16	Bus Stop			
54,000 lumens	$/lamp-mo.	$ 14.92	$ 18.71	4-60 watt unit bus Stop	$/lamp-mo.	$ 5.20	$ 1.28
				2-40 watt unit bus Stop	$/lamp-mo.	$ -	$ 0.85
Fluorescent							
213 Watts	$/lamp-mo.	$ 2.88	$ 4.16	Metal Halide (MH)			
248 Watts	$/lamp-mo.	$ 3.36	$ 4.81	400 Watts	$/lamp-mo.	$ 6.14	$ 7.61
18 Watts	$/lamp-mo.	$ -	$ 0.38	100 Watts	$/lamp-mo.	$ 1.54	$ 2.07
27 Watts	$/lamp-mo.	$ -	$ 0.57				

present the current and proposed monthly rates for the Street Lighting and Traffic Signals Service class.

Table 6-8: Medium Com. and Ind. - Primary Sample Bill Comparison

Season	Billing Demand - kW -	Load Factor - % -	Energy Usage - kWh -	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates - $/kWh -	Bill Total Proposed Rates - $/kWh -
Winter	30	38%	8,300	$ 1,209.04	$ 1,191.65	$ (17.39)	-1.44%	$ 0.14567	$ 0.14357
	162	38%	44,600	$ 6,138.12	$ 6,303.64	$ 165.53	2.70%	$ 0.13763	$ 0.14134
	299	38%	82,300	$ 11,256.34	$ 11,611.79	$ 355.45	3.16%	$ 0.13677	$ 0.14109
	30	48%	10,400	$ 1,413.70	$ 1,402.47	$ (11.24)	-0.79%	$ 0.13593	$ 0.13485
	162	**48%**	**56,400**	**$ 7,288.14**	**$ 7,488.25**	**$ 200.10**	**2.75%**	**$ 0.12922**	**$ 0.13277**
	299	48%	103,800	$ 13,351.73	$ 13,770.17	$ 418.44	3.13%	$ 0.12863	$ 0.13266
	30	58%	12,600	$ 1,628.12	$ 1,623.32	$ (4.79)	-0.29%	$ 0.12922	$ 0.12884
	162	58%	67,900	$ 8,408.93	$ 8,642.73	$ 233.80	2.78%	$ 0.12384	$ 0.12729
	299	58%	125,400	$ 15,456.86	$ 15,938.60	$ 481.73	3.12%	$ 0.12326	$ 0.12710

Season	Billing Demand - kW -	Load Factor - % -	Energy Usage - kWh -	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates - $/kWh -	Bill Total Proposed Rates - $/kWh -
Summer	30	42%	9,100	$ 1,381.01	$ 1,393.72	$ 12.71	0.92%	$ 0.15176	$ 0.15316
	177	42%	53,600	$ 7,727.04	$ 8,091.12	$ 364.08	4.71%	$ 0.14416	$ 0.15095
	299	42%	90,500	$ 12,990.38	$ 13,645.88	$ 655.50	5.05%	$ 0.14354	$ 0.15078
	30	52%	11,200	$ 1,607.37	$ 1,632.63	$ 25.27	1.57%	$ 0.14352	$ 0.14577
	177	**52%**	**66,200**	**$ 9,085.20**	**$ 9,524.62**	**$ 439.43**	**4.84%**	**$ 0.13724**	**$ 0.14388**
	299	52%	112,000	$ 15,307.86	$ 16,091.93	$ 784.07	5.12%	$ 0.13668	$ 0.14368
	30	62%	13,400	$ 1,844.51	$ 1,882.93	$ 38.42	2.08%	$ 0.13765	$ 0.14052
	177	62%	79,000	$ 10,464.91	$ 10,980.88	$ 515.97	4.93%	$ 0.13247	$ 0.13900
	299	62%	133,500	$ 17,625.35	$ 18,537.99	$ 912.64	5.18%	$ 0.13203	$ 0.13886

Table 6-9: Current and Proposed Street Lighting and Traffic Signal Electric Rates

Description	Units	Current	Proposed
Street Lighting - Metered Distribution Rate			
Street Lighting	$/kWh	$ 0.03646	$ 0.02946
Traffic Signals and Signs	$/kWh	$ 0.05397	$ 0.02946
Street Lighting - Unmetered Distribution Rate			
Street Lighting	$/kWh	$ 0.05397	$ 0.02946
Traffic Signals and Signs	$/kWh	$ 0.05397	$ 0.02946
Transmission Services Charge	$/kWh	$ 0.00821	$ 0.00885
Energy Services Charge	$/kWh	$ 0.06500	$ 0.08130

Table 6-10: Current and Proposed Unmetered Lamp Rates

Description	Units	Current	Proposed
Incandescent			
1,000 Lumen	$/lamp-mo.	$ 1.00	$ 1.42
1,500 Lumen	$/lamp-mo.	$ 1.19	$ 2.07
2,500 Lumen	$/lamp-mo.	$ 2.10	$ 3.31
4,000 Lumen	$/lamp-mo.	$ 3.36	$ 5.16
6,000 Lumen	$/lamp-mo.	$ 4.82	$ 7.61
10,000 Lumen	$/lamp-mo.	$ 7.38	$ 12.55
67 Watts	$/lamp-mo.	$ 0.91	$ 1.42
69 Watts	$/lamp-mo.	$ 0.93	$ 1.47
100 Watts	$/lamp-mo.	$ 1.39	$ 2.07
103 Watts	$/lamp-mo.	$ 1.39	$ 2.12
150 Watts	$/lamp-mo.	$ 2.03	$ 2.99
202 Watts	$/lamp-mo.	$ 2.73	$ 3.95
303 Watts	$/lamp-mo.	$ 4.10	$ 5.82
Mercury Vapor (MV)			
3,500 lumens	$/lamp-mo.	$ 1.72	$ 2.07
7,000 lumens	$/lamp-mo.	$ 2.84	$ 3.46
11,000 lumens	$/lamp-mo.	$ 3.95	$ 4.84
20,000 lumens	$/lamp-mo.	$ 6.23	$ 7.61
35,000 lumens	$/lamp-mo.	$ 10.56	$ 13.16
54,000 lumens	$/lamp-mo.	$ 14.92	$ 18.71
Fluorescent			
213 Watts	$/lamp-mo.	$ 2.88	$ 4.16
248 Watts	$/lamp-mo.	$ 3.36	$ 4.81
18 Watts	$/lamp-mo.	$ -	$ 0.38
27 Watts	$/lamp-mo.	$ -	$ 0.57

Description	Units	Current	Proposed
High Pressure Sodium (HPS)			
70 Watts	$/lamp-mo.	$ 1.37	$ 1.49
100 Watts	$/lamp-mo.	$ 1.91	$ 2.07
150 Watts	$/lamp-mo.	$ 2.61	$ 2.99
200 Watts	$/lamp-mo.	$ 3.33	$ 3.92
250 Watts	$/lamp-mo.	$ 4.24	$ 4.84
310 Watts	$/lamp-mo.	$ 5.18	$ 5.95
400 Watts	$/lamp-mo.	$ 6.44	$ 7.61
Induction Lamps			
50 Watts	$/lamp-mo.	$ 0.71	$ 1.06
65 Watts	$/lamp-mo.	$ 0.90	$ 1.38
85 Watts	$/lamp-mo.	$ 1.18	$ 1.79
135 Watts	$/lamp-mo.	$ 1.88	$ 2.72
150 Watts	$/lamp-mo.	$ 2.00	$ 2.99
Light Emitting Diode (LED)			
26 Watts	$/lamp-mo.	$ 0.37	$ 0.50
27 Watts	$/lamp-mo.	$ 0.37	$ 0.52
Bus Stop			
4-60 watt unit bus Stop	$/lamp-mo.	$ 5.20	$ 1.28
2-40 watt unit bus Stop	$/lamp-mo.	$ -	$ 0.85
Metal Halide (MH)			
400 Watts	$/lamp-mo.	$ 6.14	$ 7.61
100 Watts	$/lamp-mo.	$ 1.54	$ 2.07

6.2.5 Standby Service and Unmetered Service

6.2.5.1 Standby Service

Standby or Breakdown Service is available for any customer in the service area independently producing electrical or mechanical energy. Service is provided through a single meter and is used for outages and emergencies. Standby Service customers agree to contract with PWP and various provisions must be met. The current rate structure for Standby Service consists of a flat ESC rate based on the otherwise applicable service tariff, a monthly distribution demand rate of $10.07 per kW for secondary voltages and primary voltages.

6.2.5.2 Unmetered Service

Unmetered – Non Demand Service is available for equipment with peak demands of less than 30 kW where metering is not prudent. Unmetered – Demand Service is also available were metering is not prudent, but where manufacturers' equipment demand ratings range from 30 kW to 299 kW. Customers for each of these services are billed a monthly customer charge, ESC, TSC, and PBC. Non Demand Customers are billed a distribution charge on a cents per kWh basis while Demand customers are billed distribution charges on a dollars per kW basis. Table 6-11 presents the current and proposed Standby and Unmetered Service monthly rates.

Table 6-11: Current and Proposed Standby and Unmetered Rates Summary

Description	Units	Current	Proposed
Standby Service			
Distribution Charge	$/kW-mo.	$ 10.07	$ 15.88
Minimum Charge	$/month	$ 201.40	$ 317.60
Energy Services Charge	Based on otherwise applicable schedule.		
Unmetered Rates – Non Demand (less than 30 kW)			
Customer Charge			
Single-Phase	$/month	$ 14.16	$ 7.85
Three-Phase	$/month	$ 19.07	$ 10.57
Distribution Charge	$/kWh	$ 0.04099	$ 0.05641
Energy Services Charge			
Winter	$/kWh	$ 0.06030	$ 0.08690
Summer	$/kWh	$ 0.06901	$ 0.10049
Unmetered Rates – Demand (30-299 kW)			
Customer Charge	$/month	$ 60.22	$ 19.49
Distribution Charge	$/kW-mo.	$ 10.07	$ 15.88
Energy Services Charge			
Winter	$/kWh	$ 0.06213	$ 0.08665
Summer	$/kWh	$ 0.07338	$ 0.10019
Self Generation Rates (Residential and Small Commercial) [1]			
Customer Charge	$/month	$ 60.22	$ 19.49
Distribution Charge	$/kW-mo.	$ 10.07	$ 15.88

[1] Rates not prescribed herein shall be equal to the rates from the tariff from which customer would otherwise take service.

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7.0 TIME-OF-USE RATE DESIGN ANALYSIS

7.0 TIME-OF-USE RATE DESIGN ANALYSIS

7.1 OVERVIEW

In addition to the development of standard rates for the major PWP customer classes, Burns & McDonnell developed TOU rates each class. The cost-of-service analysis described in Section 5.0 of this report served as one input into the rate analysis and design of revised retail electric rates. Input from PWP was also taken into consideration in the development of the proposed TOU rates and structures. The TOU rates developed will provide customers with rate options that enable reductions in their costs of electricity and improve the efficiency of PWP electric system operations through monetary incentives to shift load from on-peak hours to off-peak hours.

As discussed in Section 4.0, the financial forecast indicated that PWP requires D&C and ESC test period revenue adjustments. It is expected that revised rate recommendations will be implemented in for FY 2014. Rate revenue adjustment recommendations for the remainder of the analysis period, beginning in FY 2015, remain appropriate if the FY 2014 rate recommendations are implemented July 1, 2013. In addition, the cost-of-service results indicated some imbalance in the cost recovery of the electric rates currently employed by PWP. To combat this, some rate structures were modified to more appropriately recover costs. Section 7.0 provides a discussion on the rate design considerations taken and modifications made to each rate structure from which TOU rates are billed.

7.1.1 Customer Classes

PWP has billed the current D&C and standard ESC charges to each rate payer since July 1, 2012. PWP will likely offer modified rate structures and an expanded set of electric services and classifications beginning in FY 2014. The TOU rate classifications, which will be available beginning in FY 2014, include the following:

- Residential Single Family Service
- Residential Multi-Family Service
- Small Commercial and Industrial Service
- Medium Commercial and Industrial Service – Secondary
- Medium Commercial and Industrial Service – Primary
- Large Commercial and Industrial Service – Secondary
- Large Commercial and Industrial Service – Primary
- Pilot Electric Vehicle Rate 1

- Pilot Electric Vehicle Rate 2
- Electric Vehicle Service

7.2 TOU PRICING PERIOD ANALYSIS

7.2.1 Current TOU Pricing Periods

The pricing period analysis was completed with the assumption that the general shape of PWP's hourly load would remain the same in the future. The FY 2011 average weekday demand curve for the PWP system and growth assumptions established in the load forecast were the main factors in designating the revised pricing periods. The current on-peak winter pricing periods include weekdays from 6:00 AM to 10:00 PM. The current on-peak summer pricing periods include weekdays from 12:00 PM to 8:00 PM. All other weekday hours, weekend hours and holidays are designated off-peak hours throughout the year. The current pricing periods were designed to help shield the utility from needing to buy additional spot market power to meet demand during the most expensive hours of the day. Figure 7.1 and Figure 7.2 provide comparisons of historical average LMP shapes and the FY 2014 average weekday system load shapes with currently designated pricing periods for each season.

Figure 7.1: Current System Pricing Periods - Average Winter Weekday

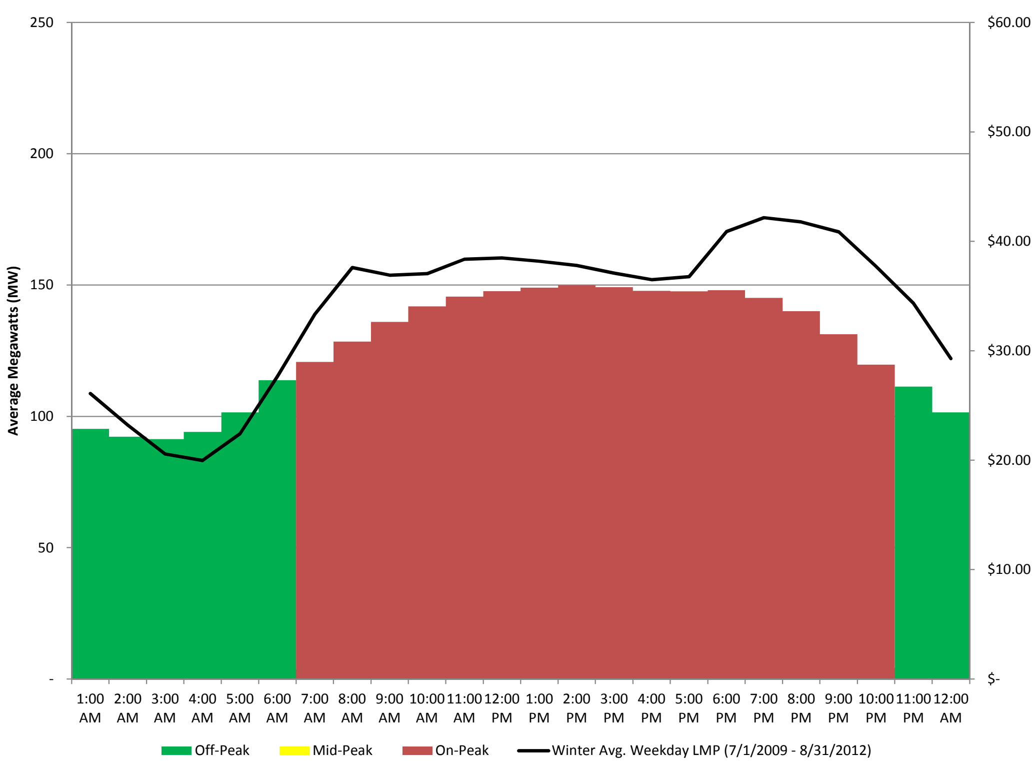
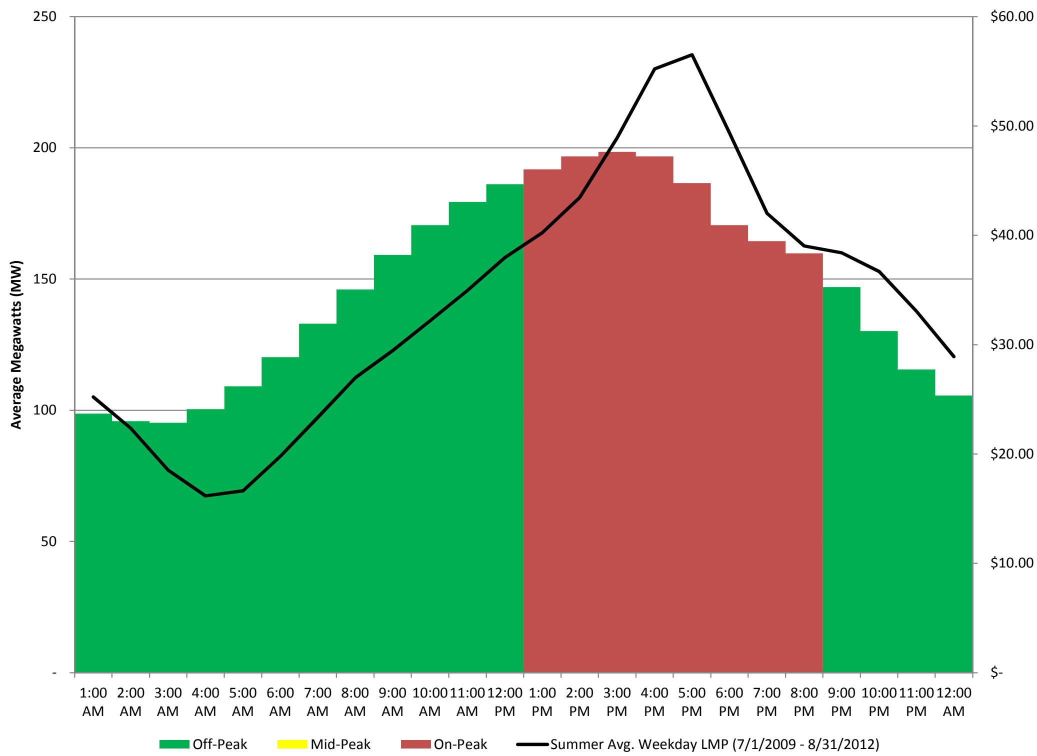


Figure 7.2: Current System Pricing Periods - Average Summer Weekday



As illustrated, the winter average weekday shape peaks at approximately 150 MW while it reaches its bottom at approximately 90 MW. In contrast, the summer average weekday shape reaches its maximum at approximately 200 MW while its minimum is approximately 90 MW. The variance of the seasonal average weekday peaks is relatively normal.

