Department of Water and Power the City of Los Angeles

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RONALD O. NICHOLS
General Manager

September 13, 2012

The Honorable City Council
City of Los Angeles
Room 395, City Hall
Los Angeles, California 90012

Honorable Members:

Subject: Authorizes the Incremental Electric Rate Ordinance

Pursuant to Charter Section 676(a), enclosed for approval by your Honorable Body is Resolution No. 013 053, adopted by the Board of Water and Power Commissioners (Board) on September 12, 2012, approved as to form and legality by the City Attorney, which authorizes the Incremental Electric Rate Ordinance. As directed by the Board, transmitted to you are supporting documents.

If there are any questions regarding this item, please contact Ms. Winifred Yancy, Director of Local Government and Community Relations, at (213) 367-0025.

Sincerely,

Barbara E. Moschos

Barbara E. Moschos
Board Secretary

BEM:oja
Enclosures: LADWP Resolution
Board Letter
Appendix 2 – Summary of Rates
Appendix 3 – Customer Rate Impacts & Comparative Analysis
Appendix 4 – Department's Power Rate Report to the RPA
Appendix 5 – Revised Financial Plan
Appendix 6 – RPA Report on Proposed Rate Action
Appendix 7 – Limited Base Rate Increase – Business Impacts
Appendix 8 – LADWP Response to the RPA Report
Appendix 9 – Detailed Explanation of Rate Drivers
Appendix 10 – Public Outreach Summary

c/enc: Mayor Antonio Villaraigosa
Councilmember Jose Huizar, Chair, Energy and the Environment Committee
Gerry F. Miller, Chief Legislative Analyst
Miguel A. Santana, City Administrative Officer
Rafael Prieto, Legislative Analyst, CLA
William R. Koenig, Chief Administrative Analyst
Winifred Yancy

LOS ANGELES DEPARTMENT OF WATER AND POWER (LADWP) BOARD APPROVAL LETTER

TO: BOARD OF WATER AND POWER COMMISSIONERS		DATE: September 12, 2012
PHILIP LEIBER Chief Financial Officer	RONALD O. NICHOLS General Manager	SUBJECT: **Authorization for Incremental Electric Rate Ordinance**
		FOR COMMISSION OFFICE USE: RESOLUTION NO. ________
CITY COUNCIL APPROVAL REQUIRED: Yes ☒ No ☐	IF YES, BY WHICH CITY CHARTER SECTION: 676(a)	

PURPOSE

The attached Resolution recommends to the Los Angeles City Council (City Council) approval of the proposed incremental electric rate ordinance ("Incremental Electric Rate Ordinance"),[1] which reflects the proposed rates and rate structures outlined in this letter. The proposed Incremental Electric Rate Ordinance will:

- Increase revenues to fund investments required to comply with mandated Federal and State regulations and related deadlines;
- Increase revenues to support the replacement/upgrade of rapidly aging infrastructure to ensure electric service reliability; and
- Enhance conservation pricing signals and simplify the rate structure as recommended by the Ratepayer Advocate (RPA) and by City Council.

The LADWP or the Department is requesting that the proposed Incremental Electric Rate Ordinance take effect as soon as possible. The impact of this rate change in Fiscal Year (FY) 2012-13 and FY 2013-14 includes a system-wide average annual 5.5 percent rate increase over these two fiscal years. Approximately 84 percent of the projected increase over these two fiscal years is related to mandates and fuel costs which are beyond LADWP's control.[2]

[1] See Appendix 1 for copies of the Resolution and Incremental Electric Rate Ordinance.
[2] Mandates include the policy established by the Board of Water and Power Commissioners to position LADWP to reach or exceed a 10.0% energy consumption reduction by 2020 as intended by Assembly Bill 2021.

In a separate Board letter, the Department is requesting your approval of a Resolution reflecting updated financial metric targets for the Power System.

This Board letter includes the following appendices to provide additional information relevant to LADWP's rate proposals as noted throughout this letter.

1. Resolution including Proposed Incremental Electric Rate Ordinance

2. Summary of Rates

3. Rate Impacts and Comparative Analysis

4. Department's Power Rate Report to the RPA with Appendices

5. Revised Financial Plan

6. LADWP – Power System Financial Review and Rate Restructuring Analysis Report (RPA Report)

7. Limited Base Rate Increase - Business Impacts

8. LADWP Response to "LADWP – Power System Financial Review and Rate Restructuring Analysis" Report

9. Detailed Explanation of Rate Drivers

10. Public Outreach Summary

NEED FOR IMMEDIATE RATE ACTION

The proposed Incremental Electric Rate Ordinance is necessary immediately in order to:

- Comply with Federal and State mandates with related deadlines including:
    - Replacement of the ocean cooling process (Once Through Cooling, or OTC) at Haynes Generating Station Units 5 and 6 by June 1, 2013, and Scattergood Generating Station Unit 3 by December 31, 2015. These projects collectively require $752.8 million of capital investment over the next two years;

- Continued integration of renewable energy resources to meet the mandated 25.0 percent Renewable Portfolio Standard (RPS) requirement by 2016, en-route to a 33.0 percent RPS requirement by 2020. The proposed rate change and rate structure will provide the necessary funding to enable LADWP to enter into long-term contracts to meet the RPS requirements; and

- Expansion of energy efficiency programs to achieve compliance with Assembly Bill 2021 that sets a goal for LADWP to reach or exceed a 10.0 percent energy consumption reduction.

- Increase revenues to support the LADWP Power Reliability Program (PRP), which includes replacements of transformers, poles, wires, cables, cross-arms, etc. and construction of distribution stations to meet load growth and improve neighborhood electrical capacity and reliability. There has not been a rate increase for these activities since July 2009.

- Increase transparency of the rates and enhance conservation price signals.

Funding for these activities shall be recovered by the proposed incremental charges outlined in Figure 1 below. The first three charges are the incremental charges related to the current ECAF.

Figure 1: Proposed Incremental Charges

Proposed Incremental Charge	Costs to be Recovered
Variable Energy Adjustment (VEA) [pass-through factor]	• Fuel • Non-RPS power purchase agreements • Non-RPS economy purchases • Legacy ECAF under-collection • Base rate decoupling from energy efficiency (EE) impact
Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA) [pass-through factor]	• RPS market purchases • RPS costs above and beyond any O&M and debt service payments
Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA) [pass-through factor]	• RPS O&M and debt service • Energy efficiency programs
Incremental Reliability Cost Adjustment (IRCA)	• O&M and debt service related to Power Reliability Program (transmission and distribution) cost • Legacy RCA under-collection
Incremental Base	• Includes costs not included in the above components, primarily generation and administrative and general (A&G) costs

Please refer to the section entitled Specific Rate Changes with Greater Level of Detail for more explanation of the proposed incremental charges.

Most of the aforementioned capital spending activities will be debt funded to mitigate the rate impact on customers, and to appropriate spread the cost recovery of these long-term investments over their useful lives. The proposed rates are designed to provide the Power System the ability to raise capital for these programs at its current high credit rating.

PROPOSED RATE ACTION IMPACTS

System Average Rate and Revenue Impacts

The rate changes over the next two fiscal years are based on an average annual revenue increase of $164.2 million, which is required to support the activities outlined above; $124.8 million of the revenue increase is for regulatory mandates and fuel costs. The remaining $39.4 million will support the Power Reliability Program. An average annual system-average rate increase of 0.71 cents per kWh for FY 2012-13 and FY 2013-14 is necessary to produce the required incremental revenue (of which 0.60 cents per kWh supports regulatory mandates and fuel). These rate increases represent a 5.5 percent average annual increase for FY 2012-13 and FY 2013-14, of which 4.6 percent is related to investments for regulatory mandates and fuel costs.

Figure 2 shows the revenue and rate increases for this rate action.

Figure 2: Annual Revenue and Rate Impact for FY 2012-13 and FY 2013-14

Revenue and Rate Increases	FY 2012-13	FY 2013-14	Average Annual Increase
Annual Revenue Increase ($M)	$144.6	$183.7	$164.2
Annual System Average Cost per kWh Increase (¢/kWh)	0.62	0.80	0.71
Annual System Average Percent Increase (%)	4.9%	6.0%	5.5%

Customer Rate Impact

The proposed programs and rates have been developed to minimize the rate impact to customers for the next two years while ensuring LADWP has adequate revenue to support the activities described above. Furthermore, LADWP is focused on implementing electric rates that send the proper conservation price signals to our customers. For residential customers, this will include higher per unit costs for higher levels of consumption.

- Approximately 76 percent of all residential customers will see an annual average rate increase less than or equal to the system average of 5.5 percent over the next two fiscal years.

- Approximately 80 percent of all Low-Income/Lifeline residential customers will see an annual average rate increase lower than the system average of 5.5 percent over each of the next two fiscal years.

- To enhance the conservation price signals, residential customers who consume at higher levels will see a greater rate increase. For example, customers who consume four times the monthly system average (roughly 2,000 kWh) will see an increase of 8.1 percent, representing 1.6 percent of the Department residential population.

Also, please note that due to the complexity of the rate structure, LADWP has created a Summary of Rates so customers can more easily determine the charges on their specific monthly bills.[3] The impact of the rate proposals on the average monthly bill depends on the kWh usage of the individual customer.

Figure 3 shows the average monthly bill for residential and small commercial customer classes for various usage levels for the next two fiscal years.

Figure 3: Illustrative Average Monthly Bills

Illustrative Average Monthly Bills		Average Bill at Current Rates ($)	Average Bill with Proposed Rate Changes ($)	
Customer Class	**Monthly Usage (kWh)**	**FY 2011-12**	**FY 2012-13**	**FY 2013-14**
Residential	500	$65.79	$67.36 *+2.4%*	$69.44 *+3.1 %*
	1,000	$134.07	$142.65 *+6.4%*	$152.86 *+7.2%*
Small Commercial (35% Load Factor)	1,000	$136.40	$142.79 *+4.7%*	$151.35 *+6.0%*

[3] See Appendix 2 for the Summary of Rates.

Figure 4 shows the illustrative customer rates for medium commercial, large commercial, and large commercial & industrial customers based on a combination of demand and energy charges.

Figure 4: Illustrative Customer Rates

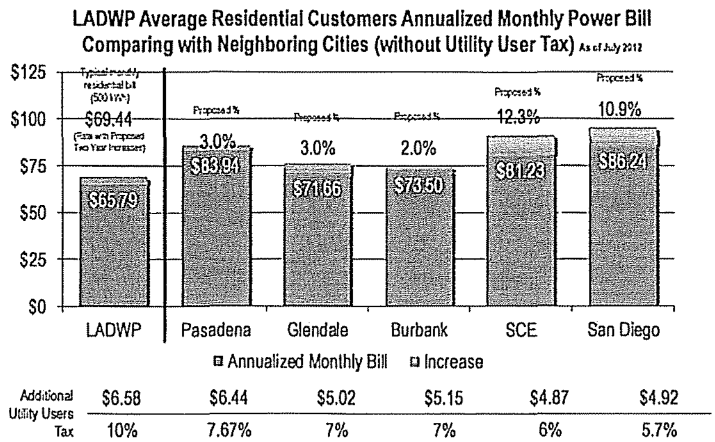
Illustrative Customer Rates		Average Customer Rate (¢/kWh)	Average Customer Rate with Proposed Rate Changes (¢/kWh)	
Customer Class	**Monthly Usage (kWh)**	**FY 2011-12**	**FY 2012-13**	**FY 2013-14**
Medium Commercial (40% Load Factor)	50,000	12.39	13.05 *+5.3%*	13.89 *+6.5%*
Large Commercial (42% Load Factor)	300,000	12.31	12.93 *+5.0%*	13.71 *+6.0%*
Large Commercial & Industrial (80% Load Factor)	240,000	10.80	11.30 *+4.6%*	11.95 *+5.8%*

Small/medium/large commercial and industrial customers with higher load factors will see lower rate increases when compared to the system average annual rate increase in an effort to promote more efficient energy usage (less variation on energy usage) and shift load outside of peak hours. For further details, see Appendix 3.

<u>Bill Comparison to Peers</u>

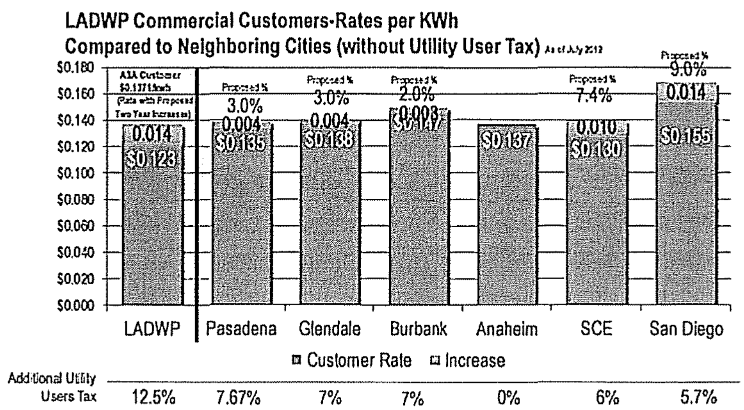
LADWP electricity rates are among the lowest when compared to other neighboring utilities. The rates after the proposed increases will maintain that favorable comparison. Based on comparative analyses, the typical LADWP customer in the major customer classes pays less for electric service than customers of many other similar regional California utilities. As shown in Figure 5, based on a typical monthly residential bill for a customer consuming 500 kWh of electricity, with the impact of the proposed rate change, LADWP has the lowest monthly electric bill compared to five of its neighboring utilities in Southern California. LADWP's rates are even more competitive than peers at higher levels of usage.

Figure 5: LADWP's Average Residential Customers Annualized Monthly Power Bill Comparing with Neighboring Cities and Southern California Investor-owned Utilities



Similarly, with this rate action, as shown in Figure 6 for large commercial customers, LADWP's commercial customer rates will remain competitive with its six neighboring utilities in Southern California.

Figure 6: LADWP's Commercial Rates Compared with Neighboring Cities and Southern California Investor-owned Utilities



RESPONSE TO RPA FINDINGS

In March 2011, ballot Measure I established the Office of Public Accountability, including a RPA. This office was established to provide public independent analysis of Department actions as they relate to water and electricity rates.

On May 3, 2012, LADWP provided a report to the RPA that summarized critical information, including financial plans and budget details supporting the Power System rate proposal and power rate design changes (see Appendix 4 for a copy of the Department's Power Rate Report to the RPA with Appendices). The RPA completed a comprehensive analysis of the proposed Power System rate action, including a substantial number of data requests from LADWP throughout the process. At the request of the RPA, LADWP completed the following:

- 95+ responses to requests for information;
- 15 alternative financial forecast and rate scenarios; and
- 20 or more interviews and meetings.

During the RPA's review process, LADWP made several key modifications to its original proposed rate plan to address specific initial recommendations from the RPA. The following changes have been incorporated into LADWP's proposal as a result of this process:

- Change the proposed Capped Incremental Reliability Cost Adjustment from a pass-through factor to a fixed rate recovery mechanism (renamed the Incremental Reliability Cost Adjustment).
- Implement a reporting requirement that LADWP provide a quarterly projection of future under-collections (if any under-collections are forecast) for the next three years for the Capped Renewable Portfolio Standard Energy Adjustment.
    - If the under-collection is equal to or greater than $50.0 million, LADWP will provide a report to the Board of Water and Power Commissioners (Board) and City Council to communicate the projected under-collection.
    - If the forecasted under-collection is equal to or greater than $100.0 million, modified rates shall, if deemed necessary, be fixed by the Board then approved by ordinance.

  This requirement will ensure that should the existing quarterly cap not fully fund these RPS projects, the Board and the City Council will be made aware of these financial shortfalls in a timely manner.

- The base rate decoupling mechanism for Energy Efficiency will be in effect for FYs 2012-13 and 2013-14; LADWP will revisit this mechanism at the end of the two fiscal years.

- Restructuring of the Energy Cost Adjustment Factor (ECAF) in a manner that more clearly links costs to specific cost recovery mechanisms in alignment with prior feedback from the City Council.

The impact of these changes on LADWP's proposed rate action has been captured in the revised financial plan provided in Appendix 5.

On August 23, 2012, the RPA, City Administrative Officer and Chief Legislative Analyst presented the City Council with the "LADWP - Power System Financial Review and Rate Restructuring Analysis" report completed by PA Consulting.[4] This report stated:

> "Given the legal and infrastructure requirements faced by the Department, and the positive developments made by the current LADWP, PA believes that this rate increase is necessary and warranted".

In addition, a summary of this report given by Dr. Frederick Pickel to the Board on August 22, 2012 stated:

> "LADWP's two-year rate proposal should be approved"

LADWP appreciates the thoughtful analysis and support for the two-year rate proposal.

The report completed by PA Consulting contained 16 specific recommendations (Appendix E of the report) with 4 recommendations specific to rate restructuring and the remaining 12 recommendations related to potential cost saving actions.

While most of the recommendations address longer term actions that do not relate directly to the rate proposals for FY 2012-13 and FY 2013-14, two of the "Rate Restructuring Recommendations" address specific aspects of the current rate proposal:

- ***"The proposed rate ordinances should be adopted on an interim basis"***

LADWP Response: LADWP agrees that the proposed rate ordinance structure should be revisited once legal issues surrounding it are resolved. These legal issues may or

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[4] See Appendix 6 for a complete copy of the report.

may not be resolved within the next two years, and a decision will have to be made at that time.

- ***"The City should explicitly consider some of the program costs that would be collected in the new surcharges"***

LADWP Response: It is LADWP's understanding that the program costs requested by PA Consulting to be specifically considered are the Power Reliability Program (PRP), the Energy Efficiency program, and other support costs. LADWP believes that the proposed levels for these areas are appropriate and consistent with the direction of the Board. Additionally, the specific rate impact identified by PA Consulting was based on prior financial cases; however, to better determine this amount, LADWP has performed an updated analysis based on the latest case:

- Power Reliability Program:
    - As discussed in this report, even at the proposed level of spending, the enhancements and replacements to LADWP's power infrastructure will continue to lag behind what has been recommended. Reliability metrics show that service levels are beginning to deteriorate and continued deferral of this infrastructure replacement may further impact system reliability if spending remains at FY 2011-12 levels.
    - The proposed increased PRP spending levels are responsible for roughly 0.22 cents/kwh of the total 1.40 cents/kwh increase over the two year period (see Figure 9). This is approximately a 1.73 percent cumulative rate increase over those two fiscal years.
- Energy Efficiency Program:
    - It has been the direction of the Board under Assembly Bill (SB) 2021 to set a goal and the corresponding funding for an energy efficiency program that positions the Department to meet a 10 percent energy consumption reduction in 10 years. LADWP's recent energy efficiency program funding levels, if continued at such low levels, would result in less than 5 percent energy efficiency by 2020. The Board previously approved a two-year energy efficiency program level which is estimated to, for the next two fiscal years, place LADWP on a path that would enable reaching at least 10 percent renewable energy by 2020, subject to maintaining those levels of annual energy efficiency savings in programs to be adopted beyond the two-year period. Thus, these

two years of energy efficiency investment are essentially a "no regrets" approach to avoid falling unreasonably behind legislatively-established State goals until such time that a more detailed program can be adopted for the period from 2015 through 2020.

- If the Department reduced the proposed Energy Efficiency funding to FY 2011-12 levels, or $55 million annually, the rate increase would be reduced by roughly 0.19 cents/kwh (of the total 1.40 cents/kwh increase) over the two year period. This is approximately a 1.41 percent cumulative rate reduction over those two fiscal years. The Department would not be able to comply with the State goal of 10 percent energy reduction and the prior direction of the Board to meet or exceed that goal.

- If all funding for the Energy Efficiency programs is eliminated, rates would be reduced by roughly 0.31 cents/kwh (of the total 1.40 cents/kwh) over the two year period. This is approximately a 2.40 percent cumulative rate decrease over those two fiscal years. Certainly, at these funding levels the Department would not comply with the State goal and the prior direction of the Board.

- Other Infrastructure and Support (not including Customer Information System funding): The Department performed an updated analysis and determined that the proposed spending levels in other infrastructure and support are responsible for approximately 0.09 cents/kwh of the total 1.40 cents/kwh increase over the two year period. This is approximately a 0.64 percent cumulative rate increase over the two year period. However, as identified in Appendix 7, there would be significant impacts to generation reliability, customer service, automation projects (including automatic meter reading, digital radio system, and replacement of financial systems), and/or other programs that could impact service to Department customers.

Related to all other recommendations that were outlined in the report, LADWP is continuing to evaluate these longer-term recommendations and will be developing a plan to address them over the coming months. A detailed response to each of the sixteen recommendations will be provided later.

FINANCIAL CONSIDERATIONS

In order to fund the capital programs over the next two years in the most cost effective manner, the Power System must borrow approximately $2.4 billion in new debt (of which $1.3 billion is for regulatory mandated programs). To finance this borrowing, debt service cost levels are projected to increase from $343.8 million in FY 2011-12 to $466.7 million (an increase of 35.7 percent in 2 years) by FY 2013-14 as shown in Figure 7.

Figure 7: Summary of Capital Expenditures and Debt Financing

Summary of Financial Plan ($M)	Current Year	Upcoming Two-Year Period	
Fiscal Year Ended June 30:	FY 2011-12	FY 2012-13	FY 2013-14
Capital Expenditures	$1,237.8	$1,444.3	$1,650.4
New Debt Required for Capital Expenditures		$1,124.5	$1,235.0
On-balance Sheet Debt	$6,406.4	$7,397.5	$8,491.5
Off-balance Sheet Debt	$2,934.7	$3,061.5	$3,433.8
Total On and Off Balance Sheet Debt	$9,341.1	$10,459.0	$11,925.2
On-balance Sheet Debt Service Costs	$343.8	$422.1	$466.7
Off-balance Sheet Debt Service Costs	$328.4	$343.0	$397.1
Total On and Off Balance Sheet Debt Service Costs	$672.2	$765.1	$863.7

To maintain its current debt rating and access to bond markets at reasonable interest rates, LADWP uses the revised proposed capitalization ratio metric shown in Figure 8 to prepare the Power System's two-year financial plan.

Figure 8: Proposed Revised Power System Financial Metrics

Board Approved Metrics	Proposed Target	Current Target
Debt Service Coverage Ratio	2.25	2.25
Capitalization Ratio	Less than 68%	Not to Exceed 60%
Unrestricted Operating Cash Target[5]	$300M	$300M

The Unrestricted Operating Cash target, in conjunction with the approximately $500 million Debt Reduction Trust Fund, provides the Power System with the recommended 110 days of operating cash to maintain an AA- (Standard &Poor's) rating.

LADWP's financial advisor, Public Resources Advisory Group (PRAG), undertook a review of LADWP's previous financial metrics in September 2011. Based on the rating attributes of other California public power utilities and the specific credit characteristics of LADWP, PRAG believes a capitalization ratio of not greater than 68.0 percent, with the other metrics remaining the same, is unlikely to result in a ratings downgrade. Given

[5] Not including the debt reduction trust fund (DRTF).

that the Power System will be issuing over $2.4 billion in new debt over the next two fiscal years, to minimize future rate impacts to its customers, it is critical that the current rating be maintained.

As previously stated, through a separate Board letter, the Department is requesting your approval of a Resolution to direct the use of a revised capitalization ratio metric for the Power System.

PROPOSED ELECTRIC RATE ORDINANCE AND STRUCTURE

Legal Considerations Affecting Rate Design

A view appears to have formed in recent years that the Department's current electricity rates fail to provide the transparency and simplicity demanded today. While there may be a desire to undertake a major modification of the current rate structure to provide a simpler rate structure, the Office of the City Attorney advises that for legal reasons the City of Los Angeles (City) may wish to avoid making radical changes to the current rate structure at this time.

A question has been raised as to whether Proposition 26, adopted at the State level in November 2010, forbids the Department's annual transfer of monies, financial conditions allowing, from the Power Revenue Fund ultimately to the City's General Fund or the electricity rates that generate that transfer. The City Attorney advises that the measure does not do so, but notes that no precedential appellate decisions have yet been rendered relating to the measure's application in this context.

The City Attorney advises, however, that as a safeguard against the absence of judicial interpretation, the City may wish to adopt an electrical rate structure that conservatively retains existing rates and layers incremental charges on top of them. This structure endeavors to maintain the status quo for the transfer payment made by the Department to the City.

In the proposed Incremental Electric Rate Ordinance, customers shall pay charges in addition to charges paid in corresponding rates of the existing Electric Rate Ordinance. The Incremental Electric Rate Ordinance provides incremental charges to fund revenue requirements unmet by the existing ordinance. Adjustable charges are to be capped and base rate charges are to remain fixed in the existing Electric Rate Ordinance at their levels as of November 3, 2010 when Proposition 26 took effect.

Therefore, for the time being, electricity rates would derive primarily from two ordinances – the existing one and the proposed incremental one. At some later point, after further legal developments related to the applicability of Proposition 26 have unfolded, rates can be modified in the manner desired in one rate ordinance. Until then, to provide for the transparency that is desired by the City Council, LADWP will prepare periodic reports of the components and total costs of the programs covered by the various rate ordinances in a manner meaningful and useful to customers.

Incremental Electric Rate Ordinance Structure

To recover additional costs of fuel, renewable energy, energy efficiency, demand side management, system reliability, and other costs sensitive to market and inflationary forces that would not be recovered by the existing ordinance, the new ordinance introduces separate charges incremental to existing charges in three categories:

- Uncapped Charges: Uncapped charges recover costs largely out of the control of the Department. This includes fuel, additional charges for receiving additional intermittent renewable generation (such as wind)[6], and other uncontrollable costs;

- Capped Charges: Capped charges will recover the costs of Operation and Maintenance (O&M) and debt service tied to these spending activities. The new ordinance will set caps on how much the capped charges can increase. Thereafter, if the Board were to find that cost recovery from a capped charge would not be sufficient to maintain the financial integrity of the Department, then the Board would be able to increase the cap with notification thereof to the City Council; and

- Base Rate Charges: The base rate charges would be set by the new ordinance for each year of the upcoming two-year period.

For both uncapped and capped charges, changes would require Board action, with the amounts calculated quarterly.

RATE DRIVERS

As illustrated previously in Figure 2, the average rate increase is 5.5 percent per year for FY 2012-13 and FY 2013-14 with an average annual revenue increase of $164.2 million. The total system average rate increase over the two years is 1.40 cents per kWh with regulatory mandates and fuel costs accounting for 84 percent of the increase. Figure 9 below separates the rate increase by cost driver.

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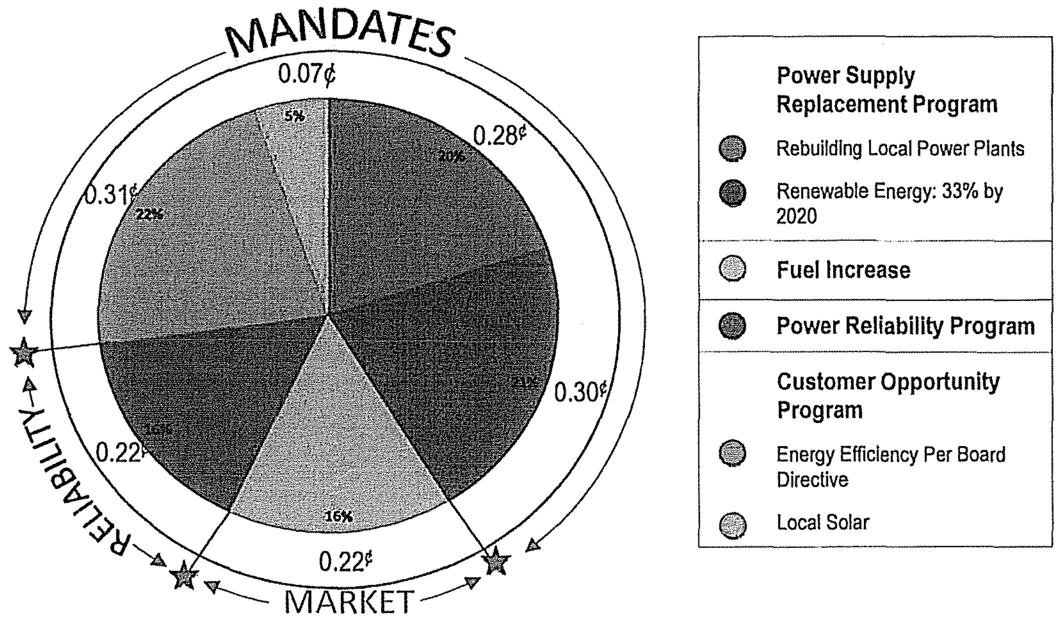
[6] Intermittent renewable energy generation sources using wind and solar energy produce power at times that, while estimated by LADWP on an annual basis, are subject to natural factors over which LADWP has no control.

Figure 9: Components of the Proposed Rate Increase

Fiscal Year 2013-14 vs. Current Year



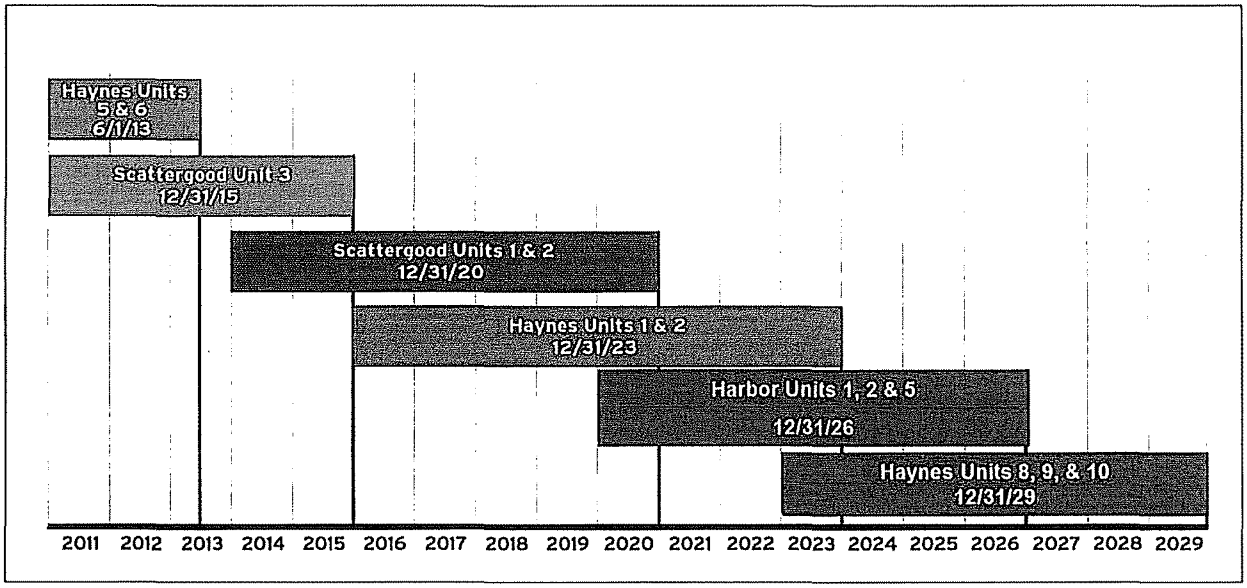
For a more detailed explanation of the rate drivers, please refer to Appendix 9.

Mandates

- Rebuilding Local Power Plants to Eliminate Once Through Cooling (OTC)

  OTC is the process where water is drawn from the ocean for cooling equipment at a power plant and then is discharged back into the ocean. Pursuant to federal and state legislation, LADWP is to reduce or eliminate mortality due to impingement and entrainment of marine life and organisms. Over the next five years, this mandate will require approximately $915 million in capital investment. During the next two years, $753 million of capital investments will be made for two of the six separate projects to replace the OTC process - Haynes Generating Station Units 5 and 6 by June 1, 2013, and Scattergood Generating Station Unit 3 by December 31, 2015. Figure 10 below provides the current OTC compliance schedule.

Figure 10: OTC Compliance Time Line



- Renewable Energy to Meet State-Mandated Renewable Portfolio Standard (RPS) Compliance Dates

  Shifting a greater amount of energy production to renewable energy sources is a major mandate and environmental initiative in California. The procurement targets under the California Renewable Energy Resources Act are 25 percent by December 31, 2016, and 33 percent by December 31, 2020. During the next five fiscal years, $3.7 billion of capital and O&M expenses will be required to ensure LADWP is able to meet these compliance targets. In addition, there will be investments made in transmission and distribution lines projects to ensure reliable delivery of these new renewable energy sources. Over the next two years, the proposed revenue increase of $69.8 million will support $1.3 billion of expenditures ($537.7 million of capital expenditures; $746.5 million of O&M expenses) for renewable energy and renewable transmission facilities. These expenditures will be financed primarily through debt borrowings, including an additional $1.3 billion of off-balance sheet debt.

  Furthermore, State Senate Bill (SB) 1, passed on August 21, 2006, mandates that all California electric utilities implement a solar incentive program by January 1, 2008, with a cap on expenditures of $3.4 billion. LADWP has a solar customer rebate program to meet this mandate (Solar Photovoltaic Incentive Program). LADWP's share of the program, based on its percentage of load served in the state, is $313.0 million. Through the end of FY 2011-12, LADWP had committed

$196.0 million to customers under this program of which $132.0 million had been actually spent. Over the next two years, LADWP has budgeted capital expenditures for the solar customer rebate program in the amount of $129.1 million. Past commitments combined with new commitments over the next two fiscal years are expected to bring LADWP close to meeting its total share of the program as set by the Legislature.

- Expansion of the Energy Efficiency Program

  Energy Efficiency is one of the most cost effective components of LADWP's power supply portfolio and serves an important role in meeting customer demand. The rate proposal includes a level of Energy Efficiency spending required to position LADWP to reach or exceed a 10 percent energy consumption reduction by 2020 as directed by the Board of Water and Power Commissioners and intended by AB 2021. Over the next two years, LADWP has budgeted capital expenditures of $264.9 million to expand its Energy Efficiency program.

Market Driven

- Fuel and Purchased Power

  LADWP must account for purchasing significant volumes of fuel and for purchased power and related fuel costs (as well as exposure to fuel price volatility) in its budget, operating, and rate plans. Fuel costs are driven primarily by free market forces and can fluctuate significantly year to year, and within a year. LADWP mitigates the risk of price volatility through financial hedging programs, owned gas fields, and long-term fixed price contracts. Additionally, the Feed-in Tariff (FiT) Program will help to encourage customers to invest in customer-owned renewable technologies, including solar facilities, and reduce the need for fuel and power purchases. Over the next two years, LADWP expects fuel and purchased power costs to total $2.7 billion. It also has budgeted O&M expenditures of $6.7 million for power acquired through the FiT program.

Power Reliability Program (PRP)

The purpose of the PRP is to replace and/or upgrade aging infrastructure necessary for the reliable delivery of power to customers. Funding for the PRP was materially reduced in FY 2011-12, pending a rate level adjustment to provide required revenue for the program. During the next two years, LADWP's rate proposal includes increased funding for the PRP to levels approximating FY 2010-11. LADWP's 2011 System Average Interruption Frequency Index (SAIFI) is 1.03 vs. the 1.1 national average, and its

System Average Interruption Duration Index (SAIDI) is 215.8 minutes vs. the 90-minute national average. These relationships indicate that, while the number of times that LADWP customers lose power is close to the national average, the length of time that they are out of power is more than twice the national average. Additionally, of more concern is the recent trend of increase in these indices. The increased funding will help move LADWP towards the average. Furthermore, the backlog of "fix-it tickets" is currently approximately 41,000 tickets. Based on the forecasted PRP funding levels, the fix-it ticket backlog will increase by approximately 1,000 tickets per year, which, while still directionally not desirable, is improved from the recent trend.

The increased PRP investment is designed to target several key components of the distribution infrastructure, which is in a condition that poses a growing threat to overall reliability, by replacing or repairing the specific facilities that are expected to have the greatest impact on reliability. The pole replacement program will be funded at such a level to increase the pole replacements from the current level of 2,100 poles per year to 2,400 poles in FY 2012-13 and 2,800 poles in FY 2013-14. However, the underground (UG) cable replacement program will be reduced from the current average level of approximately 53 miles per year to 27 miles per year due to budget constraints. To increase this replacement level, additional revenue increases would be needed. The Distribution Transformer Replacement Program will be maintained at a replacement level of approximately 2,400 transformers per year, which is generally consistent with the long-term desired level of annual transformer replacement. In addition, LADWP will begin construction of the Scattergood Olympic Transmission Line. This 11.4 mile underground transmission line provides a critical link between the Scattergood Generating Station and a west side Los Angeles bulk power station and will improve electric reliability to the entire area. Over the next two years, LADWP has budgeted capital and O&M expenditures of $1.7 billion to maintain and replace critical aging infrastructure.

ADDITIONAL DISCUSSION OF SPECIFIC RATE CHANGES

Rate Structure Objectives

Other rate structure changes reflected in the proposed new rate ordinance are intended to:

- Make the rates as transparent and easy to communicate as possible;
- Use marginal cost as the guiding principal within each rate class;

- Minimize rate change impacts on residential customers who proactively conserve energy;
- Encourage commercial and industrial customers to adopt energy efficiency, demand response, and load shifting away from the High Peak period;
- Maintain rate competitiveness in the region; and
- Enhance revenue stability for LADWP.

Key Rate Design Changes

The existing rate ordinance is unchanged. The key rate design elements in the proposed Incremental Electrical Rate Ordinance are as follows:

- For the residential customer class, the Tier 2 and Tier 3 prices will be increased at a higher rate than the Tier 1 price to send a stronger conservation signal.
- The three-tier rate structure is updated for the residential customer class to further promote energy conservation and the adoption of renewable energy solutions by increasing the Tier 2 and Tier 3 prices for the winter season to be equal to the Tier 2 price of the summer season.
- For the commercial and industrial classes, the proposed rate increase is allocated to the (1) facilities demand charge, (2) monthly demand charge (A2 and A3), and (3) energy charge in a manner that encourages customers who have the ability to shift load away from the summer high peak period to promote energy efficiency and demand reduction.
- Revenue stability tools include (1) enhanced capacity charges and (2) proposed automatic decoupling fixed cost recovery mechanism.
- An Incremental Rate Stabilization Account shall be created, and the beginning balance shall be equal to that of the existing Rate Stabilization Account. The initial Incremental Rate Stabilization Account target shall be $75 million.

Detailed Discussion of the Proposed Incremental Charges

Variable Energy Adjustment (VEA), an uncapped charge recovering the costs of:

- *Fuel*: The fuel component will be comprised of variable costs of fuel for power generation. The fuel costs will consist of costs of natural gas, coal, nuclear, and other fuels used to generate power.

- *Power Purchase Agreements (non-RPS):* This charge component will include costs of non-renewable electricity purchased from third-party generators on a bulk basis to supplement internal generation or when external generation is more cost effective. These purchases are contractual in nature through power purchase agreements and include agreements with the Intermountain Power Project, the Southern Transmission System, and the Palo Verde Nuclear Generating Station.

- *Economy Purchases (non-RPS):* The Department continually evaluates whether it is more economical to generate power or make short-term wholesale purchases on the spot market. The cost of these "economy purchases" essentially displaces natural gas costs and will be passed through to customers as part of the variable energy adjustment in a similar fashion.

- *Legacy ECAF Under-Collection:* The ECAF charge was unfrozen by an amendment to the Electric Rate Ordinance in 2006 but increases were capped at 0.1 cents per kWh per quarter, unless the Board acts to increase the limit. The ECAF has been the method for passing through the costs of natural gas and other fuel costs to Department customers. As a result of the cap, since 2006 the Department has an under-collection[7] of roughly $200.0 million largely due to the cost of natural gas. Through this new charge component, the Department intends to collect the legacy under-collection over a 10-year period.

- *Base Rate Decoupling from Energy Efficiency Impact (Automatic Decoupling Fixed Cost Recovery Mechanism):* The Department aggressively promotes a number of energy efficiency programs intended to reduce the amount and cost of energy usage by its customers. This charge component is intended to ensure that the Department will recover the needed base rate revenue without providing a financial disincentive for the Department's energy efficiency programs. The target base rate revenue, which is relatively fixed in relation to the volume of energy consumed, is based on forecasted energy consumption. This decoupling mechanism will provide a credit

[7] The term "under-collection" refers to the situation where actual fuel costs incurred to provide reliable power have exceeded the amount funded by the quarterly cap. The "under-collection" is then recovered over future years.

back to customers if sales exceed forecasted amounts. If the total costs for the above components drop below what is embedded in the fixed rates, the Variable Energy Adjustment charge could result in a credit to customers.

Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA) an uncapped charge recovering the costs of:

- *Purchases for Regulatory Requirements:* This charge will recover costs required to meet legally mandated RPS targets. The cost of market purchases for RPS required to meet these targets is market driven and largely not controlled by the Department. This charge also includes the cost for the delivery of renewable power above and beyond debt service and O&M, including delivery of excess wind and/or solar power due to climate conditions.

Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA), recovering the costs of:

- *RPS O&M and Debt Service Costs:* This adjustment will recover O&M and debt service costs (including off balance sheet debt) for which the Department can meaningfully plan to meet legally mandated RPS targets that have been established.

- *Energy Efficiency Program Costs:* This adjustment will recover costs to fund energy efficiency programs that have been established.

- *Three Years Projected Under-Collection:* As stated earlier, LADWP is required to develop a quarterly projection of future under-collections for the next three years. If the under-collection is equal to or greater than $50.0 million, LADWP will provide a report to the Board and City Council to communicate the under-collection. If the forecasted under-collection is equal to or greater than $100.0 million, if deemed necessary, modified rates will also be fixed by the Board and then approved by ordinance.

Incremental Reliability Cost Adjustment (IRCA), recovering the costs of:

- *Power Reliability Program:* This adjustment will provide funding for infrastructure replacements and upgrades, as well as for ongoing O&M activities to ensure the continued reliability of the Power System.

- *Legacy RCA Under-Collection:* The RCA factor was established to recover operation, maintenance, and debt service costs of the Power System Reliability Program (PRP). Current forecasts project the under-collection to reach $95.0 million at the end of FY 2011-12. Within this new adjustment, LADWP will account for the legacy under-collection over a 10-year period.

Incremental Base Rates

Incremental Base Rates will recover costs of providing electric utility service that are increasing, and which are not recovered by the above adjustment factors. These costs would include labor costs, real estate costs, costs to rebuild and operate local power plants, equipment costs, operation and maintenance costs, expenditures for jointly-owned plants (Navajo Generating Station and Palo Verde Nuclear Generating Station), and other inflation-sensitive costs.

PUBLIC OUTREACH

Throughout the current rate setting process, the Department has communicated openly with its customers, stakeholders, and policy makers about the cost pressures and challenges it faces and the potential impacts on its customers.

During the summer of 2011, the Department conducted over 30 public meetings to inform the public about mandates and the associated costs the Department is facing. In addition, the Department reached out to customers through various printed and electronic media, and directly to stakeholder groups, including Neighborhood Councils.

The Department has continued its outreach efforts through the spring and summer of 2012. The Department has held 51 additional workshops throughout the City to discuss its rate proposals. Additional meetings in individual throughout the City districts have also been held.

For a full listing of workshops and outreach efforts, please refer to Appendix 10.

CITY COUNCIL APPROVAL

City Council approval of the modifications is required by ordinance.

RECOMMENDATION

It is requested that your Honorable Board adopt the attached Resolution recommending the Los Angeles City Council's approval of the proposed Incremental Electric Rate Ordinance.

DET:sc
Attachments
e-c/att: Ronald O. Nichols
Richard M. Brown
Aram Benyamin
James B. McDaniel
Philip Leiber
Gary Wong
Jeffery L. Peltola
George Chen

RESOLUTION NO. 013 053

WHEREAS, revenues generated solely by the existing Electric Rate Ordinance No. 168436, as amended, (Electric Rate Ordinance) of the Department of Water and Power of the City of Los Angeles (Department) do not sufficiently fund investments required to comply with mandated Federal and State regulations and to support replacement or upgrade of aging infrastructure to ensure electric service reliability; and

WHEREAS, the major drivers for increased revenue are for funding mandates through FY 2013-14, including progressive elimination of once through cooling, shifting energy production to renewable energy sources to continue moving toward 33% by December 31, 2020, implementation of the solar incentive program mandated under State Senate Bill SB1, and meeting 10% energy consumption reduction by 2020 under Assembly Bill 2021 through investments in energy efficiency. The remaining rate drivers are for funding fuel and Power System reliability; and

WHEREAS, the Department proposes that conservation pricing signals be enhanced; and

WHEREAS, the Department proposes adoption of an incremental electric rate ordinance, by which customers would pay charges in addition to charges paid in corresponding rates of the existing Electric Rate Ordinance (Incremental Ordinance). These incremental charges recover additional costs of fuel, renewable energy, energy efficiency, demand-side management, system reliability, and other costs that are not recovered by the existing Electric Rate Ordinance; and

WHEREAS, consistent with the prior Los Angeles City Council recommendation for transparency, the proposed Incremental Ordinance shall fund expenditures of the type qualifying for funding by the Energy Cost Adjustment, not actually funded by application of the existing Electric Rate Ordinance, through use of new charges called the Variable Energy Adjustment, Variable Renewable Portfolio Standard Energy Adjustment, and Capped Renewable Portfolio Standard Energy Adjustment; and

WHEREAS, the proposed Incremental Ordinance provides for use of an Incremental Rate Stabilization Account; and

WHEREAS, the Office of Public Accountability has reviewed the terms of the proposed Incremental Ordinance and recommends approval of the electric rate proposal; and

WHEREAS, even including the expected rate impact over Fiscal Years 2012-13 and 2013-14 from implementation of the proposed Incremental Ordinance, the

Department would still have the lowest residential monthly electric bill for monthly consumption of 500 kWh when compared to five of its neighboring utilities in Southern California (Pasadena, Glendale, Burbank, SCE, and San Diego), and such rates are even more competitive than peers at higher levels of monthly usage. Commercial customer rates remain competitive with six neighboring utilities in Southern California (Pasadena, Glendale, Burbank, Anaheim, Southern California Edison, and San Diego); and

WHEREAS, the Department has conducted over 30 public meetings since June 4, 2011, to inform the public about Federal and State regulatory mandates and the associated costs facing the Department, and, in addition, has continued its outreach efforts through the summer of 2012 to discuss its electric rate proposals.

NOW, THEREFORE, BE IT RESOLVED that the Board of Water and Power Commissioners does consent that the Los Angeles City Council adopt the proposed Incremental Ordinance in words and figures as substantially follows, to wit:

ORDINANCE NO.________________

An ordinance approving the rates fixed by the Department of Water and Power of the City of Los Angeles and to be charged for electrical energy distributed and for service supplied by said Department to its customers and approving the time and manner of payment of the same, as prescribed by said Department.

THE PEOPLE OF THE CITY OF LOS ANGELES DO ORDAIN AS FOLLOWS:

Section 1. That the rates to be charged and collected and the terms, provisions and conditions to be effective respecting such rates for electrical energy distributed and for service supplied by the Department of Water and Power (Department) of the City of Los Angeles (City) to its customers, fixed by Resolution No. ___________, adopted by the Board of Water and Power Commissioners on _____________, are hereby approved. Such rates and conditions so fixed are as set forth in the following sections:

Sec. 2. That such service supplied to customers within the incorporated limits of the City of Los Angeles and to customers within the Counties of Inyo and Mono, California, shall be in accordance with rate schedules prescribed in this section as follows and any rate schedules prescribed in any other effective ordinance of the City of Los Angeles:

A. SCHEDULE R-1 [i] RESIDENTIAL SERVICE

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to service to single-family, single-family with guest house, individually metered accommodations, as well as to separately metered common areas of condominiums and cooperatives devoted primarily to residential uses and whose energy and capacity requirements do not exceed those for Small General Service Schedule A-1 [i]. Battery chargers, motors and appliances, which conform in capacities to applicable electrical codes, and meet requirements of the Department's Rules, may be served under this schedule. Not applicable to single-family residential customers with an on-site transformer dedicated solely to that individual customer.

2. Monthly Rates through June 30, 2013

	High Season June - Sep.	Low Season Oct. - May
a. Rate A - Standard Service		
1 Energy Charge [i] - per kWh		
Tier 1 - per Zone Allocation	$ 0.00161	$ 0.00161
Tier 2 - per Zone Allocation	$ 0.00251	$ 0.01751
Tier 3 - per Zone Allocation	$ 0.00451	$ 0.01751
2 VEA - per kWh	See General Provisions	
3 CRPSEA - per kWh	See General Provisions	
4 VRPSEA - per kWh	See General Provisions	
5 IRCA - per kWh	See General Provisions	

Zone 1
- Tier 1 - first 350 kWh
- Tier 2 - next 700 kWh
- Tier 3 - greater than 1050 kWh

Zone 2
- Tier 1 - first 500 kWh
- Tier 2 - next 1000 kWh
- Tier 3 - greater than 1500 kWh

	High Season June - Sep.	Low Season Oct. - May
b. Rate B - Time-of-Use Service		
1 Service Charge [i]	$ -	$ -
2 Energy Charge [i] - per kWh		
High Peak Period	$ 0.00531	$ 0.00531
Low Peak Period	$ 0.00531	$ 0.00531

Base Period	$ 0.00531	$ 0.00531
3 VEA - per kWh	See General Provisions	
4 CRPSEA - per kWh	See General Provisions	
5 VRPSEA - per kWh	See General Provisions	
6 IRCA - per kWh	See General Provisions	

c. **Rate D - Low Income Service**
Rate A

d. **Rate E - Lifeline Service**
Rate A

3. Monthly Rates beginning July 1, 2013

	High Season June - Sep.	Low Season Oct. - May
a. Rate A - Standard Service		
1 Energy Charge [i] - per kWh		
Tier 1 - per Zone Allocation	$ 0.00097	$ 0.00097
Tier 2 - per Zone Allocation	$ 0.01397	$ 0.02897
Tier 3 - per Zone Allocation	$ 0.02087	$ 0.02897
2 VEA - per kWh	See General Provisions	
3 CRPSEA - per kWh	See General Provisions	
4 VRPSEA - per kWh	See General Provisions	
5 IRCA - per kWh	See General Provisions	

Zone 1
Tier 1 - first 350 kWh
Tier 2 - next 700 kWh
Tier 3 - greater than 1050 kWh
Zone 2
Tier 1 - first 500 kWh
Tier 2 - next 1000 kWh
Tier 3 - greater than 1500 kWh

b. Rate B - Time-of-Use Service		
1 Service Charge [i]	$ -	$ -
2 Energy Charge [i] - per kWh		
High Peak Period	$ 0.00955	$ 0.00955
Low Peak Period	$ 0.00955	$ 0.00955
Base Period	$ 0.00955	$ 0.00955
3 VEA - per kWh	See General Provisions	
4 CRPSEA - per kWh	See General Provisions	
5 VRPSEA - per kWh	See General Provisions	
6 IRCA - per kWh	See General Provisions	

c. **Rate D - Low Income Service**
Rate A

d. **Rate E - Lifeline Service**
Rate A

4. Billing

The bill under:

- Rate A shall be the sum of parts (1) through (5), except that the Energy Charge [i] shall not be billed if the Minimum Charge under the Electric Rate Ordinance is billed.
- Rate B shall be the sum of parts (1) through (6).
- Rate D shall be Rate A.
- Rate E shall be Rate A.

5. Selection of Rates

a. The Department requires mandatory service under Rate B for customers whose annual monthly average consumption reach or exceed 3000 kWh during the preceding 12 month period.

b. If a customer's annual monthly average consumption does not reach or exceed the consumption levels in accordance with conditions as set forth in 5.a. above, a customer may choose to receive service either under Rate A or B, but the selection must correspond to the rate or rates under which service is received pursuant to any other effective ordinance. Also, when a customer served under Rate B requests a change to Rate A, that customer may not revert to Rate B before 12 months have elapsed.

c. To receive service under Rate D, a customer must meet eligibility requirements as set forth by the Board of Water and Power Commissioners. Low Income eligibility requirements are available online at www.ladwp.com/lowincome, or through the Customer Call Center at (800)-DIALDWP / (800) 342-5397.

d. To receive service under Rate E, a customer must meet eligibility requirements. Lifeline eligibility requirements are available online at www.ladwp.com/lifeline, or through the Customer Call Center at (800)-DIALDWP / (800) 342-5397.

B. SCHEDULE R-3 [i]
RESIDENTIAL MULTIFAMILY SERVICE

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to master-metered residential facilities and mobile home parks, where the individual single-family accommodations are privately Sub-metered.

Not applicable to service, which parallels, and connects to, customer's own generating facilities, except as such facilities are intended solely for emergency standby.

2. Monthly Rates through June 30, 2013

		High Season June - Sep.	Low Season Oct. - May
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.29	$ 0.29
3	Demand Charge [i] - per kW	$ 0.50	$ 0.40
4	Energy Charge [i] - per kWh	$ 0.00258	$ 0.00258
5	VEA - per kWh	See General Provisions	
6	CRPSEA - per kWh	See General Provisions	
7	VRPSEA - per kWh	See General Provisions	
8	IRCA - per kW	See General Provisions	

3. Monthly Rates beginning July 1, 2013

		High Season June - Sep.	Low Season Oct. - May
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.36	$ 0.36
3	Demand Charge [i] - per kW	$ 1.00	$ 0.80
4	Energy Charge [i] - per kWh	$ 0.00428	$ 0.00428
5	VEA - per kWh	See General Provisions	
6	CRPSEA - per kWh	See General Provisions	
7	VRPSEA - per kWh	See General Provisions	
8	IRCA - per kW	See General Provisions	

4. Billing

The bill shall be the sum of parts (1) through (8).

5. General Conditions

a. Demand Charge [i]

The Demand Charge [i] shall be based on the Maximum Demand recorded during the billing period.

b. Facilities Charge [i]

The Facilities Charge [i] shall be based on the highest demand recorded in the last 12 months but not less than 30 kW.

c. Selection of Rates

A customer may receive service under any of the General Service Rate Schedules, if desired, but will still be obliged to provide Schedule R-1 [i] Rate D and Rate E to eligible Sub-metered units.

d. Posting Rates

The owner shall post, in a conspicuous place, the prevailing residential electric rate schedule or schedules published by the Department, which would be applicable to the tenants if they were individually served by the Department.

e. Tenant Billing

The owner shall provide separate written electricity bills for each tenant, including the opening and closing meter readings for each billing period, the date the meters were read, the total electricity metered for the billing period, and the amount of the bill.

C. SCHEDULE A-1 [i]
SMALL GENERAL SERVICE

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to General Service below 30 kW demand, the highest demand recorded in the last twelve months, including lighting and power, charging of batteries of commercial electric vehicles, which may be delivered through the same service in compliance with the Department's Rules, and to single-family residential service with an on-site transformer dedicated solely to that individual customer. Not applicable to service which parallels, and connects to, customer's own generating facilities, except as such facilities are intended solely for emergency standby.

2. Monthly Rates through June 30, 2013

		High Season June - Sep.	Low Season Oct. - May
a.	**Rate A**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.29	$ 0.29
3	Energy Charge [i] - per kWh	$ 0.00358	$ 0.00358
4	VEA - per kWh	See General Provisions	
5	CRPSEA - per kWh	See General Provisions	
6	VRPSEA - per kWh	See General Provisions	
7	IRCA - per kW	See General Provisions	
b.	**Rate B - Time-of-Use**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.29	$ 0.29
3	Energy Charge [i] - per kWh		
	High Peak Period	$ 0.00394	$ 0.00394
	Low Peak Period	$ 0.00394	$ 0.00394
	Base Period	$ 0.00394	$ 0.00394
4	VEA - per kWh	See General Provisions	
5	CRPSEA - per kWh	See General Provisions	
6	VRPSEA - per kWh	See General Provisions	
7	IRCA - per kW	See General Provisions	

3. **Monthly Rates beginning July 1, 2013**

	High Season June - Sep.	Low Season Oct. - May
a. Rate A		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - per kW	$ 0.36	$ 0.36
3 Energy Charge [i] - per kWh	$ 0.00661	$ 0.00661
4 VEA - per kWh	See General Provisions	
5 CRPSEA - per kWh	See General Provisions	
6 VRPSEA - per kWh	See General Provisions	
7 IRCA - per kW	See General Provisions	
b. Rate B - Time-of-Use		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - per kW	$ 0.36	$ 0.36
3 Energy Charge [i] - per kWh		
High Peak Period	$ 0.00704	$ 0.00704
Low Peak Period	$ 0.00704	$ 0.00704
Base Period	$ 0.00704	$ 0.00704
4 VEA - per kWh	See General Provisions	
5 CRPSEA - per kWh	See General Provisions	
6 VRPSEA - per kWh	See General Provisions	
7 IRCA - per kW	See General Provisions	

4. **Billing**

The bill under:

- Rate A shall be the sum of parts (1) through (7).
- Rate B shall be the sum of parts (1) through (7).

5. **General Conditions**

a. **Facilities Charge [i]**

The Facilities Charge [i] shall be based on the highest demand recorded in the last 12 months, but not less than 4 kW.

b. **Selection of Rates**

(1) The Department requires mandatory service under Rate B for single-family residential service with an on-site transformer dedicated solely to that individual customer.

(2) If a customer is not a single-family residential service with an on-site transformer dedicated solely to that individual customer in accordance with conditions as set forth in 5.b.(1) above, a customer may choose to receive service either under Rate A or B, but the selection must correspond to the rate or rates under which service is received pursuant to any other effective ordinance. Also, when a customer served under Rate B requests a change to Rate A, that customer may not revert to Rate B before 12 months have elapsed.

(3) The customer shall be placed on Schedule A-2 [i] or A-3 [i] whose Maximum Demand either:

- Reaches or exceeds 30 kW in any three billing months or two bimonthly billing periods during the preceding 12 month period.
- Reaches or exceeds 30 kW during two High Season billing months or one High Season bimonthly billing period within a calendar year.

D. SCHEDULE A-2 [i]
PRIMARY SERVICE

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to General Service delivered from the Department's 4.8 kV system and 30 kW demand or greater, the highest demand recorded in the last twelve months, including lighting and power, charging of batteries of commercial electric vehicles, which may be delivered through the same service in compliance with the Department's Rules, and to single-family residential service with an on-site transformer dedicated solely to that individual customer. Not applicable to service which parallels, and connects to, the customer's own generating facilities, except as such facilities are intended solely for emergency standby.

2. Monthly Rates through June 30, 2013

	High Season June - Sep.	Low Season Oct. - May
a. Rate B - Time-of-Use		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - per kW	$ 0.29	$ 0.29
3 Demand Charge [i] - per kW		
High Peak Period	$ 0.50	$ 0.25
Low Peak Period	$ 0.25	$ -
Base Period	$ -	$ -
4 Energy Charge [i] - per kWh		
High Peak Period	$ 0.00258	$ 0.00258
Low Peak Period	$ 0.00258	$ 0.00258
Base Period	$ 0.00258	$ 0.00258
5 VEA - per kWh	See General Provisions	
6 CRPSEA - per kWh	See General Provisions	
7 VRPSEA - per kWh	See General Provisions	
8 IRCA - per kW	See General Provisions	
9 Reactive Energy Charge [i] (Applied if demand as determined for the Facilities Charge is greater than 250 kW)		
a. Unmetered - per kWh		
High Peak Period	$ 0.00001	$ 0.00001
Low Peak Period	$ 0.00001	$ 0.00001
Base Period	$ 0.00001	$ 0.00001

b. Metered - per kVArh per Power Factor level below:

	High Season (June - Sep.)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$0.00004	$0.00003	$0.00002
0.900-0.949	$0.00008	$0.00005	$0.00003
0.800-0.899	$0.00025	$0.00016	$0.00007
0.700-0.799	$0.00041	$0.00028	$0.00012
0.600-0.699	$0.00057	$0.00038	$0.00017
0.000-0.599	$0.00062	$0.00041	$0.00018

	Low Season (Oct. - May)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$0.00004	$0.00004	$0.00002
0.900-0.949	$0.00007	$0.00007	$0.00003
0.800-0.899	$0.00021	$0.00021	$0.00009
0.700-0.799	$0.00036	$0.00036	$0.00015
0.600-0.699	$0.00049	$0.00049	$0.00020
0.000-0.599	$0.00054	$0.00054	$0.00022

3. Monthly Rates beginning July 1, 2013

	High Season June - Sep.	Low Season Oct. - May
a. Rate B - Time-of-Use		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - per kW	$ 0.36	$ 0.36
3 Demand Charge [i] - per kW		
High Peak Period	$ 1.00	$ 0.50
Low Peak Period	$ 0.50	$ -
Base Period	$ -	$ -
4 Energy Charge [i] - per kWh		
High Peak Period	$ 0.00428	$ 0.00428
Low Peak Period	$ 0.00428	$ 0.00428
Base Period	$ 0.00428	$ 0.00428
5 VEA - per kWh	See General Provisions	
6 CRPSEA - per kWh	See General Provisions	
7 VRPSEA - per kWh	See General Provisions	
8 IRCA - per kW	See General Provisions	

9 Reactive Energy Charge [i]
(Applied if demand as determined for the Facilities Charge is greater than 250 kW)

a. Unmetered - per kWh

High Peak Period	$ 0.00003	$ 0.00003
Low Peak Period	$ 0.00002	$ 0.00003
Base Period	$ 0.00001	$ 0.00002

b. Metered - per kVArh per Power Factor level below:

	High Season (June - Sep.)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$0.00010	$0.00007	$0.00004
0.900-0.949	$0.00019	$0.00013	$0.00006
0.800-0.899	$0.00057	$0.00038	$0.00017
0.700-0.799	$0.00095	$0.00064	$0.00028
0.600-0.699	$0.00132	$0.00088	$0.00039
0.000-0.599	$0.00144	$0.00096	$0.00043

	Low Season (Oct. - May)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$0.00008	$0.00008	$0.00005
0.900-0.949	$0.00016	$0.00016	$0.00008
0.800-0.899	$0.00049	$0.00049	$0.00020
0.700-0.799	$0.00082	$0.00082	$0.00034
0.600-0.699	$0.00114	$0.00114	$0.00047
0.000-0.599	$0.00124	$0.00124	$0.00051

4. Billing

The bill under Rate B shall be the sum of parts (1) through (9).

5. General Conditions

a. Demand Charge [i]

The Demand Charge [i] under Schedule A-2 [i] Rate B shall be based on the Maximum Demands recorded within the applicable Rating Periods during the billing month.

b. Facilities Charge [i]

The Facilities Charge [i] shall be based on the highest demand recorded in the last 12 months, but not less than 30 kW.

c. Selection of Rates

Customers shall be placed on the applicable rate under Schedule A-1 [i] if demand, as determined for the Facilities Charge [i], drops below 30 kW.

d. Reactive Energy Charge [i]

Reference Schedule A-3 [i].5.a.

E. SCHEDULE A-3 [i]
SUBTRANSMISSION SERVICE

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to General Service delivered from the Department's 34.5 kV system and 30 kW demand or greater, the highest demand recorded in the last 12 months, including lighting and power which may be delivered through the same service in compliance with the Department's Rules. Not applicable to service which parallels, and connects to, the customer's own generating facilities, except as such facilities are intended solely for emergency standby.

2. Monthly Rates through June 30, 2013

a. Rate A - Subtransmission Service

	High Season June - Sep.	Low Season Oct. - May
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - kW	$ 0.39	$ 0.39
3 Demand Charge [i] - per kW		
High Peak Period	$ 0.35	$ 0.15
Low Peak Period	$ 0.15	$ -
Base Period	$ -	$ -
4 Energy Charge [i] - per kWh		
High Peak Period	$ 0.00254	$ 0.00254
Low Peak Period	$ 0.00254	$ 0.00254
Base Period	$ 0.00254	$ 0.00254
5 VEA - per kWh	See General Provisions	
6 CRPSEA - per kWh	See General Provisions	
7 VRPSEA - per kWh	See General Provisions	
8 IRCA - per kW	See General Provisions	
9 Reactive Energy Charge [i] (Applied if demand as determined for the Facilities Charge is greater than 250 kW)		

a. Unmetered - per kWh	High Season June - Sep.	Low Season Oct. - May
High Peak Period	$ 0.00001	$ 0.00001
Low Peak Period	$ 0.00001	$ 0.00001
Base Period	$ 0.00001	$ 0.00001

b. Metered - per kVArh per Power Factor level below

	High Season (June - Sep.)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$ 0.00004	$ 0.00003	$ 0.00002
0.900-0.949	$ 0.00008	$ 0.00005	$ 0.00003
0.800-0.899	$ 0.00024	$ 0.00016	$ 0.00007
0.700-0.799	$ 0.00040	$ 0.00027	$ 0.00012
0.600-0.699	$ 0.00056	$ 0.00038	$ 0.00017
0.000-0.599	$ 0.00061	$ 0.00041	$ 0.00019

	Low Season (Oct. - May)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$ 0.00004	$ 0.00004	$ 0.00002
0.900-0.949	$ 0.00007	$ 0.00007	$ 0.00004
0.800-0.899	$ 0.00021	$ 0.00021	$ 0.00009
0.700-0.799	$ 0.00036	$ 0.00036	$ 0.00015
0.600-0.699	$ 0.00049	$ 0.00049	$ 0.00021
0.000-0.599	$ 0.00054	$ 0.00054	$ 0.00023

3. Monthly Rates beginning July 1, 2013

	High Season June - Sep.	Low Season Oct. - May
a. Rate A - Subtransmission Service		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - kW	$ 0.56	$ 0.56
3 Demand Charge [i] - per kW		
High Peak Period	$ 0.70	$ 0.30
Low Peak Period	$ 0.30	$ -
Base Period	$ -	$ -
4 Energy Charge [i] - per kWh		
High Peak Period	$ 0.00395	$ 0.00395
Low Peak Period	$ 0.00395	$ 0.00395
Base Period	$ 0.00395	$ 0.00395

5 VEA - per kWh — See General Provisions
6 CRPSEA - per kWh — See General Provisions
7 VRPSEA - per kWh — See General Provisions
8 IRCA - per kW — See General Provisions
9 Reactive Energy Charge [i]
(Applied if demand as determined for the Facilities Charge is greater than 250 kW)

a. Unmetered - per kWh	High Season June - Sep.	Low Season Oct. - May
High Peak Period	$ 0.00003	$ 0.00003
Low Peak Period	$ 0.00002	$ 0.00003
Base Period	$ 0.00001	$ 0.00002

b. Metered - per kVArh per Power Factor level below

	High Season (June - Sep.)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$ 0.00010	$ 0.00007	$ 0.00004
0.900-0.949	$ 0.00018	$ 0.00013	$ 0.00007
0.800-0.899	$ 0.00056	$ 0.00038	$ 0.00017
0.700-0.799	$ 0.00093	$ 0.00063	$ 0.00028
0.600-0.699	$ 0.00130	$ 0.00087	$ 0.00039
0.000-0.599	$ 0.00141	$ 0.00095	$ 0.00043

	Low Season (Oct. - May)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$ 0.00008	$ 0.00008	$ 0.00005
0.900-0.949	$ 0.00016	$ 0.00016	$ 0.00008
0.800-0.899	$ 0.00049	$ 0.00049	$ 0.00021
0.700-0.799	$ 0.00082	$ 0.00082	$ 0.00036
0.600-0.699	$ 0.00114	$ 0.00114	$ 0.00049
0.000-0.599	$ 0.00124	$ 0.00124	$ 0.00054

4. Billing

The bill under Rate A shall be the sum of parts (1) through (9).

5. General Conditions

a. Reactive Energy Charge [i]

The Reactive Energy Charge [i] shall be based on the lagging kilovar-hours (kVArh) recorded during each Rating Period, dependent upon the High Peak Period Power Factor. If reactive energy is unknown or unmetered, then the Reactive Energy Charge [i] shall be replaced by additional kilowatt-hour charges.

b. Maximum Demand

The Maximum Demand is the average kilowatt load to the nearest one-tenth kilowatt during the 15-minute period of greatest use during a billing period, as recorded by the Department's meter. Demand is another term for power and is expressed in units of kilowatt.

In cases where demand is intermittent or subject to severe fluctuations, the Department may establish the Maximum Demand on the basis of measurement over a shorter interval of time or the kilowatt-amperes of installed transformer capacity required to meet the customer's load.

c. Demand Charge [i]

The Demand Charge [i] under Rate A shall be based on the Maximum Demands recorded within the applicable Rating Periods during the billing month.

d. Facilities Charge [i]

The Facilities Charge [i] shall be based on the highest demand recorded in the last 12 months, but not less than 30 kW.

e. Selection of Rates

Customers shall be placed on the applicable rate under Schedule A-1 [i] if demand, as determined for the Facilities Charge [i], drops below 30 kW.

f. Metering

Metering of energy and demand shall normally be provided by the Department on the primary side of the transformer or, at the Department's option, on the secondary side of the transformer and compensated by instruments or loss calculations to the primary side of the transformer.

F. **SCHEDULE A-4 [i]**
TRANSMISSION SERVICE

1. **Applicability**

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to General Service delivered by the Department from 138 kV or above and 80 MW demand or greater, and as established by the Department to be economically advantageous and physically feasible. Notwithstanding the above, this schedule will be provided at the sole discretion of the Department and is limited to availability on the Department's system and will be available only if determined to be feasible following comprehensive transmission system studies. All equipment or structures on customer premises necessary for the utilization of service delivered by the Department from 138 kV or above shall be owned and maintained by the customer. However, some equipment may be installed by the Department on the customer's premises. All conduit and conductors required from the nearest 138 kV source or above to the Service Point will be installed by the Department and the cost paid by the customer.

2. **Monthly Rates through June 30, 2013**

		High Season June - Sep.	Low Season Oct. - May
a.	**Rate A - Transmission Service**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.20	$ 0.20
3	Demand Charge [i] - per kW		
	High Peak Period	$ 0.35	$ 0.15
	Low Peak Period	$ 0.15	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh		
	High Peak Period	$ 0.00251	$0.00251
	Low Peak Period	$ 0.00251	$0.00251
	Base Period	$ 0.00251	$0.00251
5	VEA - per kWh	See General Provisions	
6	CRPSEA - per kWh	See General Provisions	
7	VRPSEA - per kWh	See General Provisions	
8	IRCA - per kW	See General Provisions	
9	Reactive Energy Charge [i]		

a. Unmetered - per kWh	High Season June - Sep.	Low Season Oct. - May
High Peak Period	$0.00001	$0.00001
Low Peak Period	$0.00001	$0.00001
Base Period	$0.00001	$0.00001

b. Metered - per kVArh per Power Factor level below:

	High Season (June - Sep.)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$0.00004	$0.00003	$0.00002
0.900-0.949	$0.00008	$0.00005	$0.00003
0.800-0.899	$0.00024	$0.00016	$0.00007
0.700-0.799	$0.00040	$0.00027	$0.00012
0.600-0.699	$0.00055	$0.00037	$0.00017
0.000-0.599	$0.00060	$0.00041	$0.00018

	Low Season (Oct. - May)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$ 0.00004	$ 0.00004	$ 0.00002
0.900-0.949	$ 0.00007	$ 0.00007	$ 0.00003
0.800-0.899	$ 0.00021	$ 0.00021	$ 0.00009
0.700-0.799	$ 0.00035	$ 0.00035	$ 0.00015
0.600-0.699	$ 0.00049	$ 0.00049	$ 0.00021
0.000-0.599	$ 0.00053	$ 0.00053	$ 0.00023

3. Monthly Rates beginning July 1, 2013

	High Season June - Sep.	Low Season Oct. - May
a. Rate A - Transmission Service		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - per kW	$ 0.28	$ 0.28
3 Demand Charge [i] - per kW		
High Peak Period	$ 0.69	$ 0.30
Low Peak Period	$ 0.30	$ -
Base Period	$ -	$ -
4 Energy Charge [i] - per kWh		
High Peak Period	$ 0.00391	$0.00391
Low Peak Period	$ 0.00391	$0.00391
Base Period	$ 0.00391	$0.00391

5 VEA - per kWh — See General Provisions
6 CRPSEA - per kWh — See General Provisions
7 VRPSEA - per kWh — See General Provisions
8 IRCA - per kW — See General Provisions
9 Reactive Energy Charge [i]

a. Unmetered - per kWh	High Season June - Sep.	Low Season Oct. - May
High Peak Period	$0.00003	$0.00003
Low Peak Period	$0.00002	$0.00003
Base Period	$0.00001	$0.00002

b. Metered - per kVArh per Power Factor level below:

	High Season (June - Sep.)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$0.00009	$0.00006	$0.00004
0.900-0.949	$0.00018	$0.00012	$0.00006
0.800-0.899	$0.00055	$0.00037	$0.00017
0.700-0.799	$0.00092	$0.00063	$0.00028
0.600-0.699	$0.00128	$0.00086	$0.00039
0.000-0.599	$0.00140	$0.00094	$0.00042

	Low Season (Oct. - May)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$ 0.00008	$ 0.00008	$ 0.00005
0.900-0.949	$ 0.00016	$ 0.00016	$ 0.00008
0.800-0.899	$ 0.00048	$ 0.00048	$ 0.00021
0.700-0.799	$ 0.00081	$ 0.00081	$ 0.00035
0.600-0.699	$ 0.00113	$ 0.00113	$ 0.00048
0.000-0.599	$ 0.00123	$ 0.00123	$ 0.00053

4. Billing

The bill under Rate A shall be the sum of parts (1) through (9).

5. General Conditions

a. Reactive Energy Charge [i]

The Reactive Energy Charge [i] shall be based on the lagging kilovar-hours (kVArh) recorded during each Rating Period, dependent upon the High Peak Period Power Factor.

b. Maximum Demand

The Maximum Demand is the average kilowatt load to the nearest one-tenth kilowatt during the 15-minute period of greatest use during a billing period, as recorded by the Department's meter. Demand is another term for power and is expressed in units of kilowatt.

In cases where demand is intermittent or subject to severe fluctuations, the Department may establish the Maximum Demand on the basis of measurement over a shorter interval of time or the kilowatt-amperes of installed transformer capacity required to meet the customer's load.

c. Demand Charge [i]

The Demand Charge [i] shall be based on the Maximum Demands recorded within the applicable Rating Periods during the billing month.

d. Facilities Charge [i]

The Facilities Charge [i] shall be based on the highest demand recorded in the last 12 months, but not less than 10 MW.

e. System Studies

All costs of system studies and analysis performed by the Department or outside parties will be paid by the customer to Department prior to the start of the requested work. This payment is non-refundable and will be charged on an actual cost basis.

f. Selection of Rates

Customers shall maintain a minimum 10 MW demand to remain on this Rate. If the customer's monthly Maximum Demand drops below 10 MW for six consecutive billing periods, the Department requires mandatory service under Schedule A-3 [i]. The customer shall be responsible to pay all costs associated with the transfer and modifications of the service for billing under Schedule A-3 [i].

g. Metering

Metering of energy and demand shall normally be provided by the Department on the primary side of the transformer or, at the Department's option, on the secondary side of the transformer and compensated by instruments or loss calculations to the primary side of the transformer.

G. SCHEDULE AMP [i]
PORT OF LOS ANGELES ALTERNATIVE MARITIME POWER

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to services with energy usage resulting from Merchant Ships participating in the Port of Los Angeles (POLA) Alternative Maritime Power (AMP). Seventy-five percent of energy consumed by services on this schedule must be from Merchant Ships. POLA shall be responsible for the installation and maintenance of facilities up to the high-side of the 34.5 kV Station which is serving the Merchant Ship loads. Not applicable to customers served under Service Rider Net Energy Metering and General Service Rider Enterprise Zone of the Electric Rate Ordinance.

The Department may remotely interrupt any AMP load under this service with thirty minutes' advance notice to POLA. The Department shall determine the interruption duration. POLA shall be responsible for purchasing and installing all equipment required for remote interruption.

2. Monthly Rates through June 30, 2013

a. Rate A - AMP Interruptible Rate

1	Service Charge [i]	$ -
2	Facilities Charge [i] - per kW	$ 0.08
3	Energy Charge [i] - per kWh	$ 0.00898
4	VEA - per kWh	See General Provisions
5	CRPSEA - per kWh	See General Provisions
6	VRPSEA - per kWh	See General Provisions
7	IRCA - per kWh	See General Provisions
8	Reactive Energy Charge [i]	

a. Unmetered - per kWh

High Peak Period	$ 0.00001
Low Peak Period	$ 0.00001
Base Period	$ 0.00001

b. Metered - per kVArh per Power Factor level below

Power Factor Range	
0.995-1.000	$ -
0.950-0.994	$ 0.00002
0.900-0.949	$ 0.00003

0.800-0.899	$	0.00009
0.700-0.799	$	0.00015
0.600-0.699	$	0.00020
0.000-0.599	$	0.00022

3. Monthly Rates beginning July 1, 2013

a. Rate A – AMP Interruptible Rate

1	Service Charge [i]	$ -
2	Facilities Charge [i] - per kW	$ 0.10
3	Energy Charge [i] - per kWh	$ 0.01563
4	VEA - per kWh	See General Provisions
5	CRPSEA - per kWh	See General Provisions
6	VRPSEA - per kWh	See General Provisions
7	IRCA - per kWh	See General Provisions
8	Reactive Energy Charge [i]	

a. Unmetered - per kWh

High Peak Period	$ 0.00003
Low Peak Period	$ 0.00002
Base Period	$ 0.00001

b. Metered - per kVArh per Power Factor level below

Power Factor Range		
0.995-1.000	$	-
0.950-0.994	$	0.00004
0.900-0.949	$	0.00007
0.800-0.899	$	0.00020
0.700-0.799	$	0.00034
0.600-0.699	$	0.00047
0.000-0.599	$	0.00051

4. Billing

The bill shall be the sum of parts (1) through (8).

5. General Conditions

a. Reactive Energy Charge [i]

The Reactive Energy Charge [i] shall be based on the lagging kilovar-hours (kVArh) recorded during each Rating Period, dependent upon the High Peak Period Power Factor. If reactive energy is unknown or unmetered, then the Reactive Energy Charge shall be replaced by additional kilowatt-hour charges.

b. Facilities Charge [i]

The Facilities Charge [i] shall be based on the highest demand recorded in the last 12 months, whichever is greater, but not less than 500 kW.

c. **Interruptible Service Conditions**

To receive service under this Rate, POLA shall sign a contract with the Department, unless the provisions of an existing contract already executed with the Department incorporate the charges and conditions of this rate schedule.

The Interruptible Demand, not less than 500 kW, is that portion of the demand which the Department will supply to POLA at all times except during a Period of Interruption. During a Period of Interruption, the Department will supply POLA not more than the Firm Demand.

The Department shall provide not less than 30-minutes' advance notice of a Period of Interruption. A Period of Interruption is that interval of time, initiated and terminated by the Department, during which the Department is obligated to supply no more than the Firm Demand. A Period of Interruption will occur when operating reserves, in the Department's sole judgment, are inadequate to maintain system energy supply. Load interruption shall be initiated remotely by Department Load Dispatchers. Firm Demand, which may be specified at different values for High Season and Low Season, is that portion of demand which the Department will supply to POLA without limitation on the periods of availability.

d. **Interruption Frequency and Duration**

Periods of Interruption are unlimited and interruption duration shall be at the sole discretion of the Department.

e. **Substation Equipment on Customer's Site**

All equipment or structures necessary for Department to serve customer from the 34.5 kV Subtransmission Service Voltage shall be located on the customer's site and shall be owned and maintained by POLA.

f. **Metering**

Metering of energy and demand shall be from the 34.5 kV Subtransmission Service Voltage by meters provided by the Department on the primary side of the transformer or, at the Department's option, on the secondary side of the transformer and compensated by instruments or loss calculations to the primary side of the transformer.

All non-AMP load will be metered separately from the normal AMP service. POLA will provide metering facilities for non-AMP load, and the Department will provide the TDK (non-billing) meters for the non-AMP load to ensure more than seventy-five percent of energy consumption is from Merchant Ships.

H. SCHEDULE XRT-2 [i]
EXPERIMENTAL REAL-TIME PRICING SERVICE, PRIMARY SERVICE (4.8 KV)

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to service with 250 kW demand or greater and served from the Department's 4.8 kV system, which may be delivered through the same service in compliance with the Department's Rules. Not applicable to service under Schedule CG-2 [i].

This service is experimental and the Department reserves the right to limit the number of customers receiving service hereunder.

2. Monthly Rates through June 30, 2013

		High Season June - Sep.	Low Season Oct. - May
a.	**Rate A - Voluntary Curtailment Service - Primary (4.8 kV)**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.29	$ 0.29
3	Demand Charge [i] - per kW		
	High Peak Period	$ 0.25	$ 0.25
	Low Peak Period	$ 0.25	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh		
	High Peak Period	$ 0.00258	$ 0.00258
	Low Peak Period	$ 0.00258	$ 0.00258
	Base Period	$ 0.00258	$ 0.00258
5	Alert Period Energy Charge [i] - per kWh		
	High Peak Period	$ 0.14467	$ 0.00258
	Low Peak Period	$ 0.05101	$ 0.00258
	Base Period	$ 0.00258	$ 0.00258
6	VEA - per kWh	See General Provisions	
7	CRPSEA - per kWh	See General Provisions	
8	VRPSEA - per kWh	See General Provisions	
9	IRCA - per kW	See General Provisions	
10	Reactive Energy Charge [i]	See Schedule A-2 [i]	

3. Monthly Rates beginning July 1, 2013

		High Season June - Sep.	Low Season Oct. - May
a.	**Rate A - Voluntary Curtailment Service - Primary (4.8 kV)**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.36	$ 0.36
3	Demand Charge [i] - per kW		
	High Peak Period	$ 0.50	$ 0.50
	Low Peak Period	$ 0.50	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh		
	High Peak Period	$ 0.00428	$ 0.00428
	Low Peak Period	$ 0.00428	$ 0.00428
	Base Period	$ 0.00428	$ 0.00428
5	Alert Period Energy Charge [i] - per kWh		
	High Peak Period	$ 0.33407	$ 0.00428
	Low Peak Period	$ 0.11780	$ 0.00428
	Base Period	$ 0.00428	$ 0.00428
6	VEA - per kWh	See General Provisions	
7	CRPSEA - per kWh	See General Provisions	
8	VRPSEA - per kWh	See General Provisions	
9	IRCA - per kW	See General Provisions	
10	Reactive Energy Charge [i]	See Schedule A-2 [i]	

4. Billing

The bill shall be the sum of parts (1) through (10).

5. General Conditions

a. Load Reduction

Whenever the Department, in its sole judgment, requires customer to reduce load, it shall issue an Alert Period Notification. This may include, but not be limited to, high system peaks, low generation, high market prices, temperature, and system contingencies. The Department may request customers to reduce demand for any service under this Schedule through issuance of an Alert Period with not less than 2-hours' advance notification. Customers who do not reduce demand or curtail load during each of two consecutive Alert Periods will be removed from this rate schedule, placed on the applicable General Service rate, and not be eligible for service under the Schedule XRT-2 [i] for five calendar years.

b. Demand Charge [i]

The Demand Charge [i] shall be based on the Maximum Demands recorded within the applicable Rating Periods.

c. Facilities Charge [i]

The Facilities Charge [i] shall be based on the highest demand recorded in the last 12 months.

d. Alert Period Notification

To receive service under this Schedule XRT-2 [i], all customers, at their own expense, must have access to e-mail to receive Alert Period Notifications. The Department will send one notification per Alert Period to customer's:

- Primary e-mail address
- Secondary e-mail address or a wireless device that is capable of receiving a text message

Customer contact information shall be provided to the Department prior to establishing any service under this rate schedule. If a change in customer's e-mail address or text message address occurs, the customer is required to provide written notice to the Rates and Contracts Group in the form of a letter or e-mail. Receipt of Alert Period Notification is the responsibility of the participating customer. The Department does not guarantee the reliability of the text system or e-mail system by which the customer receives notification. Customer will be responsible for all charges incurred during an Alert Period even if actual notice is not received.

e. Alert Period

Each Alert Period shall be a minimum duration of 4 hours, however not to exceed a maximum of 10 hours. Alert Period(s) are limited to six occurrences within any calendar year. Notification will be provided through Alert Period message including the date, start and end time.

f. Contracts

To receive service under this rate schedule, a customer shall sign a contract with the Department unless the provisions of an existing contract already executed with the Department incorporate the charges and conditions of this rate schedule.

I. SCHEDULE XRT-3 [i]
EXPERIMENTAL REAL-TIME PRICING SERVICE, SUBTRANSMISSION SERVICE (34.5 KV)

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to service with 250 kW demand or greater and served from the Department's 34.5 kV system, which may be delivered through the same service in compliance with the Department's Rules. Not applicable to service under Schedule CG-3 [i].

This service is experimental and the Department reserves the right to limit the number of customers receiving service hereunder.

2. Monthly Rates through June 30, 2013

		High Season June - Sep.	Low Season Oct. - May
a.	**Rate A - Voluntary Curtailment Service - Sub Transmission (34.5 kV)**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - kW	$ 0.39	$ 0.39
3	Demand Charge [i] - per kW		
	High Peak Period	$ 0.19	$ 0.15
	Low Peak Period	$ 0.15	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh		
	High Peak Period	$ 0.00254	$ 0.00254
	Low Peak Period	$ 0.00254	$ 0.00254
	Base Period	$ 0.00254	$ 0.00254
5	Alert Period Energy Charge [i] - per kWh		
	High Peak Period	$ 0.13674	$ 0.00254
	Low Peak Period	$ 0.05791	$ 0.00254
	Base Period	$ 0.00254	$ 0.00254
6	VEA - per kWh	See General Provisions	
7	CRPSEA - per kWh	See General Provisions	
8	VRPSEA - per kWh	See General Provisions	
9	IRCA - per kW	See General Provisions	
10	Reactive Energy Charge [i]	See Schedule A-3 [i]	

3. Monthly Rates beginning July 1, 2013

	High Season June - Sep.	Low Season Oct. - May
a. Rate A - Voluntary Curtailment Service - Sub Transmission (34.5 kV)		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - kW	$ 0.56	$ 0.56
3 Demand Charge [i] - per kW		
High Peak Period	$ 0.39	$ 0.30
Low Peak Period	$ 0.30	$ -
Base Period	$ -	$ -
4 Energy Charge [i] - per kWh		
High Peak Period	$ 0.00395	$ 0.00395
Low Peak Period	$ 0.00395	$ 0.00395
Base Period	$ 0.00395	$ 0.00395
5 Alert Period Energy Charge [i] - per kWh		
High Peak Period	$ 0.31576	$ 0.00395
Low Peak Period	$ 0.13372	$ 0.00395
Base Period	$ 0.00395	$ 0.00395
6 VEA - per kWh	See General Provisions	
7 CRPSEA - per kWh	See General Provisions	
8 VRPSEA - per kWh	See General Provisions	
9 IRCA - per kW	See General Provisions	
10 Reactive Energy Charge [i]	See Schedule A-3 [i]	

4. Billing

The bill shall be the sum of parts (1) through (10).

5. General Conditions

a. Load Reduction

Whenever the Department, in its sole judgment, requires customer to reduce load, it shall issue an Alert Period Notification. This may include, but not be limited to, high system peaks, low generation, high market prices, temperature, and system contingencies. The Department may request customers to reduce demand for any service under this Schedule through issuance of an Alert Period with not less than 2-hours' advance notification. Customers who do not reduce demand or curtail load during each of two consecutive Alert Periods will be removed from this rate schedule, placed on the applicable General Service rate, and not be eligible for service under the Schedule XRT-3 [i] for five calendar years.

b. Demand Charge [i]

The Demand Charge [i] shall be based on the Maximum Demands recorded within the applicable Rating Periods.

c. Facilities Charge [i]

The Facilities Charge [i] shall be based on the highest demand recorded in the last 12 months.

d. Alert Period Notification

To receive service under this Schedule XRT-3 [i], all customers, at their own expense, must have access to e-mail to receive Alert Period Notifications. The Department will send one notification per Alert Period to customer's:

- Primary e-mail address
- Secondary e-mail address or a wireless device that is capable of receiving a text message

Customer contact information shall be provided to the Department prior to establishing any service under this rate schedule. If a change in customer's e-mail address or text message address occurs, the customer is required to provide written notice to the Rates and Contracts Group in the form of a letter or e-mail. Receipt of Alert Period Notification is the responsibility of the participating customer. The Department does not guarantee the reliability of the text system or e-mail system by which the customer receives notification. Customer will be responsible for all charges incurred during an Alert Period even if actual notice is not received.

e. Alert Period

Each Alert Period shall be a minimum duration of 4 hours, however not to exceed a maximum of 10 hours. Alert Period(s) are limited to six occurrences within any calendar year. Notification will be provided through Alert Period message including the date, start and end time.

f. Contracts

To receive service under this rate schedule, a customer shall sign a contract with the Department unless the provisions of an existing contract already executed with the Department incorporate the charges and conditions of this rate schedule.

J. **SCHEDULE XCD-2 [i]**
EXPERIMENTAL CONTRACT DEMAND SERVICE, PRIMARY SERVICE (4.8 KV)

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to General Service which may be delivered through the same service in compliance with the Department's Rules. Applicable to service with an average consumption exceeding 500,000 kilowatt-hours per month and served from the Department's 4.8 kV system. Not applicable to service under Schedule CG-2 [i].

This service is experimental and the Department reserves the right to limit the number of customers receiving service hereunder.

2. Monthly Rates through June 30, 2013

	High Season June - Sep.	Low Season Oct. - May
a. Rate A - Primary Service (4.8 kV)		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - per kW	$ 0.29	$ 0.29
3 Demand Charge [i] - per kW	varies, see 5.b.	
4 Energy Charge [i] - per kWh		
High Peak Period	$ 0.00258	$ 0.00258
Low Peak Period	$ 0.00258	$ 0.00258
Base Period	$ 0.00258	$ 0.00258
5 VEA - per kWh	See General Provisions	
6 CRPSEA - per kWh	See General Provisions	
7 VRPSEA - per kWh	See General Provisions	
8 IRCA - per kW	See General Provisions	
9 Reactive Energy Charge [i]	See Schedule A-2 [i]	

3. Monthly Rates beginning July 1, 2013

	High Season June - Sep.	Low Season Oct. - May
a. Rate A - Primary Service (4.8 kV)		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - per kW	$ 0.36	$ 0.36
3 Demand Charge [i] - per kW	varies, see 5.b.	
4 Energy Charge [i] - per kWh		
High Peak Period	$ 0.00428	$ 0.00428
Low Peak Period	$ 0.00428	$ 0.00428

	Base Period	$ 0.00428	$ 0.00428
5	VEA - per kWh	See General Provisions	
6	CRPSEA - per kWh	See General Provisions	
7	VRPSEA - per kWh	See General Provisions	
8	IRCA - per kW	See General Provisions	
9	Reactive Energy Charge [i]	See Schedule A-2 [i]	

4. Billing

Billing under Rate A is applicable to loads which would normally be served under General Service Schedule A-2 [i] and shall be the sum of parts (1) through (9).

5. General Conditions

a. **Reactive Energy Charge [i]**

The Reactive Energy Charge [i] shall be based on the lagging kilovar-hours (kVArh) recorded during each Rating Period, dependent upon the High Peak Period Power Factor. If reactive energy is unknown or unmetered, then the Reactive Energy Charge [i] shall be replaced by additional kilowatt-hour charges.

b. **Demand Charge [i]**

The Demand Charge [i] shall be based on the Maximum Demands recorded within the applicable Rating Periods as shown in table below, however, unit prices may vary by terms of the contract, but shall not be less than marginal demand costs for the specified contract period.

Schedule Experimental Contract Demand
Load Factor Matrix

Rate A - Primary Service 4.8 kV

Load Factor	Bill Discount	Demand Discount*
90%	10%	28.17%
85%	8%	21.91%
80%	6%	15.96%
75%	4%	10.33%
70%	2%	5.01%

*Demand Discount as a percent of Demand Charge [i] set forth in Schedule A-2 [i].2.a. and Schedule A-2 [i].3.a. for the referenced Load Factor.

c. **Facilities Charge [i]**

The Facilities Charge [i] shall be based on the highest demand recorded in the last 12 months.

d. Contract

To receive service under this rate schedule, a customer shall sign a contract unless the provisions of an existing contract already executed with the Department incorporated the charges and conditions of this rate schedule. The contract shall be for a specified term of at least two years and not exceeding five years.

K. SCHEDULE XCD-3 [i]
EXPERIMENTAL CONTRACT DEMAND SERVICE, SUBTRANSMISSION SERVICE (34.5 KV)

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to General Service which may be delivered through the same service in compliance with the Department's Rules. Applicable to service with an average consumption exceeding 500,000 kilowatt-hours per month and served from the Department's 34.5 kV system. Not applicable to service under Schedule CG-3 [i].

This service is experimental and the Department reserves the right to limit the number of customers receiving service hereunder.

2. Monthly Rates through June 30, 2013

		High Season June - Sep.	Low Season Oct. - May
a.	**Rate A - Subtransmission Service (34.5 kV)**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.39	$ 0.39
3	Demand Charge [i] - per kW	varies, see 5.b.	
4	Energy Charge [i] - per kWh		
	High Peak Period	$ 0.00254	$ 0.00254
	Low Peak Period	$ 0.00254	$ 0.00254
	Base Period	$ 0.00254	$ 0.00254
5	VEA - per kWh	See General Provisions	
6	CRPSEA - per kWh	See General Provisions	
7	VRPSEA - per kWh	See General Provisions	
8	IRCA - per kW	See General Provisions	
9	Reactive Energy Charge [i]	See Schedule A-3 [i]	

3. Monthly Rates beginning July 1, 2013

		High Season June - Sep.	Low Season Oct. - May
a.	**Rate A - Subtransmission Service (34.5 kV)**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.56	$ 0.56
3	Demand Charge [i] - per kW	varies, see 5.b.	

4	Energy Charge [i] - per kWh		
	High Peak Period	$ 0.00395	$ 0.00395
	Low Peak Period	$ 0.00395	$ 0.00395
	Base Period	$ 0.00395	$ 0.00395
5	VEA - per kWh	See General Provisions	
6	CRPSEA - per kWh	See General Provisions	
7	VRPSEA - per kWh	See General Provisions	
8	IRCA - per kW	See General Provisions	
9	Reactive Energy Charge [i]	See Schedule A-3 [i]	

4. Billing

Billing under Rate A is applicable to loads which would normally be served under General Service Schedule A-3 [i] and shall be the sum of parts (1) through (9).

5. General Conditions

a. Reactive Energy Charge [i]

The Reactive Energy Charge [i] shall be based on the lagging kilovar-hours (kVArh) recorded during each Rating Period, dependent upon the High Peak Period Power Factor. If reactive energy is unknown or unmetered, then the Reactive Energy Charge [i] shall be replaced by additional kilowatt-hour charges.

b. Demand Charge [i]

The Demand Charge [i] shall be based on the Maximum Demands recorded within the applicable Rating Periods as shown in table below, however, unit prices may vary by terms of the contract, but shall not be less than marginal demand costs for the specified contract period.

Schedule Experimental Contract Demand
Load Factor Matrix

Rate A - Subtransmission Service 34.5 kV

Load Factor	Bill Discount	Demand Discount*
90%	10%	26.85%
85%	8%	20.88%
80%	6%	15.21%
75%	4%	9.84%
70%	2%	4.77%

*Demand Discount as a percent of the Demand Charge [i] set forth in Schedule A-3 [i].2.a. and Schedule A-3 [i].3.a. for the referenced Load Factor.

c. **Facilities Charge [i]**

The Facilities Charge [i] shall be based on the highest demand recorded in the last 12 months.

d. **Contract**

To receive service under this rate schedule, a customer shall sign a contract unless the provisions of an existing contract already executed with the Department incorporated the charges and conditions of this rate schedule. The contract shall be for a specified term of at least two years and not exceeding five years.

L. SCHEDULE CG-2 [i]
CUSTOMER GENERATION, PRIMARY SERVICE (4.8 KV)

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable when both the following conditions exist:

- Any Electric Service provided by the Department where a customer-owned electrical generating facility is interconnected with the Department's system for Parallel Operation and in compliance with the Department's Rules.

- Loads that are served from the Primary Distribution System and which would normally be served under General Service Schedules A-1 [i] and A-2 [i].

Not applicable to:

- Any person or entity that is a utility or a "Public Utility" as defined by the Public Utilities Code, including Section 216.

- Customer-owned electrical generating facilities interconnected with the Department System for Momentary Interconnection.

a. Rate A

Applicable to customers who generate either to sell Excess Energy to the Department and/or to serve their own electricity requirements but have the Department provide Electric Service including supplemental and backup power.

b. Rate C

- This rate is available to Rate A customers and is designed to support new customer generation and encourage clean on-site generation.

- Rate C is available to customers whose total Rated Generation Capacity located at a customer facility is less than 25 percent of the Maximum Coincident Demand and less than 1 MW.

- To qualify for this rate, each customer on-site generation unit shall have been installed and/or converted on/after January 1, 2001 to emit no more than 0.5 pounds/MWH of nitrous oxides. Such emission limit must be maintained to continue to qualify. Verification as the Department determines shall be provided.

c. Rate D and Rate E

Rates D and E are optional rates for customers receiving service under the Schedule CG-2 [i]. Rate D is available to Rate A customers and Rate E is available to Rate C customers. These optional rates are for those customers who have demonstrated that they have the capability to reduce load during Department system conditions including, but not limited to, high system peaks, low generation, high market prices, temperature, and system contingencies.

2. Monthly Rates through June 30, 2013

		High Season June - Sep.	Low Season Oct. - May
a. Rate A			
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.29	$ 0.29
3	Supplemental Capacity Charge [i] - per kW of Supplemental Demand		
	High Peak Period	$ -	$ -
	Low Peak Period	$ -	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh of Department supplied energy		
	High Peak Period	$ 0.00258	$ 0.00258
	Low Peak Period	$ 0.00258	$ 0.00258
	Base Period	$ 0.00258	$ 0.00258
5	Backup Capacity Charge [i] - per kWh of Backup Energy		
	High Peak Period	$ 0.00676	$ -
	Low Peak Period	$ 0.00185	$ -
	Base Period	$ -	$ -
6	VEA - per kWh	See General Provisions	
7	CRPSEA - per kWh	See General Provisions	
8	VRPSEA - per kWh	See General Provisions	
9	IRCA - per kW	See General Provisions	
10	Reactive Energy Charge [i]	See Schedule A-2 [i]	

		High Season June - Sep.	Low Season Oct. - May
b. Rate C			
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.29	$ 0.29

3	Demand Charge [i] - per kW of Maximum Demand measured at Customer's Service Point		
	High Peak Period	$ 0.50	$ 0.25
	Low Peak Period	$ 0.25	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh of Department supplied energy		
	High Peak Period	$ 0.00258	$ 0.00258
	Low Peak Period	$ 0.00258	$ 0.00258
	Base Period	$ 0.00258	$ 0.00258
5	VEA - per kWh	See General Provisions	
6	CRPSEA - per kWh	See General Provisions	
7	VRPSEA - per kWh	See General Provisions	
8	IRCA - per kW	See General Provisions	
9	Reactive Energy Charge [i]	See Schedule A-2 [i]	

		High Season June - Sep.	Low Season Oct. - May
c.	**Rate D**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.29	$ 0.29
3	Supplemental Capacity Charge [i] - per kW of Supplemental Demand		
	High Peak Period	$ -	$ -
	Low Peak Period	$ -	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh		
	High Peak Period	$ 0.00258	$ 0.00258
	Low Peak Period	$ 0.00258	$ 0.00258
	Base Period	$ 0.00258	$ 0.00258
5	Backup Capacity Charge [i] - per kWh of Backup Energy		
	High Peak Period	$ 0.00676	$ -
	Low Peak Period	$ 0.00185	$ -
	Base Period	$ -	$ -
6	Alert Period Energy Charge [i] - per kWh		
	High Peak Period	$ 0.00708	$ 0.00258
	Low Peak Period	$ 0.00416	$ 0.00258
	Base Period	$ 0.00258	$ 0.00258
7	VEA - per kWh	See General Provisions	
8	CRPSEA - per kWh	See General Provisions	
9	VRPSEA - per kWh	See General Provisions	
10	IRCA - per kW	See General Provisions	
11	Reactive Energy Charge [i]	See Schedule A-2 [i]	

		High Season June - Sep.	Low Season Oct. - May
d.	**Rate E**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.29	$ 0.29
3	Demand Charge [i] - per kW of Maximum Demand measured at Customer's Service Point		
	High Peak Period	$ 0.25	$ 0.25
	Low Peak Period	$ 0.25	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh of Department supplied energy		
	High Peak Period	$ 0.00258	$ 0.00258
	Low Peak Period	$ 0.00258	$ 0.00258
	Base Period	$ 0.00258	$ 0.00258
5	Alert Period Energy Charge [i] - per kWh		
	High Peak Period	$ 0.14467	$ 0.00258
	Low Peak Period	$ 0.05101	$ 0.00258
	Base Period	$ 0.00258	$ 0.00258
6	VEA - per kWh	See General Provisions	
7	CRPSEA - per kWh	See General Provisions	
8	VRPSEA - per kWh	See General Provisions	
9	IRCA - per kW	See General Provisions	
10	Reactive Energy Charge [i]	See Schedule A-2 [i]	

3. Monthly Rates beginning July 1, 2013

		High Season June - Sep.	Low Season Oct. - May
a.	**Rate A**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.36	$ 0.36
3	Supplemental Capacity Charge [i] - per kW of Supplemental Demand		
	High Peak Period	$ -	$ -
	Low Peak Period	$ -	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh of Department supplied energy		
	High Peak Period	$ 0.00428	$ 0.00428
	Low Peak Period	$ 0.00428	$ 0.00428
	Base Period	$ 0.00428	$ 0.00428

5	Backup Capacity Charge [i] - per kWh of Backup Energy		
	High Peak Period	$ 0.01562	$ -
	Low Peak Period	$ 0.00427	$ -
	Base Period	$ -	$ -
6	VEA - per kWh	See General Provisions	
7	CRPSEA - per kWh	See General Provisions	
8	VRPSEA - per kWh	See General Provisions	
9	IRCA - per kW	See General Provisions	
10	Reactive Energy Charge [i]	See Schedule A-2 [i]	

b. Rate C

		High Season June - Sep.	Low Season Oct. - May
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.36	$ 0.36
3	Demand Charge [i] - per kW of Maximum Demand measured at Customer's Service Point		
	High Peak Period	$ 1.00	$ 0.50
	Low Peak Period	$ 0.50	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh of Department supplied energy		
	High Peak Period	$ 0.00428	$ 0.00428
	Low Peak Period	$ 0.00428	$ 0.00428
	Base Period	$ 0.00428	$ 0.00428
5	VEA - per kWh	See General Provisions	
6	CRPSEA - per kWh	See General Provisions	
7	VRPSEA - per kWh	See General Provisions	
8	IRCA - per kW	See General Provisions	
9	Reactive Energy Charge [i]	See Schedule A-2 [i]	

c. Rate D

		High Season June - Sep.	Low Season Oct. - May
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.36	$ 0.36
3	Supplemental Capacity Charge [i] - per kW of Supplemental Demand		
	High Peak Period	$ -	$ -
	Low Peak Period	$ -	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh		

	High Peak Period	$ 0.00428	$ 0.00428
	Low Peak Period	$ 0.00428	$ 0.00428
	Base Period	$ 0.00428	$ 0.00428
5	Backup Capacity Charge [i] - per kWh of Backup Energy		
	High Peak Period	$ 0.01562	$ -
	Low Peak Period	$ 0.00427	$ -
	Base Period	$ -	$ -
6	Alert Period Energy Charge [i] - per kWh		
	High Peak Period	$ 0.01636	$ 0.00428
	Low Peak Period	$ 0.00961	$ 0.00428
	Base Period	$ 0.00428	$ 0.00428
7	VEA - per kWh	See General Provisions	
8	CRPSEA - per kWh	See General Provisions	
9	VRPSEA - per kWh	See General Provisions	
10	IRCA - per kW	See General Provisions	
11	Reactive Energy Charge [i]	See Schedule A-2 [i]	

d.	**Rate E**	High Season June - Sep.	Low Season Oct. - May
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.36	$ 0.36
3	Demand Charge [i] - per kW of Maximum Demand measured at Customer's Service Point		
	High Peak Period	$ 0.50	$ 0.50
	Low Peak Period	$ 0.50	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh of Department supplied energy		
	High Peak Period	$ 0.00428	$ 0.00428
	Low Peak Period	$ 0.00428	$ 0.00428
	Base Period	$ 0.00428	$ 0.00428
5	Alert Period Energy Charge [i] - per kWh		
	High Peak Period	$ 0.33407	$ 0.00428
	Low Peak Period	$ 0.11780	$ 0.00428
	Base Period	$ 0.00428	$ 0.00428
6	VEA - per kWh	See General Provisions	
7	CRPSEA - per kWh	See General Provisions	
8	VRPSEA - per kWh	See General Provisions	
9	IRCA - per kW	See General Provisions	
10	Reactive Energy Charge [i]	See Schedule A-2 [i]	

4. Billing

The bill under:

- Rates A or E shall be the sum of parts (1) through (10).
- Rate C shall be the sum of parts (1) through (9).
- Rate D shall be the sum of parts (1) through (11).

5. Definitions

a. Backup Capacity Charge [i]

See Capacity Charge.

b. Backup Energy

For each billing period, Backup Energy is the energy that would have been generated by the customer's generator(s) if operated at maximum output in each Rating Period (High Peak, Low Peak, Base). Backup Energy is applicable when both of the following conditions exist:

- Delivered energy as measured by the billing meter over a fifteen minute interval at the Service Point is greater than Supplemental Demand during any Rating Period within the billing month.

- Demand at the output point of the customer's generator as measured by the unit meter over a fifteen minute interval must be less than the Maximum Generation Demand during any Rating Period within the billing month.

c. Capacity Charge

There are two capacity charges in this rate schedule, Backup Capacity Charge [i] and Supplemental Capacity Charge [i]. The Capacity Charges are charges related to the cost of the facilities necessary to supply backup and supplemental services to the customer excluding costs that are recovered separately in the Facilities Charge [i].

d. Rated Generation Capacity (RGC)

The power output capacity of a generating unit(s) under normal operating conditions. Factors used in determining RGC include, but are not limited to, nameplate rating and operating characteristics of any connected generation equipment on the premises. The Generation equipment used exclusively for emergency shall not be included in the RGC.

e. Facilities Charge [i]

The Facilities Charge [i] shall be based on the largest of:

- The highest actual demand level recorded for energy delivered by the Department in the last 12-months at the Service Point.
- The highest actual demand level recorded for energy exported to the Department in the last 12-months at the Service Point.

f. Supplemental Capacity Charge [i]

See Capacity Charge.

g. Maximum Coincident Demand

The maximum of the coincident sum of the demand output at the generator or RGC as measured by the unit meter, and the Department-delivered demand at the Service Point. RGC will be used in determining Maximum Coincident Demand only in the event the customer does not have a unit meter.

h. Supplemental Demand

The Maximum Coincident Demand per Rating Period, less the maximum measured customer generation demand or RGC in the respective Rating Period, but never less than zero.

i. Momentary Interconnection

The interconnection of a generating facility to the Distribution System for one second (60 cycles) or less.

j. Parallel Operation

The simultaneous operation of a generator with power delivered or received by Department while interconnected. Parallel Operation includes only those generating facilities that are interconnected with the utility's Distribution System for more than 60 cycles (one second).

6. Special Conditions

a. Rate A

(1) Temporary Discontinuance of Customer Generation

When customer-owned generation equipment has no measured output for two billing cycles, future bills will be calculated under the General

Service Tariff to which the customer would be assigned absent customer-owned generation equipment. The customer can be returned to this schedule when the customer-owned generating equipment is again operational.

(2) Unit Meter

To qualify for this rate schedule, a meter must be installed to measure the output of the customer-owned generation equipment.

b. Rate C

(1) Operational Requirements:
Rate C is available to customers whose total Rated Generation Capacity located at a customer facility is less than 25 percent of the Maximum Coincident Demand and less than 1 MW. In the event a Rate C customer fails to comply with these requirements, the Department shall have the right to immediately transfer that customer to Rate A. If the customer does not have a unit meter on the customer-owned generation equipment, the customer's bill will be estimated until the unit meter is installed, for a period of up to six months. Upon conclusion of the six month period, if the unit meter has not been installed, the Department will terminate the customer's Interconnection Agreement and transfer the customer to the applicable General Service Rate Schedule.

(2) At a minimum, Rate C Customers must agree to operate their generating unit(s) during High Peak Period in High Season (June-Sep.).

c. Rate D and E

(1) All Special Conditions under Rate A shall apply to Rate D customers, and all Special Conditions under Rate C shall apply to Rate E customers.

(2) Rate D Load Reduction

Whenever the Department, in its sole judgment, requires customer to reduce load, it shall issue an Alert Period Notification. The Department may request customer to reduce demand for service under this rate through issuance of an Alert Period with not less than one half-hour's advance notification. Customers who do not reduce demand or curtail load during each of 2 consecutive Alert Periods will be removed from Rate D, and placed on Rate A, and shall not be eligible for service under the Rate D schedule for 5 calendar years.

(3) Rate E Load Reduction

Whenever the Department, in its sole judgment, requires customer to reduce load, it shall issue an Alert Period Notification. The Department may request customer to reduce demand for service under this rate through issuance of an Alert Period with not less than two hours' advance notification. Customers who do not reduce demand or curtail load during each of 2 consecutive Alert Periods will be removed from Rate E, and placed on Rate C, and shall not be eligible for service under the Rate E schedule for 5 calendar years.

(4) Alert Period Notification

To receive service under Rate D or E, all customers, at their own expense, must have access to e-mail to receive Alert Period Notifications. The Department will send one notification per Alert Period to customer's:

- Primary e-mail address
- Secondary e-mail address or a wireless device that is capable of receiving a text message

Customer contact information shall be provided to the Department prior to establishing any service under this rate schedule. If a change in customer's e-mail address or text message address occurs, the customer is required to provide written notice to the Rates and Contracts Group in the form of a letter or e-mail. Receipt of Alert Period Notification is the responsibility of the participating customer. The Department does not guarantee the reliability of the text system or e-mail system by which the customer receives notification. Customer will be responsible for all charges incurred during an Alert Period even if actual notice is not received.

(5) Alert Period

Each Alert Period shall be a minimum duration of 4 hours, however not to exceed a maximum of 10 hours. Alert Period(s) are limited to six occurrences within any calendar year. Notification will be provided through Alert Period message including the date, start and end time. Customers will mitigate the increased cost of energy during Alert Periods by reducing electric consumption.

(6) Contracts

To receive service under this rate schedule, a customer shall sign a contract in addition to the Customer Interconnection Agreement with the Department, unless the provisions of existing contracts already executed with Department incorporate the charges and conditions of this rate schedule.

7. General Conditions

a. Agreement

To receive service under this rate schedule, the customer must first sign a Customer Generation Interconnection Agreement which provides that the customer will design, construct, operate and maintain the generating facility in compliance with all applicable codes, laws, electric service requirements, rules and prudent utility practices as determined in good faith by the Department, unless the provisions of an existing contract already executed with the Department incorporate the charges and conditions of this rate schedule.

b. Character of Service

Service will be supplied at one of the standard voltages. The customer's generation equipment and Interconnection Facilities must be in compliance with the Department's Electric Service Requirements.

c. Energy Credit

The energy credit is calculated as the total number of Excess Energy (kWh) supplied to the Department's system by the customer during each Rating Period times the dollar per kWh charge as determined by the Standard Energy Credit or the Daily Energy Credit.

Excess Energy is the energy generated by the customer beyond the customer's requirements and supplied to the Department's system.

d. Standard Energy Credit

The Standard Energy Credit shall be revised twelve times each year on the first day of the calendar month and shall remain in effect for the entire calendar month. It shall be determined by the Department Energy Control Center estimated hourly marginal energy production costs. The hourly energy production costs shall be averaged separately for each Rating Period. The Standard Energy Credit will be posted for each Rating Period on the Department internet site. If the Excess Energy is metered at 34.5 kV, the Standard Energy Credit for each Rating Period shall be multiplied by a factor of 1.014 to adjust for reduced losses on the Power System.

e. Daily Energy Credit

The Daily Energy Credit shall be posted two (2) weekdays ahead on the Department internet site before 6:00 p.m. Pacific Time on normal Department workdays. The Daily Energy Credit shall remain in effect until reposted. For example, the Daily Energy Credit values posted on Thursday shall apply to next Monday. The Daily Energy Credit is not available on Saturday and Sunday. The Daily Energy Credit shall be based on the Department Energy Control Center estimated hourly marginal energy production costs. The hourly energy production costs shall be averaged separately for each Rating Period. If the Excess Energy is metered at 34.5 kV, the Daily Energy Credit for each Rating

Period shall be multiplied by a factor of 1.014 to adjust for reduced losses on the Power System. If the energy credit exceeds twice the customer's average monthly energy consumption bill, cash payment may be issued for the amount of Excess Energy purchased by the Department based on the Standard Energy Credit or the Daily Energy Credit. Only customers with Excess Energy and supply the Department system with demand levels greater than 100 kW may sign a contract that will allow payment for Excess Energy to be based on the Daily Energy Credit; such eligible customers need not sign such a contract if the provision of an existing contract already executed with the Department incorporates the provision to allow payment for Excess Energy to be based on the Daily Energy Credit.

f. **Metering**

Meter installation and costs will be as defined in the Customer Generation Interconnection Agreement. The Department shall supply, own and maintain all necessary meters and associated equipment utilized for billing and for measurement of Excess Energy. Time-of-use metering equipment and recorders are located at the Customer's Service Point and at the output point of the customer's generator(s) to measure electric energy and other electric parameters deemed appropriate by the Department.

g. **Reactive Energy Charge [i]**

See Schedule A-2 [i].

h. **Wheeling Credits**

Wheeling Credits are not allowed under Schedule CG-2 [i].

i. **Selection of Rates**

- A customer may choose to receive service under Rate A or D; and a customer may choose to receive service under Rate C or E; however, the selection must correspond to the rate or rates under which service is received pursuant to any other effective ordinance, and a customer voluntarily changing to Rate A from Rate D, or a customer voluntarily changing to Rate C from Rate E, may not revert to the opposing rate before 12 months have elapsed.

- A Rate A qualifying customer may elect to receive service under Rate A or Rate C; however, the selection must correspond to the rate or rates under which service is received pursuant to any other effective ordinance, and a customer changing from Rate C to Rate A may not revert to Rate C before 12 months have elapsed.

- If billing meter measures delivered energy and received energy from both generation and solar loads at the Service Point the customer shall be placed on the applicable rate under Schedule CG-2 [i].

M. SCHEDULE CG-3 [i]
CUSTOMER GENERATION, SUBTRANSMISSION SERVICE (34.5KV)

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable when both the following conditions exist:

- Any Electric Service provided by the Department where a customer-owned electrical generating facility is interconnected with the Department's system for Parallel Operation and in compliance with the Department's Rules.
- Loads that are served from the Subtransmission System and which would normally be served under General Service Schedule A-3 [i].

Not applicable to:

- Any person or entity that is a utility or a "Public Utility" as defined by the Public Utilities Code, including Section 216.
- Customer-owned electric generating facilities interconnected with the Department System for Momentary Interconnection.

a. Rate A

Applicable to customers who generate to sell Excess Energy to the Department and/or to serve their own electricity requirements and have the Department provide Electric Service including supplemental and backup power.

b. Rate C

- This optional rate is available to Rate A customers and is designed to support new customer generation and to encourage clean onsite generation.
- Rate C is available to customers whose total Rated Generation Capacity located at a customer facility is less than 25 percent of the Maximum Coincident Demand and less than 1 MW.
- To qualify for this rate, each customer on-site generation unit shall have been installed and/or converted on/after January 1, 2001 to emit no more than 0.5 pounds/MWH of nitrous oxides. Such emission limit must be maintained to continue to qualify. Verification as the Department determines shall be provided.

c. Rate D and Rate E

Rates D and E are optional rates for customers receiving service under the Schedule CG-3 [i]. Rate D is available to Rate A customers and Rate E is available to Rate C customers. These optional rates are for those customers who have demonstrated that they have the capability to reduce load during Department system conditions including, but not limited to, high system peaks, low generation, high market prices, temperature, and system contingencies.

2. Monthly Rates through June 30, 2013

	High Season June - Sep.	Low Season Oct. - May
a. Rate A		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - per kW	$ 0.39	$ 0.39
3 Supplemental Capacity Charge [i] - per kW of Supplemental Demand		
High Peak Period	$ -	$ -
Low Peak Period	$ -	$ -
Base Period	$ -	$ -
4 Energy Charge [i] - per kWh of Department supplied energy		
High Peak Period	$ 0.00254	$ 0.00254
Low Peak Period	$ 0.00254	$ 0.00254
Base Period	$ 0.00254	$ 0.00254
5 Backup Capacity Charge [i] - per kWh of Backup Energy		
High Peak Period	$ 0.00632	$ -
Low Peak Period	$ 0.00155	$ -
Base Period	$ -	$ -
6 VEA - per kWh	See General Provisions	
7 CRPSEA - per kWh	See General Provisions	
8 VRPSEA - per kWh	See General Provisions	
9 IRCA - per kW	See General Provisions	
10 Reactive Energy Charge [i]	See Schedule A-3 [i]	

	High Season June - Sep.	Low Season Oct. - May
b. Rate C		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - per kW	$ 0.39	$ 0.39

3	Demand Charge [i] - per kW of Maximum Demand measured at Customer's Service Point		
	High Peak Period	$ 0.35	$ 0.15
	Low Peak Period	$ 0.15	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh of Department supplied energy		
	High Peak Period	$ 0.00254	$ 0.00254
	Low Peak Period	$ 0.00254	$ 0.00254
	Base Period	$ 0.00254	$ 0.00254
5	VEA - per kWh	See General Provisions	
6	CRPSEA - per kWh	See General Provisions	
7	VRPSEA - per kWh	See General Provisions	
8	IRCA - per kW	See General Provisions	
9	Reactive Energy Charge [i]	See Schedule A-3 [i]	

		High Season June - Sep.	Low Season Oct. - May
c.	**Rate D**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - kW	$ 0.39	$ 0.39
3	Supplemental Capacity Charge [i] - per kW of Supplemental Demand		
	High Peak Period	$ -	$ -
	Low Peak Period	$ -	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh		
	High Peak Period	$ 0.00254	$ 0.00254
	Low Peak Period	$ 0.00254	$ 0.00254
	Base Period	$ 0.00254	$ 0.00254
5	Backup Capacity Charge [i] - per kWh of Backup Energy		
	High Peak Period	$ 0.00632	$ -
	Low Peak Period	$ 0.00155	$ -
	Base Period	$ -	$ -
6	Alert Period Energy Charge [i] - per kWh		
	High Peak Period	$ 0.03106	$ 0.00254
	Low Peak Period	$ 0.00892	$ 0.00254
	Base Period	$ 0.00254	$ 0.00254
7	VEA - per kWh	See General Provisions	
8	CRPSEA - per kWh	See General Provisions	
9	VRPSEA - per kWh	See General Provisions	
10	IRCA - per kW	See General Provisions	
11	Reactive Energy Charge [i]	See Schedule A-3 [i]	

	High Season June - Sep.	Low Season Oct. - May
d. Rate E		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - per kW	$ 0.39	$ 0.39
3 Demand Charge [i] - per kW of Maximum Demand measured at Customer's Service Point		
High Peak Period	$ 0.19	$ 0.15
Low Peak Period	$ 0.15	$ -
Base Period	$ -	$ -
4 Energy Charge [i] - per kWh of Department supplied energy		
High Peak Period	$ 0.00254	$ 0.00254
Low Peak Period	$ 0.00254	$ 0.00254
Base Period	$ 0.00254	$ 0.00254
5 Alert Period Energy Charge [i] - per kWh		
High Peak Period	$ 0.13674	$ 0.00254
Low Peak Period	$ 0.05791	$ 0.00254
Base Period	$ 0.00254	$ 0.00254
6 VEA - per kWh	See General Provisions	
7 CRPSEA - per kWh	See General Provisions	
8 VRPSEA - per kWh	See General Provisions	
9 IRCA - per kW	See General Provisions	
10 Reactive Energy Charge [i]	See Schedule A-3 [i]	

3. Monthly Rates beginning July 1, 2013

	High Season June - Sep.	Low Season Oct. - May
a. Rate A		
1 Service Charge [i]	$ -	$ -
2 Facilities Charge [i] - per kW	$ 0.56	$ 0.56
3 Supplemental Capacity Charge [i] - per kW of Supplemental Demand		
High Peak Period	$ -	$ -
Low Peak Period	$ -	$ -
Base Period	$ -	$ -
4 Energy Charge [i] - per kWh of Department supplied energy		
High Peak Period	$ 0.00395	$ 0.00395
Low Peak Period	$ 0.00395	$ 0.00395
Base Period	$ 0.00395	$ 0.00395

5	Backup Capacity Charge [i] - per kWh of Backup Energy		
	High Peak Period	$ 0.01459	$ -
	Low Peak Period	$ 0.00358	$ -
	Base Period	$ -	$ -
6	VEA - per kWh	See General Provisions	
7	CRPSEA - per kWh	See General Provisions	
8	VRPSEA - per kWh	See General Provisions	
9	IRCA - per kW	See General Provisions	
10	Reactive Energy Charge [i]	See Schedule A-3 [i]	

		High Season June - Sep.	Low Season Oct. - May
b.	**Rate C**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.56	$ 0.56
3	Demand Charge [i] - per kW of Maximum Demand measured at Customer's Service Point		
	High Peak Period	$ 0.70	$ 0.30
	Low Peak Period	$ 0.30	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh of Department supplied energy		
	High Peak Period	$ 0.00395	$ 0.00395
	Low Peak Period	$ 0.00395	$ 0.00395
	Base Period	$ 0.00395	$ 0.00395
5	VEA - per kWh	See General Provisions	
6	CRPSEA - per kWh	See General Provisions	
7	VRPSEA - per kWh	See General Provisions	
8	IRCA - per kW	See General Provisions	
9	Reactive Energy Charge [i]	See Schedule A-3 [i]	

		High Season June - Sep.	Low Season Oct. - May
c.	**Rate D**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - kW	$ 0.56	$ 0.56
3	Supplemental Capacity Charge [i] - per kW of Supplemental Demand		
	High Peak Period	$ -	$ -
	Low Peak Period	$ -	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh		
	High Peak Period	$ 0.00395	$0.00395

	Low Peak Period	$ 0.00395	$0.00395
	Base Period	$ 0.00395	$0.00395
5	Backup Capacity Charge [i] - per kWh of Backup Energy		
	High Peak Period	$ 0.01459	$ -
	Low Peak Period	$ 0.00358	$ -
	Base Period	$ -	$ -
6	Alert Period Energy Charge [i] - per kWh		
	High Peak Period	$ 0.07172	$ 0.00395
	Low Peak Period	$ 0.02060	$ 0.00395
	Base Period	$ 0.00395	$ 0.00395
7	VEA - per kWh	See General Provisions	
8	CRPSEA - per kWh	See General Provisions	
9	VRPSEA - per kWh	See General Provisions	
10	IRCA - per kW	See General Provisions	
11	Reactive Energy Charge [i]	See Schedule A-3 [i]	

		High Season June - Sep.	Low Season Oct. - May
d.	**Rate E**		
1	Service Charge [i]	$ -	$ -
2	Facilities Charge [i] - per kW	$ 0.56	$ 0.56
3	Demand Charge [i] - per kW of Maximum Demand measured at Customer's Service Point		
	High Peak Period	$ 0.39	$ 0.30
	Low Peak Period	$ 0.30	$ -
	Base Period	$ -	$ -
4	Energy Charge [i] - per kWh of Department supplied energy		
	High Peak Period	$ 0.00395	$ 0.00395
	Low Peak Period	$ 0.00395	$ 0.00395
	Base Period	$ 0.00395	$ 0.00395
5	Alert Period Energy Charge [i] - per kWh		
	High Peak Period	$ 0.31576	$ 0.00395
	Low Peak Period	$ 0.13372	$ 0.00395
	Base Period	$ 0.00395	$ 0.00395
6	VEA - per kWh	See General Provisions	
7	CRPSEA - per kWh	See General Provisions	
8	VRPSEA - per kWh	See General Provisions	
9	IRCA - per kW	See General Provisions	
10	Reactive Energy Charge [i]	See Schedule A-3 [i]	

4. Billing

The bill under:

- Rates A or E shall be the sum of parts (1) through (10).
- Rate C shall be the sum of parts (1) through (9).
- Rate D shall be the sum of parts (1) through (11).