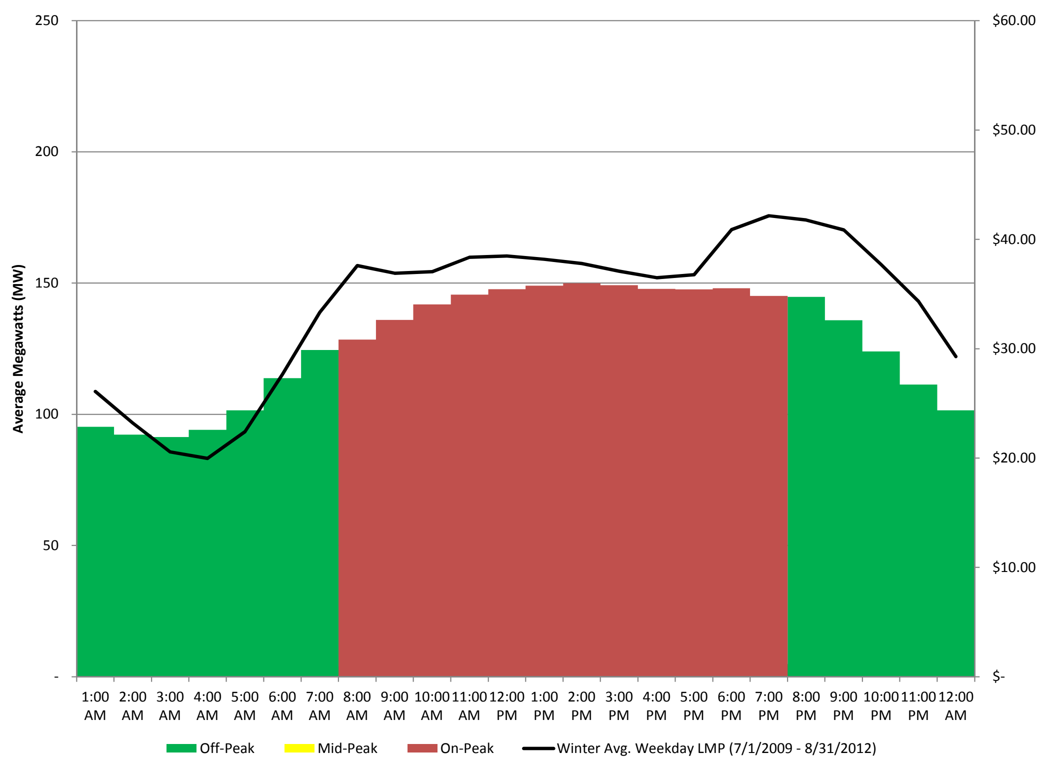
It was also concluded from the pricing period analysis that the current seasonal on-peak pricing periods may be too long to trigger load shifting behavior from a typical customer. It is the experience of Burns & McDonnell that customers typically respond to pricing signals better if the number of on-peak hours is less than the current 16-hour winter and 8-hour summer periods PWP currently employs. To that end, PWP and Burns & McDonnell worked together to formulate revised pricing periods that more closely mimic the average system peak and will offer a typical customer a greater opportunity to respond to pricing signals by reducing the hours in the pricing periods.

7.2.2 Proposed TOU Pricing Periods

As illustrated in Figure 7.1 and Figure 7.2, PWP does not currently utilize mid-peak pricing to incentivize customers to shift load. It is Burns & McDonnell's experience that, generally, customer usage behavior remains relatively unchanged during mid-peak periods. This is likely due to mid-peak price points that do not adequately penalize customers for consumption during those periods. If mid-peak price points are set to more adequately penalize customers, resulting on-peak/mid-peak price differentials may be less than sufficient or resulting on-peak/off-peak price differentials may be too great to encourage participation. For these reasons, Burns & McDonnell does not recommend offering mid-peak pricing periods at this time.

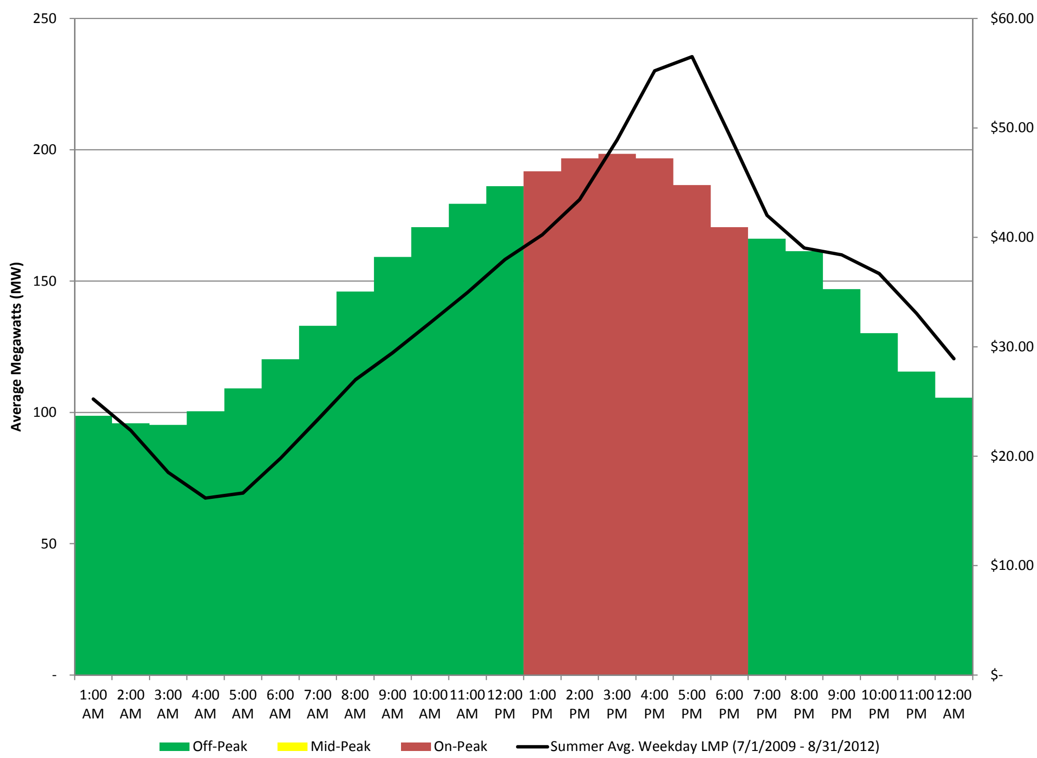
The proposed on-peak winter pricing periods include weekdays from 7:00 AM to 7:00 PM. All other weekday hours, weekend hours and holidays are designated off-peak hours throughout season. Shortening the on-peak periods from sixteen hours to twelve hours and designing the appropriate pricing signals will provide customers with a better opportunity to effectively shift load by reducing the number of hours not shifting will negatively impact them. Encouraging customers to shift during this period will also continue to manage the utility's exposure to spot market pricing. Burns & McDonnell is of the opinion that the on-peak pricing periods should be reduced to periods of no longer than four hours but understands PWP's desire to have a longer on-peak period. Figure 7.3 provides a comparison of historical average LMP pricing and the FY 2014 average winter weekday system load shape with proposed pricing periods.

Figure 7.3: Proposed System Pricing Periods - Average Winter Weekday



The proposed on-peak summer pricing periods include weekdays from 12:00 PM to 6:00 PM. All other weekday hours, weekend hours and holidays are designated off-peak hours throughout season. Shortening the on-peak periods from eight hours to six hours and designing the appropriate pricing signals will allow customers to more effectively shift load by reducing the number of hours not shifting will negatively affect them. Encouraging customers to shift during this period will also continue to manage the utility's exposure to spot market pricing. The revised pricing periods will recover costs during the hours where the market pricing remains relatively high and the system demand remains relatively strong. Figure 7.4 provides a comparison of historical average LMP pricing and the FY 2014 average summer weekday system load shape with proposed pricing periods.

Figure 7.4: Proposed System Pricing Periods - Average Summer Weekday



7.2.3 Pilot Electric Vehicle Pricing Periods

On May 1, 2012, PWP commenced its EV pilot program which offers TOU ESC rates to qualifying Residential Single Family and Residential Multi-Family customers. The program currently features two schedule options: Time-of-Use Electric Vehicle Rate 1(EV-1) and Time-of-Use Electric Vehicle Rate 2 (EV-2). Figure 7.5 and Figure 7.6 present the FY 2014 Residential Single Family seasonal hourly load shapes with the currently defined pilot pricing periods.

Figure 7.5: Current Experimental Pricing Periods - Average Winter Weekday

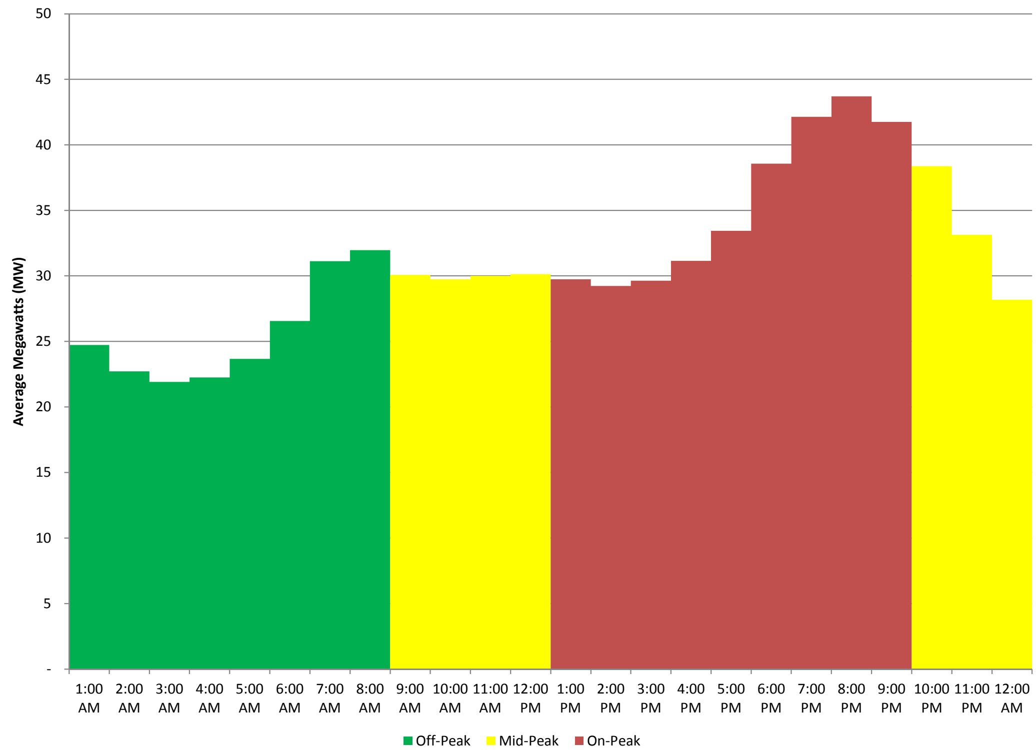
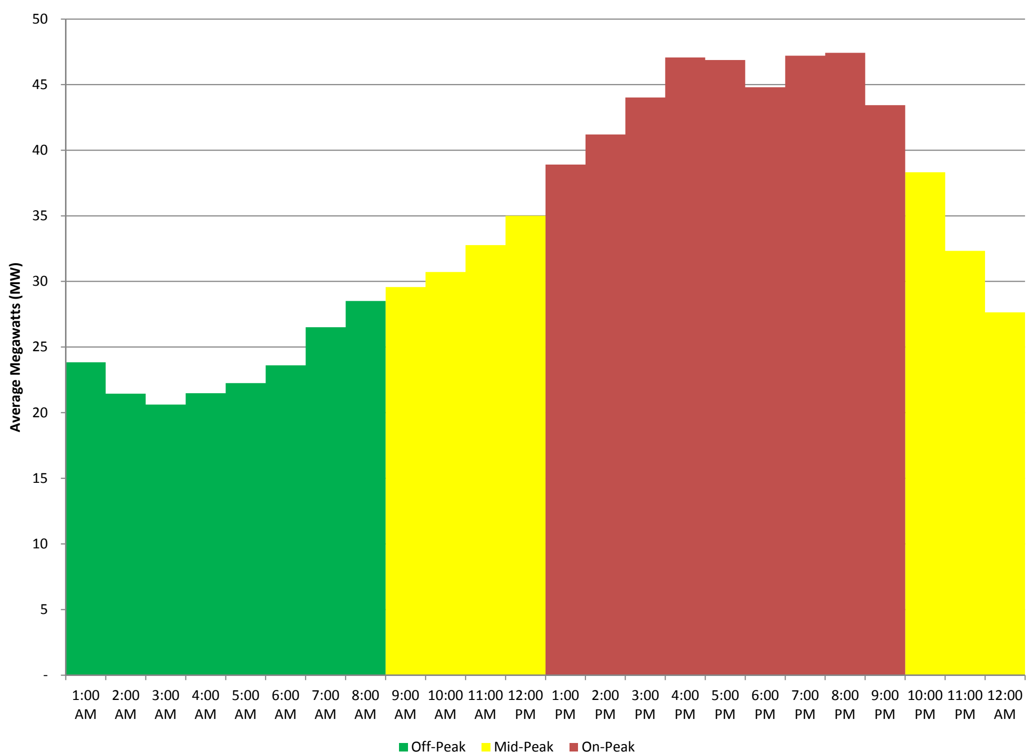


Figure 7.6: Current Experimental Pricing Periods - Average Summer Weekday



Both pilot tariffs currently define the on-peak period as 12:00 PM to 9:00 PM, mid-peak periods from 8:00 AM to 12:00 PM and from 9:00 PM to 12:00 AM, and the off-peak period as 12:00 AM to 8:00 AM on weekdays. All other weekday hours, weekend hours and holidays are designated off-peak hours. When designing its pilot pricing periods, PWP focused defining off-peak periods as times when additional load from EVs would not significantly impact the utility’s cost of power during the most expensive times during the day. In addition, the utility took into consideration the hourly daily load shape of the Residential class as they use power today.

7.2.4 Proposed TOU Electric Vehicle Pricing Periods

As stated, the pilot program will run through April 30, 2015. The associated rate schedules will remain in effect until that date as well. However, a forward looking approach was taken in the analysis and the currently defined pilot pricing periods were examined for their appropriateness beyond the program’s end date. Based on projections developed in the load forecast described in Section 3.0, Burns & McDonnell recommends PWP offer an on-peak period from 6:00 AM to 10:00 PM on weekdays for both winter and summer seasons. All other weekday hours, weekend hours and holidays shall be designated off-peak hours. Figure 7.7 and Figure 7.8 present the FY 2014 Residential Single Family seasonal hourly load shapes with the proposed EV pricing periods.

Figure 7.7: Proposed EV Pricing Periods - Average Winter Weekday

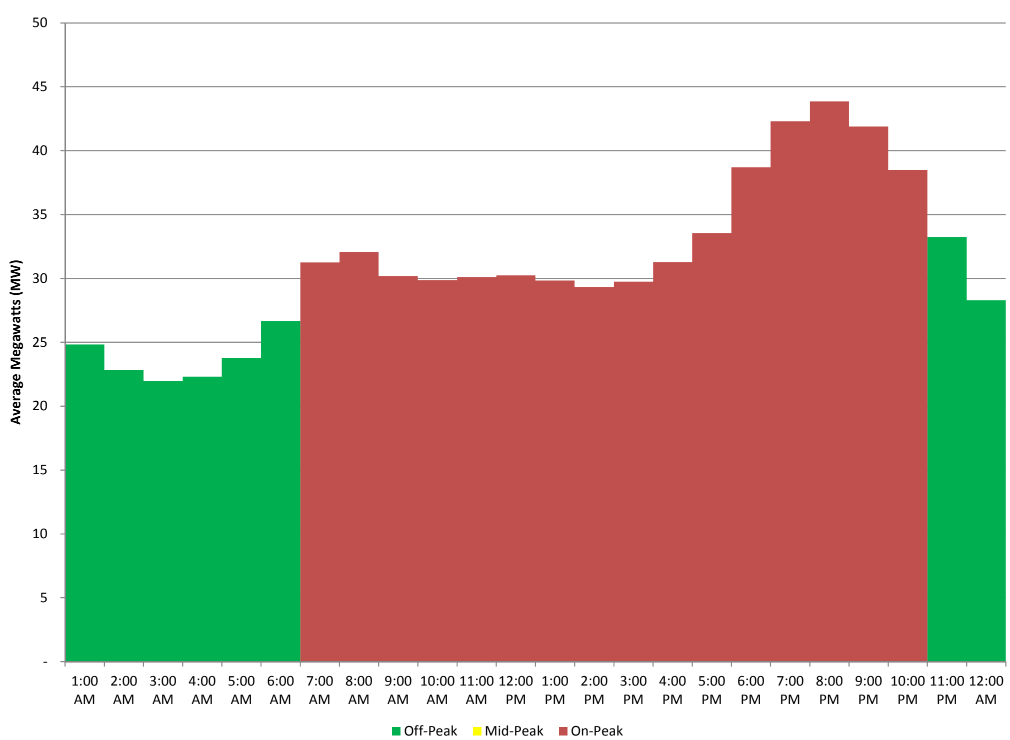
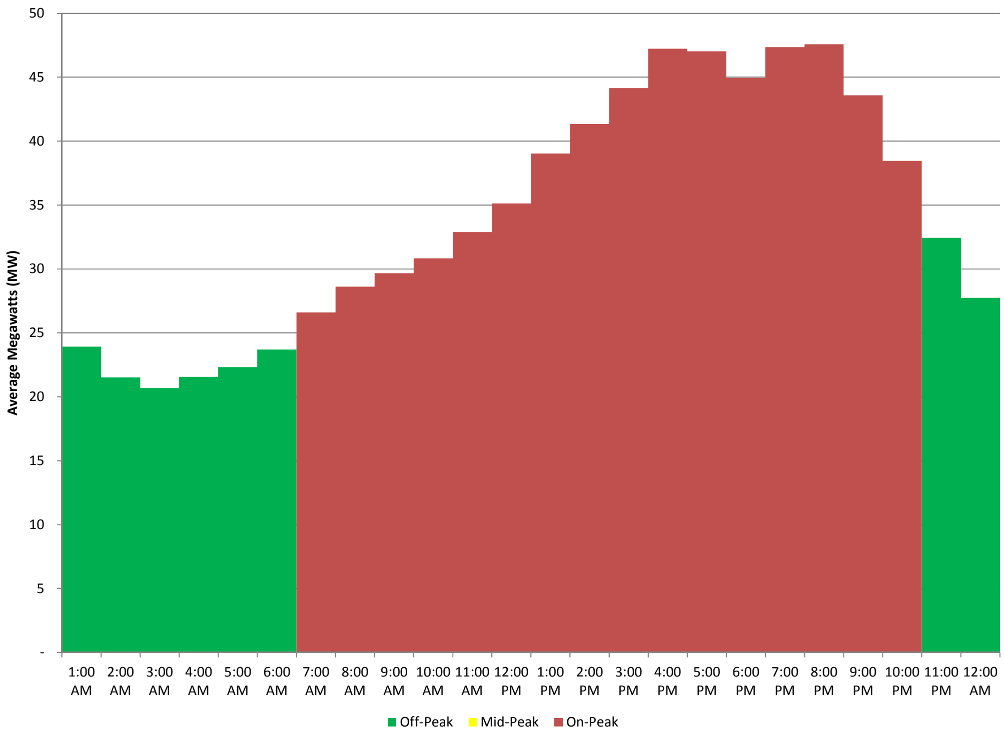


Figure 7.8: Proposed EV Pricing Periods - Average Summer Weekday



These pricing periods, combined with appropriate pricing signals will encourage customers to charge EV during periods when power is least expensive the utility. In addition, the pricing periods will reduce the potential for distribution circuit overloading during average peaking hours.

7.3 TOU RATE DESIGN ANALYSIS

7.3.1 Mandatory TOU Energy Pricing

As part of the analysis, mandatory TOU ESC pricing was evaluated for the Medium Commercial and Industrial classes. The Medium Commercial classes are currently offered both Option A, flat rate ESC pricing, and Option B, TOU ESC pricing. PWP currently only offers Large Commercial and Industrial customers TOU ESC pricing. The proposed TOU pricing periods influenced the decision on whether or not to propose mandatory TOU ESC rates for the Medium classes. The proposed on-peak periods span 12 hours and six hours in the winter and summer seasons, respectively. If implemented, the length of the proposed periods would reduce on-peak pricing hours by four hours in the winter and two hours in the summer. Reducing the number of on-peak hours is a step in the right direction, but the number of hours is still likely too great to encourage significant changes in customer behavior.

It has been Burns & McDonnell's experience that customers that voluntarily select TOU rate schedules are more likely to reduce load during on-peak hours. Conversely, customers involuntarily placed on mandatory TOU schedules, in our recent experience, have not consistently demonstrated significant reduction during on-peak pricing periods. For the reasons described, Burns & McDonnell does not recommend the mandatory migration of Option A Medium Commercial customers to TOU ESC schedules.

7.3.2 Rate Design Approach

The primary goals of the TOU rate design were to appropriately recover PWP's cost of providing electric service in each time period during the day and to provide customers the opportunity to save money by shifting loads from on-peak periods to off-peak periods. PWP currently has in place take-or-pay contracts with its three largest power suppliers: IPP, Hoover, and Palo Verde Nuclear. In addition, the utility produces power to meet some of its load and buys power from Magnolia, a natural gas fired plant. As a result, PWP can reduce its power supply expense on a dollars per MWh basis by reducing the monthly system peak demand in each month of the year. Burns & McDonnell and PWP took this into consideration in the design of the proposed TOU electric rates so that customers who shift load to off-peak periods can share in the wholesale purchased power expense savings they generate.

The foundation for the TOU pricing was historical LMP data and test period average system load data. Average seasonal weekday LMP data was summarized from FY 2010 through FY 2012. Based on the proposed pricing periods, average on-peak and off-peak costs of market power were extracted. The average LMP on-peak/off-peak price differentiation percentage for the proposed pricing periods provided one input into energy pricing differentiation for the TOU energy price rate design. The average on-peak/off-peak system load for the proposed pricing periods served and the other input into energy pricing differentiation. Each metric was given equal weighting and combined to calculate energy pricing differentiation percentages. The percentages were then applied to the proposed Option A ESC rate for each class. The seasonal energy requirements developed in the cost-of-service analysis described in Section 5.0 served as the benchmark to which the differentiation percentages were applied for the Large Commercial classes. From there, slight adjustments were made to the TOU energy rates to provide a logical descension from Residential to Large Commercial classes and to meet the cost of providing service to those classes.

Typically, TOU rates are designed to be revenue neutral so that, based on analogous billing determinants, a bill would generate the same revenue whether the customer was charged standard rates or TOU rates.

Generally, revenue neutrality drove the design of the proposed TOU rates developed in this study however, rates for certain classes were designed based on the type of service and/or certain characteristics. The rates were also designed so that (i) those customers who are able to shift load from on-peak periods to off-peak periods would realize a monthly bill reduction and (ii) the utility would see a similar level of power supply cost reduction resulting from the system peak billing demand reduction.

7.3.3 Proposed TOU Electric Rates and Sample Bills

Table 7-1 through Table 7-5 present side-by-side comparisons of proposed standard and TOU rates for the Residential, Small Commercial and Medium Commercial classes. Typical monthly bills were calculated for each table. Billing determinants are based on the test period average energy usage per customer during on-peak and off-peak hours, as developed in the load forecast. As illustrated, the TOU bills are relatively revenue neutral when compared to the bills calculated with standard rates. Therefore, on average, customers migrating from Option A schedules to Option B schedules should experience little change in their bill if their usage patterns remain unchanged. The opportunity for monthly savings is available for TOU customers that are able to shift some of their load from the on-peak periods to the off-peak periods. Customers will be required to remain on the TOU rates for a minimum of 12 months after switching from the standard rate schedule.

Table 7-1: Residential Single Family TOU Rates Summary

Description	Units	Option A	Option B
Residential Single-Family Service - Winter			
Customer Charge	$/month	$ 7.53	$ 7.53
Distribution Charge	$/kWh	$ 0.05848	$ 0.05848
Transmission Services Charge	$/kWh	$ 0.00885	$ 0.00885
Energy Charge - Option A	$/kWh	$ 0.08671	
Energy Charge - Option B			
On-Peak	$/kWh		$ 0.09720
Off-Peak	$/kWh		$ 0.07665
Avg. Monthly Energy - Option A	kWh	487	
Avg. Monthly Energy - Option B			
On-Peak	kWh		172
Off-Peak	kWh		315
Total		487	487
Monthly Energy Charges - Option A		$ 42	
Monthly Energy Charges - Option B			
On-Peak			$ 17
Off-Peak			24
Total		$ 42	$ 41
Avg. Monthly Bill		$ 83	$ 81

Description	Units	Option A	Option B
Residential Single-Family Service - Summer			
Customer Charge	$/month	$ 7.53	$ 7.53
Distribution Charge	$/kWh	$ 0.05848	$ 0.05848
Transmission Services Charge	$/kWh	$ 0.00885	$ 0.00885
Energy Charge - Option A	$/kWh	$ 0.10037	
Energy Charge - Option B			
On-Peak	$/kWh		$ 0.13702
Off-Peak	$/kWh		$ 0.08831
Avg. Monthly Energy - Option A	kWh	534	
Avg. Monthly Energy - Option B			
On-Peak	kWh		122
Off-Peak	kWh		411
Total		534	534
Monthly Energy Charges - Option A		$ 54	
Monthly Energy Charges - Option B			
On-Peak			$ 17
Off-Peak			36
Total		$ 54	$ 53
Avg. Monthly Bill		$ 97	$ 97

Table 7-2: Residential Multi-Family TOU Rates Summary

Description	Units	Option A	Option B
Residential Multi-Family Service - Winter			
Customer Charge	$/month	$ 7.53	$ 7.53
Multi-Family Discount	$/month	$ -	$ -
Distribution Charge	$/kWh	$ 0.05848	$ 0.05848
Transmission Services Charge	$/kWh	$ 0.00885	$ 0.00885
Energy Charge - Option A	$/kWh	$ 0.08671	
Energy Charge - Option B			
On-Peak	$/kWh		$ 0.09720
Off-Peak	$/kWh		$ 0.07665
Avg. Monthly Energy - Option A	kWh	369	
Avg. Monthly Energy - Option B			
On-Peak	kWh		123
Off-Peak	kWh		245
Total		369	369
Monthly Energy Charges - Option A		$ 32	
Monthly Energy Charges - Option B			
On-Peak			$ 12
Off-Peak			19
Total		$ 32	$ 31
Avg. Monthly Bill		$ 64	$ 63

Description	Units	Option A	Option B
Residential Multi-Family Service - Summer			
Customer Charge	$/month	$ 7.53	$ 7.53
Multi-Family Discount	$/month	$ -	$ -
Distribution Charge	$/kWh	$ 0.05848	$ 0.05848
Transmission Services Charge	$/kWh	$ 0.00885	$ 0.00885
Energy Charge - Option A	$/kWh	$ 0.10037	
Energy Charge - Option B			
On-Peak	$/kWh		$ 0.13702
Off-Peak	$/kWh		$ 0.08831
Avg. Monthly Energy - Option A	kWh	402	
Avg. Monthly Energy - Option B			
On-Peak	kWh		82
Off-Peak	kWh		320
Total		402	402
Monthly Energy Charges - Option A		$ 40	
Monthly Energy Charges - Option B			
On-Peak			$ 11
Off-Peak			28
Total		$ 40	$ 40
Avg. Monthly Bill		$ 75	$ 74

Table 7-3: Small Commercial Single-Phase TOU Rates Summary

Description	Units	Option A	Option B
Small Commercial and Industrial Service - Winter			
Customer Charge			
Single-Phase	$/month	$ 7.85	$ 7.85
Three-Phase	$/month	$ 10.57	$ 10.57
Distribution Charge	$/kWh	$ 0.05641	$ 0.05641
Transmission Services Charge	$/kWh	$ 0.00885	$ 0.00885
Energy Charge - Option A	$/kWh	$ 0.08690	
Energy Charge - Option B			
On-Peak	$/kWh		$ 0.09741
Off-Peak	$/kWh		$ 0.07682
Avg. Monthly Energy - Option A	kWh	1,612	
Avg. Monthly Energy - Option B			
On-Peak	kWh		713
Off-Peak	kWh		899
Total		1,612	1,612
Monthly Energy Charges - Option A		$ 140	
Monthly Energy Charges - Option B			
On-Peak			$ 69
Off-Peak			69
Total		$ 140	$ 139
Avg. Monthly Bill		$ 253	$ 252

Description	Units	Option A	Option B
Small Commercial and Industrial Service - Summer			
Customer Charge			
Single-Phase	$/month	$ 7.85	$ 7.85
Three-Phase	$/month	$ 10.57	$ 10.57
Distribution Charge	$/kWh	$ 0.05641	$ 0.05641
Transmission Services Charge	$/kWh	$ 0.00885	$ 0.00885
Energy Charge - Option A	$/kWh	$ 0.10049	
Energy Charge - Option B			
On-Peak	$/kWh		$ 0.13719
Off-Peak	$/kWh		$ 0.08842
Avg. Monthly Energy - Option A	kWh	1,898	
Avg. Monthly Energy - Option B			
On-Peak	kWh		505
Off-Peak	kWh		1,393
Total		1,898	1,898
Monthly Energy Charges - Option A		$ 191	
Monthly Energy Charges - Option B			
On-Peak			$ 69
Off-Peak			123
Total		$ 191	$ 192
Avg. Monthly Bill		$ 322	$ 324

Table 7-4: Medium Com. and Ind. Secondary TOU Rates Summary

Description	Units	Option A	Option B
Medium Commercial and Industrial Service Secondary - Winter			
Customer Charge	$/month	$ 19.49	$ 19.49
Distribution Charge	$/kW-mo.	$ 15.88	$ 15.88
Transmission Services Charge	$/kWh	$ 0.00885	$ 0.00885
Energy Charge - Option A	$/kWh	$ 0.08665	
Energy Charge - Option B			
On-Peak	$/kWh		$ 0.09713
Off-Peak	$/kWh		$ 0.07660
Avg. Monthly Demand	kW	63	63
Avg. Monthly Energy - Option A	kWh	25,000	
Avg. Monthly Energy - Option B			
On-Peak	kWh		11,339
Off-Peak	kWh		13,661
Total		25,000	25,000
Monthly Demand Charges		$ 1,000	$ 1,000
Monthly Energy Charges - Option A		$ 2,166	
Monthly Energy Charges - Option B			
On-Peak			$ 1,101
Off-Peak			1,046
Total		$ 2,166	$ 2,148
Avg. Monthly Bill		$ 3,407.43	$ 3,389

Description	Units	Option A	Option B
Medium Commercial and Industrial Service Secondary - Summer			
Customer Charge	$/month	$ 19.49	$ 19.49
Distribution Charge	$/kW-mo.	$ 15.88	$ 15.88
Transmission Services Charge	$/kWh	$ 0.00885	$ 0.00885
Energy Charge - Option A	$/kWh	$ 0.10019	
Energy Charge - Option B			
On-Peak	$/kWh		$ 0.13678
Off-Peak	$/kWh		$ 0.08816
Avg. Monthly Demand	kW	78	78
Avg. Monthly Energy - Option A	kWh	28,700	
Avg. Monthly Energy - Option B			
On-Peak	kWh		7,215
Off-Peak	kWh		21,485
Total		28,700	28,700
Monthly Demand Charges		$ 1,239	$ 1,239
Monthly Energy Charges - Option A		$ 2,875	
Monthly Energy Charges - Option B			
On-Peak			$ 987
Off-Peak			1,894
Total		$ 2,875	$ 2,881
Avg. Monthly Bill		$ 4,388	$ 4,393

Table 7-5: Medium Com. and Ind. Primary TOU Rates Summary

Description	Units	Option A	Option B
Medium Commercial and Industrial Service Primary - Winter			
Customer Charge	$/month	$ 24.81	$ 24.81
Distribution Charge	$/kW-mo.	$ 11.12	$ 11.12
Transmission Services Charge	$/kWh	$ 0.00866	$ 0.00866
Energy Charge - Option A	$/kWh	$ 0.08600	
Energy Charge - Option B			
On-Peak	$/kWh		$ 0.09640
Off-Peak	$/kWh		$ 0.07603
Avg. Monthly Demand	kW	162	162
Avg. Monthly Energy - Option A	kWh	56,400	
Avg. Monthly Energy - Option B			
On-Peak	kWh		23,282
Off-Peak	kWh		33,118
Total		56,400	56,400
Monthly Demand Charges		$ 1,801	$ 1,801
Monthly Energy Charges - Option A		$ 4,850	
Monthly Energy Charges - Option B			
On-Peak			$ 2,244
Off-Peak			2,518
Total		$ 4,850	$ 4,762
Avg. Monthly Bill		$ 7,165	$ 7,077

Description	Units	Option A	Option B
Medium Commercial and Industrial Service Primary - Summer			
Customer Charge	$/month	$ 24.81	$ 24.81
Distribution Charge	$/kW-mo.	$ 11.12	$ 11.12
Transmission Services Charge	$/kWh	$ 0.00866	$ 0.00866
Energy Charge - Option A	$/kWh	$ 0.09938	
Energy Charge - Option B			
On-Peak	$/kWh		$ 0.13567
Off-Peak	$/kWh		$ 0.08744
Avg. Monthly Demand	kW	177	177
Avg. Monthly Energy - Option A	kWh	66,200	
Avg. Monthly Energy - Option B			
On-Peak	kWh		13,405
Off-Peak	kWh		52,795
Total		66,200	66,200
Monthly Demand Charges		$ 1,968	$ 1,968
Monthly Energy Charges - Option A		$ 6,579	
Monthly Energy Charges - Option B			
On-Peak			$ 1,819
Off-Peak			4,616
Total		$ 6,579	$ 6,435
Avg. Monthly Bill		$ 9,145	$ 9,001

7.3.4 Large Commercial Service

Table 7-6 and Table 7-7 present side-by-side comparisons of the proposed electric rates and typical monthly bills for the Large Commercial and Industrial classes. Billing determinants are based on the test period average demand, load factor and resulting energy usage per customer, as developed in the load forecast. Customers for both the Secondary and Primary classes may have minimum demand requirements of 300 kW per month. Primary is served at voltages equal to or greater than 17 kV.