5. Definitions

a. Backup Capacity Charge [i]

See Capacity Charge.

b. Backup Energy

For each billing period, Backup Energy is the energy that would have been generated by the customer's generator(s) if operated at maximum output in each Rating Period (High Peak, Low Peak, Base). Backup Energy is applicable when both the following conditions exist:

- Delivered energy as measured by the billing meter over a fifteen minute interval at the Service Point is greater than Supplemental Demand during any Rating Period within the billing month.

- Demand at the output point of the customer's generator as measured by the unit meter over a fifteen minute interval must be less than the Maximum Generation Demand during any Rating Period within the billing month.

c. Capacity Charge

There are two capacity charges in this rate schedule, Backup Capacity Charge [i] and Supplemental Capacity Charge [i]. The Capacity Charges are charges related to the cost of the facilities necessary to supply backup and supplemental services to the customer excluding costs that are recovered separately in the Facilities Charge [i].

d. Rated Generation Capacity (RGC)

The power output capacity of a generating unit(s) under normal operating conditions. Factors used in determining RGC include, but are not limited to, nameplate rating and operating characteristics of any connected generation equipment on the premises. The Generation equipment used exclusively for emergency shall not be included in the RGC.

e. **Facilities Charge [i]**

The Facilities Charge [i] shall be based on the largest of:

- The highest actual demand level recorded for energy delivered by the Department in the last 12-months at the Service Point.
- The highest actual demand level recorded for energy exported to the Department in the last 12-months at the Service Point.

f. **Supplemental Capacity Charge [i]**

See Capacity Charge.

g. **Maximum Coincident Demand**

The maximum of the coincident sum of the demand output at the generator or RGC, and the Department-delivered demand at the Service Point. RGC will be used in determining Maximum Coincident Demand only in the event the customer does not have a unit meter.

h. **Supplemental Demand**

The Maximum Coincident Demand per Rating Period, less the maximum measured customer generation demand or RGC in the respective Rating Period, but never less than zero.

i. **Momentary Interconnection**

The interconnection of a generating facility to the Distribution System for one second (60 cycles) or less.

j. **Parallel Operation**

The simultaneous operation of a generator with power delivered or received by Department while interconnected. Parallel Operation includes only those generating facilities that are interconnected with the utility's Distribution System for more than 60 cycles (one second).

6. **Special Conditions**

a. **Rate A**

(1) Temporary Discontinuance of Customer Generation

When customer-owned generation equipment has no measured output for two billing cycles, future bills will be calculated under the General Service

Tariff to which the customer would be assigned absent customer-owned generation equipment. The customer can be returned to this schedule when the customer-owned generating equipment is again operational.

(2) Unit Meter

To qualify for this rate schedule, a meter must be installed to measure the output of the customer-owned generation equipment.

b. Rate C

(1) Operational Requirements:
Rate C is available to customers whose total Rated Generation Capacity located at a customer facility is less than 25 percent of the Maximum Coincident Demand and less than 1 MW. In the event a Rate C customer fails to comply with these requirements, the Department shall have the right to immediately transfer that customer to Rate A. If the customer does not have a unit meter on the customer-owned generation equipment, the customer's bill will be estimated until the unit meter is installed, for a period of up to six months. Upon conclusion of the six month period, if the unit meter has not been installed, the Department will terminate the customer's Interconnection Agreement and transfer the customer to the applicable General Service Rate Schedule.

(2) At a minimum, Rate C Customers must agree to operate their generating unit(s) during High Peak Period in High Season (June-Sep.)

c. Rate D and E

(1) All Special Conditions under Rate A shall apply to Rate D customers, and all Special Conditions under Rate C shall apply to Rate E customers.

(2) Rate D Load Reduction

Whenever the Department, in its sole judgment, requires customer to reduce load, it shall issue an Alert Period Notification. The Department may request customer to reduce demand for service under this rate through issuance of an Alert Period with not less than one half-hour's advance notification. Customers who do not reduce demand or curtail load during each of 2 consecutive Alert Periods will be removed from Rate D, and placed on Rate A, and shall not be eligible for service under the Rate D schedule for 5 calendar years.

(3) Rate E Load Reduction

Whenever the Department, in its sole judgment, requires customer to reduce load, it shall issue an Alert Period Notification. The Department may request customer to reduce demand for service under this rate through issuance of an Alert Period with not less than two hours' advance notification. Customers who do not reduce demand or curtail load during each of 2 consecutive Alert Periods will be removed from Rate E, and placed on Rate C, and shall not be eligible for service under the Rate E schedule for 5 calendar years.

(4) Alert Period Notification

To receive service under Rate D or E, all customers, at their own expense, must have access to e-mail to receive Alert Period Notifications. The Department will send one notification per Alert Period to customer's:

- Primary e-mail address
- Secondary e-mail address or a wireless device that is capable of receiving a text message

Customer contact information shall be provided to the Department prior to establishing any service under this rate schedule. If a change in customer's e-mail address or text message address occurs, the customer is required to provide written notice to the Rates and Contracts Group in the form of a letter or e-mail. Receipt of Alert Period Notification is the responsibility of the participating customer. The Department does not guarantee the reliability of the text system or e-mail system by which the customer receives notification. Customer will be responsible for all charges incurred during an Alert Period even if actual notice is not received.

(5) Alert Period

Each Alert Period shall be a minimum duration of 4 hours, however not to exceed a maximum of 10 hours. Alert Period(s) are limited to six occurrences within any calendar year. Notification will be provided through Alert Period message including the date, start and end time. Customers will mitigate the increased cost of energy during Alert Periods by reducing electric consumption.

(6) Contracts

To receive service under this rate schedule, a customer shall sign a contract in addition to the Customer Interconnection Agreement with the Department, unless the provisions of existing contracts already executed with Department incorporate the charges and conditions of this rate schedule.

7. General Conditions

a. Agreement

To receive service under this rate schedule, the customer must first sign a Customer Generation Interconnection Agreement which provides that the customer will design, construct, operate and maintain the generating facility in compliance with all applicable codes, laws, electric service requirements, rules and prudent utility practices as determined in good faith by the Department, unless the provisions of an existing contract already executed with the Department incorporate the charges and conditions of this rate schedule.

b. Character of Service

Service will be supplied at one of the standard voltages. The customer's generation equipment and Interconnection Facilities must be in compliance with the Department's Electric Service Requirements.

c. Energy Credit

The energy credit is calculated as the total number of Excess Energy (kWh) supplied to the Department's system by the customer during each Rating Period times the dollar per kWh charge as determined by the Standard Energy Credit or the Daily Energy Credit.

Excess Energy is the energy generated by the customer beyond the customer's requirements and supplied to the Department's system.

d. Standard Energy Credit

The Standard Energy Credit shall be revised twelve times each year on the first day of the calendar month and shall remain in effect for the entire calendar month. It shall be determined by the Department Energy Control Center estimated hourly marginal energy production costs. The hourly energy production costs shall be averaged separately for each Rating Period. The Standard Energy Credit will be posted for each Rating Period on the Department internet site. If the Excess Energy is metered at 34.5 kV, the Standard Energy Credit for each Rating Period shall be multiplied by a factor of 1.014 to adjust for reduced losses on the Power System.

e. Daily Energy Credit

The Daily Energy Credit shall be posted two (2) weekdays ahead on the Department internet site before 6:00 p.m. Pacific Time on normal Department workdays. The Daily Energy Credit shall remain in effect until reposted. For example, the Daily Energy Credit values posted on Thursday shall apply to next Monday. The Daily Energy Credit is not available on Saturday and Sunday. The Daily Energy Credit shall be based on the Department Energy Control Center estimated hourly marginal energy production costs. The hourly energy production costs shall be averaged separately for each Rating Period. If the Excess Energy is metered at 34.5 kV, the Daily Energy Credit for each Rating Period shall be multiplied by a factor of 1.014 to adjust for reduced losses on the Power System. If the energy credit exceeds twice the customer's average monthly energy consumption bill, cash payment may be issued for the amount of Excess Energy purchased by the Department based on the Standard Energy Credit or the Daily Energy Credit. Only customers with Excess Energy and supply the Department system with demand levels greater than 100 kW may sign a contract that will allow payment for Excess Energy to be based on the Daily Energy Credit; such eligible customers need not sign such a contract if the provision of an existing contract already executed with the Department incorporates the provision to allow payment for Excess Energy to be based on the Daily Energy Credit.

f. Metering

Meter installation and costs will be as defined in the Customer Generation Interconnection Agreement. The Department shall supply, own and maintain all necessary meters and associated equipment utilized for billing and for measurement of Excess Energy. Time-of-use metering equipment and recorders are located at the Customer's Service Point and at the output point of the customer's generator(s) to measure electric energy and other electric parameters deemed appropriate by the Department.

g. Reactive Energy Charge [i]

See Schedule A-3 [i].

h. Wheeling Credits

Wheeling Credits are not allowed under Schedule CG-3 [i].

i. Selection of Rates

- A customer may choose to receive service under Rate A or D; and a customer may choose to receive service under Rate C or E; however, the selection must correspond to the rate or rates under which service is received pursuant to any other effective ordinance, and a customer voluntarily changing to Rate A from Rate D, or a customer voluntarily changing to Rate C from Rate E may not revert to the opposing rate before 12 months have elapsed.

- A Rate A qualifying customer may elect to receive service under Rate A or Rate C; however, the selection must correspond to the rate or rates under which service is received pursuant to any other effective ordinance, and a customer changing from Rate C to Rate A may not revert to Rate C before 12 months have elapsed.

- If billing meter measures delivered energy and received energy from both generation and solar loads at the Service Point the customer shall be placed on the applicable rate under Schedule CG-3 [i].

N. SCHEDULE OAL [i]
OUTDOOR AREA LIGHTING SERVICE

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to Outdoor Area Lighting (OAL) Service supplied from the Department's existing secondary overhead facilities of suitable phase and voltage. Not applicable to Private Lighting Lease agreements under OAL Lease program and for purposes of Department utilitarian lighting, Department general purpose lighting, and street and highway lighting.

2. Base Monthly Rates through June 30, 2013

Outdoor Area Lighting Service*	Charge per Light [i]	kWh per Month
Light Type and Size		
Mercury Vapor*		
175-watt	$0.23	77
400-watt	$0.40	170
High-Pressure Sodium*		
100-watt	$0.20	53
200-watt	$0.32	94

*This Schedule is closed to all new installations.

3. Base Monthly Rates beginning July 1, 2013

Outdoor Area Lighting Service*	Charge per Light [i]	kWh per Month
Light Type and Size		
Mercury Vapor*		
175-watt	$0.54	77
400-watt	$0.92	170
High-Pressure Sodium*		
100-watt	$0.47	53
200-watt	$0.74	94

*This Schedule is closed to all new installations.

4. Billing

The bill shall be the Base Monthly Rate plus the VEA, CRPSEA, VRPSEA, and IRCA.

5. General Conditions

a. Character of Service

Unmetered photoelectrically controlled lighting service will be provided using the Department's standard luminaires, control equipment and appurtenances mounted only on existing wooden poles of the Department's distribution system. Service will be provided hereunder only where the Department deems that the Installation will be of an established character.

b. Installation and Removal of Facilities

The Department will install the necessary lighting equipment and will own, operate, and maintain all necessary facilities. The Department shall not be required to install lighting equipment at locations where, in its judgment, the service may be objectionable to others. Furthermore, should any lighting equipment, once installed, be considered objectionable by others, the Department shall have the right at any time to discontinue service. The Department shall not be required to reconstruct any of its existing facilities to provide service hereunder. Facilities once installed specifically for this service will not be moved to another location, or changed in size, unless the full cost of such relocation or change is paid by the customer. Service furnished under this schedule will be discontinued at any location where overhead distribution lines supplying the service are subsequently converted to underground distribution.

c. Operation Schedule

Lamps will be lighted daily from dusk to dawn, approximately 340 hours monthly. The Department does not guarantee continuous lighting during such periods, and shall not be liable to the customer or anyone else for damage, loss or injury resulting from any interruption in such lighting due to any cause.

d. Maintenance

The Department will make any necessary repairs or lamp replacement within a reasonable time after being notified of a lighting outage by the customer, but only during regularly scheduled weekday working hours. Monthly bills will not be adjusted for outages.

O. SCHEDULE LS-2 [i]
STREET AND HIGHWAY LIGHTING SERVICE
(CUSTOMER-OWNED SYSTEM)

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to service, including energy and maintenance, for street and highway lighting (including tunnels, bridges, and parks).

2. Base Monthly Rates through June 30, 2013

Multiple Service

a. Rate A	High Season June - Sep.	Low Season Oct. - May
1 Base Energy Charge [i]	See General Conditions in 7.g. below	
2 VEA - per estimated hours of use	See General Provisions	
3 CRPSEA - per estimated hours of use	See General Provisions	
4 VRPSEA - per estimated hours of use	See General Provisions	
5 IRCA - per estimated hours of use	See General Provisions	

3. Base Monthly Rates beginning July 1, 2013

Multiple Service

a. Rate A	High Season June - Sep.	Low Season Oct. - May
1 Base Energy Charge [i]	See General Conditions in 7.g. below	
2 VEA - per estimated hours of use	See General Provisions	
3 CRPSEA - per estimated hours of use	See General Provisions	
4 VRPSEA - per estimated hours of use	See General Provisions	
5 IRCA - per estimated hours of use	See General Provisions	

4. Series Service Adjustment [i]

$0.06 per month shall be added to the Charges Per Light in 2.a. above for Series Service. $0.15 per month shall be added to the Charges Per Light in 3.a. above for Series Service.

5. Pass-through Billing Components (VEA, CRPSEA, VRPSEA, and IRCA)

The Charges Per Light as set forth in 2.a. and 3.a. above are subject to adjustment on a kilowatt-hour basis for variation of energy costs and reliability costs as described in the General Provisions.

6. **Billing**

The bill under Rate A shall be the sum of parts of (1) through (5).

7. **General Conditions**

a. **Character of Service**

(1) The necessary posts or fixtures, brackets, luminaires, and underground interconnecting conduits and circuits must be provided by the customer at the customer's expense. Systems with overhead interconnecting circuits between posts may be served hereunder, with the customer providing posts, fixtures, brackets, and luminaires, and the Department providing, installing, and maintaining such overhead interconnecting circuits at extra cost.

(2) Energy will be supplied at service points mutually agreed upon between the customer and the Department for multiple systems at 120 or 120/240 volts, or for series systems at 6.6 amperes. The Department reserves the right to provide multiple service at voltage ratings other than specified herein.

(3) For incandescent-light systems, the Department reserves the right to use lumen-rated (group replacement) lamps.

(4) All plans and specifications for the installation of, and the construction of, or changes to lighting systems shall be subject to approval of the Department, which shall have the right to inspect and to test the installations before acceptance for service. Testing of original system installations will be made without charge provided that such testing may be done without involving unreasonable time or expense due to faulty construction. Where it is contemplated that the Department will provide, install, and maintain overhead interconnecting circuits, the posts shall be located so that no extra supports for such overhead wiring will be required except as may be determined by the Department to be reasonably necessary.

(5) Where Series Service is furnished from Department overhead lines, the customer may mount cutout boxes on the Department's poles, and service connections will be run by the Department to such boxes. The Department will furnish vaults and all necessary appurtenances therein for lighting service in locations established by the Department as underground areas. Where Series Service from a vault is furnished, the customer shall install all ducts and conductors between the posts or fixtures and the vault.

(6) Maintenance of customer's equipment will be furnished by the Department as specified under "Normal Maintenance."

(7) The Department will provide, install, and maintain overhead interconnecting circuits between posts accepted for such service subject to conditions and charges specified under "Maintenance Other Than Normal."

b. Normal Maintenance

(1) The Department will furnish normal maintenance which shall include:

(a) Periodic inspection, renewal of lamps and cleaning of glassware according to established schedules.

(b) Replacement of glassware and inoperative lamps.

(c) Maintenance of controlling devices according to established schedules.

(d) Cleaning and painting of posts.

(e) Minor repairs to wiring and electrical appurtenances on or within the posts.

(2) Normal Maintenance shall not include maintenance with respect to equipment developing defects in test or in service due to faults in design, manufacture, or installation until such defects have been satisfactorily corrected; nor replacement of damaged glassware or lamps when such damage is coincident with or is a result of partial or total demolition of post or when caused by vandalism, riots, fires, explosions, earthquakes, or Acts of Nature.

(3) Under this Schedule LS-2 [i], a $0.12 charge is included in the Charge per Light for Normal Maintenance, as set forth in 7.g. below, through June 30, 2013. Thereafter, starting July 1, 2013, this charge will be $0.28.

c. Maintenance Other Than Normal

The Department provides for maintenance or replacement of customer's equipment only as set forth in 7.b. above for Normal Maintenance. Consequently, the Department may not be required to furnish at its expense any other maintenance work, nor replacement of posts or post parts, nor of underground cables or conduits beyond the Department's service feed points. Where the Department has approved the plans for an overhead-wired system, and has agreed to provide and install the overhead interconnecting circuits between the posts, it will provide such installation and maintenance service at an additional annual charge of $1.05 per post through June 30, 2013, and thereafter, starting July 1, 2013, this charge per post will be $2.42; These charges per post are in addition to corresponding charges prescribed in any other effective ordinance.

d. **Temporary Turn-Ons**

For Temporary Turn-Ons of streetlighting at times other than regularly scheduled hours of operation, the rate shall be $3.66 per turn-on as a service charge, plus $0.00327 per kilowatt-hour, the VEA, CRPSEA, VRPSEA, and IRCA, through June 30, 2013; thereafter, starting July 1, 2013, this charge will be $8.44, plus $0.00755 per kilowatt-hour, the VEA, CRPSEA, VRPSEA, and IRCA. In such cases, the Kilowatt-hours shall be as determined by the Department. These charges for Temporary Turn-Ons are in addition to corresponding charges prescribed in any other effective ordinance.

e. **Bills to Board of Public Works**

Monthly bills for energy or lighting services rendered to the Board of Public Works or one of its subordinate departments or bureaus under this rate schedule shall be paid monthly when due.

f. **Operation Schedules**

Upon acceptance of the customer's system, lights will be controlled in accordance with one of the schedules of operation hereunder:

(1) **All-Night Schedule of Operation**

Lights shall be turned on daily at 15 minutes after sunset and turned off 25 minutes before sunrise.

(2) **1:00 a.m. Schedule of Operation**

Lights shall be turned on daily at 15 minutes after sunset and shall be turned off at 1:00 a.m. Pacific Standard Time.

(3) **All-Day Schedule of Operation**

Lights will operate at all hours other than those specified under All-Night Schedule of Operation.

(4) **Continuous Schedule of Operation**

Lights will operate 24 hours per day.

(5) **Special Schedule of Operation**

Earlier or later turn-off of lights than is provided under "Standard All-Night Schedule of Operation" may be provided under a suitable schedule of operation as mutually agreed upon by the Department and the customer, but only if the customer agrees to pay for any extra costs involved in furnishing special switching and other service required for such schedule.

(6) Photoelectric Controller Operation

In lieu of controlling any lighting system with reference to "sunset" and "sunrise" in schedules of operation, the Department may, at its option, control lamps by means of photoelectric controllers so that the lamps will be lighted daily from dusk to dawn, approximately 340 hours monthly.

g. Energy Charge Calculation

The Base Energy Charge [i] will be calculated based on the Charge per Light formula below through June 30, 2013:

(Nominal Kilowatts * kWh Price $_{\text{Season, TOU}}$ * Hour of Use $_{\text{TOU}}$ + $0.12)

The Base Energy Charge [i] will be calculated based on the Charge per Light formula below starting July 1, 2013:

(Nominal Kilowatts * kWh Price $_{\text{Season, TOU}}$ * Hour of Use $_{\text{TOU}}$ + $0.28)

Nominal Kilowatts are the kilowatts supplied by the Department to feed the lighting load. Typically specified by the lamp manufacturer or can be determined by the Department lab.

Kilowatt-hour Price $_{\text{Season, TOU}}$ is the energy price specified by season (High Season and Low Season) and time-of-use periods (High Peak Period, Low Peak Period, and Base Period). Costs are based on Schedule A-2 [i].

For any lights not covered in 7.f. above, the hours of use shall be based upon the following two time schedules:

- The Department Rating Periods schedule; and
- U.S. Naval Observatory Astronomical Application Department Sunrise and Sunset monthly average schedule for the Los Angeles area (http://aa.usno.navy.mil/data/docs/RS_OneDay.html)

P. SCHEDULE LS-3 [i]
STREET AND HIGHWAY LIGHTING SERVICE
(CUSTOMER-OWNED SYSTEM - ENERGY ONLY)

1. Applicability

The following charges are in addition to the charges of corresponding rates prescribed in any other effective ordinance.

Applicable to service to public street, highway and freeway lighting systems, including supply of energy and circuit control facilities only and supply of energy only to freeway warning facilities and guide signs which are connected to series lighting systems.

2. Base Monthly Rates through June 30, 2013

Multiple Service	High Season June - Sep.	Low Season Oct. - May
a. Rate A - Street, Highway and Freeway Lighting Facilities - Unmetered		
1 Base Energy Charge [i]	See General Conditions in 7.e. below	
2 VEA - per estimated hours of use	See General Provisions	
3 CRPSEA - per estimated hours of use	See General Provisions	
4 VRPSEA - per estimated hours of use	See General Provisions	
5 IRCA - per estimated hours of use	See General Provisions	
b. Rate B - Street, Highway and Freeway Lighting Facilities - Metered		
1 Energy Charge [i] - per kWh	$ 0.00358	$ 0.00358
2 VEA - per kWh	See General Provisions	
3 CRPSEA - per kWh	See General Provisions	
4 VRPSEA - per kWh	See General Provisions	
5 IRCA - per kWh	See General Provisions	
c. Freeway Warning Facilities and Guide Signs Connected to Series Lighting Systems		
1 Base Energy Charge [i]	$0.00327 per kWh for all energy use	
2 Base Minimum Charge [i]	$ - per service point per month	

3. Base Monthly Rates beginning July 1, 2013

Multiple Service	High Season June - Sep.	Low Season Oct. - May
a. Rate A - Street, Highway and Freeway Lighting Facilities - Unmetered		
1 Base Energy Charge [i]	See General Conditions in 7.e. below	

2 VEA - per estimated hours of use — See General Provisions
3 CRPSEA - per estimated hours of use — See General Provisions
4 VRPSEA - per estimated hours of use — See General Provisions
5 IRCA - per estimated hours of use — See General Provisions

b. Rate B - Street, Highway and Freeway Lighting Facilities - Metered

1 Energy Charge [i] - per kWh	$ 0.00661	$ 0.00661
2 VEA - per kWh	See General Provisions	
3 CRPSEA - per kWh	See General Provisions	
4 VRPSEA - per kWh	See General Provisions	
5 IRCA - per kWh	See General Provisions	

c. Freeway Warning Facilities and Guide Signs Connected to Series Lighting Systems

1 Base Energy Charge [i]	$0.00755 per kWh for all energy use
2 Base Minimum Charge [i]	$ - per service point per month

4. Series Service Adjustment [i]

$0.06 per month shall be added to the Charges Per Light as set forth in 2.a. above for Series Service, and $0.15 per month shall be added to the Charges Per Light as set forth in 3.a. above for Series Service.

5. Pass-through Billing Components (VEA, CRPSEA, VRPSEA, and IRCA)

The Charges under Rate A and Rate B are subject to adjustment on a kilowatt-hour basis for variation of energy costs and reliability costs as described in the General Provisions. The kilowatt-hours shall be determined by multiplying the Nominal kilowatts by operating hours as set forth in 7.d. below and 7.e. below, and rounded to the nearest kilowatt-hour.

6. Billing

The bill under Rate A and Rate B shall be the sum of parts (1) through (5). The bill under 2.c. and 3.c. shall be the sum of parts (1) and (2).

7. General Conditions

a. Character of Service

(1) The necessary posts or fixtures, brackets, luminaires, ducts, and interconnecting circuits for lighting systems must be provided by the customer at the customer's expense.

(2) Energy will be supplied at service points mutually agreed upon between customers and the Department for multiple systems at 120 or 120/240

volts, or for series systems at 6.6 amperes. The Department reserves the right to provide multiple service at voltage ratings other than specified herein.

(3) All plans and specifications for the installation of, and the construction of, or changes to lighting systems shall be subject to approval of the Department, which shall have the right to inspect and to test the installations before acceptance for service. Testing of original system installations will be made without charge providing such testing may be done without excessive expense due to faulty construction.

(4) Where Series Service is furnished from Department overhead lines, the customer may mount cutout boxes on the Department's poles, and service connections will be run by the Department to such boxes. The Department will furnish vaults and all necessary appurtenances therein for lighting service in locations established by the Department as underground areas. Where Series Service from a vault is furnished, the customer shall install all ducts and conductors between the posts or fixtures and the vault.

b. Determination of Billing

(1) Energy use for billing purposes under this schedule shall be calculated from Department records of customer's equipment or other records as approved by the Department. Kilowatt-hours for guide signs and other facilities shall be calculated from the connected load.

(2) It shall be the responsibility of the customer to promptly notify the Department of any change in equipment or hours of operation affecting energy use.

(3) The Department may, as it deems necessary, request an inventory of all of the customer's electrical equipment served under this schedule. Such requests shall not normally be made at intervals of less than six months.

(4) If the customer does not provide the requested inventory, the Department may initiate other means of determining the customer's energy use and bill the customer under the appropriate General Service Schedule.

c. Temporary Turn-Ons

For Temporary Turn-Ons of streetlighting at times other than regularly scheduled hours of operation, the rate shall be $3.66 per turn-on as a service charge, plus $0.00327 per kilowatt-hour, the VEA, CRPSEA, VRPSEA, and IRCA, through June 30, 2013; thereafter, starting July 1, 2013, this charge will be $8.44, plus $0.00755 per kilowatt-hour, the VEA, CRPSEA, VRPSEA, and IRCA. In such cases, the Kilowatt-hours shall be as determined by the Department. These charges for Temporary

Turn-Ons are in addition to corresponding charges prescribed in any other effective ordinance.

d. Unmetered Service Light Charges

Unmetered Service Light Charges will be calculated on an annual basis by the Electric Rates Section based on the most current lighting fixtures and standard monthly operating hours of 340 hours (All Night), 210 hours (1:00AM), 390 hours (All Day) and 730 hours (Continuous). The Department may choose the option to use actual lighting hours of use for a statistically valid sample of a group of metered lights.

e. Energy Charge Calculation

Base Energy Charge [i] will be calculated based on the formula below:
(Charge per Light = Nominal Kilowatts * kWh Price $_{\text{Season, TOU}}$ * Hour of Use $_{\text{TOU}}$)

Nominal Kilowatts are the kilowatts supplied by the Department to feed the lighting load. Typically specified by the lamp manufacturer or can be determined by the Department lab.

Kilowatt-hour Price $_{\text{Season, TOU}}$ is the energy price specified by season (High Season and Low Season) and time-of-use periods (High Peak Period, Low Peak Period, and Base Period). Costs are based on Schedule A-2 [i].

For any lights not covered in 7.d. above, the hours of use shall be based upon the following two time schedules:

- The Department Rating Periods schedule; and
- U.S. Naval Observatory Astronomical Application Department Sunrise and Sunset monthly average schedule for the Los Angeles area (http://aa.usno.navy.mil/data/docs/RS_OneDay.html)

Sec. 3.

GENERAL PROVISIONS

That the General Provisions relating to electrical service supplied under schedules prescribed herein are as follows:

A. RATE APPLICABILITY AND RULES

The application, interpretation, and administration of the provisions herein are subject to such rules as may from time to time be promulgated by the Board of Water and Power Commissioners under its power and duty to administer the affairs of the Department of Water and Power. The application, interpretation, and administration of these provisions and rules by the Board of Water and Power Commissioners shall be final.

B. SURPLUS ELECTRICAL ENERGY - PARAMOUNT RIGHT OF THE CITY OF LOS ANGELES

Only surplus electrical energy, owned or controlled by the City of Los Angeles and not required for use of customers served by the City within its limits, may be supplied or distributed outside said City; provided that the supplying or distribution of such surplus electrical energy shall, in all cases, be subject to the paramount right of the City at any time to discontinue the same, in whole or in part, and to take and hold, or to distribute such surplus electrical energy for the use of the City and its inhabitants.

C. METERING

For the purpose of computing charges, each meter on the customer's premises will be considered separately, and readings of two or more meters will not be combined as equivalent to measurement through one meter, except when such combination is for the convenience of the Department. No application shall be accepted for service through a master meter, under any schedule herein, to any multifamily dwelling consisting of two or more separate family accommodations unless the applicant submeters the individual units and charges tenants no more than if they were direct customers of the Department. If a master-metered multifamily dwelling facility is converted to individual metering, it shall not be reconverted to master metering.

D. SEASONS

High Season	The period from June 1 to September 30
Low Season	The period from October 1 to May 31

E. RATING PERIODS

High Peak Period	1:00 p.m. - 5:00 p.m. Monday through Friday (20 hours/week)
Low Peak Period	10:00 a.m. - 1:00 p.m. Monday through Friday 5:00 p.m. - 8:00 p.m. Monday through Friday (30 hours/week)
Base Period	8:00 p.m. - 10:00 a.m. Monday through Friday, All Day Saturday and Sunday (118 hours/week)

F. TIME AND MANNER OF PAYMENT OF BILLS

All bills for electric service hereunder, except as provided otherwise in the schedules, are due and payable upon presentation; bills shall become delinquent nineteen (19) days after date of presentation. If bills are not paid upon becoming delinquent, the Department may impose a late payment charge and/or discontinue the electric service in accordance with applicable law or the Department's Rules. The Department shall not be liable to the customer or anyone else for damage, loss or injury resulting from such discontinuance of service. Payment shall be made in person or by mail at offices of the Department, or at the option of the Department to its authorized collectors.

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H. INTENTIONALLY LEFT BLANK

I. RESALE OF ENERGY

The resale of electrical energy by Department customers is prohibited. However, it is not deemed a resale if energy supplied by the Department is passed through a distribution system of a landlord where the end-user of the electrical energy pays no more than if the Department provided the energy directly. Also, charging batteries for electric-powered vehicles, or other purposes, shall not be deemed resale of electrical energy.

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K. EXPERIMENTAL RATES

Experimental Rates are established to study customer reactions to new and innovative rate structures. The Power System will establish availability and eligibility criteria for Experimental Rates.

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M. TRANSFORMER CHARGE

For dedicated on-site transformer on private property, the customer will pay 100% of the transformer and installation costs. If the demand exceeds 50% of the rated transformer capacity for a minimum of 48 of the first 60 months after installation, the customer's payment may be returned in full.

N. LIMITATION OF AMOUNTS TO BE BILLED PURSUANT TO THE ELECTRIC RATE ORDINANCE

For billing purposes, no Residential RCAF of the Electric Rate Ordinance shall exceed \$0.0030 per kWh, which was the level of such RCAF applied as of November 3, 2010. The Residential RCAF, as applied subject to this limitation, shall be known as the Residential Capped Reliability Cost Adjustment Factor (Residential CRCAF) for purposes of this ordinance. If any Residential CRCAF is calculated to be less than \$0.0030 per kWh, then the Residential Incremental Reliability Cost Adjustment for that same period shall not be billed.

For billing purposes, no General Service RCAF of the Electric Rate Ordinance shall exceed \$0.96 per kW, which was the level of such RCAF applied as of November 3, 2010. The General Service RCAF, as applied subject to this limitation, shall be known as the General Service Capped Reliability Cost Adjustment Factor (General Service CRCAF) for purposes of this ordinance. If any General Service CRCAF is calculated to be less than \$0.96 per kW, then the General Service Incremental Reliability Cost Adjustment for that same period shall not be billed.

For billing purposes, no ECAF of the Electric Rate Ordinance shall exceed \$0.05690 per kWh, which was the level of such ECAF applied as of November 3, 2010. The ECAF, as applied subject to this limitation, shall be known as the Capped Energy Cost Adjustment Factor (CECAF) for purposes of this ordinance, and the associated adjustment shall be known as the Capped Energy Cost Adjustment (CECA) for purposes of this ordinance.

The Electric Rate Ordinance provides for funding of expenditures of the type qualifying for funding by ECA through the Electric Rate Ordinance's Base Rates in the amount of the specified factor at General Provision G.3.(j) of the Electric Rate Ordinance. Such factor shall be known as the Base Rate Contribution Factor (BRCF) for purposes of this ordinance. The BRCF shall be equal to $0.01236 per kWh (calculated pursuant to the Electric Rate Ordinance as $0.01344 per kWh x [1 – (8 / 100)]), which was the level as of November 3, 2010.

For billing purposes, the sum of the CECAF and the BRCF shall not exceed $0.06926 per kWh (calculated as $0.05690 per kWh + $0.01236 per kWh).

Expenditures of the type qualifying for funding by CECA and BRCF of the Electric Rate Ordinance, not actually funded by the application of CECAF and BRCF, shall be funded by application of the combination of factors for the Variable Energy Adjustment (VEA), Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA), and Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA). If the sum of any quarterly CECAF and the BRCF of the Electric Rate Ordinance is less than $0.06926 per kWh, then the VEA, CRPSEA, and VRPSEA for that same quarter shall not be billed, and any BRRTA component of the VEA shall be billed independently.

O. Variable Energy Adjustment (VEA)

1. A VEA shall be added to bills under each service schedule herein, and any contracts wherein it is specified or incorporated, on the basis of total energy use. It recovers applicable costs through application of the Variable Energy Adjustment Factor (VEAF).

2. The VEAF shall be calculated four times each year and shall take effect January 1, April 1, July 1, and October 1, respectively. The VEAF shall also be calculated and take effect upon the effective date of this ordinance.

   The VEAF formula, expressed to the nearest $0.00001 per kilowatt-hour (kWh), is

$$\text{VEAF} = \frac{(a) + (b) + (c) + (d) + (e) + (f) + (g) + (h)}{(i)} - (j) + (k)$$

   Where:

   (a) is the estimated non-renewable fuel expense for twelve months commencing with the effective date of the VEAF. This expense shall cover any non-renewable fuel-related expenses, including any prepayment, fuel transportation, storage facilities, emission credits, emission taxes, greenhouse gas emission allowance costs, audit or legal costs related to fuel acquisition, funding requirement for decommissioning of generation facilities, and other non-renewable fuel-related expenses.

(b) is the estimated non-renewable purchased power expense for twelve months commencing with the effective date of the VEAF. This expense shall include all charges associated with capacity, transmission service, prepayment expense, and parallel generators (co-generation), except charges for electricity purchased at established retail tariffs from other utilities for use in Department offices, stations, and other facilities for the production of electrical energy to serve Department's customers.

(c) is the estimated expense for legal and court costs or any judgment or settlement including interest payments thereon for twelve months commencing with the effective date of the VEAF, except for legal costs related to fuel acquisition.

(d) is an amount equal to the approved cumulative energy efficiency savings by the Board of Water and Power Commissioners in kWh commencing July 1, 2006, through June 30, 2012, multiplied by a factor of $0.05513/kWh.

(e) beginning July 1, 2014, is an amount equal to the approved cumulative energy efficiency savings by the Board of Water and Power Commissioners in kWh commencing July 1, 2012, greater than 414 gigawatt-hours (GWh), multiplied by a factor of $0.07950/kWh. This amount will be collected the following fiscal year.

(f) is an amount equal to the City Transfer Percentage multiplied by the sum of (a) through (e) immediately above.

(g) is the balance in the VEA Balancing Account.

(h) is an amount equal to the balance of the ECA Account of the Electric Rate Ordinance as of the effective date of this ordinance divided by ten in order to collect the balance evenly over a period of ten years.

(i) is the estimated retail energy sales in kWh for twelve months commencing with the effective date of the VEAF, less sales to other City departments under Schedules LS-1 and TC of the Electric Rate Ordinance.

(j) is the funding of these costs by application of the CECAF and BRCF at $0.052560 per kWh.

(k) is the BRRTAF, as calculated pursuant to General Provision T.

3. The VEA Balancing Account shall be maintained by the Department on a monthly basis except where specifically noted. Entries to this account shall be:

(a) an amount equal to the qualified expenses identified in 2.(a) through 2.(c) above as recorded during the month.

(b) an amount equal to the approved cumulative energy efficiency savings by the Board of Water and Power Commissioners in kWh commencing July 1, 2006, through June 30, 2012, multiplied by a factor of $0.05513/kWh.

(c) beginning July 1, 2014, an amount equal to the approved cumulative energy efficiency savings by the Board of Water and Power Commissioners in kWh commencing July 1, 2012, greater than 414 gigawatt-hours (GWh), multiplied by a factor of $0.07950/kWh.

(d) an amount equal to the net cost or credit for the disposal of residues as recorded during the month.

(e) Less: refunds, including interest, received from any fuel suppliers and net revenue from fuel consumed in providing steam to customers.

(f) an amount equal to the City Transfer Percentage multiplied by the sum of (a) through (e) immediately above.

(g) an amount equal to the collection as recorded during the month of the balance of the ECA Account of the Electric Rate Ordinance as of the effective date of this ordinance, as specified in 2.(h) above.

(h) an amount equal to the uncollectible VEA portion of customer energy bills and the uncollectible CECA portion of customer energy bills related to expenditures of the type qualifying for funding by VEA, as recorded during the month.

(i) on January 1, 2016, an amount equal to the balance of the BRRTA Balancing Account as prescribed in General Provision T.

(j) Less: an amount equal to the revenue billed for retail sales subject to CECA and VEA, less revenue billed due to the Base Rate Revenue Target Adjustment. Revenue billed shall also include revenue from contract customers who are not subject to CECA; the revenue from such customers shall be the lesser of the total billed revenue or the sum of energy sales multiplied by the sum of CECAF, VEAF, CRPSEAF, and VRPSEAF in effect during the period. Revenue from the steam conversion portion of the City of Los Angeles Sanitation Fund (Hyperion) contract shall be excluded from (j) and included in (e) above.

(k) Less: an amount of the wholesale generation expense, which is the lesser of the gross revenue or the sum of the hourly wholesale energy sales multiplied by the hourly system marginal cost.

(l) Less: an amount equal to the funding by a portion of the Base Rate Contribution Factor at $0.00938/kWh multiplied by retail sales, less any allocated portion for uncollectible energy bills, to customers other than Electric Rate Ordinance Schedules LS-1 and TC customers and any incremental energy portion of the City of Los Angeles Sanitation Fund contract.

P. **Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA)**

1. A CRPSEA shall be added to bills under each service schedule herein, and any contracts wherein it is specified or incorporated, on the basis of total energy use. It recovers applicable costs through application of the Capped Renewable Portfolio Standard Energy Adjustment Factor (CRPSEAF).

2. The CRPSEAF shall be calculated four times each year and shall take effect January 1, April 1, July 1, and October 1, respectively. The CRPSEAF shall also be calculated and take effect upon the effective date of this ordinance.

   The CRPSEAF formula, expressed to the nearest $0.00001 per kilowatt-hour (kWh), is

$$\text{CRPSEAF} = \frac{(a) + (b) + (c) + (d) + (e)}{(f)} - (g)$$

   Where:

   (a) is the estimated depreciation expense, interest expense, and operating and maintenance expense of Department-owned renewable portfolio standard (RPS) generation and transmission projects for twelve months commencing with the effective date of the CRPSEAF. The interest expense for a Department-owned RPS project, as directed by the Chief Financial Officer, is the prorated portion of the interest expense of a recent bond issue by the Department, if such bond proceeds are available and applicable to the project, or the interest expense of an equivalent bond issue with a prevailing market interest rate and a payoff maturity matching the life of the RPS project. The selection of a bond issue or the equivalent bond issue to be associated with an RPS project shall not be changed during the cost recovery period.

   (b) is the estimated principal payment, interest expense, and operating and maintenance expense for twelve months commencing with the effective date of the CRPSEAF typically associated with power purchase agreements for RPS generation and transmission projects in which the Department has an indirect ownership interest.

   (c) is the estimated expense incurred in the pursuit of Energy Efficiency (EE) measures that are expensed or capitalized, reduced by funding from other sources, for twelve months commencing with the effective date of the CRPSEAF. Eligible expenses include those incurred for the acquisition and installation of devices and systems, incentive payments, and audit and administrative costs related to EE measures designed to lower Power

System peak demand and energy consumption. The expense for a capitalized EE measure, as directed by the Chief Financial Officer, is the prorated portion of the debt service expense of a recent bond issue by the Department, if such bond proceeds are available and applicable to the measure, or the interest expense of an equivalent bond issue with a prevailing market interest rate and a payoff maturity matching the life of EE measures. The selection of a bond issue or the equivalent bond issue to be associated with an EE measure shall not be changed during the cost recovery period.

(d) is an amount equal to the City Transfer Percentage multiplied by the sum of (a) through (c) immediately above.

(e) is the balance in the CRPSEA Balancing Account.

(f) is the estimated retail energy sales in kWh for twelve months commencing with the effective date of the CRPSEAF, less sales to other City departments under Schedules LS-1 and TC of the Electric Rate Ordinance.

(g) is the funding of these costs by application of the CECAF and BRCF at $0.00979 per kWh.

3. The CRPSEA Balancing Account shall be maintained by the Department on a monthly basis except where specifically noted. Entries to this account shall be:

   (a) an amount equal to the qualified expenses identified in 2.(a) through 2.(c) above as recorded during the month.

   (b) an amount equal to the City Transfer Percentage multiplied by (a) immediately above.

   (c) an amount equal to the uncollectible CRPSEA portion of customer energy bills and the uncollectible CECA portion of customer energy bills related to expenditures of the type qualifying for funding by CRPSEA, as recorded during the month.

   (d) Less: an amount equal to the revenue billed for retail sales subject to CECA and CRPSEA.

   (e) Less: an amount equal to the funding by a portion of the Base Rate Contribution Factor at $0.00175/kWh multiplied by retail sales, less any allocated portion for uncollectible energy bills, to customers other than Electric Rate Ordinance Schedules LS-1 and TC customers and any incremental energy portion of the City of Los Angeles Sanitation Fund contract.

4. The CRPSEAF shall be calculated as set forth above, but no increase in the quarterly adjustment shall exceed the prior period's adjustment by more than

$0.00125 per kWh. The quarterly increase limit of $0.00125 per kWh may be increased to maintain the Department's financial integrity if deemed necessary by the Board of Water and Power Commissioners. Any proposed increase to be considered by the Board of Water and Power Commissioners shall be communicated to the City Council.

5. On January 1, April 1, July 1, and October 1, the Department shall calculate the projected balance of the CRPSEA Balancing Account as of the first, second, and third anniversary of that day, certified by the Chief Financial Officer. If any of the three projected balances is greater than $50 million but less than $100 million, then the Department shall communicate such projected balance to the Board of Water Commissioners and to the City Council within 60 days of the balance calculation by use of a report describing all proposed RPS generation and transmission projects to be directly or indirectly owned by the Department so that the potential need for increased rates may be considered. If any of the three projected balances is $100 million or greater, then the Department shall communicate such projected balance to the Board of Water Commissioners and to the City Council within 60 days of the balance calculation by use of a report describing all proposed RPS generation and transmission projects to be directly or indirectly owned by the Department, and the Board of Water and Power Commissioners shall fix rates as necessary and submit any such rates to the City Council within 180 days of the balance calculation for possible approval by ordinance.

Q. <u>Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA)</u>

1. A VRPSEA shall be added to bills under each service schedule herein, and any contracts wherein it is specified or incorporated, on the basis of total energy use. It recovers applicable costs through application of the Variable Renewable Portfolio Standard Energy Adjustment Factor (VRPSEAF).

2. The VRPSEAF shall be calculated four times each year and shall take effect January 1, April 1, July 1, and October 1, respectively. The VRPSEAF shall also be calculated and take effect upon the effective date of this ordinance.

   The VRPSEAF formula, expressed to the nearest $0.00001 per kilowatt-hour (kWh), is

$$\text{VRPSEAF} = \frac{(a) + (b) + (c) + (d)}{(e)} - (f)$$

   Where:

   (a) is the estimated expense for twelve months commencing with the effective date of the VRPSEAF to procure purchased Renewable Portfolio Standard (RPS) generation and its associated transmission service from projects in which the Department has neither direct nor indirect ownership interest.

(b) is the estimated expense for twelve months commencing with the effective date of the VRPSEAF typically associated with power purchase agreements for RPS generation and transmission projects in which the Department has an indirect ownership interest, deducting any principal payment, interest expense, and operating and maintenance expense.

(c) is an amount equal to the City Transfer Percentage multiplied by the sum of (a) through (b) immediately above.

(d) is the balance in the VRPSEA Balancing Account.

(e) is the estimated retail energy sales in kWh for twelve months commencing with the effective date of the VRPSEAF, less sales to other City departments under Schedules LS-1 and TC of the Electric Rate Ordinance.

(f) is the funding of these costs by application of the CECAF and BRCF at $0.00691 per kWh.

3. The VRPSEA Balancing Account shall be maintained by the Department on a monthly basis except where specifically noted. Entries to this account shall be:

(a) an amount equal to the qualified expenses identified in 2.(a) and 2.(b) above as recorded during the month.

(b) Less: revenues collected from the Renewable Energy Adjustment (REA) through Service Rider REO of the Electric Rate Ordinance as recorded during the month.

(c) an amount equal to the City Transfer Percentage multiplied by the sum of (a) through (b) immediately above.

(d) an amount equal to the uncollectible VRPSEA portion of customer energy bills and the uncollectible CECA portion of customer energy bills related to expenditures of the type qualifying for funding by VRPSEA, as recorded during the month.

(e) Less: an amount equal to the revenue billed for retail sales subject to CECA and the VRPSEA.

(f) Less: an amount equal to the funding by a portion of the Base Rate Contribution Factor at $0.00123/kWh multiplied by retail sales, less any allocated portion for uncollectible energy bills, to customers other than Electric Rate Ordinance Schedules LS-1 and TC customers and any incremental energy portion of the City of Los Angeles Sanitation Fund contract.

R. **Incremental Reliability Cost Adjustment (IRCA)**

1. An Incremental Reliability Cost Adjustment (IRCA) shall be added to each bill unless excluded by contract clauses. Two classes for IRCA, Residential Service and General Service, shall be established. The Residential Service IRCA shall be based on total energy use, whereas the General Service IRCA shall be based on demand, as determined for the Facilities Charge. The IRCA recovers a portion of the operation, maintenance and debt service expenses of the Power System Reliability Program (PRP).

2. The Residential Service IRCA and General Service IRCA shall take effect upon the effective date of this ordinance and shall be as follows:

Monthly Adjustment through June 30, 2013	
Residential Service IRCA	$ 0.00127 per kWh
General Service IRCA	$ 0.36 per kW

Monthly Adjustment beginning July 1, 2013	
Residential Service IRCA	$ 0.00222 per kWh
General Service IRCA	$ 0.70 per kW

S. **Incremental Rate Stabilization Account**

An Incremental Rate Stabilization Account (IRSA) shall be maintained by the Department. The beginning balance of the IRSA on the effective date of this ordinance shall be equal to the balance of the Rate Stabilization Account of the Electric Rate Ordinance as of the effective date of this ordinance. Any entries to this account shall be made at the end of each fiscal year and may include:

1. For revenue deferment, any amount not exceeding the revenue amount from wholesale generation and transmission and net gain on asset sales transacted during the fiscal year. The amount deferred shall be subject to the approval of the Board of Water and Power Commissioners.

2. Less: For revenue recognition, any amount not exceeding the balance in the IRSA. The amount recognized shall be subject to the approval of the Board of Water and Power Commissioners.

The total deferred amount in each fiscal year shall be limited such that the balance in the IRSA does not exceed the Incremental Rate Stabilization Target. The Incremental Rate Stabilization Target shall be approved by the Board of Water and Power Commissioners and may be changed from time to time by the Board of Water and Power Commissioners to maintain financial stability.

T. **Base Rate Revenue Target Adjustment (BRRTA)**

1. Base Rate Revenue consists of the revenue billed through Base Rates from this and any other effective ordinance of the City of Los Angeles. A Base Rate

Revenue Target (BRRT) is established for the following fiscal years commencing on July 1:

Fiscal Year 2012/13:	$1,653 million
Fiscal Year 2013/14:	$1,712 million

2. Beginning January 1, 2014, through December 31, 2015, a BRRTA shall be added to bills as a component of the VEA through application of the Base Rate Revenue Target Adjustment Factor (BRRTAF). The BRRTAF shall be calculated once each year and shall take effect January 1.

   The BRRTAF formula, expressed to the nearest $0.00001 per kilowatt-hour (kWh), is

$$\text{Base Rate Revenue Target Adjustment Factor (BRRTAF)} = \frac{(a)}{(b)}$$

   Where:

   (a) is the balance in the BRRTA Balancing Account.

   (b) is the estimated retail sales in kWh subject to VEA for the twelve months commencing with the effective date of the BRRTAF.

3. A BRRTA Balancing Account shall be maintained by the Department on an annual basis until December 31, 2015. Entries to this account shall be:

   (a) an amount equal to the Base Rate Revenue Target of the prior fiscal year less the actual Base Rate Revenue received by the Department for that fiscal year. After December 31, 2014, the net amount for this 3.(a) shall be equal to zero.

   (b) Less: an amount equal to the revenue billed through VEA and allocated to the BRRTA.

   (c) an amount equal to the uncollectible amount from the BRRTA portion of the VEA.

4. On January 1, 2016, the balance of the BRRTA Balancing Account shall be added to the balance of the VEA Balancing Account as prescribed in General Provision O.3.(i), leaving no remaining balance in the BRRTA Balancing Account.

U. DEFINITIONS

For the purposes of each service schedule herein, the following definitions shall apply:

Base Period	8:00 p.m. - 10:00 a.m., Monday through Friday, all day Saturday and Sunday.
Base Rate	A portion of a rate other than the adjustments.
Capacity Charge	A charge related to the cost of the facilities necessary to supply the customer.
City Transfer Percentage	The percentage of audited gross operating revenue used to calculate the latest transfer of surplus money from the Power Revenue Fund to the City's Reserve Fund.
Commercial	Activities devoted primarily to business or professional purposes.
Common Area Service(Residential)	Service to shared facilities in multifamily dwellings which are separately metered.
Connected Load	The sum of the rated capacities of all of the customer's equipment that can be connected to the Department's system at any one time.
Customer	Any person, public or private association or corporation, partnership, unincorporated association, or governmental agency supplied or entitled to be supplied by the Department.
Daily Energy Credit	Energy Credit is the amount per unit of energy that the DWP pays customers for Excess Energy. The Daily Energy Credit will be calculated on a daily basis and shall be based on the Department's estimated hourly marginal energy production costs. The hourly energy production costs shall be averaged separately for each Rating Period. The Daily Energy Credit shall be posted daily on the Department's internet site.
Date of Presentation	The date on which a bill or notice is mailed or delivered by the Department to the customer.
Demand Charge	A charge related to power consumption

measured in kilowatts.

Electric Rate Ordinance	City of Los Angeles Ordinance No. 168436, as amended by City of Los Angeles Ordinance Numbers 171968, 172338, 172431, 172706, 172958, 173788, 174175, 174340, 174475, 174481, 174503, 175017, 175722, 177331, 177868, 179268, 179801, 180127, and 181181.
Energy Charge	That portion of the bill for electric service based upon the electric energy (kilowatt-hours) consumed.
Energy Credit	An amount credited to the customer based upon the electric energy (kilowatt-hours) supplied by the customer to the Department's system.
Excess Energy	Energy generated by the customer beyond the customer's consumption requirements and supplied to the Department's system.
Facilities Charge	A charge to cover expenses of distribution system facilities dedicated to a customer.
General Service	Service to any lighting or power installation except to those eligible for service under special schedules such as residential, streetlighting, and traffic control.
High Peak Period	1:00 p.m. - 5:00 p.m., Monday through Friday.
High Season	The period from June 1 to September 30.
Industrial	Activities devoted primarily to manufacturing or processing.
Kilovar-hour (kVArh)	A unit of reactive electric energy equal to one kilovar of reactive power supplied from an electric circuit for one hour.
Kilowatt (kW)	A unit of electric load or power or demand (1000 watts).
Kilowatt-hour (kWh)	The basic unit of electric energy equal to one kilowatt of power supplied from an electric circuit for one hour.

Load Factor For any billing period, Load Factor is equal to 100 times the sum of kilowatt-hours used by the Customer at the Facility during the Rating Periods divided by the product of the highest demand recorded during the Rating Periods and the sum of the total number of hours in the Rating Periods. Load Factor is mathematically calculated as a percentage and shall be truncated to one decimal place.

Low Peak Period 10:00 a.m. - 1:00 p.m., Monday through Friday, and 5:00 p.m. - 8:00 p.m., Monday through Friday.

Low Season The period from October 1 to May 31.

Master Meter A meter used for billing purposes serving a group of otherwise unmetered dwelling units or other establishments or a group of subordinate meters.

Maximum Demand The average kilowatt load to the nearest one-tenth kilowatt during the 15-minute period of greatest use during a billing period, as recorded by the Department's meter. Demand is another term for power and is expressed in units of kilowatt. In cases where demand is intermittent or subject to severe fluctuations, the Department may establish the Maximum Demand on the basis of measurement over a shorter interval of time or the kilowatt-amperes of installed transformer capacity required to meet the customer's load.

Meter A device used for the measurement of electric service provided, including energy (kilowatt-hours), demand (kilowatts), reactive energy (kVArh), and power factor.

Minimum Charge The smallest charge a customer may receive under a rate schedule.

Nominal Kilowatts The wattage necessary to be supplied by the Department's system to the lamp and its auxiliaries.

Photoelectric Controller A device that turns an electric circuit on or off based on ambient light levels.

Power	(a)	Real - the work producing part of "apparent power" or rate of supply of energy - usually expressed in kilowatts (kW).
	(b)	Reactive - the portion of "apparent power" which does no work but must be supplied to magnetic equipment, such as motors - usually expressed in kilovars (kVAr).
Power Factor		The ratio of real power (kilowatts) to apparent power (kilovolt-amperes) for any given load and time (maximum value = 1.0).
Primary Voltage		The service voltage applicable to small and medium commercial and industrial customers, nominally at 4.8 kilovolts (kV).
Rate		An amount fixed by the Board of Water and Power Commissioners by resolution and approved by the City Council by ordinance to be charged for electric service supplied by the Department to its customers.
Rated Transformer Capacity (RTC)		Some portion of the installed transformer kilovolt-amperes dedicated to a customer.
Rating Period		See High Peak Period, Low Peak Period, or Base Period.
Residential		Activities devoted primarily to residential or household purposes in family dwelling units.
Service	(a)	The supplying of electric energy to the customer.
	(b)	The wires and related facilities necessary to supply electric energy to the customer.
Service Point		The point where the conductors of the Department are connected to the conductors of the customer.
Single-Family Accommodation		An individually metered living unit designed for one family, whether freestanding or part of a structure containing other such units.
Standard Energy Credit		Energy Credit is the amount per unit of energy that the DWP pays customers for Excess Energy.

The Standard Energy Credit will be calculated monthly and be determined by the Department Energy Control Center's estimated hourly marginal energy production costs. The hourly energy production costs shall be averaged separately for each Rating Period. This Standard Energy Credit will be posted for each Rating Period on the Department's internet site on the first day of each calendar month.

Sub-meter	A meter within a customer's internal circuit, other than the Department's billing meter.
Subtransmission Voltage	The service voltage applicable to large commercial and industrial customers, nominally at 34.5 kilovolts.
System Reliability	A measure of the ability of the system to sustain the loss of a major generating unit or transmission line and continue to meet the customer's demand for energy.
Transmission Voltage	The service voltage applicable to very large commercial and industrial customers, nominally at 138 kilovolts or above.
Voltage	Difference of potential or "electrical pressure" in an electrical circuit measured in volts.
Watt	The electrical unit of power or rate of consuming energy. The rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor.
Zones	Zones in Schedule R-1 [i] Rate A for Residential Service are determined by the Customer Service Zip Code as shown in tables below.

ZONE 1				
90004	90008	90009	90016	90018
90019	90024	90025	90027	90028
90034	90035	90036	90038	90043
90045	90046	90047	90048	90049
90056	90064	90066	90067	90068
90069	90077	90094	90210	90212
90230	90232	90245	90247	90248
90272	90275	90291	90292	90293
90402	90403	90405	90501	90502
90710	90717	90731	90732	90744

ZONE 2*				
90001	90002	90003	90005	90006
90007	90010	90011	90012	90013
90014	90015	90017	90020	90021
90023	90026	90029	90031	90032
90033	90037	90039	90041	90042
90044	90057	90058	90059	90061
90062	90063	90065	91040	91041
91042	91105	91205	91210	91214
91302	91303	91304	91305	91306
91307	91309	91311	91316	91324
91325	91326	91330	91331	91335
91340	91342	91343	91344	91345
91346	91352	91355	91356	91364
91367	91401	91402	91403	91405
91406	91411	91423	91436	91504
91505	91601	91605	91606	91607
91602	91604			

*Owens Valley is included in Zone 2

Sec. 4. That the approval of the foregoing electrical rates by this Council is exempt from the requirements of the California Environmental Quality Act under the provisions of Section 21080(b)(8), and this Council makes this claim of exemption pursuant to said section and authorizes claim of exemption to be filed with the appropriate agencies.

Sec. 5. That if any section, subsection, sentence, clause, or phrase in this ordinance or the application thereof to any person or circumstance is for any reason held invalid, the validity of the remainder of the ordinance or the application of such provision to other persons or circumstances shall not be affected thereby. The City Council hereby declares that it would have passed this ordinance and each section, subsection, sentence, clause, or phrase thereof, irrespective of the fact that one or more sections, subsections, sentences, clauses, or phrases or the application thereof to any person or circumstance be held invalid

Sec. 6. That, within two years of the effective date of this ordinance, the Department and the Office of Public Accountability, in consultation with the Office of the City Attorney, shall report to the Board of Water and Power Commissioners and to the City Council as to whether consideration should then be given to fixing revised rates.

Sec. 7. The City Clerk shall certify to the passage of this ordinance and have it published in accordance with Council policy, either in a daily newspaper circulated in the City of Los Angeles or by posting for ten days in three public places in the City of Los Angeles: one copy on the bulletin board located at the Main Street entrance to the City Hall; one copy on the bulletin board located at the Main Street entrance to City Hall East; and one copy on the bulletin board located at the Temple Street entrance to the Los Angeles County Hall of Records.

I hereby certify that the foregoing ordinance was passed by the Council of the City of Los Angeles, at its meeting of

JUNE LAGMAY, City Clerk

By ______________________________
Deputy

Approved ______________

____
Mayor

Approved as to Form and Legality

CARMEN A. TRUTANICH, City Attorney

By ___________________________
(insert name here)
Assistant City Attorney

Date ___________________________

File No. ________________________

BE IT FURTHER RESOLVED that the Incremental Rate Stabilization Target shall be $75 million upon the effective date of the Incremental Ordinance.

BE IT FURTHER RESOLVED that this matter is forwarded to the Los Angeles City Council for approval by ordinance.

I HEREBY CERTIFY that the foregoing is a full, true, and correct copy of a Resolution adopted by the Board of Water and Power Commissioners of the City of Los Angeles at its meeting held SEP 12 2012

Barbara E. Moschos

Secretary

APPROVED AS TO FORM AND LEGALITY
CARMEN A. TRUTANICH, CITY ATTORNEY

SEP 04 2012

BY Brian E. Stewart
BRIAN E. STEWART
DEPUTY CITY ATTORNEY

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Residential Service Rate Summary R-1(A) Standard

Eligibility

Applicable to service to single-family, single-family with guest house, individually metered accommodations, as well as to separately metered common areas of condominiums and cooperatives devoted primarily to residential uses and whose energy and capacity requirements do not exceed those for Small General Service Schedule A-1. Battery chargers, motors and appliances, which conform in capacities to applicable electrical codes, and meet requirements of the Department's Rules, may be served under this schedule. Not applicable to single-family residential customers with an on-site transformer dedicated solely to that individual customer.

Monthly rates through June 30, 2013	High Season June - Sep.			Low Season Oct. - May		
Residential R-1(A)	Capped	Incremental	Total	Capped	Incremental	Total
Rate A - Standard Service						
Energy Charge - per kWh						
Zone 1						
Tier 1 - first 350 kWh	$0.07020	$0.00161	**$0.07181**	$0.07020	$0.00161	**$0.07181**
Tier 2 - next 700 kWh	$0.08520	$0.00251	**$0.08771**	$0.07020	$0.01751	**$0.08771**
Tier 3 - greater than 1050 kWh	$0.12000	$0.00451	**$0.12451**	$0.07020	$0.01751	**$0.08771**
Zone 2						
Tier 1 - first 500 kWh	$0.07020	$0.00161	**$0.07181**	$0.07020	$0.00161	**$0.07181**
Tier 2 - next 1000 kWh	$0.08520	$0.00251	**$0.08771**	$0.07020	$0.01751	**$0.08771**
Tier 3 - greater than 1500 kWh	$0.12000	$0.00451	**$0.12451**	$0.07020	$0.01751	**$0.08771**
Charges below are in addition to Energy Charges						
Elements Only in Capped Ordinance						
ECA - per kWh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA - per kWh	$0.00147	$0.00000	**$0.00147**	$0.00147	$0.00000	**$0.00147**
RCA - per kWh	$0.00300	$0.00000	**$0.00300**	$0.00300	$0.00000	**$0.00300**
Minimum Charge fixed charge per month (1)	$10.00	$0.00	**$10.00**	$10.00	$0.00	**$10.00**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kWh	$0.00000	$0.00127	**$0.00127**	$0.00000	$0.00127	**$0.00127**

ECA- Energy Cost Adjustment
ESA - Electric Subsidy Adjustment
RCA - Reliability Cost Adjustment
VEA - Variable Energy Adjustment
CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment
VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment
IRCA - Incremental Reliability Cost Adjustment
(1) Plus ECA, ESA and RCA
*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Residential Service Rate Summary Time of Use R-1(B)

Eligibility

Applicable to service to single-family, single-family with guest house, individually metered accommodations, as well as to separately metered common areas of condominiums and cooperatives devoted primarily to residential uses and whose energy and capacity requirements do not exceed those for Small General Service Schedule A-1. Battery chargers, motors and appliances, which conform in capacities to applicable electrical codes, and meet requirements of the Department's Rules, may be served under this schedule. Not applicable to single-family residential customers with an on-site transformer dedicated solely to that individual customer.

The Department requires mandatory service under Rate B for customers whose annual monthly average consumption reach or exceed 3000 kWh during the preceding 12 month period.If a customer's annual monthly average consumption does not reach or exceed 3,000 kWh in a year's period, a customer may choose to receive service either under Rate A or B. However, when a customer served under Rate B requests a change to Rate A, that customer may not revert to Rate B before 12 months have elapsed.

Monthly rates through June 30, 2013	High Season June - Sep.			Low Season Oct. - May		
Residential R-1(B)	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
Rate B - Time of Use						
Service Charge $ per month	$8.00	$0.00	**$8.00**	$8.00	$0.00	**$8.00**
Energy Charge - $ per kWh						
High Peak Period	$0.16061	$0.00531	**$0.16592**	$0.06515	$0.00531	**$0.07046**
Low Peak Period	$0.08144	$0.00531	**$0.08675**	$0.06515	$0.00531	**$0.07046**
Base Period	$0.04655	$0.00531	**$0.05186**	$0.05045	$0.00531	**$0.05576**
Electric Vehicle Discount $ (1)	-$0.02500	$0.00000	**-$0.02500**	-$0.02500	$0.00000	**-$0.02500**
Rates below are in addition to above Charges						
Elements Only in Capped Ordinance						
ECA - per kWh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA - per kWh	$0.00147	$0.00000	**$0.00147**	$0.00147	$0.00000	**$0.00147**
RCA - per kWh	$0.00300	$0.00000	**$0.00300**	$0.00300	$0.00000	**$0.00300**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kWh	$0.00000	$0.00127	**$0.00127**	$0.00000	$0.00127	**$0.00127**

ECA- Energy Cost Adjustment
ESA - Electric Subsidy Adjustment
RCA - Reliability Cost Adjustment
VEA - Variable Energy Adjustment
CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment
VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment
IRCA - Incremental Reliability Cost Adjustment
High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday
Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.
Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.
(1) Conditions for this element set in the capped ordinance.
*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Residential Multi-Family R-3
Eligibility

Applicable to master-metered residential facilities and mobile home parks, where the individual single-family accommodations are privately Sub-metered. Not applicable to service, which parallels, and connects to, customer's own generating facilities, except as such facilities are intended solely for emergency standby.

Monthly rates through June 30, 2013	High Season June - Sep.			Low Season Oct. - May		
Residential Multi-Family R-3	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
Service Charge $ per month	$25.00	$0.00	**$25.00**	$25.00	$0.00	**$25.00**
Facilities Charge $ per kW (1)	$5.00	$0.29	**$5.29**	$5.00	$0.29	**$5.29**
Demand Charge $ per kW (2)	$9.00	$0.50	**$9.50**	$5.50	$0.40	**$5.90**
Energy Charge $ per kWh	$0.03645	$0.00258	**$0.03903**	$0.02995	$0.00258	**$0.03253**
Rates below are in addition to Energy Charges						
Elements Only in Capped Ordinance						
ECA - per kWh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA - per kW	$0.96	$0.00	**$0.96**	$0.96	$0.00	**$0.96**
RCA - per kW	$0.46	$0.00	**$0.46**	$0.46	$0.00	**$0.46**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36**	$0.00	$0.36	**$0.36**

ECA- Energy Cost Adjustment
ESA - Electric Subsidy Adjustment
RCA - Reliability Cost Adjustment
VEA - Variable Energy Adjustment
CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment
VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment
IRCA - Incremental Reliability Cost Adjustment
(1) The Facilities Charge shall be based on the highest demand recorded in the last 12 months but not less than 30 kW.
(2) The Demand Charge shall be based on the Maximum Demand recorded during the billing period.
R-3 Special Provisions:
A customer may receive service under any of the General Service Rate Schedules, if desired, but will be ineligible for both the Lifeline Service Credit and the Low-Income Credit, and still obliged to provide Schedule R-1.
The owner shall post, in a conspicuous place, the prevailing residential electric rate schedule published by the Department, which would be applicable to the tenants if they were individually served by the Department.
The owner shall provide separate written electricity bills for each tenant, including the opening and closing meter readings for each billing period, the date the meters were read, the total electricity metered for the billing period, and the amount of the bill.
*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Small General Service A-1(A)

Eligibility

Applicable to General Service below 30 kW demand, the highest demand recorded in the last twelve months, including lighting and power, charging of batteries of commercial electric vehicles, which may be delivered through the same service in compliance with the Department's Rules, and to single-family residential service with an on-site transformer dedicated solely to that individual customer. Not applicable to service which parallels, and connects to, customer's own generating facilities, except as such facilities are intended solely for emergency standby.

Monthly rates through June 30, 2013	High Season June - Sep.			Low Season Oct. - May		
Small General Service A-1(A)	Capped	Incremental	Total	Capped	Incremental	Total
Rate A - Standard Service						
Service Charge Monthly Charge	$6.50	$0.00	**$6.50**	$6.50	$0.00	**$6.50**
Facilities Charge $ per kW (1)	$5.00	$0.29	**$5.29**	$5.00	$0.29	**$5.29**
Energy Charge $ per kWh	$0.06558	$0.00358	**$0.06916**	$0.04268	$0.00358	**$0.04626**
Elements Only in Capped Ordinance						
ECA $/kWh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36**	$0.00	$0.36	**$0.36**

ECA- Energy Cost Adjustment
ESA - Electric Subsidy Adjustment
RCA - Reliability Cost Adjustment
VEA - Variable Energy Adjustment
CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment
VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment
IRCA - Incremental Reliability Cost Adjustment

(1) The Facilities Charge shall be based on the highest demand recorded in the last 12 months, but not less than 4 kW.

A-1(A)Special Provisions:

The Department requires mandatory service under Rate B for single-family residential service with an on-site transformer dedicated solely to that individual customer.If a customer is not a single-family residential service with an on-site transformer dedicated solely to that individual customer, a customer may choose to receive service either under Rate A or B. However, when a customer served under Rate B requests a change to Rate A, that customer may not revert to Rate B before 12 months have elapsed.The customer shall be placed on Schedule A-2 or A-3 whose Maximum Demand either:

- Reaches or exceeds 30 kW in any three billing months or two bimonthly billing periods during the preceding 12 month period
- Reaches or exceeds 30 kW during two High Season billing months or one High Season bimonthly billing period within a calendar year

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Small General Service A-1(B) TOU
Eligibility

Applicable to General Service below 30 kW demand, the highest demand recorded in the last twelve months, including lighting and power, charging of batteries of commercial electric vehicles, which may be delivered through the same service in compliance with the Department's Rules, and to single-family residential service with an on-site transformer dedicated solely to that individual customer. Not applicable to service which parallels, and connects to, customer's own generating facilities, except as such facilities are intended solely for emergency standby.

Monthly rates through June 30, 2013	High Season June - Sep.			Low Season Oct. - May		
Small General Service A-1(B) TOU	Capped	Incremental	Total	Capped	Incremental	Total
Service Charge $ per month	$15.00	$0.00	**$15.00**	$15.00	$0.00	**$15.00**
Facilities Charge $ per kW (1)	$5.00	$0.29	**$5.29**	$5.00	$0.29	**$5.29**
Energy Charge - $ per kWh						
High Peak Period	$0.16385	$0.00394	**$0.16779**	$0.05854	$0.00394	**$0.06248**
Low Peak Period	$0.10256	$0.00394	**$0.10650**	$0.05854	$0.00394	**$0.06248**
Base Period	$0.03122	$0.00394	**$0.03516**	$0.03122	$0.00394	**$0.03516**
Electric Vehicle Discount $ (2)	-$0.02500	$0.00000	**-$0.02500**	-$0.02500	$0.00000	**-$0.02500**
Elements Only in Capped Ordinance						
ECA $/kWh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36**	$0.00	$0.36	**$0.36**

ECA- Energy Cost Adjustment
ESA - Electric Subsidy Adjustment
RCA - Reliability Cost Adjustment
VEA - Variable Energy Adjustment
CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment
VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment
IRCA - Incremental Reliability Cost Adjustment
(1) The Facilities Charge shall be based on the highest demand recorded in the last 12 months, but not less than 4 kW.
(2) Conditions for this element set in the capped ordinance.
A-1(B) Special Provisions:

The Department requires mandatory service under Rate B for single-family residential service with an on-site transformer dedicated solely to that individual customer.If a customer is not a single-family residential service with an on-site transformer dedicated solely to that individual customer in accordance with above , a customer may choose to receive service either under Rate A or B. However, when a customer served under Rate B requests a change to Rate A, that customer may not revert to Rate B before 12 months have elapsed.The customer shall be placed on Schedule A-2 or A-3 whose Maximum Demand either:
- Reaches or exceeds 30 kW in any three billing months or two bimonthly billing periods during the preceding 12 month period
- Reaches or exceeds 30 kW during two High Season billing months or one High Season bimonthly billing period within a calendar year

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday
Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.
Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.
*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the ting electric rate ordinance, for which billing has be pped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Primary Service A-2(B) TOU

Eligibility

Applicable to General Service delivered from the Department's 4.8kV system and 30 kW demand or greater, the highest demand recorded in the last twelve months including lighting and power, charging of batteries of commercial electric vehicles, which may be delivered through the same service in compliance with the Department's Rules, and to single-family residential service with an on-site transformer dedicated solely to that individual customer. Not applicable to service which parallels, and connects to, the customer's own generating facilities, except as such facilities are intended solely for emergency standby.

Monthly rates through June 30, 2013	**High Season**			**Low Season**		
	June - Sep.			**Oct. - May**		
Primary Service A-2(B) TOU	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
Service Charge $ per month	$28.00	$0.00	**$28.00**	$28.00	$0.00	**$28.00**
Facilities Charge $ per kW (1)	$5.00	$0.29	**$5.29**	$5.00	$0.29	**$5.29**
Demand Charge $ per kW (2)						
High Peak Period	$9.00	$0.50	**$9.50**	$4.25	$0.25	**$4.50**
Low Peak Period	$3.25	$0.25	**$3.50**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04679	$0.00258	**$0.04937**	$0.04045	$0.00258	**$0.04303**
Low Peak Period	$0.03952	$0.00258	**$0.04210**	$0.04045	$0.00258	**$0.04303**
Base Period	$0.01879	$0.00258	**$0.02137**	$0.02252	$0.00258	**$0.02510**
Electric Vehicle Discount $ (3)	-$0.02500	$0.00000	**-$0.02500**	-$0.02500	$0.00000	**-$0.02500**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36000	**$0.36**	$0.00	$0.36000	**$0.36**
Reactive Energy Charge (4)	**High Season**	**High Season**	**High Season**	**Low Season**	**Low Season**	**Low Season**
Unmetered $ per kWh by Period	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
High Peak Period	$0.00026	$0.00001	**$0.00027**	$0.00023	$0.00001	**$0.00024**
Low Peak Period	$0.00017	$0.00001	**$0.00018**	$0.00023	$0.00001	**$0.00024**
Base Period	$0.00011	$0.00001	**$0.00012**	$0.00014	$0.00001	**$0.00015**
Metered: Power Factor Range by Period	**High Season**	**High Season**	**High Season**	**Low Season**	**Low Season**	**Low Season**
High Peak Period $ per kvarh	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
0.995-1.000	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
0.950-0.994	$0.00088	$0.00004	**$0.00092**	$0.00076	$0.00004	**$0.00080**
0.900-0.949	$0.00167	$0.00008	**$0.00175**	$0.00145	$0.00007	**$0.00152**
0.800-0.899	$0.00509	$0.00025	**$0.00534**	$0.00439	$0.00021	**$0.00460**
0.700-0.799	$0.00853	$0.00041	**$0.00894**	$0.00737	$0.00036	**$0.00773**
0.600-0.699	$0.01185	$0.00057	**$0.01242**	$0.01023	$0.00049	**$0.01072**
0.000-0.599	$0.01293	$0.00062	**$0.01355**	$0.01116	$0.00054	**$0.01170**
Low Peak Period $ per kvarh						
0.995-1.000	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
0.950-0.994	$0.00059	$0.00003	**$0.00062**	$0.00076	$0.00004	**$0.00080**
0.900-0.949	$0.00113	$0.00005	**$0.00118**	$0.00145	$0.00007	**$0.00152**
0.800-0.899	$0.00339	$0.00016	**$0.00355**	$0.00439	$0.00021	**$0.00460**
0.700-0.799	$0.00571	$0.00028	**$0.00599**	$0.00737	$0.00036	**$0.00773**
0.600-0.699	$0.00787	$0.00038	**$0.00825**	$0.01023	$0.00049	**$0.01072**
0.000-0.599	$0.00859	$0.00041	**$0.00900**	$0.01116	$0.00054	**$0.01170**
Base Period $ per kvarh						
0.995-1.000	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
0.950-0.994	$0.00036	$0.00002	**$0.00038**	$0.00043	$0.00002	**$0.00045**
0.900-0.949	$0.00058	$0.00003	**$0.00061**	$0.00070	$0.00003	**$0.00073**
0.800-0.899	$0.00153	$0.00007	**$0.00160**	$0.00183	$0.00009	**$0.00192**
0.700-0.799	$0.00254	$0.00012	**$0.00266**	$0.00305	$0.00015	**$0.00320**
0.600-0.699	$0.00351	$0.00017	**$0.00368**	$0.00421	$0.00020	**$0.00441**
0.000-0.599	$0.00383	$0.00018	**$0.00401**	$0.00460	$0.00022	**$0.00482**

ECA- Energy Cost Adjustment
ESA - Electric Subsidy Adjustment
RCA - Reliability Cost Adjustment
VEA - Variable Energy Adjustment
CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment
VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment
IRCA - Incremental Reliability Cost Adjustment

(1) The Facilities Charge shall be based on the highest demand recorded in the last 12 months, but not less than 30 kW.
(2) The Demand Charge be based on the Maximum Demands recorded within the applicable Rating Periods during the billing month.
(3) Conditions for this element set in the capped ordinance.
(4) Applied if demand as determined for the Facilities Charge is greater than 250 kW.

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday
Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.
Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.
*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the ting electric rate ordinance, for which billing has b apped, plus the new incremental electric rate ordinance. The following is intended only as summary of the two ordinances' rates for customers nd is not intended to modify the ordinances:

Subtransmission Service A-3(A)

Eligibility

Applicable to General Service delivered from the Department's 34.5kV system and 30 kW demand or greater, the highest demand recorded in the last 12 months, including lighting and power which may be delivered through the same service in compliance with the Department's Rules. Not applicable to service which parallels, and connects to, the customer's own generating facilities, except as such facilities are intended solely for emergency standby.

Monthly rates through June 30, 2013	High Season June - Sep.			Low Season Oct. - May		
Subranmission Service A-3(A)	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
Service Charge $ per month	$75.00	$0.00	**$75.00**	$75.00	$0.00	**$75.00**
Facilities Charge $ per kW (1)	$4.00	$0.39	**$4.39**	$4.00	$0.39	**$4.39**
Demand Charge $ per kW (2)						
High Peak Period	$9.00	$0.35	**$9.35**	$4.00	$0.15	**$4.15**
Low Peak Period	$3.00	$0.15	**$3.15**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04390	$0.00254	**$0.04644**	$0.03863	$0.00254	**$0.04117**
Low Peak Period	$0.03764	$0.00254	**$0.04018**	$0.03863	$0.00254	**$0.04117**
Base Period	$0.01755	$0.00254	**$0.02009**	$0.02197	$0.00254	**$0.02451**
Electric Vehicle Discount $ (3)	-$0.02500	$0.00000	**-$0.02500**	-$0.02500	$0.00000	**-$0.02500**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36**	$0.00	$0.36000	**$0.36**
Reactive Energy Charge (4)	**High Season**	**High Season**	**High Season**	**Low Season**	**Low Season**	**Low Season**
Unmetered $ per kWh by Period	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
High Peak Period	$0.00026	$0.00001	**$0.00027**	$0.00023	$0.00001	**$0.00024**
Low Peak Period	$0.00017	$0.00001	**$0.00018**	$0.00023	$0.00001	**$0.00024**
Base Period	$0.00011	$0.00001	**$0.00012**	$0.00014	$0.00001	**$0.00015**
Metered: Power Factor Range by Period	**High Season**	**High Season**	**High Season**	**Low Season**	**Low Season**	**Low Season**
High Peak Period $ per kvarh	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
0.995-1.000	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
0.950-0.994	$0.00086	$0.00004	**$0.00090**	$0.00076	$0.00004	**$0.00080**
0.900-0.949	$0.00164	$0.00008	**$0.00172**	$0.00145	$0.00007	**$0.00152**
0.800-0.899	$0.00500	$0.00024	**$0.00524**	$0.00440	$0.00021	**$0.00461**
0.700-0.799	$0.00838	$0.00040	**$0.00878**	$0.00737	$0.00036	**$0.00773**
0.600-0.699	$0.01164	$0.00056	**$0.01220**	$0.01024	$0.00049	**$0.01073**
0.000-0.599	$0.01270	$0.00061	**$0.01331**	$0.01117	$0.00054	**$0.01171**
Low Peak Period $ per kvarh						
0.995-1.000	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
0.950-0.994	$0.00059	$0.00003	**$0.00062**	$0.00076	$0.00004	**$0.00080**
0.900-0.949	$0.00113	$0.00005	**$0.00118**	$0.00145	$0.00007	**$0.00152**
0.800-0.899	$0.00338	$0.00016	**$0.00354**	$0.00440	$0.00021	**$0.00461**
0.700-0.799	$0.00570	$0.00027	**$0.00597**	$0.00737	$0.00036	**$0.00773**
0.600-0.699	$0.00785	$0.00038	**$0.00823**	$0.01024	$0.00049	**$0.01073**
0.000-0.599	$0.00857	$0.00041	**$0.00898**	$0.01117	$0.00054	**$0.01171**
Base Period $ per kvarh						
0.995-1.000	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
0.950-0.994	$0.00036	$0.00002	**$0.00038**	$0.00045	$0.00002	**$0.00047**
0.900-0.949	$0.00059	$0.00003	**$0.00062**	$0.00073	$0.00004	**$0.00077**
0.800-0.899	$0.00153	$0.00007	**$0.00160**	$0.00192	$0.00009	**$0.00201**
0.700-0.799	$0.00255	$0.00012	**$0.00267**	$0.00319	$0.00015	**$0.00334**
0.600-0.699	$0.00352	$0.00017	**$0.00369**	$0.00440	$0.00021	**$0.00461**
0.000-0.599	$0.00384	$0.00019	**$0.00403**	$0.00481	$0.00023	**$0.00504**

ECA- Energy Cost Adjustment
ESA - Electric Subsidy Adjustment
RCA - Reliability Cost Adjustment
VEA - Variable Energy Adjustment
CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment
VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment
IRCA - Incremental Reliability Cost Adjustment

(1) The Facilities Charge shall be based on the highest demand recorded in the last 12 months, but not less than 30 kW.
(2) The Demand Charge be based on the Maximum Demands recorded within the applicable Rating Periods during the billing month.
(3) Conditions for this element set in the capped ordinance.
(4) Applied if demand as determined for the Facilities Charge is greater than 250 kW.

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday
Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.
Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.
*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Transmission Service A-4(A)

Eligibility

Applicable to General Service delivered by the Department from 138 kV or above and 80 MW demand or greater, and as established by the Department to be economically advantageous and physically feasible. Notwithstanding the above, this schedule will be provided at the sole discretion of the Department and is limited to availability on the Department's system and will be available only if determined to be feasible following comprehensive transmission system studies. All equipment or structures on customer premises necessary for the utilization of service delivered by the Department from 138 kV or above shall be owned and maintained by the customer. However, some equipment may be installed by the Department on the customer's premises. All conduit and conductors required from the nearest 138 kV source or above to the Service Point will be installed by the Department and the cost paid by the customer. A customer must maintain a 10 MW load for this rate.

Monthly rates through June 30, 2013	**High Season June - Sep.**			**Low Season Oct. - May**		
Transmission Service A-4(A)	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
Service Charge $ per month	$1,000.00	$0.00	**$1,000.00**	$1,000.00	$0.00	**$1,000.00**
Facilities Charge $ per kW (1)	$2.00	$0.20	**$2.20**	$2.00	$0.20	**$2.20**
Demand Charge $ per kW (2)						
High Peak Period	$8.91	$0.35	**$9.26**	$3.96	$0.15	**$4.11**
Low Peak Period	$2.97	$0.15	**$3.12**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04341	$0.00251	**$0.04592**	$0.03819	$0.00251	**$0.04070**
Low Peak Period	$0.03721	$0.00251	**$0.03972**	$0.03819	$0.00251	**$0.04070**
Base Period	$0.01733	$0.00251	**$0.01984**	$0.02170	$0.00251	**$0.02421**
Electric Vehicle Discount $ (3)	-$0.02500	$0.00000	**-$0.02500**	-$0.02500	$0.00000	**-$0.02500**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36000	**$0.36**	$0.00	$0.36000	**$0.36**
Reactive Energy Charge	**High Season**	**High Season**	**High Season**	**Low Season**	**Low Season**	**Low Season**
Unmetered $ per kWh by Period	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
High Peak Period	$0.00026	$0.00001	**$0.00027**	$0.00023	$0.00001	**$0.00024**
Low Peak Period	$0.00017	$0.00001	**$0.00018**	$0.00023	$0.00001	**$0.00024**
Base Period	$0.00011	$0.00001	**$0.00012**	$0.00014	$0.00001	**$0.00015**
Metered: Power Factor Range by Period	**High Season**	**High Season**	**High Season**	**Low Season**	**Low Season**	**Low Season**
High Peak Period $ per kvarh	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
0.995-1.000	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
0.950-0.994	$0.00085	$0.00004	**$0.00089**	$0.00075	$0.00004	**$0.00079**
0.900-0.949	$0.00163	$0.00008	**$0.00171**	$0.00143	$0.00007	**$0.00150**
0.800-0.899	$0.00494	$0.00024	**$0.00518**	$0.00435	$0.00021	**$0.00456**
0.700-0.799	$0.00828	$0.00040	**$0.00868**	$0.00729	$0.00035	**$0.00764**
0.600-0.699	$0.01151	$0.00055	**$0.01206**	$0.01012	$0.00049	**$0.01061**
0.000-0.599	$0.01255	$0.00060	**$0.01315**	$0.01105	$0.00053	**$0.01158**
Low Peak Period $ per kvarh						
0.995-1.000	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
0.950-0.994	$0.00058	$0.00003	**$0.00061**	$0.00075	$0.00004	**$0.00079**
0.900-0.949	$0.00112	$0.00005	**$0.00117**	$0.00143	$0.00007	**$0.00150**
0.800-0.899	$0.00334	$0.00016	**$0.00350**	$0.00435	$0.00021	**$0.00456**
0.700-0.799	$0.00563	$0.00027	**$0.00590**	$0.00729	$0.00035	**$0.00764**
0.600-0.699	$0.00776	$0.00037	**$0.00813**	$0.01012	$0.00049	**$0.01061**
0.000-0.599	$0.00848	$0.00041	**$0.00889**	$0.01105	$0.00053	**$0.01158**
Base Period $ per kvarh						
0.995-1.000	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
0.950-0.994	$0.00035	$0.00002	**$0.00037**	$0.00044	$0.00002	**$0.00046**
0.900-0.949	$0.00058	$0.00003	**$0.00061**	$0.00072	$0.00003	**$0.00075**
0.800-0.899	$0.00151	$0.00007	**$0.00158**	$0.00189	$0.00009	**$0.00198**
0.700-0.799	$0.00252	$0.00012	**$0.00264**	$0.00315	$0.00015	**$0.00330**
0.600-0.699	$0.00347	$0.00017	**$0.00364**	$0.00435	$0.00021	**$0.00456**
0.000-0.599	$0.00379	$0.00018	**$0.00397**	$0.00475	$0.00023	**$0.00498**

ECA- Energy Cost Adjustment
ESA - Electric Subsidy Adjustment
RCA - Reliability Cost Adjustment
VEA - Variable Energy Adjustment
CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment
VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment
IRCA - Incremental Reliability Cost Adjustment

(1) The Facilities Charge shall be based on the highest demand recorded in the last 12 months, but not less than 10 MW.
(2) The Demand Charge be based on the Maximum Demands recorded within the applicable Rating Periods during the billing month.
(3) Conditions for this element set in the capped ordinance.

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday
Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.
Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.
*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Alternative Maritime Power AMP
Eligibility

Applicable to services with energy usage resulting from Merchant Ships participating in the Port of Los Angeles (POLA) Alternative Maritime Power (AMP). Seventy-five percent of energy consumed by services on this schedule must be from Merchant Ships. POLA shall be responsible for the installation and maintenance of facilities up to the high-side of the 34.5 kV Station which is serving the Merchant Ship loads. Not applicable to customers served under Service Rider-Net Energy Metering and General Service Rider Enterprise Zone.The Department may remotely interrupt any AMP load under this service with thirty minutes advanced notice to POLA. The Department shall determine the interruption duration. POLA shall be responsible for purchasing and installing all equipment required for remote interruption.

Monthly rates through June 30, 2013			
AMP Interruptible (1)	**Capped**	**Incremental**	**Total**
Service Charge Monthly Charge	$150.00	$0.00	**$150.00**
Facilities Charge $ per kW (2)	$1.33	$0.08	**$1.41**
Energy Charge $ per kWh	$0.05910	$0.00898	**$0.06808**
Elements Only in Capped Ordinance			
ECA $/kWh	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**
RCA $/kWh	$0.00300	$0.00000	**$0.00300**
Elements Only in Incremental Ordinance			
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**
IRCA - per kWh	$0.00000	$0.00127	**$0.00127**
Reactive Energy Charge			
Unmetered $ per kWh by Period			
High Peak Period	$0.00024	$0.00001	**$0.00025**
Low Peak Period	$0.00021	$0.00001	**$0.00022**
Base Period	$0.00013	$0.00001	**$0.00014**
Metered: Power Factor Range by Period			
High Peak Period $ per kvarh			
0.995-1.000	$0.00000	$0.00000	**$0.00000**
0.950-0.994	$0.00038	$0.00002	**$0.00040**
0.900-0.949	$0.00066	$0.00003	**$0.00069**
0.800-0.899	$0.00183	$0.00009	**$0.00192**
0.700-0.799	$0.00306	$0.00015	**$0.00321**
0.600-0.699	$0.00423	$0.00020	**$0.00443**
0.000-0.599	$0.00462	$0.00022	**$0.00484**

ECA- Energy Cost Adjustment
ESA - Electric Subsidy Adjustment
RCA - Reliability Cost Adjustment
VEA - Variable Energy Adjustment
CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment
VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment
IRCA - Incremental Reliability Cost Adjustment

(1) The Department shall provide not less than 30-minutes advanced notice of a Period of Interruption for service.

(2) The Facilities Charge shall be based on the highest demand recorded in the last 12 months, but not less than 500 kW.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Alternative Maritime Power AMP-B

Eligibility

Applicable to services with energy usage resulting from Merchant Ships with Maximum Demand of not less than 7 megawatss (MW) per month participating in the Port of Los Angeles (POLA) Alternative Maritime Power (AMP). Seventy-five percent of energy consumed by services on this schedule must be from Merchant Ships. POLA shall be responsible for the installation and maintenance of facilities up to the high-side of the 34.5 kV Station which is serving the Merchant Ship loads. Not applicable to customers served under Service Rider-Net Energy Metering and General Service Rider Enterprise Zone.The Department may remotely interrupt any AMP load under this service with ten minutes advanced notice to POLA. The Department shall determine the interruption duration. POLA shall be responsible for purchasing and installing all equipment required for remote interruption.

Monthly rates through June 30, 2013			
Rate B - AMP Interruptible over 7 MW Demand (1)	**Capped**	**Incremental**	**Total**
Minimum Charge	$0.00	$10,000.00	**$10,000.00**
Energy Charge $ per kWh	$0.00000	$0.01953	**$0.01953**
Additive elements from AMP-A rate for AMP-B			
Service Charge Monthly Charge	$150.00	$0.00	**$150.00**
Energy Charge $ per kWh	$0.05910	$0.00898	**$0.06808**
Elements Only in Capped Ordinance			
ECA $/kWh	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**
RCA $/kWh	$0.00300	$0.00000	**$0.00300**
Elements Only in Incremental Ordinance			
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**
IRCA - per kWh	$0.00000	$0.00127	**$0.00127**
Reactive Energy Charge			
Unmetered $ per kWh by Period			
High Peak Period	$0.00024	$0.00001	**$0.00025**
Low Peak Period	$0.00021	$0.00001	**$0.00022**
Base Period	$0.00013	$0.00001	**$0.00014**
Metered: Power Factor Range by Period			
High Peak Period $ per kvarh			
0.995-1.000	$0.00000	$0.00000	**$0.00000**
0.950-0.994	$0.00038	$0.00002	**$0.00040**
0.900-0.949	$0.00066	$0.00003	**$0.00069**
0.800-0.899	$0.00183	$0.00009	**$0.00192**
0.700-0.799	$0.00306	$0.00015	**$0.00321**
0.600-0.699	$0.00423	$0.00020	**$0.00443**
0.000-0.599	$0.00462	$0.00022	**$0.00484**

ECA- Energy Cost Adjustment
ESA - Electric Subsidy Adjustment
RCA - Reliability Cost Adjustment
VEA - Variable Energy Adjustment
CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment
VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment
IRCA - Incremental Reliability Cost Adjustment

(1) The Department shall provide not less than 10-minutes advanced notice of a Period of Interruption for service.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Experimental Real-Time Pricing, Primary Service XRT-2(A)

Eligibility

Applicable to service with 250 kW demand or greater and served from the Department's 4.8kV system, which may be delivered through the same service in compliance with the Department's Rules. Not applicable to service under Schedule CG-2.

Monthly rates through June 30, 2013	High Season			Low Season		
Rate A Voluntary Curtailment XRT-2	June - Sep.			Oct. - May		
Primary Service (4.8 KV)	Capped	Incremental	Total	Capped	Incremental	Total
Service Charge $ per month	$150.00	$0.00	**$150.00**	$150.00	$0.00	**$150.00**
Facilities Charge $ per kW (1)	$5.00	$0.29	**$5.29**	$5.00	$0.29	**$5.29**
Demand Charge $ per kW (2)						
High Peak Period	$4.25	$0.25	**$4.50**	$4.25	$0.25	**$4.50**
Low Peak Period	$3.25	$0.25	**$3.50**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04679	$0.00258	**$0.04937**	$0.04045	$0.00258	**$0.04303**
Low Peak Period	$0.03952	$0.00258	**$0.04210**	$0.04045	$0.00258	**$0.04303**
Base Period	$0.01879	$0.00258	**$0.02137**	$0.02252	$0.00258	**$0.02510**
Alert Period Energy Charge $ per kWh (3)						
High Peak Period	$3.00150	$0.14467	**$3.14617**	$0.04045	$0.00258	**$0.04303**
Low Peak Period	$1.05840	$0.05101	**$1.10941**	$0.04045	$0.00258	**$0.04303**
Base Period	$0.01879	$0.00258	**$0.02137**	$0.02252	$0.00258	**$0.02510**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36**	$0.00	$0.36	**$0.36**
Reactive Energy Charge, see Rate A-2(B)						

ECA- Energy Cost Adjustment

ESA - Electric Subsidy Adjustment

RCA - Reliability Cost Adjustment

VEA - Variable Energy Adjustment

CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment

VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment

IRCA - Incremental Reliability Cost Adjustment

(1) The Facilities Charge shall be based on the highest demand recorded in the last 12 months.

(2) The Demand Charge be based on the Maximum Demands recorded within the applicable Rating Periods during the billing month.

(3) During an Alert Period, the customer is expected to reduce load. For excess energy consumption during an Alert Period, the customer shall pay the Alert Period Energy Charge.

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday

Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.

Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Experimental Real-Time Pricing, Subtransmission Service XRT-3(A)

Eligibility

Applicable to service with 250 kW demand or greater and served from the Department's 34.5kV system, which may be delivered through the same service in compliance with the Department's Rules. Not applicable to service under Schedule CG-3.

Monthly rates through June 30, 2013	**High Season**			**Low Season**		
Rate A Voluntary Curtailment XRT-3	**June - Sep.**			**Oct. - May**		
Subtransmission (34.5 KV)	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
Service Charge $ per month	$150.00	$0.00	**$150.00**	$150.00	$0.00	**$150.00**
Facilities Charge $ per kW (1)	$4.00	$0.39	**$4.39**	$4.00	$0.39	**$4.39**
Demand Charge $ per kW (2)						
High Peak Period	$4.95	$0.19	**$5.14**	$4.00	$0.15	**$4.15**
Low Peak Period	$3.00	$0.15	**$3.15**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04390	$0.00254	**$0.04644**	$0.03863	$0.00254	**$0.04117**
Low Peak Period	$0.03764	$0.00254	**$0.04018**	$0.03863	$0.00254	**$0.04117**
Base Period	$0.01755	$0.00254	**$0.02009**	$0.02197	$0.00254	**$0.02451**
Alert Period Energy Charge $ per kWh (3)						
High Peak Period	$2.83700	$0.13674	**$2.97374**	$0.03863	$0.00254	**$0.04117**
Low Peak Period	$1.20140	$0.05791	**$1.25931**	$0.03863	$0.00254	**$0.04117**
Base Period	$0.01755	$0.00254	**$0.02009**	$0.02197	$0.00254	**$0.02451**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36**	$0.00	$0.36	**$0.36**
Reactive Energy Charge, see Rate A-3(A)						

ECA- Energy Cost Adjustment

ESA - Electric Subsidy Adjustment

RCA - Reliability Cost Adjustment

VEA - Variable Energy Adjustment

CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment

VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment

IRCA - Incremental Reliability Cost Adjustment

(1) The Facilities Charge shall be based on the highest demand recorded in the last 12 months, but not less than 30 kW.

(2) The Demand Charge be based on the Maximum Demands recorded within the applicable Rating Periods during the billing month.

(3) During an Alert Period, the customer is expected to reduce load. For excess energy consumption during an Alert Period, the customer shall pay the Alert Period Energy Charge.

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday

Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.

Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Experimental Contract Demand Service, Primary Service XCD-2(A)
Eligibility

Applicable to General Service which may be delivered through the same service in compliance with the Department's Rules. Applicable to service with an average consumption exceeding 500,000 kilowatt-hours per month and served from the Department's 4.8kV system. Not applicable to service under Schedule CG-2.

Monthly rates through June 30, 2013 Experimental Contract Demand Service	High Season June - Sep.			Low Season Oct. - May		
Primary Service (4.8 KV) XCD-2(A)	Capped	Incremental	Total	Capped	Incremental	Total
Service Charge $ per month	$150.00	$0.00	**$150.00**	$150.00		**$150.00**
Facilities Charge $ per kW (1)	$5.00	$0.29	**$5.29**	$5.00	$0.29	**$5.29**
Demand Charge $ per kW, varies see (2)						
Energy Charge - $ per kWh						
High Peak Period	$0.04679	$0.00258	**$0.04937**	$0.04045	$0.00258	**$0.04303**
Low Peak Period	$0.03952	$0.00258	**$0.04210**	$0.04045	$0.00258	**$0.04303**
Base Period	$0.01879	$0.00258	**$0.02137**	$0.02252	$0.00258	**$0.02510**
Schedule of Discount By Load Factor (3)	**No Seasons**	**No Seasons**				
Load Factor	**Bill Discount**	**Demand Discount**				
90%	10%	28.17%				
85%	8%	21.91%				
80%	6%	15.96%				
75%	4%	10.33%				
70%	2%	5.01%				
	High Season June - Sep.			Low Season Oct. - May		
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36**	$0.00	$0.36	**$0.36**
Reactive Energy Charge, see Rate A-2(B)						

ECA- Energy Cost Adjustment
ESA - Electric Subsidy Adjustment
RCA - Reliability Cost Adjustment
VEA - Variable Energy Adjustment
CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment
VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment
IRCA - Incremental Reliability Cost Adjustment
(1) The Facilities Charge shall be based on the highest demand recorded in the last 12 months..
(2) The Demand Charge shall be based on the Maximum Demands recorded within the applicable Rating Periods as shown in the Schedule of Discount by Load Factor, however, unit prices may vary by terms of the contract.
(3) Demand Discount as a percent of Demand Charge set forth in Schedule A-2(B) for the referenced Load Factor.
High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday
Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.
Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.
*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the capped rate ordinance plus the new incremental rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Experimental Contract Demand Service, Subtransmission Service XCD-3(A)

Eligibility

Applicable to General Service which may be delivered through the same service in compliance with the Department's Rules. Applicable to service with an average consumption exceeding 500,000 kilowatt-hours per month and served from the Department's 34.5 kV system. Not applicable to service under Schedule CG-3.

Monthly rates through June 30, 2013	High Season			Low Season		
Experimental Contract Demand Service XCD-3(A)	June - Sep.			Oct. - May		
Subtransmission Service 34.5 kV	Capped	Incremental	Total	Capped	Incremental	Total
Service Charge $ per month	$150.00	$0.00	**$150.00**	$150.00	$0.00	**$150.00**
Facilities Charge $ per kW (1)	$4.00	$0.39	**$4.39**	$4.00	$0.39	**$4.39**
Demand Charge $ per kW, varies see (2)						
Energy Charge - $ per kWh						
High Peak Period	$0.04390	$0.00254	**$0.04644**	$0.03863	$0.00254	**$0.04117**
Low Peak Period	$0.03764	$0.00254	**$0.04018**	$0.03863	$0.00254	**$0.04117**
Base Period	$0.01755	$0.00254	**$0.02009**	$0.02197	$0.00254	**$0.02451**
Schedule of Discount By Load Factor (3)	**No Seasons**	**No Seasons**				
Load Factor	**Bill Discount**	**Demand Discount**				
90%	10%	26.85%				
85%	8%	20.88%				
80%	6%	15.21%				
75%	4%	9.84%				
70%	2%	4.77%				
	High Season			Low Season		
Elements Only in Capped Ordinance	June - Sep.			Oct. - May		
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36**	$0.00	$0.36	**$0.36**
Reactive Energy Charge, see Rate A-3(A)						

ECA- Energy Cost Adjustment

ESA - Electric Subsidy Adjustment

RCA - Reliability Cost Adjustment

VEA - Variable Energy Adjustment

CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment

VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment

IRCA - Incremental Reliability Cost Adjustment

(1) The Facilities Charge shall be based on the highest demand recorded in the last 12 months..

(2) The Demand Charge shall be based on the Maximum Demands recorded within the applicable Rating Periods as shown in the Schedule of Discount by Load Factor, however, unit prices may vary by terms of the contract.

(3) Demand Discount as a percent of Demand Charge set for the in Schedule A-3(A) for the referenced Load Factor.

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday

Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.

Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Customer Generation, Primary Service (4.8 kV) CG-2(A)

Eligibility

Applicable to customers who generate either to sell Excess Energy to the Department and/or to serve their own electricity requirements but have the Department provide Electric Service including supplemental and backup power.

Applicable when both the following conditions exist:

(1) Any Electric Service provided by the Department where a customer-owned electrical generating facility is interconnected with the Department's system for Parallel Operation and in compliance with the Department's Rules.

(2) Loads that are served from the Primary Distribution System and which would normally be served under General Service Schedules A-1 and A-2.

Not applicable to:

(1) Any person or entity that is a utility or a "Public Utility" as defined by the Public Utilities Code, including Sections 216 and 9604.

(2) Customer-owned electrical generating facilities interconnected with the Department System for Momentary Interconnection.

Monthly rates through June 30, 2013 Primary Service (4.8 kV) CG-2(A)	June - Sep.			Oct. - May		
Customer Generation	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
Service Charge $ per month	$150.00	$0.00	**$150.00**	$150.00	$0.00	**$150.00**
Facilities Charge $ per kW (1)	$5.00	$0.29	**$5.29**	$5.00	$0.29	**$5.29**
Supplemental Capacity Charge $ per kW (2)						
High Peak Period	$4.70	$0.00	**$4.70**	$4.25	$0.00	**$4.25**
Low Peak Period	$3.25	$0.00	**$3.25**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04679	$0.00258	**$0.04937**	$0.04045	$0.00258	**$0.04303**
Low Peak Period	$0.03952	$0.00258	**$0.04210**	$0.04045	$0.00258	**$0.04303**
Base Period	$0.01879	$0.00258	**$0.02137**	$0.02252	$0.00258	**$0.02510**
Backup Capacity Charge $ per kWh (3)						
High Peak Period	$0.14035	$0.00676	**$0.14711**	$0.00000	$0.00000	**$0.00000**
Low Peak Period	$0.03838	$0.00185	**$0.04023**	$0.00000	$0.00000	**$0.00000**
Base Period	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36000**	$0.00	$0.36000	**$0.36000**
Reactive Energy Charge as Per A-2-B						
Energy Credit (4)						

ECA- Energy Cost Adjustment

ESA - Electric Subsidy Adjustment

RCA - Reliability Cost Adjustment

VEA - Variable Energy Adjustment

CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment

VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment

IRCA - Incremental Reliability Cost Adjustment

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday

Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.

Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.

(1) The Facilities Charge shall be based on the largest of:
The highest actual demand level recorded for energy delivered by the Department energy or the energy exported to the Department in the last 12-months at the Service Point.

(2) The Supplemental Capacity Charge is based upon the Supplemental Demand and the charges are related to the cost of the facilities necessary to supply supplemental services to the customer excluding Supplemental Demand is the Maximum Coincident Demand per Rating Period, less the maximum measured customer generation demand in the respective Rating Period, but never less than zero.

(3) The Backup Capacity Charge is based upon Backup Energy. For each billing period, Backup Energy is the energy that would have been generated by the customer's generator(s) in each Rating Period (High Peak, Low Peak, Base). Backup Energy is applicable when both the following conditions exist: 1.) Delivered energy as measured by the billing meter over a fifteen minute interval at the Service Point is greater than Supplemental Demand during any Rating Period within the billing month; 2.) Demand at the output point of the customer's generator as measured by the unit meter over a fifteen minute interval must be less than the Maximum Generation Demand during any Rating Period within the billing month.

(4) Energy Credit as per General Conditions of capped ordinance CG-2.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Customer Generation, Primary Service (4.8 kV) CG-2(C)

Eligibility

Applicable to customers who generate either to sell Excess Energy to the Department and/or to serve their own electricity requirements but have the Department provide Electric Service including supplemental and backup power.

This rate is available to Rate A customers and is designed to support new customer generation and encourage clean on-site generation. Rate C is available to customers whose total Rated Generation Capacity located at a customer facility is less than 25 percent of the Maximum Coincident Demand and less than 1 MW. To qualify for this rate, each customer on-site generation unit shall have been installed and/or converted on/after January 1, 2001 to emit no more than 0.5 pounds/MWH of nitrous oxides. Such emission limit must be maintained to continue to qualify. Verification as the Department determines shall be provided.

Applicable when both the following conditions exist:

(1) Any Electric Service provided by the Department where a customer-owned electrical generating facility is interconnected with the Department's system for Parallel Operation and in compliance with the Department's Rules.

(2) Loads that are served from the Primary Distribution System and which would normally be served under General Service Schedules A-1 and A-2.

Not applicable to:

(1) Any person or entity that is a utility or a "Public Utility" as defined by the Public Utilities Code, including Sections 216 and 9604.

(2) Customer-owned electrical generating facilities interconnected with the Department System for Momentary Interconnection.

Monthly rates thru June 30, 2013	High Season			Low Season		
Primary Service (4.8 kV) CG-2(C)	June - Sep.			Oct. - May		
Customer Generation	Capped	Incremental	Total	Capped	Incremental	Total
Service Charge $ per month	$28.00	$0.00	**$28.00**	$28.00	$0.00	**$28.00**
Facilities Charge $ per kW (1)	$5.00	$0.29	**$5.29**	$5.00	$0.29	**$5.29**
Demand Charge $ per kW (2)						
High Peak Period	$9.00	$0.50	**$9.50**	$4.25	$0.25	**$4.50**
Low Peak Period	$3.25	$0.25	**$3.50**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04679	$0.00258	**$0.04937**	$0.04045	$0.00258	**$0.04303**
Low Peak Period	$0.03952	$0.00258	**$0.04210**	$0.04045	$0.00258	**$0.04303**
Base Period	$0.01879	$0.00258	**$0.02137**	$0.02252	$0.00258	**$0.02510**
Electric Vehicle Discount $	-$0.02500	$0.00000	**-$0.02500**	-$0.02500	$0.00000	**-$0.02500**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36000**	$0.00	$0.36000	**$0.36000**
Reactive Energy Charge as Per A-2-B						
Energy Credit (3)						

ECA- Energy Cost Adjustment

ESA - Electric Subsidy Adjustment

RCA - Reliability Cost Adjustment

VEA - Variable Energy Adjustment

CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment

VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment

IRCA - Incremental Reliability Cost Adjustment

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday

Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.

Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.

(1) The Facilities Charge shall be based on the largest of:
The highest actual demand level recorded for energy delivered by the Department or the energy exported to the Department in the last 12-months at the Service Point.

(2) The maximum delivered demand at the Service Point.

(3) Energy Credit as per General Conditions of capped ordinance CG-2.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Customer Generation, Primary Service (4.8 kV) CG-2(D)

Eligibility

Applicable to customers who generate either to sell Excess Energy to the Department and/or to serve their own electricity requirements but have the Department provide Electric Service including supplemental and backup power.

Rate D is an optional rate for customers receiving service under the Schedule CG-2. Rate D is available to Rate A customers. This optional rate D is for those customers who have demonstrated that they have the capability to reduce load during Department system conditions including, but not limited to, high system peaks, low generation, high market prices, temperature, and system contingencies.

Applicable when both the following conditions exist:

(1) Any Electric Service provided by the Department where a customer-owned electrical generating facility is interconnected with the Department's system for Parallel Operation and in compliance with the Department's Rules.

(2) Loads that are served from the Primary Distribution System and which would normally be served under General Service Schedules A-1 and A-2.

Not applicable to:

(1) Any person or entity that is a utility or a "Public Utility" as defined by the Public Utilities Code, including Sections 216 and 9604.

(2) Customer-owned electrical generating facilities interconnected with the Department System for Momentary Interconnection.

Monthly rates through June 30, 2013	June - Sep.			Oct. - May		
Primary Service(4.8kV) CG-2(D) Customer Generation	Capped	Incremental	Total	Capped	Incremental	Total
Service Charge $ per month	$150.00	$0.00	**$150.00**	$150.00	$0.00	**$150.00**
Facilities Charge $ per kW (1)	$5.00	$0.29	**$5.29**	$5.00	$0.29	**$5.29**
Supplemental Capacity Charge $ per kW (2)						
High Peak Period	$4.25	$0.00	**$4.25**	$4.25	$0.00	**$4.25**
Low Peak Period	$3.25	$0.00	**$3.25**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04679	$0.00258	**$0.04937**	$0.04045	$0.00258	**$0.04303**
Low Peak Period	$0.03952	$0.00258	**$0.04210**	$0.04045	$0.00258	**$0.04303**
Base Period	$0.01879	$0.00258	**$0.02137**	$0.02252	$0.00258	**$0.02510**
Backup Capacity Charge $ per kWh (3)						
High Peak Period	$0.14035	$0.00676	**$0.14711**	$0.00000	$0.00000	**$0.00000**
Low Peak Period	$0.03838	$0.00185	**$0.04023**	$0.00000	$0.00000	**$0.00000**
Base Period	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
Alert Period Energy Charge $ per kWh (4)						
High Peak Period	$0.14699	$0.00708	**$0.15407**	$0.04045	$0.00258	**$0.04303**
Low Peak Period	$0.08633	$0.00416	**$0.09049**	$0.04045	$0.00258	**$0.04303**
Base Period	$0.01879	$0.00258	**$0.02137**	$0.02252	$0.00258	**$0.02510**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36000**	$0.00	$0.36000	**$0.36000**
Reactive Energy Charge as Per A-2-B						
Energy Credit (5)						

ECA- Energy Cost Adjustment

ESA - Electric Subsidy Adjustment

RCA - Reliability Cost Adjustment

VEA - Variable Energy Adjustment

CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment

VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment

IRCA - Incremental Reliability Cost Adjustment

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday

Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.

Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.

(1)The Facilities Charge shall be based on the largest of:

The highest actual demand level recorded for energy delivered by the Department or the energy exported to the Department in the last 12-months at the Service Point.

(2) The Supplemental Capacity Charge is based upon the Supplemental Demand and the charges are related to the cost of the facilities necessary to supply supplemental services to the customer excluding costs that are recovered separately in the Facilities Charge.

Supplemental Demand is the Maximum Coincident Demand per Rating Period, less the maximum measured customer generation demand in the respective Rating Period, but never less than zero.

(3) The Backup Capacity Charge is based upon Backup Energy. For each billing period, Backup Energy is the energy that would have been generated by the customer's generator(s) in each Rating Period (High Peak, Low Peak, Base). Backup Energy is applicable when both the following conditions exist: 1.) Delivered energy as measured by the billing meter over a fifteen minute interval at the Service Point is greater than Supplemental Demand during any Rating Period within the billing month; 2.) Demand at the output point of the customer's generator as measured by the unit meter over a fifteen minute interval must be less than the Maximum Generation Demand during any Rating Period within the billing month.

(4) Customers receiving service under Rate D are expected to reduce load. For excess energy consumption during an Alert Period, the customer shall pay the Alert Period Energy Charge.

(5) Energy Credit as per General Conditions of capped ordinance CG-2.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Customer Generation, Primary Service (4.8 kV) CG-2(E)

Eligibility

Applicable to customers who generate either to sell Excess Energy to the Department and/or to serve their own electricity requirements but have the Department provide Electric Service including supplemental and backup power.

Rates E is an optional rate for customers receiving service under the Schedule CG-2. Rate E is available to Rate C customers. This optional rate E is for those customers who have demonstrated that they have the capability to reduce load during Department system conditions including, but not limited to, high system peaks, low generation, high market prices, temperature, and system contingencies.

(1) Any Electric Service provided by the Department where a customer-owned electrical generating facility is interconnected with the Department's system for Parallel Operation and in compliance with the Department's Rules.

(2) Loads that are served from the Primary Distribution System and which would normally be served under General Service Schedules A-1 and A-2.

Not applicable to:

(1) Any person or entity that is a utility or a "Public Utility" as defined by the Public Utilities Code, including Sections 216 and 9604.

(2) Customer-owned electrical generating facilities interconnected with the Department System for Momentary Interconnection.

Monthly rates through June 30, 2013 Primary Service (4.8 kV) CG-2(E)	High Season June - Sep.			Low Season Oct. - May		
Customer Generation	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
Service Charge $ per month	$150.00	$0.00	**$150.00**	$150.00	$0.00	**$150.00**
Facilities Charge $ per kW (1)	$5.00	$0.29	**$5.29**	$5.00	$0.29	**$5.29**
Demand Charge $ per kW (2)						
High Peak Period	$4.25	$0.25	**$4.50**	$4.25	$0.25	**$4.50**
Low Peak Period	$3.25	$0.25	**$3.50**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04679	$0.00258	**$0.04937**	$0.04045	$0.00258	**$0.04303**
Low Peak Period	$0.03952	$0.00258	**$0.04210**	$0.04045	$0.00258	**$0.04303**
Base Period	$0.01879	$0.00258	**$0.02137**	$0.02252	$0.00258	**$0.02510**
Electric Vehicle Discount $	-$0.02500	$0.00000	**-$0.02500**	-$0.02500	$0.00000	**-$0.02500**
Alert Period Energy Charge $ per kWh (3)						
High Peak Period	$3.00150	$0.14467	**$3.14617**	$0.04045	$0.00258	**$0.04303**
Low Peak Period	$1.05840	$0.05101	**$1.10941**	$0.04045	$0.00258	**$0.04303**
Base Period	$0.01879	$0.00258	**$0.02137**	$0.02252	$0.00258	**$0.02510**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36000**	$0.00	$0.36000	**$0.36000**
Reactive Energy Charge as Per A-2-B						
Energy Credit (4)						

ECA- Energy Cost Adjustment

ESA - Electric Subsidy Adjustment

RCA - Reliability Cost Adjustment

VEA - Variable Energy Adjustment

CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment

VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment

IRCA - Incremental Reliability Cost Adjustment

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday

Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.

Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.

(1) The Facilities Charge shall be based on the largest of:

The highest actual demand level recorded for energy delivered by the Department or the energy exported to the Department in the last 12-months at the Service Point.

(2) The maximum Department-delivered demand at the Service Point.

(3) Customers receiving service under Rate E are expected to reduce load. For excess energy consumption during an Alert Period, the customer shall pay the Alert Period Energy Charge.

(4) Energy Credit as per General Conditions of capped ordinance CG-2.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Customer Generation, Subtransmission (34.5 kV) CG-3(A)

Eligibility

Applicable to customers who generate either to sell Excess Energy to the Department and/or to serve their own electricity requirements but have the Department provide Electric Service including supplemental and backup power.

Applicable when both the following conditions exist:

(1) Any Electric Service provided by the Department where a customer-owned electrical generating facility is interconnected with the Department's system for Parallel Operation and in compliance with the Department's Rules.

(2) Loads that are served from the Primary Distribution System and which would normally be served under General Service Schedules A-1 and A-2.

Not applicable to:

(1) Any person or entity that is a utility or a "Public Utility" as defined by the Public Utilities Code, including Sections 216 and 9604.

(2) Customer-owned electrical generating facilities interconnected with the Department System for Momentary Interconnection.

Monthly rates through June 30, 2013	June - Sep.			Oct. - May		
Subtransmission (34.5 kV) CG-3(A) Customer Generation	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
Service Charge $ per month	$150.00	$0.00	**$150.00**	$150.00	$0.00	**$150.00**
Facilities Charge $ per kW (1)	$4.00	$0.39	**$4.39**	$4.00	$0.39	**$4.39**
Supplemental Capacity Charge $ per kW (2)						
High Peak Period	$5.50	$0.00	**$5.50**	$4.00	$0.00	**$4.00**
Low Peak Period	$3.00	$0.00	**$3.00**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04390	$0.00254	**$0.04644**	$0.03863	$0.00254	**$0.04117**
Low Peak Period	$0.03764	$0.00254	**$0.04018**	$0.03863	$0.00254	**$0.04117**
Base Period	$0.01755	$0.00254	**$0.02009**	$0.02197	$0.00254	**$0.02451**
Backup Capacity Charge $ per kWh (3)						
High Peak Period	$0.13110	$0.00632	**$0.13742**	$0.00000	$0.00000	**$0.00000**
Low Peak Period	$0.03220	$0.00155	**$0.03375**	$0.00000	$0.00000	**$0.00000**
Base Period	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36000**	$0.00	$0.36000	**$0.36000**
Reactive Energy Charge as Per A-3(A)						
Energy Credit (4)						

ECA- Energy Cost Adjustment

ESA - Electric Subsidy Adjustment

RCA - Reliability Cost Adjustment

VEA - Variable Energy Adjustment

CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment

VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment

IRCA - Incremental Reliability Cost Adjustment

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday

Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.

Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.

(1) The Facilities Charge shall be based on the largest of:

The highest actual demand level recorded for energy delivered by the Department or the energy exported to the Department in the last 12-months at the Service Point.

(2) The Supplemental Capacity Charge is based upon the Supplemental Demand and the charges are related to the cost of the facilities Supplemental Demand is the Maximum Coincident Demand per Rating Period, less the maximum measured customer generation demand in the respective Rating Period, but never less than zero.

(3) The Backup Capacity Charge is based upon Backup Energy. For each billing period, Backup Energy is the energy that would have been generated by the customer's generator(s) in each Rating Period (High Peak, Low Peak, Base). Backup Energy is applicable when both the following conditions exist: 1.) Delivered energy as measured by the billing meter over a fifteen minute interval at the Service Point is greater than Supplemental Demand during any Rating Period within the billing month; 2.) Demand at the output point of the customer's generator as measured by the unit meter over a fifteen minute interval must be less than the Maximum Generation Demand during any Rating Period within the billing month.

(4) Energy Credit as per General Conditions of capped ordinance CG-3.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Customer Generation, Subtransmission (34.5 kV) CG-3(C)

Eligibility

Applicable to customers who generate either to sell Excess Energy to the Department and/or to serve their own electricity requirements but have the Department provide Electric Service including supplemental and backup power.

This rate is available to Rate A customers and is designed to support new customer generation and encourage clean on-site generation. Rate C is available to customers whose total Rated Generation Capacity located at a customer facility is less than 25 percent of the Maximum Coincident Demand and less than 1 MW. To qualify for this rate, each customer on-site generation unit shall have been installed and/or converted on/after January 1, 2001 to emit no more than 0.5 pounds/MWH of nitrous oxides. Such emission limit must be maintained to continue to qualify. Verification as the Department determines shall be provided.

Applicable when both the following conditions exist:

(1) Any Electric Service provided by the Department where a customer-owned electrical generating facility is interconnected with the Department's system for Parallel Operation and in compliance with the Department's Rules.

(2) Loads that are served from the Primary Distribution System and which would normally be served under General Service Schedules A-1 and A-2.

Not applicable to:

(1) Any person or entity that is a utility or a "Public Utility" as defined by the Public Utilities Code, including Sections 216 and 9604.

(2) Customer-owned electrical generating facilities interconnected with the Department System for Momentary Interconnection.

Monthly rates through June 30, 2013	June - Sep.			Oct. - May		
Customer Generation, CG-3(C) Subtransmission (34.5kV)	**Capped**	**Incremental**	**Total**	**Capped**	**Incremental**	**Total**
Service Charge $ per month	$75.00	$0.00	**$75.00**	$75.00	$0.00	**$75.00**
Facilities Charge $ per kW (1)	$4.00	$0.39	**$4.39**	$4.00	$0.39	**$4.39**
Demand Charge $ per kW (2)						
High Peak Period	$9.00	$0.35	**$9.35**	$4.00	$0.15	**$4.15**
Low Peak Period	$3.00	$0.15	**$3.15**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04390	$0.00254	**$0.04644**	$0.03863	$0.00254	**$0.04117**
Low Peak Period	$0.03764	$0.00254	**$0.04018**	$0.03863	$0.00254	**$0.04117**
Base Period	$0.01755	$0.00254	**$0.02009**	$0.02197	$0.00254	**$0.02451**
Electric Vehicle Discount $	-$0.02500	$0.00000	**-$0.02500**	-$0.02500	$0.00000	**-$0.02500**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only In Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36000**	$0.00	$0.36000	**$0.36000**
Reactive Energy Charge as Per A-3-A						
Energy Credit (4)						

ECA- Energy Cost Adjustment

ESA - Electric Subsidy Adjustment

RCA - Reliability Cost Adjustment

VEA - Variable Energy Adjustment

CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment

VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment

IRCA - Incremental Reliability Cost Adjustment

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday

Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.

Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.

(1) The Facilities Charge shall be based on the largest of:

The highest actual demand level recorded for energy delivered by the Department or the energy exported to the Department in the last 12-months at the Service Point.

(2) The maximum delivered demand at the Service Point.

(3) Energy Credit as per General Conditions of capped ordinance CG-3.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Customer Generation, Subtransmission (34.5 kV) CG-3(D)

Eligibility

Applicable to customers who generate either to sell Excess Energy to the Department and/or to serve their own electricity requirements but have the Department provide Electric Service including supplemental and backup power.