7.3.4.1 Large Commercial Secondary Service

The current Large Commercial and Industrial Service - Secondary rates consist of a customer charge, a kW distribution charge, an ESC, a PCA, a TSC, and a PBC. Table 7-6 demonstrates the expected impact of the rate recommendations in the form of sample monthly bill calculations. Based on average winter monthly billing demand of 421 kW and a 64 percent load factor, the proposed rates would generate a monthly bill of $25,838, compared to a bill of $23,694 calculated with current rates; a difference of $2,144 or 9.1 percent. Average summer monthly billing demand of 496 kW and a 62 percent load factor would generate a monthly bill of $32,935 with proposed rates, compared to a bill of $29,619 calculated with current rates; a difference of $3,316 or 11.2 percent.

Table 7-6: Current and Proposed Large Com. and Ind. Secondary Electric Rates

Description	Units	Current	Proposed
Large Commercial and Industrial Service Secondary - Winter			
Customer Charge	$/month	$ 160.21	$ 39.64
Distribution Charge	$/kW-mo.	$ 10.86	$ 15.78
Transmission Services Charge	$/kWh	$ 0.00821	$ 0.00885
Energy Charge			
On-Peak	$/kWh	$ 0.08829	$ 0.09584
Mid-Peak	$/kWh		
Off-Peak	$/kWh	$ 0.07909	$ 0.07558
Avg. Monthly Demand	kW	421	421
Avg. Monthly Energy			
On-Peak	kWh	107,413	85,695
Mid-Peak	kWh	-	-
Off-Peak	kWh	85,784	107,502
Total		193,197	193,197
Monthly Demand Charges		$ 4,572	$ 6,643
Monthly Energy Charges			
On-Peak		$ 9,483	$ 8,213
Mid-Peak		-	-
Off-Peak		6,785	8,125
Total		$ 16,268	$ 16,338
[1] Avg. Monthly Bill		$ 23,694	$ 25,838
Bill Difference - $			$ 2,144
Bill Difference - %			9.05%

[1] Average monthly bill calculation totals include TSC and PBC charges.

Description	Units	Current	Proposed
Large Commercial and Industrial Service Secondary - Summer			
Customer Charge	$/month	$ 160.21	$ 39.64
Distribution Charge	$/kW-mo.	$ 10.86	$ 15.78
Transmission Services Charge	$/kWh	$ 0.00821	$ 0.00885
Energy Charge			
On-Peak	$/kWh	$ 0.12644	$ 0.13496
Mid-Peak	$/kWh		
Off-Peak	$/kWh	$ 0.08093	$ 0.08698
Avg. Monthly Demand	kW	496	496
Avg. Monthly Energy			
On-Peak	kWh	68,167	54,595
Mid-Peak	kWh	-	-
Off-Peak	kWh	152,876	166,448
Total		221,043	221,043
Monthly Demand Charges		$ 5,387	$ 7,827
Monthly Energy Charges			
On-Peak		$ 8,619	$ 7,368
Mid-Peak		-	-
Off-Peak		12,372	14,478
Total		$ 20,991	$ 21,846
[1] Avg. Monthly Bill		$ 29,619	$ 32,935
Bill Difference - $			$ 3,316
Bill Difference - %			11.19%

7.3.4.2 Large Commercial Primary Service

The current Large Commercial and Industrial Service - Primary rates consist of a customer charge, a kW distribution charge, an ESC, a PCA, a TSC, and a PBC. Table 7-7 demonstrates the expected impact of the rate recommendations in the form of sample monthly bill calculations. Based on average winter monthly billing demand of 1,025 kW and a 57 percent load factor, the proposed rates would generate a monthly bill of $52,278, compared to a bill of $51,897 calculated with current rates; a difference of $382 or 0.7 percent. Average summer monthly billing demand of 1,313 kW and a 61 percent load factor would generate a monthly bill of $78,857 with proposed rates, compared to a bill of $74,210 calculated with current rates; a difference of $4,647 or 6.3 percent.

Table 7-7: Current and Proposed Large Com. and Ind. Primary Electric Rates

Description	Units	Current	Proposed
Large Commercial and Industrial Service Primary - Winter			
Customer Charge	$/month	$ 183.93	$ 44.94
Distribution Charge	$/kW-mo.	$ 10.51	$ 11.05
Transmission Services Charg	$/kWh	$ 0.00802	$ 0.00866
Energy Charge			
On-Peak	$/kWh	$ 0.08867	$ 0.09512
Mid-Peak	$/kWh		
Off-Peak	$/kWh	$ 0.07879	$ 0.07502
Avg. Monthly Demand	kW	1,025	1,025
Avg. Monthly Energy			
On-Peak	kWh	218,837	171,181
Mid-Peak	kWh	-	-
Off-Peak	kWh	200,201	247,857
Total		419,038	419,038
Monthly Demand Charges		$ 10,773	$ 11,326
Monthly Energy Charges			
On-Peak		$ 19,404	$ 16,283
Mid-Peak		-	-
Off-Peak		15,774	18,594
Total		$ 35,178	$ 34,877
[1] Avg. Monthly Bill		$ 51,897	$ 52,278
Bill Difference - $			$ 382
Bill Difference - %			0.74%

Description	Units	Current	Proposed
Large Commercial and Industrial Service Primary - Summer			
Customer Charge	$/month	$ 183.93	$ 44.94
Distribution Charge	$/kW-mo.	$ 10.51	$ 11.05
Transmission Services Charge	$/kWh	$ 0.00802	$ 0.00866
Energy Charge			
On-Peak	$/kWh	$ 0.12102	$ 0.13388
Mid-Peak	$/kWh		
Off-Peak	$/kWh	$ 0.07830	$ 0.08629
Avg. Monthly Demand	kW	1,313	1,313
Avg. Monthly Energy			
On-Peak	kWh	165,059	129,086
Mid-Peak	kWh	-	-
Off-Peak	kWh	412,616	448,589
Total		577,675	577,675
Monthly Demand Charges		$ 13,800	$ 14,509
Monthly Energy Charges			
On-Peak		$ 19,975	$ 17,282
Mid-Peak		-	-
Off-Peak		32,308	38,709
Total		$ 52,283	$ 55,991
[1] Avg. Monthly Bill		$ 74,210	$ 78,857
Bill Difference - $			$ 4,647
Bill Difference - %			6.26%

[1] Average monthly bill calculation totals include TSC and PBC charges.

7.3.5 Pilot TOU Electric Vehicle Rates

The EV pilot program offers two ESC rate schedule options: Time-of-Use Electric Vehicle Rate 1(EV-1) and Time-of-Use Electric Vehicle Rate 2 (EV-2). For EV customers, the customer, distribution, PCA, TSC, PBC are billed from the otherwise applicable Residential Option A tariff. EV-1 rates were designed to simply encourage residential customers with electric vehicles to participate in the pilot program. The peak rate was set equal to the flat charge for the current Residential Single and Multi-Family tariffs. Mid-peak and off-peak rates are reductions from the on-peak rates. There is no risk to customers for choosing the EV-1 option as they are held harmless even if all energy is consumed during peak periods. EV-2 was designed to offer customers the opportunity to save more money than the EV-1 rates during mid-peak and off-peak periods. The tradeoff, the on-peak ESC rate is 4.00¢/kWh more than the current flat Residential Single and Multi-family ESC rate.

For the Study, Burns & McDonnell proposes holding the current energy rate formulas intact for the pilot classes since the EV pilot program runs through April 30, 2015. However, since EV-1 and EV-2 customers are billed customer and distribution charges from their otherwise applicable rate tariffs, it is proposed the pilot customers be billed unbundled customer and distribution charges based on the proposed Option A Residential rate schedules. Table 7-8 summarizes the current and proposed EV energy rates.

Table 7-8: Current and Proposed Experimental EV Rates

Description	Units	Current	Proposed	Description	Units	Current	Proposed
Pilot Time-of-Use Electric Vehicle Rate 1				**Pilot Experimental Time-of-Use Electric Vehicle Rate 2**			
Energy Services Charge				Energy Services Charge			
Winter				Winter			
On-Peak	$/kWh	$ 0.08397	$ 0.08671	On-Peak	$/kWh	$ 0.12397	$ 0.12671
Mid-Peak	$/kWh	$ 0.07397	$ 0.07671	Mid-Peak	$/kWh	$ 0.05897	$ 0.06171
Off-Peak	$/kWh	$ 0.06397	$ 0.06671	Off-Peak	$/kWh	$ 0.03897	$ 0.04171
Summer				Summer			
On-Peak	$/kWh	$ 0.09323	$ 0.10037	On-Peak	$/kWh	$ 0.13323	$ 0.14037
Mid-Peak	$/kWh	$ 0.08323	$ 0.09037	Mid-Peak	$/kWh	$ 0.06823	$ 0.07537
Off-Peak	$/kWh	$ 0.07323	$ 0.08037	Off-Peak	$/kWh	$ 0.04823	$ 0.05537

7.3.6 New TOU Electric Vehicle Rates

Burns & McDonnell prepared a new rate schedule for EV customers based on the FY 2013 cost-of-service analysis. The rates were designed to be implemented for FY 2014; however, the EV pilot program is expected to end on April 30, 2015. Table 7-9 summarizes the current EV rate schedules and the proposed EV energy rates.

The ESC rates developed were based on the cost of providing service to EV customers during the on-peak and off-peak hours of the day as described in Section 7.2.4. Since EVs that charge during the on-peak hours of the day contribute to the supply peak billing demand, the on-peak rate was set equal to the winter and summer costs at 16.172¢/kWh and 17.265¢/kWh, respectively, for both the Residential Single and Multi-Family customer classes. The off-peak rate for EV customers was set equal to 80 percent of the Option A seasonal rates for the Residential Single and Multi-Family classes.

Table 7-9: Proposed Residential EV Rates

Description	Units	Proposed		Description	Units	Proposed	
Residential Single Family Time-of-Use Electric Vehicle Rate				**Residential Multi-Family Time-of-Use Electric Vehicle Rate 2**			
Energy Services Charge				Energy Services Charge			
Winter				Winter			
On-Peak	$/kWh	$	0.16172	On-Peak	$/kWh	$	0.16172
Off-Peak	$/kWh	$	0.06937	Off-Peak	$/kWh	$	0.06937
Summer				Summer			
On-Peak	$/kWh	$	0.17265	On-Peak	$/kWh	$	0.17265
Off-Peak	$/kWh	$	0.08030	Off-Peak	$/kWh	$	0.08030

Assuming an EV customer drives 10,300 miles per year while averaging three miles per kWh, the customer would consume 3,433 kWh to power his or her EV per year. If energy usage was equal each month and the car was charged only during off-peak hours, the customer would spend $501 for one year of power based on the proposed EV rates for Residential Single Family and Residential-Multi-Family Service. The total power cost determinants include the proposed ESC rates for the Residential Option A schedules, the proposed distribution rates, the TSC rate, and the PBC. A conventional gasoline car driving an equivalent distance with fuel efficiency of 25 miles per gallon and a fuel cost of $4.00 per gallon would cost the customer $1,648 per year.

If implemented, the proposed rate revenue adjustments developed as part of the Study can be applied to the proposed rates to recover the appropriate revenue at the end of the pilot program. The rates are based on the FY 2013 cost-of-service analysis and proposed Residential rates to be implemented for FY 2014.

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8.0 ADDITIONAL RATE DESIGN CONSIDERATIONS

8.0 ADDITIONAL RATE DESIGN CONSIDERATIONS

8.1 OVERVIEW

Additional rate design considerations were examined during the Study. Some initiatives are expected to be implemented with the proposed rates. The additional rate design considerations presented in this section include the following:

- Power Factor Adjustment
- Reactive Power Billing
- Self-Generation
- Net Metering
- Distributed Generation
- Demand Response
- Feed-In Tariffs
- Green Power Service
- Power Cost Adjustment
- Transmission Services Charge
- Public Benefit Charge
- Economic Development Rider
- Advanced Metering

8.2 POWER FACTOR ADJUSTMENT

PWP currently recovers cost for infrastructure built to correct customers' power factors by increasing or decreasing the published demand rates, on an incremental basis, for customers whose power factors at their monthly peaks are below or above 85 percent, respectively. Customer accounts established prior to 2002 must meet a 75 percent power factor threshold in order not be billed a power factor penalty. In conjunction with its proposed four-month demand ratchet discussed in Section 6.0, Burns & McDonnell proposes PWP implement a power factor adjustment to billing demand to recover cost for investments in power factor correction rather than adjusting the actual $/kW-month demand rate.

According to PWP, the electric system was designed with the assumption that demand customers' power factors equal 85 percent during their monthly peaks. It is proposed that PWP cease adjusting the distribution rate to recover cost for power factor correction and implement a power factor adjustment for demand customers whose power factor is less than 85 percent during their monthly maximum metered demands. Billing demand for customers that meet or exceed the 85 percent threshold would equal the maximum metered demand for that month. The formula for the proposed power factor adjustment is as follows:

$$\frac{\text{Monthly Maximum Metered Demand kW x 85\%}}{\text{Power Factor \% during Maximum Demand}} = \text{Monthly Billing Demand kW}$$

The proposed power adjustment formula, as described, has been implemented and successfully enforced by utilities across the country. However, PWP expressed concern the resulting adjustments may be too punitive for customers with particularly low power factors. To this end, Burns & McDonnell recommends using this formula but limiting the adjusted billing demand to no more than two times the maximum metered demand utilized as the dividend in the adjustment calculation. It is also recommended that PWP notify customers that fall below a 75 percent power factor in two consecutive months, to take corrective action to get back to an 85 percent power factor within 90 days before additional action would be taken. If these customers' billed power factors do not meet or exceed 75 percent within the period allowed for correction, they should be billed the maximum billing demand penalty of two times the maximum metered demand until power factor correction to 85 percent has been completed.

Table 8-1 summarizes a power factor adjustment sensitivity analysis. The upper half of the table demonstrates the impact the proposed power factor adjustment would have on maximum metered demands at different levels and at a range of power factor intervals. The lower half of the table quantifies the impact of the proposed adjustment. For example, if a customer had a maximum metered demand of 100 kW with a corresponding power factor of 75 percent, that customer's billing demand for that month would be 113 kW; 1.1 times the maximum metered demand.

Table 8-1: Power Factor Adjustment Impact Matrix

Power Factor	25%	35%	45%	55%	65%	75%	85%	95%
Metered Demand	- kW -	- kW -	- kW -	- kW -	- kW -	- kW -	- kW -	- kW -
30	60	60	57	46	39	34	30	30
100	200	200	189	155	131	113	100	100
500	1,000	1,000	944	773	654	567	500	500
1,000	2,000	2,000	1,889	1,545	1,308	1,133	1,000	1,000
5,000	10,000	10,000	9,444	7,727	6,538	5,667	5,000	5,000
10,000	20,000	20,000	18,889	15,455	13,077	11,333	10,000	10,000

Power Factor	25%	35%	45%	55%	65%	75%	85%	95%
Metered Demand								
30	2.0x	2.0x	1.9x	1.5x	1.3x	1.1x	1.0x	1.0x
100	2.0x	2.0x	1.9x	1.5x	1.3x	1.1x	1.0x	1.0x
500	2.0x	2.0x	1.9x	1.5x	1.3x	1.1x	1.0x	1.0x
1,000	2.0x	2.0x	1.9x	1.5x	1.3x	1.1x	1.0x	1.0x
5,000	2.0x	2.0x	1.9x	1.5x	1.3x	1.1x	1.0x	1.0x
10,000	2.0x	2.0x	1.9x	1.5x	1.3x	1.1x	1.0x	1.0x

If implemented, PWP should enforce the power factor adjustment no more than one year from its introduction to customers. The grace period will allow billing staff to coordinate with engineering staff to properly bill the adjustment. It will also allow customers that do not consistently meet the 85 percent level to take corrective action to improve their respective power factors. During the grace period, PWP should provide customers with billing information showing what the bill would be if the power factor adjustment were being applied. This information may provide the customer the incentive to take corrective action.

8.3 REACTIVE POWER BILLING

PWP currently includes the costs for distribution services in either the ¢/kWh rate or the $/kW-month rate, dependent on the rate class. The current rates have the costs for real and reactive power included in the energy charge. Due to certain issues associated with customers' use of net metering tariffs, PWP has expressed interest in eventually billing customers for reactive power as well under a separate rate. The cost to provide reactive power to customers is currently recovered through the current and proposed distribution rates. With this approach and the issues associated with use of the net metering tariff, the cost of reactive power is not being properly recovered.