Rates D is an optional rate for customers receiving service under the Schedule CG-3. Rate D is available to Rate A customers. This optional rate D is for those customers who have demonstrated that they have the capability to reduce load during Department system conditions including, but not limited to, high system peaks, low generation, high market prices, temperature, and system contingencies.

Applicable when both the following conditions exist:

(1) Any Electric Service provided by the Department where a customer-owned electrical generating facility is interconnected with the Department's system for Parallel Operation and in compliance with the Department's Rules.

(2) Loads that are served from the Primary Distribution System and which would normally be served under General Service Schedules A-1 and A-2.

Not applicable to:

(1) Any person or entity that is a utility or a "Public Utility" as defined by the Public Utilities Code, including Sections 216 and 9604.

(2) Customer-owned electrical generating facilities interconnected with the Department System for Momentary Interconnection.

Monthly rates through June 30, 2013	High Season			Low Season		
Subtransmission (34.5 kV) CG-3(D)	June - Sep.			Oct. - May		
Customer Generation	Capped	Incremental	Total	Capped	Incremental	Total
Service Charge $ per month	$150.00	$0.00	**$150.00**	$150.00	$0.00	**$150.00**
Facilities Charge $ per kW (1)	$4.00	$0.39	**$4.39**	$4.00	$0.39	**$4.39**
Supplemental Capacity Charge $ per kW (2)						
High Peak Period	$4.00	$0.00	**$4.00**	$4.00	$0.00	**$4.00**
Low Peak Period	$3.00	$0.00	**$3.00**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04390	$0.00254	**$0.04644**	$0.03863	$0.00254	**$0.04117**
Low Peak Period	$0.03764	$0.00254	**$0.04018**	$0.03863	$0.00254	**$0.04117**
Base Period	$0.01755	$0.00254	**$0.02009**	$0.02197	$0.00254	**$0.02451**
Backup Capacity Charge $ per kWh (3)						
High Peak Period	$0.13110	$0.00632	**$0.13742**	$0.00000	$0.00000	**$0.00000**
Low Peak Period	$0.03220	$0.00155	**$0.03375**	$0.00000	$0.00000	**$0.00000**
Base Period	$0.00000	$0.00000	**$0.00000**	$0.00000	$0.00000	**$0.00000**
Alert Period Energy Charge $ per kWh (4)						
High Peak Period	$0.64437	$0.03106	**$0.67543**	$0.03863	$0.00254	**$0.04117**
Low Peak Period	$0.18512	$0.00892	**$0.19404**	$0.03863	$0.00254	**$0.04117**
Base Period	$0.01755	$0.00254	**$0.02009**	$0.02197	$0.00254	**$0.02451**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36000**	$0.00	$0.36000	**$0.36000**
Reactive Energy Charge as Per A-3-A						
Energy Credit (5)						

ECA- Energy Cost Adjustment

ESA - Electric Subsidy Adjustment

RCA - Reliability Cost Adjustment

VEA - Variable Energy Adjustment

CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment

VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment

IRCA - Incremental Reliability Cost Adjustment

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday

Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.

Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.

(1) The Facilities Charge shall be based on the largest of:

The highest actual demand level recorded for energy delivered by the Department or the energy exported to the Department in the last 12-months at the Service Point.

(2) The Supplemental Capacity Charge is based upon the Supplemental Demand and the charges are related to the cost of the facilities

Supplemental Demand is the Maximum Coincident Demand per Rating Period, less the maximum measured customer generation demand in the respective Rating Period, but never less than zero.

(3) The Backup Capacity Charge is based upon Backup Energy. For each billing period, Backup Energy is the energy that would have been generated by the customer's generator(s) in each Rating Period (High Peak, Low Peak, Base). Backup Energy is applicable when both the following conditions exist: 1.) Delivered energy as measured by the billing meter over a fifteen minute interval at the Service Point is greater than Supplemental Demand during any Rating Period within the billing month; 2.) Demand at the output point of the customer's generator as measured by the unit meter over a fifteen minute interval must be less than the Maximum Generation Demand during any Rating Period within the billing month.

(4) Customers receiving service under Rate D are expected to reduce load. For excess energy consumption during an Alert Period, the customer shall pay the Alert Period Energy Charge.

(5) Energy Credit as per General Conditions of capped ordinance CG-3.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

Actual customer bills are determined by the existing electric rate ordinance, for which billing has been capped, plus the new incremental electric rate ordinance. The following is intended only as a summary of the two ordinances' rates for customers and is not intended to modify the ordinances:

Customer Generation, Subtransmission (34.5 kV) CG-3(E)

Eligibility

Applicable to customers who generate either to sell Excess Energy to the Department and/or to serve their own electricity requirements but have the Department provide Electric Service including supplemental and backup power.

Rate E is an optional rate for customers receiving service under the Schedule CG-3. Rate E is available to Rate C customers. This optional rate E is for those customers who have demonstrated that they have the capability to reduce load during Department system conditions including, but not limited to, high system peaks, low generation, high market prices, temperature, and system contingencies.

Applicable when both the following conditions exist:

(1) Any Electric Service provided by the Department where a customer-owned electrical generating facility is interconnected with the Department's system for Parallel Operation and in compliance with the Department's Rules.

(2) Loads that are served from the Primary Distribution System and which would normally be served under General Service Schedules A-1 and A-2.

Not applicable to:

(1) Any person or entity that is a utility or a "Public Utility" as defined by the Public Utilities Code, including Sections 216 and 9604.

(2) Customer-owned electrical generating facilities interconnected with the Department System for Momentary Interconnection.

Monthly rates through June 30, 2013	High Season			Low Season		
Subtransmission (34.5 kV) CG-3(E)	June - Sep.			Oct. - May		
Customer Generation	Capped	Incremental	Total	Capped	Incremental	Total
Service Charge $ per month	$150.00	$0.00	**$150.00**	$150.00	$0.00	**$150.00**
Facilities Charge $ per kW (1)	$4.00	$0.39	**$4.39**	$4.00	$0.39	**$4.39**
Demand Charge $ per kW (2)						
High Peak Period	$4.95	$0.19	**$5.14**	$4.00	$0.15	**$4.15**
Low Peak Period	$3.00	$0.15	**$3.15**	$0.00	$0.00	**$0.00**
Base Period	$0.00	$0.00	**$0.00**	$0.00	$0.00	**$0.00**
Energy Charge - $ per kWh						
High Peak Period	$0.04390	$0.00254	**$0.04644**	$0.03863	$0.00254	**$0.04117**
Low Peak Period	$0.03764	$0.00254	**$0.04018**	$0.03863	$0.00254	**$0.04117**
Base Period	$0.01755	$0.00254	**$0.02009**	$0.02197	$0.00254	**$0.02451**
Electric Vehicle Discount $	-$0.02500	$0.00000	**-$0.02500**	-$0.02500	$0.00000	**-$0.02500**
Alert Period Energy Charge $ per kWh (3)						
High Peak Period	$2.83700	$0.13674	**$2.97374**	$0.03863	$0.00254	**$0.04117**
Low Peak Period	$1.20140	$0.05791	**$1.25931**	$0.03863	$0.00254	**$0.04117**
Base Period	$0.01755	$0.00254	**$0.02009**	$0.02197	$0.00254	**$0.02451**
Elements Only in Capped Ordinance						
ECA $/Kwh	$0.05690	$0.00000	**$0.05690**	$0.05690	$0.00000	**$0.05690**
ESA $/kW	$0.46000	$0.00000	**$0.46000**	$0.46000	$0.00000	**$0.46000**
RCA $/kW	$0.96000	$0.00000	**$0.96000**	$0.96000	$0.00000	**$0.96000**
Elements Only in Incremental Ordinance						
VEA - per kWh*	$0.00000	-$0.00038	**-$0.00038**	$0.00000	-$0.00038	**-$0.00038**
CRPSEA - per kWh*	$0.00000	$0.00013	**$0.00013**	$0.00000	$0.00013	**$0.00013**
VRPSEA - per kWh*	$0.00000	$0.00086	**$0.00086**	$0.00000	$0.00086	**$0.00086**
IRCA - per kW	$0.00	$0.36	**$0.36000**	$0.00	$0.36000	**$0.36000**
Reactive Energy Charge as Per A-3(A)						
Energy Credit (4)						

ECA- Energy Cost Adjustment

ESA - Electric Subsidy Adjustment

RCA - Reliability Cost Adjustment

VEA - Variable Energy Adjustment

CRPSEA - Capped Renewable Portfolio Standard Energy Adjustment

VRPSEA - Variable Renewable Portfolio Standard Energy Adjustment

IRCA - Incremental Reliability Cost Adjustment

High Peak Period : 1:00 p.m. – 5:00 p.m., Monday through Friday

Low Peak Period: 10:00 a.m. – 1:00 p.m., Monday through Friday, and 5:00 p.m. – 8:00 p.m., Monday through Friday.

Base Period: 8:00 p.m. – 10:00 a.m., Monday through Friday, all day Saturday and Sunday.

(1) The Facilities Charge shall be based on the largest of:

The highest actual demand level recorded for energy delivered by the Department or the energy exported to the Department in the last 12-months at the Service Point.

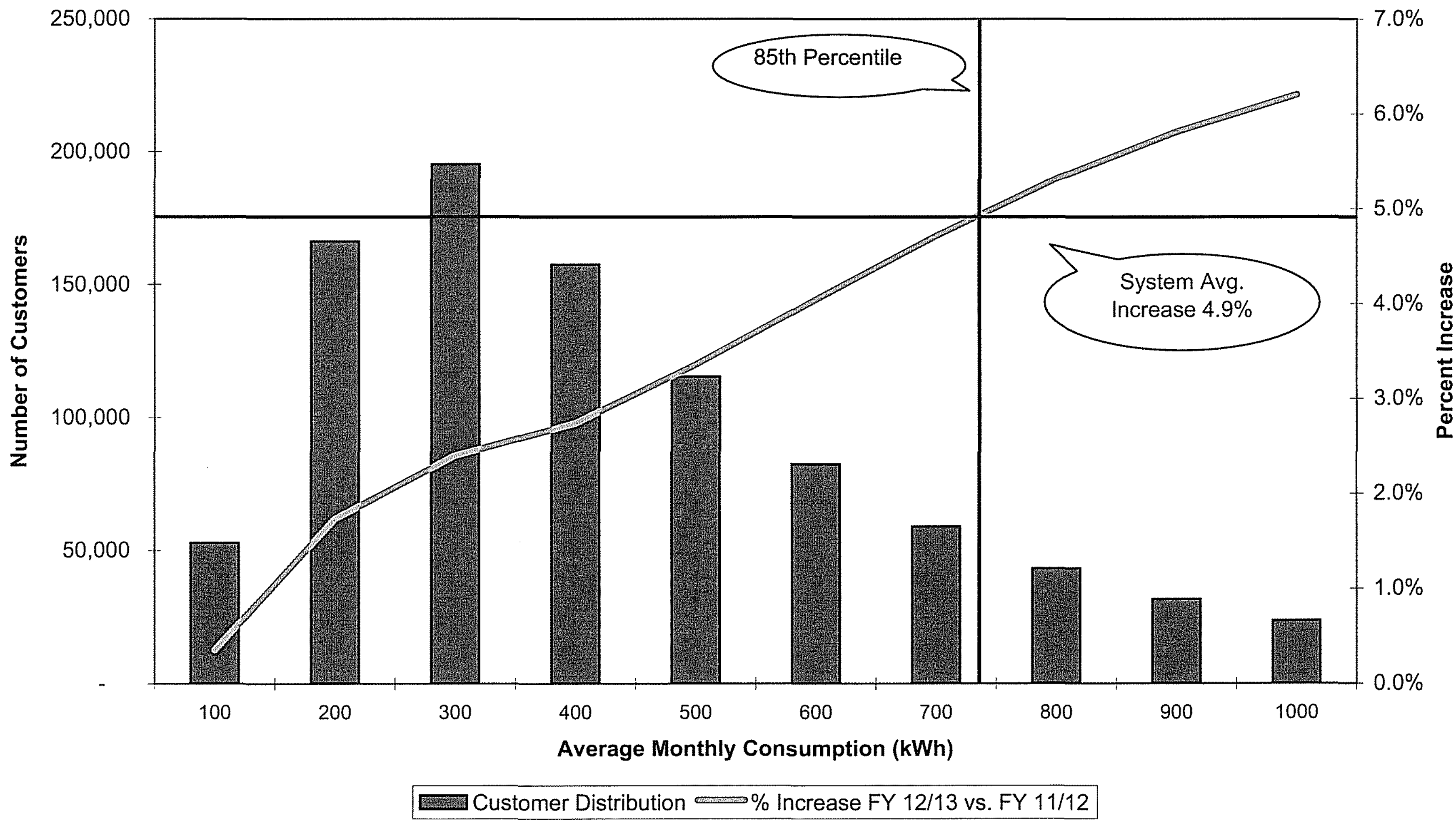
(2) The maximum delivered demand at the Service Point.

(3) Customers receiving service under Rate E are expected to reduce Load. For excess energy consumption during an Alert Period, the customer shall pay the Alert Period Energy Charge.

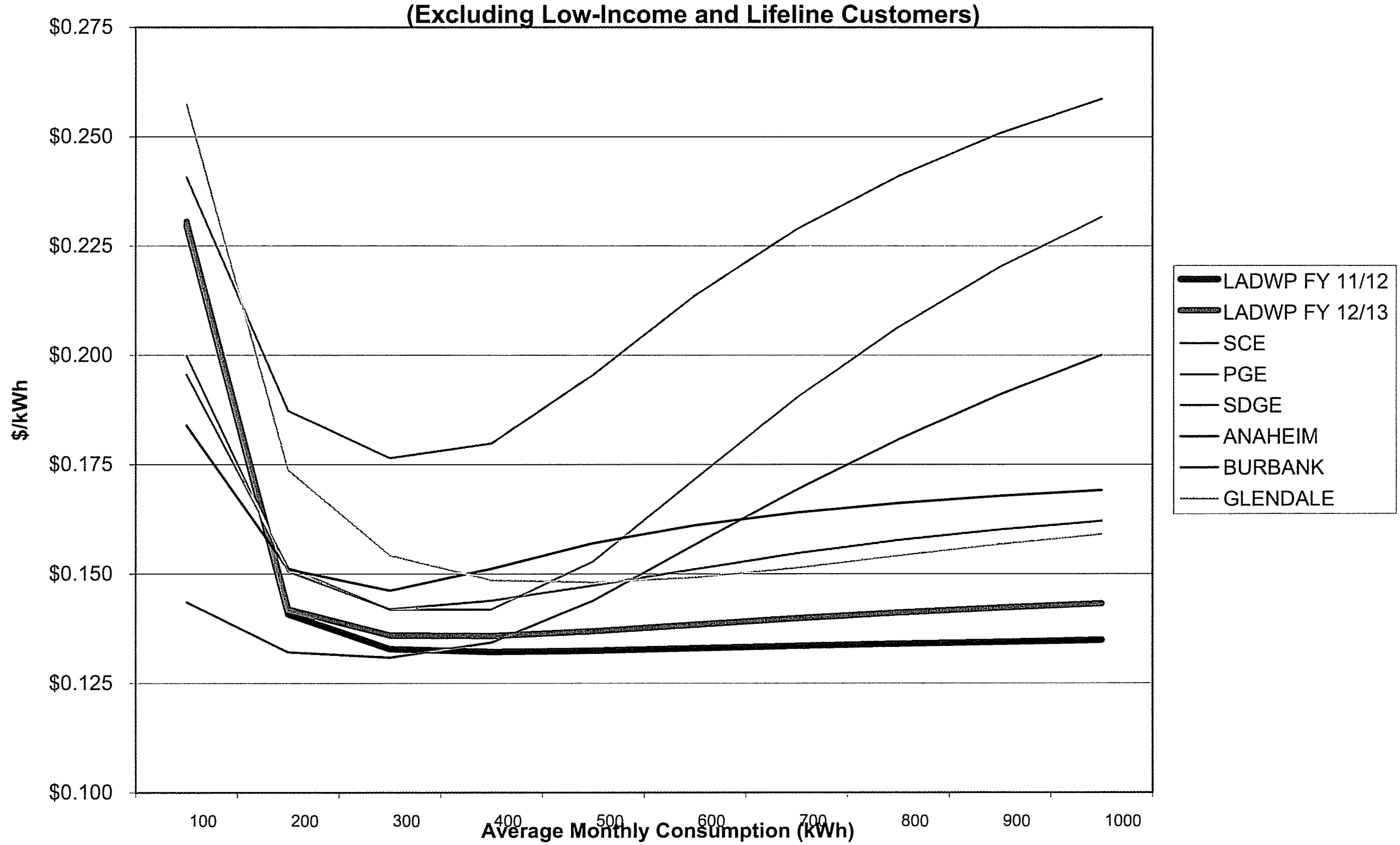
(4) Energy Credit as per General Conditions of capped ordinance CG-3.

*This is an estimated value. The actual number will be computed periodically in accordance with the incremental electric rate ordinance.

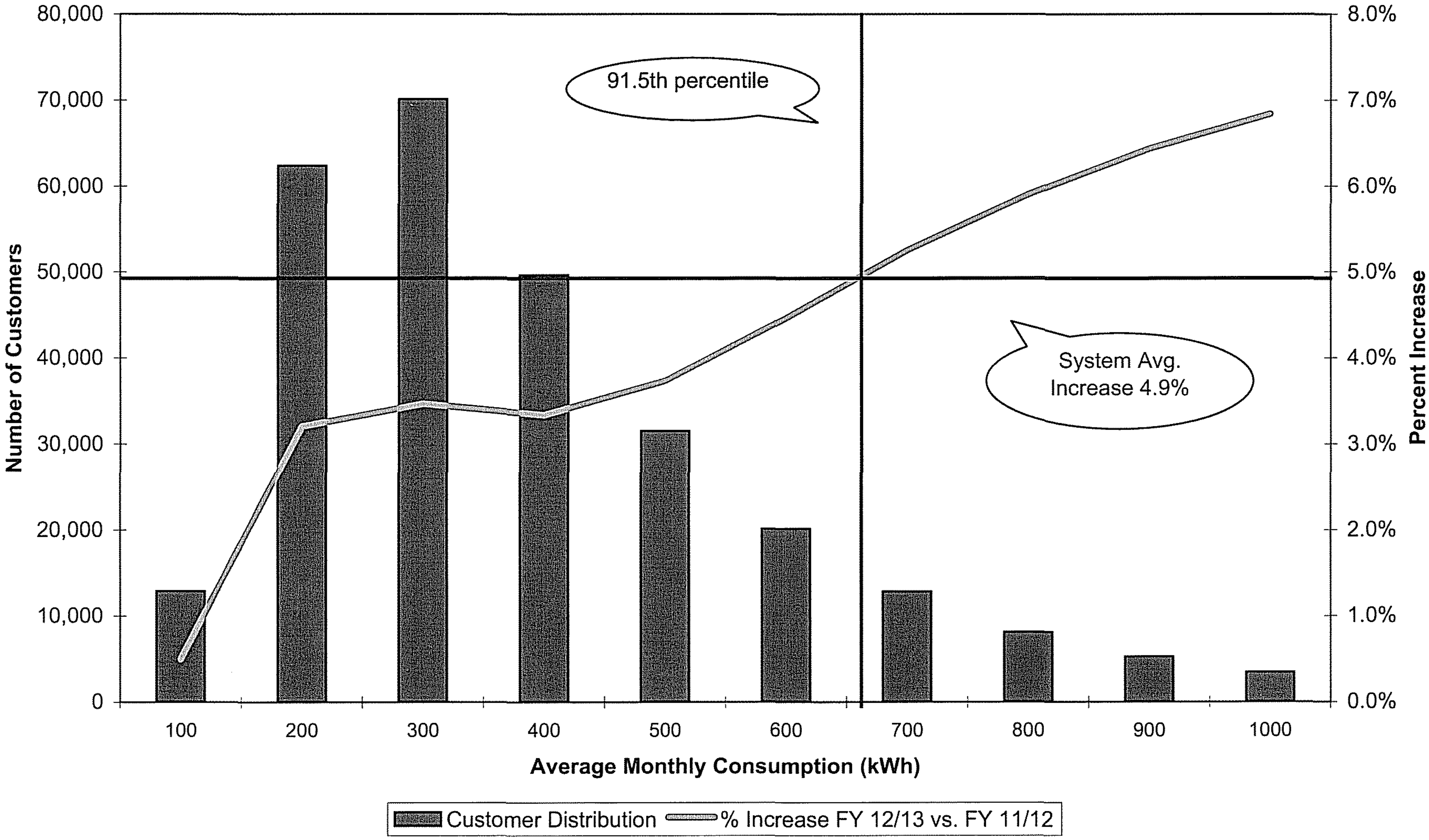
Residential Customers Usage Distribution
Rate Impact FY 12/13 vs. FY 11/12
(Excluding Low-Income and Lifeline Customers)

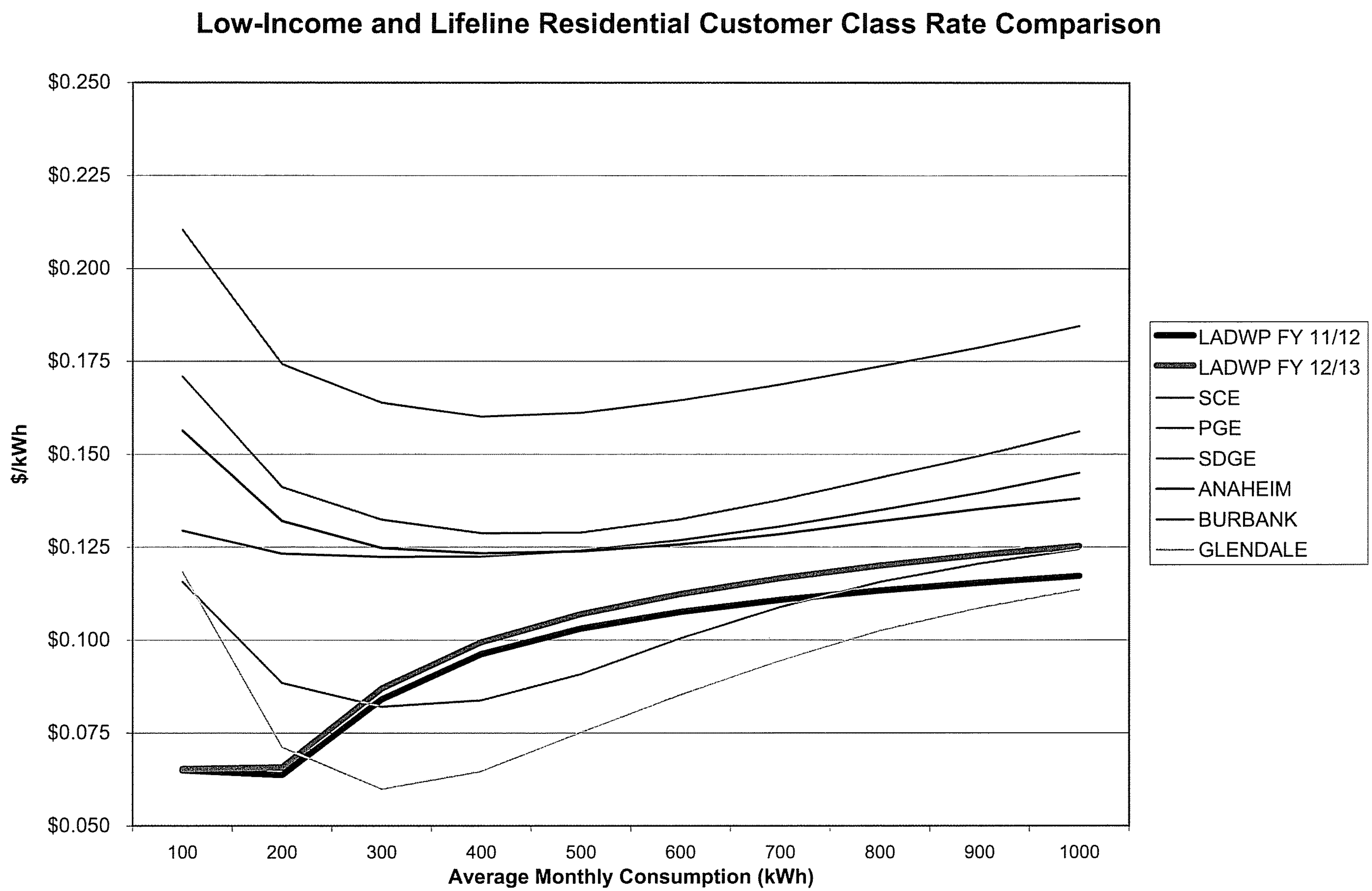


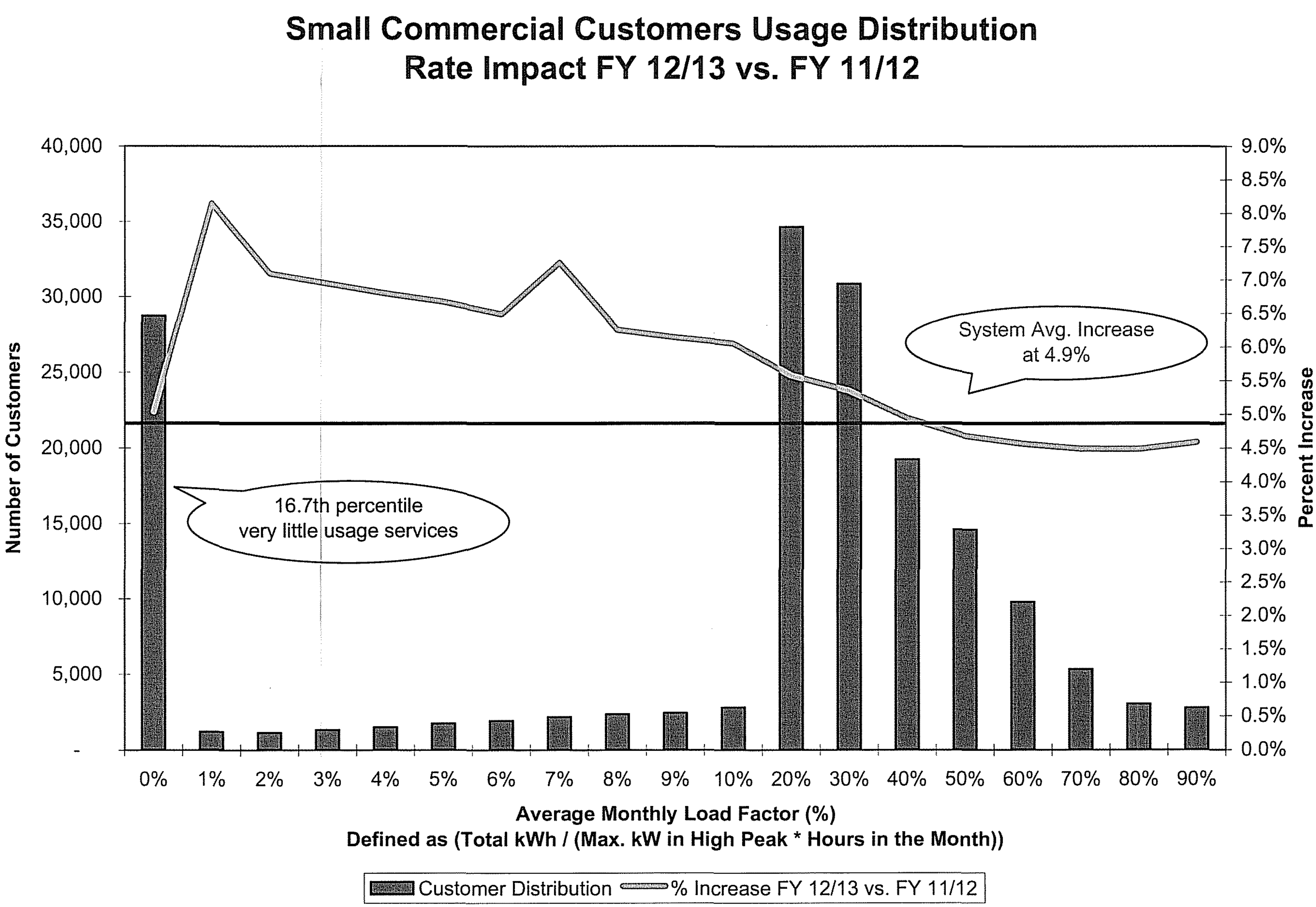
Residential Customer Class Rate Comparison



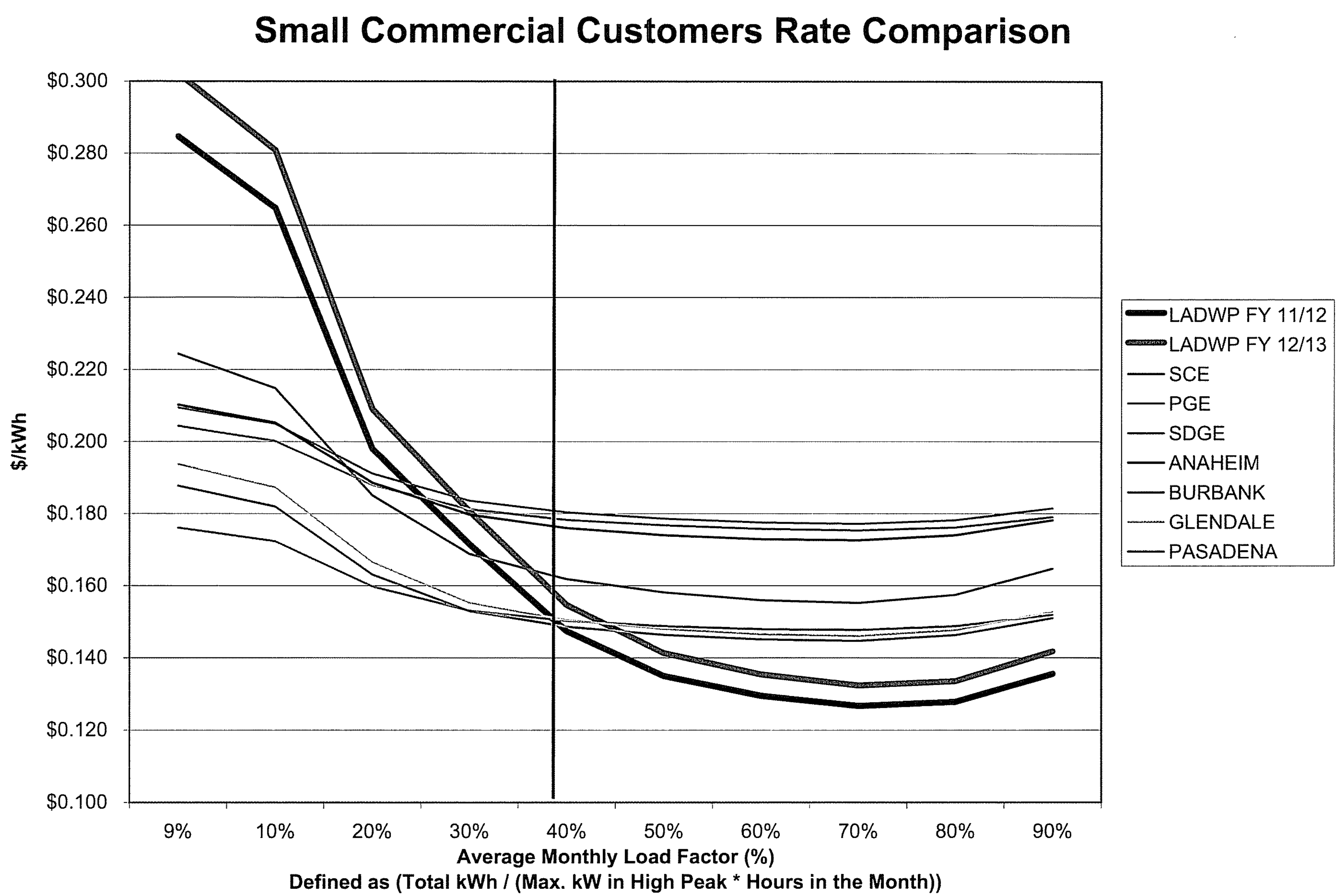
Low-Income and Lifeline Residential Customer Usage Distribution
Rate Impact FY 12/13 vs. FY 11/12



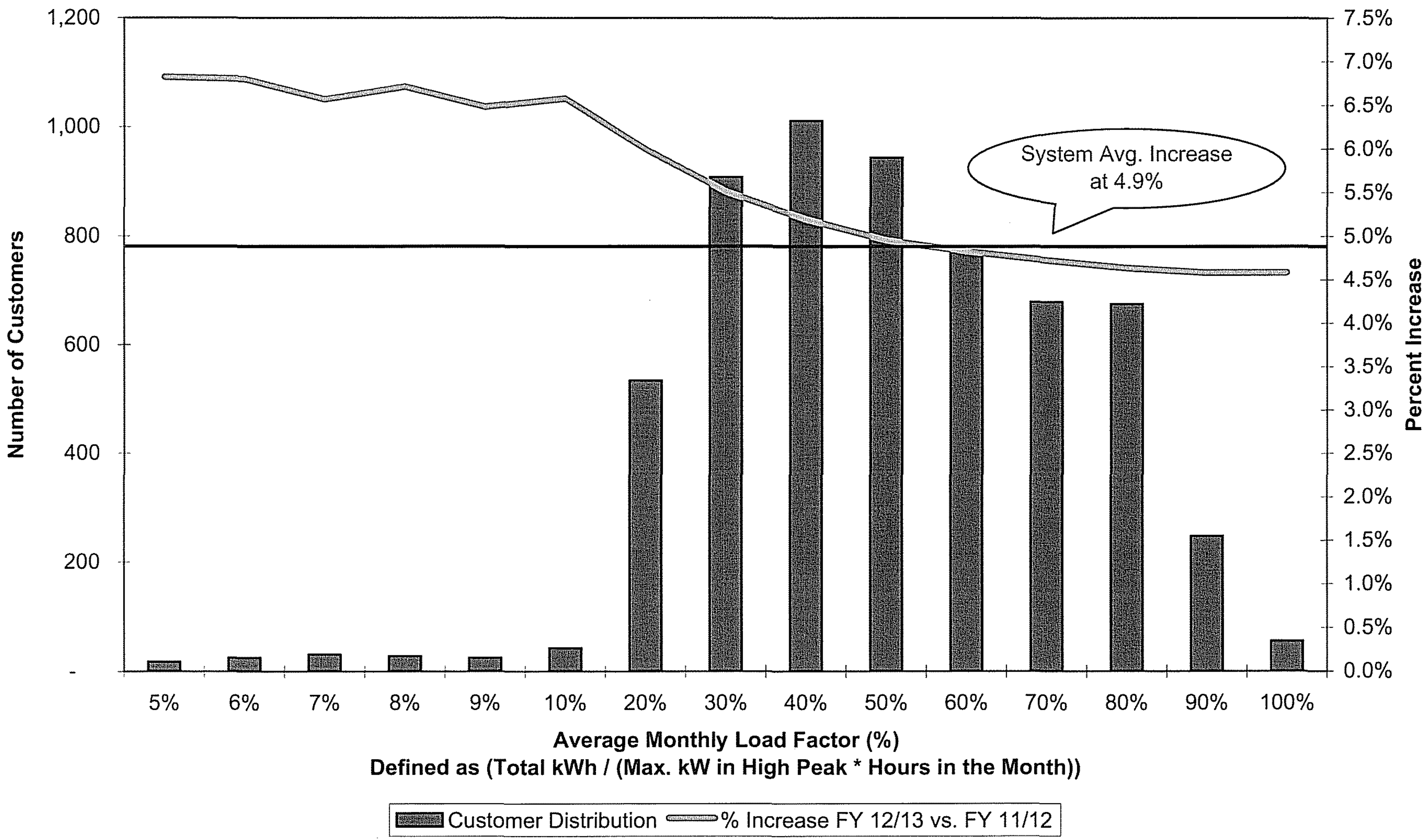

Low-Income and Lifeline Residential Customer Class Rate Comparison
$0.250
$0.225
$0.200
$0.175
$0.150
$0.125
$0.100
$0.075
$0.050
$/kWh
100
200
300
400
500
600
700
800
900
1000
Average Monthly Consumption (kWh)
LADWP FY 11/12
LADWP FY 12/13
SCE
PGE
SDGE
ANAHEIM
BURBANK
GLENDALE



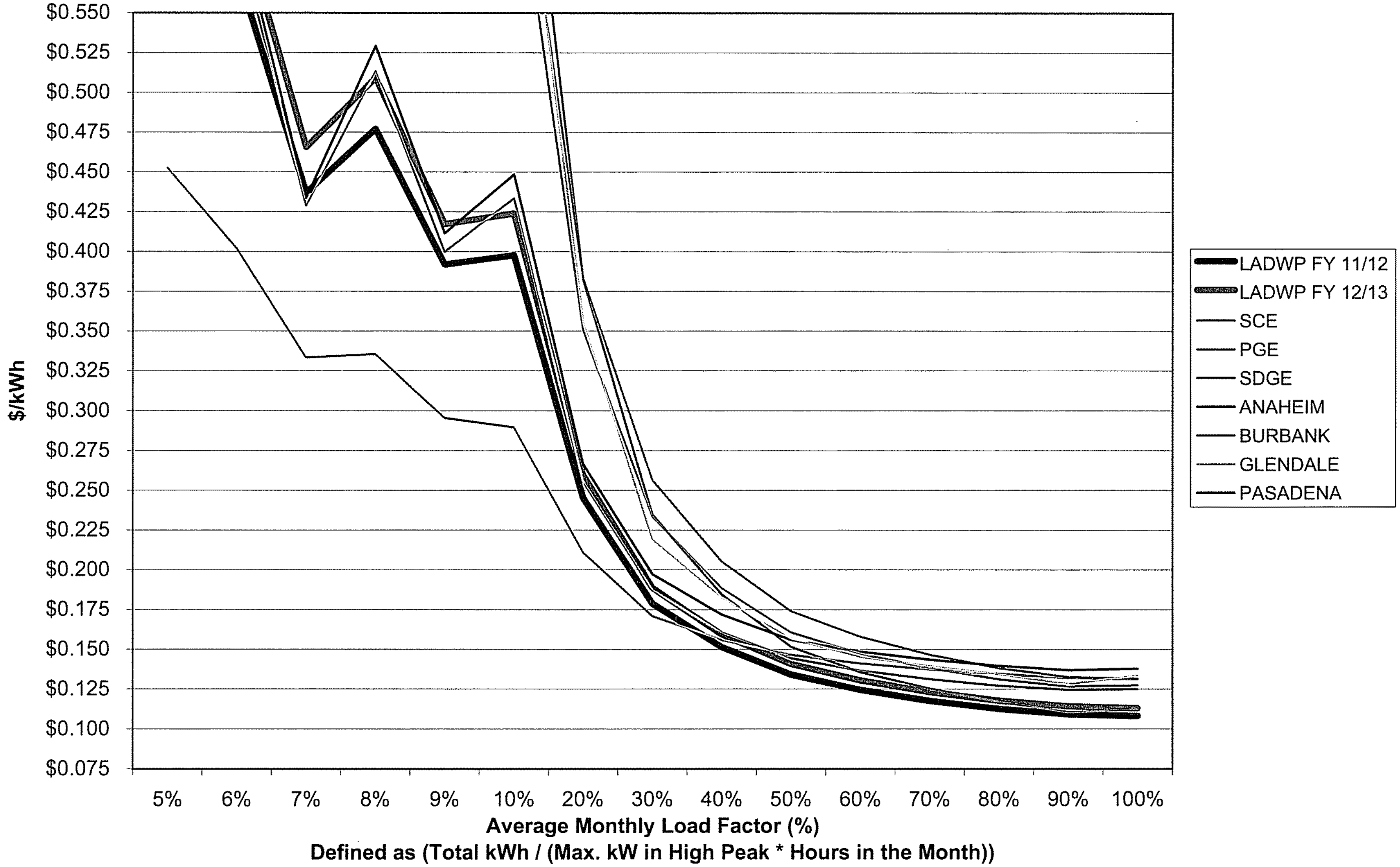
Small Commercial Customers Usage Distribution
Rate Impact FY 12/13 vs. FY 11/12
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
Number of Customers
9.0%
8.5%
8.0%
7.5%
7.0%
6.5%
6.0%
5.5%
5.0%
4.5%
4.0%
3.5%
3.0%
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
Percent Increase
System Avg. Increase at 4.9%
16.7th percentile very little usage services
0% 1% 2% 3% 4% 5% 6% 7% 8% 9% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Average Monthly Load Factor (%)
Defined as (Total kWh / (Max. kW in High Peak * Hours in the Month))
Customer Distribution
% Increase FY 12/13 vs. FY 11/12


Small Commercial Customers Rate Comparison
$0.300
$0.280
$0.260
$0.240
$0.220
$0.200
$0.180
$0.160
$0.140
$0.120
$0.100
$/kWh
9%
10%
20%
30%
40%
50%
60%
70%
80%
90%
Average Monthly Load Factor (%)
Defined as (Total kWh / (Max. kW in High Peak * Hours in the Month))
LADWP FY 11/12
LADWP FY 12/13
SCE
PGE
SDGE
ANAHEIM
BURBANK
GLENDALE
PASADENA

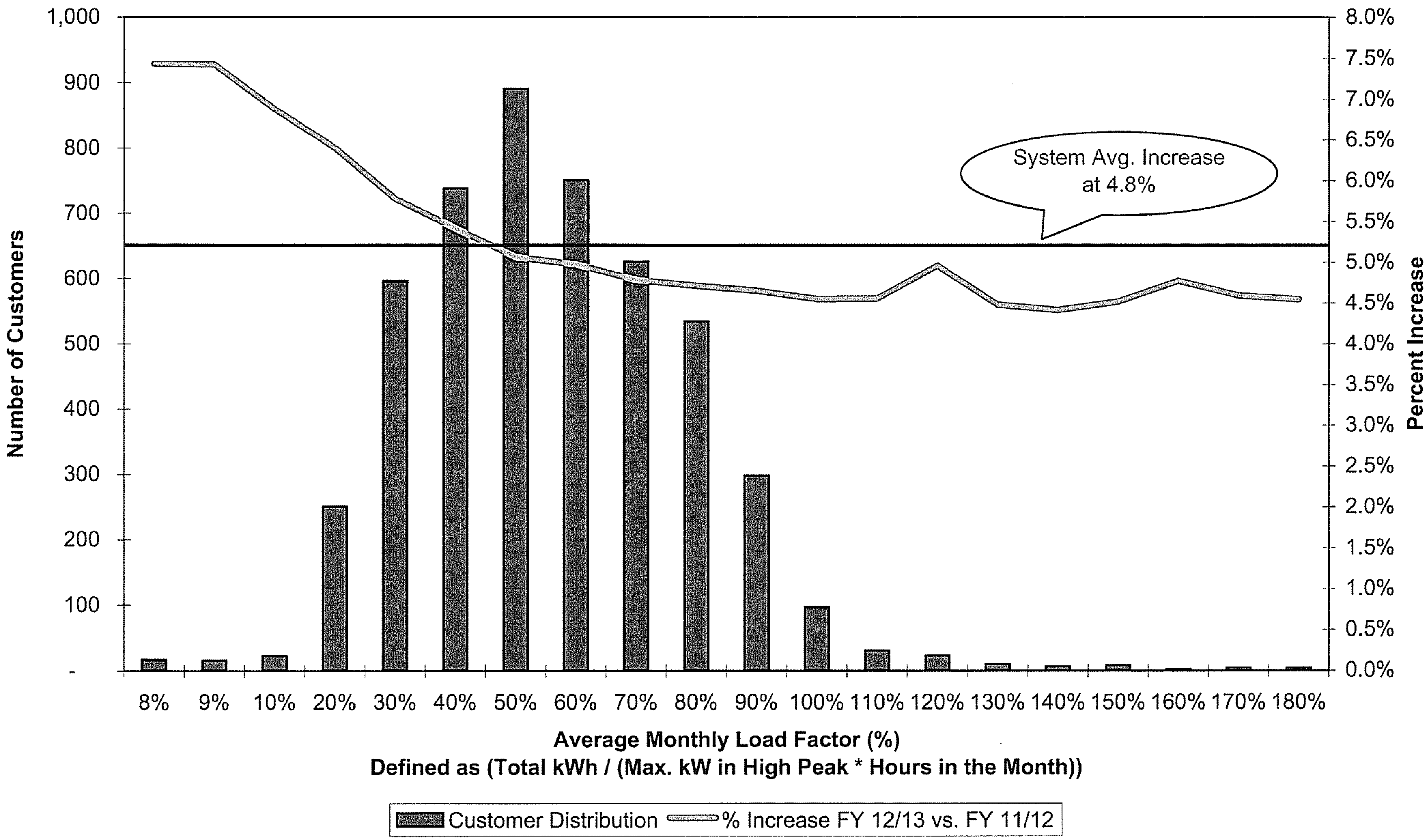
Medium Commercial Customers Usage Distribution
Rate Impact FY 12/13 vs. FY 11/12

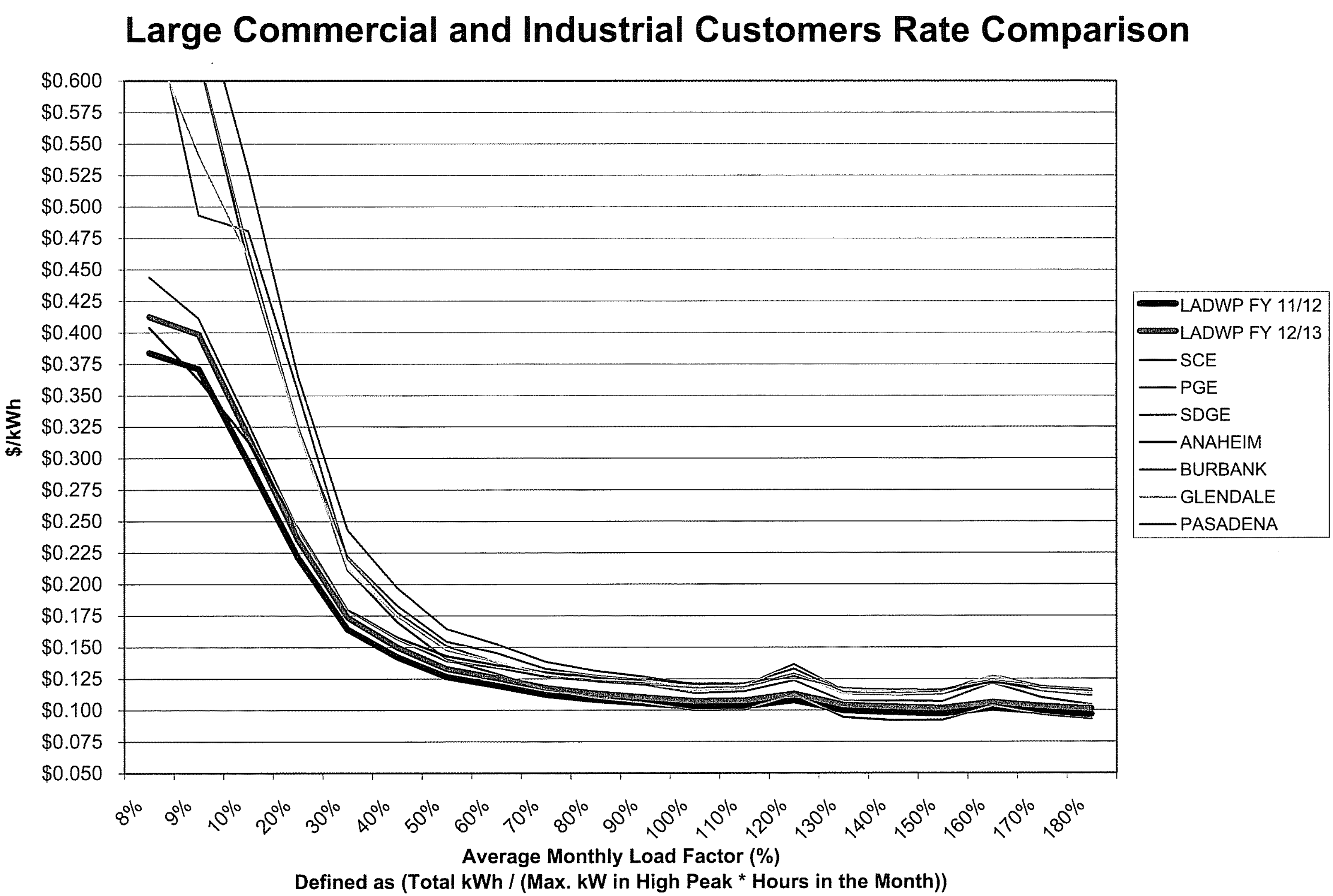


Medium Commercial Customers Rate Comparison



Large Commercial and Industrial Customers Usage Distribution
Rate Impact FY 12/13 vs. FY 11/12




Large Commercial and Industrial Customers Rate Comparison
$0.600
$0.575
$0.550
$0.525
$0.500
$0.475
$0.450
$0.425
$0.400
$0.375
$0.350
$0.325
$0.300
$0.275
$0.250
$0.225
$0.200
$0.175
$0.150
$0.125
$0.100
$0.075
$0.050
$/kWh
8%
9%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
110%
120%
130%
140%
150%
160%
170%
180%
Average Monthly Load Factor (%)
Defined as (Total kWh / (Max. kW in High Peak * Hours in the Month))
LADWP FY 11/12
LADWP FY 12/13
SCE
PGE
SDGE
ANAHEIM
BURBANK
GLENDALE
PASADENA

Power System Rate Proposal FY 12/13 and FY 13/14

Summary and Supporting Information

Prepared for the Office of Public Accountability /Ratepayer Advocate

May 3, 2012

(Section 2.4 updated 6/7/2012)

(Corrected reference to organation name in Section 4.1.2 on 6/12)

Los Angeles Department of Water and Power

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LADWP Facts & Figures

General

History	LADWP was established in 1902 to deliver water to the City of Los Angeles. Electric distribution began in 1916.
Area Served	465 square miles
Population Served	3.9 million residents Power Customers: 1,461,344
Funding Sources	LADWP's operations are financed solely through the sales of water and electric services. Capital funds are partially funded through the sale of bonds. No tax support is received.

Energy Resources (Calendar Year 2010)

Eligible Renewables*	20%
Coal	39%
Large Hydroelectric	3%
Natural Gas	22%
Nuclear	11%
Unspecified Sources of Power	5%
***Renewable energy sources include biomass and waste (4%), geothermal (1%), small hydroelectric (7%), solar (0%), and wind (8%).**	

Electric Capacity

Net Maximum Plant Capability	7,197 megawatts
Los Angeles Peak Demand	6,142 megawatts (September 27, 2010)

Power Usage

Los Angeles customers purchased about 23.1 million megawatt-hours during FY 2010-2011. The average annual residential consumption per customer is 5,725 kWh.	
Residential	8,068,000 megawatt-hours
Commercial	12,333,000 megawatt-hours
Industrial	2,189,000 megawatt-hours
Other	464,000 megawatt-hours

Other Power Facts

Miles of Transmission Lines	3,656
Miles of Overhead Distribution Lines (4.8-kV and 34.5-kV)	6,793
Miles of Underground Distribution Lines (4.8-kV and 34.5-kV)	3,547

1. EXECUTIVE SUMMARY

This section of the report will discuss:

- The Purpose of the Report;
- A Summary of the Proposed Two-Year rate Plan including major cost drivers;
- The Objectives of the Rate Proposal;
- A Description of the rate setting process for the proposed rate plan ;
- The Department's budget process that developed the details behind the proposed rate plan;
- The categories of significant cost factors that contributed to the proposed rate increases, and finally
- Implications of delays in the rate approval process.

1.1 PURPOSE

The Los Angeles Department of Water and Power ("Department") is one of the most prominent multi-commodity utilities in the United States. As the nation's largest municipal utility, the Department provides electric service to approximately four million citizens of Los Angeles through the operation of over 14,000 miles of transmission and distribution lines, and 51 generating assets that are owned or operated by the Department, or from which the Department is the majority power purchaser.

In addition to this significant operational footprint, the Department also has a long history of consistently strong financial performance, exemplified by historically low-cost sources of power, stable revenue streams and strong financial ratios reflected by high credit ratings. Customers have benefitted from this performance through comparatively low rates.

The Department has recently completed its first century of operations and has overcome a variety of challenges while achieving this level of performance. The first part of the century ahead holds challenges that are as significant as any in the past and will put pressure on the objectives just noted. The Department must now provide a coordinated response to a number of immediate and costly challenges, including meeting multiple complex regulatory requirements, the need to replace a rapidly aging infrastructure and the desire to continue "next generation" system planning and investment. In addition, meeting substantial fuel requirements, covering increasingly significant pension obligations, and maintaining the Power System's high credit rating are additional immediate requirements.

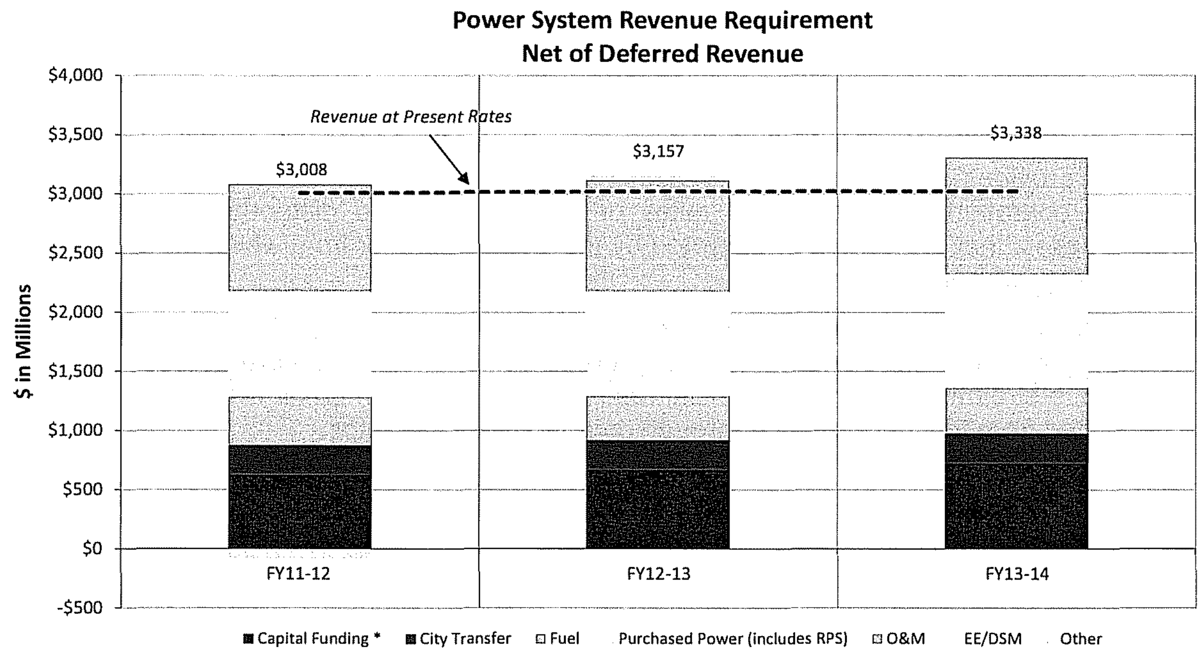
In response to these challenges, the Department has prepared a rate proposal supported by a comprehensive budget analysis and specific financial forecasts, market, and operating assumptions for the Power System. The planned expenditures underlying the rate proposal reflects choices among capital programs and O&M expenses, which then specify the proposed rate levels.

Furthermore, the revenue requirement and rate impacts presented herein are based on proposed expenditures that include an increase in energy efficiency investment from prior years, to reach the 8.6% level of cumulative savings by 2020 that has been adopted by the Board of Water and Power Commissioners (Board). However, that funding level puts the Department on a track to achieve less than the State mandated cumulative savings of 10% of total energy consumption levels by 2020. Consequently, the Department has also included in this proposal a

Recommended Energy Efficiency Alternative Plan that provides for an additional increment to energy efficiency investment which would require a small addition (averaging 0.30% per year) to the rate increases previously discussed with the Board, Council and public. The alternative energy efficiency plan is designed to achieve cumulative savings of at least 10% total energy consumption levels by 2020 as required by Assembly Bill 2021. In the coming months, the Department will evaluate, for consideration by the Board, the potential of pursuing a target energy efficiency savings in excess of 10% by 2020. **Section 7: Recommended Energy Efficiency Alternative Plan** provides further detail.

The chart below provides the Department's revenue at current rates for fiscal years (FY) 2013 and 2014, along with the revenue requirement to meet future requirements to operate the system. Funding gaps from the current revenue level to the required level of about $149 million and $330 million by FY 2014 require adjustments in rates as will be discussed further throughout this report.

Figure 1: Power System Revenue Requirement[1]



In the table below, the total revenue requirements with and without the Recommended Energy Efficiency Alterative are compared. As shown, the incremental revenue requirement resulting from the higher recommended level of energy efficiency is minimal since the costs for energy efficiency are capitalized and recovered through the Energy Cost Adjustment Factor (ECAF). The overall rate increase, however, increases slightly for the proposal with the higher recommended level of energy efficiency due to the reduced energy consumption (sales) forecast resulting from higher levels of energy efficiency investment. In other words, there are less kilowatt hours sold to recover the revenue requirement. As with any energy efficiency program, reduced energy sales leaves fixed costs of the Power System (distribution, customer service, maintenance costs, etc.) to be recovered over a smaller volume of sales. As a result, in the near term the rate (in cents per kWh) increases as the Department avoids the cost of incremental power production or purchases.

[1] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

Figure 2: Power System Revenue Requirement – 8.6% Target Energy Efficiency vs. 10% Target Recommended Energy Efficiency [2]

Revenue Requirement Summary ($M)	Current Year	Proposed Rate Period	
Fiscal Year Ended June 30:	**FY 2012**	**FY 2013**	**FY 2014**
Total Power System Revenue Requirement with Funding for Energy Efficiency to reach 8.6% Reduction by 2020	3,008	3,157	3,338
Total Power System Revenue Requirement with Recommended Energy Efficiency Alternative Plan to reach 10% Reduction by 2020	3,008	3,159	3,342

This report supplements the power rate information that has been submitted to the Board on April 3, 2012. The report also summarizes in one document significant information supporting the rate prroposal that has previously been provided to the RPA. This report also provides more detail and support for the proposed rate adjustments than was provided for past rate proposals—this is in keeping with the desire by the people of Los Angeles for more transparency about the Department's proposals. In March of 2011, ballot Measure I, established the Office of Public Accountability for the Department, including a Ratepayer Advocate (RPA). The purpose of Measure I was to provide an independent analysis of the Department's actions related to electricity rates to augment the analyses that were historically undertaken on behalf of City Council by an independent consultant.

1.2 PROPOSED RATE PLAN

The Department Expresses its Revenue Need in Terms of a "Revenue Requirement"

One of the more important utility ratemaking terms is "revenue requirement". The revenue requirement of a utility is the annual revenues required to cover operations, maintenance, administrative and other expenses; and, meet all compliance obligations. It also includes the annual costs to provide safe and reliable service to the company's customers that the company is allowed to recover through rates. Utilities request increases to their revenue requirements based on forecasts of its costs to provide service. Regulators then determine the appropriate annual revenue to be allowed.

The method utilized by municipal utilities like the Department is called the "cash-needs approach" because it focuses on the annual cash requirements to fund the Department, its operations and other obligations.

Here are the major components of the Department's revenue requirement:

Operating & Maintenance Expenses (O&M): the normal and recurring expenses incurred to run the system and maintain compliance for employee salaries, fuel, power, supplies, administrative costs, etc.

Debt Service: the principal as well as the interest on all outstanding debt for required payments to the Department's creditors.

Cash Funded Capital Expenditures: The amount of cash the utility will spend from its operating revenue in a given year on capital outlays. Financing for capital needs comes from debt, development fees, operating revenue, cash reserves and, other sources. In order to determine how much cash is required to meet the capital expenditure plan, the Department evaluates the

[2] Revenue requirement shown in this table is net of deferred revenue

financing alternatives. If after deducting all other funding sources there remains an amount to be funded by operating revenue, then there is a (cash) revenue requirement.

Planned Transfer to the City: The planned revenue requirement also includes the cash needed to fund a Transfer payment to the City of Los Angeles equalling 8% of prior fiscal year Power System revenue.

The Department's Proposed Revenue Requirement[3]

The Department has developed two proposed rate plans with and without the Recommended Energy Efficiency Alternative Plan. With the base energy efficiency plan that achieves 8.6% energy savings by 2020, an average revenue requirement increase of **$136 million** (4.60%) in FY 2013[4] and an additional **$181 million** (5.90%) in FY 2014 will be required; an annual average revenue increase of **$159 million** or 5.25% over the two-year forecast period.

To accommodate the Recommended Energy Efficiency Alternative Plan to achieve the mandated 10% energy consumption reduction by 2020, the average annual revenue requirement over the next two years would increase **$9 million per year** (total average of $168 million per year or 5.55% average annual increase). The incremental revenue requirement to accommodate the recommended energy efficiency plan is $6 million in FY 2013 (total of $142 million or 4.8% increase) and $13 million in FY 2014 (total of $181 million or 6.3% increase).

Without rate increases in recent years the Department has focused most of its investment resources on meeting regulatory mandates such as renewable energy resources. As a result, spending for energy efficiency and reliability programs has been significantly lower than otherwise would have been recommended.

While this document primarily addresses the revenue requirement, the manner in which these costs are recovered through rates from customers is also addressed in this report.

Major Cost Drivers

For the Power System, the key programs driving the proposed rate increase are:

- Power Supply Replacement Program (driven by regulatory mandates):
  - Rebuilding local power plants (principally to eliminate ocean cooling); and,
  - Renewable energy resource additions
- Power Reliability Program (replacing the rapidly aging backbone of the electric transmission and distribution system)
- Customer Opportunities Program (driven by regulatory mandates):
  - Energy efficiency
  - Customer solar program
- Fuel Costs
- Other Considerations (such as inflation and pensions)

Each of these factors will be discussed in **Section 2: Next Century Power Key Programs**.

Revised Financial Targets

With respect to the financial targets, the Power System planned expenditures and rate proposal are designed to meet revised financial targets in the following areas:

[3] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan Plan
[4] Effective July 1 2012 and 2013. The 2012 rate increase changes for each month of delay as described further in Section 1.12.

- Bond Rating: Maintain a 'AA-' bond credit rating
- Debt Service Coverage Ratio: 2.25
- Full Obligation Coverage: 1.50
- Capitalization Ratio: Not Exceeding 68%
- Unrestricted Operating Cash Balance Target: $300 million
- Net Income of at least $50 million

The unrestricted operation cash balance target, in conjunction with the $500 million Debt Reduction Trust Fund, provides the Power System with the recommended 110 days operating to maintain an AA- (S&P) rating.

Board approval for the proposed new financial targets will be sought when the new rate proposal is brought to the Board. The financial targets are subject to ongoing reviews by the Board and the Department's financial advisors. Public Resources Advisory Group (PRAG) undertook a review of the Department's previous financial metrics in September, 2011 and found that there was some potential for relaxing some of the financial metrics for the Power System without jeopardizing the current AA-/AA-/Aa3 bond ratings. Based on a peer-group comparison, PRAG found that the debt ratio could increase to about 68% and the Debt Service Coverage ratio could decrease to 2.25x. Thus, the Department believes that the proposed changes to the financial metrics, which are on the conservative side of the peer group range found by PRAG, are unlikely to result in a ratings downgrade. If the relaxed financial metrics were to result in a ratings downgrade to AA-/AA/Aa3, interest costs associated with new debt would increase, and in theory this change could reduce the Power System's access to capital. However, given the diversity and size of the Power System, PRAG has informally indicated that even at the lower rating, the Department would not likely experience any noticeable change in its access to capital. Therefore, establishing targets at the lower end of the acceptable range for the current AA-/AA-/Aa3 bond rating appears reasonable.

Summary of Rate Results

The Department has developed a revenue requirement proposal for the Power System that reflects planned expenditures capital and labor programs and market and operating assumptions. This proposal reflects the Department's key programs (Power Supply Replacement, Power Reliability and Customer Opportunities) in a manner that aims to minimize the rate impact to customers for the next two years while achieving several key strategic objectives.

The plan without the Recommended Energy Efficiency Alternative Plan results in rate increases of 4.6% and 5.9% FYs 2013 and 2014; an average of 5.25% per year. With the recommended increment to the energy efficiency program, the annual rate increases are 4.8% for FY 2013 and 6.3% for FY 2014, or an average of 5.55% per year; an average annual incremental increase of 0.30% per year.

The following charts provide a summary of the proposed programs, commitments and expenditures with and without the higher recommended level of energy efficiency.

Figure 3: Summary of Proposed Plan without the Recommended Energy Efficiency Alternative Plan (FYs 2012 – 2014) [5]

Summary of Proposed Plan ($M)	Current Year	Proposed Rate Period	
Fiscal Year Ended June 30:	**FY 2012**	**FY 2013**	**FY 2014**
Average Annual Increase	-	**4.60%**	**5.90%**
Total Operating Revenue	3,114	3,149	3,353
O&M Expenses	922	955	1,005
Non-O&M Expenses[6]	1,991	1,988	2,140
Net Income (before City transfer)	310	302	305
City Transfer	250	249	252
Capital Expenditures	1,245	1,388	1,621
New Debt Required for Capital Expenditures	-	1,072	1,200
Total Long Term Debt	6,277	7,213	8,261
Increase in Revenue Requirement	-	**136**	**181**

Figure 4: Summary of Proposed Plan with the Recommended Energy Efficiency Alternative Plan (FYs 2012 – 2014)

Summary of Proposed Plan ($M)	Current Year	Proposed Rate Period	
Fiscal Year Ended June 30:	**FY 2012**	**FY 2013**	**FY 2014**
Average Annual Increase	-	**4.80%**	**6.30%**
Total Operating Revenue	3,114	3,147	3,357
O&M Expenses	922	946	996
Non-O&M Expenses[7]	1,991	1,994	2,151
Net Income (before City transfer)	310	303	307
City Transfer	250	249	252
Capital Expenditures	1,245	1,438	1,671
New Debt Required for Capital Expenditures	-	1,103	1,234
Total Long Term Debt	6,277	7,245	8,327

[5] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan
[6] Non-O&M Expenses include fuel-related expenditures, depreciation, regulatory assets, property tax, interest expense, AFUDC and CIAC.
[7] Non-O&M Expenses include fuel-related expenditures, depreciation, regulatory assets, property tax, interest expense, AFUDC and CIAC.

Summary of Proposed Plan ($M)	Current Year	Proposed Rate Period	
Fiscal Year Ended June 30:	FY 2012	FY 2013	FY 2014
Increase in Revenue Requirement	-	142	194

1.3 SUMMARY OF RATE AND REVENUE INCREASES

Average Annual Revenue Increase[8]

For FYs 2013 and 2014, the Department is proposing an average annual revenue increase of **$159 million** without the Recommended Energy Efficiency Alternative Plan; or **$168 million** with the higher recommended level of energy efficiency to reach the 10% reduction of total energy consumption by 2020.

As shown in the Figure 5 below, **approximately 73% to 75%** of the proposed average annual revenue increase represents the repowering of local power plants, renewable energy, energy efficiency and customer solar programs due to regulatory and legislative mandates beyond the Department's control.[9]

Increased Cost per kWh[10]

For FY 2013 and FY 2014, the planned expenditures ***without*** the Recommended Energy Efficiency Alternative Plan result in an increase in the system average cost per kWh by an average **0.68 cents** annually. To ensure the Department meets the 10% reduction of total energy consumption by 2020, a minimal incremental average increase of **0.04 cents** per kWh would be required. Actual bill impacts per customer will vary depending on usage levels, as described further in **Section 5**.

It is important to note that 0.50 cents (73%) of the 0.68 cents per kWh increase (or 0.54 cents of the 0.72 cents per kWh increase for the higher recommended level of energy efficiency) is the result of regulatory and legislative mandates beyond the Department's control. As previously noted, the regulatory mandates fall under the following programs:

- Power Supply Replacement Program (repowering of local power plants, renewable energy)
- Customer Opportunities Program (energy efficiency, customer solar programs)

While the Department supports the goals of these mandates, the specific timing and manner prescribed by regulatory requirements to meet these goals are tightly specified, leaving little flexibility in how the goals are met.

Annual Average Percentage Increase[11]

The Department's planned expenditures without the higher recommended level of energy efficiency results in an average annual increase in revenues of 5.25% for FY 2013 and FY 2014 of which 73% (3.84 percentage points of the 5.25% increase) is related to regulatory requirements.

As previously stated, the recommended alternative energy efficiency plan designed to achieve cumulative savings of at least 10% total energy consumption levels by 2020, will require a small average incremental rate increase of 0.30% per year.

[8] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan
[9] Percentage range represents the plan with the Recommended EE Alternative Plan (75%) and without the higher recommended level of energy efficiency.
[10] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan
[11] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

Figure 5: Summary of Proposed Rate Increase (FYs 2013 – 2014)

Cost Element	Rate Increase Factor	Regulatory Requirement	Avg. Annual Revenue Requirement Increase ($M)	Avg. Annual System Average Cost per kWh Increase (¢/kWh)	Avg. Annual Percentage Increase (%)
Power Supply Replacement Program	Repowering Local Power Plants	✓	49	0.21	1.63
	Renewable Energy	✓	39	0.17	1.29
	Sub Total – Increase		**88**	**0.38**	**2.92**
Power Reliability Program	Power Reliability Program		**26**	**0.11**	**0.85**
Customer Opportunities Program	Energy Efficiency	✓	23	0.10	0.74
	Customer Solar Programs	✓	5	0.02	0.18
	Sub Total – Increase		**28**	**0.12**	**0.92**
Fuel Costs			**17**	**0.07**	**0.56**
Total Average Annual Increase			$159	0.68	5.25%
Cumulative 2-Year Increase				1.37	
Total Average Annual Increase with Recommended Alternative Level of Energy Efficiency					*5.55%*

1.4 AVERAGE MONTHLY BILL BY CUSTOMER CLASS

The impact of the rate proposals on the average monthly bill depends on the kWh usage of the individual customer. The tables below show the average monthly bill by customer class for various usage levels for the two-year rate increase period with and without the Recommended Energy Efficiency Alternative Plan.

Figure 6: Illustrative Average Monthly Bills without the Recommended Energy Efficiency Alternative Plan[12]

Average Customer Power Bill		Average Bill at Current Rates ($)	Average Bill with Proposed Rate Changes ($)	
Customer Class	**Usage (kWh)**	**FY 2012**	**FY 2013**	**FY 2014**
Residential	500	65.79	67.14	69.14
	600	79.44	82.14	85.75
	800	106.76	112.16	118.99
	1,000	134.07	142.17	152.22

[12] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

Average Customer Power Bill		Average Bill at Current Rates ($)	Average Bill with Proposed Rate Changes ($)	
Customer Class	Usage (kWh)	FY 2012	FY 2013	FY 2014
Small Commercial (35% Load Factor)	1,000	136.40	142.30	150.60
Medium Commercial (40% Load Factor)	50,000	6,195.00	6,502.42	6,915.33
Large Commercial (42% Load Factor)	300,000	36,930.00	38,681.67	40,994.33

The table below indicates the ***incremental*** average monthly bill impact by customer class for the proposed rates with the higher recommended level of energy efficiency detailed in **Section 7: Recommended Energy Efficiency Alternative Plan**.

Figure 7: Average Monthly Bill by Customer Class - Increases with the Recommended Energy Efficiency Alternative Plan ($M)

Incremental Increase in Average Customer Bills for Recommended EE Alternative Plan			
Customer Class	Usage (kWh)	FY 2013	FY 2014
Residential	500	0.12	0.38
	600	0.14	0.47
	800	0.20	0.65
	1,000	0.25	0.83
Small Commercial (35% Load Factor)	1,000	0.29	0.71
Medium Commercial (40% Load Factor)	50,000	12.74	26.16
Large Commercial (42% Load Factor)	300,000	63.39	139.39

1.5 RATE COMPARISON TO PEERS[13]

The Department provides electricity at competitive rates that are among the lowest for neighboring cities surrounding Los Angeles. Based on a typical monthly residential bill for a customer consuming 500 kWh of electricity, the Department has the lowest monthly electric bill

[13] The rate comparisons shown do not reflect the Recommended Energy Efficiency Alternative Plan

compared to five of its neighboring utilities in southern California. Rate increases for neighboring municipal utilities in Pasadena, Glendale and Burbank are under discussion but have not yet been announced.

The Department's rates are even more competitive than peers at higher levels of usage, as shown in Section 5.1.

Figure 8: The Department's Average Residential Customers Annualized Monthly Power Bill Comparing with Neighboring Cities and Southern California Investor-owned Utilities

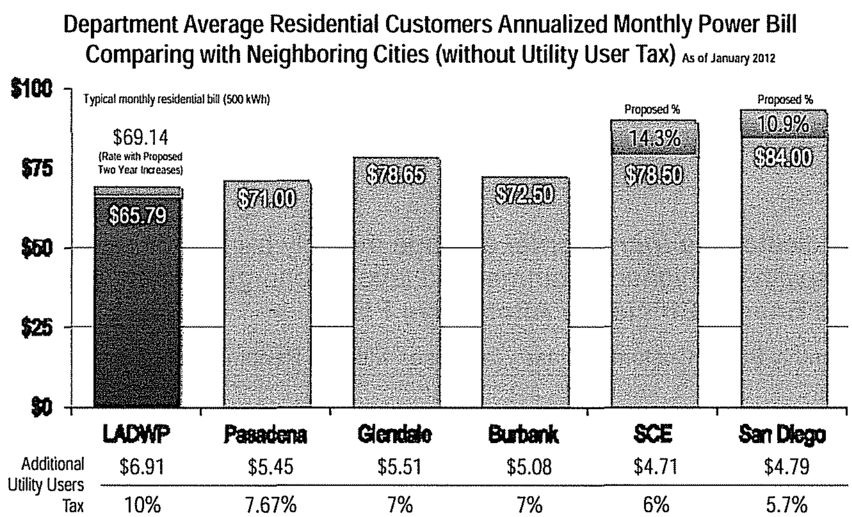
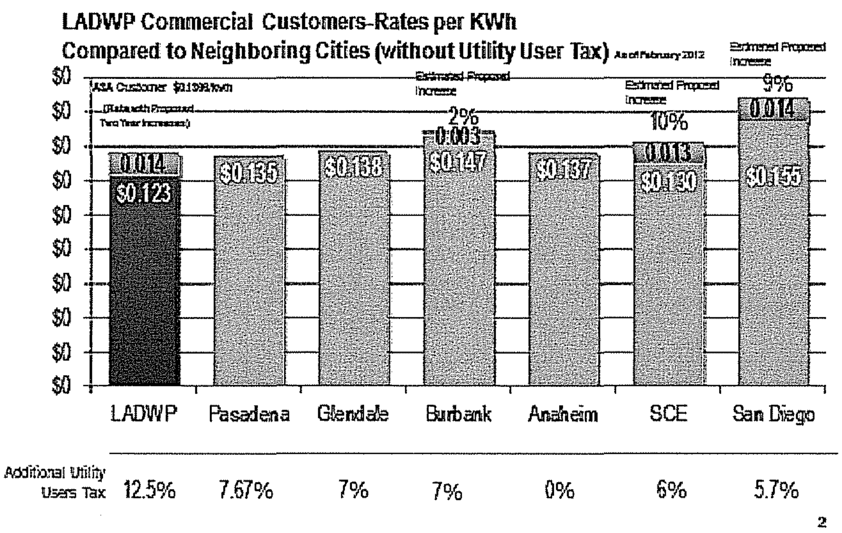


Figure 9: The Department's Commercial Rates Compared with Neighboring Cities and Southern California Investor-owned Utilities



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14 Rate increases for neighboring municipal increases have not yet all been announced, so are not reflected here. Burbank increase shown here is base rate only—fuel adjustment costs are additive.

1.6 THE RATE SETTING PROCESS

The rates process commenced on June 4, 2011. During 2011 the Department held over 30 public meetings with the public and various stakeholders.

Regional meetings were held in the East Valley, West Valley, North Valley, East Los Angeles, South Los Angeles, West Los Angeles, and Harbor areas. The Department also met with business customers, as well as stakeholders in the Owens Valley and Neighborhood Councils.

The Department reached out to encourage participation through:

- Print ads in daily and community newspapers;
- Electronic ads on City Watch website;
- Outreach to Neighborhood Councils;
- Editorial board briefings;
- Television and radio interviews;
- Social media – Twitter, YouTube; and
- Commercial and Residential Customer webinars.

Additional outreach is underway and will span April to May 2012. This is an extension of the previous process to provide information on the Department's final proposal that reflects the feedback received from customers last summer. The proposed financial plans underlying this rate proposal reflect choices among capital programs and O&M expenditures, which then specify a particular rate level. The manner in which the costs associated with doing business are allocated across various customer classes and reflected in rates is an explicit consideration of all utilities and their oversight bodies; in the case of the Department, this is principally the Department's Board and the City Council. In addition, rate adjustment proposals are reviewed by the Ratepayer Advocate and other stakeholders such as the Neighborhood Councils.

1.7 THE BUDGET PROCESS

The Department's budget development process is a thorough and methodical activity that links forecasted revenue and the costs of providing power service to derive required rates and charges.

The Board only formally adopts a budget for one fiscal year in advance. Therefore, the Department has developed proposed rates for the next two fiscal years based partly on the preliminary FY 2012-13 budget approved by the Board on March 27, 2012. A final budget has not yet been adopted, pending adoption of the first year of the proposed rate adjustment. Any changes in the proposed rates described herein would require a corresponding modification of the FY 2012-13 budget (or vice versa). The budget is structured into functional items, projects, and cost elements. Functional items typically represent multi-year programs while projects represent specific activities to be completed during a specific fiscal year (although some larger projects are multi-year) in support of the program goals.

The proposed Department budget includes a number of adjustments to major programs as compared to prior approved budgets. All major adjustments were made to ensure continued system reliability while meeting all regulatory mandates and maintaining the financial stability to facilitate the borrowing necessary to invest in compliance and infrastructure improvements at reasonable costs.

For the Power System, the most significant planning objectives are:

- Meeting external regulatory mandates for repowering coastal power plants and expanding renewable energy resources to meet State RPS requirements;
- Continuing previously announced cost reduction measures;
- Using the most current market forecast for fuel costs such as natural gas prices;
- Reinstating a portion of the previously deferred Power Reliability Program funding levels to renew the Department's efforts to replace its aging power system infrastructure; although still below desired levels; and,
- Capitalizing (recognizing through rates over time) expenditures where appropriate for assets or programs which implement or support long-term initiatives (including the energy efficiency program).

1.8 IMPLICATIONS OF INACTION ON A POWER SYSTEM RATE ADJUSTMENT

As discussed in this report, the Department has numerous regulatory, legislative, public policy and system reliability obligations. Additional funding beginning in FY 2012-13 is essential in order to meet these obligations. The Department presents in this report the required rate increase for the upcoming fiscal year assuming such a rate increase is effective July 1, 2012. Given the delay in the appointment of the Ratepayer Advocate, and the need to provide adequate review time the RPA, as well as other necessary steps in the rate approval process, a July 1, 2012 rate increase appears to be impractical. In order to collect the same dollars over fewer remaining months in the year, a progressively higher percentage rate increase will be necessary the longer the rate action is delayed. If incremental revenue is not provided at all, the Department would likely not be able to meet its mandated regulatory and legislative obligations, but in an effort to do so, would be forced to cut important but somewhat more discretionary programs such as power reliability and customer service. Further consequences of a revenue shortfall would include:

- The Department's debt service ratio would fall below the 2.25 target;
- In 2013 and 2014, the Department will not meet its targeted financial net income.

All the above consequences would be apparent to the credit rating agencies and increase the risk of a downgrade or at a minimum, having the Department's bond ratings put on credit "watch" with negative outlook.

1.9 BEYOND THE 2-YEAR PROPOSED RATE PERIOD

The Department is currently in the process of assessing rate and revenue requirements associated with both externally mandated costs as well as various levels of funding for other programs for FY 2015 through FY 2017. Costs for this period are still subject to uncertainty. In addition, the Department has not undertaken a detailed review of the allocation of power system costs among customer classes or design of its rates for several years. Such a review would warrant an extended period of time for review by the public and independent review by the RPA. The Department anticipates such a review in the next calendar year under a schedule that can be undertaken without the risk of delay to obtaining critically needed revenue to meet regulatory mandates and system infrastructure improvement funding. In addition, the Department is presently updating its Integrated Resource Plan (IRP) with a particular focus on the power resource additions and changes for the balance of this decade. Recommendations in that IRP will influence commitments beyond calendar year 2014 in levels of energy efficiency, approaches to meeting RPS requirements and the power resources that will replace coal-fired resources that will be eliminated as part of plans to comply with Senate Bill 1368 and the associated Emission Performance Standards that legislation created. These changes and the level of funding for the multi-year Power Reliability Program will be the key sources of influence for rates beyond the proposed two-year rate adjustment period.

2. NEXT CENTURY POWER KEY PROGRAMS

In the years ahead, the Department will be undertaking several key endeavors and programs that are essential to complying with regulatory mandates, ensuring reliability and providing services desired by customers. These programs also drive changes in rate during the next two years, and beyond. These programs and rate drivers are discussed in this section. :

- Section 2.1: **Power Supply Replacement Program**
    - Rebuilding Local Power Plants
    - Renewable Energy

  These programs are mainly driven by regulatory and legislative mandates with which the Department must comply.
- Section 2.2: **Power Reliability Program**: Replacing the rapidly aging electric transmission and distribution system. This includes replacements of Distribution Stations, Transformers, Poles, Wires, Cables, Cross-arms and more.
- Section 2.3: **Customer Opportunities Program:** Existing and newly planned energy efficiency and customer solar program initiatives are aimed at reducing customers' electric usage and therefore their bills
    - Energy Efficiency
    - Customer Solar Programs

As previously stated, the revenue requirement and rate impacts presented herein are based on proposed expenditures that include increased energy efficiency program investments from prior years that put the utility on a path to achieve energy savings equivalent to 8.6% of 2010's energy consumption by 2020. However, this level of funding falls short of that necessary to reach the State mandated (AB 2021) cumulative savings of 10% of total energy consumption levels by 2020. Consequently, the Department has also included in this proposal a Recommended Energy Efficiency Alternative Plan that provides additional funding that will put the Department on a path to achieve the 10% energy reduction goal by 2020. **Section 7: Recommended Energy Efficiency Alternative Plan** provides further detail.

In addition to the three programs noted above, Sections 2.4 and 2.5 cover other cost drivers that contribute to the need to adjust rates. Section 2.4 addresses anticipated changes in fuel costs that the Department incurs to produce power. Section 2.5 addresses other cost pressures related to daily operations and maintaining access to low cost financing for the capital program. Section 2.5.1 addresses changes in wages, benefits and pensions of all of the Department's employees.

Section 2.5.2 addresses rate pressures related to maintaining financial metrics associated with maintaining high quality ("AA") credit ratings. Much of the capital required to fund the Department's key programs will be obtained through additional bond issues. Therefore continued access to bond markets at the lowest possible cost and maintaining the current bond ratings are important considerations. The Department's rate proposals are designed to maintain the financial metrics associated with the current (AA) bond ratings.

The Department is required to comply with numerous regulatory and legislative mandates - State, Federal, and local. The mandates with significant impact on the Department's Power System costs include:

1. SBx1 2 (RPS) (State)
2. SCAQMD[15] (Repowering) (State)
3. Once-Through Cooling (generation cooling water) (State Water Resources Control Board)
4. AB 32, Global Warming Solutions Act (State)
5. SB 1368, Power Plant Emissions Performance Standards (California Energy Commission)
6. AB 2021 (Energy Efficiency) (State)
7. Clean Water Act – Section 316 (Federal - EPA)
8. Coal Combustion Residuals (CCR) regulations (Federal - EPA)

2.1 POWER SUPPLY REPLACEMENT PROGRAM

As previously stated, $116 million of the average annual revenue requirement increase of $159 million is for regulatory mandates over the two-year rate period covering FYs 2013 and 2014. Of the $116 million, $88 million is for mandates related to the Department's power supply replacement program. Compliance with these power supply mandates, which are not controlled by the Department, will require over $1.3 billion in combined capital and O&M expenses over the next two years.

The Department's mandated investments during FYs 2013 and 2014 fall into two separate but integrated programs:

- Repowering local power plants (largely the elimination of once through cooling or OTC for the Department's coastal units)
- Renewable energy (also referred to as renewable portfolio standards or RPS)

The following tables provide a breakdown of the Capital and O&M expenses associated with regulatory mandates over the next two years.

Figure 10: Capital and O&M Expenditures – Power Supply Replacement Program[16]

Rate Increase Cost Factor ($M)	Cost Type	Current Year	Proposed Rate Period	
		FY 2012	FY 2013	FY 2014
Rebuilding Local Power Plants	Capital	375	380	373
	O&M	0	0	0
Renewable Energy[17]	Capital	189	144	390
	O&M	26	27	28
	PPA[18]	316	336	373
Subtotal	**Capital**	**564**	**524**	**763**
	O&M	**26**	**27**	**28**
	PPA	**316**	**336**	**373**
Total Expenditures		**$906**	**$887**	**$1,164**

[15] South Coast Air Quality Management District
[16] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan
[17] Includes on and off balance sheet debt
[18] Includes biogas purchase power agreements

While O&M and purchase power agreements (PPA) are direct contributors to the annual revenue requirement, capital expenditures are funded over a number of years. The following table provides a breakdown of the annual revenue requirement impact of each of the major regulatory mandated programs in FYs 2013 and 2014. The average additional revenue required each year to satisfy these mandates is **$88 million**.

Figure 11: Power Supply Replacement Impact on Revenue Requirement[19]

Rate Increase Cost Factor ($M)	FY 2013	FY 2014	Avg. Annual Increase
Rebuilding Local Power Plants	45	53	49
Renewable Energy	27	51	39
Total	$72	$104	$88

2.1.1 Overview of the Department's Generation Resources

The Department has a diverse mix of generating resources which are wholly-owned or operated through partnerships with other power utility entities, or are otherwise contracted for.[20] Most of the regulatory mandated investments to be funded by the new rates pertain to generation resources owned by the Department the Department's portion of investments in jointly-owned facilities or power and fuel purchase agreements. A list of the Department's owned or contracted generation resources is shown in the following table.

[19] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan
[20] Generation resources that are not wholly owned by the Department are available as entitlement rights resulting from undivided ownership interests in facilities that are jointly-owned with other utilities. Other generation resources are owned by others with power supplies via purchase power agreements.

Figure 12: **Department Generation Resources**

Name of Plant	Fuel Source	Unit No.	In Service Date	Age (Years)	Net Maximum Unit Capability (MW) [2]	Net Maximum Plant Capability (MW) [3]	Net Dependable Plant Capability (MW) [4]
Harbor Generating Station	Natural Gas	1	1995	16	82	466	461
		2	1995	16	82		
		5	1995	16	65		
		10	2002	9	47.4		
		11	2002	9	47.4		
		12	2002	9	47.4		
		13	2002	9	47.4		
		14	2002	9	47.4		
Haynes Generating Station	Natural Gas	1	1962	49	222	1555.6	1525
		2	1963	48	222		
		5	1966	44	292		
		6	1967	44	243		
		7	1970	41	1.6		
		8	2005	6	250		
		9	2005	6	162.5		
		10	2005	6	162.5		
Scattergood Generating Station	Natural Gas	1	1958	53	183	817	796
		2	1959	52	184		
		3	1974	37	450		
Valley Generating Station	Natural Gas	5	2001	10	43	576	556
		6	2003	8	159		
		7	2003	8	159		
		8	2003	8	215		
Total Net Capability of Natural Gas Stations						**3415**	**3338**
Intermountain Generating Station	Coal	1	1986	25	900	1100	1100
		2	1987	24	900		
Navajo Generating Station	Coal	1	1974	37	750	477	477
		2	1974	37	750		
		3	1975	36	750		
Mohave Generating Station[21]	Coal	1	1971	40	0	0	0
		2	1971	40	0		
Total Net Capability of Coal Stations						**1577**	**1577**
Palo Verde Generating Station	Nuclear	1	1986	26	1333	387	380
		2	1986	26	1336		
		3	1988	24	1334		
Total Net Capability of Nuclear Stations						**387**	**380**
Castaic Power Plant	Hydro	Various	1972-1978	33-39	1620	1247	1175
Hoover Power Plant	Hydro	Various	1936	75	491	491	436
Total Net Capability of "Large" Hydro Stations						**1738**	**1611**
Aqueduct System	Hydro	Various	1917-1987	24-94	126.7	83.1	24.2
OwensValley System	Hydro	Various	1908-1958	53-103	16	12.5	1.2
Owens Gorge System	Hydro	Various	1952-1953	58-59	112.5	112.5	109.4
Owned & Contracted Renewables	Renewable/DG	Various	2002-2011	1-9	1141	1141	343
Total Net Capability of Small Hydro and Renewable / Distributed Generation						**1349**	**478**
Total Net Capability of the Department's Resources						**8464**	**7384**
State's Capacity Entitlement (See Note[6])						-120	-55
Total Net Capability of the Department's System						**8346**	**7329**

Notes:

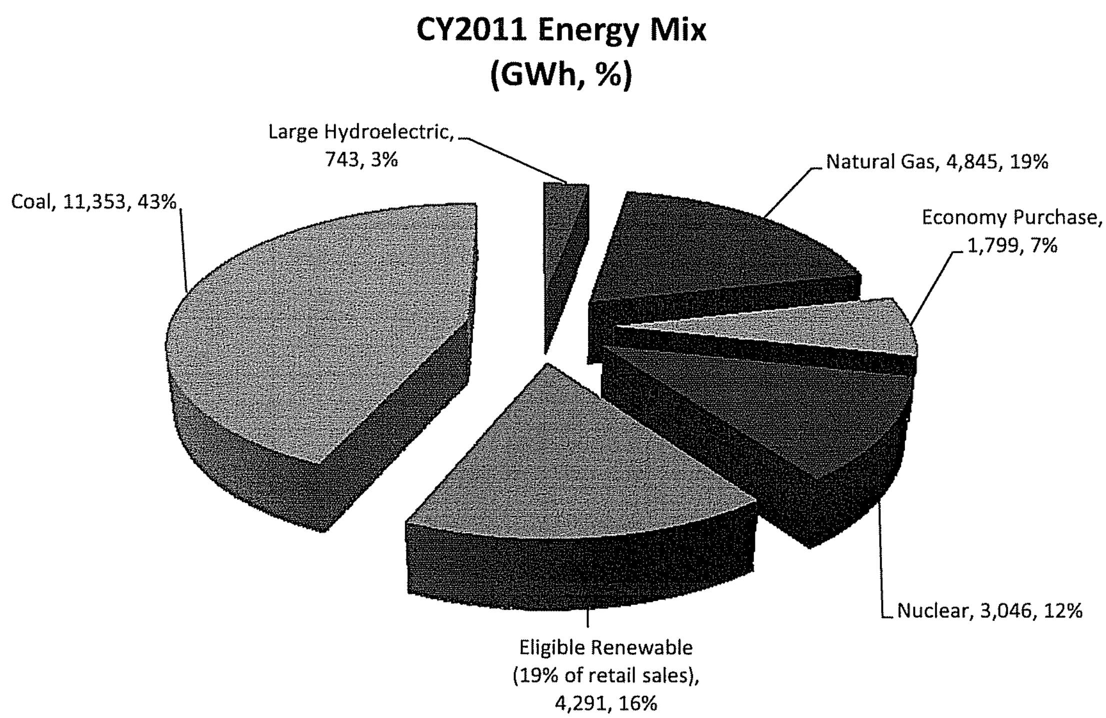
[21] Plant retired and decommissioned.

1. Power source data are based on Power System Engineering Division's January 2011 Generation Ratings and Capabilities Sheet and power purchase agreements for contract sources.
2. All units can attain maximum capability only when the weather and equipment are simultaneously at optimum conditions.
3. Reflects: water flow limits at hydro plants, sum of unit output at in-basin thermal or renewable plants, or contract entitlement of external thermal plants.
4. Reflects: year- round outputs adjusted for low-generation season. For hydro plants, winter is the low-generation season.
5. Owned or contracted renewable projects in wind, solar, hydro, landfill gas, biomass, and distributed generation in-service as of September 2011.
6. The maximum State (CDWR) Capacity Entitlement from Castaic Power Plant is 120 MW. The average for FY 2009-2010 was approximately 55 MW. The actual amount varies weekly.
7. Total Net Capability of the Department's System may vary due to unit outages, de-ratings and sales obligations.

Regulatory requirements dictate that the Department transition generation supply from coal to natural gas, renewable and other less CO_2 intensive sources of power.

The Department's energy and capacity breakdown has evolved significantly from 2006 to 2011. The largest changes over this time period has been (1) the decrease in coal-fired energy from 47% in 2006 to 43% at the end of 2011, and (2) the corresponding increase in energy from renewable resources, from 7% in 2006 to 16% at the end of 2011[22]. The 16% of eligible renewables represents the percent of total energy generated at generating stations (i.e. Net Energy for Load or "NEL"). The 16% renewables of NEL meets 19% of all customer consumption (i.e. Total Retail Load).

Figure 13: Department Energy Mix, 2011[23]



[22] The 4,291 GWh (16%) of eligible renewables in the 2011 energy mix translates to 19% of total retail sales.
[23] The 4,291 GWh (16%) of eligible renewables in the 2011 energy mix translates to 19% of total retail sales.

The proposed rates are designed to continue the transformation of the Department's generation resources in accordance with the applicable regulatory mandates. Renewable energy resource investments to be funded during the next two fiscal years are part of a transition program to allow the Department to meet the mandated 33% renewable energy resource requirement by the end of 2020. In addition, the repowering investments to be funded during the next two fiscal years are part of a transition to eliminate reliance on "once through" ocean water cooling arrangements with dry cooling by the end of 2029. During the next two years, the Haynes 5/6 and Scattergood Unit 3 plants will be replaced with new units that do not use ocean water for cooling, are more fuel efficient, and have the ability to start and stop and ramp up and down more quickly to meet the changes in renewable energy power supply levels from intermittent sources such as wind and solar generation as the Department progresses towards its mandated 33% RPS levels

The remaining part of this section discusses the three major power supply replacement programs in more detail.

2.1.2 Rebuilding Local Power Plants

The Department is the sole owner and operator of the following four natural gas fueled electric generating stations in the Los Angeles Basin:

- Haynes Generating Station, located in Long Beach;
- Harbor Generating Station, located in Wilmington;
- Scattergood Generating Station, located in Playa del Rey; and
- Valley Generating Station, located in the San Fernando Valley.

The Haynes, Harbor and Scattergood stations all currently employ once-through ocean water cooling (OTC). The current combined net capacity of these stations is 2,839 MW. Continued use of local generation capacity is important for grid reliability. The Department's local system cannot be reliably operated without generation from local thermal generating plants. The amount of generation required to provide local system reliability is termed Reliability Must Run (RMR) generation. The four in-basin stations are part of the Department's RMR generation facilities. Natural gas will continue to be the essential fuel for the Department's generation due to the reliance on the system to the location of these critical generating resources and the ability of the gas-fired units to start, stop and ramp up and down to follow changes in the Department's load as well as to follow the changes in wind energy and solar energy generation resources..

The major issues facing the in-basin stations include the need to replace some of the older units to comply with regulations related to ocean water cooling and NOX emissions as well as address the age of the facilities and fuel price volatility.

Once-Through Cooling (OTC) is the process where water is drawn from the ocean, is pumped through equipment at a power plant to provide cooling, and then is discharged back to the receiving water source. A cooling process is necessary for nearly every type of conventional electrical generating station and an OTC process utilizing ocean water is a major reason why many electrical generating stations were sited along the coastline. Typically, the water used for cooling is not chemically changed in the cooling process; however, the temperature of the water increases before it is returned to the ocean.

OTC is a major regulatory issue, stemming from the Federal Clean Water Act Section 316(b) administered nationally by the Environmental Protection Agency (EPA) and locally by the State Water Resources Control Board (SWRCB). The new state wide OTC Policy and 316(b) Federal Rule require minimizing and/or reducing the impacts on marine life. The target of this OTC policy is to reduce or eliminate the mortality to marine life due to impingement and entrainment of marine life and organisms. "Impingement" is the term for the effect of lodging fish of a size that cannot pass through screens on a power plant intake up against the intake. "Entrainment" refers to smaller fish and marine organisms which are smaller than intake screen, resulting in the marine life passing into the power plant's cooling system.

The interpretation of rules and development of guidelines for OTC by the EPA and SWRCB have been several years in the making at least partially due to a series of legal challenges and subsequent court rulings ultimately from both the Second Circuit Court of Appeals and in the U.S. Supreme Court pertaining to disputes surrounding plants using OTC outside of California. While the various challenges proceeded through the court processes, the EPA gave the states permission to continue with implementation and enforcement of the Clean Water Act 316(b) requirements using "Best Professional Judgment (BPJ)" when reauthorizing facility National Pollutant Discharge Elimination System (NPDES) permits. During this period, the Department completed the required Characterization Study to identify baseline biological impacts in order to determine appropriate impingement mortality (IM) and entrainment (E) reduction method. However, the Rule was remanded to the EPA to re-study and then re-propose a rule. Essential this remanded the Rule and placed on hold the fulfillment of its associated requirements. The EPA publicly noticed the new proposed Rule for existing facilities on April 19, 2011, and the comment period ended on August 18, 2011. The EPA is targeting the end of 2012 to finalize its Rule. In the interim, the use of BPJ by permitting authorities is still in effect, and the Department is proceeding with its OTC elimination program on the calendar agreed to with the SWRCB, as discussed further below.

The California SWRCB moved ahead with a program to limit the use of OTC for non-nuclear power plants in California prior to the EPA formulating its OTC rules. On June 30, 2009, the SWRCB released its draft Once-Through Cooling Water Policy for public review and comment, with the accompanying Supplemental Environmental Document released on July 14, 2009. A final Policy version was adopted on May 4, 2010 and became effective on October 1, 2010. The adopted Policy has major implications for the coastal power plants making it extremely difficult to continue the use of OTC and making the use of cooling towers that use either non-ocean water or air for power plant cooling as the only certain compliance path. The Policy proposes a two-track compliance pathway.

- Track I requires OTC flows to be reduced commensurate with wet closed cycle cooling (CCC) or a 93% flow reduction and essentially requires the installation of cooling towers.
- If Track I can be demonstrated as "not feasible," a Track II compliance option is available. A Track II compliance pathway requires the biological impacts to be reduced on a unit by unit basis to a level comparable with (i.e., within 10%) what would exist with CCC.

Until compliance is achieved, interim measures are required, which include flow reductions when there is no unit load and mitigation measures (commencing five years from the effective date of the policy and continuing until the facility is in full compliance).

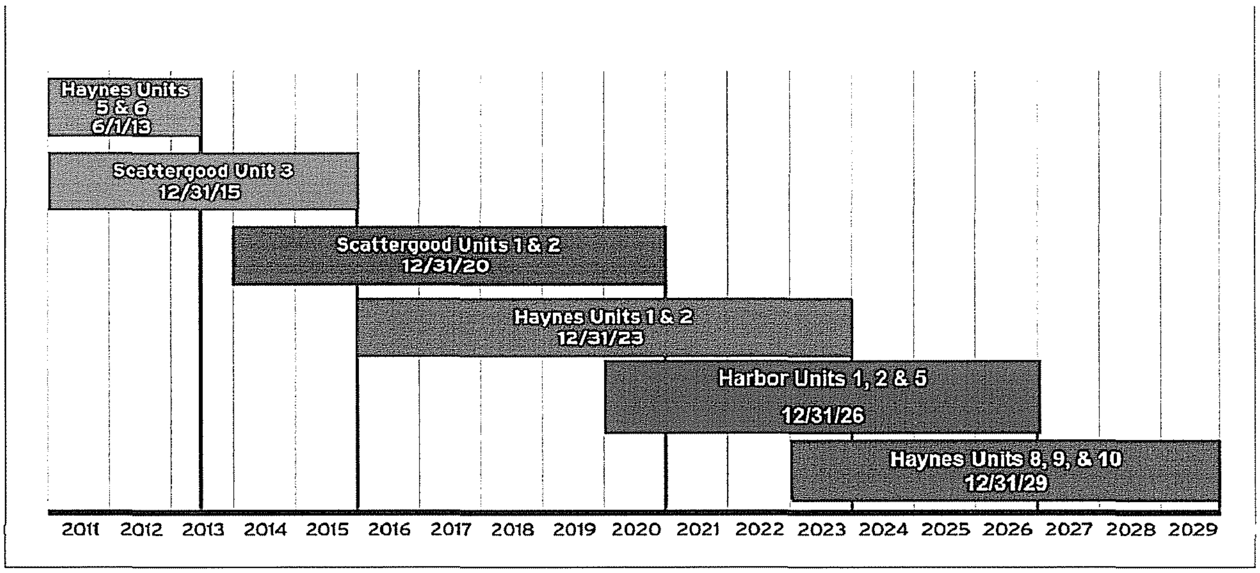
To prevent disruption in the state's electrical power supply during implementation of the Policy, a committee of state energy and resource agencies known as the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) has assisted the SWRCB in reviewing the required utility implementation plans and in monitoring the schedules. The Department's implementation plan was the first plan to be reviewed by the SWRCB and SACCWIS. As a result, the SWRCB prepared and adopted an Amendment to the Policy on July

19, 2011. This Amendment modified the Department's compliance schedule on a unit-by-unit basis with the following compliance dates for eliminating OTC:

- 6/1/2013 for Haynes units 5 and 6;
- 12/31/2015 for Scattergood unit 3;
- 12/31/2020 for Scattergood units 1 and 2;
- 12/31/2023 for Haynes units 1 and 2;
- 12/31/2026 for Harbor unit 5;[24] and
- 12/31/2029 for Haynes unit 8.[25]

Harbor units 3 and 4 have already been replaced and no longer use OTC. The Department has adopted this plan approved by the SWRCB and is moving forward with the first two stages of its replacement of its OTC units, in compliance with that approved plan. The following chart provides the current compliance schedule for complete elimination of OTC.

Figure 14: OTC Compliance Time Line



In addition, the Amendment required the Department to submit any additional information requested, by January 1, 2012, by the SACCWIS and submit the information responsive to SACCWIS to the SWRCB by December 31, 2012 in order for the SWRCB to evaluate whether further modifications to the dates are necessary. Furthermore, the Department must commit to complete elimination of OTC and in the interim conduct a study or studies, singularly or jointly with other facilities, to evaluate new technologies or improve existing technologies to reduce impingement and entrainment. The Department must submit the results of the study and a proposal to minimize entrainment and impingement to the Chief Deputy Director no later than December 31, 2015, and upon approval of the proposal by the Chief Deputy Director, complete implementation of the proposal no later than December 31, 2020. The Department is in the process of commencing these studies and has begun the Haynes Units 5 and 6 repowering project in order to meet the 2013 deadline.

The conceptual planning and design for the Scattergood Unit 3 has commenced in order to meet the 2015 deadline. The Department will issue an RFP and will need to select a vendor for

[24] Upgrades at the Harbor facility also include replacement of the aging units 1 and 2 which do not currently use OTC.
[25] The last phase of upgrades at the Haynes facility also includes replacement of the aging units 9 and 10 which do not currently use OTC.

turbine-generator equipment for Scattergood 3 by the end of 2012 to keep the replacement program on track. This is one of many of drivers for the need for rate action as soon as possible during 2012.

The repowering program to eliminate OTC will also address the Department's prior agreement with the South Coast Air Quality Management District (SCAQMD) related to NOX compliance requirements. In mid-2000, during the statewide energy crisis, the Department predicted that NOX emissions from the in-basin generating units would exceed the available supply of NOX RECLAIM Trading Credits issued by the SCAQMD. Although the Department's NOX emissions ultimately did not exceed its allocation in 2000, on August 29, 2000 the SCAQMD Hearing Board issued a "Stipulated Order for Abatement" to the Department. Under the terms of the Order, the Department was required to perform a series of repowering projects at its in-basin generating stations. The Stipulated Order was later superseded by a Settlement Agreement to accommodate scheduling and other issues. This agreement was revised in September 2011 and addresses the current repowering projects at the Haynes and Scattergood Generating Stations.

In the two-year horizon discussed in this report, investments will be made on two of the four separate projects to replace the OTC process with dry cooling:

- Haynes units 5 and 6 (also referred to as Haynes Phase I)
- Scattergood unit 3 (also referred to as Scattergood Phase I)

Figure 15: Rebuilding Local Power Plants - Capital and O&M Expenditures

Rate Increase Cost Factor ($M)	Cost Type	Current Year	Proposed Rate Period	
		FY 2012	FY 2013	FY 2014
Rebuilding Local Power Plants	Capital	375	380	373
	O&M	0	0	0
Total Expenditures		$375	$380	$373

Figure 16: Rebuilding Local Power Plants Impact on Revenue Requirement and Rates[26]

Rebuilding Local Power Plants	FY 2013	FY 2014	Avg. Annual Increase
Total System Revenue Requirement ($M)	45	98	49
Total System Average Cost per kWh (¢/kWh)	0.19	0.42	0.21
System Average Annual Percent Increase (%)	1.52%	3.27%	1.63%

For specific information regarding each of the four generation facilities, please refer to **Appendix F: Power Generation OTC Projects**.

[26] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

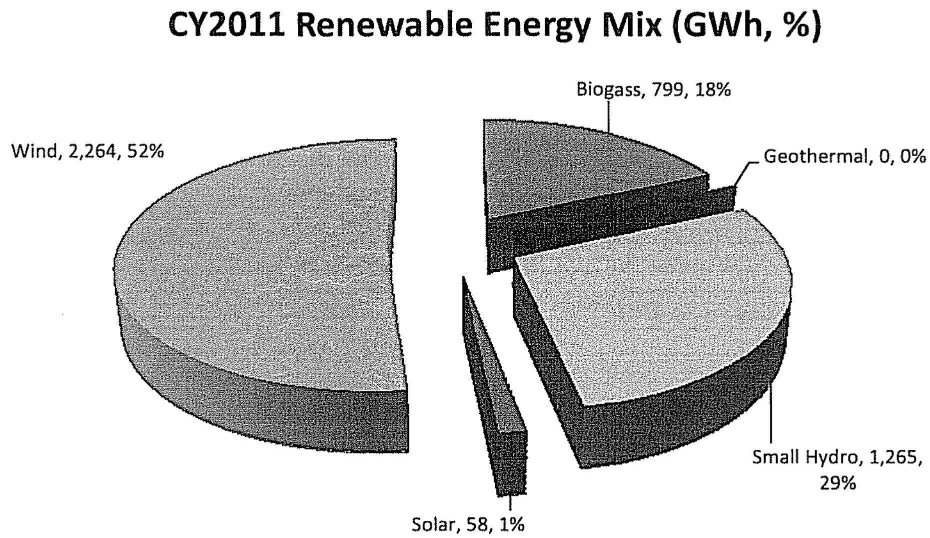
2.1.3 Renewable Energy

Renewable energy resource additions to meet the mandated 25% RPS requirement by 2016, en-route to a 33% RPS by 2020 are the second major power supply resource additions that influence revenue requirements for the next two fiscal years. Compliance with state-mandated interim milestones requires:

- 20% average for the period January 1, 2011 through December 31, 2013
- 25% average by December 31, 2016 (based on the average percentage of retail sales for the period January 1, 2016 to December 31, 2016
- 33% average by December 31, 2020 (based on the average percentage of retails sales calculations for the period January 1, 2020 to December 31, 2020

Shifting a greater amount of energy production to renewable energy sources is a major mandate and environmental initiative in California memorialized by Senate Bill 1X-2 passed in April 2011. The Department's existing secured renewable resources can provide an average annual 4,466 GWh of power through a combination of the Department owned facilities, purchase power agreements (PPA) and fuel purchases. The main components are wind, small hydro[27], solar, biogas, and geothermal resources. By the end of 2014, the Department expects to provide 5,332 GWh of power using renewable energy resources. The Department's current renewable energy mix is shown in the following chart.

Figure 17: 2011 RPS Energy Mix



The proposed rates will fund the capital and O&M expenses associated with the investments required to meet the compliance targets noted above for the incremental costs that will be incurred for renewable energy additions in the next two fiscal years. The Department will have to make commitments to renewable projects during the two-year rate period that will require additional funding beyond the next two years to meet the compliance targets through 2020. For instance, to reach the RPS targets, approximately $40 million in short-term renewable energy purchases will be required during the current fiscal year (FY 2012) and FY 2013. Furthermore, the Department's RPS plans include two solar projects that require a hard commitment in August 2012 in order for the solar plant to be brought online by January 2014. The capital,

[27] The CEC rules implementing Senate Bill 2 (1X) considers new small hydroelectric generation facilities of 30 MW or less, or a small hydroelectric generation unit with a nameplate capacity not exceeding 40 MW that is operated as part of a water supply or conveyance system to qualify as renewable energy sources.

O&M and PPA expenses associated with the expansion of the Department's renewable energy portfolio are shown in the following table.

Figure 18: Forecasted Costs of Renewable Energy Programs ($M)[28]

RPS Type	Cost Type	Current Year	Proposed Rate Period	
		FY 2012	FY 2013	FY 2014
Solar[29]	Capital	162.5	87.7	84.3
	O&M	0.8	1.4	1.4
	PPA	0.0	0.1	7.7
Solar Subtotal		**163.3**	**89.2**	**93.4**
Wind	Capital	6.7	6.4	9.5
	O&M	4.9	7.9	8.2
	PPA	209.6	224.9	232.1
Wind Subtotal		**221.2**	**239.2**	**249.8**
Geothermal	Capital	0.9	0.8	0.9
	O&M	0.0	0.0	0.0
	PPA	0.0	0.0	13.5
Geothermal Subtotal		**0.9**	**0.8**	**14.4**
Small Hydro	Capital	7.4	6.6	13.4
	O&M	9.9	17.5	18.6
	PPA	33.5	11.5	12.1
Small Hydro Subtotal		**50.8**	**35.6**	**44.1**
Biogas / Biomass	Capital	0.0	0.0	0.0
	O&M	0.0	0.0	0.0
	PPA	64.7	88.2	87.4
Biogas / Biomass Subtotal		**64.7**	**88.2**	**87.4**
Transmission	Capital	11.9	42.8	282.0

[28] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan
[29] Solar expenditures include the SB-1 incentive which is part of the Customer Opportunities Programs discussed in Section 2.3

RPS Type	Cost Type	Current Year	Proposed Rate Period	
		FY 2012	FY 2013	FY 2014
	O&M	0.0	0.0	0.0
	PPA	4.4	4.4	4.4
Transmission Subtotal		**16.3**	**47.2**	**286.4**
Generic[30]	Capital	0.0	0.0	0.0
	O&M	0.0	0.0	0.0
	PPA	3.8	7.0	15.6
Generic Subtotal		**3.8**	**7.0**	**15.6**
Total by Cost Type	**Capital**	**189.5**	**144.4**	**390.0**
	O&M	**15.6**	**26.7**	**28.2**
	PPA	**316.1**	**336.1**	**327.8**
Total		**$521.1**	**$507.2**	**$791.0**

In addition to the Department's planned $589 million in direct renewable energy supply expenditures over the next two years (shown as Capital and O&M in the above table), the Department will invest in renewables through a joint power agency--the Southern California Public Power Authority (SCPPA). With these two approaches, the Department is projecting to invest over $1.3 billion in renewable energy resources over the next two years. The majority of this investment will be debt financed; to meet the mandated RPS levels and deadlines, the Department must make the investments and start to service the debt before many of the new renewable resources are actually producing power for customers and generating revenue.

The rates proposed herein will allow the Department to meet the renewable compliance targets and maintain a pace of investment to reach the mandated targets in 2016 and 2020. In the table below are the renewable energy resource forecasts for the proposed rate period (FY 2013 and 2014); for each year/energy type, the percent contribution to total retail sales is shown.

[30] "Generic" category of renewables consists of renewable energy of unspecified type which could come from market purchase or increased size of planned renewable projects. Pricing used is $140 per MWh with no escalation.

Figure 19: Renewable Energy Resource RPS Contribution Forecast[31]

Renewable Energy Type	Current Year	Proposed Rate Period	
	2012	2013	2014
Biogas	5.71%	5.91%	5.87%
Geothermal	0.00%	0.00%	1.01%
Small Hydro	2.83%	2.57%	2.56%
Solar	0.66%	0.92%	1.53%
Wind	10.38%	11.19%	11.09%
Generic	0.21%	0.43%	0.77%
Total	**19.79%**	**21.03%**	**22.83%**
Required	**20%**[32]		**20%**

As noted earlier, California SB 2 (1X) is the State legislation that mandates the renewable energy resource requirements the Department must meet. Please refer to **Appendix G: California SB 2(1X) Summary** for more detail on this legislation.

Efforts to Maintain Low Costs for Renewable Energy

The Department procures its renewable energy supply primarily through competitive solicitations. The Department has also successfully undertaken methods to reduce the cost of its renewable energy portfolio by innovative procurement and financing mechanisms. For example, because of the lack of tax-subsidies for municipalities to build and immediately own renewable generation, the Department has used creative vehicles to address this and keep costs low for customers. One such vehicle is using the "prepay" option in lieu of traditional PPAs or straight ownership of renewable supply. The prepay method comes with the benefit of allowing the Department to:

- Take advantage of cash grants/tax credits through partnerships (an unaffiliated equity partner can use the tax credits which a municipality is ineligible for);
- Lower the cost of financing project debt (using municipal bonds);
- Maintain renewable development project management, structuring, and operating capabilities; and
- In many cases, retain the option to purchase renewable project after cash grants/tax credits expire since the benefits of non-ownership may significantly decline after the period of tax subsidies for a given renewable project rolls off

[31] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan
[32] 20% average for the period January 1, 2011 through December 31, 2013

Each group of renewable energy resource programs is discussed in more detail below.

Solar

Solar Feed in Tariff (FiT)

The Department has commenced a Solar Feed-in Tariff (FiT) program that is being released in phases. FiT seeks to purchase energy from small and medium-scale eligible renewable energy projects (from 30 kWs up to 3 MWs in ac capacity) within the service territory under a long-term Standard Offer Power Purchase Agreements (SOPPA). The SOPPA terms are standard for all participants, can be up to 20 years in duration, and participants will be paid the bid base price of energy multiplied by the Time-of-Delivery (TOD) factors. FiT is a distributed generation (DG) program designed to have generation close to the local load centers, and also provide customers the opportunity to sell energy to the Department by using their property as the DG site.

The Department has started the process with a 10 MW FiT Demonstration Program to fine tune the solar pricing mechanism, project viability, system integration, and program administration. Technology will be limited to solar projects capped at 999 kWs for the Demonstration Program. Results from the Demonstration Program will guide the development of the full FiT Program which will help the Department work towards its Integrated Resource Plan, the California Renewable Energy Resource Act SB2 (1X) and also satisfy state mandate SB 32.

The FiT is an incentive program to encourage customers to invest in customer-owned solar facilities. The rates presented in the two years covered by this report include a 75 MW FIT program phased in by year end 2016 under which the Department will purchase power generated by local solar power producers. Depending upon the results of the 10 MW Demonstration Program, the FiT may be increased above 75 MW to as much as 150 MW for contracting by or before the end of 2016. The FiT provides producers with a market for solar power at rates which compensate the producers for the costs of installing and operating small scale solar power generating facilities. The FiT is considered a PPA and is budgeted as O&M expense in the fuel power purchase budget. Given the timing of the payments under the FiT, there is essentially no rate impact to the FiT program in FY 2013 or FY 2014.

Utility Built Solar (UBS)

While solar power currently provides less than 1.0% of the Department's RPS mix, the Department plans to increase its reliance on solar power to 6.7% of the Department's RPS portfolio by the end of FY 2014. Solar power's portion of the Department's total retail load is expected to be 1.5% by the end of 2014. The specific Department utility built solar programs are discussed here.

Approximately 30 MWac worth of projects are under design and construction. To date, three projects, totaling approximately 202 kWac, have been brought in-service. Listed below are the Department's major solar projects. Please refer to **Appendix H: Utility-Built Solar Project Overview** for further project details.

- Adelanto Solar Project
- Pine Tree Solar Project
- Port of Los Angeles (POLA) Projects
- Owens Valley Solar Projects – Southern Owens Valley Solar Ranch and Owens Dry Lakebed Demonstration

Figure 20: Solar Program Costs[33] [34]

Program Costs ($M)	Cost Type	Current Year	Proposed Rate Period	
Fiscal Year		FY 2012	FY 2013	FY 2014
Utility Built Solar	Capital	97.1	16.4	14.2
Owens Valley Solar	Capital	2.1	0.5	0.1
Other Solar Projects	Capital	0.5	3.9	4.0
	O&M	0.8	1.4	1.4
	PPA	0.0	0.0	5.4
Feed-in Tariff	PPA	0.0	0.1	2.3
Total		$100.5	$22.3	$27.4

Note: Solar expenditures also include the SB-1 incentive which is part of the Customer Opportunities Programs discussed in Section 2.3. Funding for that program is not shown in the above table.

Wind

Wind power currently provides 51.5% of the Department's RPS mix. Based on the Department's current projection, wind will decrease to 48.6% of the RPS portfolio by the end of 2014 as other renewable resource types are added. The Department's wind power portfolio consists of the following programs:

- **Owned Wind Facilities:** The Department's wind facilities (including the Linden facility owned through SCPPA) include up to 185 MWs of wind power capacity.
- **PPAs:** The Department currently has six PPAs for 772 MW of capacity. 71% (549 MW) are under contracts with an option to take ownership and 29% (223 MW) are PPAs without an ownership option.

The Department's total current wind power generation capacity is 957 MW (185 MW of owned facilities plus 772 MW of PPAs). The Department estimates that additional capacity from Pine Tree and from other wind PPAs will add a potential 170 MW of wind power by the end of 2017. Below is a list of the Department's in-service and under-construction wind generation resources:

Figure 21: Renewable Energy Resource RPS Contribution Forecast[35]

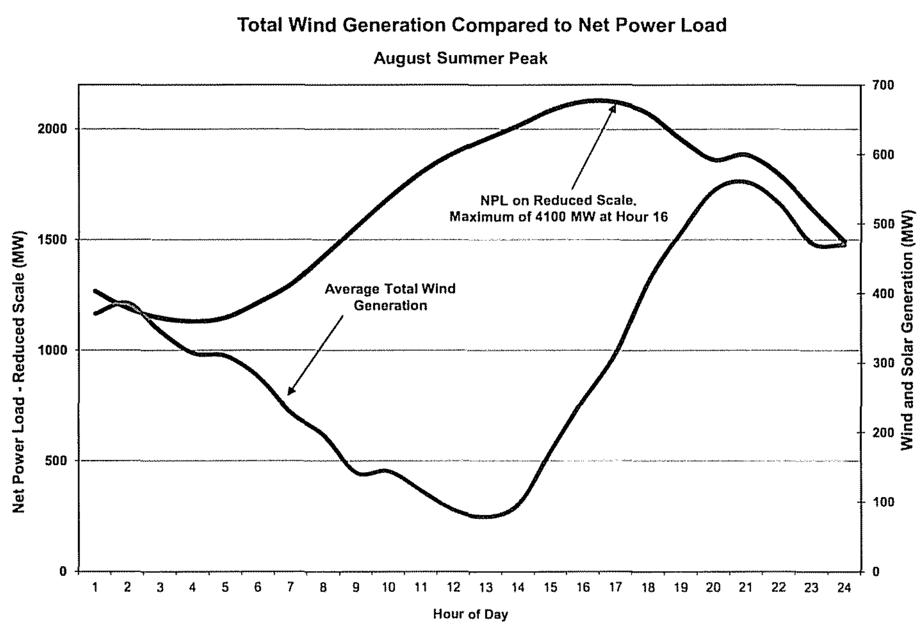
Wind Plant	Generation Capacity (MW)
PPM SW Wyoming	82
Pine Tree	120

[33] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan
[34] The solar expenditures shown here do not include the Solar Rebate Program, which is part of the Customer Opportunities Program discussed in Section 2.3.2
[35] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

Wind Plant	Generation Capacity (MW)
Willow Creek	72
Pebble Springs	69
Milford I	185
Windy Point	202
Windy Point Expansion	60
Linden Ranch[36]	50
Pine Tree Expansion	15
Milford II	102
Total Wind Generation Capacity	957

As shown in the following chart the amount of power generated from wind is not consistent throughout the day, and does not match the peak energy requirements of the Department.

Figure 22: Wind Generation Profile



Based on the location of the wind farms, about 10% of the total capacity can be counted on to be available for dispatch at any time of day.

[36] Linden facility owned jointly with the Southern California Public Power Authority (SCPPA) - the Department, currently has 100% of the power; however another SCPPA participant has an option for 10% of the power that expires in July 2013

Figure 23: Wind Program Costs ($M)[37]

Program Costs ($M)	Cost Type	Current Year	Proposed Rate Period	
Fiscal Year		FY 2012	FY 2013	FY 2014
Owned Wind Facilities	Capital	6.7	6.4	9.5
	O&M	4.9	7.9	8.2
Wind PPA	PPA	209.6	224.9	232.1
Total		$221.2	$239.2	$249.8

Geothermal

Currently, the Department has no geothermal power as part of its RPS generation sources. As described in the 2011 IRP, geothermal power sources were originally anticipated to provide roughly 4.4% of the Department's RPS portfolio by the end of 2014; however, the Department is re-evaluating geothermal power resources as part of the 2012 IRP update. The geothermal portion of the Department's total retail load is expected to be 1.0% by the end of 2014. The geothermal program will consist of PPAs and one joint facility in Imperial Valley, California that is being developed by the Department, the Imperial Irrigation District (IID) and SCPPA under a 10-year exploration/development Memorandum of Understanding (MOU) and a 35-year Land Lease Agreement (Imperial Valley Project). The exact timing of these projects is currently under evaluation. The geothermal resource capital costs shown in the figure below are for the Department's share of geothermal exploration costs for a geothermal property in which the Department is participating in the Imperial Valley. The results of that exploration effort will determine if and when the Department would go forward with participation in the actual construction of a geothermal power project to use a geothermal resource that would be proven by the exploration effort.

Figure 24: Geothermal Program Costs ($M)[38]

Program Costs ($M)	Cost Type	Current Year	Proposed Rate Period	
Fiscal Year		FY 2012	FY 2013	FY 2014
Geothermal	Capital	0.9	0.8	0.9
	PPA	0.0	0.0	13.5
Total		$0.9	$0.8	$14.4

Small Hydro

[37] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan
[38] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

Hydro power currently provides 8.7% of the Department's overall retail load; however, only 5.5% of the overall hydro portfolio qualifies as RPS. The Department's rights to hydroelectric power from the Hoover Power Plant at Boulder Dam does not "count" as renewable energy under California state RPS rules. Small hydro power which is recognized by state RPS rules currently provides 27.8% of the Department's RPS mix. Based on the proposed plans for renewable energy resource additions to the Department's portfolio, small hydro will decrease to 11.2% of the Department's RPS portfolio by the end of 2014 and account for approximately 2.6% of the Department's total retail load by end of 2014. The Department currently operates several hydro facilities that qualify as renewable energy resources:

- Los Angeles aqueduct, OV and OG (166 MW);
- North Hollywood (1 MW);
- Sepulveda (9 MW); and
- Castaic (45 MW non RPS and 30 MW RPS from the units 3 and 5 upgrades)

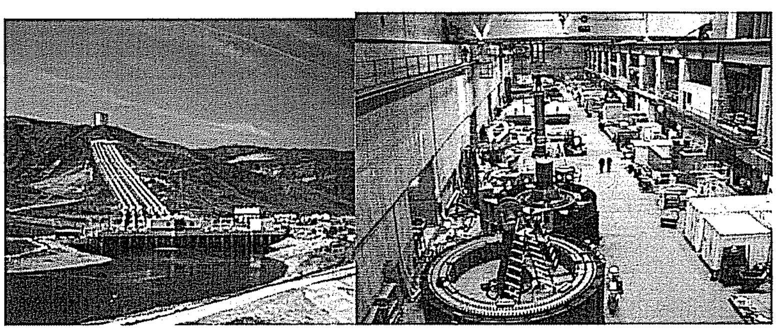
The Department has three programs to increase its hydro capacity:

- Castaic unit 1 upgrade (15 MW);
- Los Angeles aqueduct improvements (4 MW); and
- WS Hydro (4 MW) - various potential small conduit hydroelectric projects in the water supply system to the city, estimated total capacity of 4 MW.

The Castaic Pump Storage Power Plant (the "Castaic Plant") efficiency improvement project is the main hydro program contributing to the Department's renewable energy resources. This facility is located near Castaic, California, and is the Department's largest source of hydroelectric capacity consisting of seven units with a net dependable capacity of 1,175 MW.

The Castaic facility provides peaking and reserve capacity for the Department's load requirements. The Castaic facility as shown in the following pictures produces hydroelectric power and also has a pump system to pump water into a storage facility for the generation of additional hydroelectric power. The stored water is released at times of peak demand to generate additional power. This facility provides a renewable source of energy generation to fill peak gaps and gaps created by inconsistencies associated with wind and solar power.

Figure 25: Castaic Facility



The Castaic Modernization Plan is increasing the total Plant Capacity by 90 MWs by the end of 2014. 45 MWs of the additional 90 MWs achieved through the capacity improvement (modernization) project will qualify as renewable energy resources under state RPS rules; the other 45 MWs were implemented prior to the date under which *new* small hydro facilities could qualify as RPS. The major specific improvements to the Castaic Plant over the next two years are as follows:

- Modernize unit 1: Replace the runner, stator, and exciter, refurbish turbine shutoff valve, and machine and refurbish many other related parts – expected to be completed by June 2013;
- Modernize Unit 7: replace runner, generator, refurbish valve and other related items – expected to be completed by April 2014; and
- All units: Install new control system for all 7 units – expected to be complete by June 2014.

Figure 26: Small Hydro Program Costs ($M)[39]

Program Costs ($M)	Cost Type	Current Year	Proposed Rate Period	
Fiscal Year		FY 2012	FY 2013	FY 2014
New Hydro Plant at OG	Capital	0.2	< 0.1	< 0.1
LA Aqueduct Improvement	Capital	2.0	1.8	5.1
OV Plant A&Bs	Capital	4.8	4.5	7.9
WS Hydro	Capital	0.4	0.3	0.4
OG, OV, AQ	O&M	9.9	17.5	18.6
Small Hydro PPA	PPA	33.5	11.5	12.1
Total		$50.8	$35.6	$44.1

Biogas / Biomass

The Department has two types of biogas-biomass programs:

- Biogas PPAs; and
- Biogas fuel purchase agreements.

Biogas programs currently provide 18.7% of the Department's RPS mix. Based on the proposed rates biogas-biomass will increase to 25.7% of the Department's RPS portfolio by the end of 2014, which equals 5.9% of the Departments total retail load by the end of 2014.

The current California Energy Commission (CEC) Overall Program Guidebook of January, 2011 defines biogas as "a gas derived from RPS-eligible fuel including biomass, digester gas, and/or landfill gas"; the CEC is currently working on a new Guidebook to comply with the SB 2 (1X) RPS requirements to further define eligible sources of Biogas. Biogas or digester gas is typically derived from the anaerobic digestion of agricultural or animal waste and biomass is typically defined as any organic material not derived from fossil fuels. Language from the current CEC Guidebook states, "RPS-eligible biogas (gas derived from RPS-eligible fuel such

[39] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

as biomass or digester gas) injected into a natural gas transportation pipeline system and delivered into California for use in an RPS-certified multi-fuel facility may result in the generation of RPS-eligible electricity." The CEC also considers landfill gas (LFG) - gas produced by the breakdown of organic matter in a landfill - a renewable fuel. Therefore, the Department's gas-fired generating units capable of burning a mixture of biogas and conventional natural gas fall under the CEC multi-fuel designation.

The Department currently purchases biogas-biomass power through three PPAs from biogas/biomass-derived renewable energy facilities using gas-fired micro turbines located at several landfills throughout Los Angeles:

- Third party PPA Toyon (on-site landfill gas)
- Third party PPA Bradley (on-site landfill gas)
- Third party PPA (biomethane)
- Third party PPA 2009 (biomethane)
- Third party PPA 2011 (biomethane)
- Hyperion (on-site digester gas).

The current PPA procured biogas-biomass power represents approximately 50 GWh of power usage for the Department. In addition, the Department produces 722 GWh of power using biogass-biomass fuel at its own gas fired generating stations. A portion of this power is produced from a digester facility at the Hyperion wastewater treatment facility adjacent to the Scattergood generating station. The remainder is procured under short-term contracts with third-party gas producers. Under these contracts, the Department obtains landfill gas (LFG) from several landfill sites located outside California. LFG produced by the landfills is scrubbed and filtered to pipeline grade and injected into the interstate natural gas pipeline system for delivery to the Department's most efficient gas-fired generating units.

The annual amounts fluctuate depending on the contract terms with the gas suppliers. The Department will continue to evaluate the level of biogas-biomass fuel and PPA power purchases based on market conditions and its overall RPS mix.

Figure 27: Biomass / Biogas Program Costs ($M)[40]

Program Costs ($M)	Cost Type	Current Year	Proposed Rate Period	
Fiscal Year		FY 2012	FY 2013	FY 2014
Biomass Development	Capital	0.0	0.0	0.0
Biogas Purchase Power Agreements	PPA	2.8	2.8	1.9
Biogas Fuel Purchase Agreement	PPA	62.0	85.4	85.4
Total		$64.8	$88.2	$87.3

[40] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

Renewable Resource Transmission Projects

Several of the Department's generated or purchased renewable energy resources are not always located near transmission facilities with adequate capacity to handle the additional power transport. To ensure a reliable transport system to bring the Department's future reliable energy resources to its customer distribution system, two major transmission projects are under development and a third transmission line was recently upgraded to carry a portion of the Department's renewable energy to its distribution system. The proposed rates include funding for the following two major projects and line upgrade:

Figure 28: Renewable Resource Transmission Program Costs ($M)

Program Costs ($M)	Cost Type	Current Year	Proposed Rate Period	
Fiscal Year		FY 2012	FY 2013	FY 2014
Barren Ridge Renewable Transmission	Capital	5.2	32.2	205.8
PDCI Long-Term Transmission Development	Capital	6.7	10.6	76.3
STS Transmission Upgrade	PPA	4.4	4.4	4.4
Total		$16.3	$47.2	$286.5

Barren Ridge Renewable Transmission Project: The Barren Ridge project will increase the capacity of the existing 230kV Barren Ridge - Rinaldi transmission segment by the end of 2016. During the proposed rate period, however, costs will be incurred related to design and engineering as well as construction of the line. The major components of the Barren Ridge renewable transmission project included in the proposed rates are as follows:

- New Haskell Canyon switching station;
- New double-circuit 230kV transmission line from Barren Ridge switching station to new Haskell Canyon switching station;
- New 230kV circuit on existing structures from Haskell Canyon to the Castaic Power Plant;
- Reconductor the existing 230kV transmission line from Barren Ridge switching station to existing Rinaldi substation, through Haskell Canyon switching station; and
- Expand existing Barren Ridge switching station

Further information on the Barren Ridge Transmission Project is included in **Appendix I: Barren Ridge Project Detail**.

Pacific Direct Current Intertie (PDCI) Long-Term Transmission Development: This project will increase the capacity of the PDCI from 3,100 MW to 3,220 MW by the end of 2016. The Bonneville Power Authority (BPA) is moving forward with an upgrade to 3,650 MW on its portion of the PDCI, but the Department and its partners are only increasing the capacity on their portion of the facilities to 3,220 MW at this time. The Department's portion of the investment in this facility included in the proposed rates is $2 million out of the total $5 million over the next two fiscal years representing 40% of the total cost of the expanded transmission capacity.

The project will increase the capacity of the corridor for renewable wind and hydro energy from the Pacific Northwest to Los Angeles. Less aggressive options with lower capacity benefits are also being investigated to facilitate an informed decision by the PDCI partners.

In addition to the Barren Ridge and PDCI transmission projects, the **Southern Transmission System Transmission Line** was recently upgraded by 480 MW to accommodate green energy transport. 288 MW of the 480 MW is the Department's share of the line capacity.

Furthermore, the **Intermountain Power Project (IPP)** includes four important transmission lines which transport not only power from IPP but also low cost wind power from the Milford plant. The four transmission lines are:

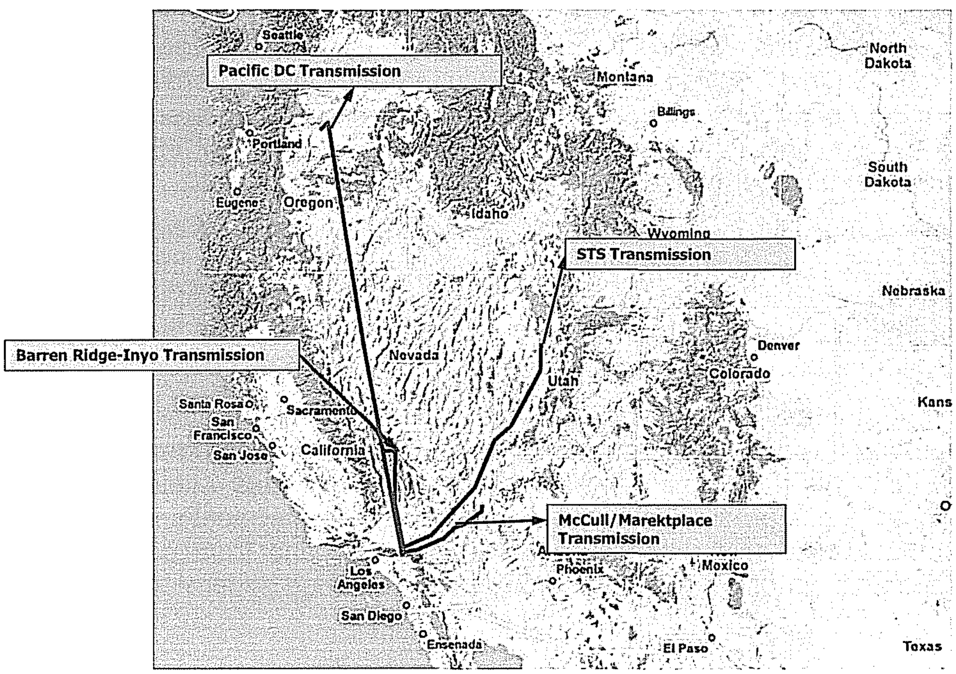
- A 500-kV DC transmission line from the generating station to Adelanto, California (a distance of 490 miles)
- Two parallel 345-kV AC transmission lines from the generating station to Mona, Utah 50 miles away
- A single 230-kV AC transmission line from the generating station to the Gonder Switchyard near Ely, Nevada about 144 miles away.

The Department believes that future renewable projects in the region of the IPP or on the path to California can make effective use of these transmission facilities.

Furthermore, the **McCullough / Marketplace Transmission** line, which currently carries energy from the Navajo Generating Station, will be used for green energy transport once the NGS is divested in 2016.

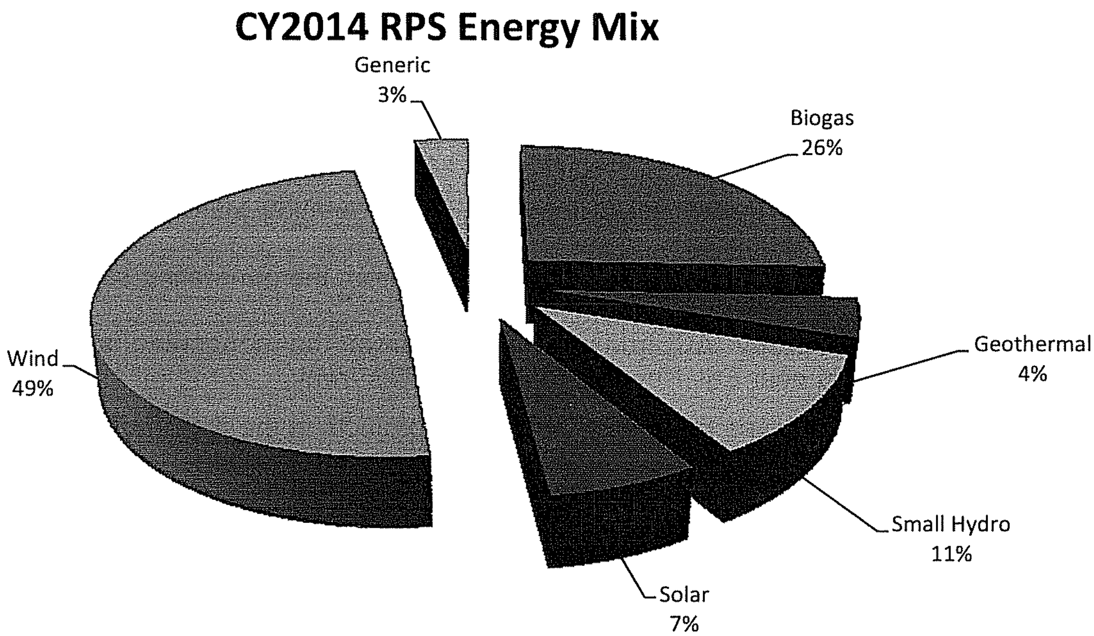
The following chart provides a map of the Department's primary renewable transmission facilities mentioned above.

Figure 29: Renewable Transmission Facilities



The collection of renewable generation and associated transmission projects discussed in this section are designed to be completed as the Department puts the new renewable energy resources discussed described above into service. At the end of the 2014 fiscal year, the Department's mix of renewable energy resources is projected to be as shown in the following chart.

Figure 30: Calendar Year 2014 RPS Energy Mix[41]



Spot Market Purchases and Sales

Although the Department's policy has been to maintain self-sufficiency and a capability to generate all of its energy needs from resources it owns or controls, it also participates in energy markets if economic conditions are favorable (i.e., when energy can be acquired from the wholesale market for a cost which is less than which the Department can produce such energy). Energy is purchased from providers within the Western Electricity Coordinating Council (WECC) jurisdiction under short-term "spot" arrangements to be delivered to the Department transmission system. These purchases are used by the Department in conjunction with other resources for economic operations.

The cost and availability of economical energy on the spot market has fluctuated greatly in recent years, mainly due to fluctuations in natural gas prices. While the Department currently continues to execute economical spot purchase opportunities, it cannot be assured of the future availability of economic energy from either the Pacific Northwest or the Southwest at prices below the Department's costs for producing power from its own resources.

The Department at times has a surplus of generating capacity and energy, depending on daily and monthly usage patterns by customers. Consistent with prudent utility practice, the Department offers this surplus into wholesale electricity markets within the WECC at prices above the Department's production costs. Therefore, the Department's ratepayers benefit both by receiving the lowest cost internally generated energy and from economic purchases, in addition to economic benefits resulting from wholesale revenue generated from sales.

[41] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

Demand Side Resources

Demand Side Resources (DSR) programs, including energy efficiency are additional elements of the Department's plans for renewable energy resources. These programs help to counter or minimize energy demand growth and thereby lessen the need to build more physical generation assets or acquire additional power including renewable energy. DSR initiatives and related support areas include the following programs:

- Energy Efficiency (EE);
- Demand Response (DR);
- Distributed Generation (DG); and
- Smart Grid

Specific projects include solar rooftop and other distributed generation, technological improvements in large scale battery systems for energy storage and using "Smart Grid" technology to help predict and manage customer load profile and resource requirements.

Energy Efficiency (EE) is an overall cost-effective resource in the Department's supply portfolio, and serves an important and multi-faceted role in meeting customer demand. As described in the Customer Opportunities Program section of this report (Section 2.3.1), the Department offers several continuing and planned new EE programs and services for residential, commercial and industrial customers to promote the efficient use of energy through the installation of energy efficient equipment.

Distributed Generation (DG) is the concept of installing and operating small-scale electric generators located at or near the electrical load. These numerous small generators are "distributed" across the service area, as opposed to the traditional configuration of a few large centralized generating stations. DG sources can be utility-owned or customer owned. A large subset of DG is combined heat and power systems, also known as cogeneration, which are primarily owned and operated by industrial and commercial customers. Solar PV is a newer technology that is forecasted to account for an increasing percentage of DG. Other DG technologies are micro turbines and fuel cells.

"Smart Grid" is a term used to describe a variety of advanced information-based utility improvements. Smart Grid refers to intelligent data gathering and advanced two-way digital communication capabilities overlaid on electric distribution networks to provide real-time data that enhances the utility's ability to optimize energy use. Smart Grid is a national policy evolving from the Energy Policy Act of 2005, and is a major enabler for many existing and potentially new DSR/EE programs. Smart Grid technologies can turn every point in the existing network—including every meter, switch and transformer—into a potential information source, able to feed performance data back to the utility instantly. Smart Grid Technologies will provide utilities with the information required to implement real-time, self-monitoring networks that are predictive rather than reactive to instantaneous system disruptions. It can enable the utility and consumer to make decisions to optimize the use of energy, improve reliability, and reduce the consumption of fossil fuels. The Department is implementing eleven Smart Grid initiatives:

- Renewable Integration
- Transmission Automation
- Substation Automation
- Distribution Automation
- Advanced Metering Infrastructure

- Demand Response
- Advance Telecommunications
- System and Data Integration
- Cyber Security
- Feed-in Tariff
- Solar Incentives

Through a US Department of Energy grant in 2009, the Department is also leading a group of local research institutions in a regional demonstration program. The program includes pilot projects in four interrelated areas – Demand Response, Consumer Behavior, Cyber Security and Electric Vehicle Integration.

Summary

The Department's renewable energy resource plan is designed to meet the requirements of California Senate Bill (SB) X12 that culminate in 33% of energy being supplied by renewable energy resources by the end of 2020. The diversity of projects included in the Department's proposed rates and discussed in this section provide the Department a balanced approach to reaching this required goal through a mix of renewable resources. For example, while solar feed-in tariffs (FiTs) are not currently cost competitive with many other renewable alternatives (such as utility scale solar power in the desert, particularly if available transmission with already sunk costs is available), the Department's proposed renewable resource plan still includes a 75 MW FiT phased in through 2016 which meets the requirements of California SB 32. This FiT program is likely to reduce the use of transmission that would otherwise be required to deliver incremental new renewable energy. This FiT-related solar energy will also provide other benefits to the local economy. The plan may be increased to 150MW depending on results of the program over the next one to two years.

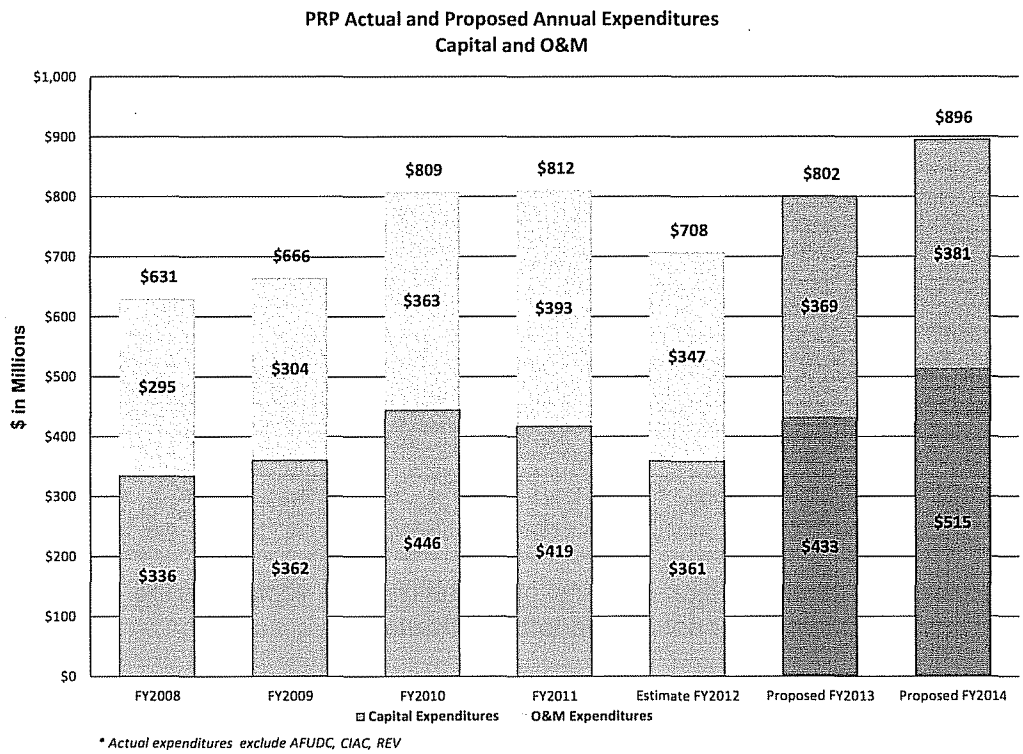
Multiple sources of renewable energy are included in the plan in a balanced manner designed to minimize the impact on customer rates. However, the renewable energy resource investment to comply with the Legislature's mandates results in an additional $105 million of revenue requirement and an average annual increase of 1.3% average annual increase in retail rates over the next two years.

2.2 POWER RELIABILITY PROGRAM

The purpose of the Power Reliability Program (PRP) is to rehabilitate aging infrastructure necessary for the reliable delivery of power to customers.

The PRP was originally approved as a five-year plan in FY 2008 and funded by the Reliability Cost Adjustment Factor (0.3 cents per kWh) which was phased in over a three year period. The actual annual expenditures from FY 2008 through FY 2012 (FYTD estimate) are shown in the chart below along with the proposed PRP spending levels for the proposed two-year rate period.

Figure 31: PRP Actual and Proposed Capital and O&M Expenditures



Proposed Rate Plan Funding

In recent years, while investments have increased, the Department has still been reacting to aging assets, often replacing facilities after they fail. To reduce the number of outages, especially those due to pole and cross-arm deterioration, a more proactive approach with increased investments is included in this rate proposal. As shown in the following table, the Department is proposing to gradually increase funding for this program over the next two years. This increase will have a positive impact on reliability, but it will not preclude the need for further reliability program increases in later years

Figure 32: Power Reliability Program Expenditures ($M)

PRP Expenditures	Current Year	Proposed Rate Period	
Fiscal Year	**FY 2012**	**FY 2013**	**FY 2014**
Capital Expenditures	361	433	515
O&M Expenditures	347	369	381
Total PRP Expenditures	$708	$802	$896

This level of PRP spending will impact the revenue requirement and rates as shown in the following chart.

Figure 33: PRP Impact on Revenue Requirement and Rates[42]

PRP Program	FY 2013	FY 2014	Avg. Annual Increase
Total System Revenue Requirement ($M)	35	51	26
Total System Average Cost per kWh (¢/kWh)	0.15	0.22	0.11
System Average Annual Percent Increase (%)	1.17%	1.71%	0.85%

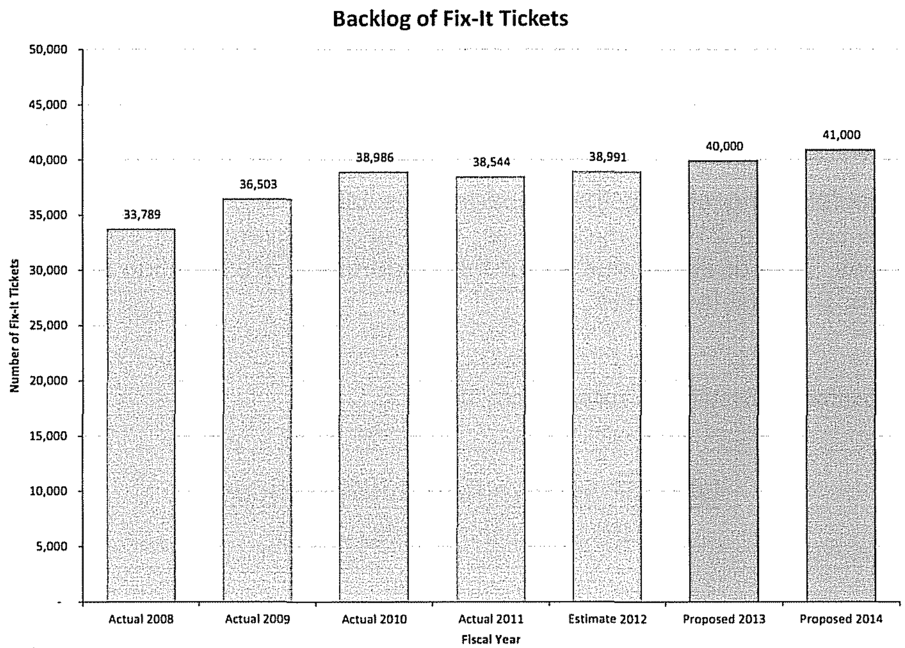
This plan addresses all the major aspects of repairing and replacing the transmission and distribution system including, but not limited to the following:

- Distribution Stations;
- Transformers;
- Poles;
- Wires;
- Cables; and
- Cross-arms.

The PRP is intended to provide resources to reduce the backlog of needed work on the energy delivery infrastructure. The Department maintains a list of known required distribution system repairs and replacements that have not been completed. The size of this backlog has grown in recent years, as illustrated below. To bring down the nearly 41,000 "fix-it tickets" in the queue to a desired base or on-going level of 2000-5000 would take 3 million work hours to catch up.

[42] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

Figure 34: Historical and Forecasted Backlog of Fix It Tickets (FY 2008 – 2014)



Funding to the PRP has been inconsistent since inception. During FY2012, PRP funding was cut by over $100 million from the previous year, given limited resources available without the rate action proposed during 2011. Progress gained through the initial years of the program is at risk without restoration of funding to a level proposed when the PRP was initially designed in 2007. The Department has been very focused on managing the cost pressures of regulatory mandates, and the need to update aging infrastructure to maintain reliability while keeping rates competitive. External regulatory mandates are demanding a growing share of the Department's limited financial resources which might otherwise be used to maintain and improve customer service and reliability. These potentially conflicting near-term challenges create the risk of reducing long-term portfolio optimization and system reliability for those parts of the infrastructure that lack appropriate funding. Similarly, there are cost pressures that may result in less than adequate long-term planning for future resource needs.

This section of the report addresses the concepts and practices/processes that Department is following to assess its planned PRP initiatives in light of the limited financial resources given the constraints noted above. The Department is seeking to employ and execute industry best practices to facilitate an effective asset management approach for its complete portfolio of enterprise assets and infrastructure. The Department's approach and overall framework is structured to provide the organization the ability to maintain reasonable reliability levels that might otherwise be lost due to the potential impacts from reduced PRP spending.

The Department's Power System Reliability Metrics

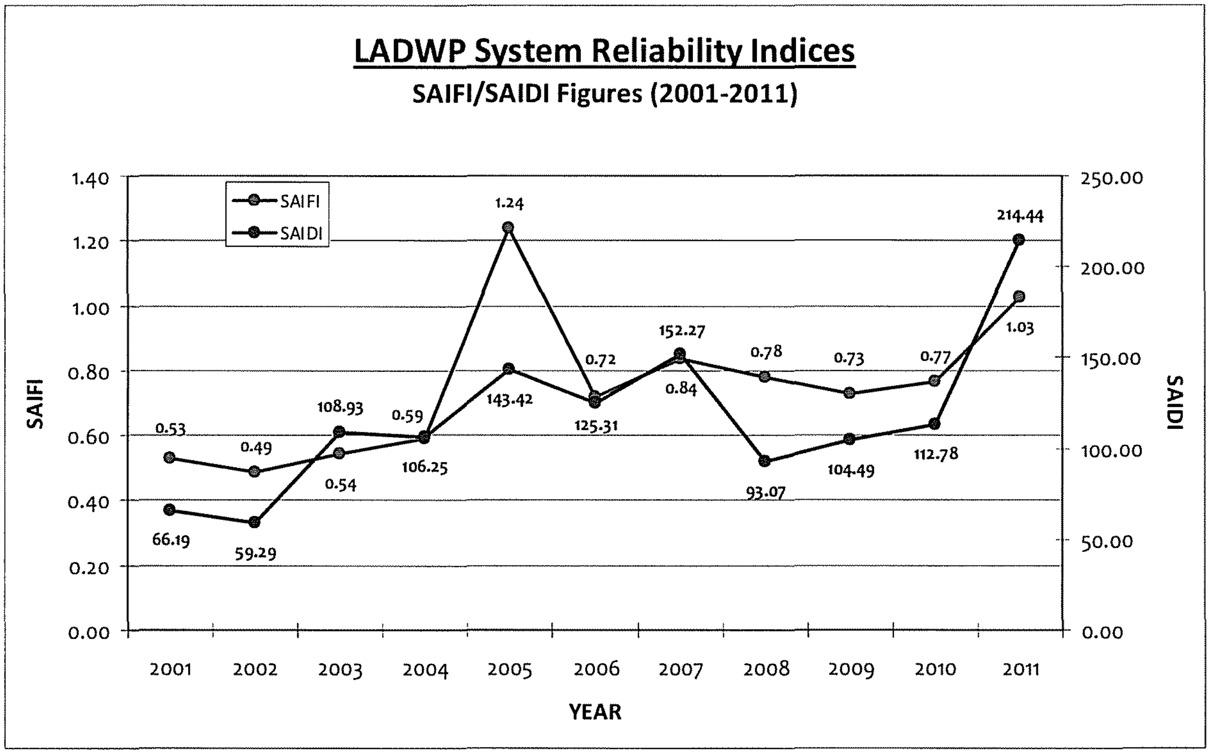
Like all other electricity utilities in the US, the Department uses a number of metric to measure the performance and reliability of its electric power system. The two primary metrics are called SAIFI and SAIDI.

System Average Interruption Frequency Index (SAIFI): SAIFI is the average number of sustained service interruptions per consumer during the year. It is the ratio of the annual number of interruptions to the number of consumers. In other words, it measures how many times the average customer has been out of service. 1.1 is the recent national average.

System Average Interruption Duration Index (SAIDI): SAIDI is the average duration of interruptions per consumers during the year. It is the ratio of the annual duration of interruptions (sustained) to the number of consumers. In other words, it measures how long the average customer0 was without power. 90 minutes is the recent national average.

As shown in the following charts, the Department's latest SAIFI is 1.03 vs. the 1.1 national average; and its SAIDI is 214.44 minutes vs. the national average of 90 minutes and, as the chart below shows, both of these indices for the Department are trending in the wrong direction and have been for the past few years.

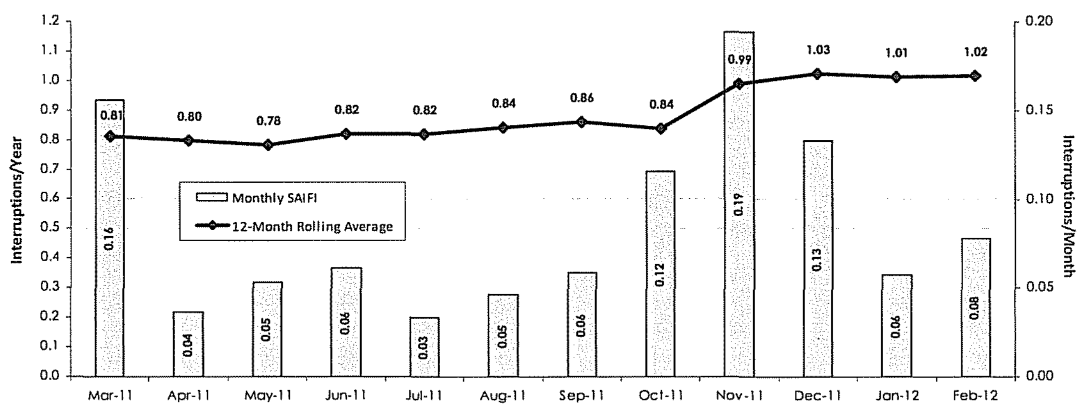
Figure 35: The Department's System Reliability Indices Trends



The following charts provide a more granular view of the past year's results for SAIFI and SAIDI.

Figure 36: Past 12 Month SAIFI Results

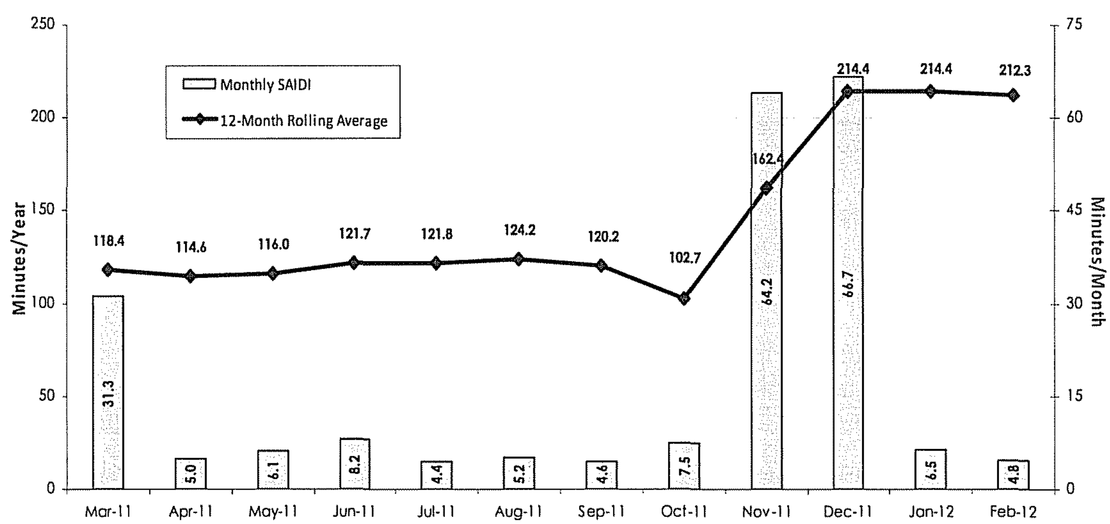
Also includes the rolling average from March 2011 to February 2012



SAIFI is the average number of sustained interruptions per year for each customer served during the 12-month period ending with the indicated month. Sustained interruptions are 5 minutes or more in duration.

Figure 37: Past 12 Month SAIDI Results

Also includes the rolling average from March 2011 to February 2012



SAIDI is the average duration of sustained interruptions per year for each customer served during the 12-month period ending with the indicated month. Sustained interruptions are 5 minutes or more in duration.

As shown in the chart below, the Department has also experienced several incidents in the past five years that caused significant interruptions in service.

Figure 38: Major Weather Events and Outages

Date of Event	Type	Duration (days)	Outages (sustained)	Customers Affected (sustained)
December 31, 2005 - January 4, 2006	Wind/Rain	3.56	189	79,918
July 21-28, 2006	Heat	6.89	1033	46,981
January 5-8, 2007	Wind	2.92	150	62,725
April 12-16, 2007	Wind / Rain	3.57	218	105,796
August 30 - September 7, 2007	Heat	7.33	858	60,891
September 21-24, 2007	Rain	2.11	86	42,452
January 4-7, 2008	Rain	3.02	129	57,981
January 24-28, 2008	Rain	4.66	119	54,236
November 15-17, 2008	Fire/Wind	2.08	200	133,524
October 13-16, 2009	Rain	2.95	156	93,754
October 27-30, 2009	Wind	2.81	176	87,763
January 18-24, 2010	Wind/Rain	5.84	319	172,883
September 27-30, 2010	Heat	2.92	228	32,010
October 4-7, 2010	Rain	2.83	116	103,112
December 19-23, 2010	Rain	4.96	139	52,786
March 20-22, 2011	Wind/Rain	2.22	196	106,491
November 30 - December 4, 2011	Wind	3.75	419	222,567

The purpose of the PRP is to reverse these trends and to bring the Department's performance back to prior levels.

<u>Aging Infrastructure</u>

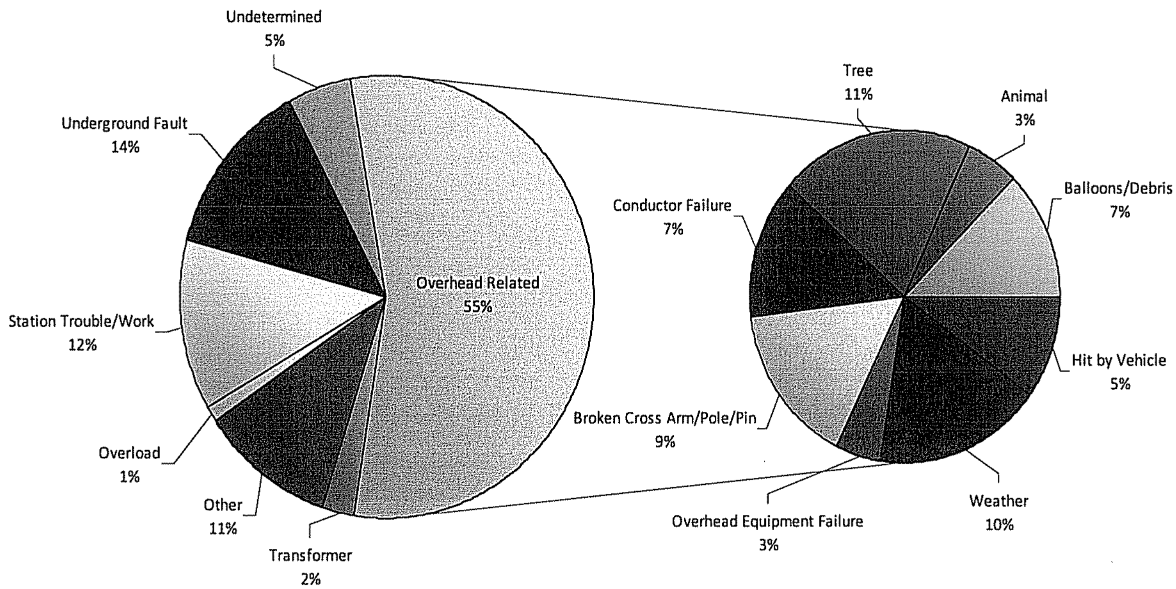
The Department has moved forward with increased infrastructure replacement in key areas to reduce the average age of the critical components of its power system. While improvements have been made to reduce the age of certain equipment, more investment is required.

Increased investment in transformer and underground cable replacement in recent years has reduced outages related to these aspects of the distribution system; however, investment in overhead facilities has continued to lag targeted levels with a corresponding increase in outages.

Despite recent investments, the Department continues to have an increasing amount of critical plant in some categories that is operating beyond its useful life. The Department has metrics to track the age, condition and impact on reliability for each major type of assets in its infrastructure. The following chart provides the major factors that impact system reliability.

This type of information allows Department to allocate resources to improve (or at least maintain) reliability levels based on quantitative measures.

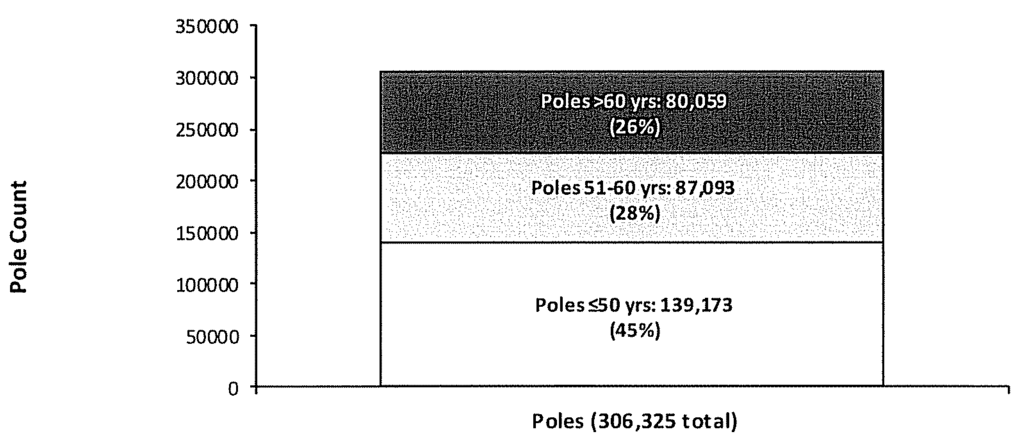
Figure 39: Causes of Service Outages



The following are some key areas where the state of the infrastructure poses a growing threat to service.

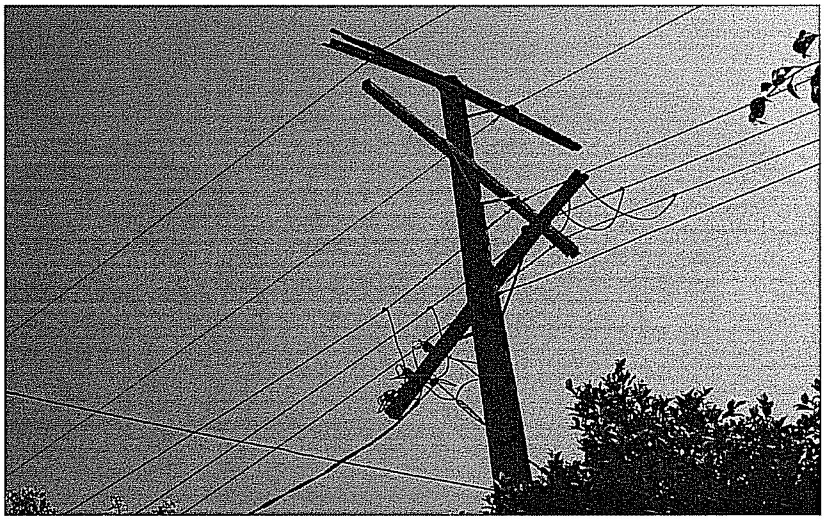
Pole Replacement Program: Since approximately 70% of Department's system is overhead, pole and cross arm replacements are a major driver of reliability. The proposed rates are designed to accelerate pole and cross-arm replacement. As shown in the following chart, the majority of Department's poles currently exceed their useful 60 year life. The recommended replacement rate is 60 years however the proposed funding for the next two years does not meet this objective. In fact, over 80,000 poles (26%) are more than 60 years old. Therefore, additional investment in pole replacement is warranted.

Figure 40: Pole Aging



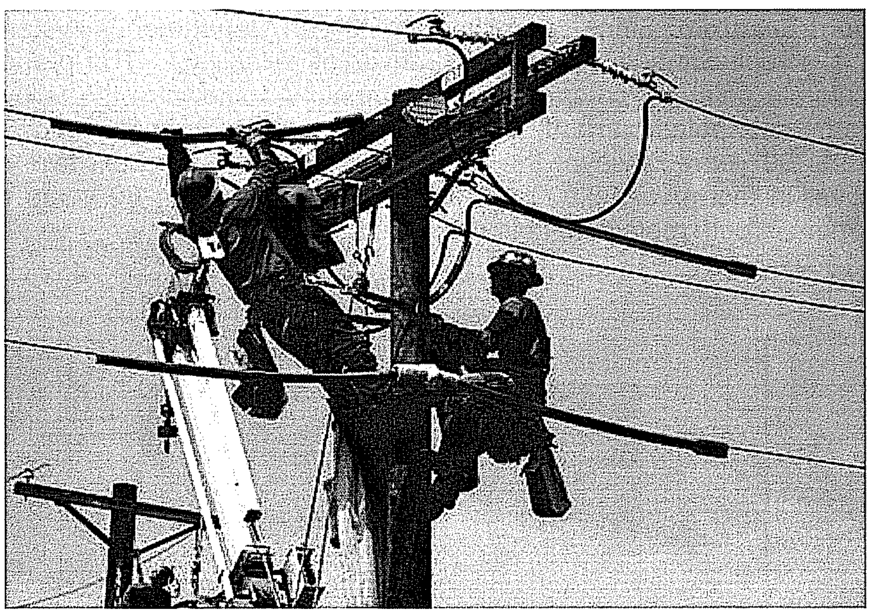
A growing number of these poles are in need of expeditious replacement. The following picture illustrates the poor condition of some of the Department's older poles.

Figure 41 Pole Condition Illustrative



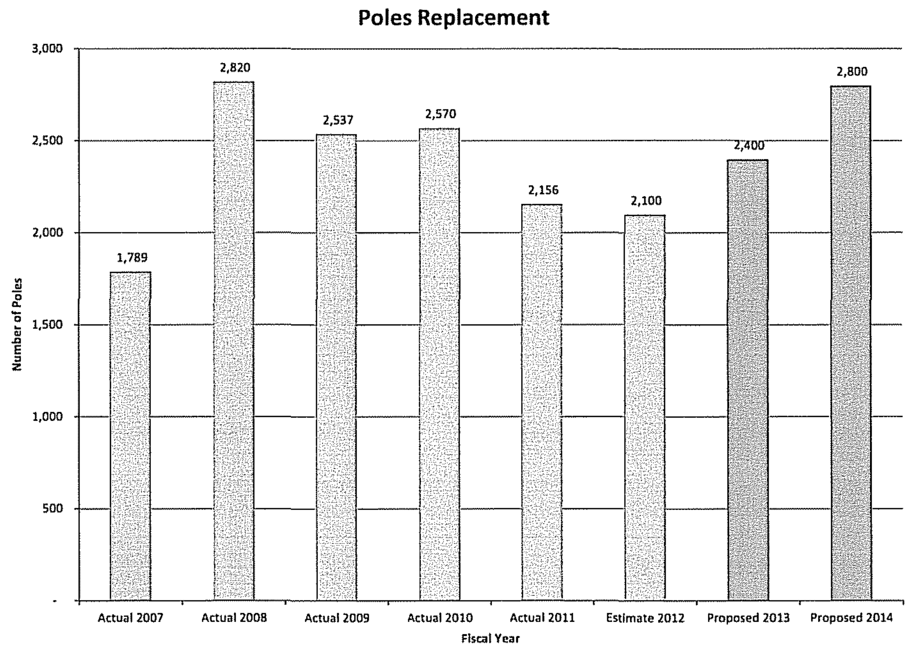
The Department identifies the poles that are most critically in need of replacement and replaces them as soon as possible. However, the Department is not replacing poles and cross-arms at a pace that is keeping up with the aging of the system.

Figure 42: Pole replacement Project Illustrative



Funding for pole replacement has the Department on a 144 year replacement cycle which is more than double the ideal 60 year cycle. The chart below shows the recent pole replacement amounts.

Figure 43: Historical and Forecasted Pole Replacement (FY 2007 – 2014)



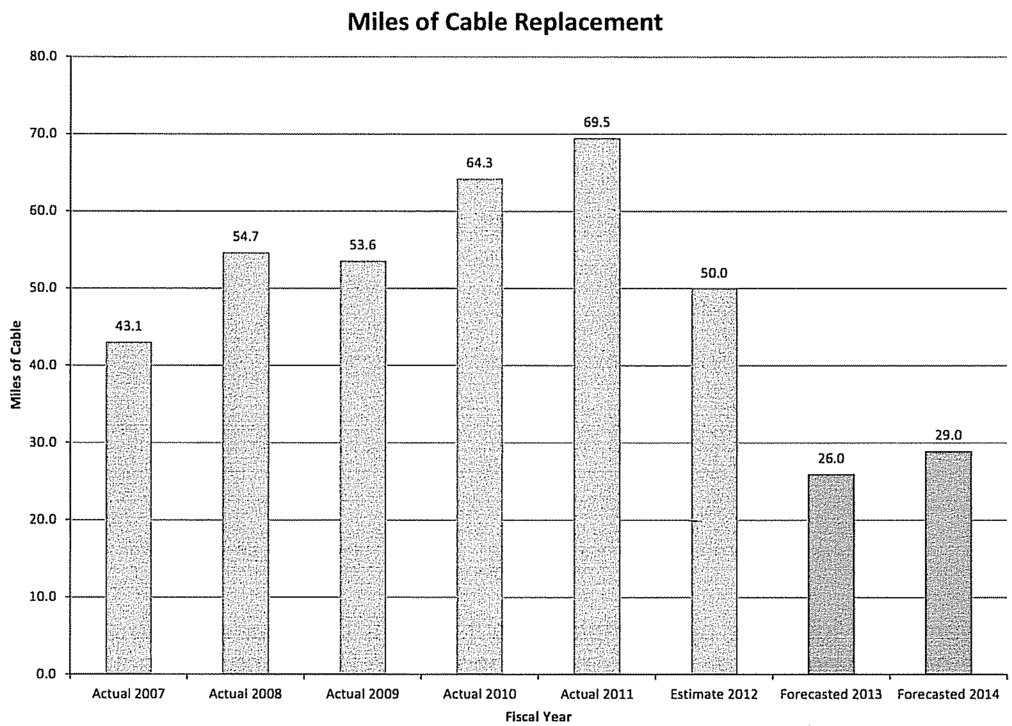
To move towards the ideal life cycle, replacements will need to ramp up to around 5,000 per year over the next several years. In this rate proposal the Department is requesting funding to begin modestly accelerating the pole replacement program as follows:

The current pole replacement program targets approximately 1% of the total population (321,780) about half of which are driven by moves and changes in the normal course of business. The proposed expenditures and rates will still result in a replacement cycle that exceeds industry standards. Aggressive replacement efforts in earlier years will help temporarily offset the impact of any short-term reductions due to limited rate increases. In addition, the Department has identified that cross arms are often the root cause of pole replacements and is more actively replacing cross arms instead of entire poles to target problem areas more economically.

Underground Cable (UG) Replacement Program: The Department has replaced on average 53 miles per year of UG cable over the past five years. Replacements have targeted cable failures that have caused outages contributing 27% to overall SAIFI. The pilot cable replacement program focused on the 5 worst performing UG circuits and produced a better than 50% reliability improvement; these circuits reflected 66% of common outage causes. Industry best practices target at least a 50% reliability improvement for those circuits in the year following completion of mitigation measures. The Department's recent programs compare favorably with best practices for utilities with aging underground cable that has deteriorated after over 30 years in the ground. In an attempt to balance spending and rate levels, the proposed expenditures and rates target replacement of 27 miles of UG cable per year for the next two years. While recent gains should help mitigate any short term decrease in reliability, over time it is likely that reliability could decrease slightly. In addition, to help mitigate reliability challenges without significant rate implications, the Department will investigate "cable injection" for primary cable where appropriate.

Following the Department's current replacement schedule, cable will be replaced every 159 years compared to a more ideal level of 72 years. In the past five years, the PRP has provided funding for the replacement of cable as shown in the following chart. Due to limited resources, the funding in the proposed rate plan reduces the cable replacement program to address areas of more critical need. The following chart provides the planned cable replacements.

Figure 44: Historical and Forecasted Cable Replacement (FY 2007 – 2014)

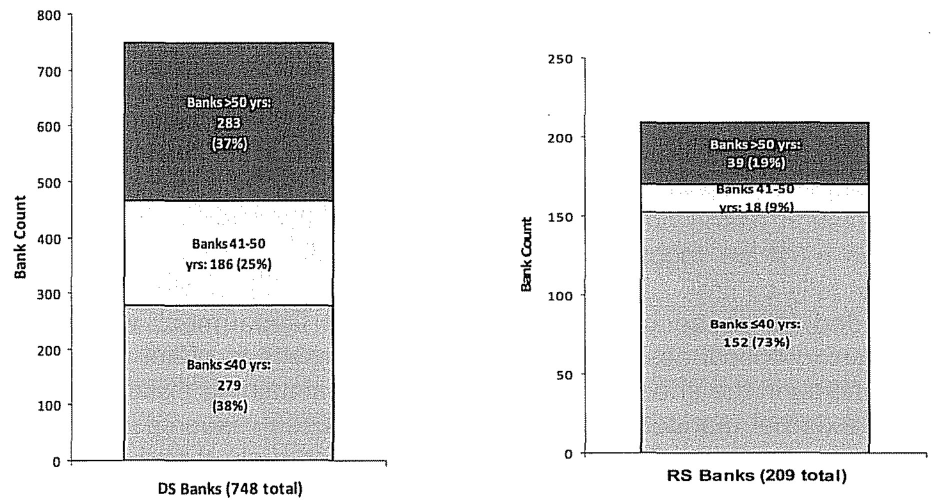


However, cables identified as in critical need of replacement, like the one shown below, are scheduled for replacement as soon as possible.

Figure 45: Illustrative of Cable Scheduled for Replacement

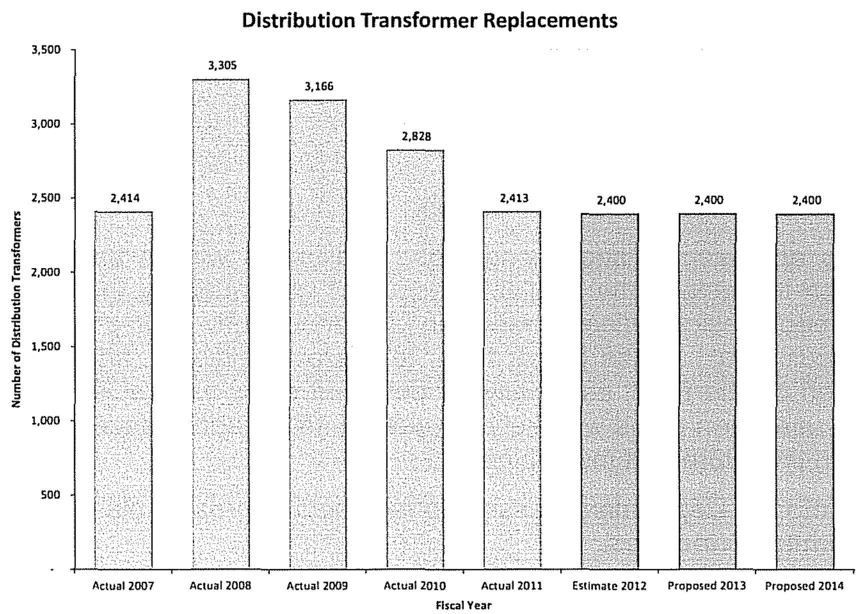
Distribution Transformer Replacement Program: Transformers play a critical role in the delivery of electricity to the city of Los Angeles. Many factors shorten the life of a transformer including: corrosion; moisture; physical damage; electrical surges; heat; loading; and, age. Transformer failures have been trending up in the past four years. With respect to age, overhead transformers have an average age to failure of 35 years; underground transformers at 23 years; and PAD transformers at 27 years. As the following chart shows, the vast majority of the Department's 957 transformer banks are over 40 years old with a significant number of those over 50 years old.

Figure 46: DS and RS Bank Aging



In recent years the PRP has provided funding to replace significant numbers of transformers as shown in the following table:

Figure 47: Historical and Forecasted Distribution Transformer Replacements (FY 2007 – 2014)



Expected transformer replacements are expected to average 2,400 for the next five-years. Existing units may be run until closer to overload status, but new business related installations will continue as in the past. However, the risks of additional failures will be at least partially mitigated by maintaining an appropriate replacement inventory to permit prompt corrective actions.

Asset Management Process

Balancing investment levels for infrastructure reliability with the need to comply with external mandates while mitigating rate increase to the extent possible will continue to be a major challenge for the Department. Careful planning and choice of trade-offs will be required to maintain reasonable levels of reliability. In addition, the choice and allocation of resources between base labor, overtime and contractors will continue to become a more important cost control measure.

The Department is implementing programs to balance asset management, efficient cost management and service levels in the near term recognizing that in the longer term, focused and increased PRP spending will be required to replace aging infrastructure (i.e., moved to critical assets prioritization based on exposure and risk). In the short term a disproportionate amount of resources must be focused on meeting externally imposed mandates which the Department does not fully control. During that period, PRP spending will be more limited than was originally intended for these years. As a result, the Department will focus available resources on maintaining critical assets and enhancing processes to offset the impact of lower than desired PRP funding in the short term with the goal of maintaining existing reliability levels. Over time, as these external mandates are completed, increased resources will be focused on reliability improvement programs. This approach considers both short and long-term business requirements in a manner that balances cost, performance and risk. However, delays in implementing proposed rates would likely reduce investment levels and reduce reliability at least in the short term as well as increase the future levels of investment required to fill the gap.

Reliability improvement in light of aging infrastructure and limited resources has become a critical issue for many utilities including the Department. Both customers and policy makers are demanding increased service levels at the same time that funding for additional initiatives is limited due to financial constraints and competing priorities. The Department's investment decisions will balance the following factors:

- Strict Asset Management Principles;
- A Rigorous Reliability Analysis; and
- Staffing and Other Resource Optimization.

The Department's approach to addressing these challenges will be based on a systematic analytical approach to manage the available resources generated by the proposed rates and expenditures to meet basic business needs in a manner that attempts to maintain overall reliability in the near term. In the longer term, to improve reliability, additional resources will need to be focused on the PRP, especially for pole and cross arm replacements. Delays in implementing the near term plans will likely increase outages and reduce reliability making the gap to be closed in the future that much bigger.

For further detail into the Department's asset management approach, please refer to **Appendix L: Asset Management Principles**.

2.3 CUSTOMER OPPORTUNITIES PROGRAM

2.3.1 Energy Efficiency Programs

Energy Efficiency (EE) is a key strategic element in the Department's planning. EE is an overall cost effective resource in the Department's supply portfolio, and serves an important and multi-faceted role in meeting customer demand. One of the most widely recognized examples of an EE program is the replacement of incandescent lights with compact fluorescent lamp (CFL) bulbs. CFLs consume up to 75% less energy than incandescent bulbs while producing an equivalent amount of illumination and last up to 10 times longer.

Since 2000, the Department has spent approximately $282 million on its energy efficiency programs, and these programs have reduced long-term peak period demand and consumption by approximately 303 MW and 1,256 GWh, respectively. The Department is committed to developing comprehensive programs with measurable, verifiable goals as well as implementing robust, cost effective energy efficiency programs.

As described previously, the revenue requirement and rate impacts presented herein are based on planned expenditures that include additional energy efficiency investment compared to prior years, but funding at a level that results in the Department falling short of mandated cumulative savings of 10% of total energy consumption levels by 2020. This plan is consistent with an Energy Efficiency Potential Study adopted by the Department's Board in December 2011. The 2010 reference point (for savings to be achieved by 2020) is specified by AB 2021 passed in 2006, which requires the state's electric utilities to achieve cumulative savings of 10% of total energy consumption levels by 2020. In adopting the Department's 8.6% 2020 reduction plan in December 2011, the Department's Board acknowledged that the plan was short of the AB 2021 requirement and requested the Department to further evaluate energy efficiency program investment options to put the Department on a path to reach the required 10% by 2020.

The base plan for revenue requirements in this report reflects energy efficiency programs that put the utility on a path to achieve energy savings equivalent to 8.6% of 2010's energy consumption by 2020, consistent with the adopted Energy Efficiency Potential Study adopted by the Board. The Department has undertaken analyses of the actions needed in the next two fiscal years to place the Department on a path that would achieve at least the 10% energy efficiency saving target by 2020. The steps required beyond the next two fiscal years to reach 10% or greater savings by 2020 will require further evaluation and are beyond the scope and purposes of this report.

Consequently, the Department has also included an option (Recommended Energy Efficiency Alternative Plan) in this rate proposal that will put the Department on the path to meet the 10% goal specified in Assembly Bill 2021.

Note: All of the figures presented in this section reflect the base energy efficiency plan which was designed to reflect the Board-adopted Energy Efficiency Potential Study that achieves 8.6% energy savings by 2020. This section discusses the base energy efficiency programs, revenue requirement and rate impact for these programs that meet the 8.6% cumulative savings goal.

The **Recommended Energy Efficiency Alternative Plan**, including the incremental energy savings and costs required to allow the Department to reach the mandated 10% energy consumption reduction by 2020, is detailed in **Section 7.** The Department's management proposes the inclusion of the additional funding and rates for FY20 13 and

FY 2014 to achieve the 10% goal by 2020, and will request that the Board adopt the 10% goal.

Under Assembly Bill 2021 (AB 2021), publicly- owned utilities such as the Department must identify and develop all potentially achievable, cost-effective EE savings and establish annual targets.

Furthermore, utilities are required to conduct periodic "Market Potential" studies to update their forecasts and targets. The Department's most recent study was carried out in late 2010 and is the basis for the EE recommendations contained in the 2011 IRP.

The study evaluated a multitude of measures for potential inclusion into the Department's EE program; including:

- The Department's existing program elements;
- High-efficiency air conditioners (higher efficiency levels, variable refrigerant flow systems);
- High-efficiency lighting (CFLs, LED lamps);
- Upgraded insulation in buildings;
- Retro-commissioning and routine maintenance; and
- Programmable communicating thermostats and energy management systems.

The following recommendations resulted from the 2011 potential study:

<u>Residential Sector</u>

- The Department should keep its existing programs, with the exception of CFL Distribution, which should be replaced with a broader Energy Efficient Lighting Program.
- Two new programs should be adopted: (1) Low-Income Energy Efficiency and (2) Whole House Performance.
- Continue public outreach to maintain and broaden public awareness of available EE benefits, and to promote participation.

<u>Commercial and Industrial Sector</u>

- The Department should keep its existing program elements, but should modify its lighting program to educate customers on expanded choices that will comply with new lighting standards.

The Department has included several EE programs for the residential and commercial and industrial sectors in its proposed two-year rate plan, reflecting the costs, capitalization, and usage reduction considerations. The following table provides the costs and demand reductions associated with each program for the base energy efficiency plan (not the Recommended Energy Efficiency Alternative Plan).

In total, the Department proposes to spend $187 million over the two year period; $159 million in capital and $27 million in operating expenses. The Department estimates that these expenditures will result in an incremental energy savings of 426 million GWh of usage.

Figure 48: Total Energy Efficiency Expenses and Usage Savings[43]

Base Energy Efficiency Plan	Current Year	Proposed Rate Period	
Fiscal Year	**FY 2012**	**FY 2013**	**FY 2014**
Capital Expenditures ($M)	55.1	73.4	85.0
O&M Expenditures ($M)	12.7	13.0	14.2
Total Expenditures	$67.8 budget $55 forecast	$87.4	$99.2
Incremental Energy Efficiency Savings (GWh)	146	194	226

This level of energy efficiency spending will impact the revenue requirement and rates as shown in the following chart.

Figure 49: Energy Efficiency Program Impact on Revenue Requirement and Rates[44]

Energy Efficiency Program	FY 2013	FY 2014	Average Annual Increase
Total System Revenue Requirement ($M)	20	45	22
Total System Average Cost per kWh (¢/kWh)	0.09	0.19	0.10
System Average Annual Percent Increase (%)	0.69%	1.49%	0.74%

The Department restructured its programs as a result of the Energy Efficiency Potential Study adopted by the Department's Board in December 2011 and now offers the following EE programs and services for residential, commercial, industrial, governmental, and institutional customers to promote the efficient use of energy through the installation of energy efficient equipment. Please refer to **Appendix K: Energy Efficiency Program Descriptions** for definitions of each program. Note: Appendix K provides descriptions of the programs included in the base Energy Efficiency option as well as the additional programs included in the Recommended Energy Efficiency Alternative Plan.

<u>Residential</u>

- Refrigerator Recycling Program
- Refrigerator Exchange Program
- Consumer Rebate Program (CRP)

[43] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan. See Section 7: Recommended Energy Efficiency Alternative Plan.
[44] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan. See Section 7: Recommended Energy Efficiency Alternative Plan.

- Income Qualified and Multi-Family Program ("Whole House Energy Retrofit Program")
- Residential Lighting Program
- Air Conditioner Tune Up & Replacement

Commercial & Industrial

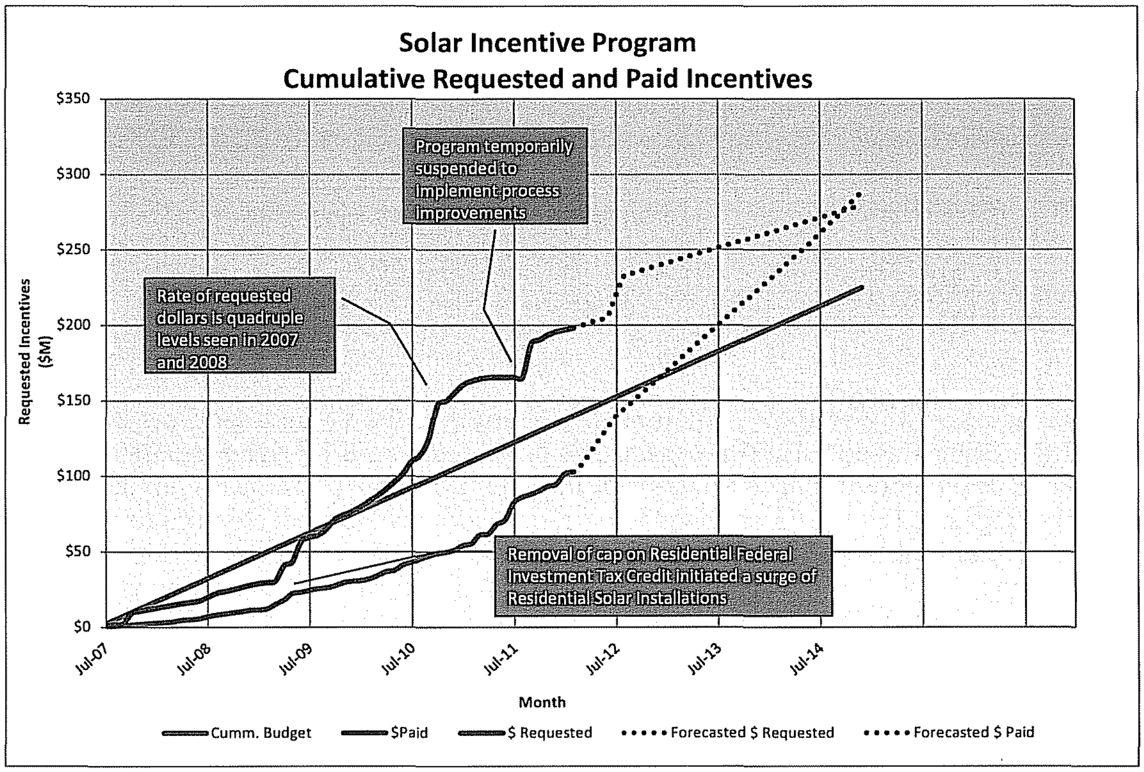
- Commercial Lighting Efficiency Offer
- Chiller Efficiency Program
- Refrigeration Program
- Custom Performance Based Program
- New Construction Program
- Los Angeles Unified School District (LAUSD) Program/Partnership
- Retrocommissioning (RCx)

The EE programs and expenditures provide for significant GWh savings in each year with a total savings of 420 GWh for the two-year period, representing 1.62% of 2010 consumption.

2.3.2 Customer Solar Programs

State Senate Bill SB1, passed on August 21, 2006, mandates that all California Electric Utilities implement a solar incentive program by January 1, 2008. SB1 established a cap on expenditures of $3.35 billion. The Department's share of the program, based on its percentage of load served in the state, is $313 million. The Solar Incentive Program (SIP) has become very popular, after a slow start, which required the payment of high incentives to encourage participation due to the Department's low electric rates. Federal tax law changes facilitated a substantial increase in participation. As a result, the Department's program had to be suspended in April 2011 and retooled to lower the incentives to a more sustainable level allowing more customers to participate in the development of more renewable energy. The annual payment budget was also doubled to $60 million in 2011. Doubling of the budget was achieved with a reduced effect on customer rates by capitalizing the cost of the rebates much in the manner the Department capitalizes costs for power generation assets it owns. Amortizing the cost of the rebates over the expected life of the solar panels installed with the benefit of the Department's rebates, coupled with the lower rebate payment per kilowatt of installed solar has enabled the program to more than double its rate of expansion. Since the reopening on 9/1/11, the program has remained extremely popular, and over $60 million in payment requests have already been received this fiscal year. The following chart provides the historical results for the program and expected activity for the next several years.

Figure 50: Projected Customer Solar Program Requests and Expenditures



The Department's program is designed to provide incentives to customers to install solar facilities at their premises. Under SB 1, customers can receive financial incentives from the Department for about one-third of the costs to install solar panels. For those facilities subsidized by the Department, the total GWH generated by the customer installed solar facilities are considered renewable energy resources by the Department. The costs of the SIP is budgeted as capital as the equipment being subsidized by the Department has a long life.

The following are included in the proposed rates. Note that the cost per kWh shown in this figure are the total costs to the entire Department power system ($/total system energy sales volume in kWh) for the payments that are made by the Department for those customers who successfully apply for and receive the solar rebate. The percent rate increase is the contribution of the SB 1 solar incentive rebate program effect on total Department rates to all customers.

Figure 51: Solar Customer Rebate Program Costs

Solar Customer Rebate Program	Current Year	Proposed Rate Period	
Fiscal Year	**FY 2012**	**FY 2013**	**FY 2014**
Capital Expenditures ($M)	$62.9	$67.0	$66.1

Figure 52: Solar Customer Rebate Program Impact on Revenue Requirement and Rates[45]

Solar Customer Rebate Program	FY 2013	FY 2014	Average Annual Increase
Total System Revenue Requirement ($M)	2	11	5
Total System Average Cost per kWh (¢/kWh)	0.01	0.05	0.02
System Average Annual Percent Increase (%)	0.8%	0.36%	0.18%

Also as discussed in **Section 2.1.3 Renewable Energy**, the Department has launched in 2012 the Solar Feed-In Tariff program that pays customers for solar power over the period it is produced rather than subsidizing the systems up-front as in the Solar Incentive Program. The FiT is an incentive program to encourage customers to invest in customer-owned solar facilities. The rates presented in the two years covered by this report include a 75 MW FIT program phased in by year end 2016 under which the Department will purchase power generated by local solar power producers. Depending upon the results of the 10 MW Demonstration Program, the FiT may be increased above 75 MW to as much as 150 MW for contracting by or before the end of 2016. The FiT provides producers with a market for solar power at rates which compensate the producers for the costs of installing and operating small scale solar power generating facilities. The FiT is considered a PPA and is budgeted as O&M expense in the fuel power purchase budget. The costs for the FiT are included in the Power Supply Replacement Program under Renewable Energy.

2.4 FUEL AND PURCHASED POWER COSTS

The Department must purchase and account for significant volumes of fuel, purchased power and related fuel costs (as well as exposure to fuel price volatility) in its budget, operating, and rate plans. Fuel in this context includes all costs associated with natural gas, coal, and nuclear fuel procurement. Fuel also includes emissions, greenhouse gas reduction, and retirement costs. Similarly, purchased power from coal, nuclear, renewable and other sources includes all costs associated with payments made for contracted energy purchases. The specific price for power typically includes fuel, debt service, O&M expenses and others such as the value of renewable energy credits (RECs) for renewable power purchases.

Fuel costs are driven primarily by free market forces and can fluctuate significantly year to year, and within a year. The Department mitigates the risk of price volatility through financial hedging programs, owned gas fields, and long-term fixed price contracts.

Natural gas procurement has two components, physical and financial. The physical gas procurement element deals with all of the steps necessary to assure gas is available for consumption at the burner tip when the gas generating units are dispatched. This includes the gas commodity portfolio made up of multiple contracts to buy gas in certain periods from counterparties, interstate and intrastate gas pipeline transportation, and storage.

[45] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

The financial component involves executing various financial hedges on the price of gas to reduce price volatility. For example, the Department utilizes price swaps with counterparties where a certain strike price for future gas is set. If the actual price at that time is higher, the counterparty pays the Department the difference. Likewise, if the future price is lower, then the Department would pay the counterparty the difference. The physical gas is purchased at the going price (spot price) and the financial hedge settlement brings the effective price to the financial hedge strike price.

Physical gas procurement is performed in the Power System's Fuels Management unit. Financial hedging is performed by the Financial Services Organization's (FSO's) Financial Planning unit. The Finance & Risk Control unit serves as the risk controller, assuring that physical and financial gas procurements are made in compliance with Los Angeles statutes and Department policies. The Department has established a working group to coordinate the activities between the Power System and the FSO. This group makes recommendations to an executive steering committee which establishes Department strategies and approves tactics.

The Department manages gas price volatility using a variety of tactics, including the following:

- Term contracts for physical gas delivery at fixed prices. For relatively short terms, the Department can lock in deliveries at known prices.
- Gas storage to assure a supply of gas at a known price. The Department purchases gas at a given price and stores it until needed.
- Gas field procurement and development. The Department has started a program to buy gas fields and reserves to assure an acceptable price in the future.
- Financial hedges to assure that future prices fall in an acceptable range.
- The Department has a fleet of gas fired generation units with different technologies and vintages.

The impact of fuel price volatility is further managed through a fuel adjustment factor separate from the base rate structure. All fuel costs, including natural gas and coal prices, have been developed based on the most recent independent market forecasts, (adjusted downward by 10% beyond 2013 reflecting an assumed 10% price premium), current hedging position and mix of current and planned facilities.

The following table shows the anticipated fuel and purchased power costs during the two-year rate period.

Figure 53: Annual Fuel and Purchased Power Costs ($M)[46]

Fuel and Purchased Power Costs	Current Year[47]	Proposed Rate Period	
Fiscal Year	**FY 2012**	**FY 2013**	**FY 2014**
Fuel			
Biomethane	$62.7	$85.4	$85.4

[46] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan
[47] Current year include actual expenditures through February 2012

Fuel and Purchased Power Costs	Current Year[47]	Proposed Rate Period	
Fiscal Year	**FY 2012**	**FY 2013**	**FY 2014**
Natural Gas	252.8	195.5	203.5
Coal	71.4	75.1	77.5
Nuclear	13.6	18.7	19.8
Others	5.2	(1.0)	0.0
Fuel Subtotal	**405.7**	**373.7**	**386.2**
Purchased Power			
Renewables	216.5	250.7	287.4
Coal	431.5	480.0	515.1
Nuclear	60.8	58.7	59.9
Others[48]	231.6	137.8	135.2
Purchased Power Subtotal	**940.4**	**927.2**	**997.6**
Total	$1,346.1	$1,300.9	$1,383.8

Figure 54: Fuel and Purchased Power Cost Impact on Revenue Requirement and Rates[49]

Fuel and Purchased Power Costs	FY 2013	FY 2014	Average Annual Increase
Total System Revenue Requirement ($M)	7	34	17
Total System Average Cost per kWh (¢/kWh)	0.03	0.15	0.07
System Average Annual Percent Increase (%)	0.24%	1.11%	0.56%

Natural Gas Hedging

The Department's gas hedging program, which began in 2002, was implemented against the backdrop of extreme volatility in natural gas prices to maintain stable net income levels and supply reliability.

[48] "Others" purchased power category includes economy purchases, cogeneration, non-RPS transmission and Hoover hydro power
[49] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

The purpose of the Department's hedging program is to reduce the volatility of the Department's costs which reduces the volatility of rates paid by its customers. Hedge programs limit the exposure to natural gas price swings via physical and financial contracts, and gas storage.

Every 10 cents per MMBtu increase/decrease in natural gas prices, results in approximately $7 million increase/decrease in purchased fuel costs.

The Department uses a combination of physical and financial hedging gas contracts for approximately 50% of the required volume over ten year periods.

For FY 2009-10, the Department had the following hedge volumes:

- Physical gas: 7.3 million MMBtu (10.1% of total needs)
- Financial gas: 47.2 million MMBtu (65.3% of total needs)
- Power purchase: 3.2 million MMBtu (4.4% of total needs)
- Pinedale gas reserves: 5.1 million MMBtu (7.1% of total needs)

For financial hedging, the Department utilizes the following standard contracts:

- Financial swaps (fixed price forward contracts)
- Option collars (limits prices within a predetermined range

The Department recently engaged PwC to perform an assessment of its gas hedging program. The objective of this assessment was to:

- Review and summarize the Department's hedging program including each of the major risks for which hedging is applied;
- Assess the impacts of the overall hedge program during the review period (spanning from 2003 to 2011) and evaluate whether the program accomplished the purpose of its design, and;
- Assess the Department's program against practices by other utilities whose operations include similar risks.

The assessment considered elements in the following categories:

- Hedging program performance;
- Program strategy and alignment with objectives;
- Program governance and oversight;
- Risk management; and
- Operational controls.

PwC found that the Department has on average reduced fuel cost variability and has realized both gains and losses subject to natural gas prices. Fuel cost stability is a primary goal of the hedging program and the average gas cost for the Department was 29 cents lower than the Southern California Index of gas prices over the period examined.

The assessment also found that the Department's financial hedges have experienced gains and losses at different periods. For example the Department realized gains in periods before March 2006 and from January through August of 2008. Gains are realized in periods where natural gas prices increased significantly. Also, PwC found that the Department realized losses for the periods in 2006 and 2007 and after August 2008. Losses are realized in periods where natural gas prices decreased significantly.

Overall PwC concluded the following:

- The natural gas hedging program is managed by a robust governance framework and sound risk management practices and controls, which are impacted by fragmented applications that result in manual processes and inefficiencies.
- The Department's natural gas hedging activities are governed by Board resolutions, City ordinances and an annual management hedge authorization process that establishes the overall objectives and risk limits for these transactions.
- The Department's risk management practices incorporate risk analysis for market and credit risk, operational controls are regularly audited, and processes can benefit from technology improvements.

2.5 OTHER CONSIDERATIONS

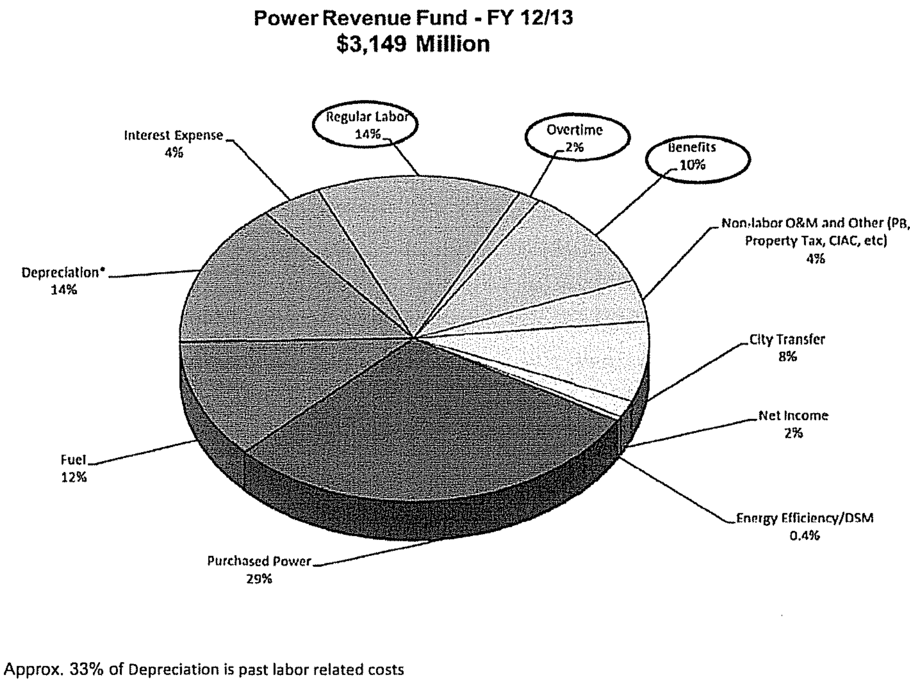
2.5.1 Labor and Non-Labor Costs

The rate covenant[50] contained within the Department's bond indentures requires that the Department pay all basic operating expenses required to operate and maintain the Power System. These expenses typically escalate over time due to inflation and provide pressure on rates, outside of the cost pressures the Department faces from the need to rebuild aging infrastructure and address regulatory mandates.

The Department has separately estimated the impact of inflation and pension costs (benefits include both pension costs and healthcare costs) on basic operations. The chart immediately below shows that portion of the Power System's revenue requirement and proposed rates represented by wages and benefits in operating and maintenance expenses; inflation (in the form of cost of living adjustments or "COLA") and pension costs cause increases in wage and benefit costs over time. Collectively, wages and benefits represent approximately 26% of the Power System's $3.149 million revenue requirement for FY 2012-2013.

[50] See Appendix E for a copy of the Master Bond Resolution

Figure 55: Power Revenue Fund (FY 2012-2013)[51]



Overall Inflation

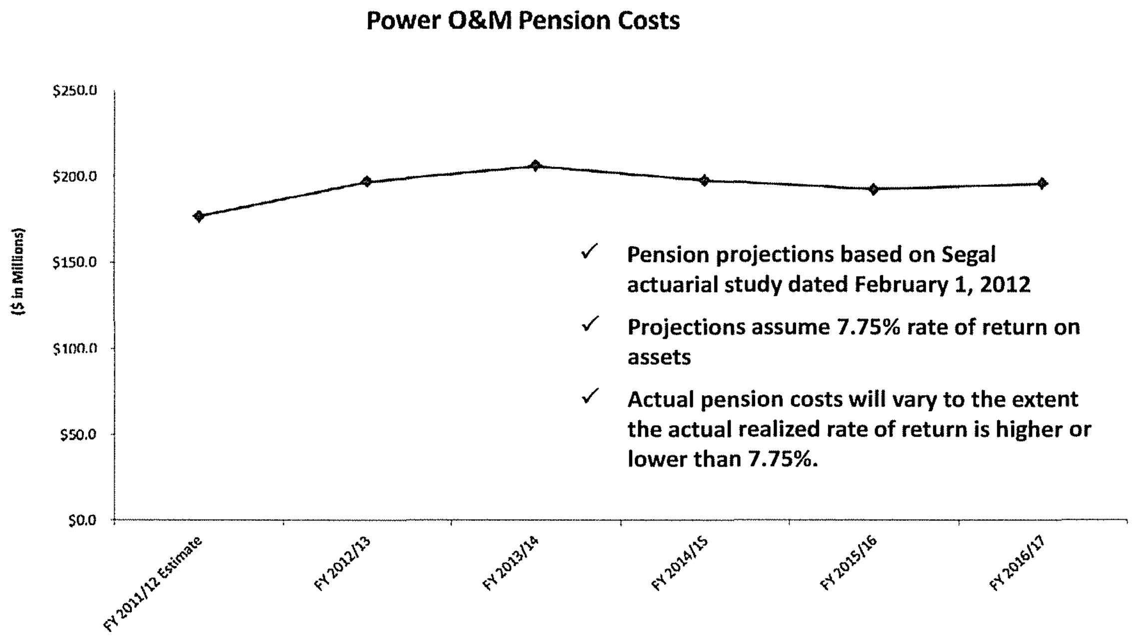
The Department forecasts inflation separately for labor and non-labor expenses. The planned expenditures and proposed rates assume cost of living adjustments for labor of 2.9% and an inflationary impact of about 2.5% per year for non-labor expenses. The inflation estimate is based on a forecast of inflation prepared by University of California-Los Angeles (UCLA) Anderson School. The labor COLA specified in the bargaining units' labor agreements provide for compensation changes at the rate of inflation, with a floor of 2% and a ceiling of 4%. For the rate projection, compensation increase rates of 2.9 percent are assumed for both FY 2013 and FY 2014.

[51] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

Pensions

The chart below shows the forecast pension expense for O&M for the Power System. The increasing through FY14 is due to the amortization of the remaining losses to the pension investments as a result of the financial market collapse in 2008-2009. To smooth the impact of these losses, based on existing actuarial requirements, the shortfalls were amortized over 5 years. In contrast, over the past two years pension investment performance was strong, and the gains now being amortized over 5 years. This trend is reflected in the relatively flat pension expense forecast. For valuation purposes the Segal Group, Actuarial Advisor for the City of Los Angeles, has estimated the assumed return on the actuarial value of assets at 7.75% representing the expected long-term rate of return, based on the Department's investment policy.

Figure 56: Power O&M Pension Costs



2.5.2 Access to the Bond Markets

Financial performance and metric evaluation criteria have been established by the three most prominent ratings agencies – Standard and Poor's (S&P), Fitch Ratings (Fitch), and Moody's – to continually assess bond issuer credit ratings. Credit ratings are assigned based on an assessment of an entity's financial risk profile (indicated by financial ratios) and a more qualitative business risk profile that takes into account other factors such as regulatory and operational restrictions and mandates that may impact its long-term position.

The Department has previously identified maintaining its AA- debt rating (S&P rating) for the Power System as a core business objective, enabling access to the low-cost debt required to fund the Power System's capital programs. Reasonable and predictable rates are also a core business objective. Therefore, programs to expand the use of renewable energy sources, meet the Power System's other regulatory compliance requirements, rebuild aged infrastructure and other large scale capital programs have been evaluated in the context of this broader business objective.

S&P, Fitch, and Moody's currently rate the Power System at AA-, AA-, and Aa3, respectively. The Department's proposed expenditures and rates are based on financial targets that are designed to avoid a ratings downgrade. However, as mentioned in recent rating reviews, a ratings downgrade could be triggered by continued significant and unexpected O&M expense variability or the failure to implement the rate increases necessary to fund its borrowing to make required investments, many of which are for externally mandated programs.

Recent Department Power System Rating Agency Report Findings

Strengths noted in recent ratings agency reports on the Department include:

- Strong Department financial liquidity and sound financial metrics;
- Direct ownership of the transmission system that serves Los Angeles;
- Independent and unregulated rate-setting authority;
- A tiered rate structure and energy cost adjustment mechanism;
- Power resource diversity and adequacy;
- Current competitive retail electricity pricing versus neighboring investor-owned utilities; and
- Department's focus on system reliability, meeting GHG emission rules, and renewable energy standards.

Challenges highlighted in recent reports include:

- An anticipated decline in the Department's key financial metrics due to an ambitious capital plan;
- Additional costs imposed by the state's renewable energy standard;
- Additional costs imposed by climate change legislation and a possible erosion in Department's existing rate advantage compared to other California utilities;
- Political risk and delays in the rate-setting process;
- A potential outage at Intermountain Power Project, the Utah coal-fired facility which accounts for approximately 30% of Department's generation portfolio; and
- Volatile natural gas prices.

The Department must closely manage and monitor the Power System's key financial metrics in the current environment throughout the forecast period to avoid the metrics deteriorating to a level that might cause a ratings downgrade.

The Department faces a significant challenge to maintain financial stability while funding both on-going operations and capital expenditures associated with regulatory mandates and infrastructure improvement programs. With several large mandated investments required over the next three to five years, rate increases are necessary to both finance the required programs and maintain access to capital markets. Additionally, as discussed below, revisions to one of the financial metrics used in financial planning for the power system are necessary.

Current Financial Metrics

The Department formalized the Power System's financial metrics in June 2009 to convey to the financial community focus and discipline around the targets against which performance and decision-making would be assessed. The following are the current financial metrics established by the Board.

Figure 57: Current Department Financial Metrics

Board Approved Metric	Target
Debt Service Coverage Ratio	2.25
Capitalization Ratio	Not to Exceed 60%
Unrestricted Operating Cash Target	$300M[52]
Key Metric	**Target**
Full Obligation Coverage	1.50

The definitions of these financial metrics are:

- **Debt Service Coverage Ratio (DSC):** This ratio divides the funds available for debt service by the sum of long-term principal and total interest payments. It is the amount of cash flow available to meet annual interest and principal payments on the Department's debt. An interest coverage ratio below 1 indicates the company is not generating sufficient revenues to satisfy interest expenses
- **Full Obligation Coverage:** This ratio represents the addition of the City Transfer and all required off balance sheet payments to the above DSC ratio.
- **Capitalization Ratio:** Defined as the long-term debt level divided by the sum of long-term debt plus equity. Companies with higher capitalization ratios face risk of insolvency if they fail to repay their debt on time. Companies with a high capitalization ratio may also find it difficult to get more loans in the future.
- **Unrestricted Operating Cash Target:** Minimum target for operating cash reserves (often defined as day's cash on hand or a total cash target amount). The unrestricted operation cash target, in conjunction with the $500 million Debt Reduction Trust Fund, provides the Department with 110 days operating cash needed to maintain its AA rating.

The proposed level of expenditures and rates contemplate an increase in the capitalization ratio above the current 60% target specified above to approximately 62% by FY 2013-2014 and possibly to the high 60% range in subsequent years. Accordingly the Department will propose that the Board adopt a revised capitalization target not to exceed 68% as discussed below.

Revised Financial Metrics

The Power System expenditures and rate proposal are designed to meet the proposed financial targets outlined in the following chart.

Figure 58: Proposed Revised Department Financial Metrics

Board Approved Metrics	Target
Debt Service Coverage Ratio	2.25

[52] Not including the debt reduction trust fund (DRTF).

Board Approved Metrics	Target
Capitalization Ratio	Not to Exceed 68%
Unrestricted Operating Cash Target	$300M[53]
Key Metric	**Target**
Full Obligation Coverage	1.50

In order to facilitate the required investments in programs to meet regulatory and infrastructure improvement programs while minimizing the impact on rates, the Department will continue to target around $300 million of unrestricted cash-on-hand for the foreseeable future. In addition, the Department plans to continue to maintain a $500 million debt reserve trust fund (DRTF) to protect bondholders and allow it to continue to borrow at interest rates that minimize the impact on customer rates. The bond advisors have indicated that these levels will help facilitate the Department's ability to borrow for the next three to five years.

Board approval for the proposed new financial targets will be sought when the rate proposal is brought before the Board for approval. The financial targets are subject to ongoing reviews by the Board and the Department's financial advisors. The Department objective is to maintain its current bond ratings to mitigate the impact of rate increases over the next three years as significant investments in regulatory mandates and other infrastructure improvements are made, and continued access to low cost financing is important. According to Department's financial advisor, Public Resources Advisory Group (PRAG), the Department's revised metrics are consistent with AA-/AA-/Aa3 rated power utilities.

Financial Metrics Resulting from the Proposed Two-Year Rate Plan

The financial metrics that result from the proposed two-year rate plan are an important consideration when evaluating the prudency of the Power System's rate proposal. The following chart provides the financial metrics associated with the Department's proposed rates and expenditures for the next two fiscal years. The resulting metrics will meet or exceed all of the targets the Board will be asked to approve.

Figure 59: Financial Metric Targets in Proposed Two-Year Rate Plan[54]

Board Approved Metrics	Revised Target	Current Year	Proposed Rate Period	
		FY 2012	FY 2013	FY 2014
Debt Service Coverage Ratio	2.25	2.64	2.53	2.37
Capitalization Ratio	<= 68%	55.7%	58.8%	61.8%
Unrestricted Operating Cash Target ($M)	300	264	309	300
Other Key Metric				
Full Obligation Coverage	1.50	1.77	1.61	1.56

Avoiding a Downgrade

[53] Not including the debt reduction trust fund (DRTF).
[54] Unless otherwise specified, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

It is essential for the Department to maintain its current bond ratings to avoid significant increases in borrowing costs. As shown in the chart below, the Department has determined that a downgrade below the current AA- (S&P) level would increase the revenue requirement and customer rates more than the proposed rates that are based on maintaining the AA- (S&P) level.

Figure 60: Impact of a Downgrade on Revenue Requirement[55]

	Current Year	Proposed Rate Period	
	FY 2012	**FY 2013**	**FY 2014**
Cumulative Revenue Requirement ($M)			
AA-	3,012	3,157	3,338
A+	3,012	3,215	3,419
System Average Rate Increase Year-Over-Year			
AA-		4.60%	5.90%
A+		6.85%	6.54%

A downgrade to A+ would result in an average annual 6.70% rate increase over the next two years as compared to the proposed 5.25% increase – a net 1.45% average annual increase. Therefore, establishing rates to meet the metrics appropriate for AA-/AA-/Aa3 bond ratings is the best alternative for the Department and customers. The financial metrics in the proposed two-year rate plan are consistent with published targets for those bond ratings.

Future Rating Agency Scrutiny

As key ratios approach the target level, ratings agencies will give more scrutiny than normal to the Department's cost controls, plans for meeting new regulatory requirements, and political risks (most notably the ability to maintain financial stability through timely rate actions). To avoid the risk of continued downgrades that would have an adverse impact on rates, Department must maintain financial ratios for the Power System consistent with rating agency expectations for AA-/AA-/Aa3 rated electric utilities at a minimum. A credit rating downgrade for the Power System would have direct and significant impacts on Department's costs in the form of higher debt service costs. These costs would come in three primary areas:

1. ***Long-Term Debt:*** Interest rates for the Power System's new long-term debt will increase. While interest payments on all existing long-term debt remain fixed, any new debt issued subsequent to a downgrade would be subject to a higher interest rate. PRAG estimates the impact at 25-30 basis points but costs could be higher depending on bond market conditions. With plans to increase borrowing by about $4.9 billion over the next five years, a downgrade below the AA- level could have a substantial and increasing impact on Department's cash position.

2. ***Short-Term Debt:*** The Power System maintains $1.2 billion[56] in Variable Rate Demand Revenue Bonds, which are short-term credit facilities that provide Department access to funds as needed to cover its short-term cash needs. In today's market, this debt has a very low interest rate that currently averages 0.25%. Significant quantities of short-term debt are typically only available to companies with

[55] Unless otherwise specified, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan
[56] Including $200 million of commercial paper.

very high credit ratings. Should Department's Power System credit ratings be downgraded below the current level, the majority, if not all, of its low-cost short-term variable-rate debt would have to be refinanced and replaced with higher cost long-term fixed-rate debt at interest rates which PRAG estimates would range between 3.75% (best case scenario) to 6.00% (worst case scenario) over the next five years. In addition, any remaining short-term line of credit would carry a higher interest rate.

3. ***PPA obligations:*** Many of Department's power purchase agreements (PPAs) are not fixed price PPAs but rather are tied to the actual debt service obligation for the project. PPAs that would be impacted by higher interest rates include agreements with IPP as well as any projects funded through SCPPA.

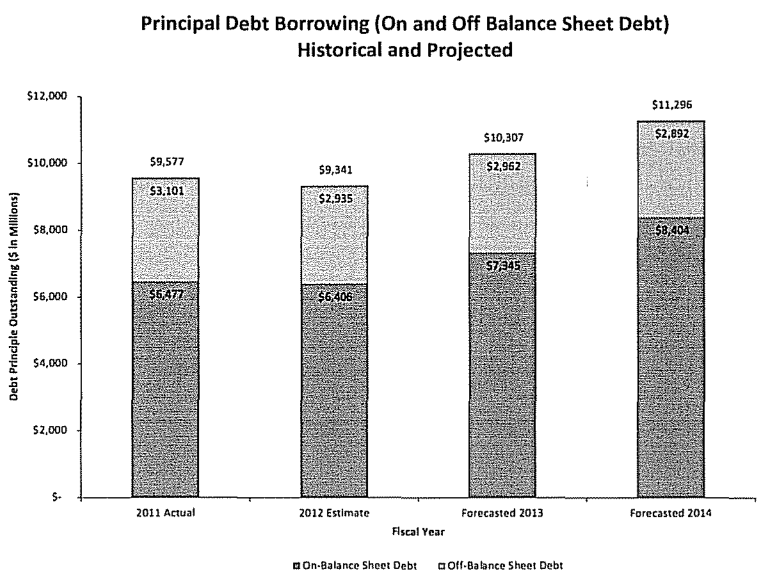
Initial Short Term Bond Issuance

To limit interest expenses for the next several years, the Department plans to issue $300 million of short-term notes to fund a portion of the Power System's capital funding requirements. The Department expects to roll the maturing notes into a future issuance of similar short-term notes or alternatively long-term fixed Bonds. By issuing these notes, the Department will be taking advantage of current low short-term interest rates. At a projected cost of 0.68%, savings could range from 3.1% to 5.3% per year compared to fixed rates are anticipated using this approach.

Off Balance Sheet Debt Financing

The Department currently holds about $2,935 million in off-balance sheet debt driven by costs related to SCPPA, Palo Verde, the Southern Transmission System and RPS pre-payments. This form of financing allows the Department to spread costs among other municipal utilities while maintaining healthy financial metrics and capitalization ratios to ensure the Department's ability to access bond markets at favorable interest rates to fund its capital and O&M expenses. While this debt is not classified as a liability and is excluded from the calculation of the Department's financial ratios, it does drive additional debt service costs.

Figure 61: On and Off Balance Sheet Debt



Summary

The proposed level of expenditures and rates for the Power System generally maintain financial ratios and targets at levels consistent with the current bond ratings. The Department is proposing that the Board adopt some minor modifications to the financial metric targets; however, according to the Department's financial advisor no significant impacts on bond ratings or the ability and costs of borrowing are expected. The Department will continue to work with PRAG, its financial advisor to monitor its financial metrics carefully.

2.5.3 Compliance with Bond Provisions Related to City Transfer

Rates are set to provide financial stability and must also comply with the provisions of the Master Bond Resolution of the Board of Water and Power Commissioners of the City of Los Angeles for the Power System (Master Bond Resolution found in Appendix E). Section 6.04 specifically identified requirements that must be met for the Power System to make the annual City Transfer payment. As part of the financial planning process, the City Transfer payment is planned at 8% of operating revenue for the previous year. The Master Bond Resolution (Section 6.04) has two requirements to be met prior to any transfers being made out of the Power System to the City. In simpler terms, these requirements are:

(a) The audited Net Income (Change in System's Net Assets Before the City Transfer) of the Power System, for the preceding fiscal year, is equal or greater than the City transfer to be made.

(b) The amount in Surplus (equity) as shown by the books of the Department shall not be less than 33-1/3% of total indebtedness. Stated another way, the amount of debt shall be less than 75% of the total capital structure (debt plus equity on the balance sheet). The Power System currently has a debt to total capital structure ratio of roughly 56%.

To ensure the first test is consistently met, rates are set annually to provide a minimum of $50 million of net income above and beyond the planned City transfer. This $50 million net income planning target helps provide some assurance that the City Transfer can be made in the event of most unplanned and/or unforeseen items that increase expenses and/or reduce revenues.

The amount of retail revenue in a given year is typically set to ensure that both the $50 million net income target and the 2.25 debt service coverage factor are met; however, for both FY12/13 and FY13/14, the minimum net income target of $50 million is the critical constraint.

3. MAJOR COST REDUCTION INITIATIVES

The Department is implementing a multi-year $440 million enterprise-wide cost reduction plan that addresses many aspects of labor, operations and capital expenditures with a focus on easy-to-implement changes that can have a quick and measurable impact on the Department's expenses. The plan, developed at the Department level (as opposed to the Water and Power fund levels) is consistent with efforts by other utilities to manage costs in light of operational, regulatory and financial challenges.

The forecasted level of expenditures used as the foundation for building the two-year rate proposal were developed with consideration of the cost reduction plan initiatives. Based on the preliminary budgets, the projected spending levels are consistent with the cost reduction plan targets. Further considerations will be made by the Department to evaluate and effectuate cost savings opportunities during the two-year rate period. These cost reduction plan initiatives balance the following needs:

- Externally Driven Legal Mandates;
- Replacement Of Critical Aging Infrastructure;
- Updating Technology;
- Reducing Staff While Replacing Large Numbers Of Retirees (Aging Workforce);
- Communicating Regularly With Customers And Other Stakeholders; and
- Maintaining Financial Stability.

Each functional area at the Department examined its entire portfolio of recurring and non-recurring projects and related labor and non-labor expenses to identify areas to reduce cost in the short term. Over a four to six week period, the functional groups worked with representatives of the Financial Services Organization and outside consultants to quantify the impact on operating and capital expenses. The senior management team met a number of times as a group to examine the tradeoffs among various proposed cost reduction opportunities. The cost reduction plan that was presented to the Board is designed to balance lower costs with maintaining service quality and meeting external mandates. The major components of Department's cost reduction plan are as follows:

- Vacancy and Attrition-based Labor Savings;
- Overtime Reductions;
- Non-Labor Operations Savings; and
- Capital Savings.

As of February/March 2012, the Department is on track to realize a substantial portion of the targeted savings. As shown in the table below, based on the latest financial data available, the Department is on track to save an estimated $196 million by the end of FY 2012:

Figure 62: Total Savings FY 2012

Initiative	Savings Target ($M)	Total Savings ($M)
Vacancy and Attrition-based Labor [57]	50.4	$65.8
Overtime Reductions	25.0	$45.0
Non-Labor Operations[58]	30.2	$33.3
Capital Savings[59]	51.6	$51.6
Total Department	**$157.2**	**$195.7**

For further insight into each of the four components of the Department's cost reduction plan, please refer to **Appendix J: Cost Reduction Plan Detail**.

[57] Excluding labor target of $10.4M for the remainder of FY 10-11 (Total target for 16 month period beginning March 2011 through June 2012 is $60.8)

[58] Includes 50% savings for VTHA as 32 of the projected 43 vehicles were turned reduced. 10 vehicles are still in use, but not taken home. The remaining vehicles were returned to the pool or disposed.

[59] Capital Savings included a multi-year Bond Refinancing saving of $55M. This amount was reduced to $31.6M to account for FY 11-12 only.

4. PROPOSED RATE AND RATE STRUCTURE CHANGES

4.1 PROPOSED POWER RATE ORDINANCE CHANGES

The primary focus of this rate proposal is to describe the additional funding necessary for the Department to meet necessary mandates and requirements related to power supply replacement, power reliability enhancement, and customer opportunity program. Rate design and cost allocation issues have not been the primary focus during this rate review process, but will be taken up in the following year.

However, rate structure and certain rate design changes have been addressed to further the objectives laid out by the Department and the City. Rate structure changes to be reflected in the proposed rate ordinance are intended to:

- Be as simple and easy to communicate as possible;
- Retain the existing cost allocation among residential, commercial, and industrial customers classes;
- Use marginal cost as the rate design basis within a rate class;
- Maintain rate competitiveness in the region;
- Minimize rate change impacts on residential customers who proactively conserve energy;
- Encourage commercial and industrial customers to adopt energy efficiency, demand response, consistent load usage, and load shifting away from the High Peak period;
- Enhance incentives based on marginal cost of services for the electrification of the Port and faster adoption of electric vehicles; and,
- Enhance revenue stability for the Department.

4.1.1 Rate Design Elements in New Ordinance

The key rate design elements to be reflected in an updated rate ordinance include:

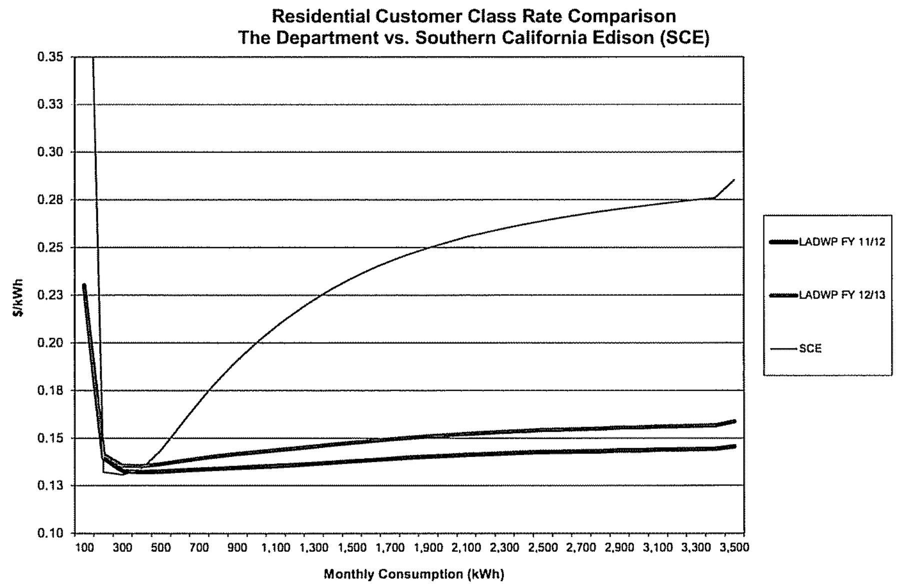
Residential Customer Class

For the residential class, the existing three tier rate structure will be updated to further promote energy conservation and the adoption of renewable energy solutions. Currently, the existing tier rate has three-tier prices in the summer season (June - September). In the winter season (October – May), the current tiered rates have the same three-tier structure; however, the winter tier 1, tier 2, and tier 3 prices are the same as the tier 1 price in the summer season.

In the updated rate design, the tier 2 and tier 3 prices of winter season will be equal to the tier 2 price of the summer season. In addition, the tier 2 and tier 3 prices will be increased at a higher rate than the tier 1 price to send a stronger price signal. By doing so, a larger portion of the necessary revenue increase proposed for the next two years will be recovered through higher consumption level customers than if the increase was allocated through proportionate increases in all three of the tiers.

The tier 2 price and tier 3 prices will gradually increase to send a stronger conservation price signal. As a result, the customers who conserve energy will be rewarded with a lower bill and the customers who consume higher amounts will have increased incentives to adopt energy efficiency measures. The data shows that two thirds of the Department's residential customers will receive a below system average rate increase, and the top 90 percentile customers (monthly usage over 1000 kWh) will have increases two percentage points above the system average, whose monthly average rate will be over 14.3 cents per kWh for the next two years. Currently, the Department's residential customers are paying significantly lower rates than neighboring utilities. For example, the Department's residential rates are approximately 29.3% below SCE rates on average, and the rate differential for higher levels of consumption is even more significant, even with the proposed increases to the tier 2 and 3 rates. At the 1,500 kWh per month usage level, the Department's prices are 13.8 cents per kWh ($207 monthly bill) for FY 2012 and 14.8 cents per kWh ($222 monthly bill) for FY 2013, as compared to SCE at 23.4 cents per kWh ($351 monthly bill) respectively. This equates to a current 69% rate advantage for FY 2012 and a forecasted rate advantage of 58% for FY 2013 below SCE's rates.

Figure 63: Residential Customer Class Rate Comparison – The Department vs. SCE[60]



Commercial and Industrial Classes

For the commercial and industrial classes, the proposed rate increase is assigned partially to the facilities demand charge, monthly demand charge (A2 and A3), and energy charge to promote energy efficiency and demand reduction. Due to the variety of load characteristics for commercial and industrial customers, the rate design had to maintain a balance between the energy needs and capacity needs of the commercial customers based on the marginal cost of service.

More consistent load usage pattern (level rather than intermittent) is preferred because it allows for economic power supply, and for seasonal or intermittent loads, they will be charged according to the capacity costs. Customers who have the ability to shift load away from the summer High Peak period avoid paying for power when production costs are the highest, and the Department avoids building peaking units needed when the power system is more constrained.

As shown in the commercial customer rate impact and comparative analysis charts in the **Section 5** and **Section 6**, the average load factor customers (A1 between 10% to 40%, A2 between 30% to 50%, and A3 between 35% to 75%) will have a close to the

[60] If not specified otherwise, the amounts shown do not reflect the Recommended Energy Efficiency Alternative Plan

system average increase. Customers with below average load factors will see an additional 1% increase, and those with better than average load factors will see a less than average increase. The difference in the increase percentages is justified by the cost for the capacity and fuel.

4.1.2 Rate Stability under Conservation Based Rates

There has been a strong trend in the last decade of electric utilities implementing conservation based rates. Conservation based rates for residential customers generally are of the form of commodity rates that increase on a dollar per energy (kWh) basis as the consumption increases. This basis is consistent with the costs to serve those customers. These rates commonly take the form of inverted tier rates for residential customers and time of use rates for other customer classes. Any variation of energy consumption by customers over time can occur for a variety of reasons, causing revenue variation. Inverted tier rates residential rate designs provide the potential for more revenue variation relative to the flat rate design. This is as a result of revenue from the upper tiers being more leveraged (subject to larger swings) from the higher unit prices.

Sources of Revenue Variation

The three major causes of revenue variation and/or reduction are:

a. Weather
b. Price Elasticity Response
c. Energy Efficiency Program Implementation Levels

Any unanticipated reduction of energy consumption under-recovers fixed costs. This is particularly true when rates are designed on average expected consumption. Revenues over time will vary around the average; however, reductions in revenue cause possible short term issues with financial metrics if not mitigated by revenue stability tools. Additionally, if there is very hot weather, collected revenues will be higher than predicted.

To ensure a stable financial planning environment for the Power System, steps should be taken to mitigate the potential impacts of any of these revenue variations. This is especially critical as the Department will be required to access the financial markets to fund a very significant capital program. To ensure that this debt is obtained at cost effective prices, financial markets expect revenue variation mitigation tools to be in place.

Revenue Stability Tools

The following are three tools for revenue stability:

1) Fixed Customer Charges and Capacity Charges with Ratchets
2) Automatic Decoupling Fixed Cost Recovery Mechanism
3) Reserves such as rate stabilization funds

Capacity Charges with Ratchets

Consistent with industry best practice rate design, the most basic revenue stability tools are customer fixed charges and capacity ratchets (on a rolling 12 months basis). These tools will not only appropriately charge customers on a cost causation basis; but, they will also smooth out revenue variation and therefore reduce levels of fixed cost under-collection. They allow the reserve level and/or automatic decoupling recovery amounts (discussed below) to be lower for weather variation, price elasticity, or energy efficiency implementation levels.

The Department currently employs capacity charges and fixed customer service charges. Included in this rate proposal are enhancements to the capacity charges to ensure the Department can recoup its fixed costs.

Automatic Decoupling Fixed Cost Recovery Mechanism

Currently, the Department uses a rudimentary lost revenue mechanism based on the amount of energy efficiency investments that have been historically made, deducting the lost energy volumes for implemented conservation measures from future forecasted consumption levels used to set rates. This mechanism only mitigates a portion of the revenue variation risk due to energy efficiency program implementation levels. It does not mitigate weather, price elasticity, and/or customer behavior conservation risks.

A better revenue stability tool is the use of an automatic decoupling fixed cost recovery mechanism. This tool allows for a standardized automatic recovery of a target revenue from customers to ensure fixed costs are recovered when sales are low, and to prevent unplanned windfalls when volumes are higher than planned. The proposed automatic decoupling mechanism will establish annual base revenue targets. If the actual revenue is above or below that target for the fiscal year, either a credit or charge will be added to customer bills in the subsequent year. Many electric public utility commissions allow this for their regulated utilities. The Department has been working with the Natural Resources Defense Council (NRDC) on developing this mechanism.

The Department will propose an automatic decoupling fixed cost recovery mechanism specifically for base rate recovery through an addendum to the ordinance.

Rate Stabilization Fund

The final tool to mitigate revenue instability is the use of the rate stabilization fund to offset possible short term variations. With the implementation of an automatic decoupling mechanism, most of the revenue risks tied to weather, price elasticity, and/or energy efficiency implementation levels will be mitigated. However, the rate stabilization fund can also mitigate any potential variations in operating and maintenance costs, unanticipated write offs, and other extraordinary expense increases. There are a variety of standard financial techniques for utilizing the rate stabilization fund on the basis of potential revenue variation in the short term. This revenue stability tool would cover annual financial variation of expenses to ensure financial targets are met. The Department's $75 million rate stabilization fund (consisting of deferred revenue; not cash) helps offset near term revenue shortfalls. The two-year rate plan proposes a drawdown of the rate stabilization fund by $31 million in FY 2013 and $33 million in FY 2014.

4.1.3 Changes to Other Rate Schedules

There are three additional rate issues that will be addressed in this rate case. Changes are in the AMP, EV, and XRT Schedules.

AMP Rate Schedule

The AMP (Alternative Maritime Power) rate option is for the mega-merchant ships/cruise liners to use shore power when docked at the Port. The major components of this rate are a minimum monthly facilities charge of $10,000, and a strict requirement for demand response from the customer. This rate will set an energy price range designed to attract mega-ships that seldom dock for more than a few hours at the Port, while ensuring that the Department is able to recoup the cost of service. In turn, the rate will facilitate further use of the Port, reduce air pollution, and expand Department load.

Electric Vehicle (EV) Rate Schedule

The EV rate enhancement is an update to the existing electric vehicle discount that reflects the upcoming EV era. Currently, the EV discount is designed for passenger cars, but the Department anticipates that there will be customers with fleets of a broader range of electric motor vehicles participating including trucks, vans, and other motors vehicles. The enhancement is necessary to have rates for charging stations separate from other energy consumption. The EV rate will also include a demand response component so customers are incentivized to charge their electric vehicle during the Base period, away from the High Peak period, at a lower than regular rate.

XRT Rate Schedule

The new proposed ordinance will feature an enhanced XRT interruptible rate. The Department has offered the interruptible rate for more than ten years. In the last five years, it has become evident that this rate will play a more critical role as the Department moves toward more energy efficiency, renewable generation, and potential capacity shortages. There are approximately 50 MW of load signed up for this rate schedule. Customers enrolled in the program receive a 5% discount on average, and in return they are willing to reduce their load to zero with a minimum two hour advanced notification time.

For example, in 2011 during the outage caused by a fire on the transmission system, the Department notified its XRT customers for interruption and they reduced their load by 41 MW. This allowed the Department not only to have the extra capacity to serve the native load, but also to provide support for neighboring utilities which were severely impacted by the outage.

The Department is seeking to increase customer participation in the interruptible rate program by allowing firm load usage during the interruption period. In other words, the new XRT rate will allow partial energy consumption during a load curtailment request. This enhancement is expected to drive an increase in participation levels and improve demand response load to meet operational needs and reduce costs.

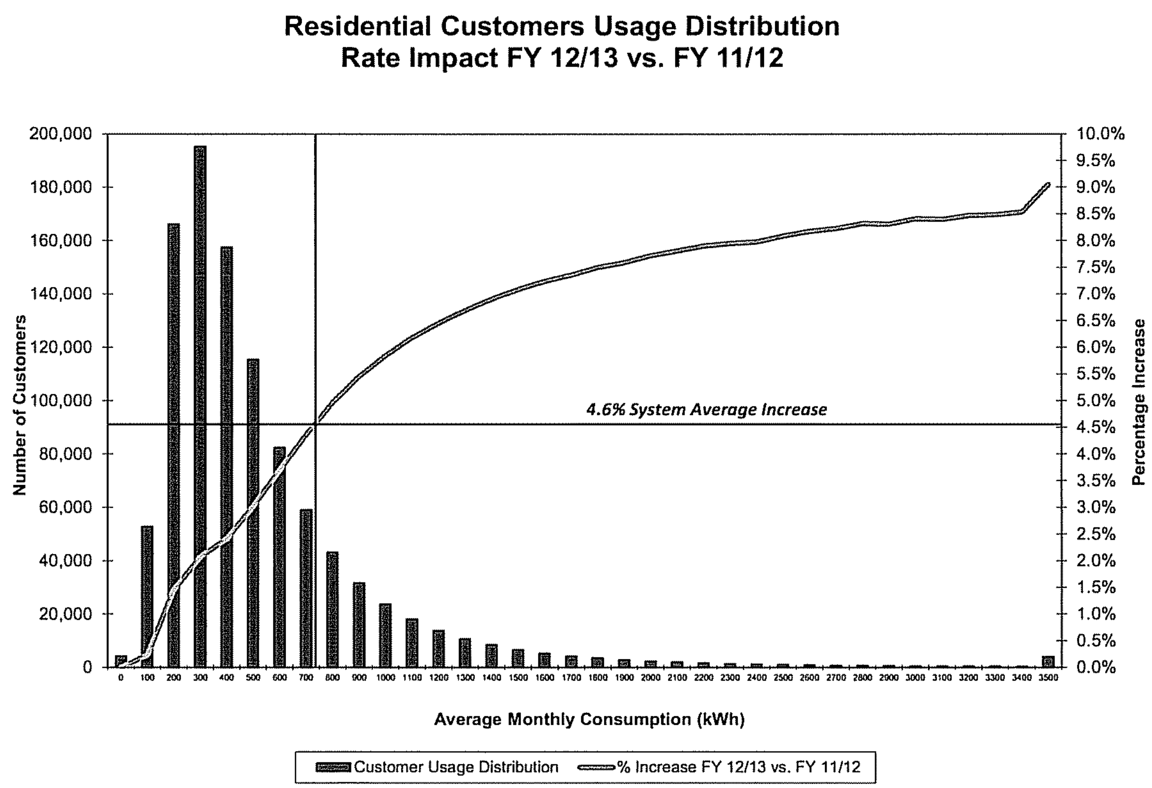
5. CUSTOMER RATE IMPACTS [61]

5.1.1 Residential Customer Class

The Department is focused on implementing conservation based electric rates for all customers including its residential customers. In order to send the proper conservation price signals to customers, electricity rates must be increased as consumption increases. This is also consistent with the marginal costs to serve these customers as well. Consistent with this approach, the proposed rate design for FY 2012/13 will allocate more of the rate increases to those customers that are consuming higher levels of electricity. As a result, roughly 80% of all residential customers will see an annual average rate increase under 5.00% for the two years in the proposed rate period; which is below the overall system average annual rate increase of 5.25% over the same two year period. However, residential customers with usage of greater than 700 kWh per month will see an average rate increase greater than the system average to encourage both implementation of energy conservation appliances, measures and behaviors.

As shown in the table below, residential customers with lower usage will receive lower rate increases than customers with a higher usage.

Figure 64: Residential Customers Usage Distribution Rate Impact FY 2012/2013 vs. FY 2011/2012

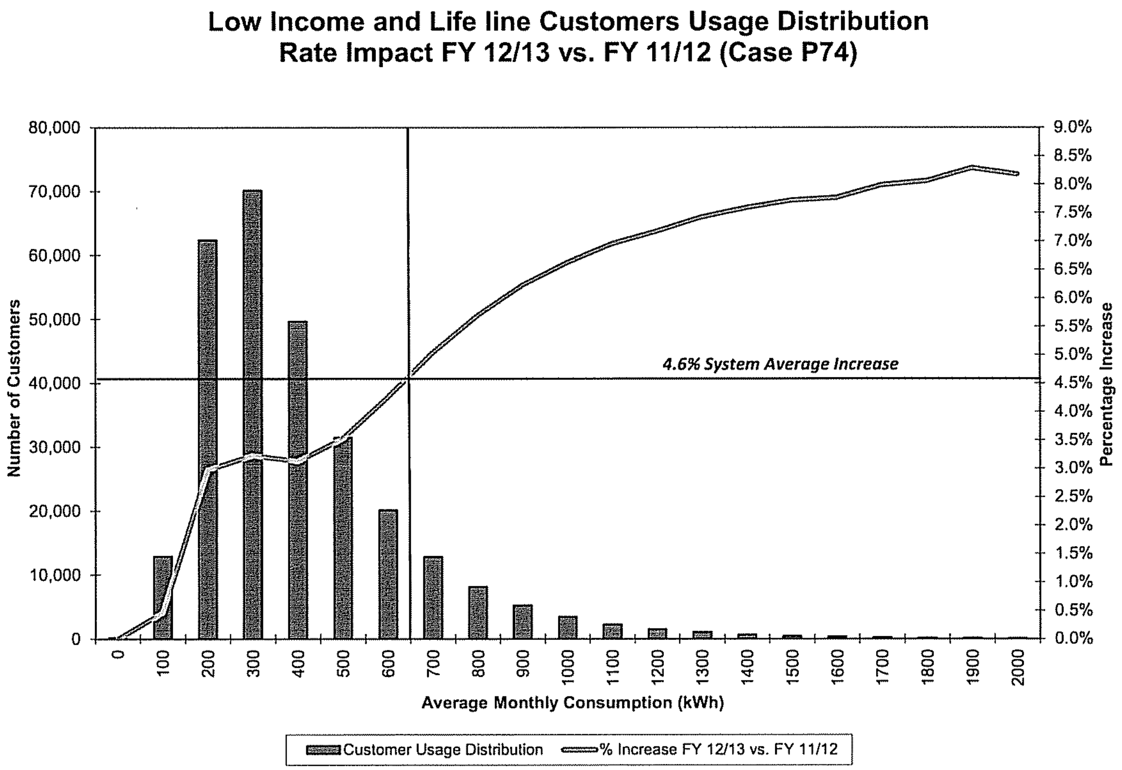


[61] The customer rate impacts shown in this section do not reflect the Recommended Energy Efficiency Alternative Plan

5.1.2 Low Income and Life Line Residential Customer Class

Consistent with the overall conservation-based rate design, customers at lower consumption levels will have lower rate increases than customers that have higher consumption levels. Low Income and Life Line customers tend to consume less electricity when compared to other residential customers. As a result, under the proposed rate action spanning the next two years approximately 87% of all Low Income/Life Line residential customers will see an annual average rate increase lower than the system average of 5.25% over the same two year period.