An argument to support billing for reactive power cost recovery becomes apparent when examining the pricing mechanisms from which net metering service is billed, as currently prescribed in the Ordinance. The current distribution rates account for the cost of supplying VArs and supporting infrastructure; however, if a customer is a net producer, in some cases, PWP does not recover any cost for supplying reactive power. Customers who are net exporters of energy are credited the ESC for the net kWh injected into the system for each billing period. Since the cost for reactive power is included in the average $/kWh rate, PWP may not be compensated for the reactive power it provides these net metering customers.

The first step in determining a billing rate for reactive power is identifying the cost components. For PWP, costs for VArs are accumulated through purchased power, power generation and erecting and maintaining supporting electrical distribution infrastructure. When PWP buys MWh from a supplier, the cost of the reactive power is currently rolled into the costs. Similarly, when PWP generates and consumes or sells MWh, reactive power is included in the cost. PWP also builds and maintains capacitor banks and other power quality related infrastructure that add to the total cost requirements of supplying VArs to customers. To develop a cost-based billing rate for kVAr or kVArh by class, PWP must determine the total system cost for VArs and allocate these costs to the appropriate rate classes. From there, dividing the allocated costs by kVAr or kVArh sold will yield a billable unit rate.

A reactive power cost analysis will require additional resources not foreseen when the project was initiated. Burns & McDonnell would appreciate the opportunity to complete a reactive power cost analysis as a supplement to the Study.

8.4 SELF-GENERATION

PWP currently offers a Self-Generation Service rate tariff, available and mandatory for customers with self-generation or cogeneration capacity. Energy charges and energy credits for self-generation customers are the same as the schedule from which the customer would ordinarily take service. For customers on TOU energy rates, billing is currently determined by the net power that the customer received from the PWP power system during each period. When considering the monthly customer charge, if the customer would normally take service from Residential or Small Commercial and Industrial rate tariffs, the rate utilized is that of the Medium Commercial and Industrial – Secondary tariff. For each month, the billing demand charge is the greater of the maximum fifteen minute kW of the absolute net power that the customer received from or injected into the PWP power system during the current month or preceding eleven months. For Self-Generation Service customers, transmission service charges are calculated as the sum, over the hours of the month, of the hourly net power that the customer received from the PWP power system, but in no event less than zero for the month. Burns & McDonnell recommends the Self-Generation Service rate tariff remain unchanged.

At this time, PWP has no cap in capacity for self-generation customers. If PWP implements a distributed generation tariff, Burns & McDonnell recommends PWP institute a percentage of system demand-based limit on Self-Generation Service subscriptions.

8.5 NET METERING

PWP currently has a rate tariff available for net energy metering customers, Residential or Commercial and Industrial, who own their own solar or wind turbine generating facility, or a hybrid system consisting of both. The assets must be located on the customer's premises with a capacity of no more than one megawatt and the generation must be intended primarily to offset part of all of that customer's own electrical requirements. Energy charges for net metering customers are the same as the schedule for which the customer would ordinarily take service. For customers billed from TOU rate schedules, billing is determined by the net power that the customer received from the PWP power system during each billing period. This rate schedule is available to eligible customers on a first-come-first-served basis until the total rated generating capacity used by eligible customer generators under this schedule exceeds 2.5 percent of PWP's system peak demand.

When customers apply for net metering service they elect for surplus energy generation to be compensated during the calculation period or given as credit against future billings based on the value of the Net Surplus Electricity generated during the calculation period. The current rate for Net Surplus

Electricity Compensation is equal to the applicable energy services charge, plus a 6.6¢/kWh premium and 2.5¢/kWh for renewable energy credits (RECs) associated with net surplus electricity delivered by the

PWP should lower its net metering premium from 6.6¢/kWh to 6.329¢/kWh. The proposed rate is the difference between the proposed winter Residential Single Family Service Option A ESC, which is the lowest proposed flat Residential ESC, and the internally developed estimated average cost of wind and solar generation in southern California. In addition, Burns & McDonnell recommends PWP lower its payment for RECs purchased from net metering customers to 2.0¢/kWh, to match the Green Power Service recommendation discussed in Section 8.9. The DOE reports that the cost of purchasing RECs has dropped consistently over the past five years. Much of this is due to the decreasing capital investment necessary for renewable energy generation installation. PWP should consider lowering the price paid for RECs from net metering customers to reflect these trends.

PWP has discussed offering a distributed generation rate tariff. If a DG rate tariff is instituted, Burns & McDonnell recommends that the maximum generating capacity for any solar or wind net metering customer be capped at 30 kW as opposed to the current 1-MW limit. A distributed generation discussion is held in Section 8.6.

8.6 DISTRIBUTED GENERATION

PWP has discussed introducing a distributed generation (DG) rate tariff. Distributed generation employs small scale generation, primarily delivering electricity to close proximity customers and provides more reliable, secure, and cleaner power to its customers. Sources of DG can come from both renewable and cogeneration technologies. Forms of renewable DG include, but are not limited to, solar photovoltaic panels and small wind turbines. Cogeneration technologies are primarily natural gas-fired microturbines or reciprocating engines, whose exhaust is sometimes used for space or water heating. Distributed generation still makes up a very small portion of the country’s total power production, although its penetration into the market is increasing. This is due to the decreased premium cost of technology and an increase in available federal funding and tax credits when installing DG technology.

Making an avoided cost distributed generation rate tariff available to PWP power customers would allow on-site power generated by the customer to be credited towards their bill. Two approaches are proposed for DG service, if PWP initiated a program today. For non-renewable DG, Burns & McDonnell proposes the energy credit for any day shall equal the published CAISO market price per MWh minus the calculated power supply return on rate base, up to nine percent. For renewable DG, Burns & McDonnell proposes the energy credits presented in Table 8-2. The energy credits are based on internal estimates for renewable power in southern California at each technology's respective avoided cost. The avoided cost of wind generation was estimated to be $120/MW based on the cost of a small scale wind project. The avoided cost of solar generation was estimated to be $150/MW based on the cost of a 1-MW, rooftop photovoltaic system. The avoided cost of renewable generation technologies should be recalculated by the utility no less than once per year. The DG rates should be appropriately adjusted based on these updated cost calculations.

Table 8-2: Proposed Renewable Distributed Generation Rates

Description	Units	Avoided Cost
Distributed Generation Compensation		
Wind:		
Winter On-Peak	$/kWh	$ 0.13452
Winter Off-Peak	$/kWh	$ 0.10608
Summer On-Peak	$/kWh	$ 0.16382
Summer Off-Peak	$/kWh	$ 0.10559
Solar:		
Winter On-Peak	$/kWh	$ 0.16814
Winter Off-Peak	$/kWh	$ 0.13260
Summer On-Peak	$/kWh	$ 0.20478
Summer Off-Peak	$/kWh	$ 0.13198

If implemented, DG service should be made available to customers whose monthly demand is greater than or equal to 30 kW. The maximum allowable demand for customer participation should be 1.0 MW. The ownership of associated DG RECs would be transferred from the customer to PWP for each kWh produced. DG customers should utilize bi-directional demand meters and maintain a power factor of at least 85 percent. Customers whose billed power factor falls between 75 and 85 percent should be billed the power factor adjustment described in Section 8.2. It is also recommended that PWP notify customers that fall below a 75 percent power factor in two consecutive months, to take corrective action to get back to an 85 percent power factor within 90 days before additional action would be taken. If these customers' billed power factors do not meet or exceed 75 percent within the period allowed for correction, they should be billed the maximum billing demand penalty of two times the maximum metered demand until power factor correction to 85 percent has been completed.

Burns & McDonnell recommends that when PWP establishes a DG rate tariff, the electric utility implement the recommendations for net metering and self-generation described in this report which includes the proposition of subscriber capacity and system demand limits for both net metering and self-generation service.

8.7 DEMAND REPONSE

Demand response (DR) is defined by the Edison Electric Institute as load response called for by others and price response managed by end-use customers. Demand side management (DSM) is defined as the planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand.**Error! Bookmark not defined.** The conservation and load management aspects of resource management are an important element in achieving an efficient use of a utility's power supply resources. Adjustment of time of usage, amount of usage, and efficiency of usage are important considerations in arriving at the optimal blend of resources to meet power supply requirements. This optimization allows existing supply resources to be used more effectively and meet load growth with existing resources for an extended time in the future. This section of the report discusses the demand side management DSM options presented for consideration by PWP.

8.7.1 Strategies

There are a number of strategies for load management that have been generally considered as standards by the electric utility industry. Each of the objectives described below refers to the impact the strategy has on an electric utility’s daily load profile curve.

- Peak Clipping – Refers to the reduction of demand at times when peak load occurs, with little, if any, impact on overall energy use. An example is the control of the timing of operation of air conditioners or water heaters by the electric utility during periods of peak energy use.

- Valley Filling – Refers to the addition of load during low-load periods, resulting in an increase in total energy use. An example is the addition of electric heating equipment to replace gas or oil heaters during off peak hours and continuing to use the gas and oil units during on-peak hours.

- Load Shifting – Refers to changing the timing of electric energy use from high-load periods to low-load periods, with no change in overall consumption of energy. This is a demand reduction only type program. Thermal energy storage systems provide for this energy shifting for example, through the making of ice during low-load periods to use for cooling during high-load periods.

- Strategic Conservation – Refers to conservation initiated by the electric utility and targeted at specific classifications of customers and industries, resulting in a decrease in total energy use. A common form of this approach is the offering of incentives, such as rebates, for the implementation of selected efficiency improvements in the customer's facilities, equipment, operations, etc. that will produce energy savings during high-load periods. Replacement of incandescent or fluorescent lighting with high intensity discharge lighting is an example of this type of program.

- Strategic Load Growth – Refers to promotion of new uses of electricity that will enhance the electric utility's load shape and load factor. The example provided is the implementation of electric-based technologies that enhance an industrial process and increases the overall load of the customer's facility, preferably improving the customer's load factor, as well. Ground source heat pumps are another type of program.

- Flexible Load Shape – Refers to provision by the electric utility of options to customers as to how they receive service, which result in changes in the customer’s load profile and overall energy costs. Interruptible rate and time-of-use rate schedules are primary examples of this type of load management strategy.

8.7.2 Program Options

The implementation of DSM requires selecting strategies that make sense, considering the end-user base and the types of energy consuming appliances and structures they utilize. Inventory of the appliances and structures is important to understand the relative age, efficiency, quantity, and other necessary data to predict the energy and/or capacity reduction expected from the program. An understanding of the customer base is beneficial to understand the expected participation levels in programs offered. The appliances that should be considered in the DSM evaluation include:

Residential:

- Clothes washers/dryers
- Electric water heaters
- Refrigerators/freezers
- Air conditioners/heat pumps
- Lighting
- Dishwashers

Commercial:

- Lighting
- Air conditioning
- Electric water heaters

PWP should consider evaluating potential DSM strategies to determine if any value to the utility can be realized. Based on discussions with PWP and because of the current provisions included in State legislation, PWP could focus its efforts on reducing its customers' peak demand requirements through load control. This could include the implementation of a load management program for residential and commercial air conditioning units. Many utilities have installed load control switches on residential and commercial air conditioning units and have achieved considerable system peak demand reduction.

8.7.3 Evaluation

The evaluation of DR programs is performed through benefit/cost analysis. An initial screening of programs is made to determine those that fit the DSM objectives. The costs of the programs are then considered and compared to the benefits derived from the implementation using a benefit/cost analysis. Those programs with a benefit/cost ratio greater than one are then compared to supply side options to determine the most economic mix of demand and supply side alternatives.

There are numerous tests that can be used to screen DR programs. The tests generally involve different ratepayer and utility perspectives on the benefits and costs of the programs. The tests include:

- Utility Cost Test: This test assumes that the utility's objective is to minimize revenue requirements. The cost components of this test include the utility's program administration (or overhead) costs, incentive costs, and any direct expenditure by the utility to purchase DSM equipment. The benefit is the utility's avoided cost.

- Participant Cost Test: Evaluation of the cost-effectiveness seen from the participant perspective rather than the utility perspective. The cost component of this test is the participant's cost of purchasing the equipment, or other expenditures necessary to participate. The benefits side of this test consists of incentives (rebates) provided by the utility and the participant's bill savings.

- Total Resource Cost Test: The Total Resource Test evaluates the impact of DR programs on the total customer bill for energy services, including participants and non-participants. The cost components include the utility's program administration (or overhead) costs and the cost of buying the actual conservation measures. Incentive costs are not included. The benefits consist of the avoided cost seen by the various parties looking at the program.

- Rate Impact Measure Test: The Rate Impact Measure Test is designed to measure the impact of a DR program on the utility's average tariff. This test is often thought of as the non-participating ratepayer's (tariff-payer's) cost test. The cost components of this test include the utility's program administration (or overhead) costs, incentive costs, any direct expenditure by the utility to purchase conservation equipment, and the utility's lost revenue. The benefit side of this test consists of the utility's avoided cost.

- Societal Cost Test: Benefit/cost test that includes total resource costs and external benefits such as residual environmental impacts. Costs include DSM measure costs and program costs. Benefits include avoided supply costs and environmental benefits.

The Total Resource Cost Test is the more commonly used test and is the initial screening test. In developing the programs for evaluation, it is worthwhile to understand the condition of the supply side pressures in order to determine the costs being confronted by the utility. These costs become the avoided costs in the benefit/cost analysis. For instance, if peaking energy is needed, programs that conserve overall energy or move on-peak energy to lower cost periods of the day are beneficial. If base load energy is needed, then overall conservation programs are of benefit.

8.7.4 Customer Reimbursement

PWP currently has a DR program in place, but the program is underutilized. The utility should review the strategies from which its current program was based and solidify the program’s goals by utilizing the strategies outlined previously as guidelines. It is the opinion of Burns & McDonnell that the utility should initially focus on a peak clipping strategy in order to reduce PWP’s exposure the market during the peak hours of the day, when power is most expensive.

If 10 percent of the approximately 56,000 Residential customers are able to reduce their respective loads by 1.25 kW during an event, based on the estimated impact of cycling off a four-ton 13 Seasonal Energy Efficiency Ratio air conditioning unit, the utility would reduce its load requirement by seven MW.

The estimated target reimbursement amount for participating in a DR program should be based on PWP’s estimated power supply demand cost savings from reducing electrical load during the system peak hour of the month. For the Study, internal estimates for the installed cost of four peaking capacity technologies were developed. The average cost for these technologies was $1,175/kW. This avoided cost of capacity should serve as the basis for the DR pricing program.

8.7.4.1 Residential Customers

In a DR program, residential customers could purchase and install a PWP approved programmable controllable thermostat (PCT) in their home which would be capable of receiving digital signals from system operators through advanced metering networks. Customers would be reimbursed on a monthly basis for allowing PWP to increase the temperature in the home via the PCT on event days during the summer months.

The annual demand response benefit to PWP would be passed back to the residential customers participating in the program through both a fixed and variable credit. The fixed credit would be provided for all 12 months of the year. The variable credit would be passed back to the participating customers in the form of a ¢/kWh rate during months in which a demand response event was initiated. The variable demand response rate would be multiplied by the energy saved over the baseline during the 1 hour demand response event period. The total cost to PWP, or total annual bill credits, should equal the benefits received in reduced power supply costs.

8.7.4.2 Non-Residential Customers

The DR variable rate amount for Small, Medium, and Large Commercial and Industrial customer classes could be set equal to the FY 2013 calculated power supply peak demand cost per kW-month. The variable credit would be passed back to the participating customers during months in which a demand response event was initiated. The variable demand response rate would be multiplied by the demand saved over the baseline during the one hour demand response event period. For example, if a Large Commercial customer reduced their load by 100 kW over the baseline during the one hour demand response event period, the customer’s bill for that particular month would be reduced by the power supply peak demand cost times 100 kW.

Once the strategy is finalized and evaluated and a pricing strategy is developed, PWP should initiate an advertising campaign to help make customers aware of the savings opportunities.

8.8 FEED-IN TARRIFS

Feed-in tariffs (FIT) encourage electrical generation from eligible renewable energy resources by offering cost compensation to energy producers. Customers participating in a FIT program enter into price certainty, long-term contracts to help finance renewable energy investments. The policies and procedures for FITs and DG for the state of California are provided under California Public Utilities Code Sections

399.20, 387.6, and 2841.5. Burns & McDonnell has researched FIT structures utilized by other utilities to form a basis from which to prescribe its recommendations.

Utility A has dedicated 100 MW of load to be supplied by renewable energy production from its users through FITs. To participate in the FIT program, customers must generate less than 5-MW of energy by way of renewable resources or with a combined heat and power (CHP) facility. The program is a first come first serve basis until 100 MW of load is reached. Participants of the FIT enter into a PPA with 10, 15, or 20-year options. Utility A pays eligible distribution generators the applicable price for metered electricity delivered during the time periods specified for the chosen contract term and start year. Utility A has two power pools for its FIT customers:

- Pool 1: 33.5 MW for renewable energy sources rated at 3 MW and less
- Pool 2: 66.5 MW for CHP facilities and renewable energy greater than 3 MW and less than 5 MW.

If Pool 1 fills, the utility can utilize Pool 2 space for any additional Pool 1 customers. Utility A also reserves the right to reallocate pool distribution at any time.