Figure 65: Low Income and Life Line Customers Usage Distribution Rate Impact FY 2012/2013 vs. FY 2011/2012

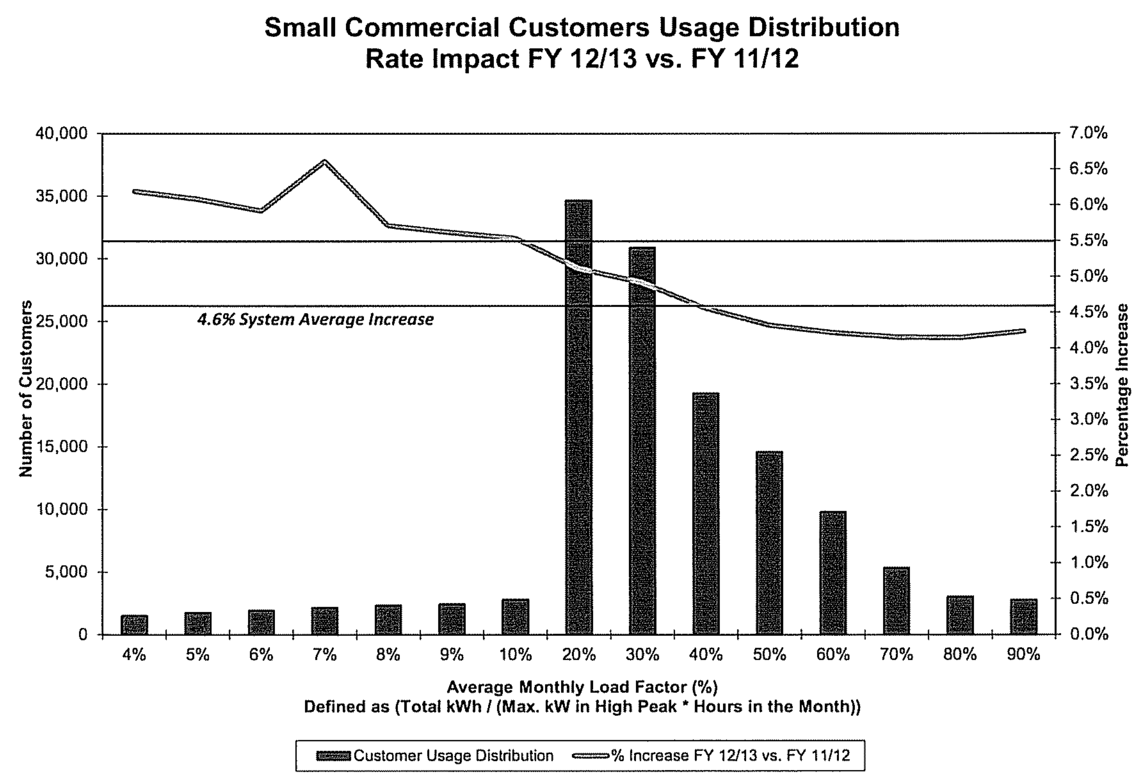


5.1.3 Small Commercial Customer Class

Load factor is an indicator of how efficiently a customer utilizes the overall electric system. Higher load factor customers use the electric system more efficiently than those with lower load factors. It costs more to serve low load factor customers, as fixed costs must be recovered over lower volumes, among other factors. As such, the proposed rate design will encourage small commercial customers to use energy with less variation and shift load outside of higher cost peak hours. In other words, small commercial customers with a higher load factors will see lower rate increases.

- Small commercial customers with load factors greater than 40% will see a rate increase below the FY2012/13 system average rate increase of 4.6% and the annual average rate increase of 5.25% for the two year period.
- Roughly 50% of all small commercial customers have a load factor of at least 20% or greater. Small commercial customers with a load factor of 20% will see an average rate increase of 5.6% over the two year period as compared to the system average of 5.25%.

Figure 66: Small Commercial Customers Usage Distribution Rate Impact FY 2012/2013 vs. FY 2011/2012

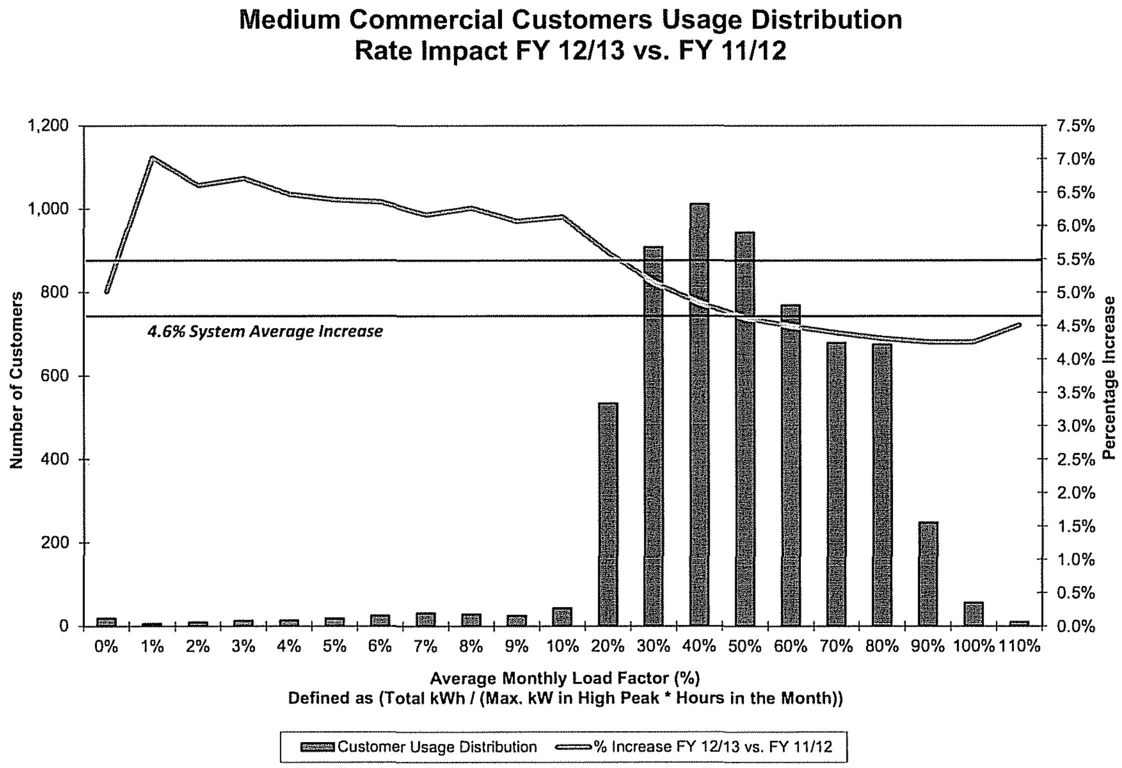


5.1.4 Medium Commercial Customer Class

Similar to the small commercial customers, the proposed rate and rate design will encourage medium commercial customers to use energy more efficiently (less variation on energy usage) and shift load outside of peak hours. In other words, medium commercial customers with a higher load factor will see lower rate increases.

- Medium commercial customers with a load factor greater than 50% will see a rate increase below both the FY2012/13 system average rate increase of 4.6% and the annual average rate increase of 5.25% for the two year period.
- Roughly 50% of all medium commercial customers have a load factor of greater than 45%. Medium commercial customers with 45% load factors will essentially see rate increases consistent with the system averages.

Figure 67: Medium Commercial Customers Usage Distribution Rate Impact FY 2012/2013 vs. FY 2011/2012

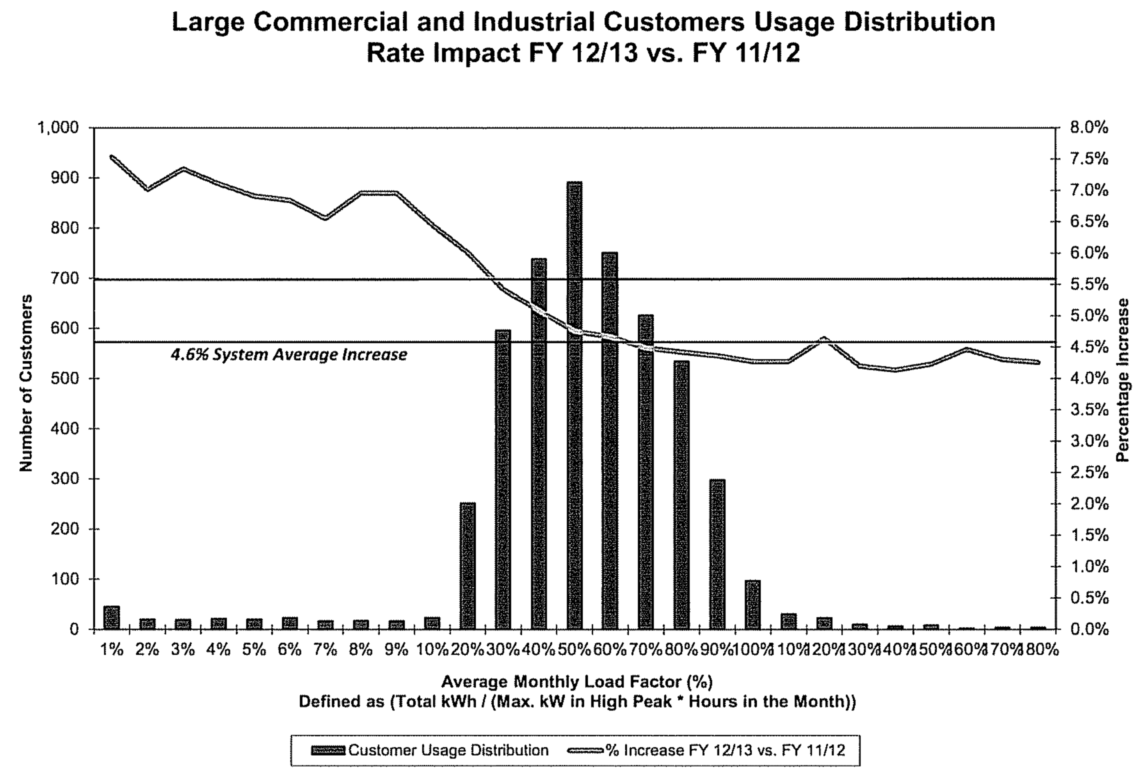


5.1.5 Large Commercial and Industrial Customer Class

Similar to the small and medium commercial customers, the proposed rates and rate design will encourage large commercial and industrial customers to use energy more efficiently (less variation on energy usage) and shift load outside of peak hours. In other words, large commercial and industrial customers with a higher load factor will see lower rate increases when compared to system averages. These customers with higher load factors can also take advantage of XRT rates.

- Large commercial customers with a load factor greater than 75% will see an increase below both the FY2012/13 system average rate increase of 4.6% and the annual average rate increase of 5.25% for the two year period.
- Of all large commercial customers, 59% have load factors between 40% and 70%. These customers will see an average two year annual rate increase between 5.19% and 5.59%.

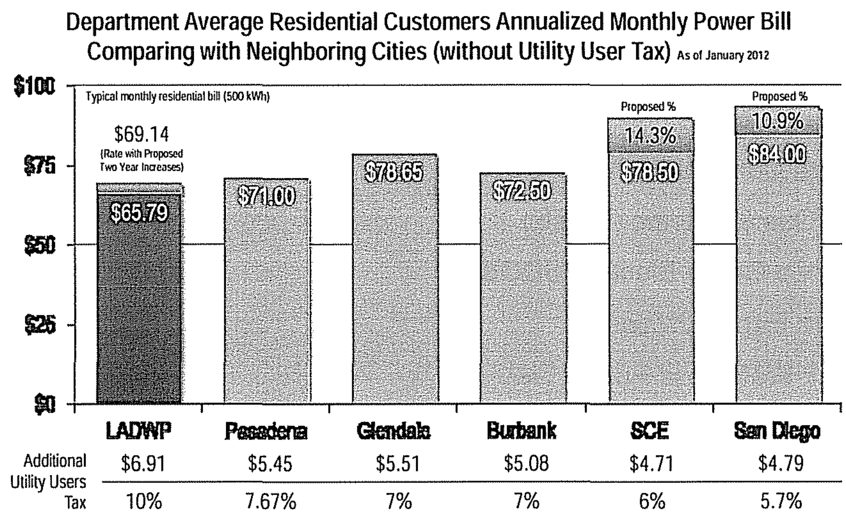
Figure 68: Large Commercial and Industrial Customers Usage Distribution Rate Impact FY 2012/2013 vs. FY 2011/2012

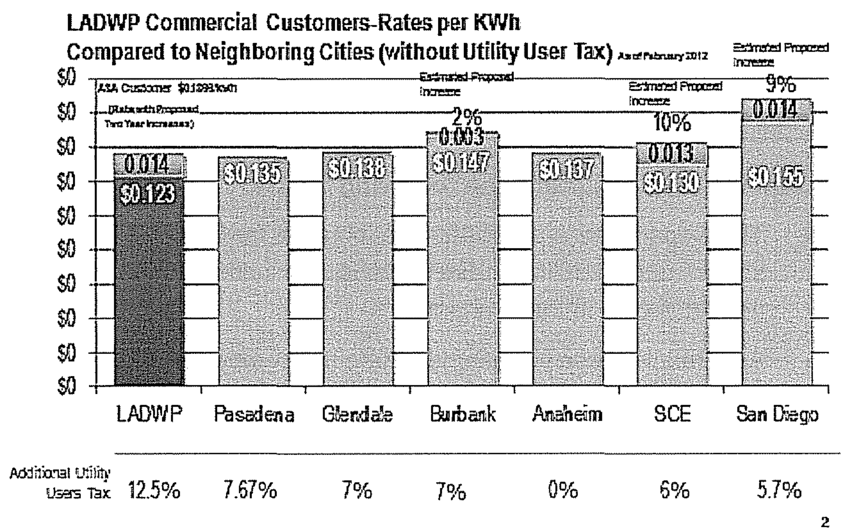


6. COMPARATIVE RATE ANALYSIS [62]

6.1 THE DEPARTMENT'S CURRENT POSITION

The Department's electric rates compare favorably to peer investor-owned and municipally-owned electric utilities in California. The Department provides electricity at competitive rates that are among the lowest for neighboring cities surrounding Los Angeles. Based on a typical monthly residential bill for a customer consuming 500 kWh of electricity, the Department has the lowest monthly electric bill compared to five of its neighboring utilities in southern California. Additionally, for the utilities where rate increases are not shown in the charts below are under discussion but have not yet been publically announced. Figure 69: **Average Residential Customers Annualized Monthly Power Bill Comparing with Neighboring Cities (without Utility User Tax)**





[62] The comparative analysis shown in this section do not reflect the Recommended Energy Efficiency Alternative Plan

6.2 COMPARATIVE ANALYSIS TO PEERS [63]

The following section shows rate comparisons within five major customer classes. The comparisons are based on the Department's Rate Design Model which utilizes individual customer billing information by rate schedule for a year to analyze proposed rate increases and rate design to meet the proposed financial plan. The following customer classifications are discussed in this section:

- Residential Customers
- Low Income and Life Line Customers
- Small Commercial Customers
- Medium Commercial Customers
- Large Commercial and Industrial Customers

Additionally, the Department rates for each class are compared against the peer regional utilities. These utilities include:

- Southern California Edison (SCE)
- Pacific Gas & Electric (PG&E)
- San Diego Gas & Electric (SDG&E)
- Anaheim Public Utilities
- Burbank Water and Power
- Glendale Water and Power
- Pasadena Water and Power

The comparative analysis clearly shows that the typical Department customer in the major customer classes pays less for electric service than customers of many other similar regional California utilities. The charts in the following section compare customer rates at various usage levels for the Department and other utilities.

Important to note regarding the following charts:

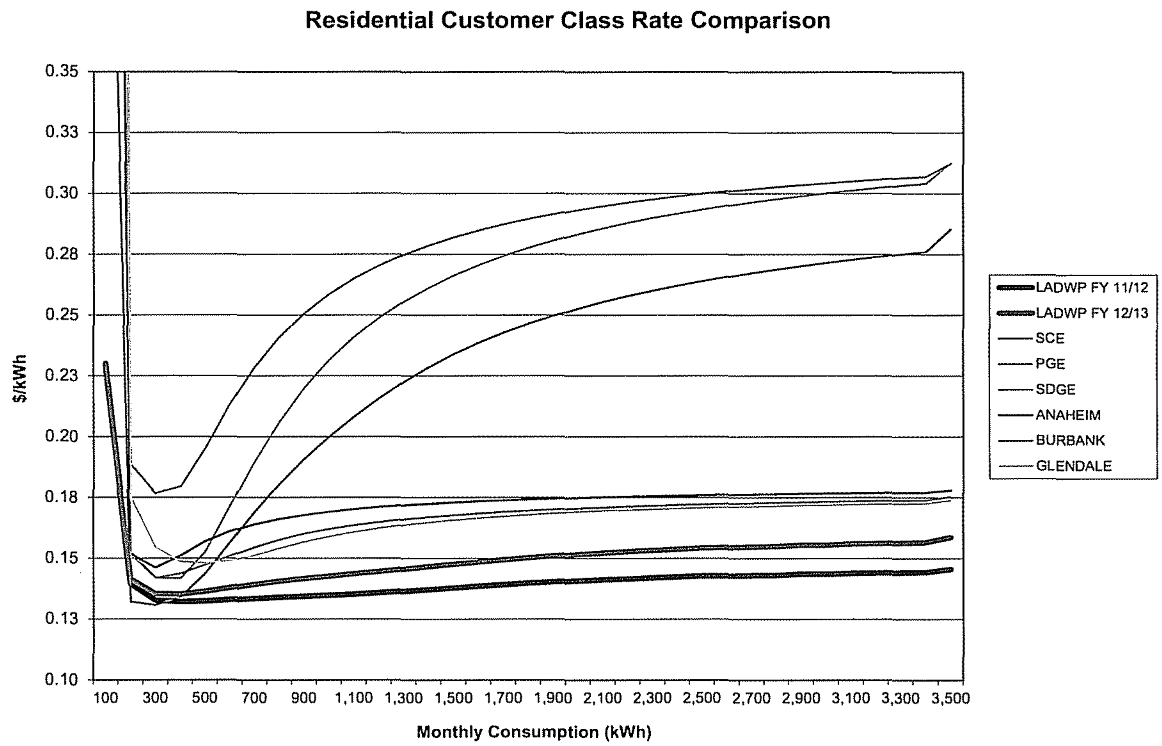
- The Department's proposed rate increase for FY12/13 is shown. Other Utilities have pending rate increases that are not yet shown in these charts.
- As a result, these charts understate the competitiveness of the Department's rates.

[63] The comparative analysis shown for each customer class in this section do not reflect the Recommended Energy Efficiency Alternative Plan

6.2.1 Residential Customer Class

The Department's proposed residential rate is competitive at all usage levels. At very low levels of consumption, due to the customer service charge (a fixed charge) for all utilities, the graph shows a sharp rate drop. The Department's rates are below all peers for all levels of consumption with the exception of SCE between 200 kWh per month and 400 kWh per month. This rate advantage is especially marked for higher levels of consumption compared to the investor-owned utilities that have up to five tier rates with very high prices in the upper usage tiers. The Department's average rate for consumption levels shown is less than or slightly above 15 cents per kWh, while for the investor-owned utilities the average rate rapidly escalated in the 20 to 30 cents per kWh levels.

Figure 70: Residential Customer Class Rate Comparison

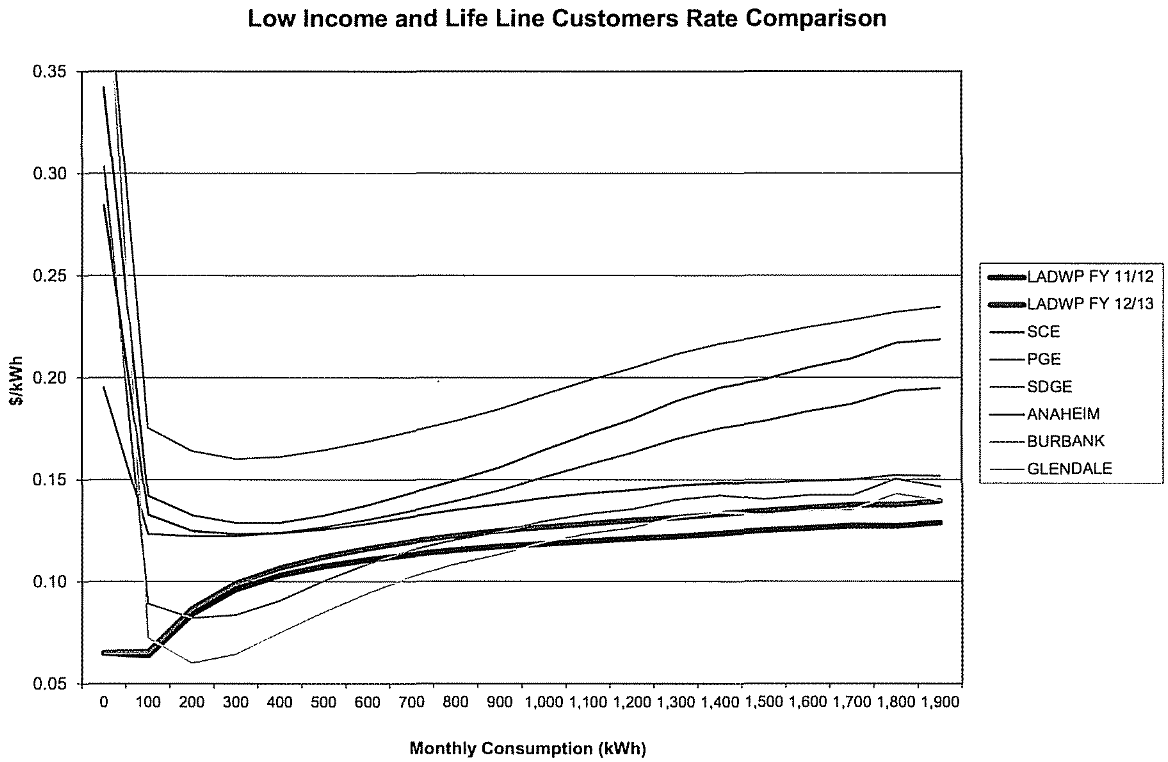


Note: The line graph above describes the relationship between $/kWh and the monthly consumption of kWh. The Department is shown in two different lines to represent different fiscal years - FY2011/2012 (large blue) & FY2012/2013 (large pink)

6.2.2 Low Income and Life Line Customers

The Department provides a fixed Low Income/Life Line subsidy in the amounts of $8.17 and $17.71 respectively. The resulting Low income/Life Line rates are very competitive at all consumption levels. In fact, at all usage levels, the only utilities that are lower than the Department are Burbank and Glendale at consumption levels of between 200 to 600 kWh per month. At all other consumption levels the Department has the lowest rates.

Figure 71: Low Income and Life Line Customers Rate Comparison

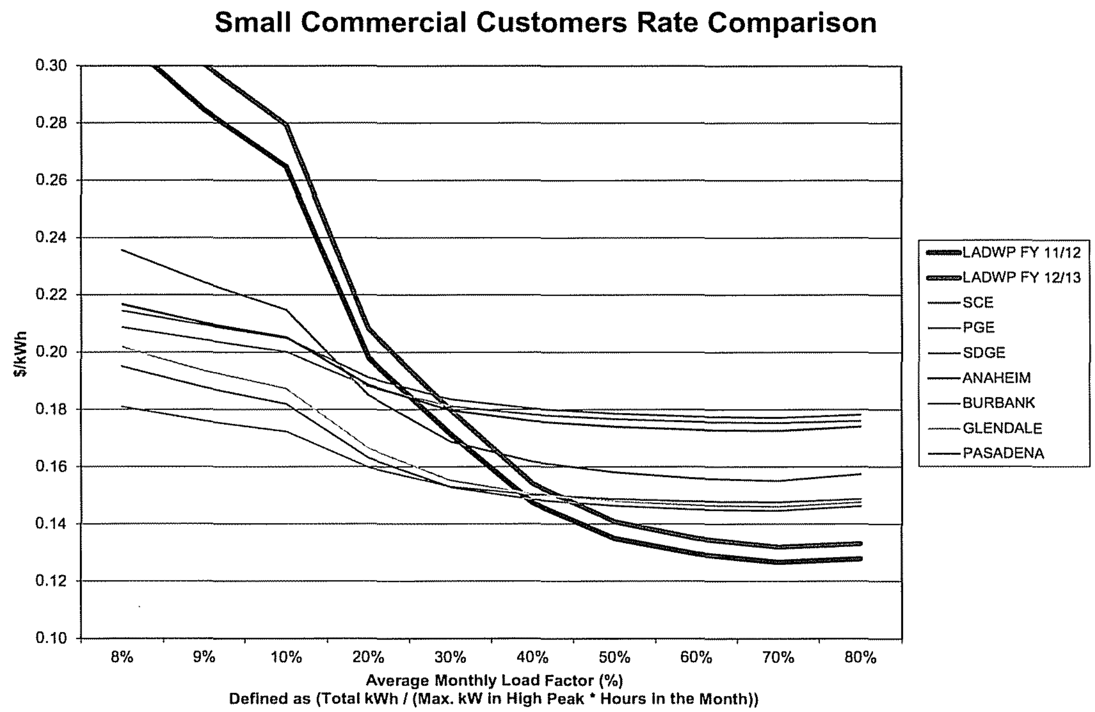


Note: The line graph above describes the relationship between $/kWh and the monthly consumption of kWh. The Department is shown in two different lines to represent different fiscal years - FY2011/20012 (large blue) & FY2012/2013 (large pink)

6.2.3 Small Commercial Customers Class

As stated previously, small commercial customers with higher load factors use energy more efficiently. As a result of the lower costs to serve them, small commercial customers with high load factors benefit from lower rates. The Department encourages this efficient usage by being the only utility in California with a facility demand charge. Over 70% of all small commercial customers have a load factor of greater than 20% (average usage of electricity is 20% of the peak) where Department rates are competitive. In fact, for small commercial customers above 50% load factor, the Department rates are the lowest of all utilities. However, any customer with a load factor of lower than 20% will have higher rates compared to the other noted utilities.

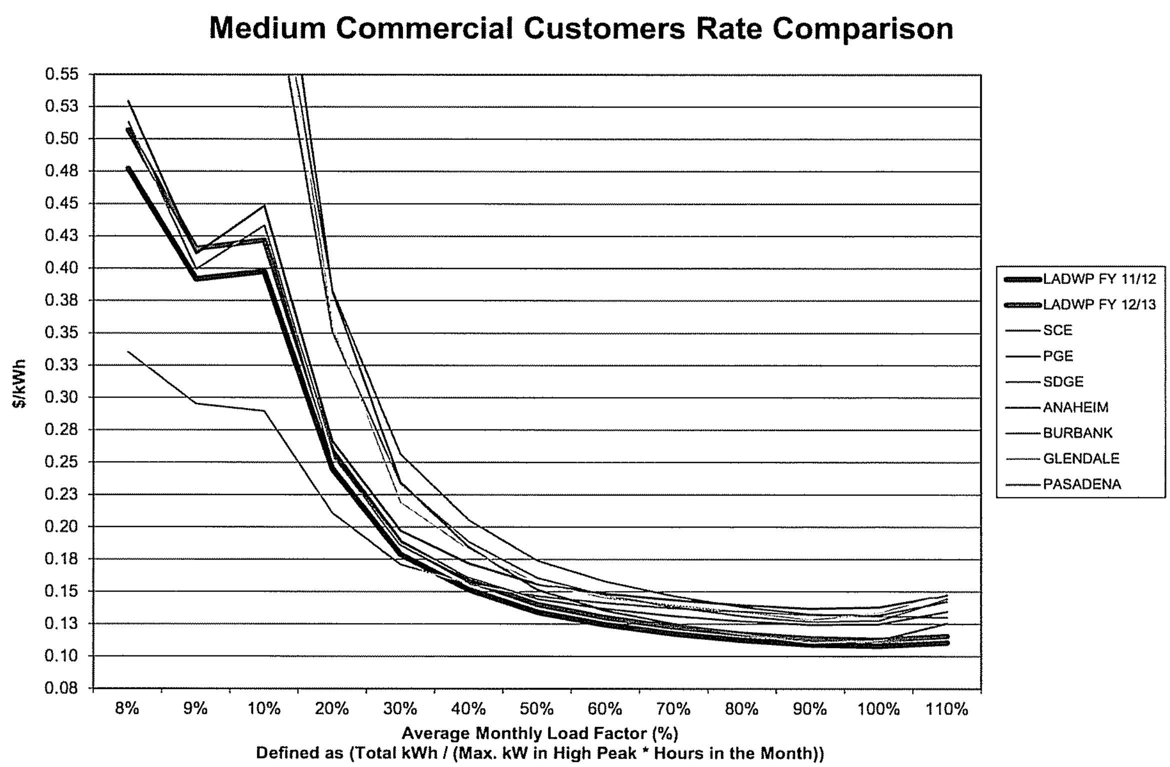
Figure 72: Small Commercial Customers Rate Comparison



6.2.4 Medium Commercial Customer Class

The Department's medium commercial customer rate is competitive with other California utilities except Pasadena with a load factor below 35%. However, most the Department's medium commercial customers (over 70%) have a load factor greater than 35%. For these customers, Department rates are among the lowest.

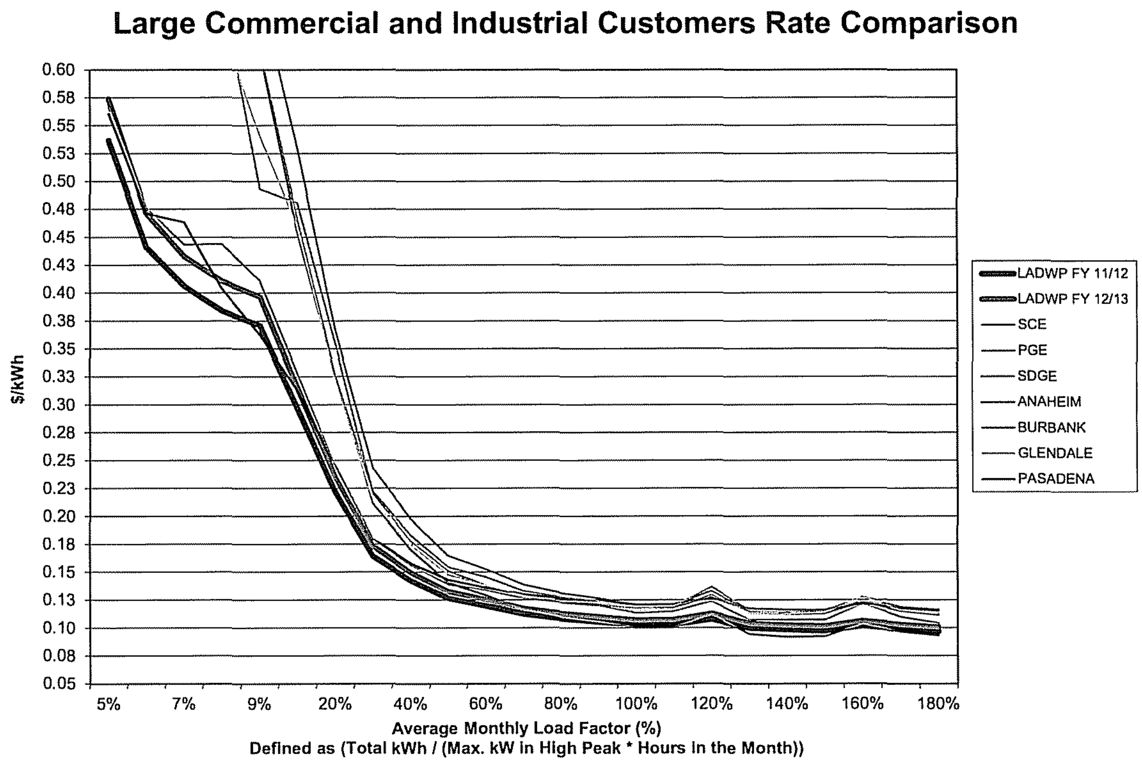
Figure 73: Medium Commercial Customers Rate Comparison



6.2.5 Large Commercial and Industrial Customer Class

For large commercial and industrial customers, the Department's rates are among the lowest for all California utilities. At extremely high load factors, however, SCE's large commercial rates are below the Department's while Anaheim's rates are below the Department's at extremely low load factors.

Figure 74: Large Commercial Industrial Customers Rate Comparison



7. RECOMMENDED ENERGY EFFICIENCY ALTERNATIVE PLAN

Since 2000, the Department has spent approximately $282 million in capital and O&M on its energy efficiency (EE) programs and these programs have reduced long-term peak period demand and consumption by approximately 1,256 GWh. The Department is committed to developing comprehensive programs with measurable, verifiable goals as well as implementing robust, cost effective energy efficiency programs.

Under Assembly Bill 2021 (AB 2021), publically-owned utilities such as the Department, must identify, develop and implement programs for all potentially achievable, cost-effective EE savings and establish annual targets.

Furthermore, utilities are required to conduct periodic “Market Potential” studies to update their forecasts and targets. The Department’s most recent study was carried out in late 2010 and is the basis for the EE recommendations contained in the 2011 IRP and used to develop the initial financial plan and proposed rates for FYs 2012-13 and 2013-14.

The study evaluated a multitude of measures for potential inclusion in the Department’s EE program; including:

- The Department’s existing program elements;
- High-efficiency air conditioners (higher efficiency levels, variable refrigerant flow systems);
- High-efficiency lighting (CFLs, LED lamps);
- Upgraded insulation in buildings;
- Retro-commissioning and routine maintenance; and
- Programmable communicating thermostats and energy management systems.

7.1 The Path to 10%

The details of the programs recommended by the 2011 IRP are described in Section 2.3.1. These energy efficiency programs put the Department on a path to achieve energy savings (GWh) equivalent to 8.6% of 2010’s energy consumption by 2020. This is the level of achievement that has currently been approved by the Department’s Board of Commissioners. The 2010 reference point is specified by AB 2021, which requires the state’s electric utilities to achieve cumulative savings of 10% of total energy consumption levels by 2020. As noted earlier in this report, the Board’s adoption of an 8.6% energy savings goal by 2020 was interim in nature. In that adoption, the Board requested the Department to evaluate options to increase the rate of energy efficiency savings to achieve the 10% savings by the 2020 state-mandated goal.

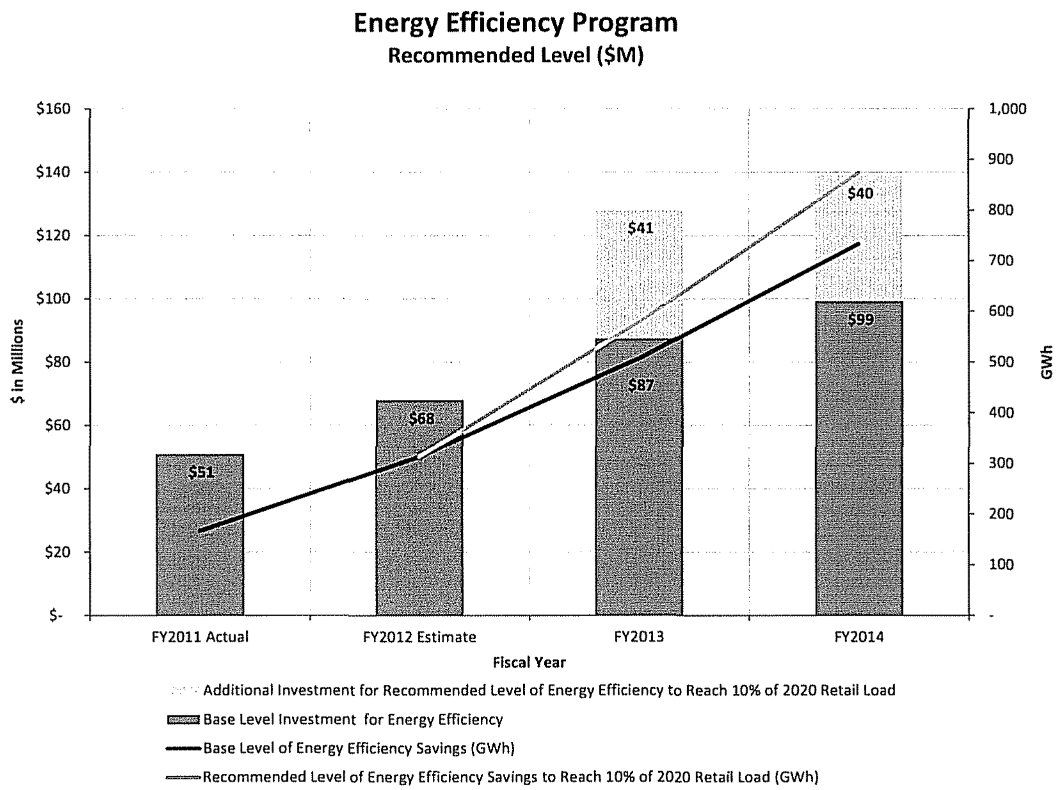
The Department’s baseline EE spending in the initial financial plan for FY 2013 and 2014 is $87M and $99M respectively. In order to achieve the 10% level of GWh savings, the Department recommends increasing spending on EE programs above the level in the initial financial plan. This change would add funding to existing programs, modify existing programs or develop new programs that provide additional GWh savings necessary to put the utility on a path to 10% savings by 2020. Other changes included reallocating costs from support functions to programs, capitalizing the vast majority of the program, and updating assumptions related to other programs.

Total Additional EE Investment Required to Reach Required 10% GWH Savings

As shown in the chart and table below, the Department recommends an additional $41 million and $40 million in expenditures in FYs 2013 and 2014 respectively for EE programs. This level of additional spending, which is well above the Department's historic and current levels produces the GWh savings required to have each of these two fiscal years put the Department on a path, which if continued beyond the two-year rate period, would reach at least the 10% required by AB 2021. Moving forward with this level of commitment then allows the Department to prepare longer-term plans to achieve the future year energy efficiency programs to achieve at least 10% savings by 2020, or to consider even further energy efficiency improvements beyond 10% if such higher than 10% savings levels are deemed appropriate.

The yellow line represents the level of energy savings required to pace the Department towards the 10% reduction target.

Figure 75: Summary of the Recommended EE Alternative Plan



As shown in the tables below, the Department proposes to spend $128M in FY 2013 and 2014, and $139M in FY 2014.

Figure 76: Summary for the Recommended EE Alternative Plan

Program	FY 2013 Recommended Funding ($000)	FY 2014 Recommended Funding ($000)	Total GWh Savings FY 2013-2014	Cost $/kWh
Residential Programs				
Refrigerator Recycling Program	1,113	1,267	31.6	0.015
Refrigerator Exchange Program	6,395	6,410	13.1	0.070
Consumer Rebate Program	2,677	3,704	4.3	0.114
Income Qualified and Multi-Family Program	11,677	11,839	4.2	0.408
Residential Lighting Program	813	1,117	15.2	0.024
Residential Home Electronics Program	113	117	0.0	0.074
Behavioral Programs	2,113	2,117	44.4	0.095
Energy Upgrade California	1,113	2,117	3.4	0.095
AC/Tune-Up	2,000	2,000	2.1	0.194
Non-Residential Programs				
Commercial Lighting Efficiency Offer	11,693	11,759	85.5	0.032
Chiller Efficiency Program	2,613	3,117	7.9	0.036
Refrigeration Program	1,113	1,617	26.6	0.026
HVAC Program (5 to 20 tons)	2,169	2,305	5.6	0.054
Custom Performance Plus	10,113	10,467	34.3	0.037
Custom Performance-Based Efficiency	12,847	14,880	137.1	0.017
New Construction	1,442	1,949	27.4	0.008
LAUSD	10,564	10,936	50.6	0.041
Lighting Direct Install Program	36,096	38,833	35.6	0.191
Retrocommissioning (RCx)	4,113	4,070	32.4	0.025
Demand Response Pgm Dev/Program Support	306	700	0.0	0.00
Subtotal General Program Support	6,995	7,698	0.0	0.00
TOTAL ENERGY EFFICIENCY PROGRAM	128,079	139,023	561.3	0.059

The above additional spending results in savings of 561.3 GWh in FY 2013 and 2014 combined at an average cost per kWh of $0.059.

The Department proposes this incremental funding necessary to achieve 10% energy efficiency by 2020, and will recommend that the Board of Commissioners adopt this target, as well as the investment necessary in FY12-13 and FY13-14 to put the utility on the path to achieve it. Energy efficiency program plans for FY 14-15 and beyond will be evaluated in more detail later to present the program adjustments needed in later years to achieve the 10% savings by 2020, as well as the potential for even further savings levels beyond the 10% for consideration by the Board, City Council, customers and stakeholders.

We have reviewed the existing EE programs and have made the fundamental adjustments noted above. Below is a brief description of programs in the recommended energy efficiency plan.

Residential Programs

Income Qualified and Multi-Family Program: This program, offers residential customers the opportunity to reduce their energy bills by allowing qualified Department staff to make energy efficiency and water conservation upgrades to their home. For residential customers residing in multi-family dwelling, common area efficiency upgrades will also be addressed. All residential customers may apply, however, first consideration will be given to registered low-income and lifeline customers, and Tier 2 residential customers who demonstrate the greatest economic need.

Behavioral Programs: Provides residential end-users with information on their energy use, comparisons with usage by others, goal setting, rewards and additional tactics that encourage efficient energy use. This is a new program not included in the base energy efficiency program. The recommended energy efficiency alternative provides:

Energy Upgrade California: This is a collaborative program administered by the California Energy Commission in partnership with public and private utilities, the California Public Utilities Commission and participating counties. The program is funded by grants and contracts from the U.S. Department of Energy, the Energy Commission, and California utility customers. This is a new program not included in the base energy efficiency program. The recommended energy efficiency alternative provides:

AC/Tune-Up: Provides qualifying residential customers with Air Conditioning refrigerant charge adjustments and condenser coil cleaning. Program is currently in development and will be refined further in the coming weeks. This recommended Energy Efficiency Alternative Plan component addition provides:

Non-Residential Programs

HVAC Program (5 to 20 tons): Offers incentives for replacing inefficient package units with high efficiency units. This is a new program not included in the base energy efficiency program.

Custom Performance Plus: An enhanced version of the Custom Performance Program that is in the base level EE plan, targeting industrial process efficiency improvements with minimum energy saving requirement of one GWh. Program is currently in development. This is a new program not included in the base energy efficiency program.

Energy Efficiency Measures for LAUSD: Los Angeles Unified School District (LAUSD) is the largest power customer of the utility. The Department is presently working with LAUSD to develop a focused energy efficiency program to reduce energy use at LAUSD facilities that are within the City of Los Angeles[64]. The Department has proposed to LAUSD undertaking specific energy efficiency measures in FY 12-13 while the Department works with LAUSD to develop a detailed energy usage and energy efficiency potential study of LAUSD facilities that will provide the basis for a multi-year energy efficiency plan that the Department and LAUSD would collaboratively undertake

[64] Some of the LAUSD facilities are located outside of the boundaries of the City of Los Angeles and are served by Southern California Edison.

as part of the Department's overall energy efficiency investment program. The Energy Efficiency Alternative Plan presented herein provides for an allocation of funding and target energy savings for the next two fiscal years. This plan will be developed in more detail in cooperation with LAUSD.

Lighting Direct Install Program (LDIP): This program will retrofit the existing lighting of qualifying business customers to new, high efficiency lighting systems. The LDIP will initially target the smallest business customers in the A1 rate class, but may be expanded to other customer segments. This program is expected to operate for three years.

Retrocommissioning (RCx) Express: (RCx Express) program is a continuation of the ARRA grant-funded pilot program for non-residential customers, replacing the ARRA grant funding with Department funding from rate revenue. The pilot program design is based on lessons learned from SCE's Retrocommissioning program. The Department program offers a cash incentive (rebate) to those who undertake a "tune-up" of their existing building system equipment and bring it back up to its original performance level. The program does not require a Retrocommissioning study, but offers a menu of 13 items that qualify for incentives. Program offerings include incentives for replacement or repair of certain lighting sensors, air conditioning economizers, restoration of fan and pump variable frequency drives, operations set point strategies for supply air, temperature or duct pressure, chilled water and condenser water, operating schedules and boiler lockout.

How Does This Recommendation Impact Customer Bills?

The Department's goals are to meet all of its mandated and service requirements while at the same time minimizing the impact on its customer's monthly bills. The first goal almost always requires increases in the Department's *rates*. However, the Department can help customers offset some of this impact in the long-term by increasing its efforts to provide energy efficiency solutions that will help customers use less energy and keep their monthly *bills* lower than they would be otherwise. Increasing EE spending and redesigning the EE programs provides the opportunity to achieve the second goal.

The Recommended EE Alternative Plan calls for a minimal amount of incremental revenue resulting in a slight increase in rates above the levels required for the base energy efficiency plan presented earlier in this report in Section 2. The incremental increase puts the Department on a path to achieve the 10% reduction in total energy consumption by 2020.

Figure 77: System Average Annual Rate Increase for Recommended EE Alternative Plan

System Average Annual Rate Increase	Current Year	Proposed Rate Period	
Fiscal Year Ended June 30:	**FY 2012**	**FY 2013**	**FY 2014**
Average Annual Increase with Baseline EE Funding	-	4.60%	5.90%
Average Annual Increase with Recommended Energy Efficiency Alternative Plan	-	4.80%	6.30%
Incremental Increase		0.20%	0.40%

The impact on monthly bills of the recommended energy efficiency alternative is very minor. The table below shows the average monthly bill ***without*** the additional EE spending

Figure 78: Average Monthly Bill by Customer Class **without** the Recommended Energy Efficiency Alternative Plan

Average Customer Power Bill		Average Bill at Current Rates ($)	Average Bill with Proposed Rate Changes ($)	
Customer Class	**Usage (kWh)**	**FY 2012**	**FY 2013**	**FY 2014**
Residential	500	$65.79	$67.14	$69.14
	600	79.44	82.14	85.75
	800	106.76	112.16	118.99
	1,000	134.07	142.17	152.22
Small Commercial (35% Load Factor)	1,000	136.40	142.30	150.60
Medium Commercial (40% Load Factor)	50,000	6,195.00	6,502.42	6,915.33
Large Commercial (42% Load Factor)	300,000	36,930.00	38,681.67	40,994.33

The average monthly bill ***with*** the recommended additional EE investment is shown below for each customer class.

Figure 79: Average Monthly Bill by Customer Class **with** Recommended Energy Efficiency Alternative Plan

Average Customer Bill		Average Bill at Current Rates ($)	Average Bill with Proposed Rate Changes ($)	
Customer Class	**Usage (kWh)**	**FY 2012**	**FY 2013**	**FY 2014**
Residential	500	$65.79	$67.25	$69.51
	600	79.44	82.29	86.22
	800	106.76	112.35	119.64
	1,000	134.07	142.42	153.05

Average Customer Bill		Average Bill at Current Rates ($)	Average Bill with Proposed Rate Changes ($)	
Small Commercial (35% Load Factor)	1,000	136.40	142.59	151.31
Medium Commercial (40% Load Factor)	50,000	6,195.00	6,515.16	6,941.49
Large Commercial (42% Load Factor)	300,000	36,930.00	38,745.06	41,133.73

Figure 80: Average Monthly Bill by Customer Class – Incremental increases with the Recommended Energy Efficiency Alternative Plan

Average Customer Bill		Bill with Proposed Rate Changes	
Customer Class	**Usage (kWh)**	**FY 2013**	**FY 2014**
Residential	500	0.12	0.38
	600	0.14	0.47
	800	0.20	0.65
	1,000	0.25	0.83
Small Commercial (35% Load Factor)	1,000	0.29	0.71
Medium Commercial (40% Load Factor)	50,000	12.74	26.16
Large Commercial (42% Load Factor)	300,000	63.39	139.39

8. PUBLIC OUTREACH PROCESS

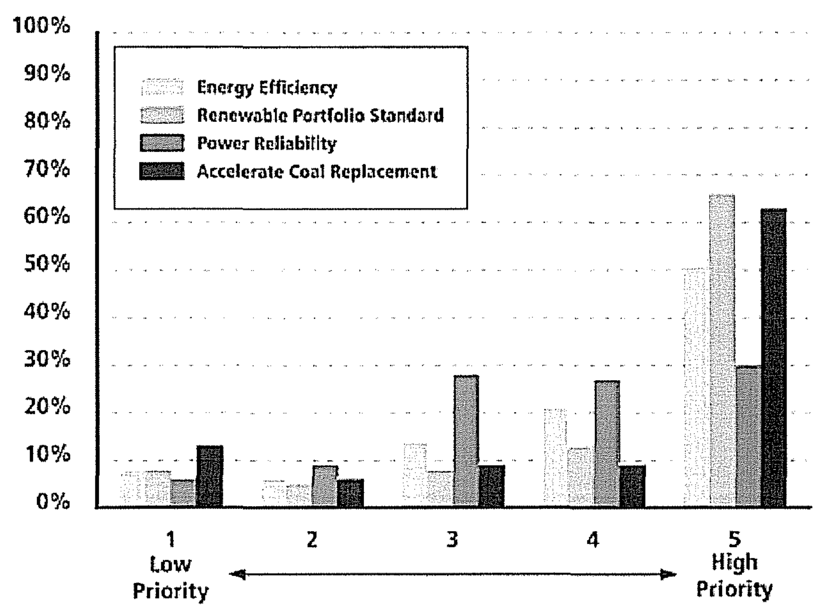
Throughout the current rate setting process, the Department has communicated openly with its customers, stakeholders and policy makers about the cost pressures and challenges it faces and the potential impacts on its customers. The Department had extensive public outreach and input regarding its Integrated Resources Plan (IRP)[65] in the Fall of 2010 and Spring of 2011 and this feedback process provided a strong foundation to build a solid case for further infrastructure investments.

Since beginning the rates process in the Spring of 2011, the Department also conducted over 30 public meetings since June 4, 2011, to inform the public about mandates and the associated costs the Department is facing. In addition, the Department has reached out through the following media:

- Print ads in daily and community newspapers
- Electronic ads on City Watch website
- Outreach to Neighborhood Councils
- Editorial board briefings
- Television and radio interviews
- Social media – Twitter, YouTube

Throughout this process, the Department has solicited input from its customers seeking their opinions on priorities and to determine what is important for the City of Los Angeles. As can be seen from the following chart, Department surveys have revealed strong support for investments in energy efficiency, renewable energy resources, power reliability and coal replacement, which are the major rate drivers.

Figure 81: Customer Prioritization of Power System Strategic Investments



[65] For copy of full plan see: https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-power/a-p-integratedresourceplanning?_adf.ctrl-state=9q5k9x7gq_21&_afrLoop=40084502762000.

As a result power supply replacement (including renewable energy and coal reduction), energy efficiency and power reliability investments have been included in the proposed expenditures and supporting rates.

To continue the public input process, several community customer meetings and stakeholder workshops were held in April and are scheduled during May 2012 to provide an opportunity for the Department's customers and other stakeholders to learn more about the rate proposal. Additional workshops may be scheduled based on community interests and needs.

Figure 82: Community Meetings

Community	Date/Time	Location
Harbor	Wednesday, April 25 6:30 PM – 8:30 PM	Crowne Plaza Hotel, Salon A 601 S. Palos Verdes St. San Pedro, 90731
West Valley	Thursday, April 26 6:30 PM – 8:30 PM	Holiday Inn Express & Suites 22617 Ventura Blvd. Woodland Hills, 91367
Metro	Saturday, April 28 9:00 AM – 11:00 AM	LADWP John Ferraro Building Headquarters 111 N. Hope St., A Level Los Angeles, 90012
South L.A.	Monday, April 30 6:00 PM – 8:00 PM	LADWP Crenshaw Service Center 4030 Crenshaw Blvd. Los Angeles, 90008
East L.A.	Wednesday, May 2 6:30 PM – 8:30 PM	Recreation and Parks Ramona Hall 4580 N. Figueroa St. Los Angeles, 90065
Central Valley	Thursday, May 3 6:30 PM – 8:30 PM	LADWP Van Nuys Service Center 14401 Saticoy St. Van Nuys, 91405
West L.A.	Thursday, May 10 6:30 PM – 8:30 PM	Stephen S. Wise Temple, South Taub Annex 15500 Stephen S. Wise Drive Los Angeles, 90077

Figure 83: Community Workshops

Stakeholder Group	Date
L.A. Chamber of Commerce	Friday, April 20
City Council Staff Briefing	Thursday, April 26
Central City Association Briefing	Thursday, May 3 9:00 AM – 11:00 AM
Premier Account Workshop	Thursday, May 3 2:00 PM – 4:00 PM
Northeast Valley City Hall / Council District 6	Thursday, May 17 6:30 PM – 8:30 PM
Saticoy Yard / Council District 7	Monday, May 21 6:30 PM – 8:30 PM
Premier Account Webinar	Wednesday, May 30 9:00 AM – 11:00 AM

9. IMPLICATIONS OF INACTION ON A POWER SYSTEM RATE ADJUSTMENT

As discussed in this report, the Department has numerous regulatory, legislative, public policy and system reliability obligations. Additional funding beginning in FY 2012-2013 is essential in order to meet these obligations. The Department presents in this report the required rate increase effective July 1, 2012. Given the delay in the appointment of the Ratepayer Advocate, and the need to provide adequate review time the RPA, as well as other necessary steps in the rate approval process, a July 1, 2012 rate increase is impractical. In order to collect the same dollars over fewer remaining months in the year, a progressively higher percentage rate increase would be necessary the longer the rate action is delayed. For example, a delay of one month raises the system average increase from 4.6% to 5.15%[66].

If incremental revenue is not provided at all, the Department would likely not be able to meet its mandatory regulatory and legislative obligations, but in an effort to do so, would be forced to cut important but somewhat more discretionary programs such as energy efficiency, Power Reliability Program levels and some of the Department's customer service functions.

Further consequences of a revenue shortfall would include:

- In 2013 and 2014, the Department will not have sufficient net income to comply with the financial tests necessary to meet its obligations;
- The Department's debt service ratio would fall below the 2.25 target; and
- The Department's debt would exceed the 68% capitalization target starting in FY 2015-16.

All the above consequences would be noted by the rating agencies and increase the risk of a downgrade or having the Department's bonds put on "watch".

[66] The Department is evaluating the viability of using a deferred revenue credit of $45 million on the balance sheet from 1998 related to the Department's participation in the Palo Verde Nuclear project to mitigate the rate impact that could result from a delay in implementing new rates.

10. PROPOSED RATE ORDINANCE

The Department is currently planning to submit to the Board for approval a revised rate ordinance reflecting the proposed rates and rate structure discussed in this report. Work on the ordinance is underway at this time.

11. INDEPENDENT THIRD PARTY REVIEW

The Department has prepared this report to facilitate the RPA's review of the proposed rates, in accordance with Charter Amendment I.

This report supplements the materials that have been provided in support of the Department's proposed rates that have been provided to the RPA between February and May 1st of this year. Information made available thus far includes more than 50 documents related to the power system operational, capital and financial plans. Additionally, 88 documents have been provided in response to 29 completed data requests (of 51 requests to date). Cumulatively, significantly more information has been developed and provided in support of the Department's rate proposals than in the past.

While this report provides a comprehensive outline of the proposed rates and supporting facts, the Department is prepared to address any questions about these rate proposals and provide additional information upon request.

12. BOARD AND CITY COUNCIL APPROVAL

The Department will present the rate proposal to the Board of Commissioners for approval after the RPA's report has been completed.

Subsequent to Board action, City Council approval of the modifications is required by ordinance.

13. LIST OF ATTACHED APPENDICES

The following appendices are attached to this report for supplemental information:

- Appendix A: Financial Models
- Appendix B: Operating Expense Budget
- Appendix C: Capital Expense Budget
- Appendix D: Integrated Resource Plan (IRP)
- Appendix E: Master Bond Resolution
- Appendix F: Power Generation OTC Projects
- Appendix G: California SB 2(1X) Summary
- Appendix H: Utility-Built Solar Projects Summary
- Appendix I: Barren Ridge Project Detail
- Appendix J: Cost Reduction Plan
- Appendix K: Energy Efficiency Program Descriptions
- Appendix L: Asset Management Principles

Case P119 -- Case110 with 50% RCA Amortization and Altered EE Ramp in Yr One

Fuel Case --> 05/14/12
O&M Case --> 05/16/12

Final FY2013 Budget	I-TEF/REF/EEF	Navajo Sold in 2016@225M	Board Metrics; No Downgrade	Base Renevue As a Passthru
	BR #19 (Case19)	Solar Incentives Capitalized	GASB45 overpmt = $75M	I-RCA Effective
Non-PRP O&M Cuts #19 (Case1	IBF1#1 (Not Used)		Pension for 9185 Heads	RCA UC As Selected
Low CO2 Price	Cap @0.6/0/0	Pinedale Gas Not Sold	Bond Refund #1 (Uniform Savir	No COLA Adjustment
EE at Altered Ramp for Yr 1	TEF Transition Cap = 0.1c	Landfill Gas REC as REF		CRPSEA Balance Carried
Solar SB-1 Final 2013	REF = 0.15 cts	RCA Balance Amortized & Zeroe	DRTF = $500M	CIRCA UnCapped; CRPSEA Capp
ICityXfer = Yes	ESA split from Base Rate	Old UC Payable in 10 Yrs	Minimum Cash = $300M	IRCAF Calculated
No Trust Fund Collection	ESAF frozen at 0.147 cts	Legacy U/C in VarECAF/TEF	City Xfer - 8%	RCA Amortization is 50% in 201
Case's Default CapEx & O&M	IECAF as 3 Factors	FPP Method 2 - FPP do not dec	Cash DSR	
Restructuring on 10/1/12	UC Multiplier = 1.0	No Delay in U/C	Normal Retail Load	

	FY2013	FY2015	
I-RCAF Annual Cap -->	5.000	5.000	cts/kWh
I-RCAF Lifetime Cap -->	5.00		cts/kWh
Restructuring Delay -->		3	Months
Base Rate Incr % -->		5.1%	
ECA Rate Incr % -->		0.6%	
RCA Rate Incr % -->		1.0%	
		6.64%	

Rate Stabilization Fund:

	Drawdown	Inject	Balance
FY2010/11	$0 M	$0 M	$75 M
FY2011/12	$0 M	$0 M	$75 M
FY2012/13	$13 M	$0 M	$62 M
FY2013/14	$36 M	$0 M	$26 M
FY2014/15	$0 M	$0 M	$26 M
FY2015/16	$0 M	$0 M	$26 M
FY2016/17	$0 M	$0 M	$26 M

Base Rate Actual Adj %	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
ECA Actual Adj %	0.3%	0.3%	0.0%	0.0%	0.0%	0.0%
RCA Actual Adj %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
ESA Actual Adj %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
I-Base Inc %	0.0%	3.4%	2.5%	3.8%	3.0%	2.3%
I-ECA Inc %	0.0%	0.5%	2.6%	3.1%	3.5%	2.5%
I-RCA Inc %	0.0%	0.7%	1.0%	1.0%	1.1%	1.2%
I-Increase %	0.0%	4.88%	6.02%	7.85%	7.53%	6.03%
Base Revenue Adj $M	5	1	0	2	0	-1
ECA Revenue Adj $M	8	8	0	0	0	0
RCA Revenue Adj $M	0	0	0	0	0	0
ESA Revenue Inc $M	0	0	0	0	0	0
I-Base Inc $M	0	101	76	124	105	87
I-ECA Inc $M	0	14	80	100	121	93
I-RCA Inc $M	0	21	30	31	38	45
Revenue Inc ($M)	0	145	185	256	263	226
			153 3-Yr Avg ->	6.25%	5-Yr Avg ->	6.46%

	Final	Final	Revised	Actuals thru Mar 2012	<====== FORECAST ======>				
FISCAL YEAR ENDING JUNE 30	2010	2011	2012	2012	2013	2014	2015	2016	2017
1. Retail Sales (GWh)	23,319	23,064	23,344	23,123	23,471	23,600	23,897	24,129	24,381
Adj. For DSM (GWh)	0	0	(73)	0	(100)	(414)	(712)	(1,019)	(1,349)
Adj. For Solar (GWh)	0	0	(15)	0	(23)	(74)	(114)	(152)	(180)
Adj. due to Others (GWh)	0	0	0	0	0	0	0	0	0
Net Retail Sales(GWh)	23,319	23,064	23,256	23,123	23,348	23,113	23,071	22,958	22,852
2. Operating Revenue:									
Base Rate	1,548	1,527	1,582	1,535	1,552	1,536	1,535	1,527	1,519
Base Rate Revenue Increases	0	0	0	0	0	0	0	0	0
Energy Cost Adjustment	1,155	1,278	1,305	1,290	1,310	1,297	1,295	1,288	1,282
Energy Subsidy Adjustment	35	35	0	35	35	35	35	35	34
Reliability Costs Adjustment	67	73	74	73	74	73	73	73	72
i-Base Revenue	0	0	0	0	101	176	299	402	488
i-ECA Revenue	0	0	0	0	14	94	194	314	406
i-RCA Revenue	0	0	0	0	21	51	82	120	164
Total Retail Revenue ($M)	2,806	2,913	2,960	2,933	3,108	3,262	3,513	3,758	3,966
Wholesale Sales (Gen. & Trans.)	126	84	59	63	53	56	62	62	63
Deferred Revenue	310	135	102	111	(15)	39	(43)	(2)	(43)
Others	(7)	(6)	19	3	(3)	6	4	3	2
Total Operating Revenue ($M)	3,235	3,126	3,141	3,111	3,143	3,363	3,537	3,822	3,988
3. Non-Operating Revenue	131	123	119	109	97	97	100	302	115
4. Total Revenue	3,367	3,249	3,260	3,220	3,239	3,460	3,637	4,123	4,102
5. Fuel, Purchased Power & Emissions Expense	1,310	1,290	1,339	1,354	1,305	1,376	1,423	1,540	1,537
6. O&M Expenditures	965	995	921	926	940	997	1,041	1,073	1,106
7. Depreciation	338	387	429	401	462	493	521	567	628
8. Property Tax	12	12	13	12	14	15	17	18	20
9a. Interest Expense	220	288	281	280	285	328	380	433	475
9b. AFUDC	(8)	(12)	(36)	(31)	(52)	(35)	(48)	(28)	(5)
9c. CIAC	(13)	(28)	(13)	(23)	(15)	(16)	(16)	(17)	(18)
10. Total Expense	2,825	2,932	2,934	2,919	2,940	3,159	3,318	3,587	3,742
11a. Net Income Before City Transfer	542	316	325	301	299	302	319	536	360
11b. City Transfer	220	259	250	250	249	251	269	283	306
11c. Increase in Fund Net Assets	322	58	75	51	51	50	50	253	54
12. Capital Expenditures	747	912	1,261	1,238	1,444	1,650	1,265	1,555	1,467
13a. Borrowing for CapEx	616	900	0	0.0	1,125	1,235	865	773	954
13b. Cash on Hand	424	561	264	322	309	300	300	300	300
13c. Total Debt Service	318	400	348	344	422	467	529	591	643
13d. Total Non-Debt Service Expenditures	3,022	3,181	3,522	3,507	3,689	4,023	3,714	4,154	4,096
14. Financial Ratios:									
Debt Service Coverage, net of BABs Subsidy	2.49	2.13	2.78	2.57	2.60	2.41	2.42	2.33	2.44
Adj. Debt Service Coverage, net of IPA Debt	2.12	1.90	2.24	2.13	2.03	1.91	1.89	1.83	1.84
Full Obligation Coverage, net of IPA Debt	1.63	1.44	1.77	1.65	1.65	1.58	1.58	1.55	1.55
Capitalization Factor	53.6%	56.5%	55.6%	55.7%	59.1%	62.1%	63.8%	64.2%	65.7%
15. Average Rate (cts/kWh)									
Residential	12.3	12.9	13.0	13.0	13.6	14.4	15.5	16.7	17.7
Small Business (A-1)	14.4	15.1	15.1	15.1	15.9	16.8	18.1	19.5	20.6
Med. Business (A-2)	12.8	13.4	13.5	13.5	14.2	15.0	16.2	17.4	18.5
Large Business (A-3)	11.3	12.0	12.0	12.0	12.6	13.4	14.5	15.6	16.5
System Average	12.0	12.6	12.7	12.7	13.31	14.1	15.2	16.4	17.4
Avg. Rate Increase (%)	7.2%	4.9%	0.8%	0.5%	4.9%	6.0%	7.9%	7.5%	6.0%
16a. ECA (Under) Over Collection	(208)	(203)	(205)	(221)	(178)	(166)	(133)	(140)	(107)
16b. RCA (Under) Over Collection	(42)	(91.0)	(95)	(94)	(90)	(80)	(71)	(61)	(52)
17a. PRP Capital Adds/(Cuts)				0	0	0	0	0	0
17b. PRP O&M Adds/(Cuts)				0	0	0	0	0	0
17c. Non-PRP Capital Adds/(Cuts)				0	0	0	0	0	0
17d. Non-PRP O&M Adds/(Cuts)				0	0	0	0	0	0
17e. Pension, COLA, RPS Adj for Capital				0	0	0	0	0	0
17f. Pension, COLA, RPS Adj for O&M				0	0	0	0	0	0
17e. Total Capital Cuts				0	0	0	0	0	0
17f. Total O&M Cuts				0	0	0	0	0	0
18. %CapEx Borrowed				0%	78%	75%	68%	50%	65%
19. City Xfer %				8%	8%	8%	8%	8%	8%

Case P119 -- Case110 with 50% RCA Amortization and Altered EE Ramp in Yr One

LOS ANGELES DEPARTMENT OF WATER AND POWER
Power System Financial Plan Summary
(In Million Dollars)

Fuel Case --> 05/14/12
O&M Case --> 05/16/12

Restructuring Delay -->	3	Months
Base Rate Incr % -->	5.1%	
ECAF Rate Incr % -->	0.6%	
RCAF Rate Incr % -->	1.0%	
	6.6%	

-- Excluding Load Growth Effect --						
Base Rate Actual Adj %	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
ECA Actual Adj %	0.3%	0.3%	0.0%	0.0%	0.0%	0.0%
RCA Actual Adj %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
ESA Actual Adj %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
I-Base Inc %	0.0%	3.4%	2.5%	3.8%	3.0%	2.3%
I-ECA Inc %	0.0%	0.5%	2.6%	3.1%	3.5%	2.5%
I-RCA Inc %	0.0%	0.7%	1.0%	1.0%	1.1%	1.2%
I-Increase %	0.0%	4.88%	6.02%	7.85%	7.53%	6.03%
Base Revenue Inc $M	5	1	0	2	0	-1
ECA Revenue Inc $M	8	8	0	0	0	0
RCA Revenue Inc $M	0	0	0	0	0	0
ESA Revenue Inc $M	0	0	0	0	0	0
I-Base Inc $M	0	101	76	124	105	87
I-ECA Inc $M	0	14	80	100	121	93
I-RCA Inc $M	0	21	30	31	38	45
I-Revenue Inc ($M)	0	136	185	256	263	226
			3-Yr Avg ->	6.3%	5-Yr Avg ->	6.5%

Rate Stabilization Fund:

	Drawdown	Inject	Balance
FY2010/11	$0 M	$0 M	$75 M
FY2011/12	$0 M	$0 M	$75 M
FY2012/13	$13 M	$0 M	$62 M
FY2013/14	$36 M	$0 M	$0 M
FY2014/15	$0 M	$0 M	$26 M
FY2015/16	$0 M	$0 M	$26 M
FY2016/17	$0 M	$0 M	$26 M

	Final	Final	Revised	<====== FORECAST ======>					
FISCAL YEAR ENDING JUNE 30	**2010**	**2011**	**2012**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
1. Retail Sales (GWh)	23,319	23,064	23,344	23,123	23,471	23,600	23,897	24,129	24,381
Adj. For DSM (GWh)	0	0	(73)	0	(100)	(414)	(712)	(1,019)	(1,349)
Adj. For Solar (GWh)	0	0	(15)	0	(23)	(74)	(114)	(152)	(180)
Adj. due to Others (GWh)	0	0	0	0	0	0	0	0	0
Net Retail Sales(GWh)	23,319	23,064	23,256	23,123	23,348	23,113	23,071	22,958	22,852
2. Operating Revenue:									
Base Rate	1,548	1,527	1,582	1,535	1,552	1,536	1,535	1,527	1,519
Base Rate Revenue Increases	0	0	0	0	0	0	0	0	0
Energy Cost Adjustment	1,155	1,278	1,305	1,290	1,310	1,297	1,295	1,288	1,282
Energy Subsidy Adjustment	35	35	0	35	35	35	35	35	34
Reliability Costs Adjustment	67	73	74	73	74	73	73	73	72
i-Base Revenue	0	0	0	0	101	176	299	402	488
i-ECA Revenue	0	0	0	0	14	94	194	314	406
i-RCA Revenue	0	0	0	0	21	51	82	120	164
Total Retail Revenue ($M)	2,806	2,913	2,960	2,933	3,108	3,262	3,513	3,758	3,966
Wholesale Sales (Gen. & Trans.)	126	84	59	63	53	56	62	62	63
Deferred Revenue	310	135	102	111	(15)	39	(43)	(2)	(43)
Others	(7)	(6)	19	3	(3)	6	4	3	2
Total Operating Revenue ($M)	3,235	3,126	3,141	3,111	3,143	3,363	3,537	3,822	3,988
3. Non-Operating Revenue	131	123	119	109	97	97	100	302	115
4. Total Revenue	3,367	3,249	3,260	3,220	3,239	3,460	3,637	4,123	4,102
5. Fuel-Related Expenditures									
5a. Fuel and Purchased Power Expense	1,310	1,290	1,327	1,347	1,300	1,369	1,393	1,511	1,513
5b. Legal Settlement Expense	0	0	0	0	0	0	16	16	16
5c. Legal Expense Allocated to FPP	0	0	3	3	0	0	0	0	0
5c. CO2 Allowance Expenses	0	0	0	0	1	2	7	5	0
5d. Other Emissions Expenses	0	0	9	3	5	5	7	7	8
6. O&M Expenditures									
6a. DSM	45	45	15	18	0	0	0	0	0
6b. Other Infrastructure	279	250	252	251	265	274	289	291	288
6c. Operating Support	229	242	278	281	289	319	327	337	347
6d. PRP	363	393	347	348	357	373	392	411	437
6f. Public Benefits	23	39	5	1	2	2	2	2	2
6g. RPS	26	26	25	26	27	29	31	32	32
6h. PRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0
6i. Non-PRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0
6j. Pension Adj	0	0	0	0	0	0	0	0	0
6k. COLA Adj	0	0	0	0	0	0	0	0	0
6l. RPS Adj	0	0	0	0	0	0	0	0	0
6k. O&M Expenditures Total	965	995	921	926	940	997	1,041	1,073	1,106
7a. Depreciation	338	387	422	393	439	454	468	499	543
7b. Regulatory Asset - Solar SB-1	0	0	3	3	6	10	11	12	12
7c. Regulatory Asset - EE	0	0	4	5	17	29	42	56	72
8. Property Tax	12	12	13	12	14	15	17	18	20
9a. Interest Expense	220	288	281	280	285	328	380	433	475
9b. AFUDC	(8)	(12)	(36)	(31)	(52)	(35)	(48)	(28)	(5)
9c. CIAC	(13)	(28)	(13)	(23)	(15)	(16)	(16)	(17)	(18)
10. Total Expense	2,825	2,932	2,934	2,919	2,940	3,159	3,318	3,587	3,742
11a. Net Income Before City Transfer	542	316	325	301	299	302	319	536	360
11b. City Transfer	220	259	250	250	249	251	269	283	306
11c. Increase in Fund Net Assets	322	58	75	51	51	50	50	253	54
12. Capital Expenditures									
12a. DSM	2	2	55	55	127	138	143	152	180
12b. Gas Drilling	15	60	51	51	20	0	0	0	0
12c. Other Infrastructure	87	88	87	106	195	134	117	123	103
12d. IRP	13	201	407	396	428	402	109	489	22
12e. Operating Support	94	117	114	89	96	77	63	48	50
12f. PRP	446	419	361	360	427	512	539	567	590
12g. Public Benefits	0	0	0	0	0	0	0	0	0
12h. RPS	90	23	186	181	150	388	293	175	522
12i. PRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0
12j. Non-PRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0
12k. Pension Adj	0	0	0	0	0	0	0	0	0
12l. COLA Adj	0	0	0	0	0	0	0	0	0
12l. Net Capital Expenditures Total	747	911	1,261	1,238	1,444	1,650	1,265	1,555	1,467
13a. Borrowing for CapEx	616	900	0	0	1,125	1,235	865	773	954
13b. Cash on Hand	424	561	264	322	309	300	300	300	300
13c. Total Debt Service	318	400	348	344	422	467	529	591	643
13d. Total Non-Debt Service Expenditures	3,022	3,180	3,522	3,507	3,689	4,023	3,714	4,154	4,096
14. Financial Ratios:									
Debt Service Coverage, net of BABs Subsidy	**2.49**	**2.13**	**2.78**	**2.57**	**2.60**	**2.41**	**2.42**	**2.33**	**2.44**
Adj. Debt Service Coverage, net of IPA Debt	2.12	1.90	1.90	2.13	2.03	1.91	1.89	1.83	1.84
Full Obligation Coverage, net of IPA Debt	1.63	1.44	1.77	1.65	1.65	1.58	1.58	1.55	1.55
Capitalization Factor	53.6%	56.5%	55.6%	55.7%	59.1%	62.1%	63.8%	64.2%	65.7%
15. Average Rate (cts/kWh)									
System Average	12.0	12.6	12.7	12.7	13.3	14.1	15.2	16.4	17.4
Avg. Rate Increase (%)	7.2%	4.9%	0.8%	0.5%	4.9%	6.0%	7.9%	7.5%	6.0%
16a. ECA (Under) Over Collection	(208)	(203)	(205)	(221)	(178)	(166)	(133)	(140)	(107)
16b. RCA (Under) Over Collection	(42)	(91)	(95)	(94)	(90)	(80)	(71)	(61)	(52)
16c. Baraket Settlement Balance	160	160	160	160	160	160	144	128	112

Los Angeles Department of Water and Power
Power System Income Statement
($ in millions)

				Actuals thru Mar			FORECAST		
	Final	Final	Revised	2012					
Fiscal Year Ending June 30	**2010**	**2011**	**2012**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Retail Sales (GWh)	23,319	23,064	23,344	23,123	23,471	23,600	23,897	24,129	24,381
Proj. Energy Eff. Prgm (GWh)		0	(73)	0	(100)	(414)	(712)	(1,019)	(1,349)
Solar Roof Top		0	(15)	0	(23)	(74)	(114)	(152)	(180)
Reductions from Weather or Actuals (GWh)		0	0	0	0	0	0	0	0
Net Retail Sales (GWh)	23,319	23,064	23,256	23,123	23,348	23,113	23,071	22,958	22,852
Revenues:									
Residential	914	927	1,105	980	1,151	1,196	1,283	1,370	1,444
Commercial	1,627	1,710	1,572	1,691	1,658	1,752	1,893	2,028	2,141
Industrial	231	244	252	230	266	280	301	322	340
Intra - Department	19	16	16	15	17	18	20	21	23
Street Lighting	17	16	16	17	16	16	16	17	18
Retail Revenue	2,806	2,913	2,960	2,933	3,108	3,262	3,513	3,758	3,966
Wholesale Sales (Generation)	90	33	27	12	21	24	30	30	31
Wholesale Sales (Transmission)	37	51	32	51	32	32	32	32	32
Distribution Other Revenue	20	22	43	27	22	22	22	22	22
Deferred IPP Revenue	97	94	96	96	0	0	0	0	0
Deferred Public Benefit	83	0	0	0	0	0	0	0	0
Deferred Rate Stabilization	(2)	0	0	0	13	36	0	0	0
Deferred SCPPA Credit	0	0	0	0	21	25	0	0	0
ECAF (Over)/Under Collection	94	(5)	2	18	(44)	(11)	(33)	7	(33)
ESA (Over) /Under Collection	0	0	0	0	0	0	0	0	0
RCA (Over)/Under Collection	26	49	4	3	(4.7)	(9.4)	(9.4)	(9.4)	(9.4)
Base Revenue (Over)/Under Collection	0	0	0	0	0	0	0	0	0
Green Power Over/Under Collection	(1)	(1)	0	0	0	0	0	0	0
Change in Accrued Revenue	13	(2)	0	(7)	0	0	0	0	0
Allowance for Bad Debt	(27)	(27)	(24)	(24)	(25)	(16)	(18)	(19)	(20)
Total Operating Revenue	**3,235**	**3,126**	**3,141**	**3,111**	**3,143**	**3,363**	**3,537**	**3,822**	**3,988**
System Average (cents/kWh)	**12.0**	**12.6**	**12.73**	**12.69**	**13.3**	**14.1**	**15.2**	**16.4**	**17.4**
Retail Rate Increase	**7.2%**	**4.9%**	**0.8%**	**0.5%**	**4.9%**	**6.0%**	**7.9%**	**7.5%**	**6.0%**
Fuel Expenses	481	436	389	395	371	369	338	329	318
Purchased Power	829	854	939	952	928	1,000	1,056	1,183	1,195
Securitized Debt Service Expense				0	0	0	0	0	0
Legal Settlement Expense	0	0	0	0	0	0	16	16	16
Legal Expense Allocated to FPP	0	0	3	3	0	0	0	0	0
CO2 Allowance Expense	0	0	0	0	1	2	7	5	0
Other Emissions Expense	0	0	9	3	5	5	7	7	8
O & M Expenses	896.6	922.9	901	907	939	995	1,039	1,071	1,104
Demand Side Management (Exld. PB)	44.7	42.5	15	18	0	0	0	0	0
Public Benefit	24	29	5	1	2	2	2	2	2
Prepaid Public benefit	0	0	0	0	0	0	0	0	0
Depreciation	338	387	422	393	439	454	468	499	543
Regulatory Asset - Solar	0	0	3	3	6	10	11	12	12
Regulatory Asset - EE	0	0	4	5	17	29	42	56	72
Property Taxes	12	12	13	12	14	15	17	18	20
TOTAL OPR EXPENSES	**2,625**	**2,684**	**2,703**	**2,693**	**2,721**	**2,881**	**3,002**	**3,198**	**3,291**
Operating Income	610	442	438	418	421	482	535	623	697
Gain/Loss On Asset Sales	0	0	0	0	0	0	0	202	0
Other Income/Expenses, Net	131	123	119	109	97	97	100	100	115
Income Before LT Debt Expenses	741	565	557	527	518	579	635	925	812
Interest on Fixed Rate Bonds	207	276	279	280	288	329	378	424	459
Interest on Variable Rate Bonds	10	1	7	2	5	6	9	16	22
Amortization of Debt Expenses	3	11	(5)	(2)	(7)	(7)	(7)	(6)	(6)
Total Debt Expenses	220	288	281	280	285	328	380	433	475
AFUDC	(8)	(12)	(36)	(31)	(52)	(35)	(48)	(28)	(5)
Net Debt Expenses	212	276	245	249	233	293	332	406	470
Contributions in Aid of Construction	13	28	13	23	15	16	16	17	18
Change in Fund Net Assets Before Transfer to the City	**542**	**316**	**325**	**301**	**299**	**302**	**319**	**536**	**360**
City Transfer	220	259	250	250	249	251	269	283	306
Extraordinary loss									
Increase in Fund Net Assets	**322**	**58**	**75**	**51**	**51**	**50**	**50**	**253**	**54**
Addtn'l Bond Test Ratio: (prev / max)	2.07	2.59	2.24	2.33	1.99	1.82	1.76	1.75	2.03
Financial Ratio (Current/Current)									
Debt Service Coverage, net of BABs Subsid	**2.49**	**2.13**	**2.78**	**2.57**	**2.60**	**2.41**	**2.42**	**2.33**	**2.44**
Adj. Debt Service Coverage, netting IPA Deb	2.12	1.90	2.24	2.13	2.03	1.91	1.89	1.83	1.84
Full Obligation Coverage, netting IPA Debt	1.63	1.44	1.77	1.65	1.65	1.58	1.58	1.55	1.55
Capitalization Ratio	53.6%	56.5%	55.6%	55.7%	59.1%	62.1%	63.8%	64.2%	65.7%
Interest Coverage	3.60	2.98	3.16	2.95	3.56	3.21	3.19	3.02	3.15

Los Angeles Department of Water and Power
Power System Balance Sheet
($ in millions)

Case P119	Final	Final			Forecast			
FY ENDING JUNE 30	2010	2011	2012	2013	2014	2015	2016	2017
Plant in Service	11,987	12,531	12,504	13,147	14,520	15,211	17,360	18,048
Nuclear Fuel - Net	44	44	43	45	47	48	47	47
Natural Gas Field	231	257	283	270	244	222	203	185
C W I P	431	685	1,752	2,333	2,383	2,779	1,958	2,486
Gross Plant	12,694	13,518	14,583	15,795	17,193	18,260	19,568	20,766
Accum. Depreciation	5,715	6,087	6,427	6,808	7,205	7,616	8,058	8,545
Net Plant	6,979	7,431	8,156	8,986	9,988	10,644	11,509	12,221
Restricted and Other Investment:								
Nuclear Decommissioning Fund	118	120	122	125	128	132	136	140
Debt Reduction Trust Funds	529	486	489	491	494	498	500	501
Sinking Funds for CREBs	0	0	0	0	0	0	0	5
RPS/EE Trust Fund	0	0	0	0	0	0	0	0
Post Retiree Benefit Fund	0	0	0	0	0	0	0	0
Natural Gas Hedging Trust Fund	3	0	0	0	0	0	0	0
DTSC	2	2	2	2	2	2	2	2
Other Investment	30	26	23	19	15	11	6	(0)
Total Restricted and Othr Invs.	683	634	637	638	640	643	645	647
Current Assets								
Construction Fund	360	553	27	0	0	0	0	0
Revenue Fund	424	561	322	309	300	300	300	300
Bond R&I Fund	232	195	269	283	318	348	372	409
Insurance Funds	108	114	124	134	144	154	164	174
Account Receivable	435	446	451	479	497	535	567	601
Accrued Revenue	159	156	156	156	156	156	156	156
Material & Supplies	150	146	147	148	149	150	151	152
Fuel Inventory	8	9	9	9	9	9	9	9
Other Prepayments and assets	68	138	46	46	46	46	46	46
Bond Issue Costs	26	31	29	38	48	54	59	65
Total Current Assets	1,970	2,349	1,579	1,601	1,666	1,752	1,824	1,912
Receivable from ISO	0	0	0	0	0	0	0	0
Regulatory Asset - Barakat Settement	160	160	160	160	160	144	128	112
Regulatory Asset - Solar Incentives	0	0	60	118	173	184	192	194
Regulatory Asset - DSM	0	0	50	161	269	371	467	574
Post Retirement Healthcare Assets	533	591	650	658	665	670	674	676
Pension Assets	53	14	11	8	6	3	0	(2)
Long - Term Notes Receivable	1,057	955	850	788	714	644	555	540
Prepaid Public Benefit	0	0	0	0	0	0	0	0
Total Assets	11,435	12,134	12,153	13,119	14,280	15,054	15,993	16,874
Retained Earnings	4,358	4,387	4,415	4,451	4,485	4,519	4,756	4,792
Acc. CIAC	521	549	572	587	603	619	635	654
Equity	4,879	4,937	4,987	5,038	5,088	5,138	5,391	5,445
Bonds & Notes	5,751	6,477	6,406	7,397	8,491	9,204	9,817	10,609
LT Debt Due in 1 Yr	123	62	129	132	142	151	153	170
Non - Current Debt	5,628	6,415	6,277	7,266	8,349	9,053	9,665	10,440
Current Liabilities								
LT Debt Due in 1 Yr	123	62	129	132	142	151	153	170
Revenue Certificates	200	200	200	200	200	200	200	200
Accrued interest	102	130	140	151	175	197	220	239
Accounts Payable	246	267	416	321	357	301	354	341
Payable to City's Reserve Fund	0	0	0	0	0	0	0	0
Payable to Water System	0	0	10	10	10	18	18	18
Accrued Payroll & Others	92	97	85	85	85	85	85	85
Potential Refund	0	0	0	0	0	0	0	0
Total Current Liabilites	763	756	981	898	970	952	1,029	1,053
Long -term accrued liabilities	12	10	9	7	5	4	2	0
Deferred RPS/EE Trust Fund	0	0	0	0	0	0	0	0
Deferred Public Benefit	0	0	0	0	0	0	0	0
ECAF Over (Under) Collection	(208)	(203)	(221)	(178)	(166)	(133)	(140)	(107)
ESA Over (Under) Collection	0	0	0	0	0	0	0	0
RCA Over (Under) Collection	(42)	(91)	(94)	(90)	(80)	(71)	(61)	(52)
Base Revenue Over (Under) Collection	0	0	0	0	0	0	0	0
Deferred Rate Stabilization	75	75	75	62	26	26	26	26
Green Power Over (Under) Collection	2	3	5	5	5	5	5	5
Deferred Revenue - Others	0	0	0	0	0	0	0	0
Workers Comp Liability	41	40	41	41	42	42	42	43
Discount on Notes	50	52	50	45	42	38	35	21
Deferred Credit (SCPPA)	45	45	45	25	0	0	0	0
Deferred IPP Credit	189	96	0	0	0	0	0	0
Total Liabilities and Equity	11,435	12,134	12,153	13,119	14,280	15,054	15,993	16,874

Los Angeles Department of Water and Power
Power System Financial Ratios
($ in millions)

FY ENDING JUNE 30	Final 2010	Final 2011	Actuals thru Mar 2012	2013	2014	Forecast 2015	2016	2017
Debt Service Coverage (Current / Current)								
Revenue:								
Operating Revenue Prior to Adjustment	3,235	3,126	3,111	3,143	3,363	3,537	3,822	3,988
Deferred Revenue Adjustment:								
Deferred - IPP Revenue	97	94	96	0	0	0	0	0
Deferred - Public Benefit	83	0	0	0	0	0	0	0
Deferred - Rate Stabilization	-2	0	0	13	36	0	0	0
Deferred - Energy Cost Adjustment	94	-5	18	-44	-11	-33	7	-33
Deferred - Energy Subsidy Adjustment	0	0	0	0	0	0	0	0
Deferred - Reliability Cost Adjustment	26	49	3	-5	-9	-9	-9	-9
Deferred - Base Revenue	0	0	0	0	0	0	0	0
Deferred - Green Power	-1	-1	0	0	0	0	0	0
Total Deferred Revenue	297	137	117	-36	15	-43	-2	-43
Operating Revenue after Adjustment	2,938	2,989	2,993	3,178	3,348	3,579	3,824	4,031
less Deferred Base Revenue Adjustment	0	0	0	0	0	0	0	0
Non-Operating Revenue	131	123	109	97	97	100	100	115
Total Cash Revenue	3,070	3,112	3,103	3,275	3,446	3,680	3,924	4,145
Expense:								
Fuel and Purchased Power	1,304	1,275	1,322	1,267	1,345	1,372	1,492	1,495
Securitized Debt Service Expense	0	0	0	0	0	0	0	0
Legal Expense Allocated to FPP	0	0	3	0	0	0	0	0
CO2 Allowance Expense	0	0	0	1	2	7	5	0
Other Emissions Expense	0	0	3	5	5	7	7	8
O&M, DSM, PB Expenses	965	995	926	940	997	1,041	1,073	1,106
Property Taxes	12	12	12	14	15	17	18	20
Total Expenses	2,281	2,282	2,267	2,227	2,365	2,444	2,596	2,629
Adjustment for Non-Cash Expense:								
Adjustment for Pension GASB 27	4	4	3	3	3	3	3	3
Adjustment for Healthcare GASB 45	-8	-8	-8	-8	-7	-6	-4	-2
Cash Balance Avail for DS include BABs Subsidy Payment	784	825	831	1,043	1,077	1,233	1,327	1,517
Cash Balance Avail for DS exclude BABs Subsidy Payment	784	801	796	1,008	1,042	1,198	1,292	1,482
Revenue Balance Avail for DS include BABs Subsidy	1,085	967	953	1,012	1,095	1,193	1,326	1,474
Revenue Balance Avail for DS exclude of BABs Subsidy	1,085	943	919	977	1,060	1,158	1,291	1,438
LTD-DUE1								
Interest on Fixed Rate Debt	207	276	280	288	329	378	424	459
Interest on Variable Rate Debt	10	1	2	5	6	9	16	22
Principal Maturities	97	123	62	129	132	142	151	153
Sinking Fund Payment for CREBs	0	0	0	0	0	0	0	10
Gross Debt Service	315	400	344	422	467	529	591	643
Net Debt Service (net of BABs Subsidy)	315	376	309	387	432	494	555	608
BABs Subsidy	0	-24	-35	-35	-35	-35	-35	-35
Max Debt Service	425	425	425	489	562	617	666	725
Balance Avail for DS include BABs Subsidy Payment	784	825	831	1,043	1,077	1,233	1,327	1,517
Gross Debt Service	315	400	344	422	467	529	591	643
Debt Service Coverage (Balance Avail for DS include BABs Subsidy / Gross Debt Service)	**2.49**	**2.06**	**2.42**	**2.47**	**2.31**	**2.33**	**2.25**	**2.36**
Balance Avail for DS exclude BABs Subsidy Payment	784	801	796	1,008	1,042	1,198	1,292	1,482
Net Debt Service (net of BABs Subsidy)	315	376	309	387	432	494	555	608
Debt Service Coverage (Balance Avail for DS exclude BABs Subsidy Payment / Net Debt Service)	**2.49**	**2.13**	**2.57**	**2.60**	**2.41**	**2.42**	**2.33**	**2.44**
City Transfer	220	259	250	249	251	269	283	306
D/S Ratio after City Transfer	**1.79**	**1.42**	**1.69**	**1.88**	**1.77**	**1.82**	**1.77**	**1.88**
Additional Bond Test Ratio (Prev / Max) -- Must Exceed 1.25								
Net Income	542	316	301	299	302	319	536	360
LT Debt Expense	220	288	280	285	328	380	433	475

Los Angeles Department of Water and Power
Power System Financial Ratios
($ in millions)

	Final	Final	Actuals thru Mar 2012			Forecast		
FY ENDING JUNE 30	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Depreciation	338	387	393	439	454	468	499	543
Adj Net Income	1,100	992	973	1,024	1,084	1,167	1,469	1,379
Max Debt Service	425	425	425	489	562	617	666	725
Additional Bond Test Ratio (Previous Period Adj. Net Income / Max Debt Service)	**2.07**	**2.59**	**2.33**	**1.99**	**1.82**	**1.76**	**1.75**	**2.03**
Capitalization Ratio -- Must Not Exceed 60%								
Long-Term Debt	5,628	6,415	6,277	7,266	8,349	9,053	9,665	10,440
Equity	4,879	4,937	4,987	5,038	5,088	5,138	5,391	5,445
Long-Term Debt + Equity	10,507	11,351	11,264	12,304	13,437	14,191	15,055	15,885
Capitalization Ratio (LT Debt / (LT Debt + Equity))	**53.6%**	**56.5%**	**55.7%**	**59.1%**	**62.1%**	**63.8%**	**64.2%**	**65.7%**
Other Ratios								
Interest Coverage	**3.60**	**2.98**	**2.95**	**3.56**	**3.21**	**3.19**	**3.02**	**3.15**
Fixed Charge or Off-Balance Sheet Debt Svc($M)	2010	2011	2012	2013	2014	2015	2016	2017
Conventional								
IGS (IPA) - Issued	151.4	198.7	187.6	171.8	196.4	186.2	209.7	121.4
NTS (IPA) - Issued	2.7	4.4	5.0	5.6	6.4	6.1	6.9	4.0
STS (SCPPA) - Issued	40.0	43.6	44.0	53.6	48.5	48.7	48.8	47.6
Mead-Adelanto (SCPPA) - Issued	8.4	8.2	8.2	8.2	8.1	8.1	7.7	7.7
Mead-Phoenix (SCPPA) - Issued	2.0	2.0	2.0	2.0	1.7	1.7	1.6	1.6
STS Upgrade (SCPPA) - Issued	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
PV (SCPPA) - Issued	8.7	8.7	8.7	8.7	8.6	8.6	8.6	8.6
Asset or Prepay RPS								
Linden (SCPPA) - $135M - Issued	0.0	4.1	7.6	8.3	8.3	8.2	8.2	8.2
Milford I (SCPPA) - $219M - Issued	4.1	10.4	17.2	17.2	17.2	17.1	17.1	17.0
Windy Point (SCPPA) - $512M - Issued	0.0	19.7	37.5	40.6	40.5	40.3	40.3	40.1
Milford II (SCPPA) - $155M Prepay - Pending	0.0	0.0	6.2	11.1	11.7	11.7	11.7	11.6
Future IRP's RPS								
Future IRP and RPS Debt Issuance ($M)		0.0	0.0	11.7	45.2	99.9	157.2	193.0
Total Off-Balance Sheet Debt Service ($M)	221.8	304.1	328.4	343.0	397.1	441.0	522.2	465.3
IPA Subordinated Notes ($M)								
IPA Notes - Interest Payment	57.4	57.4	46.1	38.9	37.9	36.2	31.1	29.2
IPA Notes - Principal Maturities	32.9	82.3	104.1	62.1	74.8	69.4	88.9	15.6
Total Income from IPA Notes	90.3	139.7	150.3	101.0	112.7	105.6	120.0	44.8
Net Off-Balance Sheet Debt Service ($M)	**131.5**	**164.4**	**178.1**	**242.1**	**284.3**	**335.4**	**402.2**	**420.5**
Adjusted Debt Service Ratio								
Adj. Funds Available for Debt Service	1,005	1,130	1,159	1,386	1,474	1,674	1,849	1,982
On-Balance Sheet Debt Service	315	400	344	422	467	529	591	643
Off-Balance Sheet Debt Service	222	304	328	343	397	441	522	465
Adjusted Debt Service Ratio	**1.87**	**1.60**	**1.72**	**1.81**	**1.71**	**1.73**	**1.66**	**1.79**
Full Obligation Coverage Ratio								
City Transfer	220	259	250	249	251	269	283	306
Full Obligation Ratio	**1.46**	**1.24**	**1.35**	**1.49**	**1.42**	**1.45**	**1.41**	**1.51**
Adjusted Debt Service Ratio (Netting IPA Debt)								
Adj. Funds Available for Debt Service	1,005	1,130	1,159	1,386	1,474	1,674	1,849	1,982
IPA Notes - Interest Payment	(57)	(57)	(46)	(39)	(38)	(36)	(31)	(29)
Adj. Funds Available for Debt Service (Alt)	948	1,072	1,113	1,347	1,436	1,638	1,818	1,953
On-Balance Sheet Debt Service	315	400	344	422	467	529	591	643
Off-Balance Sheet Debt Service (Alt)	132	164	178	242	284	335	402	420
Adjusted Debt Service Ratio (Alt)	**2.12**	**1.90**	**2.13**	**2.03**	**1.91**	**1.89**	**1.83**	**1.84**
Full Obligation Coverage Ratio (Alternate Method)								
City Transfer	220	259	250	249	251	269	283	306
Full Obligation Ratio	**1.63**	**1.44**	**1.65**	**1.65**	**1.58**	**1.58**	**1.55**	**1.55**

Natural Gas Pricing Us[illegible] in Final FY2013 Budget

Rockies

4/24/2012	FY10-11	FY11-12	FY12-13	FY13-14	FY14-15	FY15-16	FY16-17	FY17-18	FY18-19	FY19-20	FY20-21
Jul	$4.08	$3.95	$2.03	$3.09	$3.15	$3.36	$3.54	$3.71	$3.89	$4.07	$4.28
Aug	$3.78	$4.06	$2.12	$3.12	$3.17	$3.38	$3.56	$3.74	$3.92	$4.11	$4.31
Sep	$2.69	$3.70	$2.11	$3.13	$3.18	$3.39	$3.58	$3.75	$3.93	$4.12	$4.33
Oct	$3.40	$3.59	$2.21	$3.14	$3.19	$3.40	$3.58	$3.76	$3.94	$4.13	$4.34
Nov	$2.92	$3.44	$2.52	$3.30	$3.27	$3.47	$3.65	$3.83	$4.01	$4.21	$4.43
Dec	$4.00	$3.38	$2.90	$3.58	$3.51	$3.71	$3.90	$4.08	$4.27	$4.48	$4.71
Jan	$3.82	$3.08	$3.03	$3.70	$3.63	$3.83	$4.02	$4.20	$4.40	$4.62	$4.86
Feb	$4.08	$2.54	$3.05	$3.66	$3.58	$3.78	$3.97	$4.15	$4.35	$4.56	$4.80
Mar	$3.61	$2.40	$3.02	$3.57	$3.47	$3.67	$3.86	$4.04	$4.24	$4.45	$4.68
Apr	$3.97	$1.90	$2.95	$3.42	$3.29	$3.47	$3.65	$3.82	$4.01	$4.21	$4.42
May	$3.99	$1.79	$2.97	$3.42	$3.29	$3.48	$3.65	$3.82	$4.01	$4.21	$4.42
Jun	$3.98	$1.87	$3.03	$3.46	$3.32	$3.51	$3.68	$3.85	$4.04	$4.24	$4.45
Average	$3.69	$2.98	$2.66	$3.38	$3.34	$3.54	$3.72	$3.90	$4.08	$4.29	$4.50

SoCal Border

4/24/2012	FY10-11	FY11-12	FY12-13	FY13-14	FY14-15	FY15-16	FY16-17	FY17-18	FY18-19	FY19-20	FY20-21
Jul	$4.54	$4.48	$2.33	$3.32	$3.51	$3.74	$3.94	$4.14	$4.33	$4.54	$4.76
Aug	$4.34	$4.48	$2.48	$3.40	$3.51	$3.74	$3.94	$4.14	$4.33	$4.54	$4.76
Sep	$3.48	$4.05	$2.44	$3.40	$3.38	$3.60	$3.80	$3.99	$4.18	$4.38	$4.60
Oct	$3.80	$3.92	$2.44	$3.40	$3.36	$3.57	$3.77	$3.95	$4.14	$4.34	$4.56
Nov	$3.12	$3.56	$2.72	$3.53	$3.51	$3.72	$3.92	$4.11	$4.31	$4.52	$4.75
Dec	$4.31	$3.60	$3.11	$3.81	$3.72	$3.93	$4.13	$4.32	$4.53	$4.75	$4.99
Jan	$4.06	$3.40	$3.19	$3.83	$3.78	$3.99	$4.19	$4.38	$4.59	$4.81	$5.06
Feb	$4.23	$2.89	$3.22	$3.82	$3.76	$3.97	$4.17	$4.36	$4.57	$4.80	$5.04
Mar	$3.81	$2.58	$3.19	$3.77	$3.68	$3.89	$4.09	$4.28	$4.49	$4.72	$4.96
Apr	$4.23	$2.36	$3.16	$3.58	$3.48	$3.67	$3.86	$4.04	$4.24	$4.45	$4.67
May	$4.30	$2.12	$3.20	$3.63	$3.49	$3.69	$3.87	$4.06	$4.26	$4.47	$4.69
Jun	$4.28	$2.14	$3.26	$3.67	$3.52	$3.72	$3.90	$4.08	$4.28	$4.49	$4.71
Average	$4.04	$3.30	$2.90	$3.60	$3.56	$3.77	$3.97	$4.15	$4.35	$4.57	$4.80

Burnertip Price

4/24/2012	FY10-11	FY11-12	FY12-13	FY13-14	FY14-15*	FY15-16	FY16-17	FY17-18	FY18-19	FY19-20	FY20-21
Jul	$4.93	$4.84	$2.70	$3.69	$3.88	$4.11	$4.31	$4.51	$4.70	$4.91	$5.13
Aug	$4.73	$4.84	$2.85	$3.77	$3.88	$4.11	$4.31	$4.51	$4.70	$4.91	$5.13
Sep	$3.87	$4.41	$2.81	$3.77	$3.75	$3.97	$4.17	$4.36	$4.55	$4.75	$4.97
Oct	$4.19	$4.28	$2.81	$3.77	$3.73	$3.94	$4.14	$4.32	$4.51	$4.71	$4.93
Nov	$3.51	$3.92	$3.09	$3.90	$3.88	$4.09	$4.29	$4.48	$4.68	$4.89	$5.12
Dec	$4.70	$3.96	$3.48	$4.18	$4.09	$4.30	$4.50	$4.69	$4.90	$5.12	$5.36
Jan	$4.42	$3.76	$3.56	$4.20	$4.15	$4.36	$4.56	$4.75	$4.96	$5.18	$5.43
Feb	$4.59	$3.25	$3.59	$4.19	$4.13	$4.34	$4.54	$4.73	$4.94	$5.17	$5.41
Mar	$4.17	$2.94	$3.56	$4.14	$4.05	$4.26	$4.46	$4.65	$4.86	$5.09	$5.33
Apr	$4.59	$2.72	$3.53	$3.95	$3.85	$4.04	$4.23	$4.41	$4.61	$4.82	$5.04
May	$4.66	$2.48	$3.57	$4.00	$3.86	$4.06	$4.24	$4.43	$4.63	$4.84	$5.06
Jun	$4.64	$2.50	$3.63	$4.04	$3.89	$4.09	$4.27	$4.45	$4.65	$4.86	$5.08
Average	$4.42	$3.66	$3.27	$3.97	$3.93	$4.14	$4.34	$4.52	$4.72	$4.94	$5.17

* Starting FY14-15, the gas price is adjusted 10% lower than the market price on 4/24/12. This is due to the belief that the current forward contract contains risk premiums that are not warranted. The current oversupply of natural gas due to fracking w

Case P119 -- Case110 with 50% RCA Amortization and Altered EE Ramp in Yr One

Fuel Case --> 05/14/12
O&M Case --> 05/16/12

Final FY2013 Budget	I-TEF/REF/EEF	Navajo Sold in 2016@225M	Board Metrics; No Downgrade	Base Renevue As a Passthru
	BR #19 (Case19)	Solar Incentives Capitalized	GASB45 overpmt = $75M	I-RCA Effective
Non-PRP O&M Cuts #19 (Case1	IBF1#1 (Not Used)		Pension for 9185 Heads	RCA UC As Selected
Low CO2 Price	Cap @0.6/0/0	Pinedale Gas Not Sold	Bond Refund #1 (Uniform Savir	No COLA Adjustment
EE at Altered Ramp for Yr 1	TEF Transition Cap = 0.1c	Landfill Gas REC as REF		CRPSEA Balance Carried
Solar SB-1 Final 2013	REF = 0.15 cts	RCA Balance Amortized & Zeroe	DRTF = $500M	CIRCA UnCapped; CRPSEA Capp
ICityXfer = Yes	ESA split from Base Rate	Old UC Payable in 10 Yrs	Minimum Cash = $300M	IRCAF Calculated
No Trust Fund Collection	ESAF frozen at 0.147 cts	Legacy U/C in VarECAF/TEF	City Xfer - 8%	RCA Amortization is 50% in 201
Case's Default CapEx & O&M	IECAF as 3 Factors	FPP Method 2 - FPP do not dec	Cash DSR	
Restructuring on 10/1/12	UC Multiplier = 1.0	No Delay in U/C	Normal Retail Load	

	FY2013	FY2015	
I-RCAF Annual Cap -->	5.000	5.000	cts/kWh
I-RCAF Lifetime Cap -->	5.00		cts/kWh
Restructuring Delay -->		3	Months
Base Rate Incr % -->		5.1%	
ECA Rate Incr % -->		0.6%	
RCA Rate Incr % -->		1.0%	
		6.64%	

Base Rate Actual Adj %	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
ECA Actual Adj %	0.3%	0.3%	0.0%	0.0%	0.0%	0.0%
RCA Actual Adj %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
ESA Actual Adj %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
I-Base Inc %	0.0%	3.4%	2.5%	3.8%	3.0%	2.3%
I-ECA Inc %	0.0%	0.5%	2.6%	3.1%	3.5%	2.5%
I-RCA Inc %	0.0%	0.7%	1.0%	1.0%	1.1%	1.2%
I-Increase %	0.0%	4.88%	6.02%	7.85%	7.53%	6.03%
Base Revenue Adj $M	5	1	0	2	0	-1
ECA Revenue Adj $M	8	8	0	0	0	0
RCA Revenue Adj $M	0	0	0	0	0	0
ESA Revenue Inc $M	0	0	0	0	0	0
I-Base Inc $M	0	101	76	124	105	87
I-ECA Inc $M	0	14	80	100	121	93
I-RCA Inc $M	0	21	30	31	38	45
Revenue Inc ($M)	0	145	185	256	263	226
			153 3-Yr Avg ->	6.25%	5-Yr Avg ->	6.46%

Rate Stabilization Fund:

	Drawdown	Inject	Balance
FY2010/11	$0 M	$0 M	$75 M
FY2011/12	$0 M	$0 M	$75 M
FY2012/13	$13 M	$0 M	$62 M
FY2013/14	$36 M	$0 M	$26 M
FY2014/15	$0 M	$0 M	$26 M
FY2015/16	$0 M	$0 M	$26 M
FY2016/17	$0 M	$0 M	$26 M

	Final	Final	Revised	Actuals thru Mar 2012	<====== FORECAST ======>				
FISCAL YEAR ENDING JUNE 30	2010	2011	2012	2012	2013	2014	2015	2016	2017
1. Retail Sales (GWh)	23,319	23,064	23,344	23,123	23,471	23,600	23,897	24,129	24,381
Adj. For DSM (GWh)	0	0	(73)	0	(100)	(414)	(712)	(1,019)	(1,349)
Adj. For Solar (GWh)	0	0	(15)	0	(23)	(74)	(114)	(152)	(180)
Adj. due to Others (GWh)	0	0	0	0	0	0	0	0	0
Net Retail Sales(GWh)	23,319	23,064	23,256	23,123	23,348	23,113	23,071	22,958	22,852
2. Operating Revenue:									
Base Rate	1,548	1,527	1,582	1,535	1,552	1,536	1,535	1,527	1,519
Base Rate Revenue Increases	0	0	0	0	0	0	0	0	0
Energy Cost Adjustment	1,155	1,278	1,305	1,290	1,310	1,297	1,295	1,288	1,282
Energy Subsidy Adjustment	35	35	0	35	35	35	35	35	34
Reliability Costs Adjustment	67	73	74	73	74	73	73	73	72
i-Base Revenue	0	0	0	0	101	176	299	402	488
i-ECA Revenue	0	0	0	0	14	94	194	314	406
i-RCA Revenue	0	0	0	0	21	51	82	120	164
Total Retail Revenue ($M)	2,806	2,913	2,960	2,933	3,108	3,262	3,513	3,758	3,966
Wholesale Sales (Gen. & Trans.)	126	84	59	63	53	56	62	62	63
Deferred Revenue	310	135	102	111	(15)	39	(43)	(2)	(43)
Others	(7)	(6)	19	3	(3)	6	4	3	2
Total Operating Revenue ($M)	3,235	3,126	3,141	3,111	3,143	3,363	3,537	3,822	3,988
3. Non-Operating Revenue	131	123	119	109	97	97	100	302	115
4. Total Revenue	3,367	3,249	3,260	3,220	3,239	3,460	3,637	4,123	4,102
5. Fuel, Purchased Power & Emissions Expense	1,310	1,290	1,339	1,354	1,305	1,376	1,423	1,540	1,537
6. O&M Expenditures	965	995	921	926	940	997	1,041	1,073	1,106
7. Depreciation	338	387	429	401	462	493	521	567	628
8. Property Tax	12	12	13	12	14	15	17	18	20
9a. Interest Expense	220	288	281	280	285	328	380	433	475
9b. AFUDC	(8)	(12)	(36)	(31)	(52)	(35)	(48)	(28)	(5)
9c. CIAC	(13)	(28)	(13)	(23)	(15)	(16)	(16)	(17)	(18)
10. Total Expense	2,825	2,932	2,934	2,919	2,940	3,159	3,318	3,587	3,742
11a. Net Income Before City Transfer	542	316	325	301	299	302	319	536	360
11b. City Transfer	220	259	250	250	249	251	269	283	306
11c. Increase in Fund Net Assets	322	58	75	51	51	50	50	253	54
12. Capital Expenditures	747	912	1,261	1,238	1,444	1,650	1,265	1,555	1,467
13a. Borrowing for CapEx	616	900	0	0.0	1,125	1,235	865	773	954
13b. Cash on Hand	424	561	264	322	309	300	300	300	300
13c. Total Debt Service	318	400	348	344	422	467	529	591	643
13d. Total Non-Debt Service Expenditures	3,022	3,181	3,522	3,507	3,689	4,023	3,714	4,154	4,096
14. Financial Ratios:									
Debt Service Coverage, net of BABs Subsidy	**2.49**	**2.13**	**2.78**	**2.57**	**2.60**	**2.41**	**2.42**	**2.33**	**2.44**
Adj. Debt Service Coverage, net of IPA Debt	2.12	1.90	2.24	2.13	2.03	1.91	1.89	1.83	1.84
Full Obligation Coverage, net of IPA Debt	1.63	1.44	1.77	1.65	1.65	1.58	1.58	1.55	1.55
Capitalization Factor	53.6%	56.5%	55.6%	55.7%	59.1%	62.1%	63.8%	64.2%	65.7%
15. Average Rate (cts/kWh)									
Residential	12.3	12.9	13.0	13.0	13.6	14.4	15.5	16.7	17.7
Small Business (A-1)	14.4	15.1	15.1	15.1	15.9	16.8	18.1	19.5	20.6
Med. Business (A-2)	12.8	13.4	13.5	13.5	14.2	15.0	16.2	17.4	18.5
Large Business (A-3)	11.3	12.0	12.0	12.0	12.6	13.4	14.5	15.6	16.5
System Average	12.0	12.6	12.7	12.7	13.31	14.1	15.2	16.4	17.4
Avg. Rate Increase (%)	7.2%	4.9%	0.8%	0.5%	4.9%	6.0%	7.9%	7.5%	6.0%
16a. ECA (Under) Over Collection	(208)	(203)	(205)	(221)	(178)	(166)	(133)	(140)	(107)
16b. RCA (Under) Over Collection	(42)	(91.0)	(95)	(94)	(90)	(80)	(71)	(61)	(52)
17a. PRP Capital Adds/(Cuts)				0	0	0	0	0	0
17b. PRP O&M Adds/(Cuts)				0	0	0	0	0	0
17c. Non-PRP Capital Adds/(Cuts)				0	0	0	0	0	0
17d. Non-PRP O&M Adds/(Cuts)				0	0	0	0	0	0
17e. Pension, COLA, RPS Adj for Capital				0	0	0	0	0	0
17f. Pension, COLA, RPS Adj for O&M				0	0	0	0	0	0
17e. Total Capital Cuts				0	0	0	0	0	0
17f. Total O&M Cuts				0	0	0	0	0	0
18. %CapEx Borrowed				0%	78%	75%	68%	50%	65%
19. City Xfer %				8%	8%	8%	8%	8%	8%

Case P119 -- Case110 with 50% RCA Amortization and Altered EE Ramp in Yr One

LOS ANGELES DEPARTMENT OF WATER AND POW
Power System Financial Plan Summary
(In Million Dollars)

Fuel Case -->	05/14/12
O&M Case -->	05/16/12

Restructuring Delay -->	3	Months
Base Rate Incr % -->	5.1%	
ECAF Rate Incr % -->	0.6%	
RCAF Rate Incr % -->	1.0%	
	6.6%	

-- Excluding Load Growth Effect --						
Base Rate Actual Adj %	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
ECA Actual Adj %	0.3%	0.3%	0.0%	0.0%	0.0%	0.0%
RCA Actual Adj %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
ESA Actual Adj %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
i-Base Inc %	0.0%	3.4%	2.5%	3.8%	3.0%	2.3%
i-ECA Inc %	0.0%	0.5%	2.6%	3.1%	3.5%	2.5%
i-RCA Inc %	0.0%	0.7%	1.0%	1.0%	1.1%	1.2%
i-Increase %	0.0%	4.88%	6.02%	7.85%	7.53%	6.03%
Base Revenue Inc $M	5	1	0	2	0	-1
ECA Revenue Inc $M	8	8	0	0	0	0
RCA Revenue Inc $M	0	0	0	0	0	0
ESA Revenue Inc $M	0	0	0	0	0	0
i-Base Inc $M	0	101	76	124	105	87
i-ECA Inc $M	0	14	80	100	121	93
i-RCA Inc $M	0	21	30	31	38	45
i-Revenue Inc ($M)	0	136	185	256	263	226
			3-Yr Avg ->	6.3%	5-Yr Avg ->	6.5%

Rate Stabilization Fund:

	Drawdown	Inject	Balance
FY2010/11	$0 M	$0 M	$75 M
FY2011/12	$0 M	$0 M	$75 M
FY2012/13	$13 M	$0 M	$62 M
FY2013/14	$36 M	$0 M	$0 M
FY2014/15	$0 M	$0 M	$26 M
FY2015/16	$0 M	$0 M	$26 M
FY2016/17	$0 M	$0 M	$26 M

	Final	Final	Revised	<====== FORECAST ======>					
FISCAL YEAR ENDING JUNE 30	**2010**	**2011**	**2012**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
1. Retail Sales (GWh)	23,319	23,064	23,344	23,123	23,471	23,600	23,897	24,129	24,381
Adj. For DSM (GWh)	0	0	(73)	0	(100)	(414)	(712)	(1,019)	(1,349)
Adj. For Solar (GWh)	0	0	(15)	0	(23)	(74)	(114)	(152)	(180)
Adj. due to Others (GWh)	0	0	0	0	0	0	0	0	0
Net Retail Sales(GWh)	23,319	23,064	23,256	23,123	23,348	23,113	23,071	22,958	22,852
2. Operating Revenue:									
Base Rate	1,548	1,527	1,582	1,535	1,552	1,536	1,535	1,527	1,519
Base Rate Revenue Increases	0	0	0	0	0	0	0	0	0
Energy Cost Adjustment	1,155	1,278	1,305	1,290	1,310	1,297	1,295	1,288	1,282
Energy Subsidy Adjustment	35	35	0	35	35	35	35	35	34
Reliability Costs Adjustment	67	73	74	73	74	73	73	73	72
i-Base Revenue	0	0	0	0	101	176	299	402	488
i-ECA Revenue	0	0	0	0	14	94	194	314	406
i-RCA Revenue	0	0	0	0	21	51	82	120	164
Total Retail Revenue ($M)	2,806	2,913	2,960	2,933	3,108	3,262	3,513	3,758	3,966
Wholesale Sales (Gen. & Trans.)	126	84	59	63	53	56	62	62	63
Deferred Revenue	310	135	102	111	(15)	39	(43)	(2)	(43)
Others	(7)	(6)	19	3	(3)	6	4	3	2
Total Operating Revenue ($M)	3,235	3,126	3,141	3,111	3,143	3,363	3,537	3,822	3,988
3. Non-Operating Revenue	131	123	119	109	97	97	100	302	115
4. Total Revenue	3,367	3,249	3,260	3,220	3,239	3,460	3,637	4,123	4,102
5. Fuel-Related Expenditures									
5a. Fuel and Purchased Power Expense	1,310	1,290	1,327	1,347	1,300	1,369	1,393	1,511	1,513
5b. Legal Settlement Expense	0	0	0	0	0	0	16	16	16
5c. Legal Expense Allocated to FPP	0	0	3	3	0	0	0	0	0
5c. CO2 Allowance Expenses	0	0	0	0	1	2	7	5	0
5d. Other Emissions Expenses	0	0	9	3	5	5	7	7	8
6. O&M Expenditures									
6a. DSM	45	45	15	18	0	0	0	0	0
6b. Other Infrastructure	279	250	252	251	265	274	289	291	288
6c. Operating Support	229	242	278	281	289	319	327	337	347
6d. PRP	363	393	347	348	357	373	392	411	437
6f. Public Benefits	23	39	5	1	2	2	2	2	2
6g. RPS	26	26	25	26	27	29	31	32	32
6h. PRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0
6i. Non-PRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0
6j. Pension Adj	0	0	0	0	0	0	0	0	0
6k. COLA Adj	0	0	0	0	0	0	0	0	0
6l. RPS Adj	0	0	0	0	0	0	0	0	0
6k. O&M Expenditures Total	965	995	921	926	940	997	1,041	1,073	1,106
7a. Depreciation	338	387	422	393	439	454	468	499	543
7b. Regulatory Asset - Solar SB-1	0	0	3	3	6	10	11	12	12
7c. Regulatory Asset - EE	0	0	4	5	17	29	42	56	72
8. Property Tax	12	12	13	12	14	15	17	18	20
9a. Interest Expense	220	288	281	280	285	328	380	433	475
9b. AFUDC	(8)	(12)	(36)	(31)	(52)	(35)	(48)	(28)	(5)
9c. CIAC	(13)	(28)	(13)	(23)	(15)	(16)	(16)	(17)	(18)
10. Total Expense	2,825	2,932	2,934	2,919	2,940	3,159	3,318	3,587	3,742
11a. Net Income Before City Transfer	542	316	325	301	299	302	319	536	360
11b. City Transfer	220	259	250	250	249	251	269	283	306
11c. Increase In Fund Net Assets	322	58	75	51	51	50	50	253	54
12. Capital Expenditures									
12a. DSM	2	2	55	55	127	138	143	152	180
12b. Gas Drilling	15	60	51	51	20	0	0	0	0
12c. Other Infrastructure	87	88	87	106	195	134	117	123	103
12d. IRP	13	201	407	396	428	402	109	489	22
12e. Operating Support	94	117	114	89	96	77	63	48	50
12f. PRP	446	419	361	360	427	512	539	567	590
12g. Public Benefits	0	0	0	0	0	0	0	0	0
12h. RPS	90	23	186	181	150	388	293	175	522
12i. PRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0
12j. Non-PRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0
12k. Pension Adj	0	0	0	0	0	0	0	0	0
12l. COLA Adj	0	0	0	0	0	0	0	0	0
12l. Net Capital Expenditures Total	747	911	1,261	1,238	1,444	1,650	1,265	1,555	1,467
13a. Borrowing for CapEx	616	900	0	0	1,125	1,235	865	773	954
13b. Cash on Hand	424	561	264	322	309	300	300	300	300
13c. Total Debt Service	318	400	348	344	422	467	529	591	643
13d. Total Non-Debt Service Expenditures	3,022	3,180	3,522	3,507	3,689	4,023	3,714	4,154	4,096
14. Financial Ratios:									
Debt Service Coverage, net of BABs Subsidy	**2.49**	**2.13**	**2.78**	**2.57**	**2.60**	**2.41**	**2.42**	**2.33**	**2.44**
Adj. Debt Service Coverage, net of IPA Debt	2.12	1.90	1.90	2.13	2.03	1.91	1.89	1.83	1.84
Full Obligation Coverage, net of IPA Debt	1.63	1.44	1.77	1.65	1.65	1.58	1.58	1.55	1.55
Capitalization Factor	53.6%	56.5%	55.6%	55.7%	59.1%	62.1%	63.8%	64.2%	65.7%
15. Average Rate (cts/kWh)									
System Average	12.0	12.6	12.7	12.7	13.3	14.1	15.2	16.4	17.4
Avg. Rate Increase (%)	7.2%	4.9%	0.8%	0.5%	4.9%	6.0%	7.9%	7.5%	6.0%
16a. ECA (Under) Over Collection	(208)	(203)	(205)	(221)	(178)	(166)	(133)	(140)	(107)
16b. RCA (Under) Over Collection	(42)	(91)	(95)	(94)	(90)	(80)	(71)	(61)	(52)
16c. Baraket Settlement Balance	160	160	160	160	160	160	144	128	112

Los Angeles Department of Water and Power
Power System Income Statement
($ in millions)

	Final	Final	Revised	Actuals thru Mar 2012		FORECAST			
Fiscal Year Ending June 30	**2010**	**2011**	**2012**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Retail Sales (GWh)	23,319	23,064	23,344	23,123	23,471	23,600	23,897	24,129	24,381
Proj. Energy Eff. Prgm (GWh)		0	(73)	0	(100)	(414)	(712)	(1,019)	(1,349)
Solar Roof Top		0	(15)	0	(23)	(74)	(114)	(152)	(180)
Reductions from Weather or Actuals (GWh)		0	0	0	0	0	0	0	0
Net Retail Sales (GWh)	23,319	23,064	23,256	23,123	23,348	23,113	23,071	22,958	22,852
Revenues:									
Residential	914	927	1,105	980	1,151	1,196	1,283	1,370	1,444
Commercial	1,627	1,710	1,572	1,691	1,658	1,752	1,893	2,028	2,141
Industrial	231	244	252	230	266	280	301	322	340
Intra - Department	19	16	16	15	17	18	20	21	23
Street Lighting	17	16	16	17	16	16	16	17	18
Retail Revenue	2,806	2,913	2,960	2,933	3,108	3,262	3,513	3,758	3,966
Wholesale Sales (Generation)	90	33	27	12	21	24	30	30	31
Wholesale Sales (Transmission)	37	51	32	51	32	32	32	32	32
Distribution Other Revenue	20	22	43	27	22	22	22	22	22
Deferred IPP Revenue	97	94	96	96	0	0	0	0	0
Deferred Public Benefit	83	0	0	0	0	0	0	0	0
Deferred Rate Stabilization	(2)	0	0	0	13	36	0	0	0
Deferred SCPPA Credit	0	0	0	0	21	25	0	0	0
ECAF (Over)/Under Collection	94	(5)	2	18	(44)	(11)	(33)	7	(33)
ESA (Over) /Under Collection	0	0	0	0	0	0	0	0	0
RCA (Over)/Under Collection	26	49	4	3	(4.7)	(9.4)	(9.4)	(9.4)	(9.4)
Base Revenue (Over)/Under Collection	0	0	0	0	0	0	0	0	0
Green Power Over/Under Collection	(1)	(1)	0	0	0	0	0	0	0
Change in Accrued Revenue	13	(2)	0	(7)	0	0	0	0	0
Allowance for Bad Debt	(27)	(27)	(24)	(24)	(25)	(16)	(18)	(19)	(20)
Total Operating Revenue	**3,235**	**3,126**	**3,141**	**3,111**	**3,143**	**3,363**	**3,537**	**3,822**	**3,988**
System Average (cents/kWh)	**12.0**	**12.6**	**12.73**	**12.69**	**13.3**	**14.1**	**15.2**	**16.4**	**17.4**
Retail Rate Increase	**7.2%**	**4.9%**	**0.8%**	**0.5%**	**4.9%**	**6.0%**	**7.9%**	**7.5%**	**6.0%**
Fuel Expenses	481	436	389	395	371	369	338	329	318
Purchased Power	829	854	939	952	928	1,000	1,056	1,183	1,195
Securitized Debt Service Expense				0	0	0	0	0	0
Legal Settlement Expense	0	0	0	0	0	0	16	16	16
Legal Expense Allocated to FPP	0	0	3	3	0	0	0	0	0
CO2 Allowance Expense	0	0	0	0	1	2	7	5	0
Other Emissions Expense	0	0	9	3	5	5	7	7	8
O & M Expenses	896.6	922.9	901	907	939	995	1,039	1,071	1,104
Demand Side Management (Exld. PB)	44.7	42.5	15	18	0	0	0	0	0
Public Benefit	24	29	5	1	2	2	2	2	2
Prepaid Public benefit	0	0	0	0	0	0	0	0	0
Depreciation	338	387	422	393	439	454	468	499	543
Regulatory Asset - Solar	0	0	3	3	6	10	11	12	12
Regulatory Asset - EE	0	0	4	5	17	29	42	56	72
Property Taxes	12	12	13	12	14	15	17	18	20
TOTAL OPR EXPENSES	**2,625**	**2,684**	**2,703**	**2,693**	**2,721**	**2,881**	**3,002**	**3,198**	**3,291**
Operating Income	610	442	438	418	421	482	535	623	697
Gain/Loss On Asset Sales	0	0	0	0	0	0	0	202	0
Other Income/Expenses, Net	131	123	119	109	97	97	100	100	115
Income Before LT Debt Expenses	741	565	557	527	518	579	635	925	812
Interest on Fixed Rate Bonds	207	276	279	280	288	329	378	424	459
Interest on Variable Rate Bonds	10	1	7	2	5	6	9	16	22
Amortization of Debt Expenses	3	11	(5)	(2)	(7)	(7)	(7)	(6)	(6)
Total Debt Expenses	220	288	281	280	285	328	380	433	475
AFUDC	(8)	(12)	(36)	(31)	(52)	(35)	(48)	(28)	(5)
Net Debt Expenses	212	276	245	249	233	293	332	406	470
Contributions in Aid of Construction	13	28	13	23	15	16	16	17	18
Change in Fund Net Assets Before Transfer to the City	**542**	**316**	**325**	**301**	**299**	**302**	**319**	**536**	**360**
City Transfer	220	259	250	250	249	251	269	283	306
Extraordinary loss									
Increase in Fund Net Assets	**322**	**58**	**75**	**51**	**51**	**50**	**50**	**253**	**54**
Addtn'l Bond Test Ratio: (prev / max)	2.07	2.59	2.24	2.33	1.99	1.82	1.76	1.75	2.03
Financial Ratio (Current/Current)									
Debt Service Coverage, net of BABs Subsid	**2.49**	**2.13**	**2.78**	**2.57**	**2.60**	**2.41**	**2.42**	**2.33**	**2.44**
Adj. Debt Service Coverage, netting IPA Deb	2.12	1.90	2.24	2.13	2.03	1.91	1.89	1.83	1.84
Full Obligation Coverage, netting IPA Debt	1.63	1.44	1.77	1.65	1.65	1.58	1.58	1.55	1.55
Capitalization Ratio	53.6%	56.5%	55.6%	55.7%	59.1%	62.1%	63.8%	64.2%	65.7%
Interest Coverage	3.60	2.98	3.16	2.95	3.56	3.21	3.19	3.02	3.15

Los Angeles Department of Water and Power
Power System Balance Sheet
($ in millions)

Case P119	Final	Final	Forecast					
FY ENDING JUNE 30	2010	2011	2012	2013	2014	2015	2016	2017
Plant in Service	11,987	12,531	12,504	13,147	14,520	15,211	17,360	18,048
Nuclear Fuel - Net	44	44	43	45	47	48	47	47
Natural Gas Field	231	257	283	270	244	222	203	185
C W I P	431	685	1,752	2,333	2,383	2,779	1,958	2,486
Gross Plant	12,694	13,518	14,583	15,795	17,193	18,260	19,568	20,766
Accum. Depreciation	5,715	6,087	6,427	6,808	7,205	7,616	8,058	8,545
Net Plant	6,979	7,431	8,156	8,986	9,988	10,644	11,509	12,221
Restricted and Other Investment:								
Nuclear Decommissioning Fund	118	120	122	125	128	132	136	140
Debt Reduction Trust Funds	529	486	489	491	494	498	500	501
Sinking Funds for CREBs	0	0	0	0	0	0	0	5
RPS/EE Trust Fund	0	0	0	0	0	0	0	0
Post Retiree Benefit Fund	0	0	0	0	0	0	0	0
Natural Gas Hedging Trust Fund	3	0	0	0	0	0	0	0
DTSC	2	2	2	2	2	2	2	2
Other Investment	30	26	23	19	15	11	6	(0)
Total Restricted and Othr Invs.	683	634	637	638	640	643	645	647
Current Assets								
Construction Fund	360	553	27	0	0	0	0	0
Revenue Fund	424	561	322	309	300	300	300	300
Bond R&I Fund	232	195	269	283	318	348	372	409
Insurance Funds	108	114	124	134	144	154	164	174
Account Receivable	435	446	451	479	497	535	567	601
Accrued Revenue	159	156	156	156	156	156	156	156
Material & Supplies	150	146	147	148	149	150	151	152
Fuel Inventory	8	9	9	9	9	9	9	9
Other Prepayments and assets	68	138	46	46	46	46	46	46
Bond Issue Costs	26	31	29	38	48	54	59	65
Total Current Assets	1,970	2,349	1,579	1,601	1,666	1,752	1,824	1,912
Receivable from ISO	0	0	0	0	0	0	0	0
Regulatory Asset - Barakat Settement	160	160	160	160	160	144	128	112
Regulatory Asset - Solar Incentives	0	0	60	118	173	184	192	194
Regulatory Asset - DSM	0	0	50	161	269	371	467	574
Post Retirement Healthcare Assets	533	591	650	658	665	670	674	676
Pension Assets	53	14	11	8	6	3	0	(2)
Long - Term Notes Receivable	1,057	955	850	788	714	644	555	540
Prepaid Public Benefit	0	0	0	0	0	0	0	0
Total Assets	11,435	12,134	12,153	13,119	14,280	15,054	15,993	16,874
Retained Earnings	4,358	4,387	4,415	4,451	4,485	4,519	4,756	4,792
Acc. CIAC	521	549	572	587	603	619	635	654
Equity	4,879	4,937	4,987	5,038	5,088	5,138	5,391	5,445
Bonds & Notes	5,751	6,477	6,406	7,397	8,491	9,204	9,817	10,609
LT Debt Due in 1 Yr	123	62	129	132	142	151	153	170
Non - Current Debt	5,628	6,415	6,277	7,266	8,349	9,053	9,665	10,440
Current Liabilities								
LT Debt Due in 1 Yr	123	62	129	132	142	151	153	170
Revenue Certificates	200	200	200	200	200	200	200	200
Accrued interest	102	130	140	151	175	197	220	239
Accounts Payable	246	267	416	321	357	301	354	341
Payable to City's Reserve Fund	0	0	0	0	0	0	0	0
Payable to Water System	0	0	10	10	10	18	18	18
Accrued Payroll & Others	92	97	85	85	85	85	85	85
Potential Refund	0	0	0	0	0	0	0	0
Total Current Liabilites	763	756	981	898	970	952	1,029	1,053
Long -term accrued liabilities	12	10	9	7	5	4	2	0
Deferred RPS/EE Trust Fund	0	0	0	0	0	0	0	0
Deferred Public Benefit	0	0	0	0	0	0	0	0
ECAF Over (Under) Collection	(208)	(203)	(221)	(178)	(166)	(133)	(140)	(107)
ESA Over (Under) Collection	0	0	0	0	0	0	0	0
RCA Over (Under) Collection	(42)	(91)	(94)	(90)	(80)	(71)	(61)	(52)
Base Revenue Over (Under) Collection	0	0	0	0	0	0	0	0
Deferred Rate Stabilization	75	75	75	62	26	26	26	26
Green Power Over (Under) Collection	2	3	5	5	5	5	5	5
Deferred Revenue - Others	0	0	0	0	0	0	0	0
Workers Comp Liability	41	40	41	41	42	42	42	43
Discount on Notes	50	52	50	45	42	38	35	21
Deferred Credit (SCPPA)	45	45	45	25	0	0	0	0
Deferred IPP Credit	189	96	0	0	0	0	0	0
Total Liabilities and Equity	11,435	12,134	12,153	13,119	14,280	15,054	15,993	16,874

Los Angeles Department of Water and Power
Power System Financial Ratios
($ in millions)

FY ENDING JUNE 30	Final 2010	Final 2011	Actuals thru Mar 2012	Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017
Debt Service Coverage (Current / Current)								
Revenue:								
Operating Revenue Prior to Adjustment	3,235	3,126	3,111	3,143	3,363	3,537	3,822	3,988
Deferred Revenue Adjustment:								
Deferred - IPP Revenue	97	94	96	0	0	0	0	0
Deferred - Public Benefit	83	0	0	0	0	0	0	0
Deferred - Rate Stabilization	-2	0	0	13	36	0	0	0
Deferred - Energy Cost Adjustment	94	-5	18	-44	-11	-33	7	-33
Deferred - Energy Subsidy Adjustment	0	0	0	0	0	0	0	0
Deferred - Reliability Cost Adjustment	26	49	3	-5	-9	-9	-9	-9
Deferred - Base Revenue	0	0	0	0	0	0	0	0
Deferred - Green Power	-1	-1	0	0	0	0	0	0
Total Deferred Revenue	297	137	117	-36	15	-43	-2	-43
Operating Revenue after Adjustment	2,938	2,989	2,993	3,178	3,348	3,579	3,824	4,031
less Deferred Base Revenue Adjustment	0	0	0	0	0	0	0	0
Non-Operating Revenue	131	123	109	97	97	100	100	115
Total Cash Revenue	3,070	3,112	3,103	3,275	3,446	3,680	3,924	4,145
Expense:								
Fuel and Purchased Power	1,304	1,275	1,322	1,267	1,345	1,372	1,492	1,495
Securitized Debt Service Expense	0	0	0	0	0	0	0	0
Legal Expense Allocated to FPP	0	0	3	0	0	0	0	0
CO2 Allowance Expense	0	0	0	1	2	7	5	0
Other Emissions Expense	0	0	3	5	5	7	7	8
O&M, DSM, PB Expenses	965	995	926	940	997	1,041	1,073	1,106
Property Taxes	12	12	12	14	15	17	18	20
Total Expenses	2,281	2,282	2,267	2,227	2,365	2,444	2,596	2,629
Adjustment for Non-Cash Expense:								
Adjustment for Pension GASB 27	4	4	3	3	3	3	3	3
Adjustment for Healthcare GASB 45	-8	-8	-8	-8	-7	-6	-4	-2
Cash Balance Avail for DS include BABs Subsidy Payment	784	825	831	1,043	1,077	1,233	1,327	1,517
Cash Balance Avail for DS exclude BABs Subsidy Payment	784	801	796	1,008	1,042	1,198	1,292	1,482
Revenue Balance Avail for DS include BABs Subsidy	1,085	967	953	1,012	1,095	1,193	1,326	1,474
Revenue Balance Avail for DS exclude of BABs Subsidy	1,085	943	919	977	1,060	1,158	1,291	1,438
LTD-DUE1								
Interest on Fixed Rate Debt	207	276	280	288	329	378	424	459
Interest on Variable Rate Debt	10	1	2	5	6	9	16	22
Principal Maturities	97	123	62	129	132	142	151	153
Sinking Fund Payment for CREBs	0	0	0	0	0	0	0	10
Gross Debt Service	315	400	344	422	467	529	591	643
Net Debt Service (net of BABs Subsidy)	315	376	309	387	432	494	555	608
BABs Subsidy	0	-24	-35	-35	-35	-35	-35	-35
Max Debt Service	425	425	425	489	562	617	666	725
Balance Avail for DS include BABs Subsidy Payment	784	825	831	1,043	1,077	1,233	1,327	1,517
Gross Debt Service	315	400	344	422	467	529	591	643
Debt Service Coverage (Balance Avail for DS include BABs Subsidy / Gross Debt Service)	**2.49**	**2.06**	**2.42**	**2.47**	**2.31**	**2.33**	**2.25**	**2.36**
Balance Avail for DS exclude BABs Subsidy Payment	784	801	796	1,008	1,042	1,198	1,292	1,482
Net Debt Service (net of BABs Subsidy)	315	376	309	387	432	494	555	608
Debt Service Coverage (Balance Avail for DS exclude BABs Subsidy Payment / Net Debt Service)	**2.49**	**2.13**	**2.57**	**2.60**	**2.41**	**2.42**	**2.33**	**2.44**
City Transfer	220	259	250	249	251	269	283	306
D/S Ratio after City Transfer	**1.79**	**1.42**	**1.69**	**1.88**	**1.77**	**1.82**	**1.77**	**1.88**
Additional Bond Test Ratio (Prev / Max) -- Must Exceed 1.25								
Net Income	542	316	301	299	302	319	536	360
LT Debt Expense	220	288	280	285	328	380	433	475

Los Angeles Department of Water and Power
Power System Financial Ratios
($ in millions)

	Final	Final	Actuals thru Mar 2012			Forecast		
FY ENDING JUNE 30	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Depreciation	338	387	393	439	454	468	499	543
Adj Net Income	1,100	992	973	1,024	1,084	1,167	1,469	1,379
Max Debt Service	425	425	425	489	562	617	666	725
Additional Bond Test Ratio (Previous Period Adj. Net Income / Max Debt Service)	**2.07**	**2.59**	**2.33**	**1.99**	**1.82**	**1.76**	**1.75**	**2.03**
Capitalization Ratio -- Must Not Exceed 60%								
Long-Term Debt	5,628	6,415	6,277	7,266	8,349	9,053	9,665	10,440
Equity	4,879	4,937	4,987	5,038	5,088	5,138	5,391	5,445
Long-Term Debt + Equity	10,507	11,351	11,264	12,304	13,437	14,191	15,055	15,885
Capitalization Ratio (LT Debt / (LT Debt + Equity))	**53.6%**	**56.5%**	**55.7%**	**59.1%**	**62.1%**	**63.8%**	**64.2%**	**65.7%**
Other Ratios								
Interest Coverage	**3.60**	**2.98**	**2.95**	**3.56**	**3.21**	**3.19**	**3.02**	**3.15**
Fixed Charge or Off-Balance Sheet Debt Svc($M)	2010	2011	2012	2013	2014	2015	2016	2017
Conventional								
IGS (IPA) - Issued	151.4	198.7	187.6	171.8	196.4	186.2	209.7	121.4
NTS (IPA) - Issued	2.7	4.4	5.0	5.6	6.4	6.1	6.9	4.0
STS (SCPPA) - Issued	40.0	43.6	44.0	53.6	48.5	48.7	48.8	47.6
Mead-Adelanto (SCPPA) - Issued	8.4	8.2	8.2	8.2	8.1	8.1	7.7	7.7
Mead-Phoenix (SCPPA) - Issued	2.0	2.0	2.0	2.0	1.7	1.7	1.6	1.6
STS Upgrade (SCPPA) - Issued	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4
PV (SCPPA) - Issued	8.7	8.7	8.7	8.7	8.6	8.6	8.6	8.6
Asset or Prepay RPS								
Linden (SCPPA) - $135M - Issued	0.0	4.1	7.6	8.3	8.3	8.2	8.2	8.2
Milford I (SCPPA) - $219M - Issued	4.1	10.4	17.2	17.2	17.2	17.1	17.1	17.0
Windy Point (SCPPA) - $512M - Issued	0.0	19.7	37.5	40.6	40.5	40.3	40.3	40.1
Milford II (SCPPA) - $155M Prepay - Pending	0.0	0.0	6.2	11.1	11.7	11.7	11.7	11.6
Future IRP's RPS								
Future IRP and RPS Debt Issuance ($M)		0.0	0.0	11.7	45.2	99.9	157.2	193.0
Total Off-Balance Sheet Debt Service ($M)	221.8	304.1	328.4	343.0	397.1	441.0	522.2	465.3
IPA Subordinated Notes ($M)								
IPA Notes - Interest Payment	57.4	57.4	46.1	38.9	37.9	36.2	31.1	29.2
IPA Notes - Principal Maturities	32.9	82.3	104.1	62.1	74.8	69.4	88.9	15.6
Total Income from IPA Notes	90.3	139.7	150.3	101.0	112.7	105.6	120.0	44.8
Net Off-Balance Sheet Debt Service ($M)	**131.5**	**164.4**	**178.1**	**242.1**	**284.3**	**335.4**	**402.2**	**420.5**
Adjusted Debt Service Ratio								
Adj. Funds Available for Debt Service	1,005	1,130	1,159	1,386	1,474	1,674	1,849	1,982
On-Balance Sheet Debt Service	315	400	344	422	467	529	591	643
Off-Balance Sheet Debt Service	222	304	328	343	397	441	522	465
Adjusted Debt Service Ratio	**1.87**	**1.60**	**1.72**	**1.81**	**1.71**	**1.73**	**1.66**	**1.79**
Full Obligation Coverage Ratio								
City Transfer	220	259	250	249	251	269	283	306
Full Obligation Ratio	**1.46**	**1.24**	**1.35**	**1.49**	**1.42**	**1.45**	**1.41**	**1.51**
Adjusted Debt Service Ratio (Netting IPA Debt)								
Adj. Funds Available for Debt Service	1,005	1,130	1,159	1,386	1,474	1,674	1,849	1,982
IPA Notes - Interest Payment	(57)	(57)	(46)	(39)	(38)	(36)	(31)	(29)
Adj. Funds Available for Debt Service (Alt)	948	1,072	1,113	1,347	1,436	1,638	1,818	1,953
On-Balance Sheet Debt Service	315	400	344	422	467	529	591	643
Off-Balance Sheet Debt Service (Alt)	132	164	178	242	284	335	402	420
Adjusted Debt Service Ratio (Alt)	**2.12**	**1.90**	**2.13**	**2.03**	**1.91**	**1.89**	**1.83**	**1.84**
Full Obligation Coverage Ratio (Alternate Method)								
City Transfer	220	259	250	249	251	269	283	306
Full Obligation Ratio	**1.63**	**1.44**	**1.65**	**1.65**	**1.58**	**1.58**	**1.55**	**1.55**

Natural Gas Pricing Us Final FY2013 Budget

Rockies 4/24/2012	FY10-11	FY11-12	FY12-13	FY13-14	FY14-15	FY15-16	FY16-17	FY17-18	FY18-19	FY19-20	FY20-21
Jul	$4.08	$3.95	$2.03	$3.09	$3.15	$3.36	$3.54	$3.71	$3.89	$4.07	$4.28
Aug	$3.78	$4.06	$2.12	$3.12	$3.17	$3.38	$3.56	$3.74	$3.92	$4.11	$4.31
Sep	$2.69	$3.70	$2.11	$3.13	$3.18	$3.39	$3.58	$3.75	$3.93	$4.12	$4.33
Oct	$3.40	$3.59	$2.21	$3.14	$3.19	$3.40	$3.58	$3.76	$3.94	$4.13	$4.34
Nov	$2.92	$3.44	$2.52	$3.30	$3.27	$3.47	$3.65	$3.83	$4.01	$4.21	$4.43
Dec	$4.00	$3.38	$2.90	$3.58	$3.51	$3.71	$3.90	$4.08	$4.27	$4.48	$4.71
Jan	$3.82	$3.08	$3.03	$3.70	$3.63	$3.83	$4.02	$4.20	$4.40	$4.62	$4.86
Feb	$4.08	$2.54	$3.05	$3.66	$3.58	$3.78	$3.97	$4.15	$4.35	$4.56	$4.80
Mar	$3.61	$2.40	$3.02	$3.57	$3.47	$3.67	$3.86	$4.04	$4.24	$4.45	$4.68
Apr	$3.97	$1.90	$2.95	$3.42	$3.29	$3.47	$3.65	$3.82	$4.01	$4.21	$4.42
May	$3.99	$1.79	$2.97	$3.42	$3.29	$3.48	$3.65	$3.82	$4.01	$4.21	$4.42
Jun	$3.98	$1.87	$3.03	$3.46	$3.32	$3.51	$3.68	$3.85	$4.04	$4.24	$4.45
Average	$3.69	$2.98	$2.66	$3.38	$3.34	$3.54	$3.72	$3.90	$4.08	$4.29	$4.50

SoCal Border 4/24/2012	FY10-11	FY11-12	FY12-13	FY13-14	FY14-15	FY15-16	FY16-17	FY17-18	FY18-19	FY19-20	FY20-21
Jul	$4.54	$4.48	$2.33	$3.32	$3.51	$3.74	$3.94	$4.14	$4.33	$4.54	$4.76
Aug	$4.34	$4.48	$2.48	$3.40	$3.51	$3.74	$3.94	$4.14	$4.33	$4.54	$4.76
Sep	$3.48	$4.05	$2.44	$3.40	$3.38	$3.60	$3.80	$3.99	$4.18	$4.38	$4.60
Oct	$3.80	$3.92	$2.44	$3.40	$3.36	$3.57	$3.77	$3.95	$4.14	$4.34	$4.56
Nov	$3.12	$3.56	$2.72	$3.53	$3.51	$3.72	$3.92	$4.11	$4.31	$4.52	$4.75
Dec	$4.31	$3.60	$3.11	$3.81	$3.72	$3.93	$4.13	$4.32	$4.53	$4.75	$4.99
Jan	$4.06	$3.40	$3.19	$3.83	$3.78	$3.99	$4.19	$4.38	$4.59	$4.81	$5.06
Feb	$4.23	$2.89	$3.22	$3.82	$3.76	$3.97	$4.17	$4.36	$4.57	$4.80	$5.04
Mar	$3.81	$2.58	$3.19	$3.77	$3.68	$3.89	$4.09	$4.28	$4.49	$4.72	$4.96
Apr	$4.23	$2.36	$3.16	$3.58	$3.48	$3.67	$3.86	$4.04	$4.24	$4.45	$4.67
May	$4.30	$2.12	$3.20	$3.63	$3.49	$3.69	$3.87	$4.06	$4.26	$4.47	$4.69
Jun	$4.28	$2.14	$3.26	$3.67	$3.52	$3.72	$3.90	$4.08	$4.28	$4.49	$4.71
Average	$4.04	$3.30	$2.90	$3.60	$3.56	$3.77	$3.97	$4.15	$4.35	$4.57	$4.80

Burnertip Price 4/24/2012	FY10-11	FY11-12	FY12-13	FY13-14	FY14-15*	FY15-16	FY16-17	FY17-18	FY18-19	FY19-20	FY20-21
Jul	$4.93	$4.84	$2.70	$3.69	$3.88	$4.11	$4.31	$4.51	$4.70	$4.91	$5.13
Aug	$4.73	$4.84	$2.85	$3.77	$3.88	$4.11	$4.31	$4.51	$4.70	$4.91	$5.13
Sep	$3.87	$4.41	$2.81	$3.77	$3.75	$3.97	$4.17	$4.36	$4.55	$4.75	$4.97
Oct	$4.19	$4.28	$2.81	$3.77	$3.73	$3.94	$4.14	$4.32	$4.51	$4.71	$4.93
Nov	$3.51	$3.92	$3.09	$3.90	$3.88	$4.09	$4.29	$4.48	$4.68	$4.89	$5.12
Dec	$4.70	$3.96	$3.48	$4.18	$4.09	$4.30	$4.50	$4.69	$4.90	$5.12	$5.36
Jan	$4.42	$3.76	$3.56	$4.20	$4.15	$4.36	$4.56	$4.75	$4.96	$5.18	$5.43
Feb	$4.59	$3.25	$3.59	$4.19	$4.13	$4.34	$4.54	$4.73	$4.94	$5.17	$5.41
Mar	$4.17	$2.94	$3.56	$4.14	$4.05	$4.26	$4.46	$4.65	$4.86	$5.09	$5.33
Apr	$4.59	$2.72	$3.53	$3.95	$3.85	$4.04	$4.23	$4.41	$4.61	$4.82	$5.04
May	$4.66	$2.48	$3.57	$4.00	$3.86	$4.06	$4.24	$4.43	$4.63	$4.84	$5.06
Jun	$4.64	$2.50	$3.63	$4.04	$3.89	$4.09	$4.27	$4.45	$4.65	$4.86	$5.08
Average	$4.42	$3.66	$3.27	$3.97	$3.93	$4.14	$4.34	$4.52	$4.72	$4.94	$5.17

* Starting FY14-15, the gas price is adjusted 10% lower than the market price on 4/24/12. This is due to the belief that the current forward contract contains risk premiums that are not warranted. The current oversupply of natural gas due to fracking w

Appendix 8 to be provided subsequently.

APPENDIX 9: DETAILED EXPLANATION OF RATE DRIVERS

MANDATES:

Rebuilding Local Power Plants to Eliminate Once Through Cooling (OTC)

Once Through Cooling (OTC) is the process by which water is drawn from the ocean for cooling equipment at a power plant and then is discharged back to the ocean. OTC is a major regulatory issue, stemming from the Federal Clean Water Act Section 316(b), administered nationally by the Environmental Protection Agency (EPA) and locally by the State Water Resources Control Board (SWRCB). The new state-wide OTC policy and 316(b) federal rule require LADWP to reduce or eliminate mortality due to impingement and entrainment of marine life and organisms.

Over the next five years, this legal mandate will require $914.6 million in capital investment. During the next two years, as outlined in the IRP, $752.8 million of capital investments will be made for two of the six separate projects to replace the OTC process:

- Haynes Generating Station Units 5 and 6 (also referred to as Haynes Phase I)
- Scattergood Generating Station Unit 3 (also referred to as Scattergood Phase I)

Figure 1 provides the current compliance schedule for complete elimination of OTC.

Figure 1: OTC Compliance Time Line

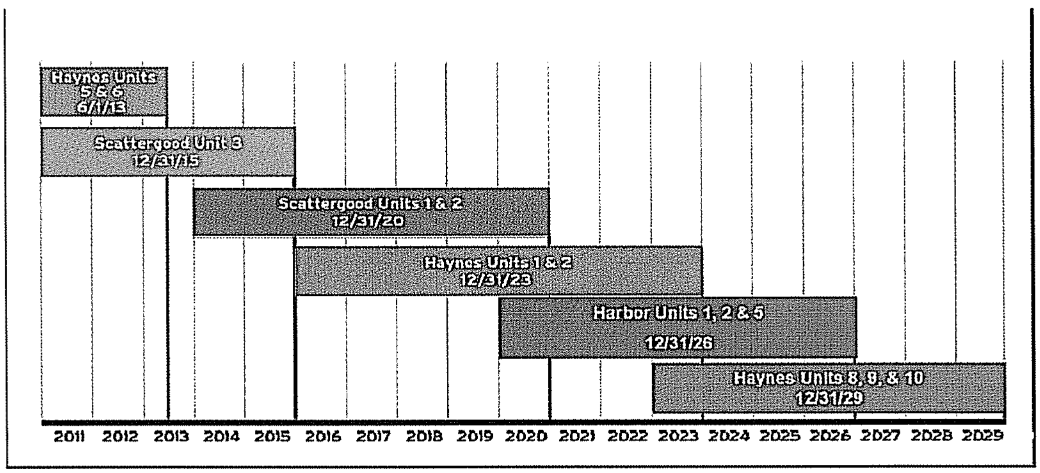


Figure 2 summarizes the budgeted capital and O&M expenditures and annual percentage rate impact for FYs 2012-13 and 2013-14.

Figure 2: Rebuilding Local Power Plants - Capital and O&M Expenditures and Annual Rate Increase

Cost Driver ($M)	Cost Type	Current Year	Upcoming Two-Year Period	
		FY 2012	FY 2013	FY 2014
Rebuilding Local Power Plants	Capital	$375.0	$380.0	$372.8
	O&M	0.00	0.00	0.00
Total Expenditures		$375.0	$380.0	$372.8
Annual Incremental Percentage Rate Increase		-	**1.0%**	**1.2%**

Renewable Energy to Meet State-Mandated Renewable Portfolio Standard (RPS) Compliance Dates

Shifting a greater amount of energy production to renewable energy sources is a major mandate and environmental initiative in California memorialized by the California Renewable Energy Resources Act, signed into law in April 2011. The rates proposed herein will allow LADWP to meet the current renewable compliance targets and maintain a pace of investment to reach the mandated targets in 2016 and 2020. During the next five fiscal years, as outlined in the IRP, $3.7 billion capital and O&M expenses will be required to ensure LADWP is able to meet the RPS compliance targets of:

Compliance with state-mandated interim milestones requires:

- 20.0% average for the period of January 1, 2011, through December 31, 2013
- 25.0% average by December 31, 2016 (based on the average percentage of retail sales for the period of January 1, 2016, to December 31, 2016)
- 33.0% average by December 31, 2020 (based on the average percentage of retail sales calculations for the period of January 1, 2020, to December 31, 2020)

Figure 3 provides the estimated renewable energy resource forecasts for the next two fiscal years (FY 2012-13 and 2013-14) for each year and energy type.

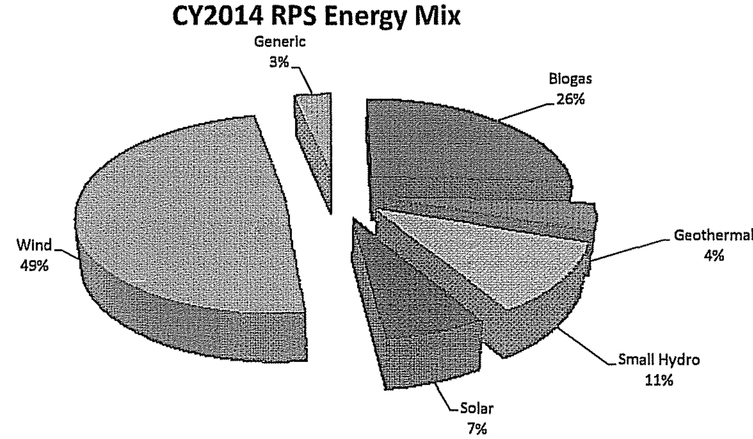
Figure 3: Renewable Energy Resource RPS Contribution Forecast

Renewable Energy Type	Current Year	Proposed Rate Period	
	FY 2012	**FY 2013**	**FY 2014**
Biogas	5.4%	5.6%	4.4%
Geothermal	0.0%	0.0%	0.0%
Small Hydro	1.8%	2.5%	2.7%
Solar	0.5%	0.8%	4.2%
Wind	10.1%	10.2%	10.5%
Generic[1]	1.7%	1.6%	0.1%
Total	**19.5%**	**20.8%**	**21.9%**
Required	20%[2]		

At the end of FY 2013-14, LADWP's mix of renewable energy resources is projected to include a diverse portfolio as shown in Figure 4.

[1] "Generic" category of renewables consists of renewable energy of unspecified type which could come from market purchase or increased size of planned renewable projects. Pricing used is $140 per MWh with no escalation.
[2] 20% average for the period January 1, 2011, through December 31, 2013

Figure 4: Calendar Year (CY) 2014 RPS Energy Mix



To ensure a reliable transport system to bring the Department's future reliable energy resources to its customer distribution system, LADWP is following a renewable energy transmission strategy that encompasses three prioritized options:

1. Utilize existing transmission lines;
2. Upgrade existing transmission lines to transport renewable power; or
3. Construct new transmission facilities.

The proposed rates and forecasted costs include funding for the following projects and line upgrade:

- *Barren Ridge Renewable Transmission Project:* Increase the capacity of the existing 230kV Barren Ridge - Rinaldi transmission segment by the end of 2016. During the next two fiscal years, however, costs will be incurred related to design and engineering as well as construction of the line.
- *Long-Term Transmission Development:* This program consists of several projects which will increase the transfer capacity of the Department's transmission network, principally the upgrade of the Pacific DC Intertie from 3,100 MW to 3,220 MW, Path 42 Imperial Irrigation District line upgrade to transport renewable power from the Coachella Valley, Victorville-Century line conversion to DC to increase capacity from 600 MW to 1,000 MW, and reactive power management of the Department's transmission network.
- *STS Transmission Upgrade:* Intermountain Power Agency (IPA) and Asea Brown-Boveri (ABB) entered into a contract to upgrade the Southern Transmission System (STS) from 1,920 MW to 2,400 MW. LADWP will perform all design and construction at the Adelanto AC Switching Station. LADWP, in its capacity as Operating Agent for IPA, is acting as the Project Manager and the contract administrator on behalf of IPA. The additional 480 MW will allow STS to transmit energy from authorized and planned wind turbines and other renewable electric generating resources to LADWP's service territories.

Over the next two years, the proposed revenue increase of $69.8 million will support $1.3 billion of expenditures ($537.7 million of capital expenditures; $746.5 million of O&M expenses) for renewable energy and renewable transmission facilities. The capital expenditures will be financed through debt borrowings, including $1.3 billion of off-balance sheet debt. Figure 5 summarizes the budgeted capital and O&M expenditures and annual percentage rate impact for FYs 2012-13 and 2013-14.

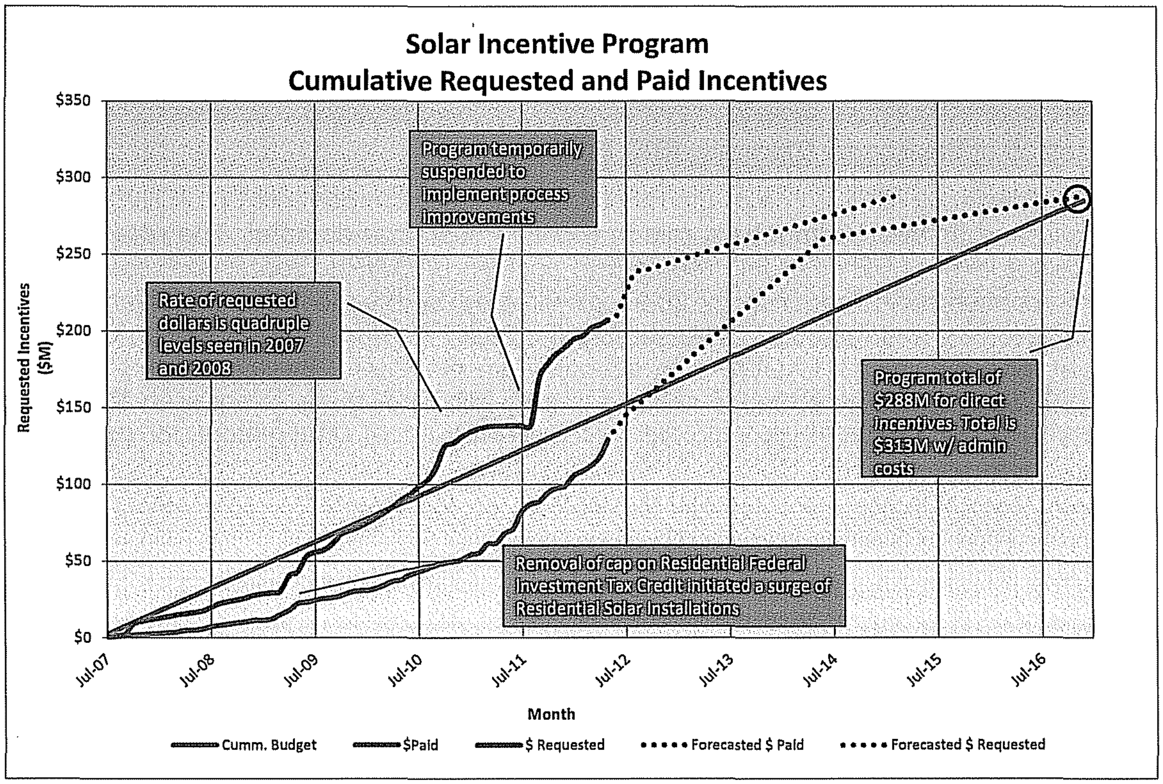
Figure 5: Renewable Energy and Transmission - Capital and O&M Expenditures and Annual Rate Increase

Renewable Energy Type ($M)	Current Year	Proposed Rate Period	
	FY 2012	FY 2013	FY 2014
Solar	$160.5	$95.4	$124.2
Wind	216.7	228.1	234.0
Geothermal	0.9	0.8	0.8
Small Hydro	56.0	31.6	41.8
Biogas / Biomass	62.9	84.4	84.1
Transmission	16.2	46.9	285.5
Generic	9.1	17.9	8.5
Total	$522.3	$505.2	$779.0
Annual Incremental Percentage Rate Increase		**1.2%**	**1.1%**

Solar Customer Rebate Program:

A part of the renewable energy shift is focused on solar energy production. State Senate Bill SB1, passed on August 21, 2006, mandates that all California electric utilities implement a solar incentive program by January 1, 2008 with a cap on expenditures of $3.4 billion. LADWP's program to meet this mandate is the Solar Photovoltaic Incentive Program. LADWP's share of the program, based on its percentage of load served in the state, is $313.0 million. Figure 6 provides the historical results for the program and expected activity for the next several years.

Figure 6: Projected Solar Customer Rebate Program Requests and Expenditures



LADWP's program is designed to provide incentives to customers to install solar facilities at their premises. Under SB 1, customers can receive financial incentives from LADWP for about one-third of the costs to install solar panels. For those facilities subsidized by LADWP, the total GWh generated by the customer-installed solar facilities are considered renewable energy resources for the purpose of meeting LADWP's mandated targets.

Over the next two years, LADWP has budgeted capital expenditures of $129.1 million for the solar rebate program. Figure 7 summarizes the budgeted capital expenditures and annual percentage rate impact for FYs 2012-13 and 2013-14.

Figure 7: Solar Customer Rebate Program – Capital Expenditures and Annual Rate Increase

Solar Customer Rebate Program ($M)	Current Year	Proposed Rate Period	
Fiscal Year	**FY 2012**	**FY 2013**	**FY 2014**
Capital Expenditures ($M)	$62.9	$64.5	$64.6
Annual Incremental Percentage Rate Increase	-	**0.3%**	**0.3%**

Expansion of the Energy Efficiency (EE) Program

Energy Efficiency (EE) is one of the most cost effective components of LADWP's supply portfolio and serves an important role in meeting customer demand. The rate proposal includes a level of EE spending required to position LADWP to reach or exceed a 10% energy consumption reduction by 2020, as directed by the Board of Water and Power Commissioners and intended by Assembly Bill 2021. As part of the adoption of the EE budget for FY 2012-13, LADWP with support from the Board, has committed to review alternatives in the years ahead to achieve energy efficiency goals of between 10.0% and 15.0% by 2020. LADWP has included the costs and usage assumptions for various EE programs in all customer classes to meet this target as part of this rate proposal. The planned expenditures are projected to result in an incremental energy savings of 561 GWh of usage by the end of FY 2013-14.

Over the next two years, LADWP has budgeted capital expenditures of $264.9 million to expand its EE program to meet the conditions of AB 2021. Figure 8 summarizes the budgeted capital and O&M expenditures, estimated incremental energy efficiency savings (GWh) and annual percentage rate impact for FYs 2012-13 and 2013-14.

Figure 8: Energy Efficiency – Capital and O&M Expenditures, Incremental Energy Efficiency Savings (GWh) and Annual Rate Increase

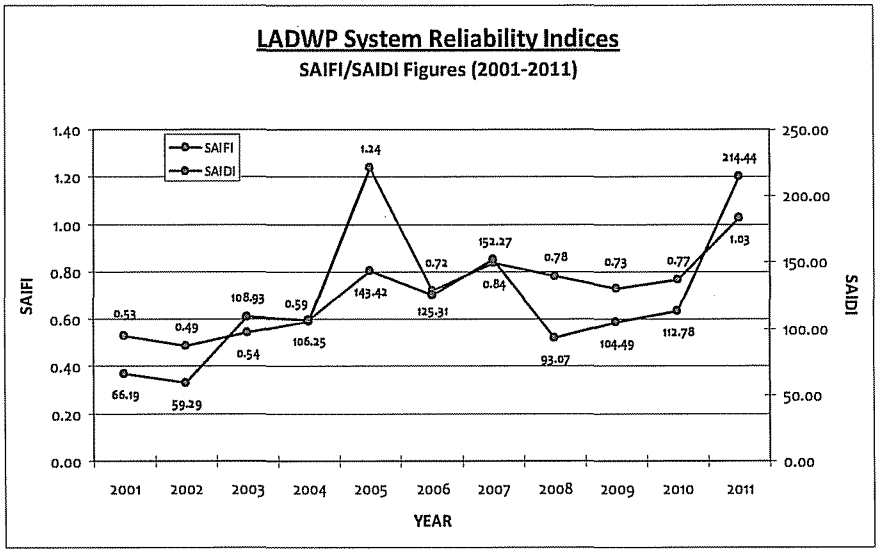
Energy Efficiency Plan ($M)	Current Year	Proposed Rate Period	
Fiscal Year	**FY 2012**	**FY 2013**	**FY 2014**
Capital	$55.1	$127.2	$137.7
O&M	18.0	0.0	0.0
Total Expenditures	$73.1 budgeted $55 forecast	$127.2	$137.7
Incremental Energy Efficiency Savings (GWh)	146	266	295
Annual Incremental Percentage Rate Increase	-	**0.9%**	**1.5%**

POWER RELIABILITY PROGRAM

The purpose of the Power Reliability Program (PRP) is to replace and/or upgrade aging infrastructure necessary for the reliable delivery of power to customers. During the next two years, LADWP's rate proposal includes increased funding for the PRP. This increase, while on the surface appearing substantial, brings expenditures to a level close to that of two years ago and falls short of that which would be necessary to truly get ahead of the rate of decline that LADWP faces with the aging system to deliver reliable power to customers.

As shown in Figure 9, LADWP's latest SAIFI is 1.03 vs. the 1.1 national average, and its SAIDI is 215.8 minutes vs. the national average of 90 minutes. As the chart below shows, both of these indices for LADWP are trending in the wrong direction.

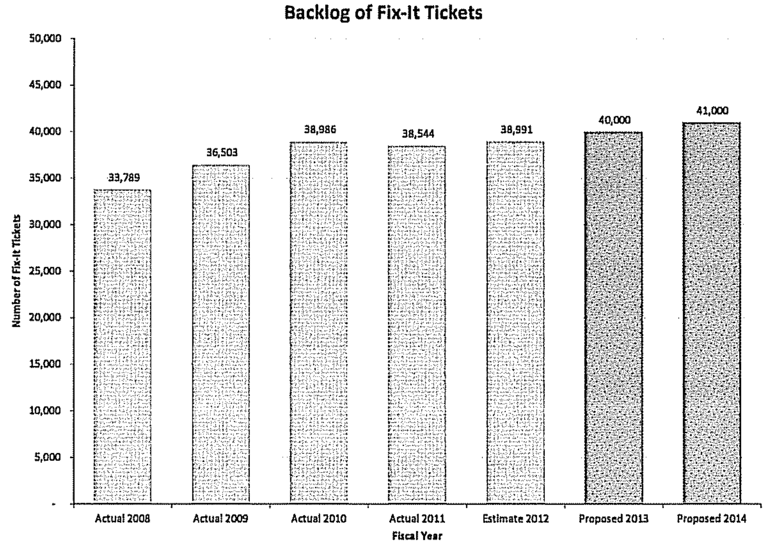
Figure 9: LADWP's System Reliability Indices Trends



In recent years, while investments have increased, LADWP has still been reacting to aging assets, often replacing facilities after they fail. To reduce the number of outages, especially those due to pole and cross-arm deterioration, a more proactive approach with continued investments over the next two years is proposed. This increased investment will have a positive impact on reliability, but it will not preclude the need for further reliability program increases in later years. The specific aspects of the PRP are discussed below.

Backlog of Fix-It Tickets: Fix-it tickets represent maintenance work required to provide permanent repairs to temporary fixes. To reduce the approximately 41,000 fix-it tickets in the queue to a desired more reasonable base, or ongoing level, of 2,000 to 5,000, it would take 3 million work hours to catch up. The proposed level of funding for the PRP in the FY 2012-13 and FY 2013-14 does not provide sufficient funding for this catch-up. Based on the forecasted PRP funding levels, the fix-it ticket backlog will increase by approximately 1,000 tickets per year, as shown in Figure 10.

Figure 10: Historical and Forecasted Backlog of Fix It Tickets (FYs 2007-08 – 2013-14)

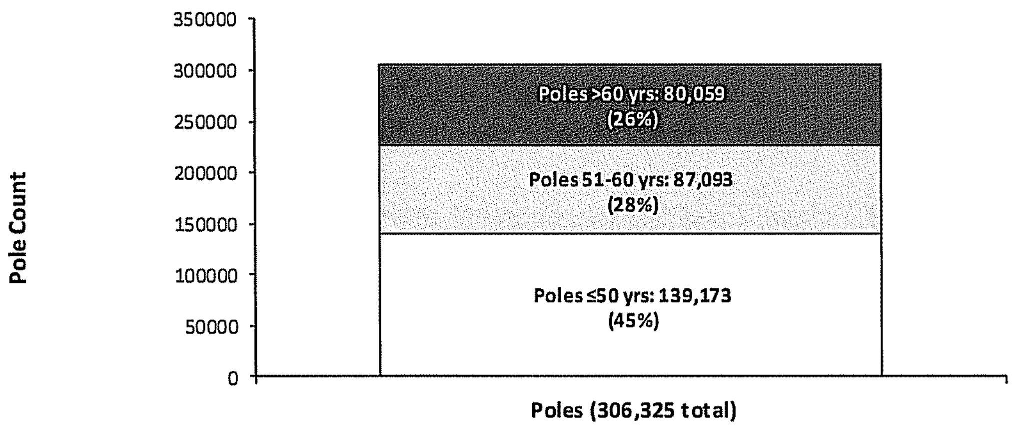


Replacement/Upgrade of Aging Infrastructure

The condition of several key components of the distribution infrastructure poses a growing threat to overall reliability. The increased PRP investment is designed to target these areas by replacing or repairing the specific facilities that are expected to have the greatest impact on reliability.

Pole Replacement Program: Since approximately 70.0% of LADWP's system is overhead, pole and cross arm replacements are a major driver of reliability. The proposed rates are designed to accelerate pole and cross-arm replacement. As shown in Figure 11, 26.0% of LADWP's poles currently exceed their 60-year useful life, and an additional 28.0% of LADWP's poles will reach 60 years of age during the next 1 to 10 years.

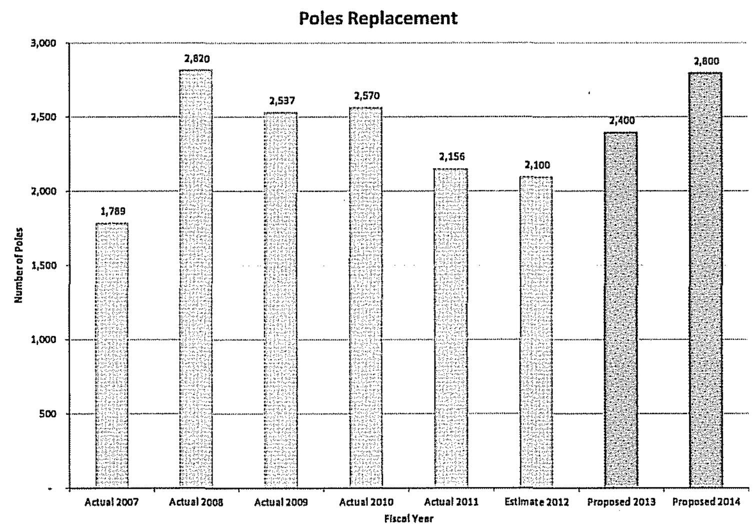
Figure 11: Pole Aging



The recommended replacement rate is 60 years; however, LADWP is currently on a 152-year replacement cycle, which is more than double the recommended cycle. Therefore, additional investment in pole replacement is warranted.

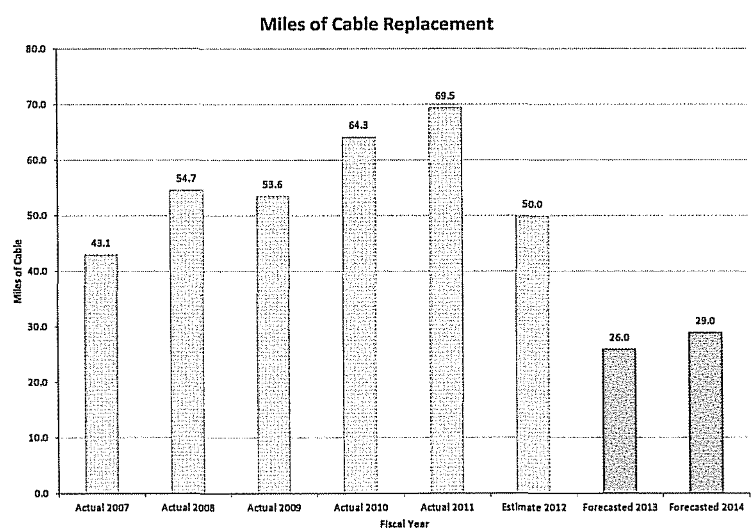
As shown in Figure 12, LADWP is requesting funding to begin modestly accelerating the pole replacement program from the current level of 2,100 poles per year to approximately 2,400 poles in FY 2012-13 and 2,800 poles in FY 2013-14, which would reduce the replacement cycle to 133 years. To achieve the recommended 60-year cycle, 5,000 poles per year would need to be replaced each year.

Figure 12: Historical and Forecasted Pole Replacement (FYs 2006-07 – 2013-14)



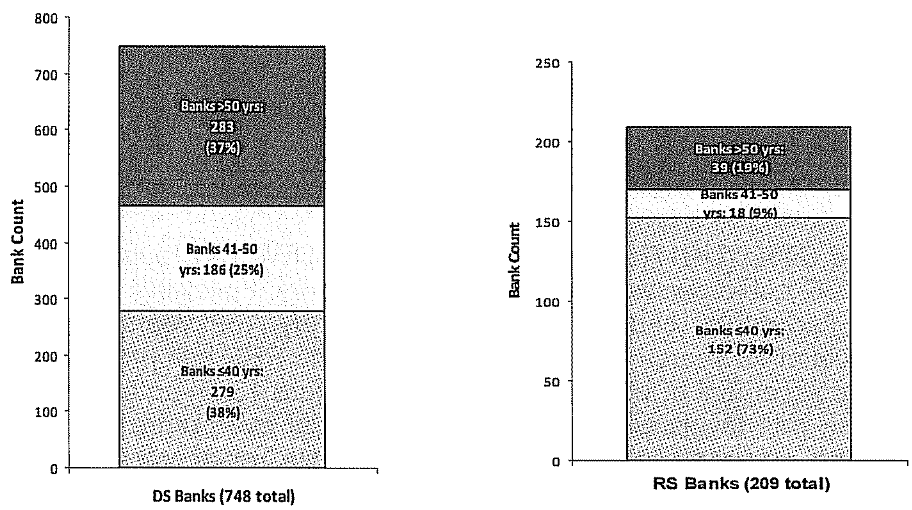
Underground Cable (UG) Replacement Program: LADWP has replaced, on average, 53 miles of UG cable per year over the past five years. Following LADWP's current replacement schedule, cable will be replaced every 159 years compared to a preferred level of 75 years. In the past five years, the PRP has provided funding for the rate of replacement of UG cable as shown in Figure 13. In an attempt to balance spending and rate levels and address other areas of even more critical need, the funding in the proposed rate plan reduces the cable replacement program to an average annual replacement of 27 miles of UG cable per year for the next two years. To achieve the preferred level of cable replacements, the rate of replacement would need to be 60 miles of cable per year, which would require additional revenue increases.

Figure 13: Historical and Forecasted Cable Replacement (FYs 2006-07 – 2013-14)



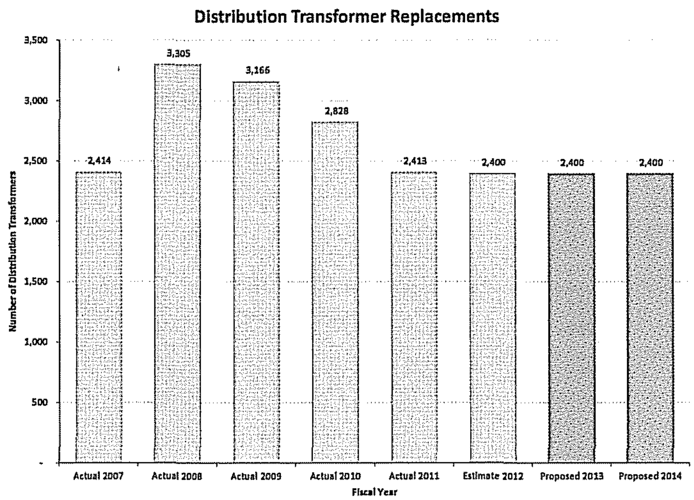
Substation Transformer Replacement Program: As Figure 14 shows, over 60.0% of LADWP's 957 substation transformer banks are over 40 years old, with 37.0% over 50 years old. These transformer banks are nearing the end of their service life and are critical to the continued reliability of the Power Distribution System. Replacement of these banks is needed due to the large number of customers that lose power when these transformers fail. From the aging graph below, significant progress has been made over the past five years to address the very old, large bulk power receiving station banks. Work continues for these as well as increased replacements for aging neighborhood distributing station transformer banks. Two areas that need to be addressed, not shown in the illustration, are needed replacements for large switching station transformer banks and replacement of the large transformers in LADWP's generating stations. A plan is being developed to address those assets.

Figure 14: Distribution System and Receiving System Bank Aging



Distribution Transformer Replacements: In recent years, the PRP has provided funding to replace significant numbers of transformers as shown in the figure below. Prior to the heat wave in July 2006, LADWP installed about 2,000 transformers per year. Following that heat wave, which caused a significant number of transformer failures, LADWP increased transformer installations by 20.0%, implemented an asset modeling tool, and does substantial replacements every year in preparation for summer. Transformer replacements are expected to average 2,400 for the next two years, as depicted in Figure 15. At this rate of replacement, the average age of LADWP's transformers will remain at 27 years.

Figure 15: Historical and Forecasted Distribution Transformer Replacements (FYs 2006-07 – 2013-14)



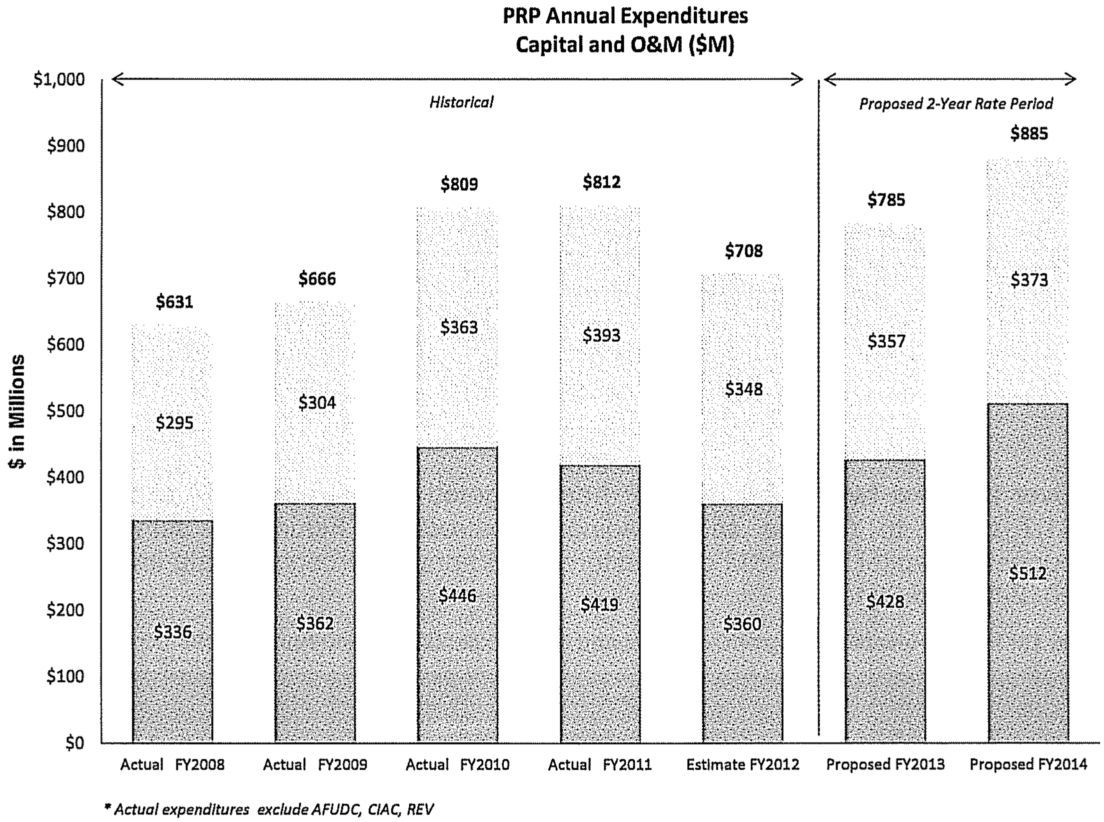
Over the next two years, LADWP has budgeted capital and O&M expenditures of $1.7 billion to replace critical aging infrastructure. Figure 16 summarizes the budgeted capital and O&M expenditures and annual percentage rate impact for FYs 2012-13 and 2013-14.

Figure 16: Power Reliability Program – Capital and O&M Expenditures and Annual Rate Increase

Cost Driver ($M)	Cost Type	Current Year	Proposed Rate Period	
		FY 2012	**FY 2013**	**FY 2014**
PRP Expenditures	Capital	$360.2	$427.5	$511.9
	O&M	348.1	357.1	373.3
Total Expenditures		$708.3	$784.6	$885.2
Annual Incremental Percentage Rate Increase		-	**0.9%**	**0.8%**

The actual annual expenditures from FY 2008 through FY 2012 (FY 2012 estimated) are shown in Figure 17 below, along with the proposed PRP spending levels for the next two fiscal years.

Figure 17: PRP Historical and Upcoming Two-Year Period - Capital and O&M Expenditures



Balancing investment levels for infrastructure reliability with the need to comply with external mandates while mitigating rate increases to the extent possible will continue to be a major challenge for LADWP. As a result, the Department will focus available resources on maintaining critical assets and enhancing processes to offset the impact of lower than desired PRP funding in the short term with the goal of maintaining existing reliability levels. LADWP is implementing programs to balance asset management, efficient cost management, and service levels in the near term, recognizing that, in the longer term, focused and increased PRP spending will be required to replace aging infrastructure (i.e., move to critical assets prioritization based on exposure and risk).

MARKET DRIVEN

Fuel and Purchased Power

LADWP must account for purchasing significant volumes of fuel and for purchased power and related fuel costs (as well as exposure to fuel price volatility) in its budget, operating, and rate plans. Fuel in this context includes all costs associated with natural gas, coal, and nuclear fuel procurement. Fuel also includes emissions, greenhouse gas reduction, and retirement costs. Similarly, purchased power from coal, nuclear, renewable, and other sources includes all costs associated with payments made for contracted energy purchases.

Fuel costs are driven primarily by free market forces and can fluctuate significantly year to year, and within a year. LADWP mitigates the risk of price volatility through financial hedging programs, owned gas fields, and long-term fixed price contracts. The Department's gas hedging program, which began in 2002, was implemented against the backdrop of extreme volatility in natural gas prices to maintain stable net income levels and supply reliability. The purpose of the Department's hedging program is to reduce the volatility of the Department's costs and resulting rates paid by its customers. Hedge programs limit the exposure to natural gas price swings by using physical and financial contracts and gas storage.

Over the next two years, LADWP expects fuel and purchased power costs to total $2.7 billion. Figure 18 summarizes the budgeted fuel and purchased power costs and annual percentage rate impact for FYs 2012-13 and 2013-14.

Figure 18: Annual Fuel and Purchased Power Costs and Annual Rate Increase

Fuel / Purchased Power Costs ($M)	Current Year	Proposed Rate Period	
Fiscal Year	**FY 2012**	**FY 2013**	**FY 2014**
		Fuel	
Biomethane	$60.0	$81.5	$81.5
Natural Gas	252.8	199.2	189.8
Coal	69.9	74.2	76.6
Nuclear	20.8	16.6	21.0
Fuel Subtotal	**403.6**	**371.5**	**368.9**
		Purchased Power	
Renewables	255.0	246.8	281.0
Coal	427.5	476.7	515.3
Nuclear	58.2	61.4	63.0
Others[3]	155.3	143.1	140.9
Purchased Power Subtotal	**896.0**	**928.1**	**1,000.2**
Total	$1,299.5	$1,299.6	$1,369.1
Annual Incremental Percentage Rate Increase	-	**0.5%**	**1.2%**

Feed-in Tariff Program: The FiT is a program to encourage customers to invest in customer-owned renewable technologies, including solar facilities. Power supplied by the FiT is considered a power purchase agreement (PPA) and is budgeted as O&M expense in the fuel and purchased power budget. LADWP and the City benefit from the procurement of this power in several ways — the power counts toward the RPS requirement, and there are reliability and economic benefits to having the power produced in the City. The rates presented in this letter include a 75 MW FiT program phased in by year-end of 2016, under which LADWP will purchase power generated by

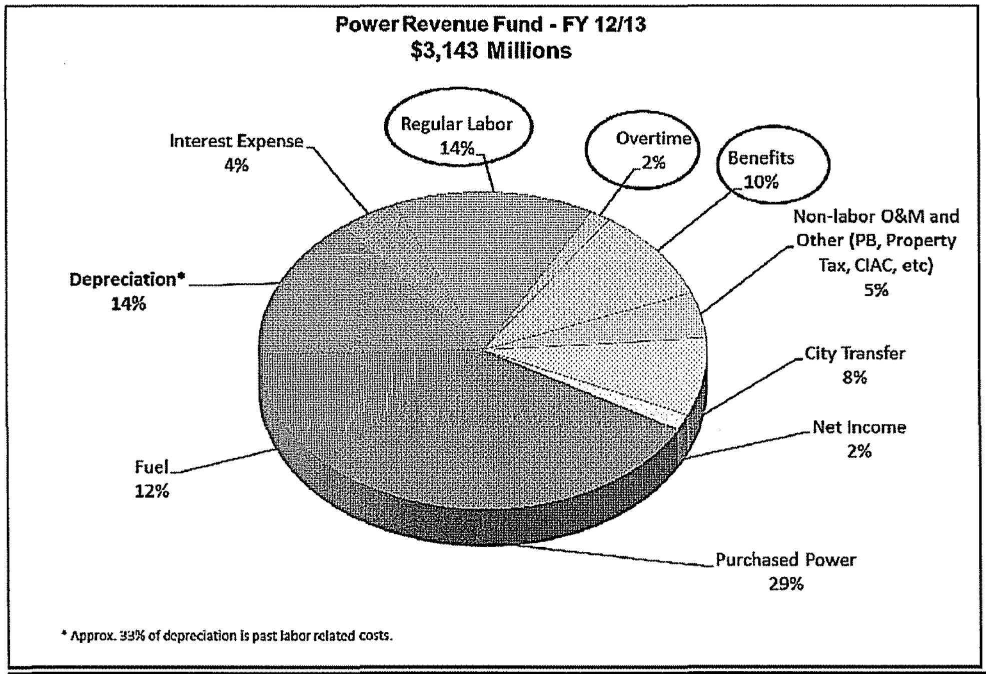
[3] "Others" category includes economy purchases, cogeneration, non-RPS transmission, and Hoover hydro power

local solar power producers. Over the next two years, LADWP has budgeted O&M expenditures of $6.73 million for the FiT program.

Other Considerations

The rate covenant contained within LADWP's bond indentures requires that LADWP pay all basic operating expenses required to operate and maintain the Power System. These expenses typically escalate over time due to inflation and provide pressure on rates other than the cost pressures LADWP faces from the need to rebuild aging infrastructure and address regulatory mandates and goals. LADWP has separately estimated the impact of inflation and pension costs (benefits include both pension costs and healthcare costs) on basic operations. Figure 19 shows that portion of the Power System's revenue requirement and proposed rates represented by wages and benefits in operating and maintenance expenses; inflation (in the form of cost of living adjustments, or COLA) and pension costs cause increases in wage and benefit costs over time. Collectively, wages and benefits represent approximately 26.0% of the Power System's $3.15 million revenue requirement for FY 2012-13. The proposed rates for the next two years are designed to provide the revenue to cover these expenses.

Figure 19: Power Revenue Fund (FY 2012-13)



APPENDIX 10: Public Outreach Summary (April – August 2012)

Group	Date	Attendance
Neighborhood Councils		
Greater Wilshire NC	04/11/12	31
Rates Briefing with DWP MOU Committee	04/16/12	
Rampart Village NC	04/17/12	22
NC Valley Village	04/25/12	25
Sunland Tujunga NC	05/09/12	40
Valley Alliance of NCs (VANC)	05/10/12	35
NC/DWP MOU OSC & LANNC	06/02/12	45
Tarzana NC	06/12	
Sylmar NC	06/12/12	6
Pacoima NC	06/20/12	36
Hollywood United NC	07/16/12	35
NC Valley Village	07/18/12	15
Central Hllywd NC	07/23/12	14
Winnetka NC	07/12	
Greater Valley Glen NC	08/06/12	15
South Robertson NC	08/12	
Glassell Park NC	6/19/12 & 8/21/12	
Harbor Gateway North	5/10/12	
Harbor Gateway South	5/10/12	
Highland Park	4/15/12	
Arroyo Seco	4/15/12	
Toluca Lake	08/21/12	35

Group	Date	Attendance
Sub-Total	**22**	
General Workshops		
Harbor Area (CD 15) Rates Briefing	04/25/12	
West Valley Area (CD 3) Rates Briefing	04/26/12	
DWP Metro regional rates workshop	04/28/12	
South LA Area (CD 8) Rates Briefing	04/30/12	
East LA Area (CD 14) Rates Briefing	05/02/12	
Central Valley Area (CD 6) Rates Briefing	05/03/12	
West LA Area (CD 5) Rates Briefing	05/10/12	
Sub-Total	**7**	
Council Office Hosted Workshops		
CD 4 local area community meeting	05/15/12	1
CD 2 local area community meeting	05/16/12	32
CD 7 local area community meeting	05/17/12	0
CD 6 local area community meeting	05/21/12	8
CD 8 local area community meeting	5/12	
CD 11 local area community meeting	5/12	
CD 10 local area community meeting	5/12	
CD 12 local area community meeting	5/12	
CD 15 local area community meeting	5/12	
CD 9 local area community meeting	06/13/12	
CD 15 local area community meeting	06/14/12	10
Sub-Total	**11**	
Business Workshops		
Rates Briefing with Los Angeles Area Chamber of Commerce Energy, Water & Environmental	04/20/12	

Group	Date	Attendance
Sustainability Council (committee)		
Rates Briefing with Central City Association	05/03/12	
Premier Accounts Rates Briefing	05/03/12	
Rates Briefing with VICA (Valley Industry & Commerce Association)	05/31/12	
Rates Briefing with VICA Energy, Environment, & Utilities Committee	06/07/12	
Rates Briefing with BOMA (Building Owners & Managers Association)	06/08/12	
Rates Briefing with LABC Executive Committee (LA Business Council)	06/12/12	
Follow Up Rates Briefing with VICA Energy, Environment, & Utilities Committee	08/02/12	
Sub-Total	**8**	
Other Workshops		
Council Staff Rates Briefing	04/26/12	
LADWP Employee Rates Meeting	05/30/12	
Community Rates Briefing with Repower LA Coalition/Scope/Agenda	07/21/12	
Sub-Total	**3**	
Total	**51**	

CITY OF LOS ANGELES

CALIFORNIA

August 23, 2012

The Honorable Members of the Los Angeles City Council
City Hall
Los Angeles, CA 90012

Honorable Members:

Please find attached the **Los Angeles Department of Water and Power (LADWP) – Power System Financial Review and Rate Restructuring Analysis** report. The Financial Review was prepared in accordance to Council Action, of April 8, 2011, instructing the City Administrative Officer (CAO) and the Chief Legislative Analyst (CLA) to conduct an independent third party review of the LADWP's Revenue Requirements/Rate Restructure and Rate Action proposals (CF#10-0475-S7). On December 2, 2011, the City Council also instructed the CAO and the CLA to include an assessment of cost reduction options as part of the Financial Review (CF#10-0475-S8).

The Office of Public Accountability (OPA) was included as a joint administrator of the Review upon the establishment of the Office. PA Consulting Group (PA) prepared the Financial Review through a contractual agreement through the CAO/CLA and the OPA.

The objective of the Financial Review of the LADWP's power system rate and rate restructuring proposal is to ensure that the financial interests of the City residents are protected by conducting a rigorous analysis of the financial condition of the LADWP, major cost drivers and the impact on the ratepayers. Furthermore, the goal is to provide greater transparency, comprehension and confidence of each of these elements prior to consideration of a proposal by the City's decision making bodies.

<u>Please note that PA's Review provides the following key findings and recommendations:</u>

Power Rate Proposal:

- The LADWP's increasing revenue requirements are driven by regulations, power system reliability needs, and credit rating considerations.

- To address these needs in the short-term, the LADWP's proposed 5.5% average annual two-year rate increase is determined to be reasonable and warranted.

- The surcharge-based restructuring approach of the two-year rate increase should be revisited in two years' time and be replaced with fully restructured permanent rates once legal considerations allow.

Cost Reduction Assessment:

- In 2011, the LADWP launched a 3-year cost reduction plan and has met or exceeded its first year objectives through the implementation of a hiring freeze, eliminating vacancies, reducing overtime costs, refinancing debt and increased collections.

- Achieving operational cost containment will help mitigate significant future rate increases. Many of the transformational changes cannot occur without renegotiating the existing labor contracts. The existing labor contracts expire in approximately two years.

In conducting the Financial Review, every attempt was made to ensure the independence of PA from the LADWP. Information was provided and verified by the LADWP. PA was tasked with reviewing information, comparing LADWP to other utilities and developing their own analysis and conclusions. The PA scope of work was established independently by the CAO/CLA and OPA. Our Offices limited our interaction with PA to clarification of information, formatting, contract compliance and the checking of logic. PA was not directed in the formulation of conclusions and/or recommendations.

Sincerely,

Raymond P. Ciranna for
Miguel A. Santana
City Administrative Officer

Gerry F. Miller
Chief Legislative Analyst

Frederick H. Pickel
Office of Public Accountability/
Ratepayer Advocate

CC: Honorable Mayor Antonio R. Villaraigosa
Honorable Board of Water and Power Commissioners
Ronald O. Nichols, LADWP General Manager

PA Consulting Group

Los Angeles Department of Water and Power Power System Financial Review and Rate Restructuring Analysis

Prepared for the Office of Public Accountability (OPA), Chief Legislative Analyst and the City Administrative Officer (CAO) of the City of Los Angeles

August 23, 2012

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One California Plaza
300 S. Grand Avenue, Suite 3840
Los Angeles, CA 90071
USA
www.paconsulting.com

Executive summary

The Los Angeles Department of Water and Power (LADWP or "the Department"), driven by regulatory mandates and infrastructure requirements, is transforming the Power System into a more nimble, efficient, and environmentally friendly system. This transformation will increase costs, driven by capital investments to meet regulatory compliance obligations, upgrades for system reliability, expanding the energy efficiency program, and cash reserves required to maintain the Power System's AA- credit rating. To fund these programs, LADWP is proposing rate increases to be implemented with a new set of rate surcharges authorized under new rate ordinances.

LADWP is facing multiple regulatory mandates, including compliance with a Renewable Portfolio Standard (RPS) and the elimination of once-through cooling (OTC) in its ocean side plants. Additionally, the Department is planning to accelerate its regulatory compliance away from coal with a desirable but costly early divestment of its portion of the Navajo coal plant. Funding is also needed to maintain a power system infrastructure that has suffered chronic under investment over the years.

The current financial plan[1] – and LADWP's preliminary numbers for fiscal years 2015 through 2017 – feature increasing operations and maintenance (O&M) expenses and an expanding capital funding plan that calls for more than $7 billion in capital expenditures over the next five years, more than two-thirds of it funded by debt. Meeting the financial needs of the LADWP system will require nearly $500 million in increased retail revenue in FYs 2013 & 2014,[2] and preliminary estimates indicate the need for an additional $2.4 billion in the three years following.

These are costly but necessary obligations. To meet them a utility can raise rates, reduce costs, or both to free up the necessary capital. After considering the regulatory challenges faced by the Department, examining the Power System's financial analyses, and considering a range of cost reduction options, PA finds that LADWP's two-year financial plan, with its underlying programs to meet regulatory mandates and maintain system reliability, should be funded. With significant cost reduction opportunities limited in the next two years, the proposed rate increase is reasonable and warranted. For this two year period the majority of the additional funding needed will come from revenue increases. In the years following this two-year rate cycle there are significant opportunities for cost reduction, which are discussed later in this report.

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[1] The Department's financial plan used for the revenue requirement analysis, Case 89, reflects the 2-year rate increase proposal for FYs 2013 and 2014 and offers preliminary projections for fiscal years 2015 through 2017. The Department's rate request is based on the figures for 2013 and 2014, and it considers the figures for future years to be indicative and preliminary. PA has generally reviewed spending levels over all five years, because the longer time period captures the range of near-term spending needs, better indicates trends over time, and is not as easily distorted by cost shifts from one year to another. However, PA does acknowledge that the outer year projections are not necessarily based on firm plans and are thus subject to much greater uncertainty.

[2] A set of PA recommendations on the rate restructuring – specifically, removing the cap on the Incremental Reliability Cost Adjustment surcharge (IRCA) and moving away from the corresponding balancing account – caused LADWP to revise its Financial Plan. The new plan (Case 119), will change the rate increase from 4.8% and 6.0% in FY 2013 and FY 2014, respectively, to 4.9% and 6.0%. However, the financial plan presented by the Department in its Power System Rate Proposal and on which this report's financial analysis is based is Case 89. Other than the different treatment of the IRCA (referenced in the first sentence of this note), the only significant differences between Cases 89 and 119 are the timing of the amortization of the outstanding balance in the RCA Adjustment Account and an assumption on how quickly FY2013 energy efficiency investments will impact usage. O&M and capital expenditures, for example, are identical.

LADWP's base rates have also not increased since 2009 and the Energy Cost Adjustment Factor has not increased since July 2010. PA recommends approving the proposed rate increases of 4.9% and 6.0% in fiscal years 2013 and 2014, respectively, and supports the accompanying rate restructuring as an imperfect but necessary adjustment to account for current legal considerations (see Section 4.5).

PA sees evidence of improving fiscal discipline under new management and a level and quality of communication from Department management that has improved markedly from prior leadership. The Department has effectively harvested low hanging fruit for cost reduction opportunities which has relieved some pressure from near-term revenue requirements. Achieving needed transformational cost reductions in the years ahead will require leadership and cooperation from City management, the LADWP and its labor unions. In other words, changing the way LADWP operates and lowering its costs is not a problem that LADWP management can successfully undertake alone.

Part One of this report looks at the programs and issues that drive the Department's rate request, the structure of the rate request itself, and the proposed changes to the power ordinances. In Part Two, the report separately examines cost reduction issues and opportunities that should be pursued in the years ahead.

Part One - Rate Proposal

LADWP customers have enjoyed some of the lowest electricity rates in the State of California in the past five years, with system average electricity rates 10% to 20% lower than its peers' rates. Power System costs are increasing though, driven by regulatory mandates and reliability investments, and are expected to continue increasing through 2014. The Department is proposing to meet its increasing costs through a rate increase. Given the legal and infrastructure requirements faced by the Department, and the positive developments made by current LADWP leadership, PA believes that this rate increase is necessary and warranted.

LADWP rates and O&M costs have historically been lower than those of its peers, but are increasing rapidly

LADWP electricity base rates have not increased since 2009 – the Energy Cost Adjustment Factor (ECAF) increased in July 2010 – and have historically been lower than those of its publicly-owned (POU) and investor-owned utility (IOU) peers. A benchmarking analysis comparing LADWP to its utility peers reveals that LADWP's electricity prices from 2006 to 2011 were much lower than average and lower than those of nearly all of its IOU and POU peers, aided by low-variable cost coal and nuclear generation. As described in Section 2.1.1 with the exception of Sacramento Municipal Utility District (SMUD) (in 2009, 2010 and 2011), LADWP has enjoyed lower average system retail rates than other municipal utilities and California investor-owned utilities. LADWP's O&M cost metrics have also been lower than average.[3]

These historical cost advantages appear to be eroding. The Department's retail rates and O&M costs have been increasing more rapidly than those of its peers. LADWP's system average retail rates grew at a compounded annual growth rate of 5.7% over the same 2006-2011 time period, higher than any of its peers. Similarly, LADWP O&M per MWh and O&M cost per customer increased at annual rates of 7.3% and 6.6%, respectively, 39% and 62% higher than the equivalent panel averages. Finally, the

[3] Note that it is harder to interpret the source of lower O&M costs, which could theoretically result as much from underinvestment or greater commitment to capitalizing activities as it could from efficiency (especially given the findings of higher salaries at LADWP).

Department's 56% capitalization rate is already higher than that of all other utilities reviewed with the exception of SMUD, indicating the Department's greater reliance on debt funding than its peers.

The Department's proposed 2-year financial plan and preliminary projections through FY 2017 require significant rate increases, driven by obligatory investment in system reliability and regulatory compliance

Reversing the trends in cost and rate growth will be extremely difficult given the capital funding obligations required in coming years. In spite of well-conceived compliance plans and initial efforts to limit O&M cost growth, the Department's current 2-year financial plan and preliminary projections through FY 2017 reflect ongoing cost and rate increases.

The Department's increasing revenue requirements are driven by regulations, power system reliability, and credit rating consideration.

Regulations

A major part of the Department's financial plan is driven by a series of regulatory mandates. In particular, the Department is required to meet the following regulatory constraints in Table ES-1.

Table ES- 1: Major Mandated and Non-Mandated Regulations

SCAQMD Stipulated Order and the OTC elimination policy
The SCAQMD stipulated order requires LADWP to reduce local air emissions through repowering its less efficient in-basin generating facilities. The Once-Through Cooling (OTC) elimination policy, as implemented by the State Water Resources Control Board, mandates that the Department's in-basin fossil generators with a "once-through" cooling system be repowered or shut down.
SBX1-2, California's Renewable Portfolio Standard
SBX1-2 requires that 20%, 25%, and 33% of the Department's electricity sales be met through renewable sources by 2013, 2016, and 2020, respectively. Currently, penalties associated with non-compliance have not been defined under the mandate.
AB 32 and SB 1368
AB 32's goal is to reduce California's Greenhouse Gas Emissions to 1990 levels by 2020. LADWP is in compliance with AB 32 and does not currently project future AB 32-related expenditures. SB 1368 prevents LADWP from taking any new coal-fired power under long term contract. Due to the grandfathering of current ownership stakes and contracts embedded in SB 1368, the Department's financing plan will not be heavily impacted by the bill until the expiration of its contract share in Navajo Generating Station in 2019. Once the Navajo contract expires, or should LADWP follow through with plans to divest in 2016, the cost of transitioning away from coal will be substantial. LADWP receives approximately 40% of its power through its interests in the Intermountain Power Project and Navajo, and 14% from Navajo alone, at a significant discount to the gas-fired and renewable generation options that would likely replace this generation.
Energy Efficiency (AB 2021) (Non-mandated)
AB 2021 calls on publicly-owned utilities to "identify all potentially achievable cost-effective electricity energy savings and establish annual targets for energy efficiency savings and demand reduction for the next 10-year period." LADWP does not technically have a legally binding obligation to meet any specific target, but the Department has committed to a 10% target for its energy efficiency program as part of the Board-mandated objectives.

Power System Reliability

In the 2010 Power Integrated Resource Plan (IRP), LADWP stated that the majority of its electrical infrastructure is 40 to 70 years old. The Department also has an increasing maintenance backlog. To replace aging transmission and distribution infrastructure in a systematic and sustained manner, the Department has implemented the Power Reliability Program (PRP). The PRP's goals are:

- Improve reliability of lines and substations
- Conduct regular inspections and maintenance to discover potential setbacks and prevent faults and outages
- Replace equipment according to life expectancy.

LADWP's power supply also faces reliability challenges stemming from its aging fleet of plants, tightening reserve margins, and RPS-driven trend towards intermittent generation. As LADWP increases its reliance on intermittent renewable sources such as wind and solar, it also needs ample generation capacity that possesses high power ramp rates and quick response ability.

Credit Rating Considerations

For the Power System, maintaining its AA- credit rating and preserving the associated borrowing cost are critical to maximizing the cost-effectiveness of its capital program, and LADWP determines its revenue requirement with an eye towards meeting the debt service coverage ratio and cash on hand metrics needed to maintain its current rating. This is not unusual, and just as there is a benefit to having a low cost of capital there is a cost to being downgraded (in the form of higher interest payments). Still, there may be room to consider how far a utility should go to protect its credit rating.

The Department has responded effectively, but meeting its obligations will be costly in future years

The Department has generally positioned itself quite well to meet its obligations in a sensible and fairly cost effective manner. On RPS, for example, the Department owns or has contracted with a portfolio of assets that is fairly diverse (both technologically and geographically), includes cost-effective wind and biogas deals, and generally takes advantage of existing LADWP transmission. To meet air emission standards and eliminate once-through cooling, the Department has initiated an ongoing effort to repower its in-basin generation in a manner that will increase the flexibility and performance of the system. While PA recommends closely monitoring the associated construction costs and benchmarking them against like projects elsewhere to gauge their ultimate cost effectiveness, we believe the effort to add more quick start capability and voltage support will serve LADWP well as it seeks to integrate increasing quantities of intermittent renewable resources in future years.

Although necessary and well–conceived, the costs of compliance and maintaining reliability do add up:

- O&M costs are projected to grow from $926 million in 2012 to $997 million in 2014, a compound annual growth rate of 3.7%.
- Capital expenditures are projected to grow at a much greater annual rate of 15.5% over the same time period, from $1,238 million to $1,650 million.[4]

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[4] Note: capital costs are "lumpier" than O&M, as capital expenditures in a given year tend to be driven by individual large investments. As a result, growth rates are heavily impacted by the start and end years selected. Capital expenditures are high in 2014 due to repowering costs at Scattergood, major expenditures on the Barren Ridge Transmission Project, and heavy PRP

- The bulk of the capital expenditures are fueled by debt. The Power System did not borrow in FY 2012 – a prudent decision given the likely negative response of ratings agencies had borrowing preceded a rate action – but expects to borrow $1,131 and $1,238 million in FYs 2013 and 2014, respectively.

The Department has made an effort to limit near-term cost increases, but this effort to contain rate growth has generally been achieved not through widespread cost reduction but by shifting labor and other O&M costs (which impact rates in the year incurred) to capital (which can be amortized over a number of years).

In spite of the more muted impact on rates, debt-fueled capital spending increases like these cannot be sustained indefinitely. These costs will have to be borne by ratepayers, so rates need to rise.

The Department's rate restructuring proposal

To implement the necessary rate increases, the Department has created new rate surcharges to be approved as an addition to the current rate structure. Legal considerations have led LADWP to design this new rate structure rather than redesign and increase the current rates (see Section 4.5). The Department has created a set of surcharges on top of the current rates, broken down by cost categories. These surcharges will be applied over and above the rates previously in effect – based on the increase in the Department's costs – and will be grossed-up to account for City Transfer expenses. The surcharge structure is the recommendation of the City Attorney's Office, based on legal considerations (see Section 4.5). This complex structure is not desirable for the long term, but based on the advice from the City Attorney it is warranted for a limited time.

In a 2010 review, PA suggested that the Energy Cost Adjustment Factor (ECAF) be decomposed into several differently treated rate components. Different cost recovery principles would be applied to the three components, depending on their controllability and predictability. The Department has characterized its set of surcharge components as a "good faith" move towards restructuring because even if the current ECAF is not restructured, the additional charges will be.

The set of surcharges is illustrated in Figure ES-1. In addition to the three components derived from the ECAF, the new structure includes the Incremental Reliability Cost Adjustment (IRCA), which is associated with increases in PRP costs, and explicit (not pass-through) additions to the base rates in the current ordinance.

Finally, the new structure includes a Base Rate Target Adjustment (BRTA) which has been characterized as a revenue decoupling charge related to energy efficiency. A revenue decoupling charge is a way to ensure that if rates based on sales volume (kWh) do not achieve a desired revenue level, rates will subsequently be increased to account for the shortfall. The BRTA would guarantee collection of the base revenue target if revenues fall short due to energy efficiency or any other reason. PA thought that application was unnecessarily broad and in response the Department agreed to limit BRTA to target revenues for only the two years FY2013 and FY2014.

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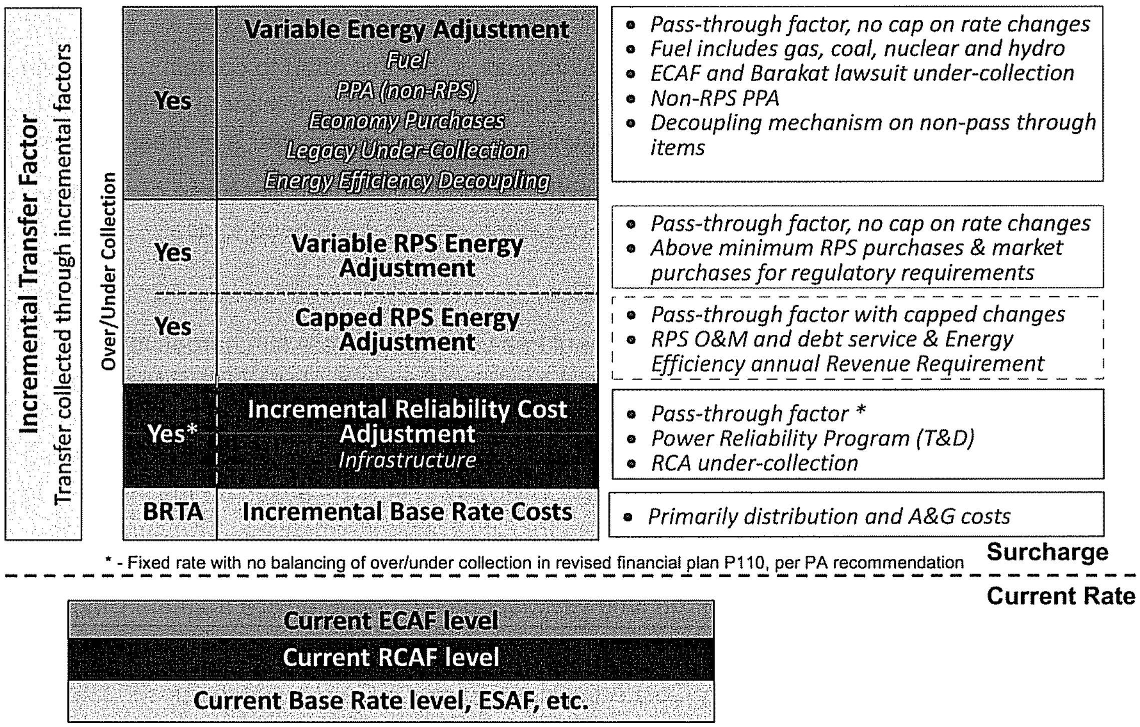
investment, but preliminary projections for 2015 through 2017 project lower levels of investment in those years. The annual growth rate from 2012 through 2017, when preliminary estimates call for $1,467 million in capital expenditures, is only 3.5%.

Figure ES-1: Structure of the surcharge rate proposal



Based on LADWP diagram "Proposed Power Rate Structure" updated 5/3/12 and draft Incremental Rate Ordinance

The Department's rate proposal involves two new ordinances. Ordinance 180127 (the Electric Rate Ordinance) will not be amended or repealed; the rates and Factors (ECAF, RCAF, etc.) specified in that ordinance will remain in force. The City Council will be asked to pass two separate and independent ordinances. The first new ordinance defines the set of rate surcharges but is intended to leave all rates and schedules in the Electric Rate Ordinance unchanged. The second new ordinance will effectively modify the Electric Rate Ordinance by adding two new rates to be used by customers instead of current rates: a new Experimental Alternative Maritime Power (AMP) interruptible schedule and a new Rider EV for electric vehicles. The two ordinances are designed to become effective simultaneously.

The rate restructuring proposal requires close scrutiny by City policy makers and the Ratepayer Advocate in the areas of precedents, cost controls, and transparency. However, it is reasonable to approve this restructuring on a temporary or interim basis until uncertainty arising from legal considerations is resolved (see Section 4.5).

PA believes that short of making unprecedented and significant cuts, further delaying the adoption of the rate increases will only exacerbate the level of future needs. The longer approval takes the greater the near-term rate increase will be and the greater the risk of compromise to the current slate of important spending programs. 41% of the estimated surcharges in FY14 are for funding mandated programs, and if at least that level of rate increase is not approved LADWP and the City will be faced with being in non-compliance or further increasing LADWP debt beyond already high levels.

Rate proposal recommendations

LADWP's two year financial plan with its underlying programs to meet regulatory mandates and maintain system reliability should be approved and funded. With significant cost reduction opportunities limited in the next two years, the proposed rate increase is reasonable and warranted. Similarly, PA recommends the proposed rate ordinances be adopted on an interim basis.

Additional recommendations:

- PA recommends the surcharge-based restructuring approach be revisited in two years' time, and that it be replaced with fully restructured permanent rates once legal considerations allow (see Section 4.5). Their replacement should not be left to chance: specific language calling for a study of the appropriateness of a full restructuring and a recommendation to the Mayor, City Council, and LADWP management, should be written into the proposed ordinance to ensure rates are properly redesigned as soon as possible.
- As explained later in the document, PA recommends the Department conduct a new formal cost of service study in order to prepare for subsequent rate restructuring.
- PA believes that in the upcoming rate action the City should explicitly consider some of the program costs that would be collected in the new surcharges, such as energy efficiency and PRP, and the new surcharge for base costs. The incremental base rate surcharge, for example, represents 0.34¢/kWh in FY 2014 rates that are not directly attributable to the key mandates related to conventional power plants (NOx control and replacement of once-through cooling).[5]

Part Two – Cost Reduction

The Department has effectively identified the quick wins in cost reduction opportunities and has relieved pressure from near-term revenue requirements. Additional near-term cost reduction opportunities that could reduce the magnitude of the proposed rate request are limited by the current union agreements. Over the long term to reduce its costs in a meaningful way, the Department with the cooperation of its unions and City Management will need to make transformational changes. Better financial planning, optimization of capital expenditures, and revisiting of options for regulatory compliance can all help limit expenditures, but the Department's biggest potential savings will come from reevaluating and readjusting its labor-related costs and policies, including salaries, pension, health benefits, and contracting out.

LADWP launched a 3-year cost reduction plan in 2011 and has met or exceeded its first year's objectives

In mid-2011, the Department proposed a three-year, $449 million cost reduction plan. Cuts included baseline cost reductions such as hiring freezes and cuts in overtime costs, cuts to projected future expenditures by eliminating vacancies or reducing non-labor planned investments, and cost reductions through refinancing or increased collections (which have no impact on operational activities and should really be made no matter what the financial environment).

The goals are relatively modest and the plan is weighted more towards curtailing projected cost increases than to eliminating existing costs, but it's a start. Early efforts have been promising -- after eight months,

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[5] See Section 4.4.3 for more details.

the Department projected it would meet or exceed each of its first-year cost reductions goals, indicating a commitment to cost containment that has not been seen previously.

Major future cost reductions will require transformational change

Assuming the Department intends to heed all regulatory compliance obligations, the number of cost cutting levers available to the Department is limited in this two year rate proposal period. RPS and repowering investments are in response to regulatory obligations – compliance strategies could be reconsidered, but the ultimate investments will remain significant. LADWP could potentially save money by cutting non-mandated investments, such as energy efficiency and the PRP or other infrastructure investments. From a cost perspective alone these reductions might make sense, but any significant cuts would have major reliability consequences or negatively impact popular programs such as energy efficiency. There may be middle ground worth considering if immediate reductions are imperative, but such cuts would not be without consequences.

Achieving cost reductions that will generate significant, long-lasting impacts on future rates will require transformational change at LADWP. To make meaningful cuts, LADWP will need to overhaul its work rules, pursue aggressive process improvements, and address the "building blocks" that impact the cost of all operational and investment activities. This will require close cooperation of the LADWP, City Management and relevant unions. It is not a given that this transformation can happen, it will require the collective will of all involved.

Two separate benchmarking studies suggest that Power System salaries are significantly higher than those of its peer utilities, and its health and pension benefits appear more generous than industry norms. LADWP's work rules also prevent effective outsourcing, a practice that serves as a primary cost reduction tool at similar entities. PA has not seen evidence of any major structural cost reduction programs to combat this, like those undertaken by other City Departments such as increasing employee retirement contributions, creating tiered pension programs, instituting employee co-pays and contributions for health benefits, or aggressively increasing the effort to achieve operational efficiency through contracting out.

The principal hurdles to implementing programs to restructure these labor costs are the current set of labor agreements, which prescribe wage and benefit levels and include clauses that limit the effectiveness of outsourcing as a cost reduction tool, and the lack of process improvement programs.

The Department could realize significant savings after 2014, and should take action to insure against cost increases from market forces outside its control

None of the labor related changes can likely transpire without successful renegotiation of the existing collective bargaining agreement, which does not expire until September 2014 in the case of IBEW. Change will not be easy and there is no guarantee of success, but the Department, with the support of the City and the cooperation of its labor unions, needs to work towards a contract that continues to protect the interests of its employees while also permitting compensation and benefit levels that are more consistent with market rates and removing obstacles to the efficiency measures that are needed to keep the Power System viable.

To evaluate the potential savings available from controlling these foundational costs, PA requested that the Department's financial staff complete financial planning scenarios to identify the possible savings from bringing employee compensation and benefits more in line with market rates. These cases were designed by PA and run at PA's request, and should not be considered to be endorsed or supported by the Department.

- Salaries – If the Department were able to achieve a 10% cut to labor costs, it could reduce the outer year retail revenue requirement by 1-2%.
- Medical benefits – Revenue requirement savings of 0.6% in 2016-17 could be generated by adjusting the medical plan.
- Pension benefits – Revenue requirement savings of 0.15% per year from 2013 to 2015 and 0.3% per year from 2016 to 2017 could be generated by adjusting the pension plan

The Department must also control costs because of the need to protect itself against downside risk resulting from market forces outside its control. Major generation outages, increased interest rates, or rising natural gas costs all stand to impact the Department. To evaluate the downside risk, PA worked with LADWP to run scenarios simulating the impact of high natural gas prices, high interest rates, and an extended outage. The changes assumed were enough to be significant but also well within the realm of possibility from an historical perspective.

- $6.50/MMBtu natural gas prices from 2015-17 could cost ratepayers $75 million per year
- With its increased borrowing, the Department will be vulnerable to interest rates moves
- A two-year outage at the Palo Verde nuclear facility would create cost increases of nearly $70 million per year in 2013 and 2014.

Cost reduction recommendations

The ground work for meaningful and transformational cost-cutting efforts and process improvement initiatives should begin immediately with the Department and a task force of City and Union personnel, beginning work towards a culture of process improvement and cost containment. With guidance from City leaders, LADWP should:

- Begin to work with the union to find common ground that allows greater flexibility to contract out effectively and bring salaries and benefits closer to market rates, as indicated by LADWP's utility peers.
- Conduct an independent benchmarking assessment or otherwise review the cost per plant and technology for the OTC repowering program to ensure that costs are reasonable on a per MW basis.
- Conduct a similar benchmarking effort or cost review for the Power Reliability Program. With $800 million to $1 billion in PRP expenditures annually, split roughly 50/50 between O&M and capital, small adjustments could generate significant savings (which could accrue to ratepayers or be reinvestment in further reliability upgrades).
- Find greater efficiency by pursuing process improvement efforts across a range of areas and practices. Appropriate studies should be completed to identify the cost reduction potential associated with a range of process improvements.
- Complete a rigorous review of its hedging plan in the interest of locking in today's low fuel prices and protecting ratepayers from downside risk.
- Evaluate the net impact of increasing the number of odd-hour shifts (at a 4-7% salary premium) as a means of limiting overtime.
- Identify opportunities to contract out and explore the potential savings to begin making a case where promising opportunities exist.
- Adopt a more methodical approach to assessing and communicating the viability of new investments, an important effort that has been practiced more effectively in the Water System. All

evaluations should include the consequences of inaction, alternatives considered, and cost-benefit analysis. Any non-mandated projects that cannot be shown to reduce costs or increase revenue collection should not be undertaken without further review.

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Glossary

AB	Assembly Bill
AMR	Automated Meter Reading
BRTA	Base Rate Target Adjustment
CAO	City Administrative Officer
CEC	California Energy Commission
CIS	Customer Information System
CLA	Chief Legislative Analyst
CPUC	California Public Utilities Commission
CRPSEA	Capped Renewable Portfolio Standard Energy Adjustment
DSM	Demand-Side Management
ECA	Energy Cost Adjustment
ESA	Electric Subsidy Adjustment
FY	Fiscal Year
GHG	Greenhouse Gases
IEA Survey	Industrial, Economic, and Administrative Survey
IOU	Investor-Owned Utility
IRCA	Incremental Reliability Cost Adjustment
LADWP	Los Angeles Department of Water and Power
MMBtu	Million Metric British Thermal Units
MOU	Memorandum of Understanding
MWh	Megawatt hour
O&M	Operations and Maintenance
OPA	Office of Public Accountability
OTC	Once-Through Cooling
POU	Publicly-Owned Utility
PPA	Purchased Power Agreement
PRP	Power Reliability Program
RCA	Reliability Cost Adjustment
RPA	Ratepayer Advocate (of the Office of Public Accountability)
RPS	Renewable Portfolio Standard
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SB	Senate Bill
SBX1-2	California Senate Bill - 33% by 2020 Renewable Energy Resources Program
SCAQMD	South Coast Air Quality Management District

SCPPA	Southern California Public Power Authority
SMUD	Sacramento Municipal Utility District
SWRCB	State Water Resources Control Board
T&D	Transmission and Distribution
VEA	Variable Energy Adjustment
VRDO	Variable Rate Demand Obligations
VRPSEA	Variable Renewable Portfolio Standard Energy Adjustment

1 Context

1.1 Study Objectives

PA was retained by the Office of Public Accountability (OPA)/Ratepayer Advocate (RPA), the Chief Legislative Analyst (CLA), and the City Administrative Officer (CAO) to provide support in conducting a revenue requirement analysis of the Los Angeles Department of Water & Power (LADWP or "the Department") rate and budget proposal released April 3, 2012. The study detailed in this report was completed with two primary objectives:

- Financial review and consideration of cost reduction opportunities – In September 2011, PA completed a comprehensive financial review of the LADWP Power System, working from its FY 2012 financial plan published in June 2011. The PA team reviewed and documented the financial and operational attributes within the Department's financial plan and made recommendations where appropriate. PA has now been retained to evaluate the Power System's latest financial plan and identify potential cost reduction opportunities.
- Analysis of LADWP's power rate restructuring proposal -- LADWP has provided details on its proposed new rate surcharges and the underlying rate design principles and mechanics. The rate proposal is extremely complicated as it strives to address legal considerations while protecting existing revenues (see Section 4.5). The core principles of the LADWP proposal strive to leave the current rates untouched but to add several surcharge components to cover the increases LADWP seeks in its revenue requirement. In this report PA provides a review of the Department's conceptual approach and offers several alternative design concepts that could provide greater transparency and oversight control.

1.2 Process

The team assembled to complete this review has significant familiarity with LADWP and insight into its operations, garnered through participation in previous projects focused on the Department. The majority of the staff was also involved in the 2011 Core Financial Review, the 2010 Energy Cost Adjustment Factor review, the 2012 water quality adjustment factor rate increase, the 2009 IEA Survey, and other small projects, and have extensive experience in the rate making process.

Over the course of this evaluation, PA has analyzed the Department's most recent budget and financial plan, reviewed the Memoranda of Understanding (MOUs) with labor and any "side letters" provided to us, and benchmarked LADWP's rates, O&M expenditures, capitalization ratio, and salaries against its utility peers. PA has also requested and reviewed documentation related to the Department's operations, staff, and work rules, and has performed interviews with key LADWP and City of LA staff.

PA's exploration of the options for (and impacts of) cost cutting began with a comprehensive data request to allow a robust analysis. PA then analyzed the Department's proposed cost reduction strategies and reviewed the Department's financial plan and supporting budget. PA's analysis is based on the LADWP's proposed 2-year financial plan (fiscal years 2013 and 2014) and the accompanying, but preliminary, projections for FY 2015-2017. Finally, PA worked with the Department's financial analysis team to complete a range of financial planning scenarios designed to gauge the revenue requirement impacts of cost cutting measures (e.g. reduced labor, health, and pension costs) and sensitivities outside of LADWP's control (e.g. high natural gas prices, high interest rates, and extended plant outages).

On the ratemaking side, PA's review has involved discussions with many members of LADWP staff, representatives of the City Attorney, and CLA and CAO staff. More recent discussions have also included the Ratepayer Advocate.

1.3 Report Structure

This report is presented in two main sections. The first focuses on the Department's proposals: the rate increase request and the rate restructuring proposal. The second part focuses on cost-cutting, from what the Department has done to mitigate the rate increase and what possible further cost-cutting alternatives exist. The report is organized as follows:

Part One - Rate Proposal

PA sought to shed light on the various aspects of the rate increase request from its magnitude, to its drivers and impacts on ratepayers. The rate increase analysis is based on the Department's two-year proposal (for Fiscal Years 2012-13 and 2013-14). Observations for the following three fiscal years are only based on preliminary numbers provided by the Department. With respect to rate restructuring, LADWP, the City, and PA worked closely together as the Department refined its conceptual approach. The amount of communication and cooperation we received from LADWP has been exemplary and all parties have strived to find an optimal solution to an extremely difficult situation. This report details the outcome of that effort.

- Background -- Provides some perspective on the magnitude of the proposed rate increase by first comparing LADWP's historical electricity rates, O&M expenses, and capitalization ratio to those of its municipal and California investor-owned utility peers. It also highlights the main drivers of costs behind the rate increase and the obligations that drive the Power System's revenue requirement.
- Power System Revenue Requirement -- Provides a systematic review of the Department's revenue requirement. It categorizes and explains the Department's O&M and capital spending plans as well as the City Transfer requirements.
- Power Rate Restructuring -- Focuses on the temporary rate restructuring mechanism proposed by LADWP. The rate proposal is extremely complicated as it strives to address legal considerations while protecting existing revenues (see Section 4.5). The core principles of the LADWP proposal strive to leave the current rates untouched but add several surcharge components to cover the increases LADWP seeks in its revenue requirement. In this section PA provides an overview of utility ratemaking, reviews the Department's conceptual approach, and offers several alternative design concepts that could provide greater transparency and oversight control.
- LADWP's Rates and Revenues Computation – Explains the ratemaking process and explains PA's review of LADWP's rates and revenues computation.
- Impact of the Rate Increase and Rate Restructuring on LADWP's Customers – Identifies impact of rate increase on LADWP customers.
- Rate Proposal Recommendations -- Provides conclusions from the rate proposal and rate restructuring review.

Part Two - Cost Reduction

- LADWP-Implemented Cost Cutting Efforts -- Assesses LADWP's most recently released cost cutting strategies, as laid out in a FY 2011-12 budget presentation in the summer of 2011, and details the performance against first-year targets as of March 2012.

- Future Cost Reduction Considerations -- Presents the considerations that will help inform and target any proceeding aimed at reducing costs at LADWP and follows by introducing cost reduction opportunities. PA presents results from two benchmarking studies that benchmark LADWP salaries against those of other utilities. PA also introduces the case for outsourcing, and expands on the contractual constraints that prevent LADWP from contracting out as much as it should. Finally, PA introduces 12 financial planning scenarios that were run with LADWP financial staff and identifies the savings potential of various cost reduction measures.
- Cost Reduction Recommendations -- PA identifies and recommends Power System cost reduction opportunities that merit further exploration.

Appendices

Part One
Rate Proposal

2 Background

LADWP is requesting a 5.5% average annual rate increase over the 2-year FY 2013-14 period.[6] Sections 2.2 and 3 examine the basis for this request by looking at the sources of increased costs, such as fuel and purchased power expenses, operating expenses, and the costs of complying with regulatory mandates, amongst other drivers. To put that rate proposal in perspective, note that LADWP's base rates have not increased since 2009 – the ECAF increased in July 2010 -- and that LADWP's electricity rates have in fact been very low in the last five years relative to those of its peers, both IOU and POU. As described in Section 2.1.1, with the exception of Sacramento Municipal Utility District (SMUD) (in 2009, 2010 and 2011), LADWP has enjoyed lower average system retail rates than other municipal utilities and California investor-owned utilities. Its O&M costs have also been lower.

Cost advantages historically enjoyed by LADWP appear to be eroding though, as both LADWP prices and costs are now increasing more rapidly than those of its peers. From 2006-2011, its system average retail rates grew at a compounded annual growth rate of 5.7%, higher than any of its peers. Similarly, LADWP O&M per MWh and O&M cost per customer increased at annual rates of 7.3% and 6.6%, respectively, 43% and 72% higher than the panel averages, respectively.

In the absence of power rate increases, the Department has met its growing costs by increasing its borrowing rate. Section 2.1.3 shows the Department has borrowed at a higher rate than its utility peers, though in 2012 the Department prudently stopped borrowing for fear of facing a credit rating downgrade given its debt levels in the absence of a rate action.

The Department faces a collection of significant challenges for which it will eventually need additional revenue, including:

- Meeting the Renewable Portfolio Standard (RPS), repowering generation facilities, and complying with other regulatory mandates (the costs of complying are detailed in Section 2.2.1 below)
- Providing reliable service with an aging infrastructure and the requirements of renewable resource integration (see Section 2.2.2)
- Maintaining the Power System's 'AA-' bond rating in the face of rising costs and an unstable economy (see Section 2.2.3).

2.1 Benchmarking LADWP's Rates, O&M Costs, and Capitalization Ratios[7]

PA completed a benchmarking analysis comparing LADWP to its municipal and California investor-owned utility peers, looking specifically at electricity prices and O&M costs. As expected, LADWP's electricity prices have historically been very low compared to those of its IOU and POU peers, aided by low variable-cost coal and nuclear generation. LADWP's O&M cost metrics have also been lower, though it is harder

[6] The 5-year average annual rate increase through FY 2017 would be 6.4% based on preliminary FY 2015-2017projections.

[7] Sources for electricity rates and O&M expenses are: SNL Financial, FERC Form 1, CPUC average customer rates presentation for PG&E, SCE and SDG&E, PWP annual reports, BWP annual reports, GWP annual reports, SMUD annual reports and SCL financial report.

to interpret the source of lower O&M costs, which could result as much from underinvestment as efficiency. At any rate, any cost advantages historically enjoyed by LADWP appear to be rapidly diminishing, as prices and costs have been increasing more rapidly than those of its peers. These rate and cost increases show no sign of slowing down, and will become increasingly difficult to contain in the event that the Department begins the anticipated transition away from its low-cost coal options.

PA developed a list of comparable utilities based on geographic location and core operating businesses. The list includes the following investor-owned and municipal utilities:

- Pacific Gas & Electric Co. (PG&E)
- San Diego Gas & Electric Co. (SDG&E)
- Southern California Edison Co. (SCE)
- Pasadena Water & Power (PWP)
- Burbank Water & Power (BWP)[8]
- Glendale Water & Power (GWP)[9]
- Sacramento Municipal Utility District (SMUD)

The analysis examines electricity rates (system average and residential) and O&M costs (per customer and per MWh).

2.1.1 Customer Electricity Rate

LADWP customers have enjoyed some of the lowest electricity rates in the State of California. In the past five years, the LADWP system average electricity rates have been 10% to 20% lower than the average rate of the peer panel every year between 2006 and 2009. This price advantage has been eroding, however, as evidenced by the steeper line reflected in Figure 2.1. The Department's average electricity rate has increased at a compounded annual growth rate of 5.7% since 2006, almost 64% higher than the average 3.5% growth rate of its peers' prices.

Electricity rates are driven by costs, so it follows that LADWP's annual costs are lower per kWh, on average, than those of its peers. Certain cost elements are driven by factors that are more difficult for the utility to control, at least in the short term. Fuel costs, for example, are a major driver of electricity prices. While a utility can and should plan to minimize these costs over time, there is little a utility can do in the near term outside of hedging effectively to control these costs.

[8] Burbank Water & Power's 2011 Annual Report does not provide data regarding customer counts and electricity rates.

[9] Glendale Water & Power is not included in the O&M expense benchmarking analysis due to differences in its operating expense statement structure.

Figure 2.1: Historical System Average Retail Rate and Residential Rates Peer Comparison (2006-2011)

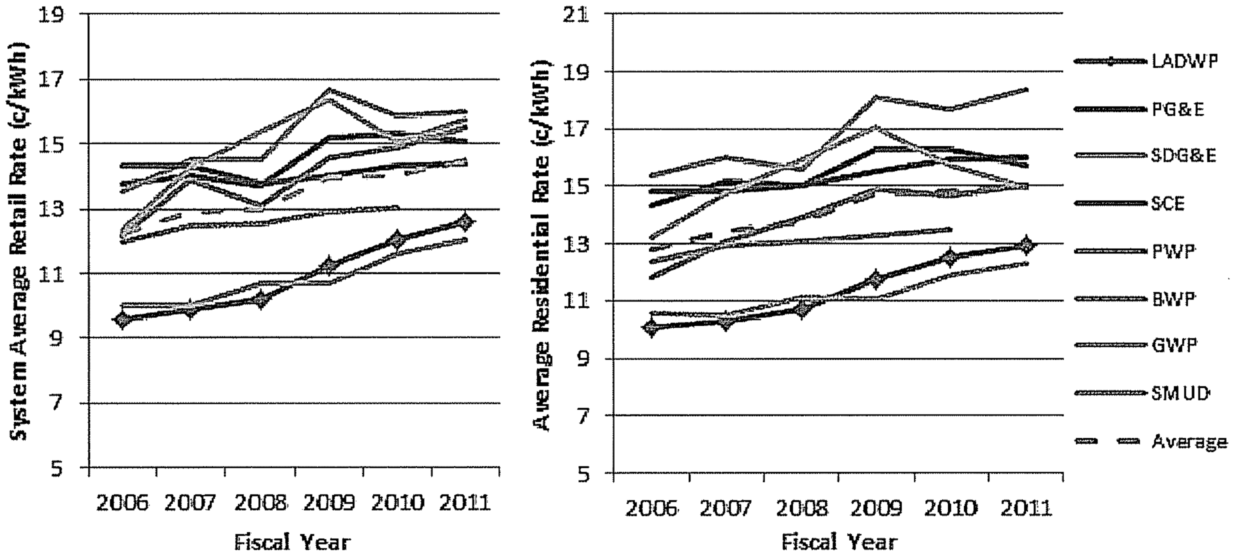


Table 2.1: Electricity Rates - Annual Growth Rate (2006-2011)

System Average Retail Rate - Annual Growth Rate							
LADWP	PG&E	SDG&E	SCE	PWP	GWP	SMUD	Average
5.67%	1.82%	3.46%	0.14%	4.90%	4.91%	3.78%	3.46%
Residential Retail Rate - Annual Growth Rate							
LADWP	PG&E	SDG&E	SCE	PWP	GWP	SMUD	Average
5.08%	1.89%	3.62%	1.57%	4.92%	2.55%	3.07%	3.25%

2.1.2 O&M Expenses

As indicated in Section 2.1.1, retail rates tend to effectively represent the utility's positioning over time and generally speak to the cost of contracting as well as building, fueling, and operating its generation portfolio. A utility's O&M expenses are different. Management can more effectively staff to meet current needs, can outsource where it makes sense to do so, and can generally control these expenses much more effectively than they can with fuel costs or capital costs. O&M expenses are thus more representative of a utility's day-to-day efficiency, and because management can expeditiously effect change in this area, O&M-related benchmarking results tend to provide more important conclusions from the perspective of shaping near-term strategy.

In order to provide a fair representation of how LADWP's O&M expenses compared to its peers, PA normalized O&M expenses on a per customer basis and per MWh of retailed electricity sold. On a per customer basis, LADWP is at or near the middle of the peer group for every year analyzed. On average, the Department's O&M spending per customer is 13% lower than the peer panel average. As in the case of electricity rates, the growth of LADWP's O&M spending has outpaced that of its peers. Annual O&M costs per customer have increased by 6.6%, the highest growth rate among the peer group. On the other hand, LADWP's O&M per MWh of retail electricity sales is above the middle of the peer group and higher than most other POUs in 2010 and 2011. The O&M costs per MWh increased by 7.3% annually, a higher growth rate than any peer other than Pasadena Water & Power. The increase in O&M expenses can at least partially be explained by the ramp up in PRP spending starting in 2008, but also highlights a need to contain O&M spending where possible.

Figure 2.2: Historical O&M per Customer and per MWh Retail Sales Peer Comparison (2006-2011)

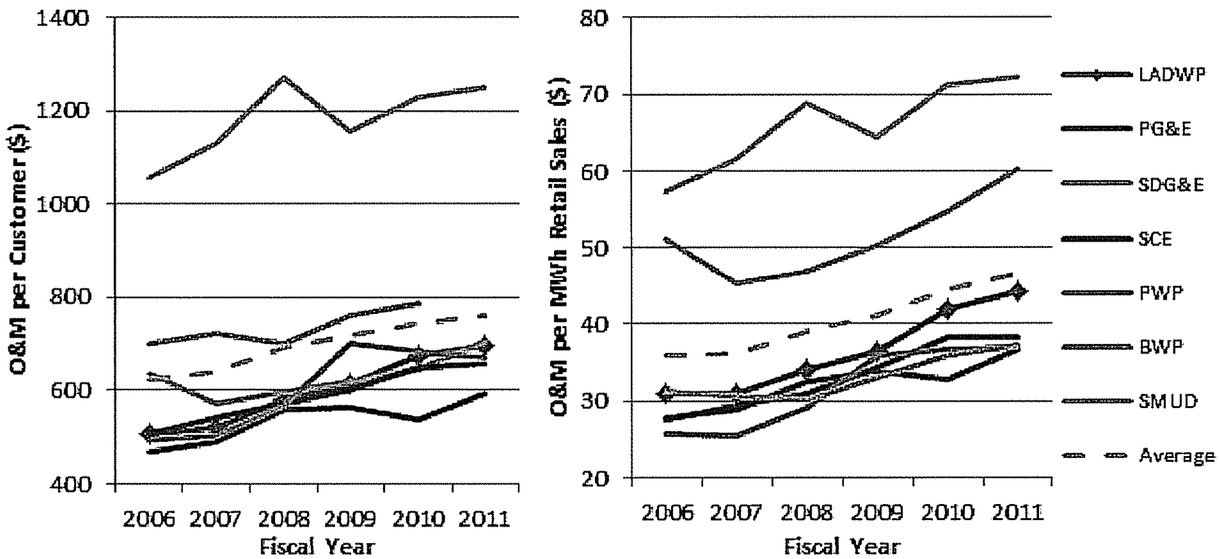


Table 2.2: Normalized O&M Expenses - Annual Growth Rate (2006-2011)

O&M Expenses per Customer - Annual Growth Rate							
LADWP	PG&E	SDG&E	SCE	PWP	BWP	SMUD	Average
6.58%	4.88%	2.05%	5.29%	6.40%	N/A	3.38%	4.07%
O&M Expenses per MWh Sold - Annual Growth Rate							
LADWP	PG&E	SDG&E	SCE	PWP	BWP	SMUD	Average
7.34%	5.63%	3.41%	6.89%	7.49%	3.49%	4.71%	5.29%

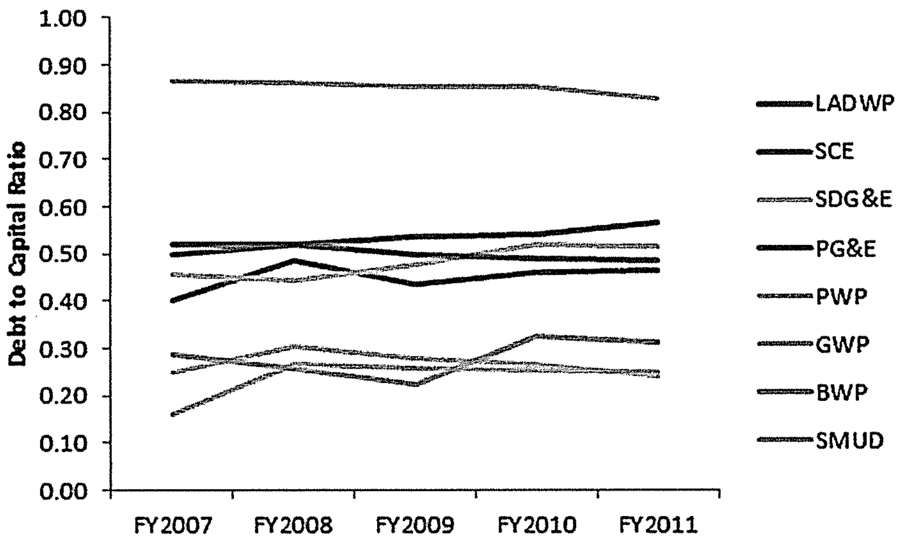
Without a more granular benchmarking effort and in-depth analysis of day-to-day O&M practices it can be difficult to determine the source, or even the general implications (positive or negative), of LADWP's O&M cost position compared to its utility peers.

2.1.3 Capitalization Ratio

Figure 2.3 shows the ratio of long-term debt to total capital for LADWP and other utilities in California for the past five years. LADWP's capitalization rate has been higher than that of its peers, with the exception of SMUD, and is continuing on an upward trend. Instead of maintaining a set debt to capitalization ratio and seeking rate increases to maintain it, the Power System has not been getting the rate increases it needs and projects to continue increasing its borrowing. As a result, the Power System's capitalization rate,[10] which is already higher than that of its peers at 56%, is projected to rise to 66% by 2017 according to preliminary projections assuming continuing rate increases throughout that period.

[10] Calculated as long-term debt divided by long-term debt plus equity.

Figure 2.3: LADWP Capitalization Ratio – Peer Comparison



2.2 Key Issues Facing the Power System

There are three key issues facing the Power System, including:

- Regulatory obligations
- Power system reliability
- Credit rating considerations

LADWP's aging power infrastructure requires significant capital investments to be made over the next 5 years: parts of the transmission and distribution systems will need to be upgraded or replaced and some generating units will need to be repowered. Given the importance of this effort PA recommends the RPA conduct a benchmarking assessment of the PRP's targets, spending level, and effectiveness to make sure the appropriate resources are being brought to bear in this area.

In addition, the Department is taking necessary measures to comply with a series of environmental mandates, which will further increase the need for substantial capital expenditures. LADWP has implemented some prudent measures to limit the impact of regulatory compliance-related expenses on rates, such as the use of biogas for compliance with the RPS mandate.[11] LADWP should seize any other opportunities it has to reduce expenditures associated with regulatory mandates, and this may be done by exploring a greater range of compliance options (as done with the OTC mandate).

As previously discussed, to fund its increasing capital needs without further increasing near-term rates, LADWP has been borrowing heavily. Capitalization ratios have risen from 54% in 2010 and are projected to top 68% by 2017, reflecting the Department's increasing use of leverage. In addition to the costs required to service this debt, the Department must collect revenue to preserve the borrowing options

[11] In March 2012, the California Energy Commission (CEC) suspended the RPS eligibility guidelines for certification of power plants generating electricity using biomethane. There is still some uncertainty as to what will happen when the suspension is lifted, but even if existing biomethane contracts are grandfathered, as many project, the expected loss of incremental biogas as a compliance option going forward will raise the cost of compliance.

currently available to it. The Department believes maintaining its AA- credit rating and preserving the associated borrowing cost to be critical to facilitating and maximizing the cost-effectiveness of its capital program. DWP determines its revenue requirement with consideration of the debt service coverage ratio and cash on hand metrics needed to maintain its current rating. This is not unusual, and there is certainly a benefit to having a low cost of capital and a cost to being downgraded (in the form of higher interest payments). Current LADWP leadership does not appear to prioritize maintaining its AA- rating as highly as its predecessors did in past years, but there may still room to consider how far a utility should go to protect its credit rating. Section 2.2.3 considers the consequences of this approach.

2.2.1 Regulatory Obligations and Cost of Compliance

Much of the current capital program is devoted to responding to regulatory requirements. In particular, the Department is required to meet the following regulatory constraints:

Table 2.3: LADWP's Regulatory Constraints

Constraints	Goals
AB 32	Aims to reduce California's GHG (Green House Gas) emissions to 1990 levels by 2020.
SB 1368	Establishes a standard for baseload generation owned by, or under long-term contract to, publicly-owned utilities (POUs), of 1,100 lbs CO2 per megawatt-hour (MWh) (which corresponds to a combined cycle's CO2 emissions level). This mandate prevents LADWP from taking any new coal-fired power under long-term contract upon expiration of existing coal generation obligations.
SBX 1-2	Investor-owned utilities (IOUs) and POUs are required to meet an increasing percentage of their electricity sales through renewable energy: – 20% by December 31, 2013 (a 20% average must be maintained between 2011 and 2013) – 25% by December 31, 2016 – 33% by December 31, 2020 and maintain at 33% thereafter.
Local Air Emissions Rules	The South Coast Air Quality Management District (SCAQMD) issued a Stipulated Order for Abatement in 2000 that required LADWP to reduce local air emissions through repowering its less efficient in-basin generating facilities. – Haynes units 5 and 6 and Scattergood unit 3 must be repowered by 2013 and 2015, respectively.
Elimination of Once-Through Cooling (OTC)[12]	The State Water Resources Control Board (SWRCB) has approved a policy for the implementation of §316(b) of the Clean Water Act, that would eliminate OTC in coastal power plants by 2029.
AB 2021	Aims to decrease California's total forecasted electricity consumption by 10% over the 10-year period 2007-2016 through energy efficiency. POUs are required to "identify all potentially achievable cost-effective electricity energy savings and establish annual targets for energy efficiency savings."
AB 2514	Requires the CPUC and municipal utilities in California to open proceedings by March 1, 2012 to determine appropriate targets, if any, for the procurement of viable and cost-effective energy storage systems by load-serving entities.

[12] Once-Through Cooling (OTC) is a cooling solution for electric generating or industrial plants. Cold water is pumped either from the ocean or a river through a condenser and then discharged back to into the water source. The discharged water is significantly warmer than the source which can be harmful to marine and fluvial life.

The regulatory obligations that are expected to have the most significant impact on the budget are: the RPS, the SCAQMD Stipulated Order, and the OTC elimination policy. The major capital expenses associated with these three regulations are the installation or repowering of power plants and the installation or upgrade of transmission infrastructure. Expenses related to energy efficiency efforts will constitute another 1% of the revenue requirement in FY 2013 and are projected to increase to 6% in FY 2017, based on preliminary data. These costs include the additional revenue needed to meet the Department's debt service coverage ratio of 2.25.

LADWP is currently taking the necessary measures to comply with SBX1-2 and the SCAQMD Stipulated Order. PA reviewed the Department's RPS and repowering strategies and found that LADWP has ultimately made prudent and timely decisions to comply with air emissions and renewable energy-related mandates. PA recommends instituting consistent processes for all investment decisions, including discussions of the alternatives considered as well as presentations of cost-benefit analyses. Such a disciplined process may have been followed in certain cases – LADWP staff mention over 1,000 pages of documentation on SCAQMD and OTC plans – but exchanges with Department staff during data request and fulfillment discussions indicated that the Power System has not systematically performed robust financial analyses prior to all significant capital investments.

A. SCAQMD Stipulated Order and the OTC elimination policy

The SCAQMD stipulated order requires LADWP to reduce local air emissions through repowering its less efficient in-basin generating facilities, and the Once-Through Cooling (OTC) elimination policy mandates that the Department's in-basin fossil generators with a "once-through" cooling system be repowered or shut down.

The Department's repowering efforts address both requirements by replacing current steam production equipment with more efficient combined-cycle system to reduce local air emissions and installing dry cooling systems to eliminate the existing once-through cooling systems. This repowering strategy is laid out in the Power System Rate Proposal. The Department presented PA with some of the alternatives considered. Based on reliability considerations and the need to comply with both regulations, the adopted repowering strategy seemed to be most appropriate. The new units will be more efficient, cleaner, more reliable, and will allow renewable resource integration through higher ramp rates. Overall, repowering Haynes Units 5 and 6 and Scattergood Unit 3 is projected to require an investment of $752M over the next two years and an additional spending of $162M over the period of FYs 2015-17. PA would recommend examining the cost of the repowerings, perhaps through a benchmarking study or through a bottom up review of costs and consideration of equipment procurement practices.