Utility B has a Solar FIT program in which customers invest in their photovoltaic generating system and sell on 20-year fixed price contracts. Energy contracts are determined by placing customers into one of three capacity and rate based classes. Utility B's solar FIT program is limited to a total capacity of 4 MW per calendar year. Applicable systems must also adhere by the following requirements:

- Ground-mounted systems: Combined capacity of all systems cannot exceed 1-MW each year.
- Parcel restrictions: Limit of 300 kW of roof or pavement-mounted systems per parcel per year. Also, each parcel can have no more than 10 kW of Class 1 systems. Further additions will be deemed Class 2 or 3, depending on mounting locations.

Several PWP customers are currently billed from net metering rate structures and may be good prospective FIT customers. Burns & McDonnell recommends the following parameters for PWP's FIT program:

- Customer must be certified by the California Energy Commission to participate
- Customer's generation technology must have a minimum load of 100 kW
- Customer's generation technology may have maximum load of 1,000 kW

- 10, 15, 20-year fixed price contracts
- System-wide generation within this program must not exceed 10 MW

For a renewable FIT, Burns & McDonnell recommends the 2014 energy credits average 15.0¢/kWh. The energy credits are based on internally developed estimates for the avoided cost of solar power in southern California. The current value of solar generation was estimated to be $150/MW based on the cost of a 1-MW, rooftop photovoltaic system.

The recommended compensation amount reflects the average rate PWP would pay for FIT distributed generation. Analysis should be completed to develop seasonal time-based rates for the program. The rates would not vary over the term of the purchase power agreement. However, the rates should be recalibrated no less than each year for the program to reflect varying costs of power. Detailed analysis should be completed to further solidify program scope and pricing.

8.9 GREEN POWER SERVICE

Green power programs are offered by utilities to provide customers with an option to pay a premium price for energy so that the utility will utilize the premium to procure renewable or green energy in return. Renewable energy refers to electric energy generated from wind, solar, geothermal, biomass, landfill gas, or any other renewable energy resource. PWP’s Green Power Service rider allows customers buy 100-kWh blocks of green energy for $2.50 per block or purchase green energy on a per kWh basis for 2.5¢/kWh per month in addition to the retail ESC rate from which customers are otherwise billed. In order to develop voluntary green energy premium pricing, utilities typically contract with a wholesale energy suppliers to purchase green energy, analyze energy markets to determine pricing, or develop and value their own renewable energy resource.

The California Renewable Portfolio Standard (RPS) established in 2002 Senate Bill 1078, accelerated in 2006 under Senate Bill 107 and expanded in 2011 under Senate Bill 2, set statewide goals reaching a power supply mix of 33 percent renewables in 2020. Based on analyses conducted in preparation of its 2009 IRP, the City passed legislation for PWP to reach an asset mix of 40 percent renewables in 2020. The utility is using revenue from its Green Power Service rider to procure green energy to help meet the RPS requirement, in addition to renewable power purchases and REC purchases.

The DOE reports that the cost of purchasing RECs has dropped consistently over the past five years. Much of this is due to the decreasing capital investment necessary for renewable energy generation installation. The same premise has translated to green power premiums charged by utilities. Table 8-3 presents a cross section of green power pricing in the state of California.

Table 8-3: California Green Power Pricing [2]

State-Specific Utility Green Pricing Programs (last updated May 2012)				
State	Utility Information	Type	Start Date	Premium
CA	Anaheim Public Utilities	various renewables	2002	2.0¢/kWh
CA	Anaheim Public Utilities	PV	2002	Contribution
CA	City of Alameda	wind, solar	2012	1.5¢/kWh
CA	Los Angeles Department of Water and Pow er	wind, landfill gas	1999	3.0¢/kWh
CA	Marin Energy Authority: City of Belvedere, Tow n of Fairfax, County of Marin, City of Mill Valley, Tow n of San Anselmo, City of San Rafael, City of Sausalito, Tow n of Tiburon	25% renewable	2008	0.0¢/kWh
CA	Marin Energy Authority: City of Belvedere, Tow n of Fairfax, County of Marin, City of Mill Valley, Tow n of San Anselmo, City of San Rafael, City of Sausalito, Tow n of Tiburon	100% renewable	2010	1.0¢/kWh
CA	PacifiCorp: Pacific Pow er	wind	2000	1.95¢/kWh
CA	Palo Alto Utilities / 3Degrees	wind, PV	2003 / 2000	1.5¢/kWh
CA	Pasadena Water & Pow er	wind	2003	2.5¢/kWh
CA	Roseville Electric	wind, PV	2005	1.5¢/kWh
CA	Sacramento Municipal Utility District	wind, landfill gas, hydro, PV	1997	1.0¢/kWh or $6/month
CA	Sacramento Municipal Utility District	PV	2007	5.0¢kWh or $30/month
CA	Silicon Valley Pow er / 3Degrees	wind, PV	2004	1.5¢/kWh
CA	Truckee Donner PUD	wind	2008	2.0¢/kWh

Burns & McDonnell reviewed information on California utilities' green energy premium programs summarized by the National Renewable Energy Laboratory (NREL). The NREL is the DOE's primary laboratory for renewable energy and energy efficiency research and development. As of December 2010, the City of Palo Alto Utilities had the greatest percentage of customer participation in a utility green energy program in the state.[3] Palo Alto's Green Power Electric Service schedule, as of 2012, priced its green energy premium for solar and wind energy at 1.5¢/kWh, a value consistently lower than most other utility green energy premiums in the state.

PWP currently has a green power premium of 2.5¢/kWh, which is higher than most other voluntary solar and wind green power programs in California. It is the opinion of Burns & McDonnell that PWP should lower the premium required to purchase Green Power Service to 2.0¢/kWh. The combination of a lower premium and increased focus and resources on advertising the program, to increase visibility, should help spur voluntary participation.

[2] DOE, U. S. (2012, December 10). Buying Green Power. Retrieved June 13, 2012, from US DOE Energy Efficiency and Renewable Energy: http://apps3.eere.energy.gov/greenpower/buying/buying_power.shtml?state=CA
[3] NREL. (2011, May 9). NREL Highlights 2010 Utility Green Power Leaders. Retrieved June 13, 2013, from National Renewable Energy Laboratory: http://www.nrel.gov/news/press/2011/1367.html

8.10 REAL-TIME PRICING

Energy suppliers have begun offering real-time pricing (RTP) options, allowing customers to purchase electric power and energy supply from the company where their energy charge will reflect the hourly wholesale market price for the company's wholesale electric supplier's delivery point. Real-time prices fluctuate based on market supply and demand. Pricing tends to be at its highest during the peak demand portion of the day, and during the summer months of the year. Real-time pricing allows for customers to monitor potential fluctuation in energy cost, and adjust energy usage accordingly by leveraging day-ahead wholesale market pricing provided by their energy supplier.

Burns & McDonnell has conducted research on existing RTP tariffs across the nation. A specific utility offers day-ahead real time pricing to customers based on projections of the hourly running cost of incremental generation, provisions for losses, projections of hourly transmission costs and reliability capacity costs for each day, and a recovery factor. The amount of fuel charges from hourly incremental kWh usage are applied to the recovery of fuel cost at the hourly average marginal fuel cost for the applicable hour.

Real-time pricing options can be an effective tool to benefit both the energy supplier and the customer. Through RTP customers would be incentivized to monitor electrical usage during high priced, peak usage hours. This will provide customers the opportunity to, at times, achieve an average energy rate lower than the flat rate offered to the customers' normal rate class. With the promotion of demand reduction through RTP, PWP could see a more levelized load shape due to customer participation. RTP would also offer billing flexibility to customers. However, Burns & McDonnell is not currently recommending that PWP offer an RTP tariff. Significant infrastructure spending for metering associated costs is necessary to support a system-wide roll-out. Offering an RTP option would also likely result in decreased energy sales and a corresponding reduction in revenues. In addition, PWP would likely see increased in recurring costs to administer the program.

At such time that PWP implements an RTP tariff, it should be available to all customers with TOU metering infrastructure and be applicable to the ESC portion of the bill. The day-ahead CAISO market price per MWh plus the calculated power supply return on rate base, up to nine percent, should be utilized as the ESC.

8.11 POWER COST ADJUSTMENT

In addition to a monthly energy, distribution and transmission charges, PWP customers are currently billed a PCA. The PCA is designed to recover fluctuating power supply costs caused by recurring changes in the price of fuel, maintenance and purchased energy. A PCA charge enables PWP to manage energy cost changes without having to make frequent changes to its base rate structures. Residential Service, Commercial and Industrial Service, and metered Street Lighting customer classes are all charged a PCA charge, which is billed on a ¢/kWh basis. Since the price of fuel, maintenance and purchased energy fluctuates frequently, the PCA billing rate is adjusted on a regular basis. Burns & McDonnell recommends that PWP continue to utilize the PCA mechanism to offset fluctuating energy costs. The PCA revenue requirement and rate formula appears reasonable. No changes are recommended or required at this time.

8.12 TRANSMISSION SERVICES CHARGE

PWP customers pay a monthly TSC in order to capture the Transmission Revenue Requirement (TRR) and net cost savings from joining PTO with CAISO. PWP's TRR is defined as the sum of all costs related to the high-voltage transmission of energy, including, but not limited to, all transmission contracts, wheeling fees, pertinent labor and operating costs, associated with general fund transfer, operating margin, debt service, and ISO access fees, less the sum of all wholesale revenues received in connection with the sale of any transmission entitlements. The TSC is calculated quarterly and results are rounded to the nearest mill per kWh. The TSC is billed to PWP customers on a ¢/kWh basis.

Burns & McDonnell recommends that PWP continue to utilize the TSC to offset the TRR. The TSC revenue requirement and rate formula appears reasonable. No changes are recommended or required at this time.

8.13 PUBLIC BENEFIT CHARGE

PWP customers pay monthly PBC as a state mandated charge to fund Lifeline, Utility Assistance, energy efficiency, and renewable resources programs. Currently PWP charges on a ¢/kWh basis at a rate of approximately 0.0573¢/kWh. Burns & McDonnell recommends that PWP continues to utilize the PBC pursuant to state legislation.

8.14 ECONOMIC DEVELOPMENT RIDER

Economic Development Rider (EDR) contracts are offered by utilities to stimulate job growth, add new customers and promote system expansion. EDRs typically offer bill discounts to new and existing commercial and industrial customers. Flat discounts are sometimes offered, but many electric utilities offer new customers declining discount rates which provide large discounts during the first year of the agreement to help businesses establish themselves. Over the life of the contract, the discounts decrease until the incentive provision expires, typically after three or five years. Demand, energy consumption, and load factor should be considered when developing and EDR.

Burns & McDonnell recommends that PWP offer an economic development rider (EDR). The program should be made available to customers bringing at minimum 100 kW of new load to the system. The program should be capped at 50 customers or 5 MW at any one time. This electric demand requirement qualifies Medium and Large Commercial rate class customers. Along with meeting the demand requirements, customers who wish to participate in the EDR must also meet a minimum 75 percent monthly load factor. The EDR tariff should be available to either new PWP customers meeting demand and load factor requirements, or existing customers who meet the load factor requirements and are increasing their maximum demand by at least the minimum qualifying threshold of 100 kW. Existing customers would only receive the discount for the additional or new load. The proposed EDR offers a three-year discount on Total Electric Services, as currently designated in PWP's billing system. Eligible customers would receive a 25 percent discount in year 1, followed by discounts of 15, and 5 percent in year two and year three, respectively. The discounted rate shall never fall below the cost to provide power to the EDR customer. Annual energy billing analysis should be conducted in order to determine whether or not the revenues equal or exceed the cost-of-service expenses. Additional lump-sum charges or credits may be due to the customer following the annual analysis.

In addition to the proposed qualifying criteria outlined above, electric utilities and/or municipalities often times mandate additional requirements be met. These requirements sometimes include minimum capital investment requirements, minimum full-time job creation parameters, metering requirements, retail versus non-retail commerce, and reimbursement requirements if an EDR customer's business ceases to operate or if the customer does not consistently meet the qualifying criteria established in the EDR.

8.15 ADVANCED METERING

To achieve operational effectiveness, interval metering, two-way communication with customers, and advanced distribution system awareness, many utilities are implementing advanced metering networks. Customer usage information may be coupled with cost and utilized by customers to make informed energy use decisions. Real-time usage information and remote control can be utilized by the utility to improve operational efficiency and offer better energy choice to customers, tailored to their needs. Advanced functionality from the use of advanced metering networks includes:

- More precise consumption data in intervals down to one hour or less;
- Remote meter reading as well as on-demand reads and status checks to eliminate truck rolls;
- Remote connect and disconnect of service to customers to eliminate truck rolls;
- Automatic outage notifications to outage management systems, operators, and field crews;
- Enable time varying rate structures such as TOU and real-time pricing, to better align retail rates with the costs to generate or purchase power from wholesale markets; and
- Facilitate direct load control/demand response messages to customer displays and/or devices.

All of the advanced features listed above may be achieved through the implementation of a complete advanced metering infrastructure (AMI) solution that includes new solid state meters at each customer location and a high bandwidth, two-way communication system that transmits information between the meters and the service center. An AMI solution can provide numerous benefits to the capability and precision of utility operations but it represents a significant investment for the utility.

While an AMI solution will accomplish all the above described functionality, ultimately, there are numerous ways for a utility to achieve each advanced feature regarding customer usage monitoring and measuring and service control. For example, a modern advance meter reading (AMR) system can provide precise consumption data at short read intervals; cellular or radio communication units on customer meters can enable remote interval and on-demand readings; communications from the service center may be delivered to the customer via the Internet; etc. and other solutions may be considered in lieu of implementing a full AMI solution. PWP should consider investment in advanced metering technology for all its customers over a reasonable time period based on program costs, achievable benefits, and internal rate of return analysis. If desired, PWP could undertake a business planning study to determine an appropriate strategy for moving forward with an advanced metering implementation program.

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9.0 SUMMARY & RECOMMENDATIONS

9.0 SUMMARY & RECOMMENDATIONS

9.1 SUMMARY

This report described the approach and assumptions used to complete the Cost-of-Service and Rate Design Study and presented the resulting proposed retail electric rates. The following is a summary of the results of the Study and Burns & McDonnell's recommendations for the PWP electric utility.

A financial forecast was developed for the Study which included projections of cash flows for the seven-year period. These projections included capital improvement plan expenses, the projected cash from operations, and other sources and uses of funds. From the financial forecast, annual revenue requirements were calculated from FY 2014 through FY 2020. The annual cost of electric service is projected to increase from $224.0 million in budget year 2013 to $292.6 million in FY 2020.

9.2 RECOMMENDATIONS

Burns & McDonnell recommends a number of actions be taken by PWP based on the analyses conducted during the Study. The Study recommendations include the following:

9.2.1 Revenue Adjustments

It is recommended PWP increase the Distribution, Customer, and ESC rates by 10.0 percent for FY 2014. This will allow PWP to meet its outstanding debt service obligations and its required City Transfer. Moving forward, PWP should increase its distribution, customer, and ESC rates in subsequent years by the percentages shown in Table 9-1.

Table 9-1: Proposed Revenue Adjustments

Fiscal Year	# of Months Effective	Adjustment
FY 2013	12	0.0%
FY 2014	12	10.0%
FY 2015	12	4.0%
FY 2016	12	0.0%
FY 2017	12	1.0%

9.2.2 Residential Billing

PWP should bill Residential customers separately for distribution and customer service associated costs. This approach will allow PWP to recover costs from Residential consumers more appropriately, as opposed to the combined Distribution & Customer charge currently being billed to Residential customers.

PWP should eliminate the $2.00 per month credit given to Residential Multi-Family customers as the cost-of-service for the class was calculated and rates were designed to recover appropriate levels of revenue.

9.2.3 Billing Demand Ratchet

Analysis was conducted to develop an alternative to the current 12-month billing demand ratchet. The billing demand ratchet options closely examined included the following:

- Current 12-month demand ratchet
- Four-month demand ratchet
- Seasonal four-month demand ratchet
- No ratchet

Table 9-2 compares estimates of each of these options' relative impact on test year demand billing prior to rate adjustments.

Table 9-2: Demand Average Cost Summary

Description	12-Month *Current Rates*	4-Month *Option*	4-Month Seasonal *Winter Option*	*Summer Option*	1-Month *Option*
	$/kW-month	$/kW-month	$/kW-month	$/kW-month	$/kW-month
Seondary Service	10.89	11.72	10.50	14.09	16.72
Primary Service	10.76	11.53	11.10	12.36	16.34

Based on its detailed demand billing cost analysis, Burns & McDonnell recommends the adoption of a four-month billing demand ratchet. Section 6.2.2 of the report provides a billing cost comparison to demonstrate the impact the recommended change will have on a customer. A four-month ratchet approach to determining billing demand will simultaneously provide rate relief to winter peaking customers, when distribution infrastructure is burdened the least, while maintaining PWP's mechanism to recover costs for distribution assets built to enable adequate power delivery for all customers during the summer months, when system load is greatest and when investment in distribution infrastructure is most critical.

9.2.4 Power Cost Adjustment

PWP should maintain the use of the PCA as a mechanism to recover power supply or energy related cost. On the occasion that revenue exceeds the theoretical ESC fund balance target, PWP should credit customers appropriately. The PCA revenue requirement and rate formulas appear reasonable. No formula modifications are recommended or required at this time.