On July 19, 2011, the State Water Board issued a decision to amend its policy on the elimination of OTC. The amendment extends the 2020 deadline to 2029 for 6 of LADWP's coastal units out of a total of 9 units that must be repowered (3 units are scheduled to be repowered by 2020). The Department will also be required to provide additional details on its plan to eliminate OTC to the State Water Board by the end of 2012. Based on the information provided by the Department, the State Water Board may revise its July 19, 2011 OTC policy amendment by the end of 2013.

B. SBX1-2, California's Renewable Portfolio Standard

The Department has complied effectively with what was until recently a voluntary RPS, and projects to remain in compliance with the new SBX1-2 targets. SBX1-2 requires that 33% of the Department's 2020 portfolio come from renewable sources. The Department has pursued a strategy to attain its current level of renewable integration (nearly 20% of sales), and projects to continue following a relatively cost-effective path through 2016. To comply with SBX1-2 RPS requirements, the Department has developed and contracted with a portfolio of assets that are fairly diverse (both technologically and geographically), includes lots of cost-effective wind deals, and generally takes advantage of existing LADWP transmission. LADWP aims to maintain the 20% RPS requirement with primarily biogas and some wind (a strategy that seems to be cost-effective in the short term assuming grandfathering of existing biogas RPS-eligibility), and works towards fulfilling the 33% RPS requirement by 2020 with a mix expected to be nearly 35% solar, 33% wind and 16% geothermal. Near-term plans to be at 20% before 2014 focus primarily on cost-effective wind, hydro, and biogas resources. Central station solar investment will pick up in 2014, taking advantage of increasingly more favorable solar prices, its coincidence with peak loads, and its availability via transmission on which LADWP has transfer rights. Such decisions represent material impacts to the revenue requirement.

RPS compliance will involve almost $600M in capital and O&M costs over the next two years and more than $1 billion over the period of 2015-2017. If the Department stopped all RPS spending going forward, letting contracts expire without renewing them, the overall impact would be a $62M decrease in retail revenue requirement over the 2013-2014 period and a total reduction of $478M from 2015 to 2017 (see "Stop New RPS Spending" Case in Appendix C). Penalties for non-compliance have not yet been defined, but should be expected in the event of compliance delays (which would also carry public relations/political ramifications).

As with OTC, the Department could benefit from a greater suite of compliance options on SBX1-2. An official extension akin to that granted by the SWRCB on OTC is unlikely -- SBX1-2 was signed into law in April 2011 -- but the Department could benefit from lenient penalties and flexible compliance options, neither of which has been finalized yet. Any such flexibility achieved in renewables compliance could represent savings, as technologies continue to develop and become increasingly more cost-effective each year. While the Department did make official comment during California Energy Commission staff workshops in June 2011 seeking greater flexibility, PA has not seen evidence that LADWP has sought or considered seeking the same level of financial relief from its renewable targets that it has achieved on OTC. Such possibilities are discussed further in Section 9.

C. Energy Efficiency (AB 2021)

LADWP's energy efficiency program, while not mandated per se, is also regulation-driven. With this financial plan, the Department has stepped up its projected energy efficiency investments from around $73M in 2012 to $265M over the next two years and $475M from 2014 to 2017. The current financial plan assumes a target of reducing demand by 10% from 2010 to 2020, a Board objective set in accordance with Assembly Bill 2021, which calls on publicly-owned utilities to "identify all potentially achievable cost-effective electricity energy savings and establish annual targets for energy efficiency savings and demand reduction for the next 10-year period." LADWP does not technically have a legally binding obligation, but treats it as such because of the Board-mandated objective. The Department also notes that some energy efficiency investments can be more cost-effective than renewable energy investments and also help meet the RPS mandate by reducing kilowatt-hours of energy sold (the RPS "denominator").

In December 2011, the Board adopted an energy efficiency target of 8.6% by FY 2020-21. This target was based on the results of a third-party market potential study conducted for the Department. Although the study did not support a 10% goal, the Board prompted staff to evaluate the cost of increasing the target to 10%. In May 2012, staff proposed increasing the target to at least 10% by 2020 at an additional annual cost of $40M annually for FY 2013 and 2014, which the Board adopted. LADWP is considering a 15% target by 2020. Under the 8.6% target, the energy efficiency program budget was $187M over the next two years and $369M over the period of 2014-2017. Under the 10% target, it is $265M over the next two years and $475M from 2014 to 2017. Appendix C.8 discusses the impacts of lowering the target to 8.6% and concludes it would reduce the overall revenue requirement impact to rate payers by a total of $9M in 2013 and 2014 and another $30M over the 2015-2017 period. However, it should be noted that LADWP is planning a new energy efficiency potential study that will inform its future efforts.

D. AB32 and SB1368

Coal-focused regulations including AB 32 and SB 1368 do not pose immediate impacts to the Department, but will impact policies and costs going forward. LADWP is already in compliance with AB 32 and is not currently projecting any future AB 32-related capital expenditures, although these projections could change as further details emerge, especially with regards to the allowance allocation process. Due to the grandfathering of current ownership stakes and contracts embedded in SB 1368, the Department's financing plan will not be heavily impacted by the bill until the expiration of its contract share in Navajo Generating Station in 2019.[13]

However, once the Navajo contract expires, the cost of transitioning away from coal will be substantial. LADWP receives approximately 40% of its power through its interests in the Intermountain Power Project (IPP) and Navajo, at a significant discount to the gas-fired and renewable generation options that would likely replace this generation.

The Department appears poised to move forward on this effort, at least in the case of Navajo (which alone meets 14% of LADWP's electricity demand). The costs incurred as a result of this transition may not be enough to reconsider the Department's policy objectives, but costs should be considered as the Department identifies its priorities. The financial plan suggests the Department plans to sell its stake in Navajo for $225M and replace it with a new combined cycle at a cost of $456M.[14] In addition to the $231 million in additional capital costs, the cost of fueling a new combined cycle facility will exceed the current costs of fueling Navajo. There is uncertainty however around the timing of Navajo's divestment, such that the recommended scenario reflected in the IRP is not consistent with LADWP's current financial plan. The financial plan assumes that Navajo is sold in 2016, consistent with the current contract terms but not with the recommended scenario of the IRP, which recommends the retirement of Navajo in 2014 in response to environmental concerns from the public and the City. Should the early divestment of Navajo move forward, LADWP's budget and financial plan would need to be substantially revised.

Other regulation-driven costs are relatively minor by comparison; targets for the procurement of energy storage systems under AB 2514 have not yet been set -- expenses associated with AB 2514 compliance do not appear to be included in LADWP's budget and financial plan at the time this report is written.

2.2.2 Power System Reliability

The major challenges to ensuring Power System reliability are: replacing the aging generation facilities, continuing to upgrade the transmission and distribution infrastructure, and integrating renewable energy.

The primary goal of an electric utility is to ensure service availability. To meet this goal a utility must continuously monitor its system's health, a responsibility that entails reviewing equipment condition and

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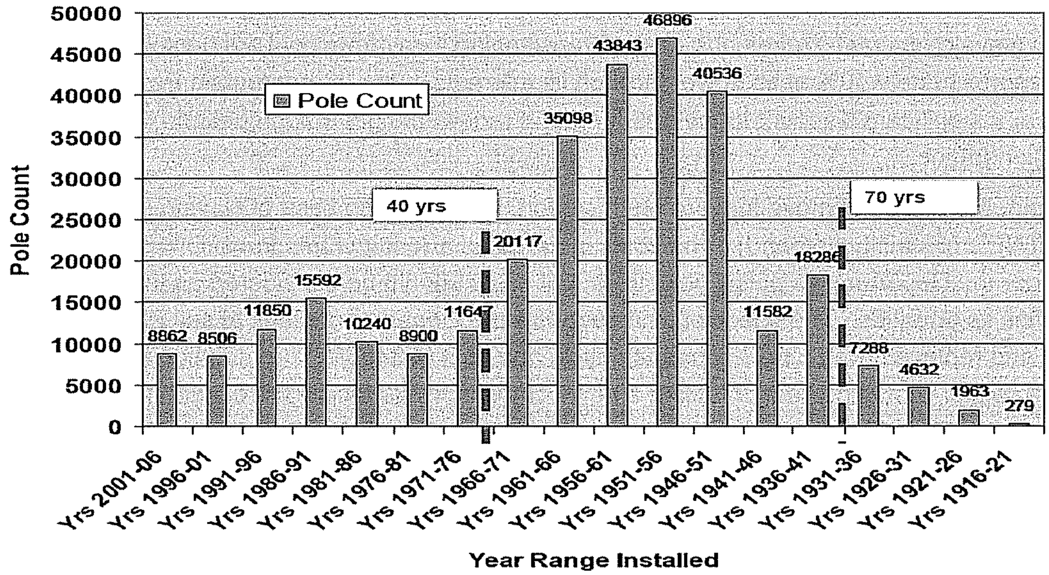
[13] Navajo is a 2,250 MW coal plant in Arizona in which the Department owns a 22% stake. Once the power supply contract expires, LADWP will have to replace the electricity it currently receives from Navajo, either through in-state resources or out-of-state resources that are at least as clean as a combined cycle.

[14] Compared to LADWP's Integrated Resource Plan (IRP) which shows that the Department plans to sell its stake in Navajo in 2014 for $360M.

performance, tracking the frequency and duration of outages, and generally implementing programs that seek to minimize degradation of Power System performance. In FY 2011, the Department's system reliability index failed to meet the target in both frequency and duration perspectives, and the total number of electricity poles replaced fell short of its goal. These issues are indicative of the challenges LADWP's transmission and distribution system is facing.

The LADWP system is aging and increasingly prone to malfunction, a fact which has been noted by the Department. In the 2010 Power IRP, LADWP stated that the majority of its electrical infrastructure is 40 to 70 years old. The Department's FY 2012 budget presentation notes that 79% of the electricity poles are over 40 years old. The age profile of LADWP's poles, which serves as a decent proxy for system infrastructure, is indicated in Figure 2.4.

Figure 2.4: LADWP's Pole Quantity and Year Installed[15]



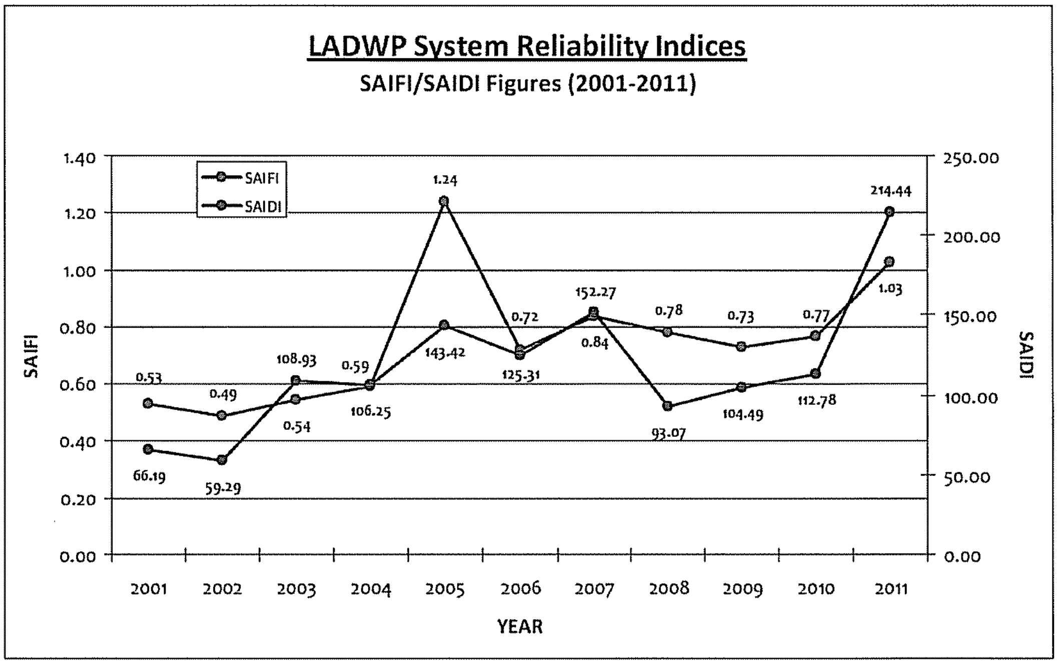
LADWP also has an increasing maintenance backlog. Among other things, the Department's maintenance backlog shows an increase in distribution circuit needs. For example, the electrical system has a total of 1,630 4.8kV circuits, and the backlog of malfunctioning or temporarily overloaded circuits was 138 circuits (8.5%) and 158 (9.7%) for 2010 and 2011, respectively, and is now 154 (9.4%) with a FY 2012 target of 92 (5.6%).[16]

Aging infrastructure correlates with performance deterioration. LADWP stated in its IRP that there has been an increase in system outage rates in the past few years and several major outages caused by deteriorating equipment, and it expects an ongoing decline in system reliability. Figure 2.5 shows LADWP's System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI). SAIDI measures the average number of minutes of electricity service interruption per customer per year.

[15] Figure from LADWP 2010 Power Integrated Resource Plan, Appendix E: Power Reliability Program.

[16] Source: LADWP Power Reliability Program Activity website. Updated as of September 11, 2011.

Figure 2.5: LADWP System Average Interruption Frequency and Duration Indices (SAIFI/SAIDI) (2001-2010) 17



To replace aging transmission and distribution infrastructure in a systematic and sustained manner, the Department has implemented the PRP. The PRP's goals are:

- Improve reliability of lines and substations
- Conduct regular inspections and maintenance to discover potential setbacks and prevent faults and outages
- Replace equipment according to life expectancy.

LADWP's power supply also faces reliability challenges stemming from its aging fleet of plants, tightening reserve margins, and RPS-driven trend towards intermittent generation. As LADWP increases its reliance on intermittent renewable sources such as wind and solar, it also needs ample generation capacity that possesses high power ramp rates and quick response ability. LADWP is currently in the process of repowering nearly 1,500MW of Los Angeles Basin generating units with more efficient and reliable natural gas units, an effort that has been ongoing since 1994. Repowering will modernize the Department's system by essentially replacing its in-basin gas-fired units, which were reportedly built in 1950s and 1960s, with new units.

Like other California utilities, the Department will have to comply with the aggressive renewable energy obligations mandated in SBX1-2, a challenge that will require significant investment in the years ahead. Grid integration of renewable energy presents a challenge because of the intermittent characteristics of renewable energies, which must be compensated for through the use of demand-side management, energy storage, or backup generation capable of ramping up and down quickly to compensate for swings in energy production. New energy storage solutions generally remain unattractive from a cost perspective, but the Department will use its pumped storage capacity from the Castaic Power Plant. LADWP is also planning to install new combustion turbines at Haynes and Scattergood as part of the

[17] Figure from LADWP Power Rate Restructuring Proposal FY 12/13 and FY 13/14, 6/7/2012.

repowering effort. Finally, LADWP is counting on the implementation of demand response (DR) and energy efficiency (EE) measures to reduce energy demand and consequently relieve the burden on generating units and transmission infrastructures.

Capital expenditures related to the ongoing integration of renewable energy will be significant, putting additional pressure on rates.

2.2.3 Credit Rating Considerations

This section examines the evaluation criteria established and utilized by the three most prominent ratings agencies – Standard and Poor's (S&P), Fitch Ratings (Fitch), and Moody's – to continually assess issuer credit ratings. The analysis also describes the Department's financial targets. Finally, it assesses the financial impact of a ratings downgrade, as calculated by LADWP.

A. Ratings considerations

Ratings agencies assign credit ratings to specific debt instruments and their underlying issuers to provide an indication of the likelihood of default for that given instrument. These ratings are used by purchasers and traders of bonds to help indicate the value of the bond relative to other debt instruments. For a bond of a given term and character, a higher credit rating will typically be associated with a higher bond value and a lower interest rate for the borrower.

The three most prominent credit ratings agencies use very similar scales to indicate the quality of a given debt issue. AAA is the highest rating, followed by AA, A, BBB, and C. Within each class, the ratings agencies further distinguish between quality by indicating a "+" or "-" within each class (for Moody's, a scale of 1 to 3 is used, with 1 the highest subclass).

Each of the three major ratings agencies uses a multifaceted approach to assess these risk profiles. Financial ratios addressing coverage, profitability, capital structure/leverage, and perhaps most importantly cash flow, provide a critical point of reference when assessing financial risk. Ratio medians for a particular rating provide an illustration of where a specific issuer "fits" relative to its peers within a specific industry.

In addition to specific financial ratios, the agencies examine a variety of business risk factors or ratings topics that may impact each rated issuer's ability to make timely payment of principal and interest obligations. Many of these will be specific to a particular industry. For public power utilities, for example, Moody's has laid out 44 separate measurements across 6 broad ratings factors and 22 sub-factors.

Therefore, in addition to financial ratios, assessment parameters include an evaluation of management and governance, the utility's generation portfolio, local government credit characteristics, cost competitiveness, the rate setting process, and the utility's strategic planning process for addressing both traditional power supply as well as emerging issues such as CO_2 reduction and renewables requirements. While numerical ratios play a critical role in outlining the financial risk of a utility, any of these other factors may emerge as a risk that could influence a financial rating. In general, each of the ratings agencies employ quantitative as well as qualitative analyses to derive issuer ratings.[18]

S&P, Fitch, and Moody's currently rate LADWP's Power System at AA-, AA-, and Aa3, respectively. These ratings are at the low end of the "double-A" rating provided by the agencies, one notch above the

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[18] See Standard and Poor's, *Corporate Ratings Criteria Methodology*, May 2009; Moody's, *U.S. Public Finance Rating Methodology for U.S. Public Power Electric Utilities*, April 2008. Fitch Ratings, *Public Power Ratings Guidelines*, March 2011.

lower "A" rating level. Maintaining this rating allows LADWP to access low-cost funds in both long-term and short-term financial markets. The debt rating also supports LADWP's long-term purchase agreements and provides a competitive advantage in accessing renewable power projects at the lowest possible rates.

B. LADWP's financial targets

During its financial planning process the Department focuses on three main financial metrics, each established with the advice of financial advisors to protect the Department's AA- rating:

- Debt Service Coverage Ratio
- Unrestricted Cash Balance
- Capitalization Ratio

Debt Service Coverage Ratio

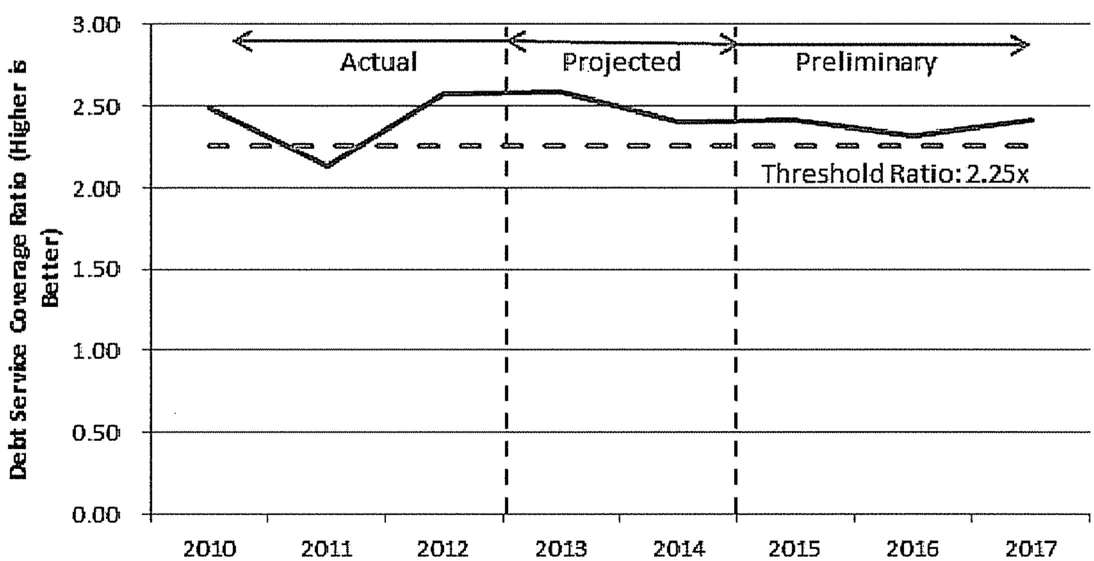
Given the complexities of debt and other obligations, the components of debt service coverage can be defined in different ways. (For instance, Fitch provides three different definitions which are useful in assessing the ability to repay debt.) However, debt service coverage is generally defined as the ratio of the funds available to pay debt service to the actual debt service itself.

The primary ratio considered is the Debt Service Coverage ratio. This ratio divides the funds available for debt service by the sum of long-term principal and total interest payments. This ratio treats fixed charges other than debt payment as they are shown on the balance sheet, typically as expenses.

LADWP has identified its target Debt Service Coverage ratio of 2.25x with consideration to these other metrics.

The debt service coverage ratio for FY 2011 was 2.13x, below the target ratio of 2.25x. However, the Department's FY 2012 budget accounts for this deficiency, increasing the revenue requirement as needed to restore the 2.25x debt service coverage ratio.

Figure 2.6: Debt Service Coverage Ratio (2010-2017)



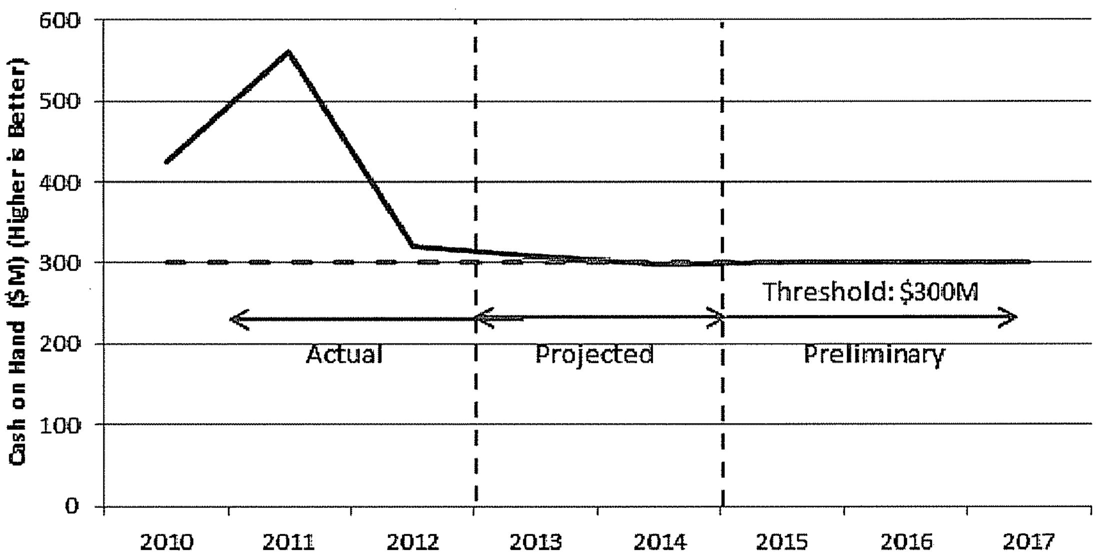
Unrestricted Cash Balance

A utility's ability to service its debt payments is of paramount importance, but ratings agencies also focus on liquidity metrics such as cash on hand to ensure that an entity can survive short-term volatility in costs and revenues.

In the case of LADWP, the most likely source of such volatility is a sharp increase in purchased power or fuel costs, either due to commodity price increases or an unexpected outage at one of LADWP's low-cost coal or nuclear facilities.

It is worth noting that the Department owns a Debt Reduction Trust Fund which allows LADWP to utilize cash under this fund only for debt related activities such as debt refinancing and early retirement of debt. This restricted fund is considered part of the available cash by rating agency. The Department has developed its unrestricted cash balance target as $300 million unrestricted cash. Including the Debt Reduction Trust Fund this amount is approximately 110 days of operating expenses. Under the proposed budget, unrestricted cash balances are expected to fall to $300M in FY 2014 and remain at that level over the next three years. Figure 2.7 levels assume rate increases.

Figure 2.7: Unrestricted Cash on Hand (2010-2017)

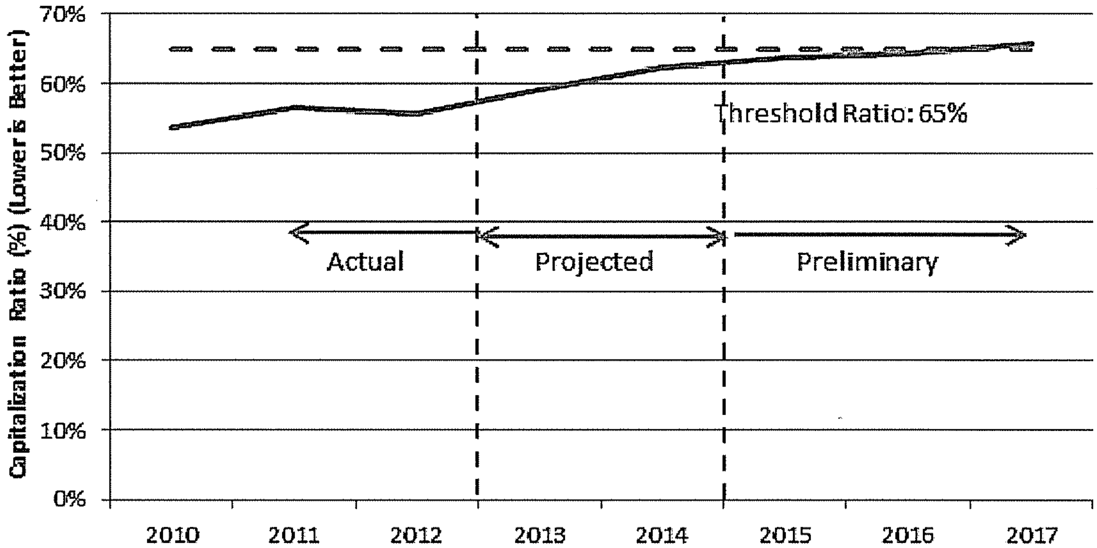


Capitalization Ratio

A company's capitalization ratio is defined as the long-term debt level divided by the sum of long-term debt plus equity.

LADWP's choice of a capitalization ratio is closely tied to its choice of debt coverage. An increase in capitalization ratio implies that the percentage of debt in the portfolio is increasing and coverage ratios are decreasing. While it is important not to lose sight of the overall structure of the balance sheet, it is also important to recognize that maintaining stable debt coverage ratio should be a primary indicator of a stable Capitalization Ratio. In 2010, under the guidance of its financial advisor, Public Resources Advisory Group, the Department adjusted its capitalization ratio target from 60% to 68%. To make this possible -- thereby clearing the way for greater debt levels in the future -- the Department also increased its cash on hand limits, which had previously been set at $300 million, to be the greater of $300 million or 110 days of operating expenses (Debt Reduction Trust Fund included).

Figure 2.8: Capitalization Ratio (2010-2017)



C. Cost of a Downgrade

If LADWP is unable to meet the financial targets explained above, the Department's financial advisors have stated that the Power System would be at risk of a credit rating downgrade. A downgrade would impact the Department's financial flexibility and increase its cost of borrowing. These costs of a downgrade would be felt in four primary areas:

- Short-Term Variable-Rate Debt: LADWP maintains more than $1 billion in Variable Rate Demand Obligations (VRDOs), short-term credit facilities that provide LADWP access to funds as needed to cover its short-term cash needs. In today's market, this debt has a very low interest rate. Should LADWP be downgraded, a portion of this short-term debt might no longer be available and any remaining short-term line of credit would likely carry a higher interest rate than it does today. LADWP's analysis projects that this short-term option would become unavailable to a lower-rated Power System--possibly because of higher collateral demands making short-term borrowing uneconomic--but PA has not independently reviewed the likelihood of this somewhat conservative assumption. If LADWP did in fact lose its short-term "Standby Purchase Agreement", as projected, and did not have other short-term options, it would be compelled to rely only on longer-term fixed-rate debt, resulting in a material financial hit in today's debt markets.
- Long-Term Fixed-Rate Debt: A ratings downgrade would also impact the interest rates available for LADWP's long-term debt. While interest payments on all existing long-term debt remain fixed, any new debt issued subsequent to a downgrade would be subject to a higher interest rate. With plans to issue over $2 billion in long-term debt over the next two years and preliminary plans for more than $2 billion more in FYs 2015-17, a downgrade could have a substantial and increasing impact on LADWP's cash position.
- PPA obligations: Many of LADWP's power purchase agreements (PPAs) are not fixed price PPAs but rather are tied to the actual debt service obligation for the project. PPAs that would be impacted include agreements with IPP as well as projects funded through the Southern California Public Power Authority (SCPPA). Just as LADWP's direct debt contains long-term and short-term components, the debt associated with these individual projects can also contain both. It is

important to take the terms of these individual PPAs into account when quantifying a debt downgrade impact.

- Hedging costs: LADWP has approximately a dozen counterparties with whom it trades swaps and other derivatives as part of the ongoing effort to limit the volatility of its fuel supply costs. The relationship with each of these counterparties includes a credit threshold that dictates the Department's collateral needs with that counterparty. Once the mark-to-market (MTM) value of a position exceeds that threshold, the Department must post collateral to cover it, thereby tying up costly funds in a margin account. In the event of a downgrade, the threshold available to the Department would be greatly reduced. As a result, a downgrade could impact short-term cash flows and the cost of the Department's hedging program, particularly in a declining natural gas price environment.

Determining the costs of a ratings downgrade requires a detailed description of current debt service, a projection of future debt requirements, and an estimation of the impact posed by a downgrade to each debt instrument. The Department provided details on debt instruments held currently as well as its preliminary 5-year capital investment plans.

PA has reviewed the Department's analysis regarding the projected costs to the Power System of a one-notch downgrade to A+. In quantifying the impact of a ratings downgrade, LADWP appears to have made the following assumptions:

- A credit spread[19] of 30 basis points between AA- and A+ -- The Department's financial advisor, Public Resources Advisory Group, has estimated an additional long-term interest costs of 30 basis point (0.3%) for a one-notch downgrade from a AA- rating to A+ rating. PA reviewed this estimate and believes it to be in-line with the credit spreads in the current fixed income market.
- Loss of Short-Term Borrowing Option -- The Department assumes that the existing Standby Purchase Agreement (SBPA) would have to be converted to fixed rate debt, an assumption based on the fact that a downgrade could trigger termination events on short-term credit facilities, forcing this borrowing to take place through higher-cost long-term instruments.[20]

LADWP estimates that a downgrade would cumulatively cost the Department and its customers $329 million over the next five years, as shown in Table 2.4.

Table 2.4: Estimated Cost Impact of a Rating Downgrade ($M)

Event	FY2013	FY2014	FY2015	FY2016	FY2017
LT debt cost increases by 30 bps	$5.1	$16.6	$20.2	$11.1	$13.6
ST variable rate debt refinanced at LT fixed rate	$51.6	$56.1	$53.0	$46.3	$39.8
Off-balance sheet LT debt increases by 30 bps	$0.3	$1.2	$2.6	$4.1	$5.0
Off-balance sheet variable rate debt increases by 30 bps	$0.6	$0.6	$0.6	$0.3	$0.3
Total Cost of Downgrade	$57.6	$74.6	$76.4	$61.8	$58.7
System Average Rate Impact (c/kWh)	+0.25	+0.33	+0.35	+0.29	+0.24

[19] A credit spread is the difference in interest rates between one bond rating and the next. The greater the spread between a AA-rated bond and an A-rated bond, the greater the cost of a downgrade.

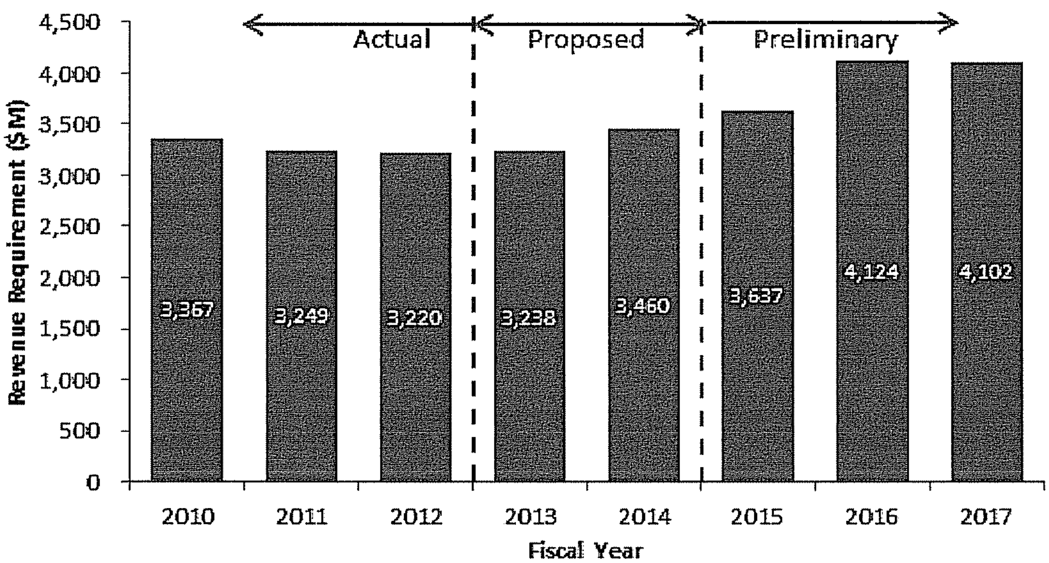
[20] PA believes this to be a conservative assumption, but would suggest further review. 75% of the Department's estimate of the total 5-year impact of a downgrade to A+ stems from the assumed need to convert the SBPA to fixed-rate debt. More expensive variable-rate borrowing may be a more likely consequence of a one-notch downgrade.

Although the Department can avoid costs associated with a downgrade by maintaining its current credit rating, the financial ratio thresholds impose several restrictions on the Department's revenue requirement. For example, in order to sustain a debt service coverage ratio of at least 2.25x, for every additional dollar worth of debt service, the Department not only has to collect a dollar to cover the debt service but also has to collect an additional one dollar and twenty-five cents from the ratepayers. PA advises that the City work with its financial advisor, if it has not already, to perform further analysis into whether the interest expense savings facilitated by maintaining the Power System's AA- rating, as well as the magnitude of the savings themselves, merit the annual cost of meeting the financial metrics needed to avoid a downgrade.

3 Power System Revenue Requirement

To meet the regulatory obligations outlined in Section 2.2, meet the costs of maintaining an aging infrastructure, and maintain its financial standing, the Department will have to increase its rates or reduce its costs, or likely a combination of the two. This section details the sources of cost that drive LADWP's revenue requirement, including: fuel and purchased power, O&M, capital funding, and the annual city transfer, all of which are projected to continue increasing over the next five years.[21] After a year with limited growth, the Department's "Case 89" -- the financial plan upon which this report is focused -- projects a system average rate growth of 5.4% annually over the FYs 2013-14 period.

Figure 3.1: LADWP's Power System Annual Total Revenue (2010 - 2017)



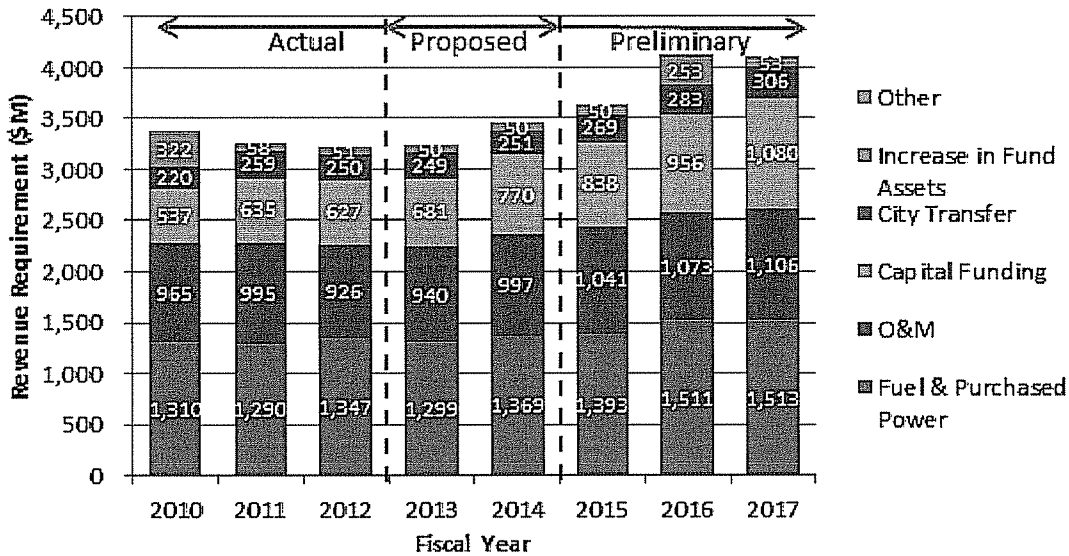
As indicated in Figure 3.2, the revenue requirement increases are being heavily driven by capital funding (i.e. debt service payments and depreciation expense), in many ways not surprising given the emphasis on RPS-driven investment in wind and solar, which feature no fuel costs but higher capital costs than conventional generation options, and energy efficiency investment, among others. Capital funding is expected to grow at a 10.8% average annual rate over the next two years and preliminary projections call for it to increase at an average rate of 11.9% per year over the FYs 2015-2017 time period. The Department's capital investment plan will feature more than $1.4 billion and $1.6 billion in investment in FY 2013 and FY 2014 respectively and will maintain a similar level of capital spending over the FYs 2015-2017 period, quite a steep increase relative to capital expenditures in 2010 and 2011, which averaged $830 million annually. Capital costs will be driven by the PRP, repowering costs at Haynes and

[21] The figures in this section have been derived the Department's Case 89 financial plan, which offers projections for fiscal years 2013 through 2017. The Department has committed only to the figures for 2013 and 2014, the years upon which their current rate proposal is based. Numbers for fiscal years 2015 through 2017 were only offered on a preliminary basis. PA has generally reviewed spending levels over all five years, because the longer time period captures the range of near-term spending needs, better indicates trends over time, and is not as easily distorted by cost shifts from one year to another. However, PA does acknowledge that the outer year projections are not necessarily based on firm plans and are thus subject to much greater uncertainty.

Scattergood to meet local air emission and once-through cooling rules, renewable energy-related transmission and generation investments, and demand-side management.

Fuel and purchased power and O&M spending increase at average annual rates of 0.8% in FY 2013 and 3.7% and FY2014, both reasonably within range of inflation.

Figure 3.2: LADWP's Power System Annual Total Revenue (2010 - 2017)



Note: The difference between expenses and retail revenue can be explained by wholesale generation and transmission as well as deferred and non-operating revenue.

3.1 Fuel and Purchased Power

Fuel expense includes all costs associated with natural gas, coal, and nuclear fuel procurement. Fuel costs are driven primarily by market forces, with volatility managed through a mix of hedging programs and long-term fixed price contracts.

LADWP owns and/or operates several non-renewable generating stations that run using coal, natural gas and uranium fuels.

In addition to its own generation, the Department also purchases power externally to meet its sales demand. This covers short-term energy market purchases as well as long-term power purchase agreements (PPA) through the Southern California Public Power Authority (SCPPA)[22] or bilateral agreements negotiated directly with the independent power producer.

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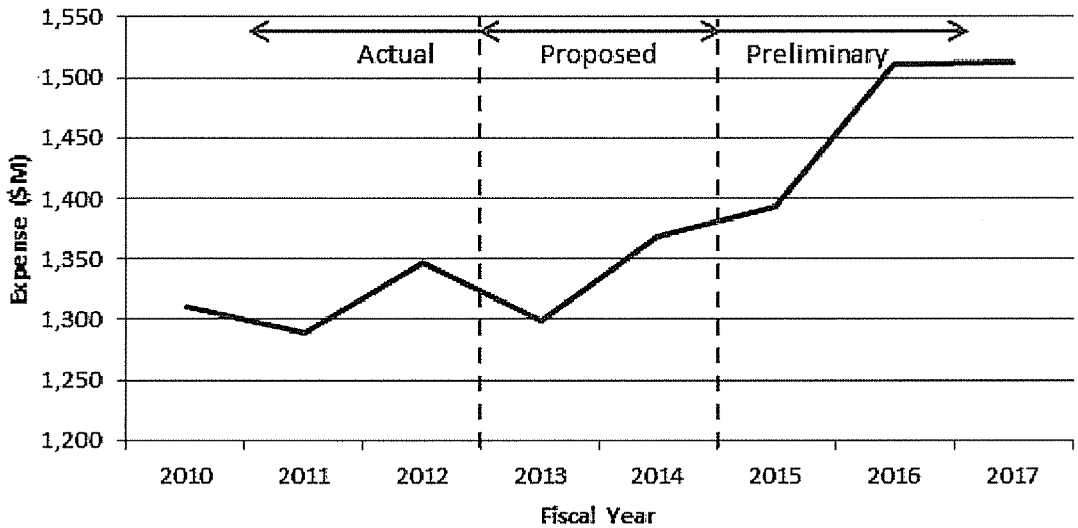
[22] As is the case at many other utilities, LADWP carries significant long-term payment obligations that are not treated as debt payments on the balance sheet. At LADWP, the largest long-term obligations are for power purchases from Intermountain Power Project (IPP) and SCPPA, as well as charges associated with transmission built through SCPPA. SCPPA is a joint powers authority, consisting of 10 municipal utilities and IID, through which LADWP procures a significant amount of its renewable energy in particular. Both IPP and SCPPA issue debt that is passed through directly to LADWP as part of its power purchase agreements. The debt associated with these projects is sometimes referred to as "off-balance sheet" debt.

Like the majority of the vertically integrated utilities, the Department's fuel and purchased power represents its largest expense. Most of the Department's fuel and purchased power-related expenses will impact the ratepayers through the ECAF. Fuel and purchased power expense is expected to decrease by 3.6% in FY 2013 but is projected to increase by 5.4% in FY 2014. Spending associated with fuel and purchased power will continue increasing at an average rate of 3.4% over the FY 2015-17 period.

Figure 3.3: Fuel and Purchase Power Expense (2010-2017)



Note: FY 2012 value is based on actual spending through March 2012 plus 3-month estimate.

3.2 Operations and Maintenance Expenses

Like fuel and purchased power expense, O&M expenses have an immediate, dollar-for-dollar impact on the revenue requirement for the current year. O&M expenses cover a wide range of cost categories from labor and benefit costs related to day-to-day O&M expenses for assets. LADWP's O&M expenses for the past two years, current year, and the next five years are plotted below. Major components include the PRP, infrastructure reliability, and operating support, each of which are expected to increase at a steady rate and play a significant role in the annual revenue requirement, as indicated in Figure 3.4 and Figure 3.5.

Figure 3.4: Annual O&M Expense Allocation 2010-2017

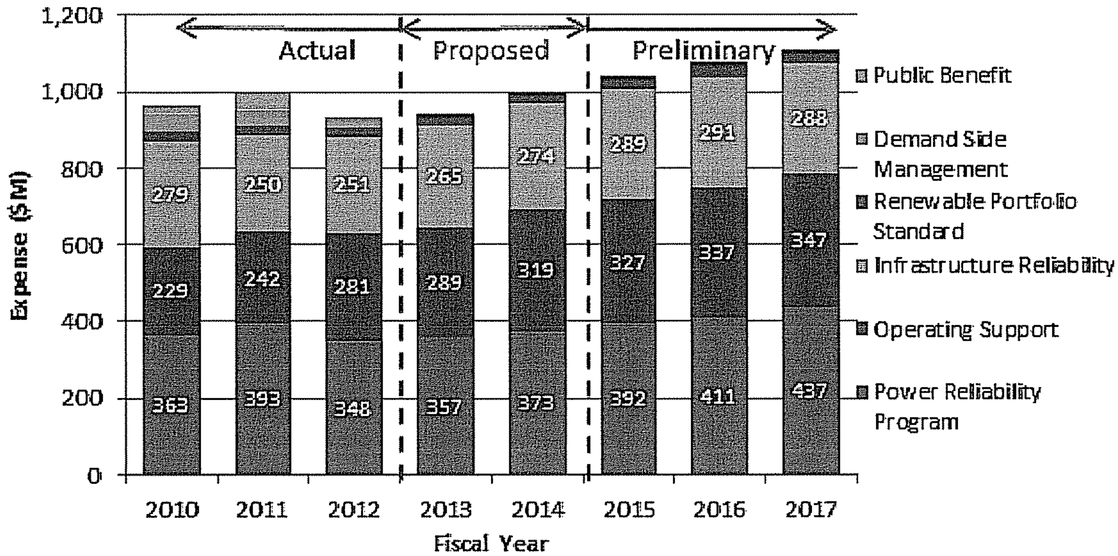
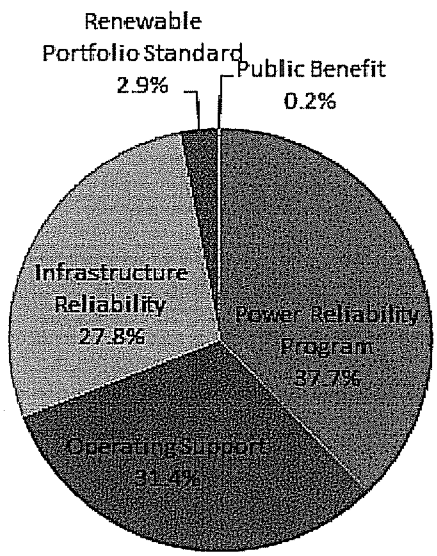


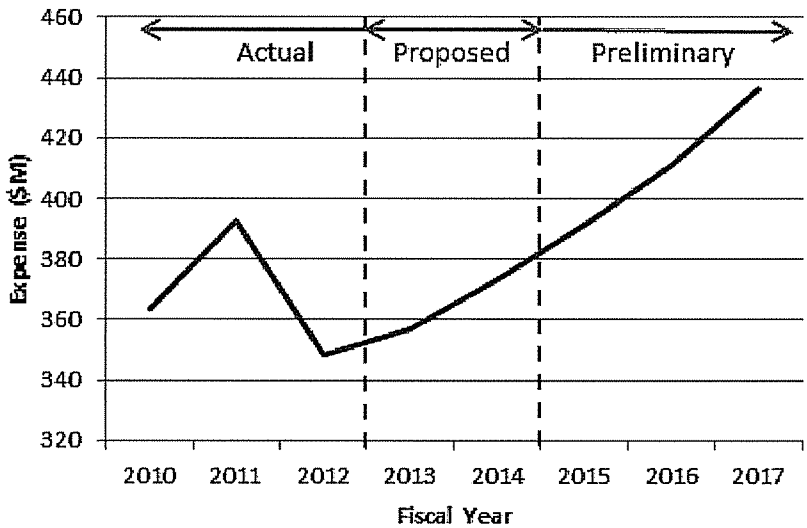
Figure 3.5: Total O&M Expense Allocation 2013-2014 (Two Year Total O&M = $ 1.937 billion)

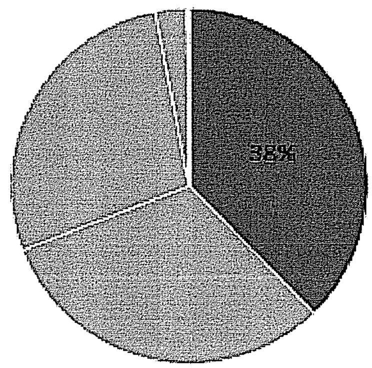


A. O&M Expense - Power Reliability Program

As a vertically integrated utility, LADWP owns and operates its own transmission and distribution (T&D) system. As this equipment ages, system reliability can be threatened by failing equipment. In order to maintain a dependable T&D system, the Department developed the PRP, a major driver of O&M and capital expenses through 2017. The PRP covers the transmission and distribution system, focusing on areas that include failing lead cable, deteriorating poles, and overloaded pole top transformers. The program represents a significant step towards addressing LADWP's aging infrastructure and will help improve overall system reliability. PRP expenses are designed to be funded through the RCA. However, as of FY 2011 the RCA rate has reached its maximum cap of 0.3¢/kWh, explaining the under collection balances from FY 2011 through FY 2017.

Figure 3.6: Power Reliability Program O&M Expense Shown Annually (2010-2017) and Compared to Total O&M Expenses (2013-2014)





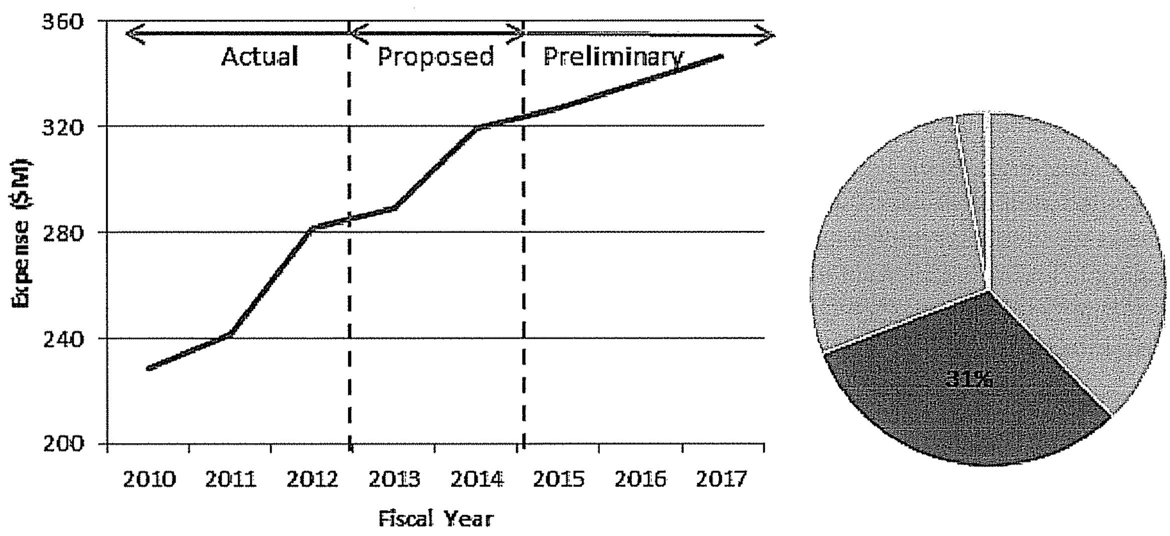
The main cost drivers for the PRP are maintenance costs for substations, overhead and underground distribution systems, and the training program. The PRP contributes 38% of the total O&M for the next two years. The PRP O&M budget declined by 11% in FY 2012 as training and maintenance to distribution lines and substations has been reduced. However, this appears to be only a one-year cost reduction as PRP costs are projected to increase by 3% and 4% in FY 2013 and FY 2014 respectively and will continue increasing at an average rate of more than 5% per year over the FY 2015-17 period.

A well-funded PRP is essential to the long-term reliability of the LADWP power system, but it is also one of the early targets when short-term cost reductions are needed, a fact driven by the large O&M spend and the lack of regulatory requirements that drive the so many other major sources of cost for the Department.

B. O&M Expense - Operating Support

Operating support covers the day-to-day administrative, infrastructure, and overhead costs that enable LADWP to provide power to its customers. These expenses are allocated to both the Power and Water Systems by Shared Services.

Figure 3.7: Operating Support O&M Expense Shown Annually (2010-2017) and Compared to Total O&M Expenses (2013-2014)

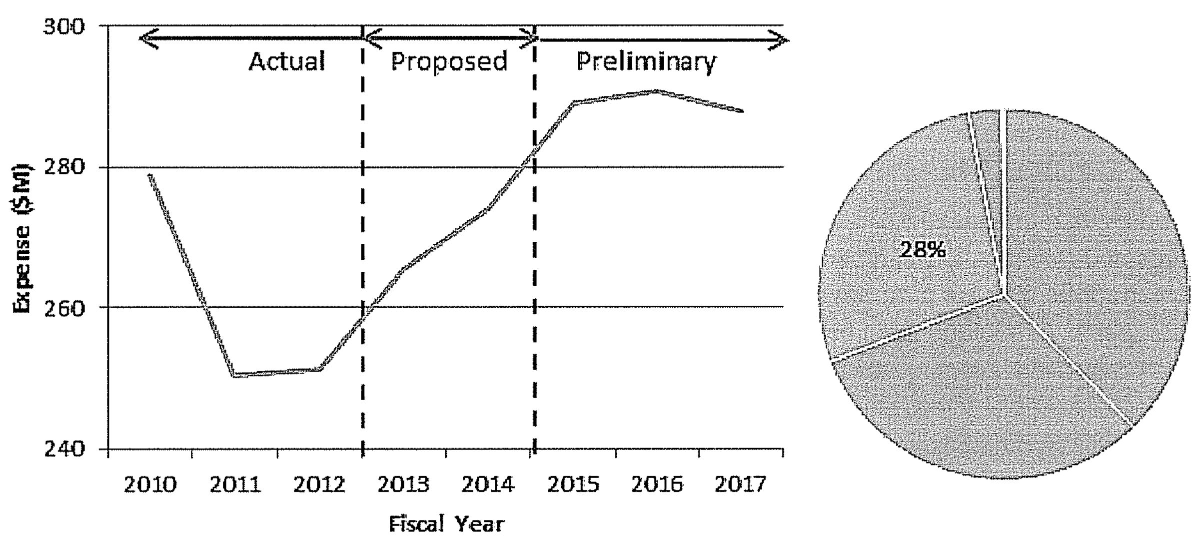


Operating support, which contributes 31% of the total O&M for the next two years, is expected to increase by 3% and 10% in FY 2013 and FY 2014 respectively, and this category will increase at an average rate of 3% per year over the FY 2015-17 period. Some of the major costs drivers under operating support are expenses for customer services, information technology, and CFO administrative and general (A&G) overhead, which are projected to increase in spite of the deployment of new capital such as the new customer information system, scheduled to be released in 2014.

C. O&M Expense - Infrastructure Reliability (Generation)

Infrastructure reliability represents the cost of operating and maintaining generation facilities. Included in this cost element are the operating costs associated with generation facilities owned outright by the Department as well as LADWP's share of costs associated with jointly-owned generating stations.

Figure 3.8: Infrastructure Reliability O&M Expense Shown Annually (2010-2017) and Compared to Total O&M Expenses (2013-2014)

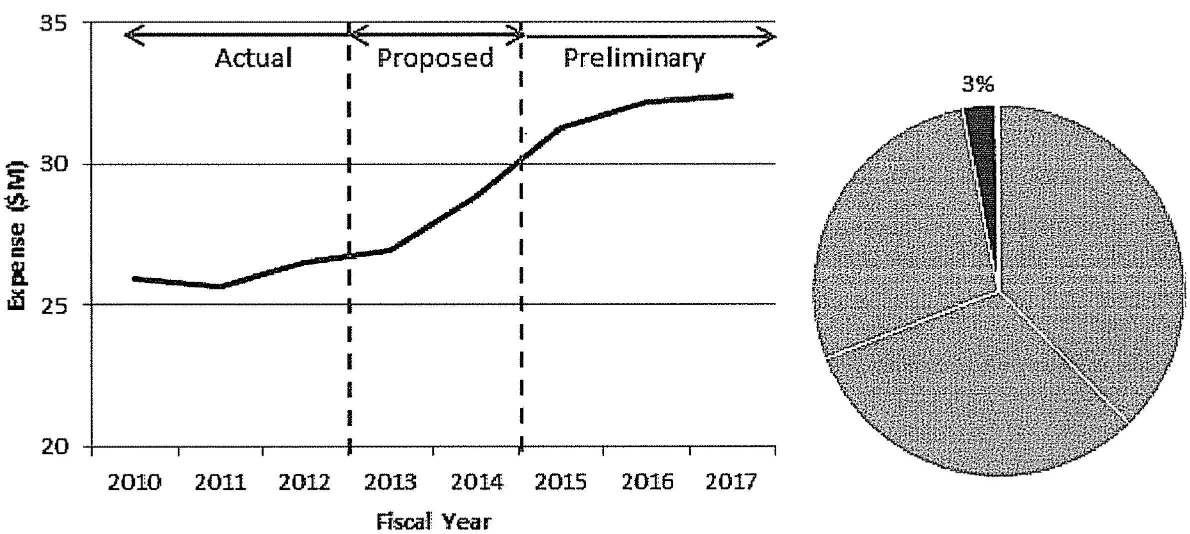


Some of the major costs drivers under infrastructure reliability program are payments for LADWP's share of Navajo and Palo Verde[23] power generating stations and operating expenses for its own power supply assets. Infrastructure reliability, which contributes 28% of the total O&M for the next two years, is expected to increase by 5% in FY 2013, driven by a $7M increase in steam generation SPA 1 training program. This category will increase by 3% in FY 2014 and will continue the upward trend at an average rate of 2% per year over the FY 2015-17 period. The steep increase in FY 2015 is caused by a 25% increase in payments for the Navajo Generating Station, as a shift from minor overhauls to more major ones prompts LADWP's share of the O&M cost to rise from $32M to $40M.[24] The lower O&M costs at the new combined cycle plant which will replace Navajo's generating capacity will contribute to the projected decrease in 2017.

D. O&M Expense - Renewable Portfolio Standard

RPS expense, which contributes 3% of the total O&M for the next two years, is expected to increase by 2% in FY 2012. Over the FY 2013-2014 period, this category will increase at an average rate of more than 4% per year and will continue to increase by the same rate for the next three years.

Figure 3.9: Renewable Portfolio Standard O&M Expense Shown Annually (2010-2017) and Compared to Total O&M Expenses (2013-2014)



E. O&M Expense - Demand-Side Management

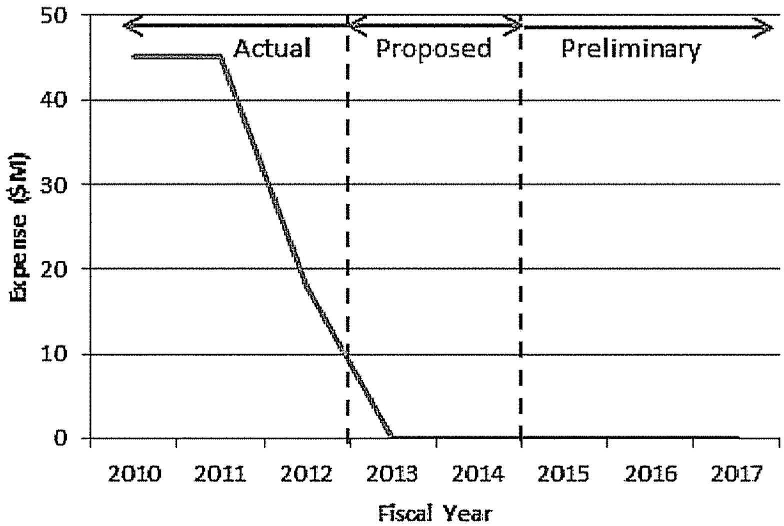
Demand-side management (DSM) expense includes costs incurred for the acquisition and installation of devices and systems, including incentive payments, audit costs related to DSM, and administrative costs, which are parts of those programs or projects designed to lower and control Power System demand or consumption. One of the main components of the Department's DSM programs is Energy Efficiency (EE),

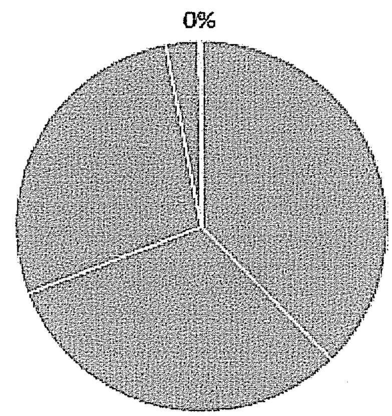
[23] While LADWP does not develop the budgets for Navajo and Palo Verde stations, it does have the responsibility to audit the budget proposed by the plant operators. LADWP is expecting to sell its ownership at Navajo station in 2016.

[24] LADWP's financial staff has caveated this cost increase by saying that the 2015 cost increase might not occur if Navajo's co-owners decide to shut down the facility rather than selling it, in which case they would scale down the O&M work scope for the remaining years of the station.

which reduces energy consumption through efficiency improvement. Examples of LADWP's EE program include replacing traditional incandescent light bulbs with compact fluorescent lamps (CFLs) and replacing inefficient refrigerators for low-income customers.

Figure 3.10: Demand Side Management O&M Expense Shown Annually (2010-2017) and Compared to Total O&M Expenses (2013-2014)

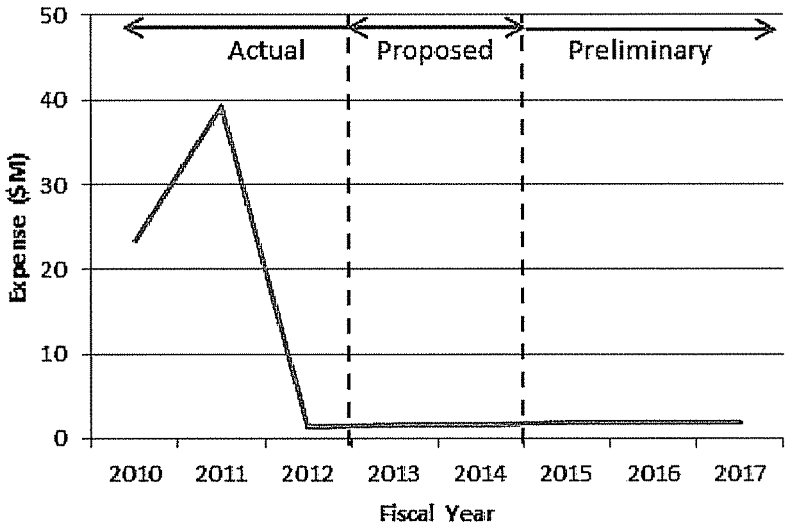


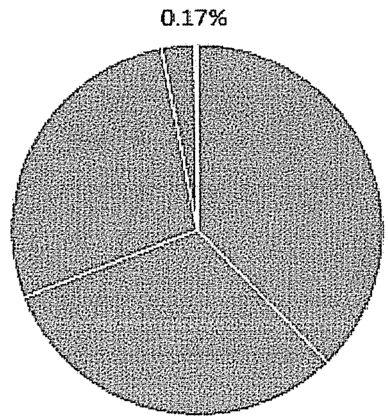


Beginning in FY 2012, LADWP has begun capitalizing DSM expenditures as regulatory assets, shifting annual expenses to capital. By FY 2013, all DSM expenditures will be capitalized. The benefit of shifting O&M to capital is the lower current-year revenue requirement impact and the amortization over multiple years of expenditures with multi-year effects, but because it will create ongoing depreciation and possibly interest payments, the new accounting treatment essentially shifts what had been today's costs to future years.

F. O&M Expense - Public Benefit

Figure 3.11: Public Benefit O&M Expense Shown Annually (2010-2017) and Compared to Total O&M Expenses (2013-2014)





The main cost driver for public benefit expense has been the SB1 solar incentive program. Annual public benefit expense contributes less than 1% of the total O&M for the next two years. As with the DSM expense decline, this decline does not indicate declining costs but rather a change in accounting treatment. Starting in 2012, LADWP will begin capitalizing solar incentive expenditures as regulatory assets (under RPS capital expenditure) rather than expensing them annually. The impact, as with the capitalizing of DSM expenditures, will be to reduce the current revenue requirement as the bulk of the cost is spread over the revenue requirements of future years.

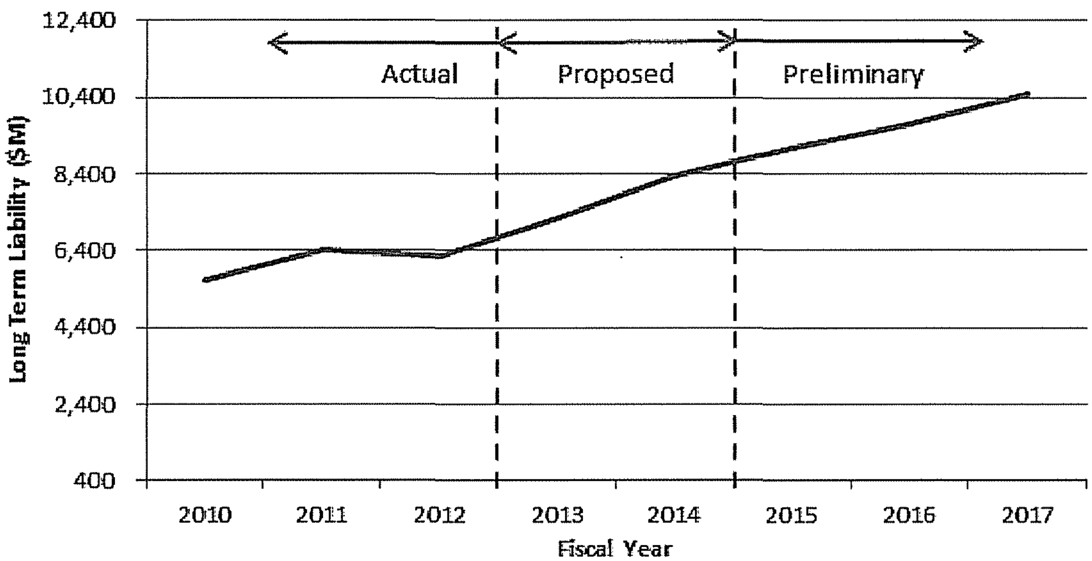
3.3 Capital Funding

Capital expenditures are costs that a company incurs to purchase or update fixed assets that will have a useful life beyond the current year. Common examples include the construction or purchase of a generation facility or the development of information technology. These expenditures become assets on the balance sheet, and because an asset creates future benefit, its cost is not recognized as it is incurred (as with an expense) but is rather amortized over the life of the asset. Unlike O&M expenses, which have a direct 1:1 impact on the revenue requirement in the year incurred, the rate impact associated with capital expenditures is felt over time in the form of asset depreciation and interest expense.

Although major investments with long useful lives have a smaller effect on the electricity rate during the year in which the investment is made than would an equivalent expense, the capital expenditure will influence the price of electricity for a longer period of time. Today's investment decisions will have significant impacts on tomorrow's ratepayer, particularly as the Department increases its reliance on debt to fund its capital investment. The Department is projected to rely increasingly heavily on debt to fund its capital plans. See Figure 3.12. The Department's capitalization ratio -- non-current debt relative to non-current debt plus equity -- is projected to increase from 54% in 2010 to 66% in 2017 (based on preliminary numbers). As capital expenditures and reliance on debt financing increase over the next five years, the burden of depreciation expense and debt service payments will continue to increase and put upward pressure on the revenue requirement.

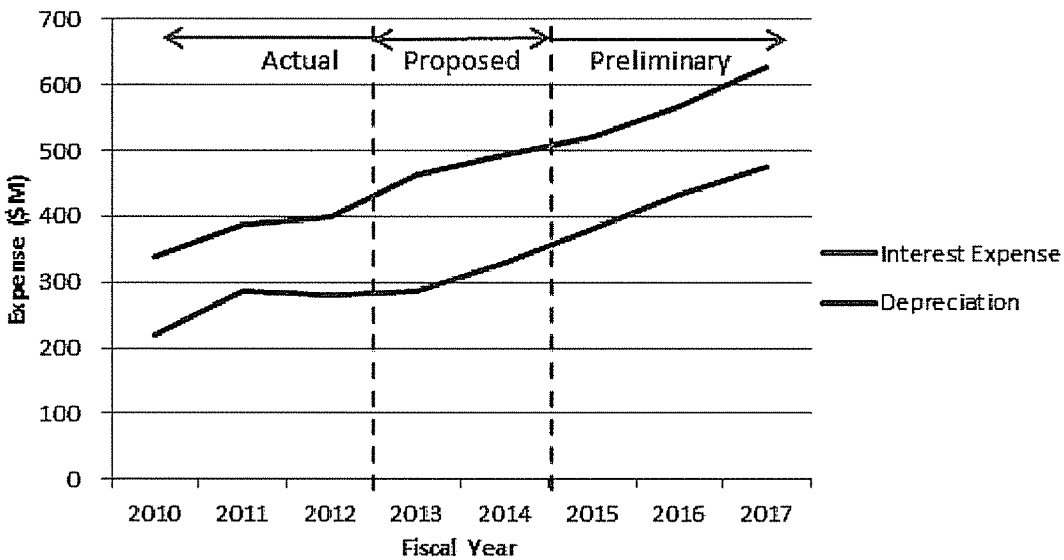
From 2010 to 2017, the Department's net plant assets--the non-depreciated portion of gross plant – are projected to increase from $7.0 billion to $12.2 billion, based on preliminary FY2015-17 numbers. More than half of this capital will be funded through debt. The majority of the Department's long-term debt is still a product of past project investment and financing decisions, but current spending practices are rapidly adding to leverage totals. The Power System's long-term debt is projected to increase by more than $2 billion over the next two years--from $6.3 billion in FY 2012 to $8.4 billion in FY2014, and this trend will continue through FY 2017 when the long-term debt level reaches almost $10.5 billion—as the Department borrows nearly $5 billion to finance capital investments included in the financial plan.

Figure 3.12: Long-Term Debt (2010-2017)



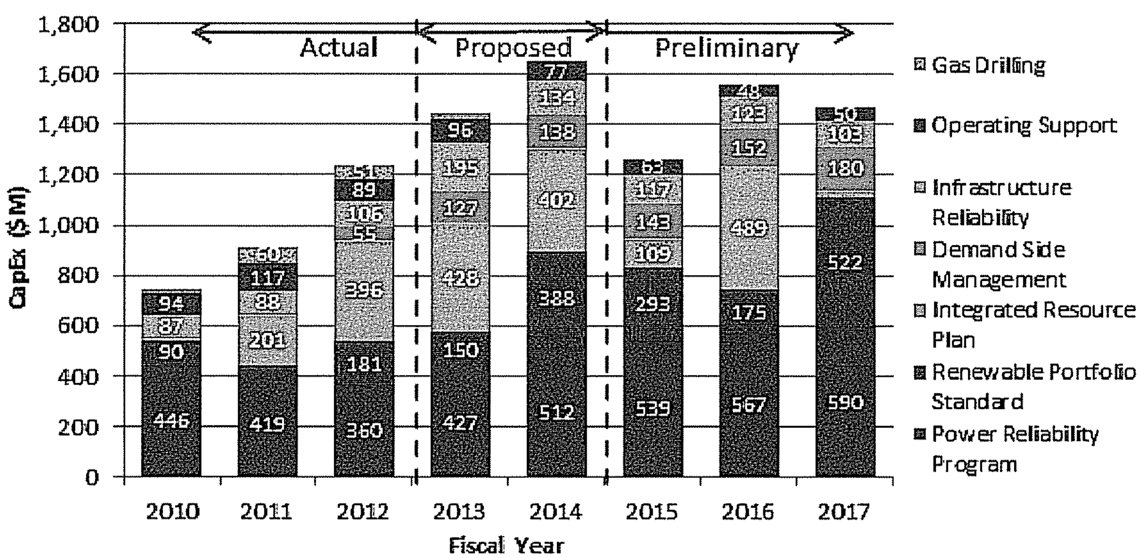
As a result of the increase in debt outstanding, interest expense and depreciation expense will increase considerably for the next five years, posing an increasing impact on annual revenue requirements. In FY 2010, interest expense accounts for 9.5¢ of every dollar in the electricity bill; that figure will rise to 12.0¢ by FY 2017. Funding an expanding capital investment plan through debt allows LADWP to take advantage of low interest rates in the current fixed income market, but the accumulation of debt and increase in interest expense will not only drive rate increases for future ratepayers but also put pressure on the Department's ability to stay within its financial targets. In order to maintain a debt service coverage ratio of at least 2.25x, the Department will have to increase its net revenue by at least $2.25 for every additional $1 of debt service accumulated.

Figure 3.13: Annual Interest Expense and Depreciation (2010-2017)



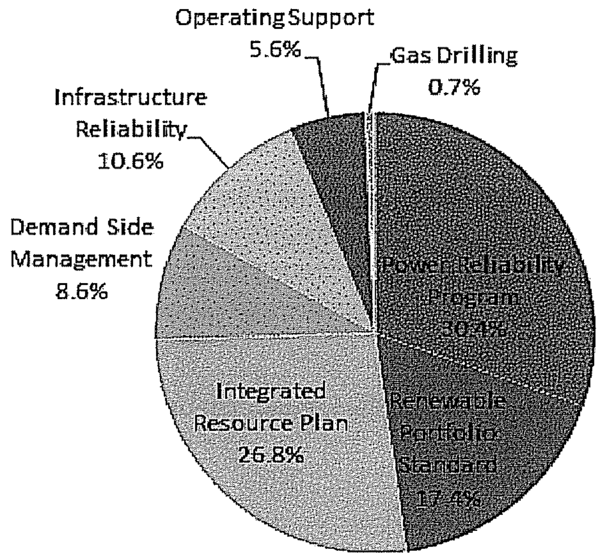
As shown in Figure 3.14, LADWP's annual capital expenditures are projected to exceed $1 billion every year from FY 2012-2017, based on preliminary numbers for FYs 2015-17. The main drivers are costs associated with maintaining the system (PRP), complying with regulatory requirements (repowering and RPS) and capitalizing demand side management expenses. While ratepayers may not see the full impact of these investments on their electric bill immediately, the long-term impact can be considerable.

Figure 3.14: Annual Capital Expenditure Allocation (2010 - 2017)



See Figure 3.15 for two-year total capital expenditures by category from FY 2013-2014.

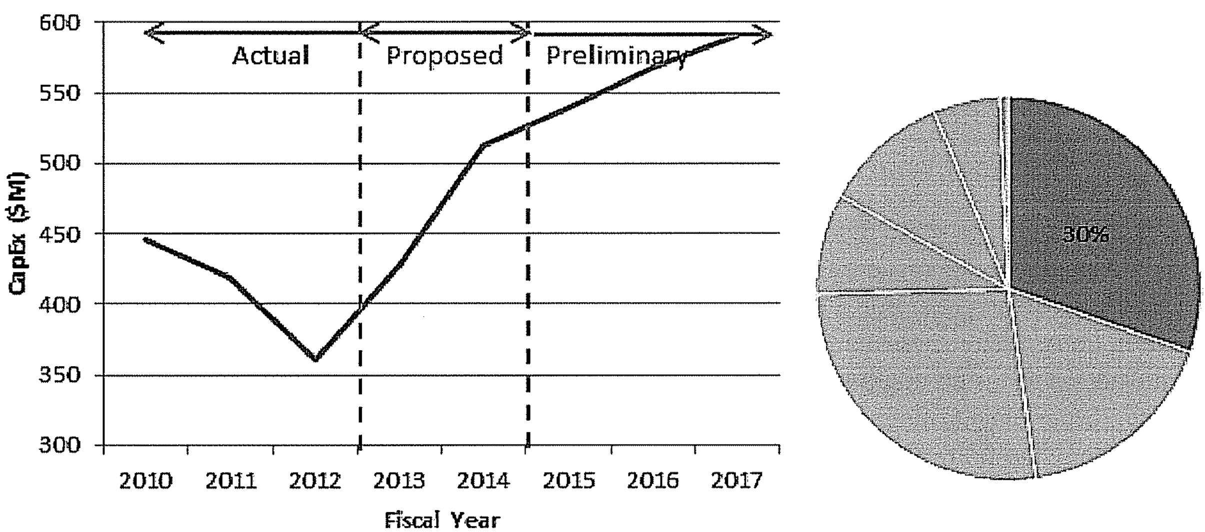
Figure 3.15: Total Capital Expenditure Allocation 2013-2014 (Two Year Total CapEx = $ 3.095 billion)



A. Capital Expenditures - Power Reliability Program

PRP capital expenditures include replacement of major components of LADWP's transmission and distribution systems, including transformers, poles, and conductors. The Department will also construct new transmission lines and enable substation automation.

Figure 3.16: Power Reliability Program Capital Expenditure Shown Annually (2010-2017) and Compared to Total Capital Expenditure (2013-2014)



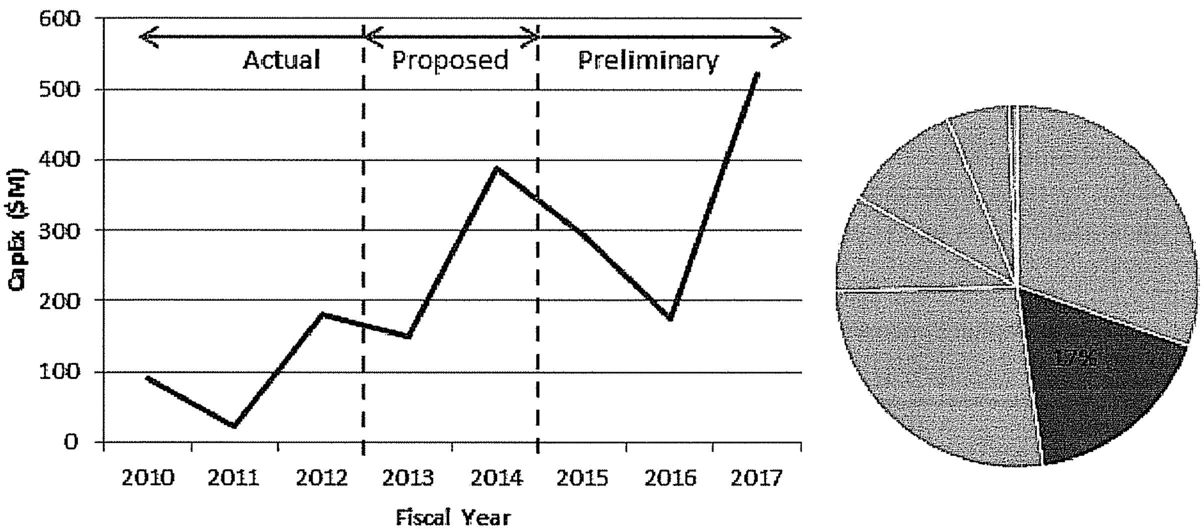
The main investment drivers for the PRP are new customer interconnections, distribution system and substation reliability, and substation automation. PRP investment, which contributes 30% of total capital expenditures for the next two years, is expected to increase by 19% and 20% in FY 2013 and FY 2014 respectively. Over the next three years this increase will continue, with PRP-related capital expenditures projected to increase at an average rate of 5% per year through FY 2017.

B. Capital Expenditure - Renewable Portfolio Standard

The Department has aggressively pursued its renewable energy targets, though RPS investment has been largely frozen since the conclusion of the 2010 ECAF discussions. RPS investment decreased after 2009, with FY 2011 showing the lowest RPS related spending in the last five years. Investment accelerated again in FY 2012, however, as the Department makes projected investments in biogas and other generic resources to replace the expiring Powerex hydro contract and help LADWP increase its renewable generation from 19.8% of sales in 2011 to 25.6% in 2016.

There are a number of renewable options available to LADWP as it seeks to comply with the SBX1-2 targets, each of which carry different rate, environmental, and economic development impacts. The Department's current financial plan includes more economic biogas purchases in the 2012 (while they still qualify for the California RPS), with more solar and some geothermal investment following the biogas moratorium.

Figure 3.17: Renewable Portfolio Standard Capital Expenditure Shown Annually (2010-2017) and Compared to Total Capital Expenditure (2013-2014)



RPS capital spending, which represents 17% of total Power System capital expenditures from FY 2013-2014, is expected to decrease by 17% in FY 2013. This is driven by completion of the majority of Adelanto and Pine Tree solar systems in FY 2012. Over the next five years, LADWP is expected to continue its long-term transmission development project which will account for $273M of the RPS capital expenditure. The project will focus on upgrading underground transmission system, electrode lines and voltage/current capacity. Other main investment drivers for RPS include the capitalization of SB1 solar incentives and construction of the Barren Ridge renewable transmission project, which will provide access to renewable resources in Tehachapi and the Mojave Desert. Barren Ridge investment alone will peak at $205M investment in FY 2014, explaining the major RPS increase in that year. In addition, LADWP will pursue several major solar projects over the next five years to ensure compliance with the RPS target. Overall, six major projects or programs account for approximately 90% of the RPS capital spending between FY 2013 and 2017 (see Table 3.1).

Table 3.1: Major RPS Projects - Annual Capital Expenditures (2012-2017)

Major RPS Projects	Annual RPS Capital Expenditure ($M)					
	FY2012	FY2013	FY2014	FY2015	FY2016	FY2017
Barren Ridge Renewable Transmission Project	5	32	205	126	21	0
Long-Term Transmission Development	7	11	76	91	74	22
Pine Canyon Wind Development	2	2	5	7	6	246
Solar Incentive Program	63	64	65	22	19	15
200MW Owens Valley Solar Project	2	1	0	0	0	138
Development of 120MW Solar on City Property	7	14	15	15	16	61
Total Capital Investment - Major RPS Projects	85	123	365	261	137	482
Percent of Total RPS Capital Investment	47%	82%	94%	89%	78%	92%

C. Capital Expenditure - Integrated Resource Plan

The IRP provides LADWP a strategic investment direction by addressing regulatory, environmental, and reliability challenges. The main investment drivers for the IRP cost element are investments for repowering Scattergood Unit 3 and Haynes Units 5 & 6, replacing Navajo station, and modernization efforts at Castaic station. The decision to repower Scattergood 3 and Haynes 5 & 6 was driven by once-through cooling and local air emission rules. The new units will be more efficient, more reliable, and will allow renewable resource integration through higher ramp rates. The annual costs of repowering Scattergood Unit 3 and Haynes Units 5 & 6 with combined cycle system for the next 5 years are shown in Figure 3.18.

Figure 3.18: Projected Repowering Costs - Near Term (2013-2017)

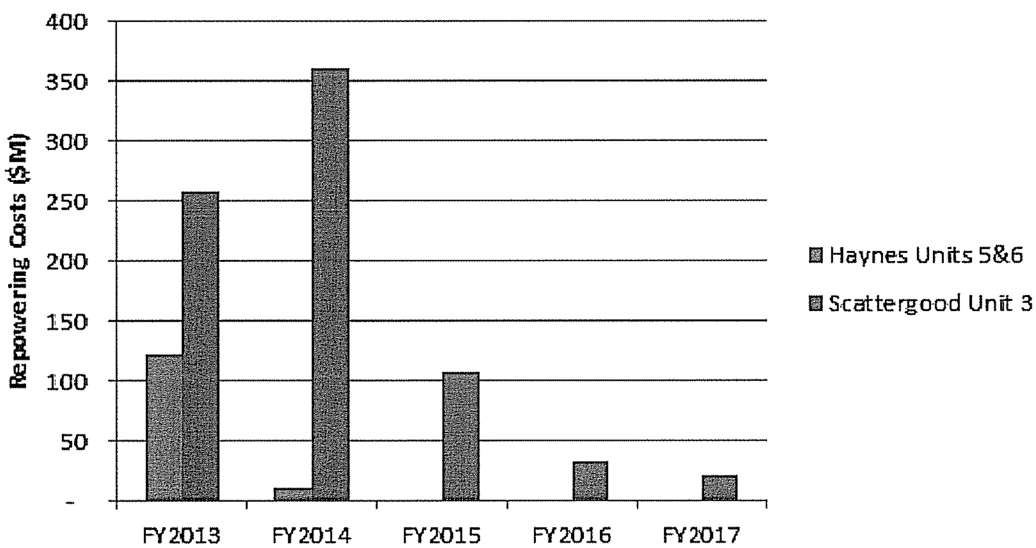
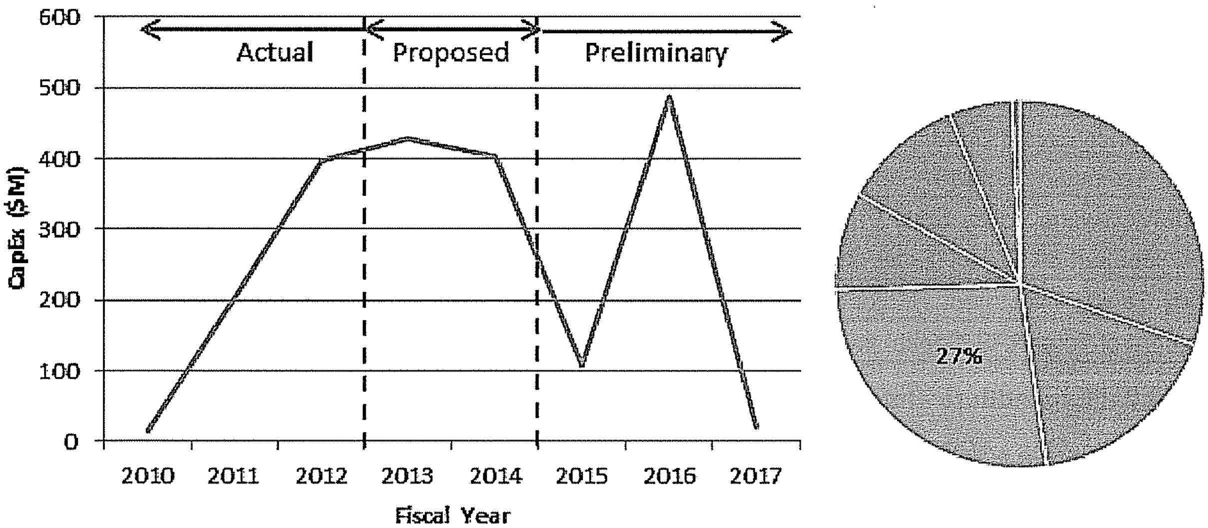


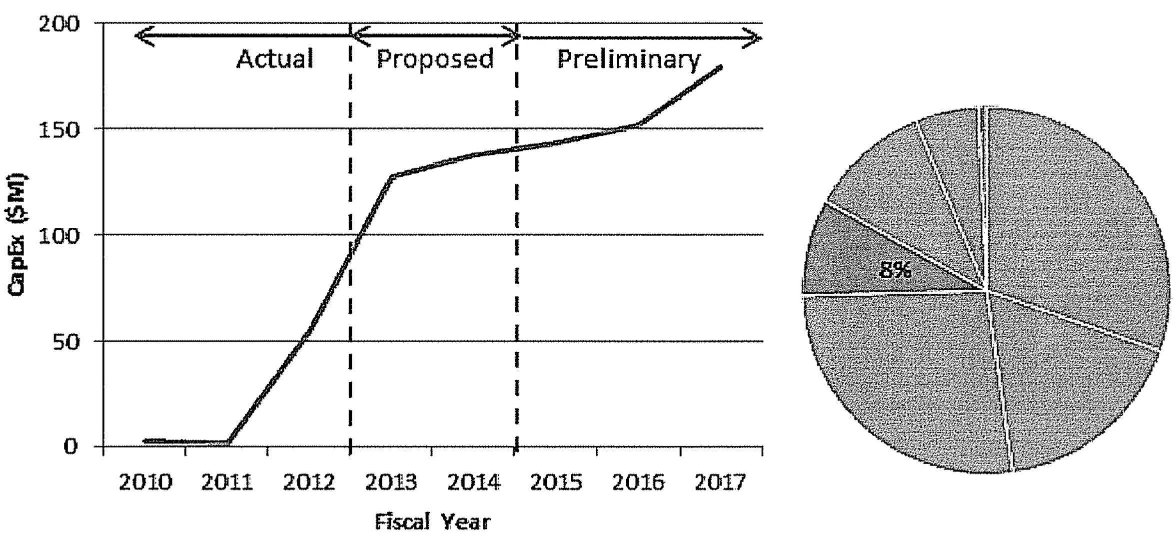
Figure 3.19: Integrated Resource Plan Capital Expenditure Shown Annually (2010-2017) and Compared to Total Capital Expenditure (2013-2014)



IRP will contribute 27% of total capital expenditures for the next five years (based on preliminary numbers provided by the Department). The drop after FY 2014 can be explained by the completion of the Scattergood repowering. The expected construction or purchase of the $456M combined cycle plant which will replace Navajo's capacity drives the increase in investment in FY 2016.

D. Capital Expenditure - Demand-Side Management

Figure 3.20: Demand-Side Management Capital Expenditure Shown Annually (2010-2017) and Compared to Total Capital Expenditure (2013-2014)



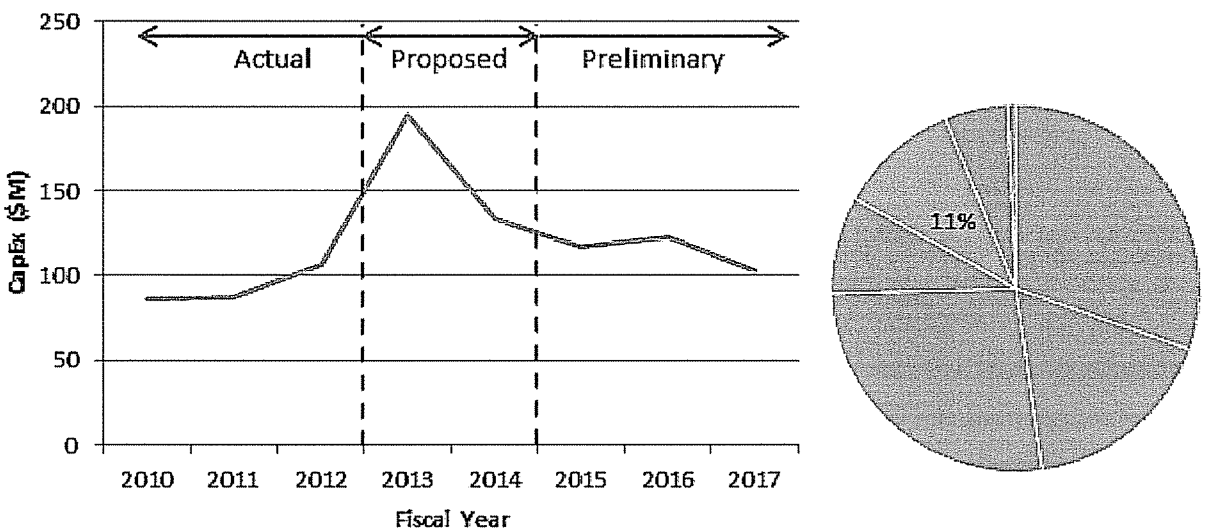
LADWP's energy efficiency public benefit program is the main cost driver for the DSM program. DSM, which contributes 8% of the total capital expenditure for the next two years, is one of the major new sources of capital spending. Last year's Power System financial plan, released in June 2011, reflected relatively flat DSM capital expenditure levels of less than $40 million annually through 2016. The current plan projects much greater DSM investment, starting with a projected spending increase to $127M in FY

2013 and $138M in FY 2014. The increase is projected to continue at an average of 9% per year over the FY 2015-17 period, although the Department has noted new numbers would be reached in the second half of calendar year 2013 based on the results of a new energy efficiency potential study. Part of the cause for this significant rise, as stated in the O&M section of this report, is the capitalizing of energy efficiency incentive expenditures that were previously expensed, but regardless there is a much more significant commitment to DSM on the part of the Department.

E. Capital Expenditure - Infrastructure Reliability

Capital expenditures related to infrastructure reliability include fleet purchases, automatic meter reading (AMR) systems, and generation asset improvement.

Figure 3.21: Infrastructure Reliability Capital Expenditure Shown Annually (2010-2017) and Compared to Total Capital Expenditure (2013-2014)



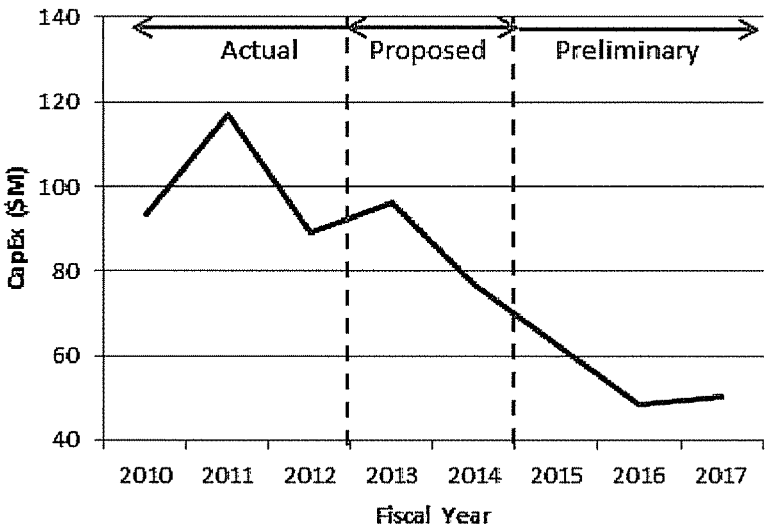
Infrastructure reliability, which contributes 11% of the total capital expenditure for the next two years, is expected to increase by 84% in FY 2013 due to major investments in the AMR program ($72M over two years) and fleet ($77M over two years). In FY 2014, investment in infrastructure reliability will reverse the trend and decrease by more than 31%. The reduction in infrastructure reliability related spending will continue to decline over the next three years at an average rate of 8% per year. This long-term downward trend is driven by declining spending on LADWP's generating facilities and the AMR program. Despite major capital investment in the AMR program, O&M expenses associated with meter reading will continue to increase over the next five years.

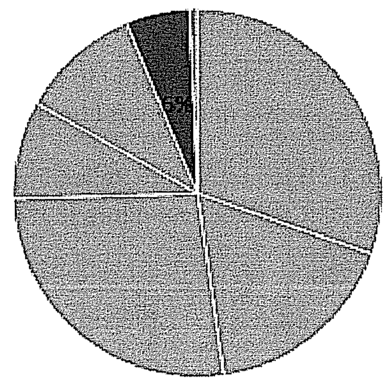
F. Capital Expenditure - Operating Support

LADWP's Joint System will be conducting multiple major IT projects in the next five years. The capital plan includes a customer information system (CIS) replacement, a fiber optic enterprise (FOE) project, core financial and accounting systems replacement, and a new telecommunication system installation.

The Department's limited business case for the CIS project states that the replacement of the old system is necessary to move away from outdated software, provide new functionality, and avoid the consequences of declining institutional knowledge associated with the old system.

Figure 3.22: Operating Support Capital Expenditure Shown Annually (2010-2017) and Compared to Total Capital Expenditure (2013-2014)



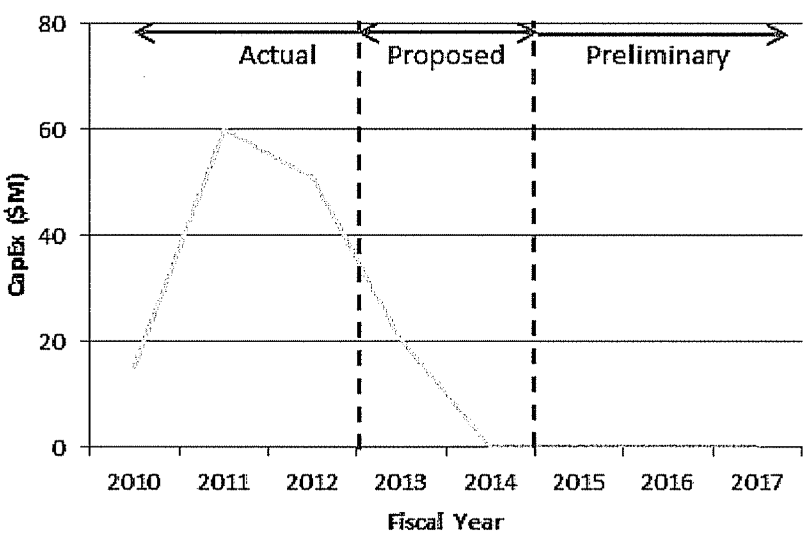


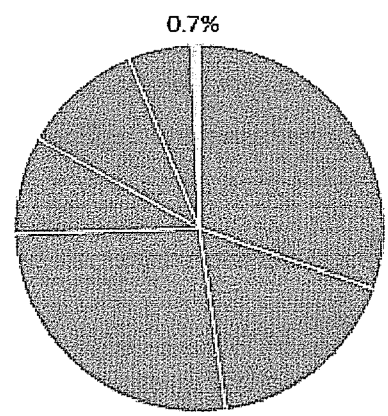
Operating support, which contributes 6% of the total capital expenditure for the next two years, will decrease at an average rate of 7% per year from FY 2012 to FY 2014 following the ramp down and completion of the CIS project. This downward trend will continue over the FY 2015-17 period with an average decrease of 13% per year.

G. Capital Expenditure - Gas Drilling

LADWP invested in the Pinedale Natural Gas Project (natural gas reserves in Wyoming) in 2005. The purchase provides LADWP a secure source of natural gas and a natural hedge against price volatility in the natural gas market. In order to increase production, additional capital investment is required to drill new wells.

Figure 3.23: Gas Drilling Capital Expenditure Shown Annually (2010-2017) and Compared to Total Capital Expenditure (2013-2014)



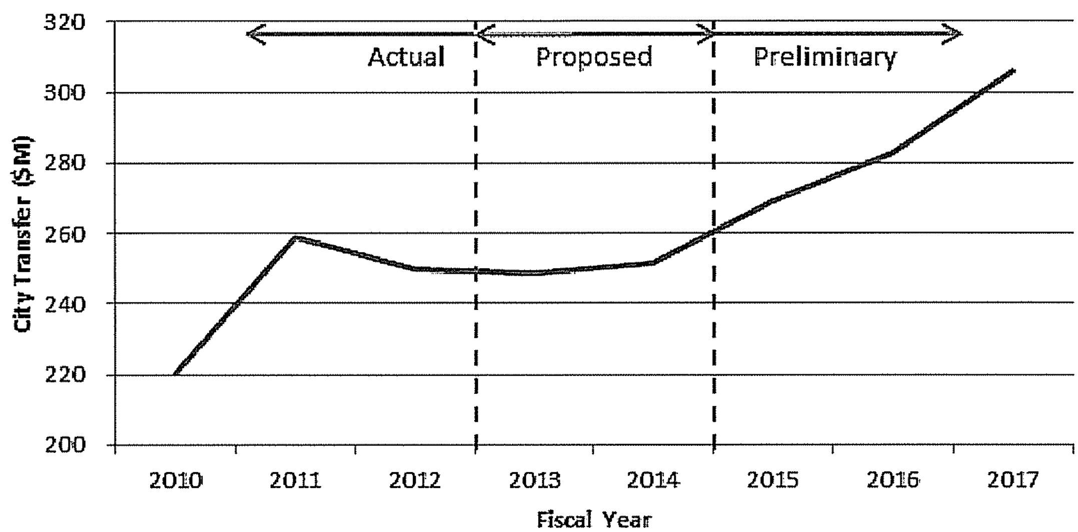


Gas drilling investment, which contributes less than 1% of total Power System capital expenditures for the next two years, is expected to decline significantly in the coming years with the depressed price of natural gas. Gas drilling investment is projected to decrease by 60% between 2012 and 2013 and then be discontinued in FY 2014.

3.4 City Transfer

Each year, LADWP makes a cash transfer to the City of Los Angeles equal to 8% of the previous year's total operating revenue. The "city transfer" is projected to remain relatively flat though FY 2014, but increases at an average rate of 6.8% per year over the FY 2015-17 period. The Department desires that the City Transfer be a fixed fraction of total revenue. Therefore, increases in the City Transfer are driven by the increases in the Department's other costs.

Figure 3.24: Annual City Transfer (2010 - 2017)



4 Power Rate Restructuring

Power base rates have not increased since 2009 and the ECAF has not increased since July 2010; LADWP did not request the periodic ECAF increases to which it is entitled due to legal considerations (see Section 4.5) and other factors including commitments to defer rate changes until the RPA was in place. The Power System now believes its financial situation and the Board's direction to increase Energy Efficiency spending together require rate increases averaging approximately 5.5% annually over the next two years (6.5% annually in the Department's indicative forecast for the next five years). It is clear the Department will need to increase rates to maintain its infrastructure and stay in compliance with the laws to which it is subject, but the Department, with the support of the City, also needs to take a more transformational approach to reducing costs: PA has found that many of the areas needing attention are subject to the current union agreements and changes cannot be implemented until those terms are renegotiated.

Legal considerations have led LADWP to design a new rate structure. LADWP's rate redesign construct has been developed with the City Attorney's guidance so as to address the legal considerations (see Section 4.5). Based on that guidance LADWP has chosen to restructure its power rates using a set of surcharges over and above the rates previously in effect. Ordinance 180127 (the Electric Rate Ordinance) will not be amended or repealed; rates specified in the Electric Rate Ordinance will remain in force as will the previously specified additional Factors (ECAF, RCAF, etc.)

The Department will propose that the City Council pass two new separate and independent ordinances. The first new ordinance (the "incremental ordinance") defines a set of rate surcharges with multiple components, but is intended to leave all rates and schedules in the Electric Rate Ordinance unchanged. The second new ordinance (the AMP-EV ordinance) will effectively modify the Electric Rate Ordinance by adding two new rates to be used by customers instead of current rates: a new Experimental AMP interruptible schedule to be used by certain eligible customers as an alternative to the current AMP schedule, and a new Rider EV to be used instead of the Electric Vehicle Discounts available under several schedules in the Electric Rate Ordinance.

There are three steps involved in utility ratemaking. First, one determines the total amount of revenue the utility needs ("revenue requirements determination"). Second, that revenue is allocated to groups of customers, such as individually metered residential customers, medium-sized commercial customers, master-metered residential customers, etc., based on some measure of the amount it costs to serve each group ("revenue allocation"). Another type of revenue allocation is rate unbundling, in which revenues are divided among several component services, so that customer rates can be built up from rates for those individual services; LADWP has taken a partial unbundling approach in its definition of the surcharges. Third, the specific rates, that is, the rate structure (metrics of consumption) and prices to apply are defined for each group ("rate design").

- *Revenue requirement.* The Power System believes its financial situation requires an average rate increase of approximately 5.5% annually over the next two years. The rate increase is driven by increases in the Department's operation and capital revenue requirements as well as the collection of costs that were previously deferred to reduce rates.
- *Revenue allocation.* The Electric Rate Ordinance implicitly allocates "base revenues" (the revenues not collected by pass-through factors such as ECAF, RCAF and ESAF) among

customer groups by defining rates differently by schedule; the incremental ordinance does not change the set of schedules.

- The Department is recommending an unbundling of the amount by which the revenue requirement exceeds the amount collected under the Electric Rate Ordinance, among several surcharge components. This chapter primarily describes that unbundling, including PA's recommendation in its ECAF report, the decision to base the restructuring on surcharges, the design principles that should underlay the unbundling, the process by which the surcharge components were defined, and the allocation of current rate revenues among those components.
- The unbundled components must be allocated among rate schedules. They include a set of "pass through" components – ICRA and the three "pass throughs" VEAF, CRPSEAF, and VRPSEAF-- which are allocated almost uniformly across schedules on a c/kWh energy charge basis (the IRCA rate for some schedules is defined as a $/kW demand charge). The remainder of the additional revenue is allocated to the incremental base rate component. Incremental base rate revenue is allocated across schedules so that the total incremental revenue allocated to each schedule (incremental base rate revenue plus forecasted VEAF, CRPSEAF, VRPSEAF and IRCA revenue) is proportional to that schedule's anticipated total FY 2012 revenue from the Electric Rate Ordinance, with a constant proportion across schedules.

- *Rate design*. PA received the most recent draft of the incremental ordinance on Aug. 3. PA has proceeded with an evaluation of the customer impact of restructuring power rates based on that draft and the Department's representation of limited changes to the language to reflect financial plan case 119, subject to confirmation relative to the final version of the incremental ordinance. There are two key differences between the design of the incremental base rates and of the base rates previously adopted in the Electric Rate Ordinance:
  - As a matter of public policy, the Electric Rate Ordinance included low income and lifeline discounts to residential base rates (schedules R-1D and R-1E) as well as low income and lifeline credits to multi-family rates for each qualified sub-metered unit. The pass-through factors were not discounted. The incremental ordinance does not apply low income or lifeline discounts to either the incremental base rates or the incremental pass through factors.
  - The basic design of the interim base rates (billing determinants, tiering) is the same as in the Electric Rate Ordinance. However, the numeric prices do not have the same relationship in the two ordinances. For example, the ratio of tier 2 prices to tier 1 prices is much greater in the incremental ordinance than in the Electric Rate Ordinance (steeper tiering). This means that the surcharge will have less impact on customers with low usage, somewhat offsetting the lack of incremental low income and lifeline discounts (on the assumption that customers who would have received those discounts have low usage). Also, for schedules like A-3 with both energy and demand billing determinants, the energy and demand charges in the incremental ordinance do not bear equal proportions to those in the Electric Rate Ordinance. Therefore the fractions of the total interim base revenue requirement for those schedules collected by demand charges and by energy charges are different than the corresponding fractions for the base revenue requirement in the Electric Rate Ordinance.

4.1 PA's previous recommendations

In its Independent Fiscal Review of the Energy Cost Adjustment Factor (ECAF), dated February 25, 2010, PA described how the current structure of the ECAF obscured the drivers of the Department's costs by lumping together disparate components, and how it allowed pass-through of costs that should have been controllable even while it did not have enough flexibility to deal with truly unpredictable and volatile rate components. PA suggested that the ECAF be decomposed into several, differently treated rate components. PA stated,

"This will provide the Council with greater visibility of LADWP's cost structure and of the justification for any rate increases. It will clearly identify the Council's actions to stabilize rates. It will ensure that controllable costs are subject to appropriate controls. And, by applying to each separate component a review of appropriate detail and frequency, lenders and rating agencies will be able to take comfort in the City's commitment to cost recovery."

Under the Electric Rate Ordinance, the Department was able to reset the ECAF rate quarterly. The ECAF rate was designed to collect revenue sufficient to cover costs in certain identified categories. Those cost categories are shown in Table 4.1. It was intended that the rate would reflect LADWP's actual costs as closely as possible. Unlike the "base" component of rates, which is based on relatively stable capital and labor costs, ECAF was to reflect fluctuating fuel costs. Therefore, the ECAF had to be reset frequently: each quarter the ECAF rate was changed to reflect expectations of fuel prices. The ECAF rate would be further adjusted to "true up" the difference between previous quarters' actual costs and revenues (that were based on expected costs).

Table 4.1: ECAF Cost Categories

• Floating-price fuel-related costs	• Fixed long-term PPA costs
• Fixed-price fuel costs	• Fixed short-term PPA costs
• Fixed transmission capacity costs	• Floating-price PPA costs
• RPS contract costs (base volumes, debt service)	• DSM capital costs
• RPS O&M costs	• DSM subsidy costs
• RPS surplus energy costs	• DSM/EE lost revenue
• Short-term renewable energy purchases	• Decommissioning costs
• Accumulated deferral (under-/over-collection)	• Legal settlements/penalties

ECAF rates actually reflect two somewhat contradictory principles. By changing quarterly in response to fuel markets, and by being "trued up" quarterly for the deviation between actual and expected costs, ECAF would reflect the expectation that these costs were beyond the Department's control or ability to predict. However, quarterly increases in ECAF were capped, as if the Department was still expected to control the increase in those costs. This would not be a problem if ECAF were based only on mean-reverting market prices, but ECAF also included certain contract costs with significant and predictable built-in growth so that its cost increases regularly exceeded the cap.

PA recommended that ECAF be replaced by at least three separate components, which would separately collect:

- Costs that are clearly out of the LADWP's control, such as short-horizon gas, coal, and power purchases
- Costs that are predictable, such as long-term contract costs or energy efficiency costs

- Revenue losses attributable to DSM.

Different cost recovery principles would be applied to the three components. Uncontrollable costs would be recovered on a pure pass-through basis as long as the Department was following an approved procurement plan. Predicable costs, such as the fixed costs of long-term renewable PPAs, should be reviewed before any rate adjustments, e.g., Council approval of a contract would include review of its rate impact so that it can be included in rates when deliveries start. DSM revenue losses based on the reduction in the demand over which the revenue requirement is spread would be passed through with a budgetary cap only on the targeted demand reduction.

PA also recommended that the City Transfer should not be tied to fluctuating ECAF revenues, but rather entirely to more stable base rate revenues. Doing so would create greater certainty of City Transfer payments and remove elements of the City Transfer from the current ECAF structure.

4.2 Rate design should increase cost control and transparency

PA believes the way rates are set should reflect the utility's ability to control costs, and should provide management an incentive to control costs. If rates are designed to allow built-in cost increases to accumulate for several years without review, the incentive to control costs is reduced. If a rate design does not appear to allow cost overruns to be passed into rates, although it actually defers them for later "true-up" without review, management sees no pressure to avoid overruns. On the other hand, truly uncontrollable costs should be passed into rates as soon as possible. "Rate stabilization", where the utility defers expected and legitimate rate increases by financing rather than immediately collecting the costs, should be reserved for exceptional situations; otherwise such financing can become a regular feature of ratemaking and indistinguishable from borrowing to fund operations.

PA recommends that costs be categorized by controllability and predictability. Cost should be subject to automatic "true-up" only to the extent that they are uncontrollable. Rate increases to cover predictable costs should be made explicitly rather than automatically (not necessarily by an election or supermajority, but in such a way that the responsibility for approving the increase is clear). Rate design principles that reflect cost recovery include:

- Costs that are unpredictable and uncontrollable (like market-driven fuel prices) should be collected on as close to a pure pass-through basis as possible
- Costs that are knowable in advance (like the costs of fixed price contracts) should not be trued-up; rates can be adjusted when actions are taken, or contracts approved, that will cause predictable cost increases
- Costs that are generally (not completely) controllable around a predictable level (like O&M costs or the costs of excess RPS energy) can be trued-up to a limited extent (subject to a cap), with specific reporting to ensure management attention
- Costs that are variable but controllable to a budget (like annual DSM subsidies) should not lead to automatic rate changes except possibly downward from the nominal level; in general the associated rate component should not have any automatic adjustment.

In addition to cost control, PA's ECAF recommendations attempted to increase the transparency of LADWP rates. ECAF included a number of different types of costs, not all of which fit the usual concept of an "energy cost adjustment clause" (rate adjustment to account for variable supply costs). This made it difficult for ratepayers and even Council members and staff to determine which costs were driving ECAF, and the extent to which decisions made several years earlier should have been expected to contribute to rate increases.

4.3 The Department's surcharge approach

LADWP has chosen to restructure its power rates using a set of surcharges over and above the rates previously in effect. Ordinance 180127 (the Electric Rate Ordinance) will not be amended or repealed; rates specified in the Electric Rate Ordinance will remain in force as will the previously specified additional Factors (ECAF, RCAF, etc.) The Department will propose that the City Council pass a separate and independent ordinance (the "incremental ordinance") defining a set of rate surcharges. This is the recommendation of the City Attorney based on legal considerations (see Section 4.5).

LADWP's proposed rate restructuring approach may be described as a surcharge with multiple components. Under the Electric Rate Ordinance, rate factors that are defined by formulas, such as the ECAF, contain explicit gross-ups for a City Transfer. The surcharge proposal has involved a number of components with varying degrees of true-up or automatic adjustment; in general, over the last year components have been combined in the name of simplification (reducing the degree and benefit of unbundling) and true-ups increased. Also the surcharge approach was extended to include surcharges for "base costs" (cost not assigned by the Electric Rate Ordinance to any of the adjustment factors). The Department's original surcharge proposal as presented to PA was not grossed-up for an allowance for City Transfer. The current conceptual proposal includes gross-ups on the surcharge; we understand it to be consistent with the recommendation of the City Attorney.

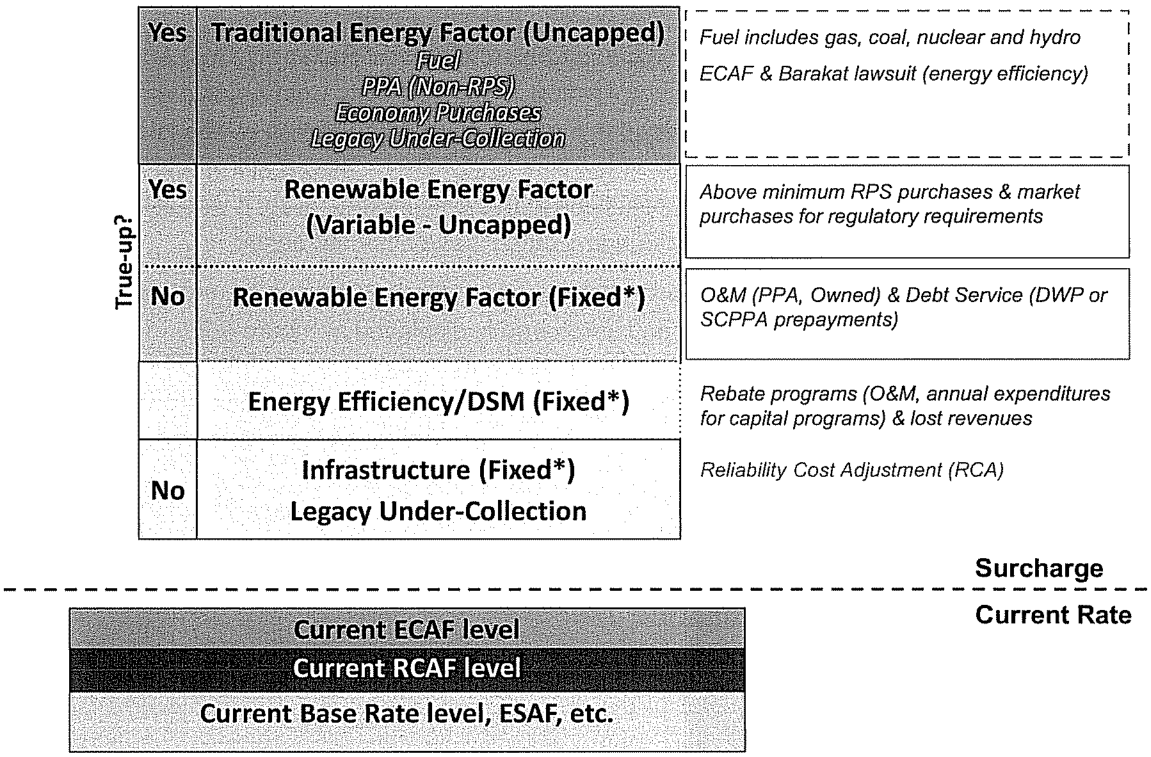
Leaving the Electric Rate Ordinance unchanged would mean the Council and Department would be unable to fully restructure rates, particularly ECAF, as PA had recommended in 2010 (the Council has endorsed that recommendation). The Department has said that it supports PA's recommendation and wants to implement it but cannot so restructure current rates due to legal considerations (see Section 4.5). The Department has made a "good faith" move towards restructuring by using a set of surcharges, rather than a single surcharge. PA suggests that the new surcharges, once finalized, be approved on a temporary basis for a set time period and they be replaced with fully restructured permanent rates once legal considerations allow (see Section 4.5).

4.3.1 Evolution of the surcharge concept

The next set of figures illustrates the evolution of the surcharge approach. While it meets some of the goals of PA proposed restructuring it falls short in other areas which we explore on the following pages. The rate making environment has been made difficult by legal considerations (see Section 4.5). PA believes these surcharges are appropriate for this environment as long as there is a mandatory review of their continuing need called for in the ordinance in two years from their implementation.

In June 2011, the Department had proposed that the component surcharge rates would be structured, relative to the cost increases, along the lines of PA's earlier ECAF recommendation, and including a surcharge on the Reliability Cost Adjustment Factor for PRP cost increases. This structure is illustrated in Figure 4.1.

Figure 4.1: LADWP's original surcharge concept



Based on LADWP diagram "Alternative Interim Rate Structure" dated 6/28/11

The five components of the proposed surcharge are:

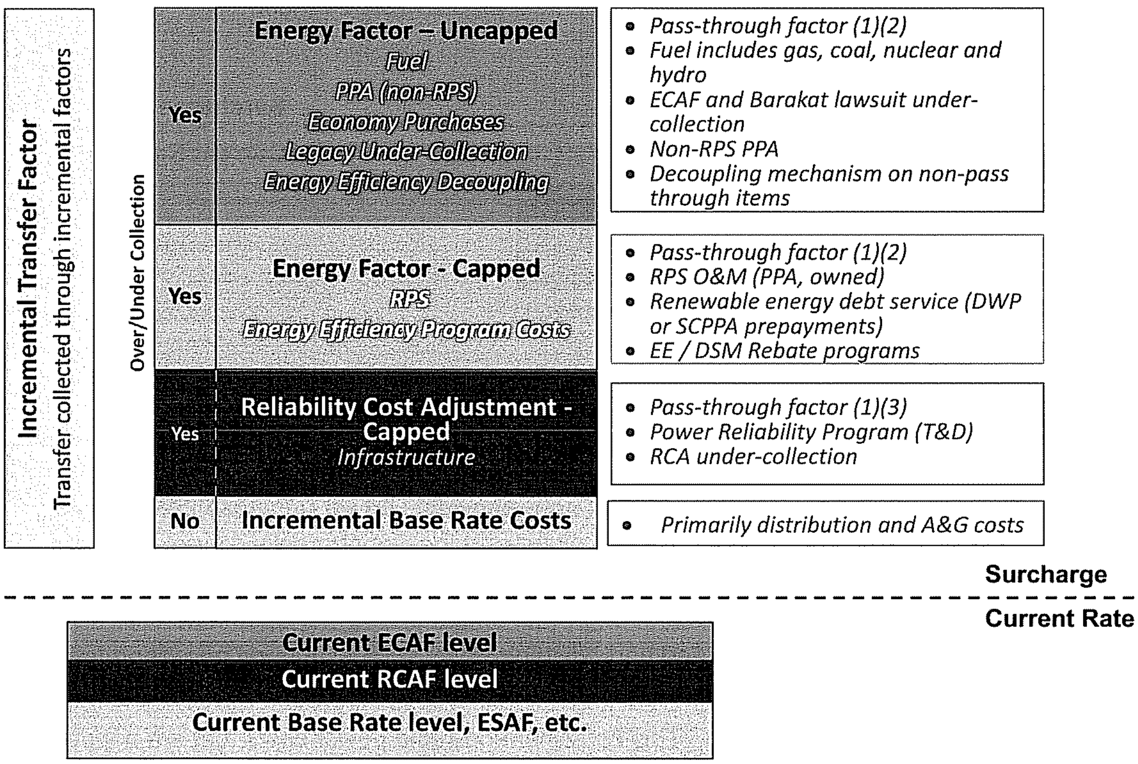
- Traditional Energy Factor – Uncapped. This contains short-term fuel and power purchase costs; the "legacy under-collection", representing the amount of under-collection in the Energy Cost Adjustment Account when rates are restructured; non-renewable power purchase agreements (PPAs); and a legal settlement. These costs are all beyond the Department's control although several of them (e.g., the legacy under-collection and the legal settlement) are predictable or known. This factor would be a direct pass-through with an automatic true-up and no cap. PA supports uncapping the uncontrollable and unpredictable costs such as natural gas, short term power purchases, etc.
- Renewable Energy Factor – Uncapped. This contains renewable power costs that are not part of the Departments "take-or-pay" PPA obligations (excess power). These too may be considered as beyond the Department's control and in addition they relate to regulatory or legislative mandates. This factor would be also a direct pass-through with an automatic true-up and no cap.
- Renewable Energy Factor – Fixed. This contains the fixed cost of renewables. These are costs which the Department should be able to predict and control, and the Department indicated at the time that there would be no automatic true-up. It is denoted as "Fixed", not just "Capped", implying there would be no automatic adjustment.
- Energy Efficiency / DSM – Fixed. This contains Energy Efficiency and DSM program costs, which should be based on preapproved budgets and contracts, as well as the lost revenues associated with Energy Efficiency and DSM (decoupling). The Department should be able to predict and control the program costs as they are based on annual subsidy awards; lost revenues may be

less controllable. At the time the Department had not determined whether it would propose a true-up, which might be appropriate for lost revenues even if not for program costs.

- Infrastructure – Fixed. This contains PRP expenditures (the current Reliability Cost Adjustment Factor (RCAF)) as well as the legacy under-collection in the Reliability Cost Adjustment Account. This component should be controllable, because the legacy under-collection will be known and PRP expenditures can be tied to a budget. At the time LADWP indicated that it would not be proposing an automatic true-up of under-collections in this component. Also, it was PA's impression that this component did not include any other "base cost" increases.

The Department continued to modify its surcharge structure, and in March 2012 communicated a "simplified" version. This structure of Base Rates and surcharge is displayed in Figure 4.2.

Figure 4.2. LADWP's March proposal "simplified" the previous but does not distinguish categories to facilitate transparency or cost control



Based on LADWP diagram "Frozen Existing Rate and Incremental Surcharge" received 3/15/12

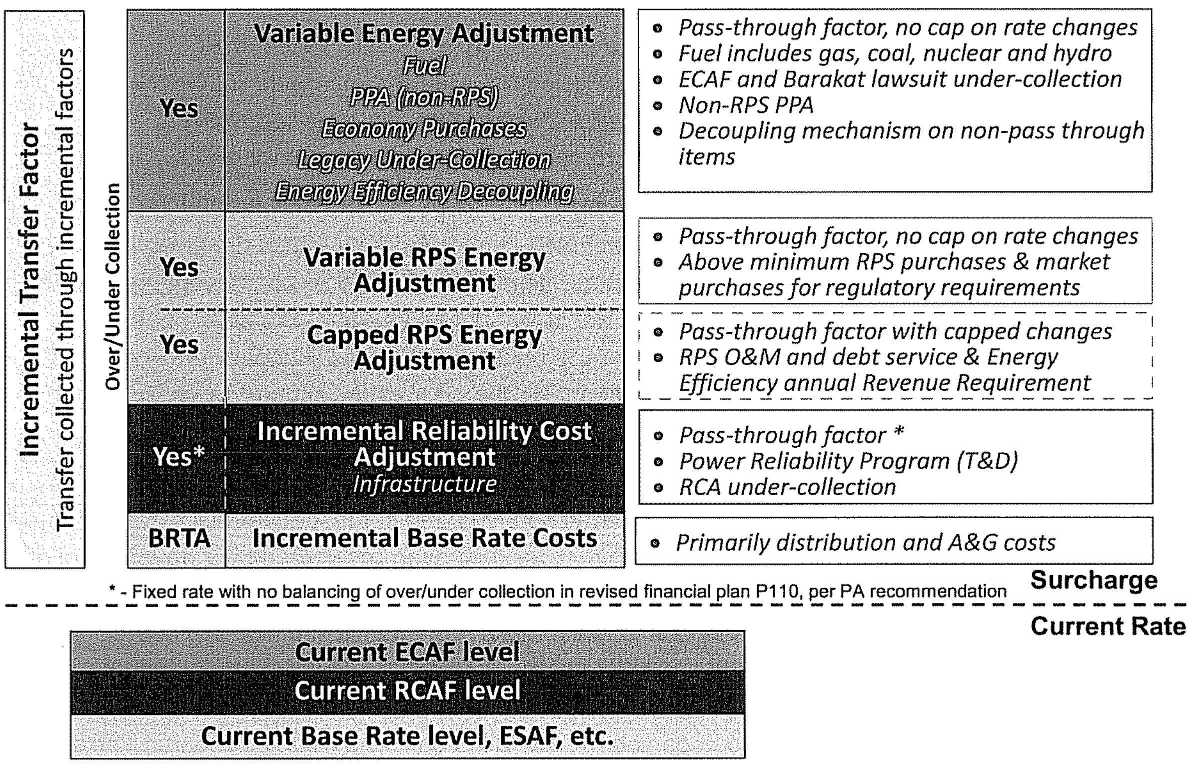
The most significant changes to the composition of the surcharges were:

- The first four components displayed in Figure 4.1 were collapsed into two. This is not a fine enough detail to distinguish cost categorization for rate design, or to improve transparency.
- Figure 4.2 includes an additional surcharge component for "incremental base rate costs". The original components were associated with the ECAF and RCAF, and were limited to specific, identifiable cost categories. This last component is a catchall category that allows for any other cost increases. If Base Rates are to be surcharged, PA believes it should be clearly separate, and further broken down into several components (e.g., by cost category) to increase transparency.