9.2.5 Transmission Services Charge

Burns & McDonnell recommends that PWP continue to utilize the TSC to recover the Transmission Revenue Requirement. The TSC revenue requirement and rate formula appears reasonable. No changes are recommended to those formulas. Moving forward, PWP should adjust its TSC to the rates shown in Table 9-3.

Table 9-3: Proposed TSC Rate Adjustments

Fiscal Year	TSC Secondary	TSC Primary
	$/kWh	$/kWh
FY 2013 [1]	0.00821	0.00802
FY 2014	0.00885	0.00866
FY 2015	0.00931	0.00912
FY 2016	0.00998	0.00979
FY 2017	0.01069	0.01050

[1] Current TSC rates.

9.2.6 Current and Proposed Electric Rates

Distribution, Customer, and ESC rate recommendations were prepared based on the Residential billing, billing demand and PCA proposals. It is expected that revised rate recommendations will be implemented for FY 2014. Table 9-4 through Table 9-10 present side-by-side comparisons of the current and proposed electric rates by customer classification.

Table 9-4: Current and Proposed Residential Single Family Rates

Rate Component	Current Rates		Recommended Rates	
	Flat	TOU	Flat	TOU
D&C Charge - $/month			Recommendation: Bill Distribution and Customer Charges Separately. See Below	
0 to 250	6.02	6.02		
251 to 350	12.32	12.32		
351 to 450	24.94	24.94		
451 to 550	35.97	35.97		
551 to 650	45.43	45.43		
651 to 750	56.47	56.47		
751 to 1,000	67.5	67.5		
> 1,000	89.57	89.57		
Customer Charge - $/month	---	---	7.53	7.53
Minimum Charge - $/month	6.02	6.02	7.53	7.53
Distribution Charge - $/kWh	---	---	0.05848	0.05848
Energy Services Charge - $/kWh				
winter on-peak	0.08397	0.08892	0.08671	0.09720
winter off-peak		0.07891		0.07665
summer on-peak	0.09323	0.12454	0.10037	0.13702
summer off-peak		0.08132		0.08831
Transmission Services Charge - $/kWh	0.00821	0.00821	0.00885	0.00885

Table 9-5: Current and Proposed Residential Multi-Family Rates

Rate Component	Current Rates Flat	Current Rates TOU	Recommended Rates Flat	Recommended Rates TOU
D&C Charge - $/month			Recommendation: Bill Distribution and Customer Charges Separately. See Below	
0 to 250	6.02	6.02		
251 to 350	12.32	12.32		
351 to 450	24.94	24.94		
451 to 550	35.97	35.97		
551 to 650	45.43	45.43		
651 to 750	56.47	56.47		
751 to 1,000	67.5	67.5		
> 1,000	89.57	89.57		
Customer Charge - $/month	---	---	7.53	7.53
Minimum Charge - $/month	6.02	6.02	7.53	7.53
Distribution Charge - $/kWh	---	---	0.05848	0.05848
Energy Services Charge - $/kWh				
winter on-peak	0.08397	0.08892	0.08671	0.09720
winter off-peak		0.07891		0.07665
summer on-peak	0.09323	0.12454	0.10037	0.13702
summer off-peak		0.08132		0.08831
Transmission Services Charge - $/kWh	0.00821	0.00821	0.00885	0.00885

Table 9-6: Current and Proposed Small Commercial Rates

Rate Component	Current Rates Flat	Current Rates TOU	Recommended Rates Flat	Recommended Rates TOU
Customer Charge - $/month				
Single-Phase	14.16	14.16	7.85	7.85
Three-Phase	19.07	19.07	10.57	10.57
Minimum Charge - $/month				
Single-Phase	14.16	14.16	7.85	7.85
Three-Phase	19.07	19.07	10.57	10.57
Distribution Charge - $/kWh	0.04475	0.04475	0.05641	0.05641
Energy Services Charge - $/kWh				
winter on-peak	0.0828	0.08681	0.0869	0.09741
winter off-peak		0.07861		0.07682
summer on-peak	0.09151	0.12713	0.10049	0.13719
summer off-peak		0.07956		0.08842
Transmission Services Charge - $/kWh	0.00821	0.00821	0.00885	0.00885

Table 9-7: Current and Proposed Medium Commercial – Secondary Rates

Rate Component	Current Rates Flat	Current Rates TOU	Recommended Rates Flat	Recommended Rates TOU
Customer Charge - $/month	60.22	60.22	19.49	19.49
Minimum Charge - $/month	362.32	362.32	495.90	495.90
Distribution Charge - $/kW [1]	10.89	10.89	15.88	15.88
Energy Services Charge - $/kWh				
winter on-peak	0.08463	0.08828	0.08665	0.09713
winter off-peak		0.08035		0.07660
summer on-peak	0.09588	0.12468	0.10019	0.13678
summer off-peak		0.08313		0.08816
Transmission Services Charge - $/kWh	0.00821	0.00821	0.00885	0.00885

[1] Recommended Distribution Charge includes consideration for revenue adjustments and proposed four-month ratchet.

Table 9-8: Current and Proposed Medium Commercial – Primary Rates

Rate Component	Current Rates		Recommended Rates	
	Flat	TOU	Flat	TOU
Customer Charge - $/month	83.92	83.92	24.81	24.81
Minimum Charge - $/month	376.72	376.72	358.40	358.40
Distribution Charge - $/kW [1]	10.54	10.54	11.12	11.12
Energy Services Charge - $/kWh				
winter on-peak	0.08371	0.08731	0.08600	0.09640
winter off-peak		0.07963		0.07603
summer on-peak	0.09404	0.12378	0.09938	0.13567
summer off-peak		0.08220		0.08744
Transmission Services Charge - $/kWh	0.00802	0.00802	0.00866	0.00866

[1] Recommended Distribution Charge includes consideration for revenue adjustments and proposed four-month ratchet.

Table 9-9: Current and Proposed Large Commercial – Secondary Rates

Rate Component	Current Rates	Recommended Rates
Customer Charge - $/month	160.21	39.64
Minimum Charge - $/month	3181.21	4773.65
Distribution Charge - $/kW [1]	10.86	15.78
Energy Services Charge - $/kWh		
winter on-peak	0.08829	0.09584
winter off-peak	0.07909	0.07558
summer on-peak	0.12644	0.13496
summer off-peak	0.08093	0.08698
Transmission Services Charge - $/kWh	0.00821	0.00885

[1] Recommended Distribution Charge includes consideration for revenue adjustments and proposed four-month ratchet.

Table 9-10: Current and Proposed Large Commercial – Primary Rates

Rate Component	Current Rates	Recommended Rates
Customer Charge - $/month	183.93	44.94
Minimum Charge - $/month	3111.93	3359.95
Distribution Charge - $/kW [1]	10.51	11.05
Energy Services Charge - $/kWh		
winter on-peak	0.08867	0.09512
winter off-peak	0.07879	0.07502
summer on-peak	0.12102	0.13388
summer off-peak	0.07830	0.08629
Transmission Services Charge - $/kWh	0.00802	0.00866

[1] Recommended Distribution Charge includes consideration for revenue adjustments and proposed four-month ratchet.

As part of the Study, a Street Lighting and Traffic Signals Service cost analysis was prepared and rate adjustments were developed for implementation with the rate adjustments for the other classes. The cost-of-service analysis established the allocated cost recovery requirement for the Lighting classes. Based on the allocated costs, there is a need for significant rate adjustments for some lighting types. Much of the adjustment is driven by a reduction in allocated distribution cost. For unmetered lamp lighting, a cost buildup was completed for each lamp type the utility offers. Consideration was made for each lamp's demand, ballast losses, estimated useful life, and average power supply cost. The lighting cost analysis indicated, in some instances, that significant changes should be made to rates to be more reflective of the costs for providing the service. Table 9-11 and Table 9-12 present the current and proposed monthly rates for the class.

Table 9-11: Current and Proposed Street Lighting and Traffic Signals Rates

Description	Current Rates	Recommended Rates
	- $/kWh -	- $/kWh -
Street Lighting - Metered Distribution Rate		
Street Lighting	0.03646	0.02946
Traffic Signals and Signs	0.05397	0.02946
Street Lighting - Unmetered Distribution Rate		
Street Lighting	0.05397	0.02946
Traffic Signals and Signs	0.05397	0.02946
Energy Services Charge	0.06500	0.08130
Transmission Services Charge	0.00821	0.00885

Table 9-12: Current and Proposed Monthly Unmetered Lamp Rates

Description	Current Rates	Recommended Rates	Description	Current Rates	Recommended Rates
	- $/month -	- $/month -		- $/month -	- $/month -
Incandescent			High Pressure Sodium (HPS)		
1,000 Lumen	1.00	1.42	70 Watts	1.37	1.49
1,500 Lumen	1.19	2.07	100 Watts	1.91	2.07
2,500 Lumen	2.10	3.31	150 Watts	2.61	2.99
4,000 Lumen	3.36	5.16	200 Watts	3.33	3.92
6,000 Lumen	4.82	7.61	250 Watts	4.24	4.84
10,000 Lumen	7.38	12.55	310 Watts	5.18	5.95
67 Watts	0.91	1.42	400 Watts	6.44	7.61
69 Watts	0.93	1.47			
100 Watts	1.39	2.07	Induction Lamps		
103 Watts	1.39	2.12	50 Watts	0.71	1.06
150 Watts	2.03	2.99	65 Watts	0.90	1.38
202 Watts	2.73	3.95	85 Watts	1.18	1.79
303 Watts	4.10	5.82	135 Watts	1.88	2.72
			150 Watts	2.00	2.99
Mercury Vapor (MV)					
3,500 lumens	1.72	2.07	Light Emitting Diode (LED)		
7,000 lumens	2.84	3.46	26 Watts	0.37	0.50
11,000 lumens	3.95	4.84	27 Watts	0.37	0.52
20,000 lumens	6.23	7.61			
35,000 lumens	10.56	13.16	Bus Stop		
54,000 lumens	14.92	18.71	4-60 w att unit bus Stop	5.20	1.28
			2-40 w att unit bus Stop	0.00	0.85
Fluorescent					
213 Watts	2.88	4.16	Metal Halide (MH)		
248 Watts	3.36	4.81	400 Watts	6.14	7.61
18 Watts	0.00	0.38	100 Watts	1.54	2.07
27 Watts	0.00	0.57			

9.2.7 TOU Pricing Periods

There is an opportunity to encourage customers' selection of TOU rate schedules by reducing potential barriers. One of the limiting factors of participation may be the timing and number of hours in the on-peak pricing periods. It is recommended that the winter on-peak pricing period be reduced from sixteen hours to twelve hours and the summer on-peak pricing period be reduced from eight hours to six. The reduction of on-peak hours is a step in the right direction; however, PWP should consider reducing its on-peak periods even more to encourage participation in the TOU program. Shorter on-peak timeframes during hours when customers are more likely to respond combined with greater pricing signals would likely encourage selection of TOU rate schedules. This can be done while managing system load and associated costs. Another limiting factor may be placing the up-front metering installation cost burden on the customer. Without specifics on costs, customers may choose not to research, select a contractor and have metering equipment installed independently. To encourage participation, the electric utility should consider funding the installation cost of metering equipment and recouping the cost through a TOU metering charge.

9.2.8 Power Factor Adjustment

It is recommended PWP implement a power factor adjustment to billing demand to recover cost for investments in power factor correction rather than adjusting the actual $/kW-month demand rate, as it does today. The adjustment should be made to the maximum metered demand to determine billing demand for customers whose power factors at their metered billing period peaks are not at least 85 percent. It is also recommended that the adjusted billing demand be no more than two times the maximum metered demand utilized as the dividend in the adjustment calculation.

9.2.9 Net Metering

Burns & McDonnell recommends that PWP lower its net metering premium from 6.6¢/kWh to 6.329¢/kWh. The proposed rate is the difference between the proposed winter Residential Single Family Service Option A ESC, which is the lowest proposed flat Residential ESC, and the internally developed estimated average cost of wind and solar generation in southern California. In addition, Burns & McDonnell recommends PWP lower its payment for renewable energy credits (RECs) or attributes purchased from net metering customers. Table 9-13 presents side-by-side comparisons of the current and proposed net metering rates.

The recommended REC rebate reduction is due in part to the fact that those RECs are not used by PWP to meet RPS goals. In addition, the proposed rebate for net metering RECs would match the proposed Green Power premium as it does today. If a distributed generation rate tariff is implemented, Burns & McDonnell recommends that the maximum generating capacity for any solar or wind net metering customer be capped at 30 kW as opposed to the current 1-MW limit.

Table 9-13: Proposed Net Metering Premium and REC Compensation

Description	Current Rates	Recommended Rates
	- $/kWh -	- $/kWh -
Retail Energy Services Charge Rate	As Applicable	As Applicable
Net Energy Metering Compensation	0.06600	0.06329
Net Energy Metering Compensation for Credits/Attributes	0.02500	0.02000

9.2.10 Distributed Generation

Burns & McDonnell recommends that when PWP establishes a Distributed Generation (DG) rate tariff, service should be made available to customers with a minimum monthly demand of 30 kW and a maximum demand of 1.0 MW. DG customers should utilize bi-directional demand meters and maintain a power factor of at least 85 percent. It is proposed that the energy credit for non-renewable distributed generation for any day shall equal the published California Independent System Operator (CAISO) market price per MWh minus the calculated power supply return on rate base. For renewable DG, Burns & McDonnell recommends the energy credits presented in Table 9-14.

Table 9-14: Proposed Renewable Distributed Generation Rates

Description	Avoided Cost
	- $/kWh -
Wind:	
Winter On-Peak	0.13452
Winter Off-Peak	0.10608
Summer On-Peak	0.16382
Summer Off-Peak	0.10559
Solar:	
Winter On-Peak	0.16814
Winter Off-Peak	0.13260
Summer On-Peak	0.20478
Summer Off-Peak	0.13198

The energy credits are based on internal estimates for renewable power in southern California at each technology’s respective avoided cost. The avoided cost of wind generation was estimated to be $120/MW based on the cost of a small scale wind project. The avoided cost of solar generation was estimated to be $150/MW based on the cost of a 1-MW, rooftop photovoltaic system. The avoided cost of renewable generation technologies should be recalculated by the utility no less than once per year. The DG rates should be appropriately adjusted based on these updated cost calculations. The ownership of associated DG RECs would be transferred from the customer to PWP for each kWh produced.

9.2.11 Demand Response

PWP currently has a DR program in place, but the program is underutilized. The utility should review the strategies on which its current program was based and solidify the program's goals by utilizing the strategies outlined previously as guidelines. It is the opinion of Burns & McDonnell that the utility should initially focus on a peak load reduction strategy in order to reduce PWP's exposure the market during the peak hours of the day, when power is most expensive.

A demand response 'event' occurs at a specific time when a utility calls for load curtailment from program participants. If 10 percent of the approximately 56,000 Residential customers are able to reduce their respective loads by 1.25 kW during an event, the utility would reduce its load requirement by 7 MW. The estimated demand reduction of 1.25 kW per customer is based on the estimated impact of cycling off a four-ton 13 Seasonal Energy Efficiency Ratio air conditioning unit; a typical sized unit for a four person home.

The estimated target reimbursement amount for participating in a DR program should be based on PWP's estimated power supply demand cost savings from reducing electrical load during the system peak hour of the month. For the Study, internal estimates for the installed cost of four peaking capacity technologies were developed. The average cost for these technologies was $1,175/kW. This avoided cost of capacity should serve as the basis for the DR pricing program.

9.2.12 Feed-in Tariff

A PWP FIT program should be made available for customers capable of generating between 100 kW and 1,000 kW of renewable power. The summation of contract subscriptions should not exceed 10 MW. The program should offer contract lengths of 10, 15, or 20 years. Burns & McDonnell recommends the 2014 energy credits average 15.0¢/kWh. The energy credits are based on internally-developed estimates for the avoided cost of solar power in southern California.

The recommended compensation amount reflects the average rate PWP would pay for FIT distributed generation. Analysis should be completed to develop seasonal time-based rates for the program. The rates would not vary over the term of the purchase power agreement. However, the rates should be recalibrated no less than each year for the program to reflect varying costs of power. Detailed analysis should be completed to further solidify program scope and pricing.

9.2.13 Green Power Service

Burns & McDonnell recommends PWP lower the premium required to participate in the Green Power Service program from 2.5¢/kWh to no more than 2.0¢/kWh. The combination of a lower premium and increased focus and resources on advertising the program, to increase visibility, should help spur voluntary participation. This recommendation is based on data available in the California market for green power programs.

9.2.14 Real-time Pricing

Burns & McDonnell is not currently recommending that PWP offer a real-time pricing (RTP) tariff. Through RTP customers would be incentivized to monitor electrical usage during high priced, peak usage hours. This will provide customers the opportunity to, at times, achieve an average energy rate lower than the flat rate offered to the customers' normal rate class. RTP would also offer billing flexibility to customers, but there are investments PWP would need to make as well. Significant infrastructure spending for metering associated costs is necessary to support a system-wide roll-out. Offering an RTP option would also likely result in decreased energy sales and a corresponding reduction in revenues. In addition, PWP would likely see increased recurring costs to administer the program.

At such time that PWP implements an RTP tariff, it should be available to all customers with TOU metering infrastructure and be applicable to the ESC portion of the bill. The day-ahead CAISO market price per MWh plus the calculated power supply return on rate base, up to nine percent, should be utilized as the ESC.

9.2.15 Economic Development Rider

Burns & McDonnell recommends that PWP offer an economic development rider (EDR). The program should be made available to customers bringing at minimum 100 kW of new load to the system. The program should be capped at 5 MW. The EDR tariff should be available to either new PWP customers meeting demand and load factor requirements, or existing customers who meet the load factor requirements and are increasing their maximum demand by at least the minimum qualifying threshold of 100 kW. The proposed EDR offers a three-year discount on Total Electric Services, as currently designated in PWP's billing system. Eligible customers would receive a 25 percent discount in year 1, followed by discounts of 15, and 5 percent in year two and year three, respectively. EDR contracts are offered by utilities to stimulate job growth, add new customers and promote system expansion.

9.2.16 Advanced Metering

To achieve operational effectiveness, interval metering, two-way communication with customers, and advanced distribution system awareness, many utilities are implementing advanced metering networks. PWP should consider investment in advanced metering technology for all its customers over a reasonable time period based on program costs, achievable benefits, and internal rate of return analysis. If desired, PWP could undertake a business planning study to determine an appropriate strategy for moving forward with an advanced metering implementation program.

9.2.17 Conclusion

PWP should monitor the financial position of the PWP electric utility, including adequacy of cost recovery and cash balances on an on-going basis to confirm that the implementation of the proposed rates is maintaining its financial requirements. Burns & McDonnell recommends the reexamination of the utility's financial plan, costs of service, and electric rates every five years.

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APPENDIX A

SUPPLEMENTAL ANALYSIS TABLES

Revenue Requirement Unbundled Assignment Summary

Description	Budget Yr. FY 2013	PS	TDEL	DIST-P	DIST-S	PBC	MT	BL	CC	CS
Operating Expenses										
General Manager's Office & Legal	$ 2,314,277	$ -	$ 25,500	$ 2,288,777	$ -	$ -	$ -	$ -	$ -	$ -
Public Benefit Charge	6,778,827	-	-	-	-	6,778,827	-	-	-	-
Power Supply Business Unit	128,802,491	104,513,141	24,289,350	-	-	-	-	-	-	-
Power Production (Power Plant)	11,572,003	11,571,628	-	375	-	-	-	-	-	-
Power Delivery Business Unit	36,410,637	-	548,192	29,790,762	5,157,014	-	884,669	30,000	-	-
Customer Service	5,738,279	501,609	107,157	165,267	22,122	29,079	501,410	1,996,881	636,009	1,778,746
Finance & Administrative Business Unit	4,337,360	850,273	117,386	3,164,956	-	-	-	204,745	-	-
Finance & Administrative General Expenses	3,282,145	-	-	3,282,145	-	-	-	-	-	-
Total Operating Expenses	$ 199,236,018	$ 117,436,650	$ 25,087,586	$ 38,692,281	$ 5,179,136	$ 6,807,906	$ 1,386,079	$ 2,231,626	$ 636,009	$ 1,778,746
Return on Rate Base (6.11% Return)	$ 24,757,096	$ 6,463,372	$ 1,303,139	$ 14,984,802	$ 2,005,783	$ -	$ -	$ -	$ -	$ -
Total Cost of Service	$ 223,993,113	$ 123,900,022	$ 26,390,725	$ 53,677,083	$ 7,184,919	$ 6,807,906	$ 1,386,079	$ 2,231,626	$ 636,009	$ 1,778,746
Less Other Revenues:										
Wholesale Energy Sales-ISO	$ (3,332,473)	$ (3,332,473)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Wholesale Sales	(2,131,624)	(2,131,624)	-	-	-	-	-	-	-	-
ISO-PTO	(14,691,793)	-	(14,691,793)	-	-	-	-	-	-	-
Unbilled/Miscellaneous	-	-	-	-	-	-	-	-	-	-
Total Other Revenue Deduction	$ (20,155,890)	$ (5,464,097)	$ (14,691,793)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue Requirement	$ 203,837,224	$ 118,435,925	$ 11,698,932	$ 53,677,083	$ 7,184,919	$ 6,807,906	$ 1,386,079	$ 2,231,626	$ 636,009	$ 1,778,746
Functional Service Distribution	100.0%	58.1%	5.7%	26.3%	3.5%	3.3%	0.7%	1.1%	0.3%	0.9%

Large Com. and Ind. Secondary Sample Bill Comparison

Winter

Billing Demand	Load Factor	On-Peak Energy Usage	Off-Peak Energy Usage	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates	Bill Total Proposed Rates
- kW -	- % -	- kWh -	- kWh -					- $/kWh -	- $/kWh -
300	54%	51,488	64,591	$ 14,811	$ 16,226	$ 1,415	9.56%	$ 0.12759	$ 0.13979
421	54%	72,256	90,643	$ 20,720	$ 22,755	$ 2,035	9.82%	$ 0.12720	$ 0.13969
1,000	54%	171,628	215,303	$ 48,996	$ 53,995	$ 4,999	10.20%	$ 0.12663	$ 0.13955
3,000	54%	514,885	645,909	$ 146,666	$ 161,905	$ 15,239	10.39%	$ 0.12635	$ 0.13948
5,000	54%	858,142	1,076,515	$ 244,337	$ 269,816	$ 25,478	10.43%	$ 0.12629	$ 0.13946
7,500	54%	1,287,212	1,614,772	$ 366,425	$ 404,703	$ 38,278	10.45%	$ 0.12627	$ 0.13946
10,000	54%	1,716,283	2,153,030	$ 488,514	$ 539,591	$ 51,078	10.46%	$ 0.12625	$ 0.13945
300	64%	61,069	76,610	$ 16,931	$ 18,367	$ 1,436	8.48%	$ 0.12297	$ 0.13341
421	**64%**	**85,695**	**107,502**	**$ 23,694**	**$ 25,758**	**$ 2,065**	**8.71%**	**$ 0.12264**	**$ 0.13333**
1,000	64%	203,565	255,366	$ 56,062	$ 61,132	$ 5,070	9.04%	$ 0.12216	$ 0.13321
3,000	64%	610,695	766,099	$ 167,866	$ 183,317	$ 15,451	9.20%	$ 0.12193	$ 0.13315
5,000	64%	1,017,824	1,276,832	$ 279,669	$ 305,501	$ 25,832	9.24%	$ 0.12188	$ 0.13314
7,500	64%	1,526,736	1,915,248	$ 419,424	$ 458,232	$ 38,808	9.25%	$ 0.12186	$ 0.13313
10,000	64%	2,035,648	2,553,664	$ 559,178	$ 610,962	$ 51,784	9.26%	$ 0.12184	$ 0.13313
300	74%	70,650	88,629	$ 19,051	$ 20,508	$ 1,458	7.65%	$ 0.11961	$ 0.12876
421	74%	99,146	124,376	$ 26,670	$ 28,764	$ 2,094	7.85%	$ 0.11932	$ 0.12869
1,000	74%	235,501	295,430	$ 63,128	$ 68,269	$ 5,141	8.14%	$ 0.11890	$ 0.12858
3,000	74%	706,504	886,290	$ 189,065	$ 204,728	$ 15,663	8.28%	$ 0.11870	$ 0.12853
5,000	74%	1,177,507	1,477,150	$ 315,001	$ 341,187	$ 26,185	8.31%	$ 0.11866	$ 0.12852
7,500	74%	1,766,260	2,215,724	$ 472,422	$ 511,760	$ 39,338	8.33%	$ 0.11864	$ 0.12852
10,000	74%	2,355,014	2,954,299	$ 629,843	$ 682,334	$ 52,491	8.33%	$ 0.11863	$ 0.12852

Summer

Billing Demand	Load Factor	On-Peak Energy Usage	Off-Peak Energy Usage	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates	Bill Total Proposed Rates
- kW -	- % -	- kWh -	- kWh -					- $/kWh -	- $/kWh -
300	52%	27,692	84,427	$ 15,628	$ 17,433	$ 1,804	11.55%	$ 0.13939	$ 0.15549
496	52%	45,784	139,586	$ 25,734	$ 28,796	$ 3,062	11.90%	$ 0.13883	$ 0.15535
1,000	52%	92,307	281,423	$ 51,721	$ 58,017	$ 6,296	12.17%	$ 0.13839	$ 0.15524
3,000	52%	276,920	844,268	$ 154,843	$ 173,972	$ 19,129	12.35%	$ 0.13811	$ 0.15517
5,000	52%	461,534	1,407,114	$ 257,965	$ 289,927	$ 31,962	12.39%	$ 0.13805	$ 0.15515
7,500	52%	692,301	2,110,670	$ 386,867	$ 434,870	$ 48,003	12.41%	$ 0.13802	$ 0.15515
10,000	52%	923,067	2,814,227	$ 515,769	$ 579,813	$ 64,044	12.42%	$ 0.13801	$ 0.15514
300	62%	33,027	100,692	$ 17,981	$ 19,882	$ 1,901	10.57%	$ 0.13447	$ 0.14869
496	**62%**	**54,595**	**166,448**	**$ 29,619**	**$ 32,841**	**$ 3,222**	**10.88%**	**$ 0.13400**	**$ 0.14857**
1,000	62%	110,090	335,640	$ 59,562	$ 66,181	$ 6,619	11.11%	$ 0.13363	$ 0.14848
3,000	62%	330,270	1,006,919	$ 178,366	$ 198,464	$ 20,098	11.27%	$ 0.13339	$ 0.14842
5,000	62%	550,449	1,678,198	$ 297,170	$ 330,747	$ 33,577	11.30%	$ 0.13334	$ 0.14841
7,500	62%	825,674	2,517,297	$ 445,676	$ 496,101	$ 50,425	11.31%	$ 0.13332	$ 0.14840
10,000	62%	1,100,899	3,356,396	$ 594,181	$ 661,455	$ 67,274	11.32%	$ 0.13331	$ 0.14840
300	72%	38,362	116,957	$ 20,333	$ 22,331	$ 1,998	9.83%	$ 0.13091	$ 0.14378
496	72%	63,425	193,369	$ 33,513	$ 36,895	$ 3,382	10.09%	$ 0.13050	$ 0.14368
1,000	72%	127,873	389,856	$ 67,403	$ 74,345	$ 6,942	10.30%	$ 0.13019	$ 0.14360
3,000	72%	383,619	1,169,569	$ 201,890	$ 222,956	$ 21,067	10.43%	$ 0.12998	$ 0.14355
5,000	72%	639,365	1,949,282	$ 336,376	$ 371,568	$ 35,191	10.46%	$ 0.12994	$ 0.14354
7,500	72%	959,048	2,923,923	$ 504,484	$ 557,332	$ 52,848	10.48%	$ 0.12992	$ 0.14353
10,000	72%	1,278,730	3,898,564	$ 672,592	$ 743,096	$ 70,503	10.48%	$ 0.12991	$ 0.14353

Large Com. and Ind. Primary Sample Bill Comparison

Winter

Billing Demand	Load Factor	On-Peak Energy Usage	Off-Peak Energy Usage	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates	Bill Total Proposed Rates
- kW -	- % -	- kWh -	- kWh -					- $/kWh -	- $/kWh -
300	47%	41,273	59,760	$ 13,208	$ 13,650	$ 442	3.35%	$ 0.13073	$ 0.13510
500	47%	68,788	99,600	$ 21,890	$ 22,720	$ 829	3.79%	$ 0.13000	$ 0.13493
1,025	47%	141,016	204,181	$ 44,682	$ 46,529	$ 1,846	4.13%	$ 0.12944	$ 0.13479
3,000	47%	412,731	597,602	$ 130,423	$ 136,094	$ 5,671	4.35%	$ 0.12909	$ 0.13470
5,000	47%	687,884	996,004	$ 217,249	$ 226,794	$ 9,545	4.39%	$ 0.12902	$ 0.13468
7,500	47%	1,031,826	1,494,006	$ 325,782	$ 340,169	$ 14,387	4.42%	$ 0.12898	$ 0.13468
10,000	47%	1,375,769	1,992,008	$ 434,315	$ 453,543	$ 19,229	4.43%	$ 0.12896	$ 0.13467
300	57%	50,097	72,536	$ 15,318	$ 15,758	$ 440	2.87%	$ 0.12491	$ 0.12850
500	57%	83,495	120,894	$ 25,408	$ 26,234	$ 826	3.25%	$ 0.12431	$ 0.12835
1,025	**57%**	**171,181**	**247,857**	**$ 51,897**	**$ 53,735**	**$ 1,839**	**3.54%**	**$ 0.12385**	**$ 0.12824**
3,000	57%	500,969	725,364	$ 151,526	$ 157,176	$ 5,650	3.73%	$ 0.12356	$ 0.12817
5,000	57%	834,948	1,208,940	$ 252,421	$ 261,931	$ 9,509	3.77%	$ 0.12350	$ 0.12815
7,500	57%	1,252,422	1,813,411	$ 378,540	$ 392,873	$ 14,334	3.79%	$ 0.12347	$ 0.12815
10,000	57%	1,669,895	2,417,881	$ 504,659	$ 523,816	$ 19,158	3.80%	$ 0.12346	$ 0.12814
300	67%	58,921	85,313	$ 17,428	$ 17,866	$ 438	2.51%	$ 0.12084	$ 0.12387
500	67%	98,201	142,188	$ 28,925	$ 29,747	$ 822	2.84%	$ 0.12033	$ 0.12375
1,025	67%	201,312	291,485	$ 59,103	$ 60,934	$ 1,832	3.10%	$ 0.11993	$ 0.12365
3,000	67%	589,207	853,126	$ 172,629	$ 178,258	$ 5,629	3.26%	$ 0.11969	$ 0.12359
5,000	67%	982,011	1,421,877	$ 287,593	$ 297,067	$ 9,474	3.29%	$ 0.11964	$ 0.12358
7,500	67%	1,473,017	2,132,815	$ 431,298	$ 445,578	$ 14,280	3.31%	$ 0.11961	$ 0.12357
10,000	67%	1,964,022	2,843,754	$ 575,002	$ 594,089	$ 19,087	3.32%	$ 0.11960	$ 0.12357

Summer

Billing Demand	Load Factor	On-Peak Energy Usage	Off-Peak Energy Usage	Bill Total Current Rates	Bill Total Proposed Rates	Dollar Difference	Percentage Difference	Bill Total Current Rates	Bill Total Proposed Rates
- kW -	- % -	- kWh -	- kWh -					- $/kWh -	- $/kWh -
300	51%	24,666	85,717	$ 14,845	$ 16,074	$ 1,229	8.28%	$ 0.13449	$ 0.14562
500	51%	41,110	142,862	$ 24,619	$ 26,760	$ 2,141	8.70%	$ 0.13382	$ 0.14546
1,313	51%	107,955	375,157	$ 64,351	$ 70,199	$ 5,848	9.09%	$ 0.13320	$ 0.14531
3,000	51%	246,661	857,175	$ 146,796	$ 160,336	$ 13,540	9.22%	$ 0.13299	$ 0.14525
5,000	51%	411,101	1,428,625	$ 244,537	$ 267,196	$ 22,659	9.27%	$ 0.13292	$ 0.14524
7,500	51%	616,652	2,142,937	$ 366,714	$ 400,772	$ 34,058	9.29%	$ 0.13289	$ 0.14523
10,000	51%	822,202	2,857,250	$ 488,890	$ 534,347	$ 45,457	9.30%	$ 0.13287	$ 0.14522
300	61%	29,493	102,491	$ 17,097	$ 18,478	$ 1,381	8.08%	$ 0.12954	$ 0.14000
500	61%	49,155	170,818	$ 28,373	$ 30,767	$ 2,394	8.44%	$ 0.12898	$ 0.13987
1,313	**61%**	**129,086**	**448,589**	**$ 74,210**	**$ 80,723**	**$ 6,513**	**8.78%**	**$ 0.12846**	**$ 0.13974**
3,000	61%	294,928	1,024,908	$ 169,315	$ 184,375	$ 15,060	8.89%	$ 0.12829	$ 0.13970
5,000	61%	491,546	1,708,180	$ 282,069	$ 307,262	$ 25,193	8.93%	$ 0.12823	$ 0.13968
7,500	61%	737,319	2,562,270	$ 423,012	$ 460,871	$ 37,858	8.95%	$ 0.12820	$ 0.13968
10,000	61%	983,092	3,416,360	$ 563,955	$ 614,479	$ 50,524	8.96%	$ 0.12819	$ 0.13967
300	71%	34,319	119,264	$ 19,349	$ 20,882	$ 1,533	7.92%	$ 0.12598	$ 0.13596
500	71%	57,199	198,774	$ 32,126	$ 34,773	$ 2,648	8.24%	$ 0.12550	$ 0.13585
1,313	71%	150,205	521,979	$ 84,063	$ 91,241	$ 7,178	8.54%	$ 0.12506	$ 0.13574
3,000	71%	343,194	1,192,641	$ 191,835	$ 208,415	$ 16,580	8.64%	$ 0.12491	$ 0.13570
5,000	71%	571,991	1,987,735	$ 319,602	$ 347,328	$ 27,726	8.68%	$ 0.12486	$ 0.13569
7,500	71%	857,986	2,981,603	$ 479,311	$ 520,970	$ 41,659	8.69%	$ 0.12483	$ 0.13568
10,000	71%	1,143,982	3,975,471	$ 639,019	$ 694,611	$ 55,592	8.70%	$ 0.12482	$ 0.13568

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