- Compared with Figure 4.1, the differences in cost recovery between the components were largely erased -- all but the "incremental base" component would be trued up. If under-collections are deferred then there is effectively no cost cap, only a rate cap – which is exactly the situation that led to the current ECAF under-collection.

PA communicated its concerns to the Department, and in early May the Department released a further modified surcharge structure which was embodied in the incremental ordinance. That structure is illustrated in Figure 4.3. The renewables-related costs are separated into two components and all other ECAF costs are put into a "Variable Energy Adjustment" which would have an automatic true-up adjustment for any cost increases. Energy Efficiency/DSM costs, which represented a separate fixed component in Figure 4.1, are included in the "-- Capped RPS Energy Adjustment", but two different revenue decoupling mechanisms – one for energy efficiency investments through June 30, 2012, and the Base Revenue Target Adjustment described below, are included in the Variable Energy Adjustment.

Figure 4.3: The rate structure in the incremental ordinance restores some surcharge detail



Based on LADWP diagram "Proposed Power Rate Structure" updated 5/3/12 and draft Incremental Rate Ordinance

4.3.2 Transparency and cost control in the surcharge approach

PA previously identified transparency and cost control as two key guidelines for rate restructuring. These two goals are somewhat in conflict with the Department's third goal of simplicity. We do believe that is not an irreconcilable conflict, and that it is possible to have a more transparent structure than the Department's proposal, which would improve cost control while still appearing simple to the ratepayer. The key is to distinguish between the bill itself and supporting information.

Transparency would be come from reporting rates or revenue requirements broken down into logical categories, so that one can understand how ratepayer revenues are being spent, without lumping together disparate costs. This clearly would require a more detailed rate structure than the Department has proposed, and would produce confusing bills. A solution would be to define rates with a larger number of categories or components, and accumulate categories together on the bill.

For example, the Department's March proposal (Figure 4.2) contained two ECAF-related surcharge components, "capped" and "uncapped". Each of these components could collect several different types of costs. Rates should be built up by defining a revenue requirement and rate for each cost type, and then separately adding the "capped" and "uncapped" types to produce two reportable rate components. The monthly bill would only contain two components but an interested ratepayer could find the finer detail about how their rate was constructed by looking, for example, at the LADWP website.

Traditionally, ratemaking incentivized cost control by fixing rate levels: a utility's price would be set and the utility would bear the responsibility of controlling costs to within that price level. Certain costs were then determined to be outside the utility's control, such as energy purchase costs, and part of the rate was allowed to fluctuate with those costs.

PA recommended that, in restructuring the ECAF, costs be classified by the degree to which LADWP could control them, and the degree to which costs were passed through would reflect their uncontrollability. On the contrary, disparate cost types are included in the "uncapped" category in the Department's proposal, including some that are not at all uncontrollable, as we noted above. Furthermore, because all the components (except "Incremental Base") are subject to true-up, none of them is really fixed.

The collapse of the ECAF into two components was attributed to simplification, but a simplified bill presentation can be compatible with a more sophisticated rate design. Furthermore, the logic behind the categorization of costs as "capped" and "uncapped" is not clear; it would be better to define cost categories first -- based for example on controllability -- and then label them as "capped" or "uncapped". Finally, in the original version of the surcharge proposal, the ability to "true up" differed by cost category.

The value of expressing cost control goals through rates is generally accepted in the case of investor-owned utilities; it is also present for a municipal utility. If an investor-owned utility cannot recover all its costs, then investors' returns suffer. A municipal utility has no investors: it must cover all its costs through rates and borrowing. If the Department were unable to recover cost overruns it would not have a pool of "LADWP dollars" from which to pay those costs. But, the application of ratemaking principles based on recovering only allowed costs can help motivate the Department's management to improve cost control, and the transparency of revenues and costs in multiple logically defined components would help ratepayers and the City judge LADWP's success in cost control. These goals are not sufficiently served by the LADWP rate proposal (unless it is accompanied by a detailed cost and revenue reporting proposal).

4.3.3 Allocating revenue to surcharges: Identifying cost increases

A surcharge is designed to recover only cost increases above a base level. LADWP therefore had to determine the base level of costs for each of the four categories above. The first three components are costs that have thus far been collected through the ECAF. The Department determined that “current costs” would mean the current level of rates, even if costs are actually higher or lower (ongoing under- or over-collection). In other words, current costs would not be the costs based on a current budget or set of programs. This makes the definition of the cost baseline a little complicated: while budgeted or actual costs can be associated with the specific functions assigned to each component, the rates cannot. LADWP addressed this difficulty by allocating the current rates to components, proportionate to the actual FY 2011 costs of the functions assigned to each component.

The Department identified the current rate level as an average of 6.926 c/kWh, representing the current ECAF of 5.69c/kWh plus 1.236c/kWh excluded from the ECAF rate under General Provision G.2 of the Electric Rate Ordinance. LADWP provided a computation of the costs allocated to each component, based on a breakdown into a "Traditional Energy Factor", "Renewable Energy Factor – Fixed", "Renewable Energy Factor – Variable" and "Energy Efficiency Factor", as in Figure 4.1. We have translated these into the components listed in Figure 4.3 by combining "Renewable Energy Factor – Fixed" and "Energy Efficiency Factor". The current level of "Reliability Cost Adjustment" costs would be the current RCAF, and the current level of "Base Rate Costs" would be the FY 2011 level of Base Rates, less the1.236c/kWh allocated to ECAF costs. The frozen cost levels, along with the projected surcharges for fiscal 2013 and 2014, are exhibited in Table 4.2.

Table 4.2. Current cost levels and projected surcharges

Component	Current level (c/kWh)	FY2013 surcharge (c/kWh)	FY2014 surcharge (c/kWh)
• Energy Factor -- Uncapped (VEAF)	5.256	(0.038)	(0.044)
• Renewable Energy -- Uncapped (VRPSEAF)	0.691	0.086	0.233
• Renewable Energy -- Capped (CRPSEAF)	0.979	0.013	0.222
ECAF total	6.926	0.061	0.411
Reliability Cost Adjustment (IRCA)			
• As an energy charge	0.300 c/kWh	0.090 c/kWh	0.221 c/kWh
• As a demand charge	$0.96/kW	$0.28/kW	$0.70/kW
Base Rate Costs	5.565	0.444	0.762
Total	12.729	0.595	1.394

Sources: "Frozen ECAF Breakdowns" received from LADWP 3/15/12 in pdf form; other current costs, and; ECAF surcharge amounts, from LADWP Financial Plan case 89 received 5/17/12; IRCA surcharge values based on summary of LADWP Financial Plan case 119 received 8/10/12.

The values in Table 4.2 do not exactly represent the rates that customers will see when the restructuring is implemented. The surcharge values for FY2013 are averaged over the year. Because the rates will not go into effect until several months into the year, the actual surcharges will be higher (but will be averaged with zero surcharges from the first few months to get the values which Table 4.2 projects).

4.3.4 The surcharge approach in the incremental ordinance

The incremental ordinance contains a set of rate surcharges. PA reviewed the incremental ordinance with the City Attorney and does not believe there are material changes to the rates in the Electric Rate Ordinance, just new surcharges. This section describes the various surcharges, in the order in which they appear in Figure 4.3 (top to bottom).

Variable Energy Adjustment (VEA)

The VEA is computed based on the total of the following types of cost:

- Non-renewable fuel expenses, including transportation, storage, prepayment costs, emissions-related costs, associated legal costs, and decommissioning costs (which really are not fuel related)

- Non-renewable power purchase costs, relating to PPAs, firm LD contracts, economy purchases, etc., and including all capacity, transmission, and prepayment costs
- Legal and court costs; presumably this refers to the Barakat lawsuit referenced in the three figures above.
- The amount of energy that was forecasted be saved by energy efficiency investments made between July 1, 2006 and June 30, 2012, multiplied by $0.05513/kWh. This is supposed to represent the amount of base rate revenue (at the rates in the Electric Rate Ordinance) not collected due to those sales reductions. The sales reduction figures were forecasts whose use has been approved by the Board, and total 1.034 billion kWh per year
- Gross-up for City Transfer
- Base Rate Target Adjustment rate (see Section 4.3.5 below)
- Cumulative prior shortfall in the ECA account, amortized over ten years
- Any under- or over-collected balance in the VEA balancing account.

The VEA is designed with an automatic quarterly adjustment and no cap on its size or quarterly change.

Capped Renewable Portfolio Standard Energy Adjustment (CRPSEA)

The CRPSEA is computed based on the total of the following types of cost:

- Debt service and O&M costs for Department-owned renewable resources
- Estimated debt service and O&M costs "typically associated with power purchase agreements for RPS generation and transmission". PA does not completely understand this language (for example, which PPAs does it refer to, or what size).
- Energy efficiency expenses (whether expensed or capitalized).
- Gross-up for City Transfer
- Any under- or over-collected balance in the CRPSEA balancing account.

The CRPSEA is designed with an automatic quarterly adjustment whose quarterly increase is capped at 0.125c/kWh. LADWP staff have told PA that the cap was chosen so that over the first three years the possible increases in CRPSEA would be sufficient to cover the projected costs.

Note that the CRPSEA is based on cost estimates; PA's recommendation had been that this component be based on the known costs of approved resources and contracts, and the approved Energy Efficiency budget, with no true-up.

Variable Renewable Portfolio Standard Energy Adjustment (VRPSEA)

The VRPSEA is computed based on the total of the following types of cost:

- Estimated purchase cost for RPS generation from projects that the Department does not own directly or indirectly. "Indirect ownership" is probably meant for SCPPA projects. It is not obvious how this this item differs from the second component of CRPSEA.
- Costs associated with RPS generation from projects in which the Department has an indirect ownership interest, except for debt service and O&M costs. We believe this corresponds to "above minimum RPS purchases" in Figure 4.1 and Figure 4.3.
- Gross-up for City Transfer
- Prior VRPSEA under-collection

The VRPSEA is designed with an automatic quarterly adjustment no cap on its size or quarterly change.

Incremental Reliability Cost Adjustment (IRCA)

The IRCA is designed to collect the total of the following types of cost:

- The amount by which PRP O&M costs exceed $290 million
- The amount by which PRP debt service costs exceed $320 million.
- Gross-up for City Transfer

Unlike the previous three factors, the IRCA is not always collected on a cents/kWh basis. It is allocated between who are billed based on energy usage on a cents/kWh basis, and those who are billed based on non-coincident maximum demand. The incremental ordinance describes these as "residential service customers" and "general service customers" even though the first category includes more than just residential customers; the language is from the Electric Rate Ordinance and there has been no problem to date with its application.

At PA's suggestion, the IRCA is not explicitly designed as a pass-through. We expect IRCA rates to be stated explicitly in the incremental ordinance.

4.3.5 Rate decoupling and the Base Rate Target Adjustment (BRTA)

This section addresses the Base Rate Target Adjustment (BRTA) defined in the incremental ordinance. The BRTA is characterized as a revenue decoupling charge. When it was originally proposed that utilities sponsor investments in Energy Efficiency and Demand Side Management advocates quickly realized that utilities could see their revenues threatened by load reduction, which would lead the utilities to resist Energy Efficiency. Utility revenues generally recover two types of costs: fixed investment cost (including profit for investor-owned utilities) and variable operating costs (e.g., fuel). Declining sales will reduce the amount of money available to pay for both fixed and variable costs; but the variable costs themselves should also decline. Rates are set to allow utilities to recover all their fixed costs, and sales reductions endanger that recovery. Energy efficiency advocates sought to "decouple" fixed cost recovery from sales, in order to remove the incentive for utilities to resist energy efficiency expenditures. In practice this means that rates would rise if Energy Efficiency reduced utility sales.

When rates are set on a volumetric (per-kWh) basis, expected fixed costs are divided by estimated electricity sales to yield "unit fixed cost recovery". If actual sales are below the estimate, whether because of energy efficiency, weather, or other reasons, the shortfall in fixed cost recovery in a given time period can be computed by multiplying the change in sales by the unit fixed cost recovery. A decoupling rate is implemented by adding that shortfall to the following time period's revenue requirement (in other words, by increasing rates enough that, over the next time period, revenues will exceed cost enough to cancel the shortfall). By the same token, if sales are greater than expected and the utility's revenues exceed its fixed costs, the excess revenue (additional sales times unit fixed cost recovery) should be subtracted from the next period's revenue requirement.

The Base Rate Target Adjustment implements decoupling for base rate revenue. "Base rates" refer to the charges defined for each rate schedule in the Electric Rate Ordinance and also the charges defined for each rate schedule in the incremental ordinance, except for charges defined by reference to the General Provisions in the current ordinance (ECAF, RCAF, ESAF) and in the incremental ordinance (VEAF, CRPSEAF, VRPSEAF, IRCA), minus the Base Rate Contribution Factor (1.236 c/kWh). The Base Rate Target is a value that should represent the part of the revenue requirement attributable to Base Rates. The actual base rate collection is the total actual revenue collected minus the product of actual kWh sales and the sum of ECAF, RCAF, ESAF, BRCF, VEAF, CRPSEAF, VRPSEAF, and IRCA.

The Base Rate Target Adjustment (BRTA) rate equals the difference between a period's Base Rate Target and actual base rate collection, divided by the estimated kWh sales for the following period. It is in rate units of c/kWh. The BRTA rate is added to rates in the following period -- specifically to the VEAF. To that extent the BRTA is a typical revenue decoupling charge. It is an automatic true-up of deferred revenue, with no limit or cap. It is reasonable for LADWP rates to include such a charge if the Department is to be discouraged from trying to increase sales (or encouraged to reduce them through energy efficiency expenditures), or if total sales are out of the Department's control.

The BRTA trues up revenue to the Target, in other words, it eliminates any discrepancies between actual revenue and the revenue target to ensure that, in the long run, the Base Rate Target revenue is fully collected but no greater amount. This is the expected role of a decoupling charge and it does not impair cost control as long as the Target is an approved revenue requirement. By contrast, the other "true-ups" discussed in section 4.3 are designed to eliminate discrepancies between actual revenue and *actual costs*. They can impair cost control if the utility has no other motivation to control actual costs to the level of the revenue requirement.

4.4 PA's Observations and Comments on the Proposed Incremental Rate Ordinance

4.4.1 The Incremental Ordinance should be reviewed in two years

The City Attorney has given LADWP guidance in structuring its surcharge proposal so as to address current legal considerations. Because the law is in a state of development (there is ongoing litigation over Proposition 26 involving another city), greater flexibility in rate structuring could arise as the law becomes clearer. Therefore, PA recommends that this surcharge-based restructuring be considered as an interim step. The rate structure should be revised in two years' time and preferably be replaced with fully restructured permanent rates once legal considerations allow (see Section 4.5).

The Department expressed concern about an explicit sunset date with no further authorization of these rates, and the City Attorney's representatives expressed the opinion that one could not use an ordinance to mandate consideration of a later ordinance. PA therefore has recommended that the incremental ordinance direct that after two years a study of the appropriateness of a full restructuring should be conducted with a recommendation to the Mayor, City Council and DWP management on whether the need for a two-ordinance, surcharge-based rate structure has changed or been eliminated.

4.4.2 Observations and comments on the rate design

1. Under the Electric Rate Ordinance, rate factors that are defined by formulas, such as the ECAF, contain explicit gross-ups for a City Transfer. Similar gross-ups have been included in the VEAF, CRPSEAF, VRPSEAF and IRCA.
2. As a matter of public policy, the Electric Rate Ordinance included low income and lifeline discounts to residential rates (schedules R-1D and R-1E) as well as low income and lifeline credits to multi-family rates for each qualified sub-metered units. The pass-through factors were not discounted due to legal considerations. The incremental ordinance does not apply to low income or lifeline discounts in either the incremental base rates or the new pass-through factors.
3. The definition of BRTA as originally proposed in the draft incremental ordinance went beyond a simple revenue decoupling charge. The draft included specific base revenue targets fiscal 2013 but stated that targets for the following fiscal years would be set by the Board and communicated to, but

not necessarily approved by, the City Council (presumably the Council could have taken jurisdiction over a rate increase through a "245" process but that is awkward and post hoc). PA told the Department that the part of the draft incremental ordinance that empowers the Board to set the target unilaterally was problematic and should be deleted. The Department deleted that section.

4. PA further noted that the BRTA would guarantee collection of the Base Rate target regardless of why revenues fell short. Base revenue under-collection could occur for a number of other reasons beside load reduction due to energy efficiency, including load reductions due to reductions in economic activity, customer departure, loss of load in outages, or delayed approval of a rate increase. PA objected to the breadth of the BRTA. In response the Department agreed to eliminate the BRTA accounting after two years (in other words, after June 30, 2014 the under- or over-collection of base revenues would no longer be accrued although the Department could continue to include under- and over-collections through that date in the VEAF until the end of 2015).

5. As we have noted above and in the past, PA generally believes that "true-ups" of controllable costs, costs that can be held to a budget, or costs that are known in advance, have a deleterious effect on cost management. The incremental ordinance was originally drafted to include a balancing account associated with the IRCA, with a cap on IRCA increases. The Department agreed that it was able to control PRP spending and accepted PA's recommendation to eliminate both the cap and the balancing account, so that under the latest proposed ordinance, the IRCA (and effectively the PRP budgets) will be explicitly included in the incremental ordinance.[25]

6. PA similarly objected to the structure of the CRPSEA, which includes a balancing account and a cap on increases. It was PA's position that the CRPSEA revenue requirement is based on contracts that are approved in advance, and even if there are construction cost overruns, those costs will be observable prior to the quarterly determination of the CRPSEA rate and therefore could be included in it.

   The Department disagreed with PA, taking the position that there could be other reasons why the CRPSEA revenue would be less than target, These included all the types of under-collection cited for BRTA (see item 4 in this list) as well as the workings of the cap itself: the costs associated with approved contracts could increase more than the CRPSEAF cap of 0.125c/kWh, and the cap would act to prevent their collection even if they had been clearly described when the contracts were considered.

   In fact, after PA suggested eliminating the balancing account and cap, the Department returned with new language that directed the Department to produce a three-year forecast of the CRPSEA balancing account each quarter, and report to the Board and Council if that balance exceeded a set amount. Apparently the Department was motivated by the possibility of approved contract costs that exceeded the rate increase cap. PA responded that (a) this is something the Department ought to do as a matter of good management not by ordinance; and (b) the report would not help the Department address under-collections since it did not authorize or even propose a rate action. The Department

[25] The lifting of the CIRCA cap and balancing account caused LADWP to recently revise its Financial Plan (Case 119), which would change the rate increase from 4.8% to 4.9% in FY 2013 (see footnote 2). However, the financial plan that has been presented by the Department in its Power System Rate Proposal and on which this report's financial analysis is based, is Case 89. There is no difference between the revenue requirements and costs of running the system between Cases 89 and 119.

agreed to add language mandating that it seek a rate action if the cumulative under-collection exceeded a second, larger amount.

PA continues to believe that a superior formulation of the CRPSEA would include neither a balancing account nor a cap on periodic increases in the CRPSEAF. In that case the new under-collection reporting requirement would be unnecessary.

4.4.3 The universe of possible modifications, or, non-mandated components of the rate increase

In the current macroeconomic environment the Council should strive to minimize cost and rate increases to the greatest extent. Policy choices that involve cost increases should be made explicit. As the Department has noted, much of its added revenue need is attributable to prior regulatory and legislative policy mandates. Those mandates must be observed but added policy choices should be carefully considered. Rates should not be increased due to the ongoing cost of doing business -- those costs should be controllable -- and while it may be desirable to increase the pace of reliability-related maintenance, that too should be an explicit choice.

In addition to the recommendation above about BRTA language, PA recommends that the following parts of the rate increase be considered explicitly. PA is not recommending that any of these specific cuts be made, but we believe it is incumbent upon us to identify all possible sources of rate reduction.

Table 4.3. Possible modifications to the surcharge proposal

Modification	FY2014 impact relative to FY2012 (c/kWh)
Keep load reduction target at 8.6% vs. 10%	0.09
Reduce energy efficiency spending to 2012 levels (value over and above the previous line)	0.17
Maintain PRP spending at level consistent with 2012 RCAF (eliminate IRCA)	0.22
Eliminate incremental base rate surcharge, except for the "Rebuilding Local Power Plants" and CIS replacement revenue requirements	0.32
Additionally eliminate CIS replacement revenue requirement	0.02
Total	0.82

In creating Table 4.3 PA sought to identify cost increases relative to the base level that cannot be attributed to regulatory or legislative mandates. PA is not making a recommendation that any or all of these reductions should be made to the surcharges. For example, the reliability improvement attributable to increased PRP spending may be very important to LADWP customers, and the replacement CIS may be critical to a variety of initiatives (in addition to which if the project were cancelled the Department would have to write off the CIS investment to date). PA's recommendation is that explicit consideration be given to these items:

- The Department states that the rate surcharges "include an increase in energy efficiency investment from prior years" to reach a target load reduction of 8.6% from 2010, as set by the Board of Water and Power Commissioners. The 8.6% target was based on a market potential study. The Department has also proposed an alternative approach to energy efficiency that would target a 10% reduction. There has been no new market potential study supporting the 10% goal. AB2021 states that the legislature's goal is to reduce load by 10% state-wide, but does not place a specific 10% requirement on any individual municipal utility. The Financial Plan that LADWP provided PA includes Energy Efficiency expenditures consistent with the alternative approach. PA estimates that the policy decision to target a 10% reduction will contribute 0.09c/kWh to the rate increase in FY 2014. Continuing to pursue an 8.6% target would reduce the rate increase by those amounts.
- The RCAF, which funds the PRP, has been limited to 0.3c/kWh by the Electric Rate Ordinance. This represents a policy decision on the level of funding for the PRP. The Department has chosen to exceed that level of spending, as evidenced by the cumulative under-collection in the RCA Account. The condition of the LADWP system may well justify increasing the level of PRP funding but that should be an explicit choice. Choosing instead to leave PRP funding at 0.3c/kWh would mean that there would be no IRCA surcharge, reducing the rate increase by 0.22c/kWh in FY 2014.
- ECAF and RCAF increases are clearly tied to uncontrollable costs, mandates and reliability; Base Rates are not. The City could consider limiting the base rate surcharges of $0.444c/kWh in FY 2013 and 0.762c/kWh in FY 2014. The Department will still have to meet certain external mandates, though. It has negotiated plans to address environmental mandates related to NOx emissions and the replacement of ocean cooling, which will involve capital expenses to repower Haynes 5-6 and Scattergood 3 over the next few years. The rate impact of those plans is estimated to be 0.42c/kWh in FY 2014.[26] Eliminating the incremental base rate surcharge, except for the "Rebuilding Local Power Plants" revenue requirement will reduce the rate increase by 0.34c/kWh in FY 2014.
- The Department is also engaged in a multi-year capital project to replace its Customer Information System. This project involves incremental capital expenditures of $24.0M, $38.3M and $3.7M in fiscal 2012, 2013 and 2014 respectively. PA has estimated the rate impact at $.02/kWh. Therefore, eliminating the incremental base rate surcharge, except for the "Rebuilding Local Power Plants" and CIS replacement revenue requirements, will reduce the rate increase by 0.32c/kWh in FY 2014. Note that this item and the previous are mutually exclusive.

4.5 Legal Considerations Affecting Rate Design

A widely held view appears to have formed in recent years that the Department's current electricity rates fail to provide the transparency and simplicity demanded today. All indications are that the Department would prefer to propose, and that the City Council would prefer to receive, a major overhaul of the current rate structure to achieve these goals. The Office of the City Attorney advises, however, that for legal reasons the City may wish to avoid making radical changes to the current rate structure at this time.

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[26] *Ibid.*, Fig. 16 on p. 25.

A question has been raised as to whether Proposition 26, adopted in November 2010, forbids the Department's annual transfer of monies, financial conditions allowing, from the Power Revenue Fund ultimately to the City's General Fund or electricity rates that generate that transfer. The City Attorney advises that the measure does not do so, but notes that no precedential appellate decisions have yet been rendered relating to the measure's application in this context.

The City Attorney advises, however, that as a safeguard against the absence of judicial interpretation, the City may wish to adopt an electrical rate structure that conservatively retains existing rates and layers incremental charges on top of them. Since it is clear enough that Proposition 26 was not meant to be retroactive for local government, retention of existing rates most likely would at least shelter from attack under that measure the transfer component built into rates existing when the measure took effect, which equates to the bulk of the transfer anticipated today and in the near future.

Therefore, for the time being, electricity rates would derive primarily from two ordinances – the existing one and the proposed incremental one. At some later point, presumably after enough is learned about Proposition 26, rates can be redone in the manner desired in one rate ordinance. Until then, the Department advises that should this multiple ordinance approach be taken, it will be prepared to develop a summary sheet consolidating rates established by the multiple ordinances in a manner meaningful and useful to customers.

5 LADWP's Rates and Revenues Computations

5.1 LADWP's Ratemaking Process

Ratemaking is the process by which utilities set their rates. In the context of public power utilities, the ratemaking process should ensure revenue adequacy (i.e. no over or under revenue collection), generate the lowest possible rates for customers, and define financial incentives which promote energy efficiency.

There are three steps involved in utility ratemaking: revenue requirements determination, revenue allocation, and rate design. LADWP's revenue requirements determination is a product of its financial plan. The Department undertook three activities to accomplish its revenue allocation and rate design: define revenue targets for each customer class, set pass through charges and finally, given the fixed pass through charges previously computed, adjust each customer class Base Rates and Facilities Charges to meet the revenue targets defined in the first step. In more detail:

1. Revenue targets were set for each customer class for FY 2013 and FY 2014: using the estimated FY 2012 retail revenue (based on the currently approved rates) as a base, LADWP derived projected revenue for FY 2013 and FY 2014 by applying the total annual retail revenue requirement increases outlined in the financial plan. LADWP assumed total revenue requirement increases of 4.8% and 6.0% in FY 2013 and FY 2014, respectively.
2. The ECA and RCA Energy Charges as well as the RCA Demand Charge were set for FY 2013 and FY 2014: the average Energy Charges associated with the ECA (VEAF+CRPSEAF+VRPSEAF) and RCA (IRCA) accounts (in $/kWh) as well as the average Demand Charge (in $/kW) associated with the RCA account (IRCA) were defined for FY 2013 and FY 2014, based on the total power system revenue requirements included in the latest financial plan.
3. Each customer class Base Rates (in $/kWh) and Facilities Charges (in $/kW) were set: given the fixed ECA & RCA Energy Charges and RCA Demand Charges computed in step 2, LADWP adjusted each customer class Base Rates and Facilities Charges so that each customer class revenues matched the targets computed in step 1.

A commonly used tool in the utility sector for revenue allocation and rate design is the Cost of Service Study. A Cost of Service Study effectively and accurately allocates costs to customer classes and prevents price discrimination. This is also a useful instrument to justify rate differentials among customer classes. To be implemented efficiently, a Cost of Service Study must be supported by load profiling for at least a representative sample of customers. LADWP sponsored a full Cost of Service Study and updated it in FY2011; the result of that update was a spreadsheet used for rate design rather than a formal study document. PA recommends the Department conduct a new formal cost of service study in order to prepare for subsequent rate restructuring.

5.2 LADWP's Computations of the Pass-Through Factors' Base Portion

As discussed in previous sections, the proposed power rates are broken down into two portions: the first portion of the rate (which will be referred as "base portion" in the remainder of this report) is set by the

Electric Rate Ordinance at FY 2011 expenditure levels while the second portion (which will be referred as the "incremental portion") is set by the proposed incremental ordinance.

This section of the report presents how the Department deconstructed the FY 2011 ECAF expenditures to define the base portion of the VEAF, VRPSEAF and CRPSEAF.

VEAF, VRPSEAF and CRPSEAF Base Portion Computation

As shown in Table 5.1, LADWP reallocated the FY 2011 ECA expenditures to the VEA, VRPSEA and CRPSEA accounts based on expenditure types:

- VEA expenditures include: non-RPS fuel and purchased power expense, legal cost, DSM revenue loss recovery from FY 2007 to FY 2012 and the corresponding City Transfer portion
- VRPSEA expenditures include: PPA expense of RPS projects (any prepayment expense) and the corresponding City Transfer portion
- CRPSEA expenditures include: interest, depreciation and O&M expenses of LADWP-owned RPS projects, prepayment expense of Indirectly Owned RPS projects, DSM expenses and the corresponding City Transfer portion.

LADWP then computed ratios corresponding to the VEA, VRPSEA and CRPSEA shares of the total FY 2011 ECA expenses. These ratios were then applied to the sum of the FY 2011 ECA Base rate Contribution Factor and Capped ECAF (see Table 5.2) in order to define the base portion of the VEAF, VRPSEAF and CRPSEAF.

Table 5.1: Allocation of the FY 2011 ECA Expenses to the VEA, VRPSEA and CRPSEA Accounts (in $M)

	FY2011 Total Expenses	Share of Total ECA Expenses
ECA	$1,587	100%
VEA Allocation	$1,202	76%
VRPSEA Allocation	$158	10%
CRPSEA Allocation	$224	14%

Table 5.2: Computations of the VEAF, VRPSEAF and CRPSEAF (in c/kWh) [27]

	FY2011	Share of Total ECA Expenses
(1) FY2011 ECA Base Rate Contribution Factor	$1.236	N/A
(2) FY2011 Capped ECAF	$5.690	N/A
FY2011 Total Rate: (1) + (2)	$6.926	N/A
VEAF	$5.256	76%
VRPSEAF	$0.691	10%
CRPSEAF	$0.979	14%

[27] The Capped ECAF and ECA Base Rate Contribution Factor have been frozen at 5.69c/kWh (since July 2010) and 1.236 c/kWh, respectively.

IRCAF Base Portion Computation

For the IRCAF base portion computations, LADWP simply implemented the current ordinance formulas: it is projected to equal $0.30c/kWh for residential customers and $0.96/kW for general service (commercial customers).

5.3 PA's Examination of LADWP's Rates and Revenues Computations

The following review shows that LADWP's rates and revenues computations appear to be accurate but may lead to a slight over collection for customer classes which include reactive energy revenues. **Note that both LADWP's computations and PA's are based on case 89 and do not include the elimination of the IRCA balancing account as per case 119.**

PA verified the revenue computations used by LADWP to define the Base Rates and Facilities Charges for its four major customer classes: residential, small, medium as well as large commercial and industrial customers.

PA was able to match the Department's revenue computations for these four customer classes: as shown in Table 5.3, PA's total revenue calculation only differs by 0.1% (or $4M) relative to the total revenue presented by LADWP. This minor difference is due to simplification assumptions used by LADWP in the revenue computations Excel spreadsheets which have been provided to PA. Such simplification assumptions were needed to approximate the Department's large SAS database.

Table 5.3: LADWP's vs. PA's Revenue Computations for Residential, Small, Medium as well as Large Commercial and Industrial Customers

		LADWP's Computation	PA's Computation	Absolute Difference (PA minus LADWP)	Difference in % (PA/LADWP)
FY2013	Residential (R1A)	$984,445,980	$984,947,257	$501,277	0.1%
	Small Commercial (A1A)	$399,855,230	$399,855,230	$0	0.0%
	Medium Commercial (A2B)	$281,825,104	$281,808,443	-$16,661	0.0%
	Large Commercial and Industrial (A3A)	$968,255,148	$969,154,739	$899,591	0.1%
FY2014	Residential (R1A)	$1,044,116,949	$1,045,248,243	$1,131,294	0.1%
	Small Commercial (A1A)	$424,812,504	$424,812,504	$0	0.0%
	Medium Commercial (A2B)	$298,977,585	$298,944,244	-$33,341	0.0%
	Large Commercial and Industrial (A3A)	$1,026,703,224	$1,028,502,406	$1,799,182	0.2%
	TOTAL	**$5,428,991,723**	**$5,433,273,065**	**$4,281,342**	**0.1%**

While LADWP's revenue calculations seem accurate, they do not include reactive energy revenues for customer classes for which Reactive Energy Charges apply. Furthermore, the Department inflated these Reactive Energy Charges by 4.8% and 6%, in FY 2013 and FY 2014 in the proposed incremental ordinance. Inflated Reactive Energy Charges will therefore supplement the proposed Energy and Demand Charges, which have already been computed in order to meet the overall revenue target increase of 4.8% and 6.0% in FY 2013 and FY 2014. This will ultimately lead to an over collection, but PA believes that it will not be material relative to the total revenue requirement.

Future reactive energy revenues may be challenging to project; however, the Department could have estimated these revenues based on previous year's annual averages.

6 Impact of the Rate Increase and Rate Restructuring on LADWP's Customers

This chapter shows the impact of the rate restructuring on customer bills. It is based on the rate increase compatible with LADWP financial case 89. The rates based on case 119 would be slightly (0.1%) higher in FY2013 but the Department's agreement to that modification came too late for PA to revise all the calculations in this section.

6.1 Impact on Revenues and Monthly Bills

As discussed previously, LADWP revenue calculations are based on an annual 4.8% and 6.0% total revenue increase in FY 2013 and FY 2014. These increases are equally implemented across each customer class, as shown in the table below:

Table 6.1: Revenues by Customer Class[28]

Customer Classes	FY2012	FY2013	FY2014	FY2013/FY2012 Increase	FY2014/FY2013 Increase	FY2014/FY2012 Increase
Residential Service (R1A)	$ 939,200,023	$ 984,445,980	$ 1,044,116,949	4.8%	6.1%	11.2%
Residential Service - Time-of-Use (R1B)	$ 235,613	$ 247,029	$ 261,936	4.8%	6.0%	11.2%
Small General Service (A1A)	$ 393,995,094	$ 413,066,320	$ 438,027,647	4.8%	6.0%	11.2%
Small General Service - Time-of-Use (A1B)	$ 2,011,585	$ 2,108,534	$ 2,236,701	4.8%	6.1%	11.2%
Primary Service - Time-of-Use (A2B)	$ 270,772,268	$ 283,840,684	$ 300,993,165	4.8%	6.0%	11.2%
Residential Multifamily Service (R3A)	$ 52,219	$ 54,740	$ 58,020	4.8%	6.0%	11.1%
Port of Los Angeles Alternative Maritime Power Service (AMP)	$ 39,899	$ 41,828	$ 44,337	4.8%	6.0%	11.1%
Customer Generation, Subtransmission Service (CG3)	$ 5,065,439	$ 5,311,069	$ 5,628,837	4.8%	6.0%	11.1%
Subtransmission Service (A3A)	$ 927,839,899	$ 972,565,848	$ 1,031,013,924	4.8%	6.0%	11.1%
Experimental Real-Time Pricing Service, Subtransmission Service (XRT3)	$ 421,189	$ 440,807	$ 467,135	4.7%	6.0%	10.9%

The overall revenue increase is projected to be slightly larger than 11% between FY 2012 and FY 2014.

The tiered rate structure implemented by the Department for residential customers is meant to motivate energy savings by favoring low levels of consumption. As shown in Table 6.1 and Figure 6.1, customers with low average electricity consumption[29] (mainly Tier 1 customers, and which represent 90.4% of the residential customers) will be less impacted by the rate increase than customers with large electricity consumption (mainly Tier 2 and 3 customers): the low consumption customers' average monthly bill will

[28] Not all customer classes' revenues are included in Table 6.1 as there is no LADWP customer subscribed to customer classes CG2, XRT2 and A4A, and PA was not provided with revenues for customer classes LS2, LS3, OAL, XCD2 and XD3.

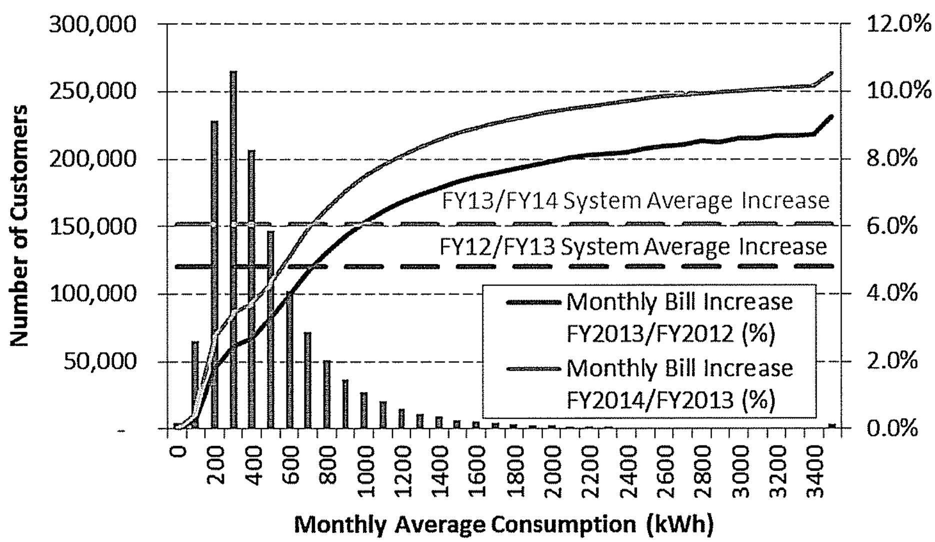
[29] In its definition of low consumption customers, PA includes customers which Tier 1 monthly average electricity consumption is larger than the sum of their second and third tier monthly average electricity consumption.

increase by 3.5% and 4.6% in FY 2013 and FY 2014 respectively, while high consumption customers will see their bill increase by 7.4% and 8.9%. Applying a larger rate increase to high consumption customers is consistent with LADWP's goal to promote energy efficiency.

Table 6.2: Monthly Bills for Residential Customers

	Customers Distribution	Average Consumption (KWh)	Average Load Factor	Average Monthly Bill FY2012	Average Monthly Bill FY2013	Average Monthly Bill FY2014	FY2013/FY2012 Increase	FY2014/FY2013 Increase	FY2014/FY2012 Increase
Residential Service (R1A) - Low Consumption Customers	90.4%	352	N/A	$44	$46	$48	3.5%	4.6%	8.3%
Residential Service (R1A) - High Consumption Customers	9.6%	1487	N/A	$205	$220	$240	7.4%	8.9%	17.0%

Figure 6.1: Usage Distribution vs. Revenue Increase for Residential Customers (Schedule R1A)



As shown in Table 6.3 and in Table 6.4, high season residential rates will increase by a smaller margin than low season rates for high consumption customers (Tier 2 and Tier 3 groups): the low season Total Tier 2 rate will increase by 14.3% in FY 2013 while the high season Total Tier 2 rate will increase by 2.6%. This is by design. LADWP aims to extend its energy savings message from the high season to the whole year round.

Table 6.3: Impact on the Low Season (October - May) Residential Rates (R1A) of LADWP's proposed rate increase and restructuring (charges in $/kWh)

	FY2012	FY2013	FY2014	FY2013/FY2012 Increase	FY2014/FY2013 Increase	FY2014/FY2012 Increase	FY2014/FY2012 Increase
Base Rate Tier 1	$ 0.0702	$ 0.0718	$ 0.0712	2.3%	-0.9%	1.4%	$ 0.0010
Base Rate Tier 2	$ 0.0702	$ 0.0877	$ 0.0992	24.9%	13.1%	41.3%	$ 0.0290
Base Rate Tier 3	$ 0.0702	$ 0.0877	$ 0.0992	24.9%	13.1%	41.3%	$ 0.0290
VEA	$ 0.0432	$ 0.0428	$ 0.0427	-0.9%	-0.1%	-1.0%	$ (0.0004)
CRPSEA	$ 0.0080	$ 0.0082	$ 0.0103	1.6%	25.6%	27.6%	$ 0.0022
VRPSEA	$ 0.0057	$ 0.0065	$ 0.0080	15.1%	22.5%	41.0%	$ 0.0023
ESA	$ 0.0015	$ 0.0015	$ 0.0015	0.0%	0.0%	0.0%	$ -
CIRCA	$ 0.0030	$ 0.0037	$ 0.0050	23.0%	36.3%	67.7%	$ 0.0020
Total Rate Tier 1	$ 0.1316	$ 0.1345	$ 0.1387	2.2%	3.1%	5.4%	$ 0.0071
Total Rate Tier 2	$ 0.1316	$ 0.1504	$ 0.1667	14.3%	10.8%	26.7%	$ 0.0351
Total Rate Tier 3	$ 0.1316	$ 0.1504	$ 0.1667	14.3%	10.8%	26.7%	$ 0.0351

Table 6.4: Impact on the High Season (June - September) Residential Rates (R1A) of LADWP's proposed rate increase and restructuring (charges in $/kWh)

	FY2012	FY2013	FY2014	FY2013/FY2012 Increase	FY2014/FY2013 Increase	FY2014/FY2012 Increase	FY2014/FY2012 Increase
Base Rate Tier 1	$ 0.0702	$ 0.0718	$ 0.0712	2.3%	-0.9%	1.4%	$ 0.0010
Base Rate Tier 2	$ 0.0852	$ 0.0877	$ 0.0992	2.9%	13.1%	16.4%	$ 0.0140
Base Rate Tier 3	$ 0.1200	$ 0.1245	$ 0.1409	3.8%	13.1%	17.4%	$ 0.0209
VEA	$ 0.0432	$ 0.0428	$ 0.0427	-0.9%	-0.1%	-1.0%	$ (0.0004)
CRPSEA	$ 0.0080	$ 0.0082	$ 0.0103	1.6%	25.6%	27.6%	$ 0.0022
VRPSEA	$ 0.0057	$ 0.0065	$ 0.0080	15.1%	22.5%	41.0%	$ 0.0023
ESA	$ 0.0015	$ 0.0015	$ 0.0015	0.0%	0.0%	0.0%	$ -
CIRCA	$ 0.0030	$ 0.0037	$ 0.0050	23.0%	36.3%	67.7%	$ 0.0020
Total Rate Tier 1	$ 0.1316	$ 0.1345	$ 0.1387	2.2%	3.1%	5.4%	$ 0.0071
Total Rate Tier 2	$ 0.1466	$ 0.1504	$ 0.1667	2.6%	10.8%	13.7%	$ 0.0201
Total Rate Tier 3	$ 0.1814	$ 0.1872	$ 0.2084	3.2%	11.3%	14.9%	$ 0.0270

The rate structure for commercial and industrial customers aims at promoting an efficient use of capacity[30] by limiting the impact of the rate increase for customers with high load factors. This can be considered as a sound strategy for the Department to limit the variability or intermittency of demand on the power system, and to spread capital costs as widely as possible. Small commercial customers with an average load factor of less than 40% will bear a rate increase larger than their customer class average (as shown in Figure 6.2). This also applies to medium and large commercial customers with load factors of less than 60% and 70% respectively (as shown in Figure 6.3 and Figure 6.4).

[30] In addition of the Energy Charge (which is applied to the quantity of electricity consumed by a customer and expressed in $/KWh), a Demand Charge is added to the commercial and industrial customers' bill. The demand charge is applied to the customer's peak demand of electricity during a billing period and is expressed in $/kW. An efficient use of capacity (or high load factor) would consist of running large machineries and building equipment at a rate close to their maximum load, therefore limiting the variability of demand on the power system. In other words, a commercial or industrial customer should seek to use power at a more or less constant rate through the billing period rather than using a large amount of power in a short period of time.

Figure 6.2: Load Factor Distribution vs. Revenue Increase for Small Commercial Customers (Schedule A1A)

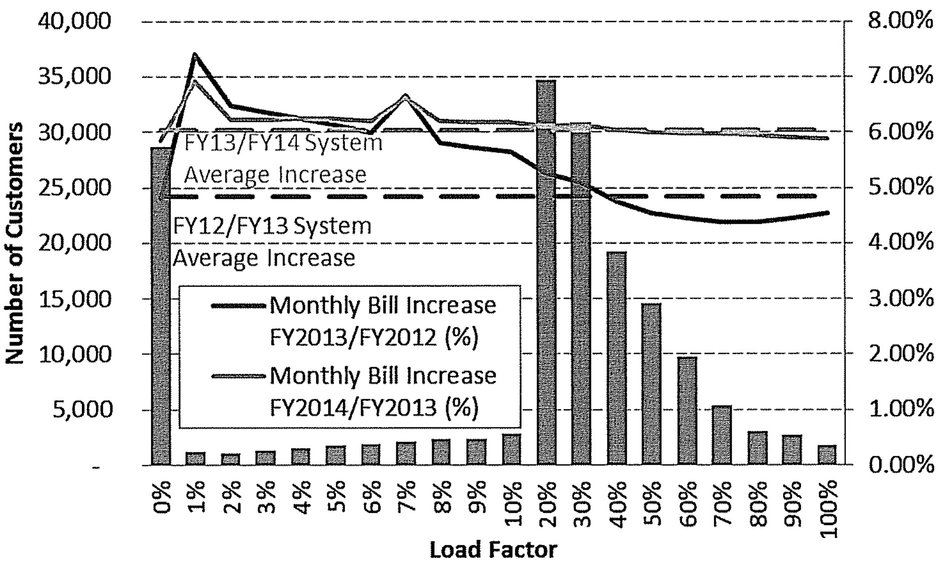


Figure 6.3: Load Factor Distribution vs. Revenue Increase for Medium Commercial Customers (Schedule A2B)

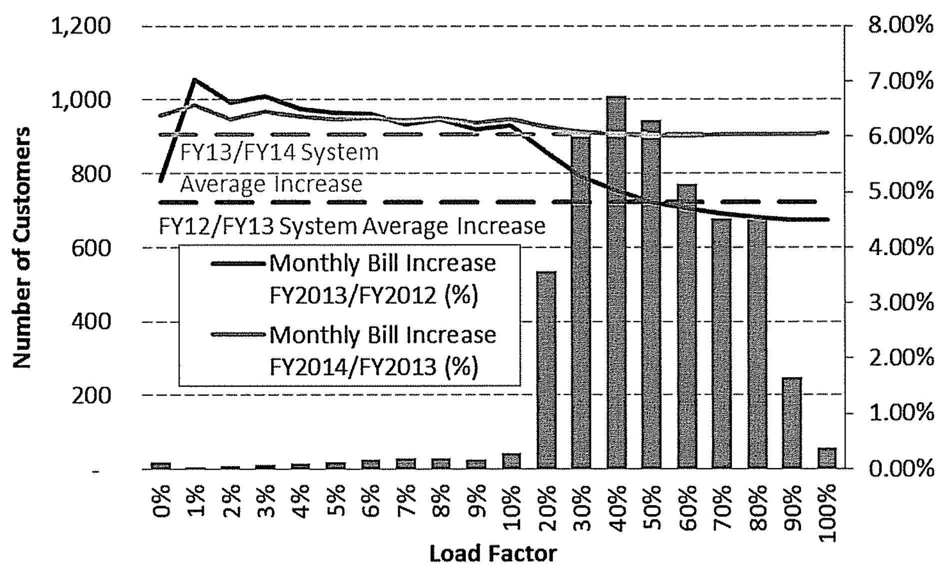
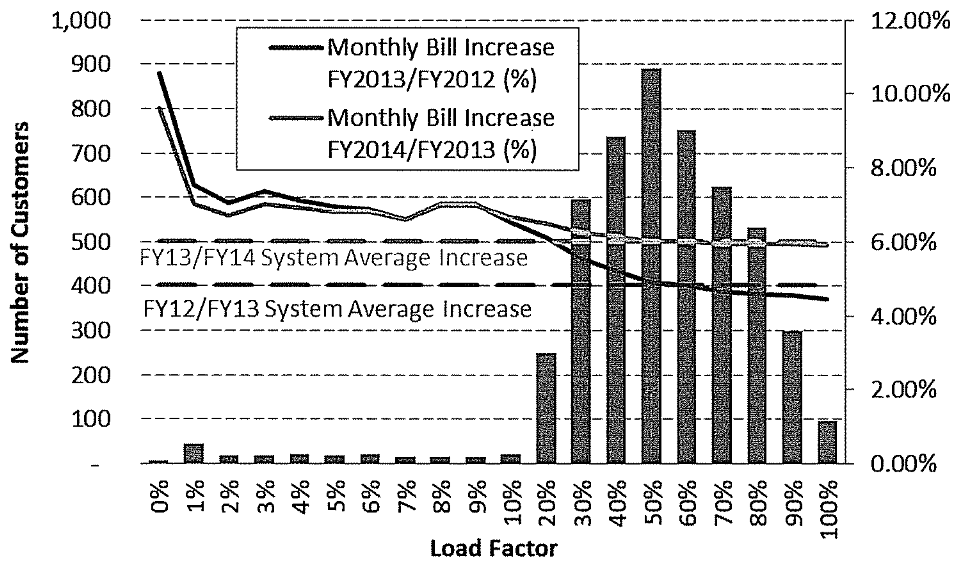


Figure 6.4: Load Factor Distribution vs. Revenue Increase for Large Commercial and Industrial Customers (Schedule A3A)



Note that the Energy Charge for small commercial customers will increase more in the low season than in the high season: the high season energy charge should increase by 5.5% in FY 2013 as opposed to 8.4% for the low season energy charge (see Table 6.5). Overall, though, the energy charge will still be higher in the high season.

Table 6.5: Changes in low and high season rate increases for small commercial customers (A1A) (FY 2012-2013 period)

	High Season		Low Season		High Season	Low Season
	FY2012	FY2013	FY2012	FY2013	FY2013/FY2012 Increase	FY2013/FY2012 Increase
Service Charge	$6.5000	$6.5000	$6.5000	$6.5000	0.0%	0.0%
Facilities Charge ($/kW)	$5.0000	$5.2900	$5.0000	$5.2900	5.8%	5.8%
Energy Charge ($/kWh)	$0.0656	$0.0692	$0.0427	$0.0463	5.5%	8.4%
VEA ($/kWh)	$0.0432	$0.0428	$0.0432	$0.0428	-0.9%	-0.9%
CRPSEA ($/kWh)	$0.0080	$0.0082	$0.0080	$0.0082	1.6%	1.6%
VRPSEA ($/kWh)	$0.0057	$0.0065	$0.0057	$0.0065	15.1%	15.1%
ESA ($/kW)	$0.4600	$0.4600	$0.4600	$0.4600	0.0%	0.0%
CIRCA ($/kW)	$0.9600	$1.1700	$0.9600	$1.1700	21.9%	21.9%

Renewables and reliability expenditures will drive the Tier 1 rate increase over the FY 2012-2014 period (as shown in the tables above), as increases of the RPS and IRCA pass through factors will be larger than Base Rate increases: the CRPSEAF, VRPSEAF and IRCA will increase by 0.22c/kWh, 0.23c/kWh and 0.34c/kWh respectively while the Tier 1 base rate increase will be limited to 0.10c/kWh.

However, for the second and third tiers, the base rate related expenditures will drive the rate increase: while the CRPSEAF, VRPSEAF and CIRCA increases will be identical to those observed for the first tier, the low season Tier 2 and 3 Base Rates will rise by 2.9c/kWh and the high season Tier 2 and 3 Base Rates will increase by 1.4c/kWh and 2.09c/kWh, respectively.

7 Rate Proposal Recommendations

7.1 Power Rate Increase

Given the challenges faced by the Department, PA believes that a rate increase is necessary in the short term. After comprehensive review of LADWP budgets and financial plans, PA sees no evidence of straight forward near-term solutions to reduce costs -- there are no obvious programs to cut or cheaper alternatives to pursue. A short term rate increase will give LADWP the opportunity to remain compliant, maintain infrastructure reliability and moderate the increase of its debt level, while the City and Department consider renegotiating the labor agreement. Furthermore, it should be noted that the longer the rate increase is delayed, the greater the rate shock will be to ratepayers.

7.2 Power Rate Restructuring

As in the case of the rate increase, the rate restructuring is necessary but only advisable for a short time period. PA believes there is still room for improvement in terms of maximizing accountability and transparency and provides recommendations to that end below. PA recommends the Department conduct a new formal cost of service study in order to prepare for subsequent rate restructuring. LADWP leadership reports that the Department intends to do so in the next two years.

A "surcharge" would normally be used to collect extraordinary costs, as opposed to "normal" cost growth. But the complexity of current legal considerations, as well as the need to ensure sufficient revenue for both the Department and the City, drive reasonable parties to endorse the surcharge strategy as an interim measure until legal considerations no longer require the surcharge strategy (see Section 4.5). Within that context:

- PA recommends the surcharge-based restructuring approach be revisited in two years' time, and that it be replaced with fully restructured permanent rates once legal considerations allow (see Section 4.5). Their replacement should not be left to chance: specific language calling for a study of the appropriateness of a full restructuring and a recommendation to the Mayor, City Council, and LADWP management should be written into the proposed ordinance to ensure rates are properly redesigned as soon as possible.
- In particular, the single base rate component is not transparent. Although this can be mitigated by limiting the base rate surcharge to mandatory programs. PA believes the City should carefully consider whether it is appropriate to reduce or eliminate the new surcharge for base costs in the upcoming rate action. Most of the components of the other four surcharges represent costs that are hard to control (fuel) or attributable to specific budgeted programs (RPS, DSM, PRP). Base costs represent the basic cost of doing business. Eliminating the incremental base rate surcharge, except for the "Rebuilding Local Power Plants" revenue requirement will reduce the rate increase by 0.25¢/kWh in FY 2013 and 0.34¢/kWh in FY 2014.
- The Reliability Cost Adjustment (RCA) factor, which funds the PRP, has been limited to 0.3¢/kWh by the Rate Ordinance. This represents a policy decision on the level of funding for the PRP. The Department has previously chosen to exceed that level, which led to a cumulative under-collection in the RCA Account, and plans to continue to spend more on PRP (necessitating the IRCA surcharge). The condition of the LADWP system may well justify increasing the level of PRP funding but that should be an explicit choice.

The City should strive to minimize cost and rate increases to the greatest extent. Policy choices that involve cost increases should be made explicit and should bear the approval of the City Council. PA has identified items in the rate increase that could be considered explicitly for potential modification, which together represent more than half of the rate increase.

Part Two
Cost Reduction

8 Current LADWP-Implemented Cost Cutting Efforts

To meet growing revenue needs, one has to increase income (in this case, rates) or reduce costs, or a combination of the two. In a difficult political context that made increasing rates challenging, the Department has put in place a three-year cost reduction initiative. Section 8.1 details the components of this effort and parses them according to their potential to reduce the revenue requirement to conclude that the initiative is likely to have limited impact on reducing the revenue requirements in the long run. Section 8.2 presents the Department's accomplishments in its first year of implementing the proposed measures and shows it is committed to meeting its goals and has even exceeded some of its cost reduction targets for FY 2012.

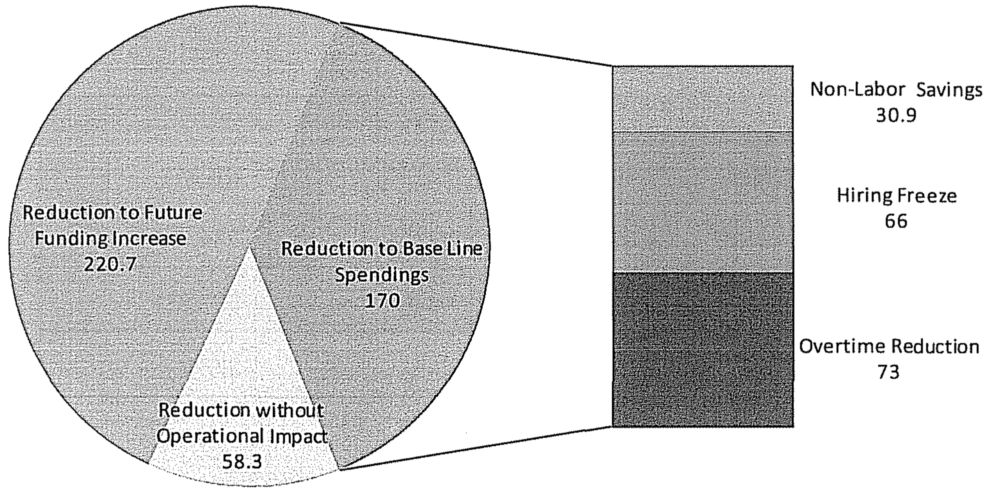
8.1 Projected Cost Reductions

As part of the fiscal year 2011-2012 budget presentation effort in mid-2011, LADWP provided a list of proposed cost cutting measures, with savings estimated at $449M over the following three years. LADWP staff has confirmed that there have been no additional cost cutting efforts introduced since that time. The cost reduction measures range from cuts to existing spending to reductions of budgeted future costs or cost increases. In an effort to provide perspective on the nature of the cuts, PA reviewed all proposed cost-cutting elements and categorized them as follows:

- Reduction to Baseline Cost - Cost cutting options that reduce existing spending level.
- Reduction to Proposed Funding Increase - Cost cutting options that reduce future year budget increases.
- Opportunistic Cost Reductions - Reductions that have no impact on operational activities (which should be pursued under normal as well as austerity conditions).

As indicated in Figure 8.1, nearly half of LADWP's cost cutting under the current financial plan represents cuts to projected future expenditures, while an additional $58M represent opportunistic cuts that should be made no matter what the financial environment.

Figure 8.1: Projected 3-Year Savings by LADWP Cost Reduction Category ($M)
(Total = $449M)



8.1.1 Reductions to Baseline Cost

Based on the proposed cost cutting schedule, LADWP will reduce its current baseline (FY 2011) spending level by $170M over three years. This is done through the following cost cutting options:

- Labor savings, achieved through a hiring freeze and reduced overtime costs
- Non-labor operational savings

A. Labor Savings - Hiring Freeze ($22M per year)

Upon release of these cost reduction measures, LADWP had an approved funded budget for 9,604 positions. Attrition alone, whereby positions deemed non-essential will be allowed to remain unfilled after opening, is projected to reduce LADWP's workforce by 206 positions over the next three years. By implementing the hiring freeze, LADWP projected to reduce its budget by $66M over three years through attrition, or an average of approximately $107,000 per position per year.

B. Labor Savings - Overtime Reduction ($24M per year)

LADWP projected to reduce labor costs associated with overtime, estimating savings of $73M over three years through this measure. Table 8.1 demonstrates the goals and savings of this reduction.

Table 8.1: LADWP Projected Cost Savings from Overtime Reduction

System	System Actual Overall Time% (as of Jan 2011)	Revised Overtime %	Three Year Savings
Water	12.4%	10.0%	$12M
Power	24.8%	22.0%	$34.3M
Joint	13.0%	10.0%	$27.3M
Total			$73M

C. Non-Labor Operational Savings ($10M per year)

LADWP has also proposed non-labor related operational cost reductions -- including both O&M and capital savings -- that will reduce the spending level. As stated previously, while O&M savings will impact the revenue requirement on a one-to-one basis in the year the cuts are made, capital expenditure reductions will only result in partial reductions to the current year revenue requirement. Therefore, while the savings represented by capital cost cuts are important and will be fully realized over time, the immediate benefits will be smaller and the savings will accrue to future customers as well as existing ones.

Proposed cost reductions include:

- Eliminate all non-field management take home vehicles - $1M savings per year
- Reduce travel costs - $1.5M savings per year
- Reduce new computer purchases and increasing life cycle to 5 years - $3M savings per year
- Reduce office supplies - $0.6M savings per year
- Reduce training[31] - $3.2M savings per year
- Eliminate funding for Holiday Light Festival - $1M savings per year

8.1.2 Reduction to Proposed Funding Increase

Nearly half of the Department's proposed cost-cutting measures represent reductions to future year budget increases, not reductions to baseline spending levels. While they serve to mitigate the need for future rate increases, such cuts do not reduce the current revenue requirement. The reductions that serve to limit future budget increases include the elimination of current vacant position and the reduction of a proposed non-labor operational funding increase.

A. Labor Savings – Vacancy Elimination ($47M per year)

Permanent elimination of existing vacancies represents a reduction to budgeted funding increases, not mitigation of current spending, because removing future funding for unoccupied positions has no impact

[31] Funding will be provided for training related to union, safety, regulatory requirements, and software implementation. The saving is caused by elimination of discretionary trainings.

on the existing spending level. LADWP had an approved funded budget for 9,604 positions at the time of the release. For three years, the Department will eliminate funding for all vacant positions and limit the number of new hires. In addition to the attrition discussed previously, the Department will also eliminate funding for 419 vacant positions, resulting in a $141M reduction to the proposed budget increase over three years which amounts to less than 6% of the Department's labor budget (an average of approximately $112,000 per position per year).

B. Reduction to Proposed Non-Labor Operational Funding Increase ($27M per year)

In addition to the vacancy elimination, LADWP has other cost cutting options that belong in this category. These options are predominantly capital savings, which will not result in a one-to-one reduction in current year revenue requirement. The following is a list of these cost cutting options:

- Reduce incremental security technology investment - $3M savings per year
- Suspend office remodels and furniture purchases - $0.5M savings per year
- Cancel property purchase - $6M savings per year
- Cut facility refurbishment - $16M savings per year
- Cancel additional truck purchases - $1M savings per year

8.1.3 Opportunistic Cost Reductions

LADWP also planned to pursue certain cost reductions that can be achieved without any impact to day-to-day operational activities or financial stability. Opportunistic cost reductions such as those provided by refinancing or enhancing revenue collection activities should generally be pursued where available, regardless of the circumstances.

Such opportunities for the Department include:

- Increase collection (1.5M per year) -- LADWP has targeted multi-residential accounts with total overdue payment of more than $7.3M. The Department is expecting to increase collection by $1.5M per year over the next three years.
- Bond refinancing (NPV of savings) - $18M per year

LADWP has identified potential savings in debt service through bond refinancing. The current low interest rate environment allows the Department to gain savings through reduction in interest and principal payments over the next eleven years. As indicated in Table 8.2, the $53.8M refinancing savings specified by LADWP are actually savings over the next five years, and the three year savings should be $38.3M (a combination of $31.8M principal savings and $6.5M interest savings). Instead of experiencing the full refinancing savings, the ratepayers will mostly see the reduction to revenue requirements due to interest savings instead of principal reduction.

Table 8.2: LADWP's bond refinancing savings

FYE	Interest Savings ($000)	Principal Reduction* ($000)	Total Savings ($000)
2012	2,555	70,195	72,750
2013	2,233	5,535	7,768
2014	1735	6,030	7,765
2015	1327	6,440	7,767
2016	813	6,950	7,763
2017	856	(855)	1
2018	901	(900)	1
2019	742	(740)	2
2020	578	(575)	3
2021	408	(405)	3
2022	205	(200)	5
Total	12,353	91,475	103,828

* $50M of the principal reduction is the result of deployment of Debt Reduction Trust Fund

8.2 Performance Against Objectives

In its March 2012 "Power System Rate Proposal" for FYs 2013 and 2014, LADWP discusses its three-year Cost Reduction Initiative and notes achievements from implementing last year's proposed measures. Based on the Rate Proposal, the Department appears to be on schedule to meet its cost reduction plan set in 2011. While LADWP's cost reduction objectives were not very aggressive, as stated in the previous sections, savings from its FY 2012[32] operating results are a good sign that the Department is committed to achieving its stated goal.

Table 8.3 shows the Department's projected savings through attrition and vacancy removal for FY 2012 and compares the results with the presented FY 2012 savings goal required to achieve the Department's 2011 cost reduction plan. Based on the operating results in FY 2012, LADWP is exceeding its projections regarding labor reduction.

[32] Based on results from the first 8 months of FY2012.

Table 8.3: LADWP Savings through Attrition and Vacancy Removal for FY 2012

	Targeted FY 2012 Savings[33] ($M)	Expected Realized Savings in FY12 ($M)	3-yr Target Savings ($M)
Attrition	-	23.4	24
Vacancies	-	42.4	68
Total Labor Savings	50.4	65.8	92

The Rate Proposal also provides savings associated with overtime spending in FY 2012. The Department not only achieved its overtime reduction goal set in 2011 but also managed to decrease overtime spending by an additional $20M. Table 8.4 documents the comparisons between the FY 2012 overtime savings and the Department's 2011 proposed overtime saving plan.

Table 8.4: Savings from Overtime Reduction

	Baseline Overtime Rates (Jan 2011)	Proposed Overtime Rates in 2011 for FY12	FY2012 Overtime Rates	Targeted FY12 Savings ($M)	Expected Realized Savings in FY12 ($M)	3-yr Target Savings ($M)
Power	24.8%	22%	17.4%	11.5	30	34.3
Water	12.4%	10%	8.4%	4	6	12
Joint	13%	10%	10.1%	9.2	9	27.3
LADWP				25	45	73.6

In addition to labor reduction and overtime savings, LADWP also proposed several non-labor operations reduction and capital savings measures. Compared to the average of its three-year cost saving plan in 2011, the Department was able to achieve significant savings in these areas as shown in Table 8.5.

Table 8.5: Non-Labor and Capital Savings

	Targeted FY12 Savings($M)	Expected Realized Savings in FY12 ($M)	3-yr Target Savings ($M)
Non-Labor Operations Savings	30.2	33.3	104.1
Capital Savings	20	20	20
Bond Refinancing	31.6	31.6	55

[33] The goals for FY2012 are not in all cases one-third of the 3-year goals.

9 Future Cost Reduction Considerations

As detailed above, the Department has made progress on cost reduction. It will also have to do a lot more to contain costs going forward. The cost reduction efforts detailed in Section 8 are a start, however, even after employing LADWP-devised austerity measures and considering the RPS and repowering plans – all of which have been included in the current two year and preliminary five year financial plan – meeting the financial needs of the LADWP system will still require $2.9 billion in increased retail revenue over the next five years.

Reducing the revenue requirement in the long run will require significantly more savings than the cost cutting measures identified by the Department in 2011; it will necessitate a deep transformation in the way LADWP conducts its operations. To make significant, long-lasting cuts, LADWP will have to target the building blocks of its operational costs and seek, for example, system-wide performance improvements as well as review its labor costs (salaries but also health care pensions and costs).

These are long-term commitments however; in the near term (FY 2013 and 2014), there aren't significant additional opportunities to reduce costs. Whether a commitment to performance improvement or to a review of labor costs (assuming all parties involved cooperate in reaching a new labor agreement) these changes will take time. But by focusing on the right areas, the Power System potentially could realize significant savings starting in 2015. To help identify the source of potential cost cutting areas, PA worked with the Department to categorize the Power System's financial needs by cost type to help offer some insight into the costs that may be reduced and those that may not.

Capital funding areas will benefit from process improvements and greater fiscal responsibility, but are not likely to be the source of major cost reductions over the next five years. Past investment costs are sunk and future investments, whether mandated or not, are important to the compliance and reliability of the Power System. The Power System certainly needs to implement a more fiscally responsible, data-driven investment process, as the Water System has done, but PA has seen no evidence of significant programs that appear unnecessary and should be cut altogether. In short, efforts to control capital funding should start immediately, but should not be expected to generate immediate revenue requirement savings over the next five years.

The most immediate way to cut revenue requirements and mitigate rate increases will be to address the costs of running the system. And to reduce these costs, the Department needs to focus on the building block costs that drive them: labor costs, benefits and productivity. There appear to be opportunities in these areas. Benchmarking studies completed by LADWP, the City, and PA all indicate that the Power System's salaries are significantly above those of their peers, and the Department's benefits appear to be more generous than industry norms. Addressing the Department's outsourcing provisions and engaging in a large scale process reengineering initiative may also be sources of significant efficiency gains.

To address these labor-related costs and rules will likely require adjustment of the labor agreement that covers the bulk of LADWP employees and which is not set to expire for two years. If the labor requirements addressing these issues can be readjusted appropriately, the Department should be able to reduce 2015-2017 revenue requirements significantly. Reaching new labor agreements that support a reduction in the Department's revenue requirement will necessitate leadership and cooperation from City management, LADWP and its labor unions. In other words, changing the way LADWP operates and lowering its costs is not a problem LADWP alone can undertake successfully.

9.1 PA's Analytical Framework: Breakdown of the System's Financial Requirements

To help identify other potential cost cutting areas, PA has worked with the Department to categorize its required revenue into the following four categories:

- Existing Capital Funding Requirement
- Cost of Running the System
- Future Capital Funding Requirements from Regulatory Mandates
- Future Capital Funding Requirements from Non-Mandates

Figure 9.1 displays the breakdown over the next five years. The figures have been provided by LADWP Financial Planning staff to meet the breakdown requested by PA. The figures for fiscal years 2015 through 2017 were only provided on a preliminary basis and are not part of the Department's 2-year rate proposal.

Figure 9.1: Projected Annual Revenue Requirement by Cost Category (2013-2017)

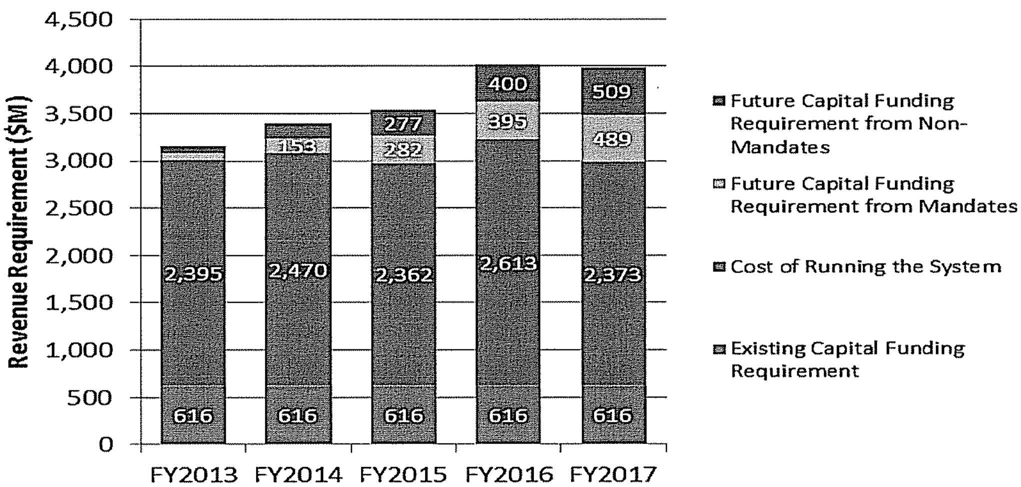
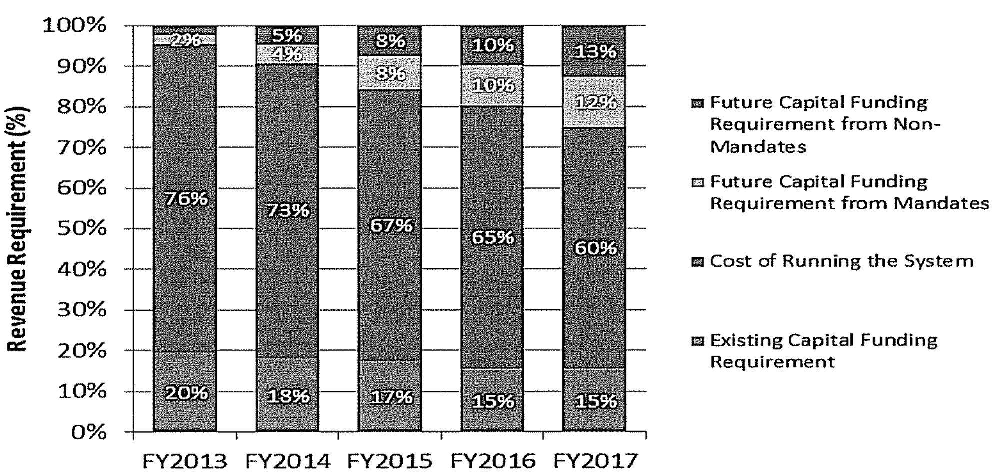
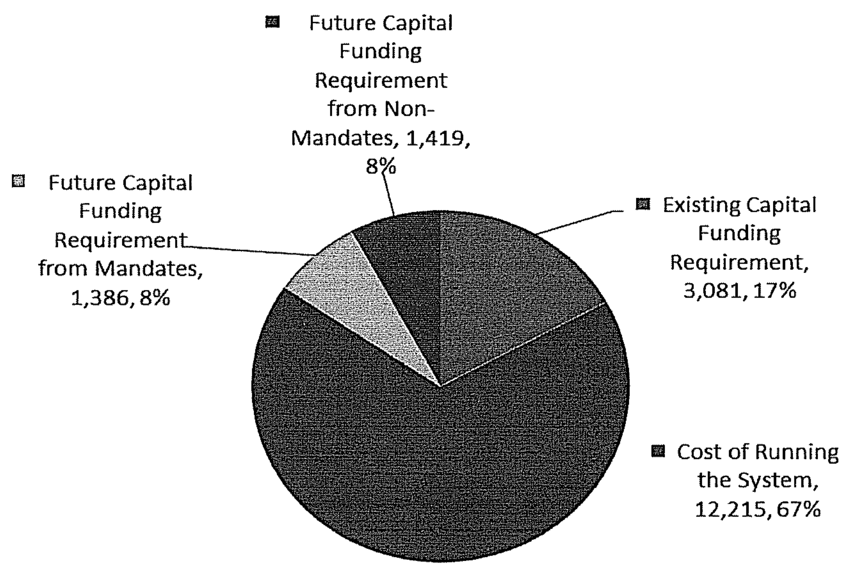


Figure 9.2: Projected Annual Share of Revenue Requirement Components (2013-2017)



As shown in Figure 9.2, the share of capital funding in LADWP's revenue requirement is projected to increase rapidly between 2013 and 2017 while the relative "cost of running the system" declines as a result, thereby reducing LADWP's flexibility as it searches for future cost cutting opportunities.

Figure 9.3: Projected 5-Year Total Revenue Requirement by Cost Category (2013-2017) ($M)



A. Existing Capital Funding Requirement

Existing capital funding requirements are expenses associated with depreciation and interest expense from past capital investment decisions. Under the Power System's current financial plan, existing capital funding requirement will account for approximately 17% of the revenue requirement over the next five years. These costs are sunk: aside from simple refinancing of debt, there will be few cost cutting opportunities to reduce the magnitude of these costs.

B. Costs of Operating the System

Costs associated with operating the electrical system account for almost 68% of LADWP's revenue requirement. Fuel, purchased power, and O&M expenses account for the majority of the costs of running the system.

C. Future Capital Funding Requirements from Regulatory Mandates

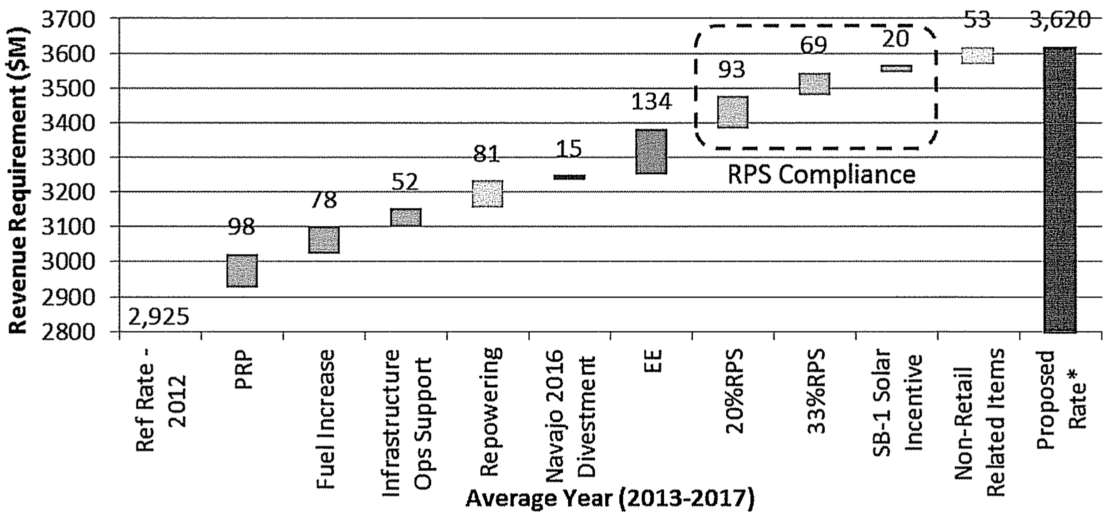
Much of the Department's current capital program is devoted to responding to regulatory requirements. Due to the nature of the mandates, funding required under this category is not likely to be a significant cost cutting candidate. The regulatory obligations that are expected to have the most significant impact on the budget are:

- SBX1-2, which requires that 33% of the Department's 2020 energy sales come from renewable sources
- The SCAQMD stipulated order which requires that LADWP reduce local air emissions through repowering its less efficient in-basin generating facilities
- The Once-Through Cooling (OTC) elimination policy, which mandates that the Department's in-basin fossil generators with a "once-through" cooling system be repowered or shut down.

The major capital expenses associated with these three regulations are the installation or repowering of power plants and the installation or upgrade of transmission infrastructure.

As Figure 9.4 shows below, all the spending associated with RPS compliance will result in an average annual increase in revenue requirement of $181M over the reference rate during the five year period (2013-2017). Similarly, the repowering of in-basin power plants will result in an average increase in revenue requirement of $81M over the reference rate during the five year period (2013-2017).

Figure 9.4: Average Annual Revenue Requirement Attribution from 2013-2017



*The average annual revenue requirement is based on the two years covered in the proposed rate increase and three years of preliminary projections.

Note: Figures include revenue collected to meet the 2.25x debt service coverage ratio.

D. Future Capital Funding Requirement from Non-Mandates

In addition to the future capital funding requirements resulting from regulatory requirements, the Department makes material investments each year in capital undertakings that are deemed necessary but not obligatory. Examples include the PRP, infrastructure, and operational support investments such as the new AMR and financial information system. PA has also included energy efficiency in this Non-Mandated category. The Department has to date considered its demand-side management or energy efficiency investments to be mandatory, but the 10% demand reduction target upon which their latest financial plan comes from a Board mandate, not legal obligation. California Assembly Bill 2021 requires publicly owned utilities (POUs) to "identify all potentially achievable cost-effective electricity energy savings and establish annual targets for energy efficiency savings and demand reduction for the next 10-year period," but does not itself establish a specific target.

The Future Capital Funding from Non-Mandated Investments category accounts for $1,419M in total revenue requirement over the next 5 years, or 8% of LADWP's average annual revenue requirement over that time period.

9.2 Reducing the Revenue Requirement

Reducing the revenue requirement from the currently forecast levels will not happen overnight. In fact, it is not likely that LADWP will be able to make significant reductions in FY 2013 and FY 2014 without compromising important programs that probably should not be sacrificed. There will be opportunities to reduce costs though, particularly if the Department, with the support of the City and the cooperation of the unions, is able to renegotiate its labor agreements to allow greater flexibility to make changes that will help the Power System remain viable while still protecting its employees and ensuring they are not asked to accept below-market compensation or benefits. Evidence suggests that Power System employees are compensated and receive benefits that are better than those their peers elsewhere receive. By adjusting the labor agreement to bring salaries and benefits more in line with industry standards and removing certain constraints that prevent efficient practices such as contracting out, the Department could significantly reduce revenue requirements from 2015 to 2017.

9.2.1 Analyses Show LADWP Salaries Well Above Market

Any effective cost reduction effort will need to address labor costs, which represent approximately one quarter of LADWP's annual revenue requirement for FYs 2013-17. In an effort to put LADWP's salaries in perspective, PA has examined the level of salaries at the Department compared to those of other utilities. PA reviewed a 2005 survey of the Department's compensation scheme and has completed its own salary benchmarking effort using its proprietary database. Both studies reveal that, on average, LADWP salaries are materially higher than those of its peers.

A. 2005 LADWP Wage and Total Cash Compensation Survey

In 2005, the City of Los Angeles' City Administrative Officer and LADWP's Human Resources Department oversaw a Dembrowsky and Associates survey of LADWP employees' compensation.

The survey reviewed wage, salary, and other cash compensation data from 21 companies. The report compared job classifications represented by the IBEW, Local 18; the Management Employee Association (MEA), and the Load Dispatcher Association (LDA). The survey participants used to benchmark LADWP compensation were made up primarily of investor-owned and municipally-owned energy utilities as well as municipal water utilities. Most utilities were in California, but the list also included a few out-of-state entities. A select group of peers was chosen to provide a "better comparative market perspective" due to their geographic proximity.

In comparing base salary levels, the study analyzed the variance between LADWP's annual base salary levels and that of all the survey's participants, as well as that of the Select Group of geographically close utilities. For each group ("All Participants" and the "Select Group"), the study looked at both the variance between average salary levels and the variance between LADWP's average salaries and the peers' 75th percentiles. The 75th percentile is the salary level that marks the low end of the highest salary quartile (or the low end of the 25% highest salary bracket in each category). Presumably, the survey's intent in looking at the variance between LADWP salary levels and other utilities' highest brackets was to assess how widely the Department's compensation levels differed from industry practices and if the variance of averages could be explained by pointing to LADWP employees' tenure.

Table 9.1 below shows LADWP's average base salaries were on average 12.7% higher than those of all the survey's participants and 11% higher than its geographical peers' average salary levels. When comparing to the higher brackets of salary ranges at other utilities (the 75th percentiles), LADWP's salaries were still on average 8.5% higher than all participants' top quartiles and 6.4% higher than the Select Group's.

Table 9.1: 2005 Variance from Market Annual Average Base Salary Data

Variance from Market Annual Base Salary				
	All Participants		Select Group	
Employee Group	From Market Average	From Market's 75th Percentile	From Select Group's Average	From Select Group's 75th Percentile
IBEW Local 18	+12.6%	+8.6%	+10.9%	+6.5%
MEA	+9.4%	-6.0%	+6.2%	-4.2%
LDA	+26.1%	+14.7%	+23.1%	+7.9%
OVERALL	**+12.7%**	**+8.5%**	**+11.0%**	**+6.4%**

The 2005 study concluded "LADWP's pay levels noticeably exceed those of the market weighted average for its three employee groups for both the all participant group and the select participant group." It noted LADWP's pay levels were "closer to the 75th percentile market", suggesting that LADWP's average salaries paralleled the top salary quartiles at other utilities more, yet, "still beyond the plus or minus 5% competitive parameter" that may otherwise have justified the higher wages, the study added.

B. PA's Salary Benchmarking

As a second means of gauging LADWP's Power System salaries relative to the market, PA used its Polaris database to benchmark LADWP salaries provided in the context of this report. Polaris offers a comprehensive data collection of Transmission, Distribution, and Customer Service spending across a large array of utilities, including the three major California investor-owned utilities and local municipal utilities included in the 2005 study participant group.

In terms of employee compensation, the Polaris survey collects Transmission, Distribution and Substation (T&D) data separately from Customer Service data. T&D wages are collected as "Maximum Hourly Rate", while Customer Service data are collected as "Average Hourly Rates." For this reason, PA has compared both categories of employees separately and presents results here in different tables.

PA chose to use 2007 salary data, which allowed the most detailed comparison with LADWP data. In order to adequately compare to LADWP's current salaries, PA inflated the Polaris salaries to 2012 levels using the Consumer Price Index cited in the LADWP Memoranda of Understanding (MOU)[34] and used to adjust salary levels annually for every year covered under the MOU.

LADWP provided the distribution of annual base salaries for each job classification as well as the number of employees earning every salary within that range. Job Descriptions available on LADWP's Labor Relations site[35] were reviewed for each job classification to ensure job classifications were appropriately matched to Polaris' categories. For positions where there were outstanding questions about the match or insufficient data to ensure a reliable comparison, the job category was dropped. PA ultimately compared salary levels for 13 select job categories, 10 in T&D and 3 in customer service. A detailed list of the Polaris job categories and the LADWP matched job classifications is available in Appendix B.

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[34] The CPI for Urban Wage Earners and Clerical Workers for U.S. City Average (1982-84=100) http://labrel.ladwp.com/MouInfoPage.cfm

[35] http://labrel.ladwp.com/ClassDdrPage.cfm

Similarly to the 2005 survey approach, PA selected a group of peers to include companies operating in high cost, urban environments. In the case of Customer Service positions, the Select Group includes many of LADWP's geographical peers that could be construed as competitors in the labor market, such as Pasadena Water and Power, Southern California Edison, Southern California Gas, San Diego Gas and Electric, and Pacific Gas and Electric.

For the 10 Distribution categories matched with LADWP positions, PA compared the averages of available data (i.e. maximum salaries based on "Maximum Hourly Rates"), for both the "All Participants" group as well as the "Select Group". Results are presented in Table 9.2 in Columns (1) and (3) respectively.

PA weighted LADWP's Average Salaries by the number of employees in the classification (in order to account for the relevance of a given job classification in the overall comparison and ensure a job occupied by only 2 people is not given equal weight as one that is staffed with 600 employees). PA then compared this weighted salaries' average against the average of maximum salaries at other utilities. This comparison is motivated by the tenure of the company's staff and the entire industry's tendency to develop workforces with great seniority in grade (likely to have salaries close to range maxima). The results of the weighted salary averages are displayed in columns (2) and (4).

While PA tried to ensure the most accurate comparison, this type of exercise typically entails some margin of error, whether on the consistency of data across utilities or in the matching process. Still, as Table 9.2 indicates, the results appear very convincing: LADWP's maximum salaries exceed those of all participants in 9 out of the 10 matched categories. Even when compared to the Select Group, LADWP's maximum salary levels[36] exceed those[37] of its closer peers in 7 out of 8 instances. Analysis of salary levels in Customer Service positions confirms this trend: for both the "All Participants" and the "Select Group", LADWP average salary levels exceed that of its peers in all instances.

When comparing maximum salaries by T&D position across all utilities, the analysis indicates LADWP maximum salaries by position are on average 26% higher than maximum salaries for the same positions at their peer utilities. When compared to the Select Group of utilities, LADWP maximum salaries for a given position are on average 23% higher, as shown in Table 9.2 below. Even when comparing the average of a salary range, weighted for the number of positions in that salary range, the Department's compensation levels are on average 16% higher than maximum salary levels in the "All Participants" group and 12% in the Select Group. The data consistently suggest that administrative positions at LADWP receive between 5% and 7% less than at other utilities.

[36] Measured as the "Average of the Maximum Salaries" in matched functions (average of: maximum salary for civil engineer, maximum salary for electrical engineer, etc.)

[37] Measured as the Average of the Maximum Salaries given by peers (average of: maximum salary for engineer in companies A, B, C, etc...)

Table 9.2: Variance between LADWP and Polaris' Maximum Annualized Salaries for Distribution Positions

Variance from Market Salaries in Distribution Positions					
		All Participants		Select Group	
		(1)	(2)	(3)	(4)
Job Category	Number of LADWP matched positions	LADWP Max Salary Averages vs. Max Salary Averages of Panel Companies	LADWP Average Salaries Weighted by number of employees vs. Max Salary Averages of Panel Companies	Variance between Maximum Salaries	LADWP Weighted Average Salaries vs. Select Panel Companies Maximum
Engineer	**116**	**33%**	26%	38%	30%
Designer	**23**	**16%**	14%	11%	8%
Engineering/Design Technician or Anal	**130**	**1%**	-5%	4%	-2%
Journeyman lineman	**668**	**38%**	20%	35%	17%
Apprentice lineman	**139**	**43%**	28%	50%	34%
Groundman/Utility Worker	**795**	**41%**	15%	11%	-9%
Cable splicer	**28**	**43%**	36%	40%	33%
Technician/Shop	**112**	**36%**	25%	* ID	* ID
Tree trimmer	**31**	**19%**	12%	* ID	* ID
Administrative	**185**	**-5%**	-11%	-7%	-13%
Average		**26%**	**16%**	**23%**	**12%**

* ID = Insufficient data in the Select Group (less than 3 data points)

Table 9.3 below shows the results of the Customer Service average annual salaries comparison. Again, LADWP average salaries were weighted by the number of employees in that category. In the case of Customer Service positions, LADWP pays its employees on average 28% higher than all other utilities in the database and 29% more than its closer peer utilities.

Table 9.3: Variance between LADWP and Polaris' Customer Service Average Annualized Salaries

Variance from Market Average Range			
		All Participants	**Select Group**
Job Category	**Number of LADWP matched positions**	**LADWP Weighted Average Salaries vs. Database Average Salaries**	**LADWP Weighted Average Salaries vs. Database Average Salaries**
Field Service Representative	164	17%	19%
Contact Center Representative	626	21%	20%
Meter Reader	176	47%	46%
Average		**28%**	**29%**

Both 2005 and 2012 studies therefore indicate that LADWP salary levels are materially higher than those of their utility peers. This would suggest that one way for the Department to reduce its projected rate increases would be to bring its employee compensation more into line with that of its peers. However, the immediate promise of savings from labor cuts may be limited in two ways. Firstly, and as discussed in Section 3.2, labor savings do not result in a dollar-for-dollar reduction to the revenue requirement because labor costs are spread across O&M and capital expenditures, with savings on the latter realized in small chunks over a number of years. Secondly, the majority of the Department's salary levels are subject to the Memorandum of Understanding between the LADWP and the International Brotherhood of Electrical Workers (IBEW), which does not expire until September 2014. IBEW workers represent about 93% of the Department's workforce.[38] A reduction in salary levels, if it could be negotiated, would therefore only impact revenue requirements for 2015 and beyond.

9.2.2 Cost Reduction Opportunities in Shared Services

A. Corporate restructuring potential

In addition to the Power and Water Enterprises, LADWP also operates various corporate and shared services. A sample list of LADWP's major shared service departments includes:

Shared Services Departments	
Customer Service	Legal
Environmental Affairs	Public Affairs
Fleet Services	Real Estate
Facility Management	Retirement Planning
Finance and Accounting	Real Estate
Human Resources	Retirement Planning
Information Technology	Security Services

[38] The Management Employee Association (MEA) represents another 3.5% of the LADWP's workforce, while the Service Employees International Union (SEIU) and the Load Dispatchers Association (LDA) represent the remaining 2.8% and 0.6% respectively. MEA's contract expires in September 2012, LDA's in September 2013, and SEIU's expired in September 2010.

Labor Relations	Supply Chain Management

Shared Services (or Joint System) is a larger part of the organization at LADWP than at most utilities. LADWP's Joint System has 3,625 full-time employees--lead by Customer Service (1,192) and Information Technology (453)--accounting for nearly 40% of the Department's full-time staff. PA's Corporate and Shared Service benchmarking indicates that the average across U.S. utilities is 20%. The allocation of shared services costs to the Water and Power Systems is described in Appendix D. PA recommends a review of the cost allocation methodology to ensure that both systems are bearing their appropriate share of the costs. As a general rule of thumb, 70% of the costs are allocated to the Power system and 30% to Water, though the actual percentages will vary by expense category. About 37% of the staff charging to the Power System budget and 45% of the staff charging to the Water System budget are from Joint Services.

B. Outsourcing Opportunities in Shared Services

In order to reduce expenses and limit rate increase to ratepayers, LADWP might consider increasing its level of outsourcing. Firms tend to outsource elements of their operations for one of the following three reasons:

- Strategic – The activity can be outsourced because it is not a core competency of the company. Strategic outsourcing allows a business to utilize its own resources and assets more effectively.
- Operational – The activity can be done more efficiently by a vendor that is highly specialized. Operational savings can come from improved efficiency, stronger discipline and potential economies of scale.
- Financial – The activity can be performed more economically by a vendor. Financial savings can be obtained through lower wages, higher effectiveness and potential economies of scale.

Most utilities of LADWP's size have implemented various outsourcing strategies, and similar opportunities are worthy of consideration for LADWP. Some common areas for outsourcing are customer, transmission, and distribution and non-core utility services.

Currently, the Department's primary outsourcing efforts relate to certain transmission and distribution services including vegetation management and equipment replacements. The Department has a contract for vegetation maintenance that outsources 78% of the overhead line clearance tasks. There are a few other areas that might work, but representations from LADWP generally indicate the Department has not investigated and studied further outsourcing opportunities.

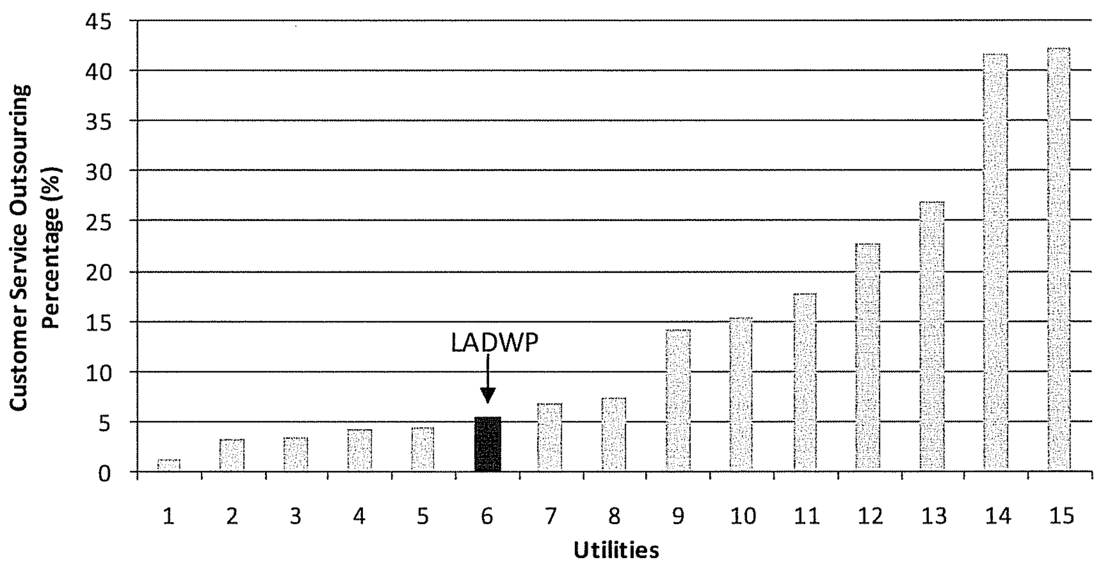
One prominent example of an area that has been effectively outsourced at other organizations is Customer Service, which covers a wide variety of functions and provides substantial outsourcing potential. Some of the most commonly outsourced tasks are:

- Contact Center - 20% to 50% of calls are typically outsourced for general call or for specific call types (cut-in or C&C or call overflow).
- Bill Issuance and Payment Processing - 100% of payment processing and bill issuance (both bill printing and electronic delivery) can be outsourced.
- Meter Reading - Manual meter reading can usually be outsourced to some degree but rarely completely. Remote meter reading, however, can be outsourced almost completely and provided as service. LADWP should consider accelerating the installation of AMR meters to reduce meter reading staff and using contractors to do the installation instead of its own staff.

- CIS - Utility can gain savings by outsourcing either server/mainframe maintenance or CIS management.
- Credit & Collection - Several credit and collections functions including credit evaluations and account receivable collections can be outsourced to third-party vendors.

In FY 2012, 6% of LADWP customer service spending was outsourced, well below the national average Based on PA's benchmarking program, the Department's customer service outsourcing effort is lower than the median of the benchmarking peer group, as shown in Figure 9.5. PA believes there are potential cost reduction opportunities through outsourcing for the Department in the customer service areas.

Figure 9.5: LADWP's FY 2010 Customer Service Outsourcing Benchmarking Result (as a percentage of spending)



PA recommends investigation of outsourcing potential across all Systems, with the best additional opportunities expected to found in Joint Services. Given that every utility has a unique operating environment, PA would suggest a more detailed analysis to determine the overall benefit LADWP can gain by pursuing certain outsourcing strategies. Table 9.4 and Table 9.5 show the average annual budgets for some business units for the years 2013 thru 2017 in the Joint and Power Systems respectively. The tables also include the 5 year average of those budgets' shares that are allocated to outsourcing contracts. Table 9.4 shows for example, that on average, LADWP is only expecting to outsource 1% of its Security Services and 3% of it Human Resources' budgets over the FY 2013-17 period. Table 9.4 seems to suggest there may be outsourcing opportunities in Customer, Fleet, Security and Human Resources Services as well as Supply Chain Management functions.

Similarly on the Power System side, Table 9.5 indicates levels of outsourcing in the Transmission and Distribution, Safety and Training, Integrated Support Services and Critical Repair/Fabrication functions are very low (under 5% of annual budgets on average).

Table 9.4: Examples of Contracting Out levels at LADWP by Joint System Business Units

Joint System Functions/Business Unit	Fiscal Years 2013 through 2017	
	Average Annual Budget (in $1,000s)	**% of Annual Budget Contracted Out**

Customer Services	263,085	7%
Fleet Services	133,011	3%
Human Resources	289,620	3%
Security Services	44,559	1%
Supply Chain Management	66,704	1%

Table 9.5 LADWP Power System Outsourcing Levels by Business Unit

Power System Functions/Business Unit	Fiscal Years 2013 through 2017	
	Average Annual Budget (in 1,000s)	**% of Annual Budget Contracted Out**
Power System Planning & DV*	242,549	75%
Power System Engineering Services	951,926	31%
Power System Generation	549,233	18%
Power System Executive	81,929	10%
PT&D Transmission and Distribution	241,725	5%
Safety and Training	70,087	4%
Integrated Support Services	154,624	1%
Critical Repair/Fabrication	51,258	1%

9.2.3 Outsourcing Holds Significant Promise but Labor Rules Prevent Effective Outsourcing

From a cost-cutting perspective, the number of levers available to the Department is limited in the near term because of constraints contained in its labor agreements, as embodied in the Memorandums of Understanding (MOUs) between LADWP and its labor force.[39] These contractual obligations are relevant from a cost cutting perspective because they limit the Department's flexibility in pursuing the most efficient labor resource allocation. In an institution such as the LADWP with a personnel headcount around 9,000, the inability to operate nimbly can come at a high cost.

Many of the most restrictive clauses were made "in consideration for [the IBEW] Local 18's agreement" to the Focused Separation Program of 1995 (now included as the MOU Appendix D), where in return for the terms of a buy-out plan for more than 1,200 LADWP positions, LADWP agreed to prescriptions on minimum staffing levels, outsourcing, and layoff-related conditions, among other clauses. Most importantly, these rules prevent the Department from outsourcing effectively by essentially increasing the cost of doing so and by limiting any potential efficiency to be gained from a human resource perspective , depriving management of an effective tool that can be used to promote efficiency.

If the Department contracts out bargaining unit work, the Union may request that LADWP offer employees that would normally perform the work to be performed by the contractor at least 10% overtime per pay

[39] PA focused its analysis on the IBEW's MOU because this MOU covers 93% of the Department's employees and therefore impacts the Department's flexibility most significantly.

period during the time the contractor is performing work. As a case in point, PA found this clause discussed in an April 2012 Letter of Agreement regarding a "Substation Automation System" agreement with Schweitzer Engineering Laboratories. The letter states, "Schweitzer will be asked to submit a list of job classifications that will be used to perform the contracted work" and that the LADWP will offer employees that will be impacted at least 10% overtime per pay period for the duration of the contract.

There are also limits that prevent against displacement of existing workers as a consequence of outsourcing work. Article 35 of the MOU ("Job Security") specifies that "No regular annual-rated, Civil Service bargaining unit employee within the classification and major division affected by the contracting out of bargaining unit work will be laid off or placed on a lower level DDR." [Duties Description Records are job descriptions]. This clause does not contain further detail, but seems to prevent the Department from laying off any employee in a classification in which any contracting out is taking place. As an example of the impact of article 35, consider the fact that large organizations commonly achieve efficiencies by contracting out a portion of their call centers. LADWP would not currently be in the position to do so, as it would appear to be bound to maintain all 600 contact center representatives on the payroll at similar levels.

9.3 Savings Potential of Cost Reduction Measures

PA cannot estimate the potential savings that could result from wider application of outsourcing where appropriate; LADWP will need to study that potential to prepare for labor agreement negotiations and position itself to contract out non-core competencies or areas that could be performed more efficiently by outside firms. PA has however sought to evaluate the revenue requirement savings to be garnered from addressing the level of other building block costs – such as labor, pension, and healthcare – that contribute to the cost of virtually all Department projects or undertakings. PA has also attempted to determine the impact, from a programmatic perspective, of not receiving an increase at all or of having to reduce the rate increase by 20%.

LADWP has completed all scenarios requested based on PA's requests. Observations for the three fiscal years beyond fiscal years 2013 and 2014 should only be considered preliminary and the scenarios should not be considered endorsed or supported by the Department. In some cases, the results presented are less explicit than originally hoped. However, these scenarios indicate a significant potential for savings if the Department has the contractual flexibility to address certain out-of-market costs.

Results for all scenarios are presented in detail in Appendix C. Some highlights are below.

Potential for 2013-2014 cost reductions is limited

To test the potential for near-term cost reduction, PA requested several separate scenarios designed to explore the Department's priorities and identify near-term cost reduction possibilities.

- Reducing non-mandated spending could save ratepayers an average of more than 4% per year over the next five years, but may lead to problems.

  Freezing non-mandated spending on the PRP, operating support, infrastructure reliability, and energy efficiency[40] at 2012 levels would reduce O&M and capital expenses by $594M and

[40] The current financial plan assumes 10% demand side management reductions, a Board objective that has been set according to Assembly Bill 2021, which calls on load-serving entities to "identify all potentially achievable cost-effective electricity energy savings

$1,454M respectively over the next five years. The overall impact to the ratepayer is an $802M reduction in retail revenue requirement over the same five-year period. However, doing so completely would have major reliability consequences and the demand-side management setback could result in fines under AB 2021. There may be middle ground worth considering if immediate reductions are imperative, but such cuts are not without consequences.

- No Rate Increase Scenario: PA asked LADWP to produce a financial plan assuming no rate increase was approved. The result showed the Department does not appear to have a viable contingency plan to face the eventuality of no rate increase for the next five years. Under this scenario, LADWP would not reduce its O&M spending. Instead it would eliminate capital expenditures for non-mandated projects such as PRP and infrastructure improvements; investments for IRP and RPS would remain unchanged. Finally, because LADWP has a limited ability to reduce debt service associated with borrowings from previous years, its financial ratios would fall below the preferred thresholds quickly, and the Department would not be able to fulfill its city transfer obligation.
- Cost of a Downgrade: As described in Section 2.2.3, LADWP estimates that a downgrade would cumulatively cost the Department and its customers $329 million over the next five years
- Lower the Energy Efficiency target to the previous 8.6%: The LADWP Board recently approved a 10% by 2020 target, in spite of the recommendations of an Energy Efficiency Potential Study's recommendation. Lowering the target to 8.6%, would reduce the overall impact to rate payers by a total of $39M over the 2013-2017 period.
- 20% Reduction to Rate Increases: PA asked the Department to show how it would potentially reduce its incremental rate increase by 20% without issuing new borrowing beyond what was already assumed in the financial plan and still meet all legally mandated compliance obligations. Results showed LADWP would reduce non-PRP O&M expenses by $588M. LADWP would not adjust its capital expenses because capital reductions would not provide a dollar-to-dollar reduction to the annual revenue requirement. Because new capital borrowing is proscribed, the Department would be unable to capitalize other O&M expenses. The overall impact to the ratepayer would be a total of $632M decrease in retail revenue requirement over the five year period. The Department has not provided a detailed list of impacted activities and the potential effect of the 20% reduction to the incremental rate increase.

<u>Cutting "building blocks" costs could save millions</u>

The Department could garner significant savings by adjusting salaries and benefits plans.

- A 10% cut to labor costs could reduce the outer year retail revenue requirement by 1-2%

The cuts to labor costs scenario will reduce O&M and capital expenses by more than $223M and $125M respectively over the next five years. The overall impact to the ratepayer is a $203M decrease in retail revenue requirement over the five year period.[41]

- Revenue requirement savings of 0.6% in 2015-2017 could be generated by adjusting the medical plan

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and establish annual targets for energy efficiency savings" in the interest of helping the state meet its goal of reducing electricity consumption by 10% by 2020. LADWP does have a Board requirement, but does not technically have a mandated obligation.

[41] Note: since 55% of regular and overtime labor expenses fall under capital expenditures, which are amortized over time, cuts to labor costs will not result in a dollar-for-dollar rate reduction.

By shifting to a 20% employee contribution and increasing co-pays, the Department could save more the $70 million in O&M spending and $30 million in capital spending over the 2013-2017 time frame. The vast majority of these savings would stem from the increased employee contribution rate and could not accrue until renegotiation of the labor agreement.

- Savings from pension plan reductions are approximately 0.3% per year from 2013-2017

Through the creation of a tiered system whereby pension benefits of new joiners could be made to be more in line with those of City employees, the Department could reduce O&M and capital expenses by $38M and $16M respectively from 2013-2017. The overall impact to the ratepayer is a $36M reduction in retail revenue requirement over the five-year period.

- Sensitivities indicate need to protect against downside risk

The Department must protect itself against downside risk resulting from market forces outside its control. Major generation outages, increased interest rates, or rising natural gas costs all stand to impact the Department. To evaluate the downside risk, PA worked with LADWP to run scenarios simulating the impact of high natural gas prices, high interest rates, and an extended outage. The changes assumed were enough to be significant but also certainly within the realm of possibility from an historical perspective.

- $6.50/MMBtu natural gas prices from 2015-2017 could cost ratepayers $75 million per year

$6.50 per MMBtu natural gas prices from 2015-2017, approximately 50% higher than today's price but not an unreasonable high case given historical prices of recent years, would result in cost increases. Fuel and purchased power cost, as collected through the Energy Cost Adjustment, would exceed currently projected levels by $225 million over the 2015-2017 time period.

- With its increased borrowing, the Department will be vulnerable to interest rates moves

Worst case interest rates, as determined by the Department's financial advisor, would have major costs associated with it. Interest expense will increase by $215M. In addition, fuel and purchased power costs will increase by almost $58M. The overall impact to the ratepayer would be a total of $255M increase in retail revenue requirement over the five year period.

- A two-year outage at the Palo Verde nuclear facility would create cost increases of nearly $70 million per year in the 2013-2014.

Currently, LADWP owns almost 10%[42] of the power output at the 3,875MW Palo Verde Nuclear Power Plant, and the Reference Case assumes Palo Verde will have a capacity factor of 92% for FY 2013 and 2014. An outage could be costly. A two-year outage, in this case FY 2013-2014, would have no impact on O&M and capital expenses over the next five years. However, in order for the Department to replace the capacity at Palo Verde, fuel and purchased power expense will increase by almost $100M. In addition, CO2 allowance expenses will increase by $35M. The overall impact to the ratepayer is a total of $138M increase in retail revenue requirement over the five year period.

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[42] LADWP has 5.7% of direct ownership in Palo Verde and also owns 3.96% of power output from Palo Verde through entitlement interest from SCPPA.

10 Cost Reduction Recommendations

PA has identified additional cost reduction opportunities, though most will not provide significant savings in the FY 2013-2014 two year period. Transformational change of LADWP labor costs and process reengineering are needed but require a new union agreement to be in place.

To limit annual rate increases now without hamstringing ratepayers later, the Department needs to address foundational costs that drive all spending, such as labor-related costs. These include:

- Salary levels ("Regular Labor")
- Overtime
- Benefits (health care and pension).

Most of these costs however are inscribed in labor agreements and cannot be cut until the agreements are renegotiated in 2014. PA makes several recommendations for LADWP to consider as it seeks the City's support and the unions' cooperation in renegotiating the terms of its labor contracts.

PA also makes recommendations on:

- Implementing process improvement initiatives
- Approaches to control rising capital expenditures
- Considering the costs and benefits of a ratings downgrade.

Labor-Related Cost Reduction

As described in Section 9.1, it is likely that the most significant cost-cutting effort will have to address the day-to-day costs of operating the system. The Department has generally sought to remain compliant with regulatory mandates to avoid penalties and political fallout.[43] There will be occasional opportunities to trim compliance-related spending, as mentioned later in this section, but it will not likely be a major source of savings. Significant cuts to non-regulatory capital requirements such as the PRP can significantly undermine system viability, and while cuts should be explored to certain non-mandated investment areas, the immediate impact of such cuts would be significantly less impactful, from today's ratepayer's perspective, than direct cuts to expenses.

As Figure 10.1 shows, labor-related costs account for 25% of the Power System Revenue Requirement for FY 2013 (with an additional 4.6% of past labor costs being accounted for in depreciation)[44] and 63% of the total O&M costs over the next five years. So that needs to be a major focus of LADWP. Some of the options for reducing these figures include reducing headcount, salaries, and/or healthcare and pension costs.

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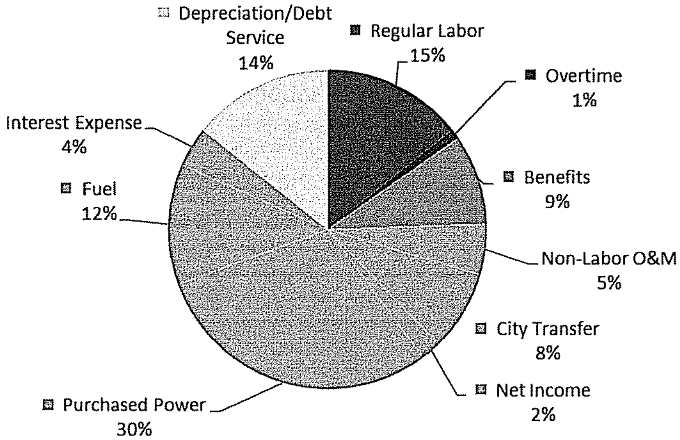
[43] Penalties for non-compliance remain uncertain under some regulations. Although the ultimate penalties may not always be so punitive to render non-compliance a non-option, the assumption for the purposes of this review is that LADWP intends to comply where possible with all regulatory mandates. Having already leveraged most of the cost effective technology choices available, it is likely that the bulk of the Department's cost cutting will have to take place elsewhere.

[44] As cited in LADWP's presentation of its "Final Budget Fiscal Year 2012-2013" to its Board, "approximately 33% of depreciation is past labor-related costs". These past labor costs are part of past capital projects and are therefore sunk costs.

Figure 10.1: Labor Costs in the Allocation of Power Costs, FY 2012-13



The ability to cut labor-related expenses will be constrained in the short term though. Salary levels, benefits and a share of overtime are inscribed in the Memoranda of Understanding (MOU) between LADWP and its labor force. The most significant of these contracts does not expire before September 2014. PA believes that in the interim, LADWP and the City should prepare to renegotiate the terms of the MOU and makes a few recommendations in that respect:

- Salaries: PA recommends LADWP consider aligning its employees' salaries closer to those of their peers.

Regular labor, which accounts for 36% of the O&M budget in FY 2013, is expected to grow at 3.6% annually from FY 2013-2017. Though not increasing as rapidly as other sources of cost, this is by far the greatest individual source of controllable cost to LADWP. PA's benchmarking of LADWP salaries suggested wages at the Department are significantly higher than those of other market participants (see Section 9.2.1). Reducing labor costs by 10% would mean O&M reductions of $74 million annually and capital reductions of $42 million annually over the FY 2015-17 period.

- **Staffing levels and outsourcing**: **PA recommends that LADWP benchmark its staffing and outsourcing levels against that of its utility peers.**

The Department has indicated such an analysis has not been conducted. Another way of reducing "Regular Labor" costs is to reduce headcount and increase productivity. Staffing levels are high at LADWP. Shared Services, for example, is a larger part of the organization at LADWP than at most utilities. LADWP's Joint System has 3,479 full-time employees -- led by Customer Service (1,138) and Information Technology (IT) (428) -- accounting for nearly 40% of the Department's full-time staff. PA's Corporate and Shared Service benchmarking indicates that the average across U.S. utilities is 20%. Both Customer Service and IT functions, or significant parts thereof, are typically outsourced. However, given that every utility has a unique operating environment, PA would suggest a more detailed analysis to determine the overall benefit LADWP can gain by pursuing certain outsourcing strategies.

- **Overtime**: **PA recommends a review of overtime expenses allocation, as well as a review of LADWP's contractual requirements that have an impact on overtime** (such as premiums for odd hour shifts and implications associated with outsourcing), described below.

Current overtime levels of 1% of Power Revenue Requirement equate to $31 million annually. Overtime costs also represent 4% of total O&M costs for FY 2013, or more than 10% of total labor costs.

- Several functions accumulate a large amount of overtime despite a relatively small regular labor bill. For example, energy control operations account for 3% of the regular labor expenses but 9% of the total labor overtime costs.
- Other functions show the opposite effect -- distribution station O&M requires 7% of the regular labor O&M budget, but it only incurs less than 1% of the FY 2012 labor OT costs. These inconsistencies may be reasonable in some cases, but should be further examined.
- PA believes LADWP could potentially reduce its overtime costs through creative scheduling, such as by shifting more daily employees to odd hour shifts. But the MOU limits the appeal of that option by enforcing a 4-7% salary premium for odd hour shifts.

- **Benefits: Undertake a benefits review and benchmark LADWP's benefits versus IOUs, other munis, cooperatives, City Departments, or public utilities or entities (if not yet completed)**

Benefits account for a significant proportion of the FY 2013 O&M budget and are expected to grow at 3.2% annually from 2013-2017. Benefits include health care plan and pensions contributions.

- At least half of LADWP active employees do not contribute a co-pay when visiting a physicians' office.[45] By introducing a $25 office visit co-pay and $15 prescription co-pay, the Department could save $5 million annually in 2016 and 2017.
- Increasing employee contribution premiums to 20% could save $35-40 million per year over the same years.
- PA reviewed LADWP's pension plan. LADWP's plan is broadly similar to the City's. Like most public pension plans it is underfunded, but it is less underfunded than the City's. One major difference is that LADWP's plan includes increased benefits for those who retire after reaching age 55 and 30 years of service. The Department's pension plan also suffered a significant cost when a large number of City employees were transferred to LADWP in 2010. By increasing the employee contribution from 6% to 7%, the Department could save $5-10 million per year from 2013-2017.

Other Costs of Running the System

The Department could find greater efficiency by pursuing process improvement efforts across a range of practices. PA has seen no evidence that sweeping process improvement programs have been considered. Appropriate studies should be completed to identify the cost reduction potential associated with a range of process improvements.

Capital Investment Controls

In trying to reduce costs, the Department has focused on reducing its O&M budget or shifted these costs to capital, changes that yield the largest near-term rate impacts. However, as O&M costs growth slows, capital spending rates are accelerating, fueled by increased borrowing. The costs of borrowing are felt for

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[45] As explained by LADWP in its response to a PA inquiry on co-pay, "All plans except Kaiser, IBEW Local 18 and UHC Owens Valley have a co-pay ranging from $3.00-$25.00 for office physician visits". The Department also noted, "Approximately 50% of the active employees are enrolled in the IBEW-Local 18 plan which is administered separately by the IBEW-Local 18 Health and Welfare Trust."

years and cannot be easily reduced. If not brought under control, the Department's debt service obligations will seriously hamper the Department's flexibility in future years. The Power System capital plan calls for over $1 billion in annual capital expenditures over the next five years. There are limited options for reducing capital costs immediately, but there may be options to reduce these costs over time.

- **Minimize the cost of mandated capital expenditures**

Where possible, minimize the cost of mandated capital expenditures through use of the most cost-effective options or negotiation of less expensive options for compliance with regulatory and legislative mandates (unless compelling reasons not to do so can be presented). The Department appears to have well-thought out RPS and OTC compliance plans, but might find opportunities in other areas, such as DSM.

- **Minimize the cost and maximize the effectiveness of all capital expenditures by requiring comprehensive analyses of any capital investment and benchmarking activities against peers**

– PA recommends that the Power System adopt a more methodical approach to assessing and communicating the viability of new investments, an important effort that has been practiced more effectively in the Water System. PA has not seen a consistent emphasis on least-cost alternative choices, or on rigorous justification of the choice of alternatives that are not least-cost. All evaluations should include the consequences of inaction, alternatives considered, and cost-benefit analysis. Any non-mandated projects that cannot be shown to reduce costs or increase revenue collection should not be undertaken without further review.

– Conduct an independent benchmarking assessment of the cost per plant and technology for the OTC repowering program to ensure that costs are reasonable on a per MW basis. A similar benchmarking effort should be conducted for the Power Reliability Program.

– Non-mandated capital expenditures, excluding DSM, represent $730 million in capital costs annually over the next 5 years. PA recommends benchmarking non-mandated capital expenditure levels, such as the PRP's, against peer utilities. Every utility and its infrastructure have different needs at different times, so the overall level of spending may not be too informative. But benchmarking of individual cost areas will help identify sources of relative overinvestment.

- **Make sure DSM targets are established according to the latest findings on the potential of cost effective programs and that savings are verified**

PA recommends that the Department set a firm three-year plan for energy efficiency, similar to that of the other large California utilities, that plans expenditure levels at a realistically achievable tempo according to cost effectiveness measurements and includes savings verification. PA believes this to be in keeping with the spirit of AB 2021, and believes that attempts to arbitrarily accelerate spending would not be in the best economic interest of the Department and its ratepayers.

<u>Reconsider Cost of Maintaining Financial Metrics</u>

- **Finally, PA recommends considering the costs and benefits of a ratings downgrade.**

During its financial planning process the Department focuses on three main financial metrics, each established with the advice of financial advisors to protect the Department's AA- rating: debt service coverage ratio of 2.25x, maintaining an unrestricted cash balance (the higher of $300 million unrestricted cash or 110 days of operating expenses, including the Debt Reduction Trust Fund); and a capitalization ratio of 68% maximum.

PA has no reason to question these metrics themselves, but advises that the City work with its financial advisor, if it hasn't already, to perform further analysis into whether the interest expense savings facilitated by maintaining the Power System's AA- rating, as well as the magnitude of the savings themselves, merit the annual cost of meeting the financial metrics needed to avoid a downgrade. While the current LADWP leadership is committed to maintaining the AA- rating, the objective does not appear to drive the financial plan to the extent it did under leadership in past years.

Appendix A: Power System Financial Plan Summary

Case P89 - FY2013 Final Budget

LOS ANGELES DEPARTMENT OF WATER AND POWER
Power System Financial Plan Summary
(In Million Dollars)

Fuel Case -->	05/14/12
O&M Case -->	05/16/12

Restructuring Delay -->	3	Months
Base Rate Incr % -->	5.2%	
ECAF Rate Incr % -->	0.6%	
RCAF Rate Incr % -->	0.7%	
	6.5%	

Rate Stabilization Fund:

	Drawdown	Inject	Balance
FY2010/11	$0 M	$0 M	$75 M
FY2011/12	$0 M	$0 M	$75 M
FY2012/13	$13 M	$0 M	$62 M
FY2013/14	$36 M	$0 M	$0 M
FY2014/15	$0 M	$0 M	$26 M
FY2015/16	$0 M	$0 M	$26 M
FY2016/17	$0 M	$0 M	$26 M

-- Excluding Load Growth Effect --						
Base Rate Actual Adj %	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
ECA Actual Adj %	0.3%	0.3%	0.0%	0.0%	0.0%	0.0%
RCA Actual Adj %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
ESA Actual Adj %	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
I-Base Inc %	0.0%	3.5%	2.4%	3.8%	3.0%	2.3%
I-ECA Inc %	0.0%	0.5%	2.6%	3.1%	3.5%	2.5%
I-RCA Inc %	0.0%	0.6%	1.0%	1.1%	1.0%	1.0%
I-Increase %	0.0%	4.80%	6.00%	7.95%	7.50%	5.80%
Base Revenue Inc $M	5	1	0	1	0	-1
ECA Revenue Inc $M	8	8	0	0	0	0
RCA Revenue Inc $M	0	0	0	0	0	0
ESA Revenue Inc $M	0	0	0	0	0	0
I-Base Inc $M	0	103	74	124	105	86
I-ECA Inc $M	0	14	80	100	121	95
I-RCA Inc $M	0	16	31	35	36	36
I-Revenue Inc ($M)	0	134	184	259	262	217
			3-Yr Avg ->	6.2%	5-Yr Avg ->	6.4%

	Final	Final	Revised	<------- FORECAST ------->					
FISCAL YEAR ENDING JUNE 30	2010	2011	2012	2012	2013	2014	2015	2016	2017
1. Retail Sales (GWh)	23,319	23,064	23,344	23,123	23,471	23,600	23,897	24,129	24,381
Adj. For DSM (GWh)	0	0	(73)	0	(133)	(414)	(712)	(1,019)	(1,349)
Adj. For Solar (GWh)	0	0	(15)	0	(23)	(74)	(114)	(152)	(180)
Adj. due to Others (GWh)	0	0	0	0	0	0	0	0	0
Net Retail Sales(GWh)	23,319	23,064	23,256	23,123	23,315	23,113	23,071	22,958	22,852
2. Operating Revenue:									
Base Rate	1,583	1,561	1,582	1,570	1,584	1,571	1,569	1,561	1,553
Base Rate Revenue Increases	0	0	0	0	0	0	0	0	0
Energy Cost Adjustment	1,155	1,278	1,305	1,290	1,308	1,297	1,295	1,288	1,282
Energy Subsidy Adjustment	0	0	0	0	0	0	0	0	0
Reliability Costs Adjustment	67	73	74	73	74	73	73	73	72
I-Base Revenue	0	0	0	0	103	176	300	403	488
I-ECA Revenue	0	0	0	0	14	94	194	314	407
I-RCA Revenue	0	0	0	0	16	47	82	118	153
Total Retail Revenue ($M)	2,806	2,913	2,960	2,933	3,101	3,258	3,512	3,757	3,955
Wholesale Sales (Gen. & Trans.)	126	84	59	63	53	56	62	62	63
Deferred Revenue	310	135	102	111	(9)	43	(42)	0	(33)
Others	(7)	(6)	19	3	(3)	6	4	3	2
Total Operating Revenue ($M)	3,235	3,126	3,141	3,111	3,141	3,363	3,537	3,822	3,987
3. Non-Operating Revenue	131	123	119	109	97	97	100	302	115
4. Total Revenue	3,367	3,249	3,260	3,220	3,238	3,460	3,637	4,124	4,102
5. Fuel-Related Expenditures									
5a. Fuel and Purchased Power Expense	1,310	1,290	1,327	1,347	1,299	1,369	1,393	1,511	1,513
5b. Legal Settlement Expense	0	0	0	0	0	0	16	16	16
5c. Legal Expense Allocated to FPP	0	0	3	3	0	0	0	0	0
5c. CO2 Allowance Expenses	0	0	0	0	1	2	7	5	0
5d. Other Emissions Expenses	0	0	9	3	5	5	7	7	8
6. O&M Expenditures									
6a. DSM	45	45	15	18	0	0	0	0	0
6b. Other Infrastructure	279	250	252	251	265	274	289	291	288
6c. Operating Support	229	242	278	281	289	319	327	337	347
6d. PRP	363	393	347	348	357	373	392	411	437
6f. Public Benefits	23	39	5	1	2	2	2	2	2
6g. RPS	26	26	25	26	27	29	31	32	32
6h. PRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0
6i. Non-PRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0
6j. Pension Adj	0	0	0	0	0	0	0	0	0
6k. COLA Adj	0	0	0	0	0	0	0	0	0
6l. RPS Adj	0	0	0	0	0	0	0	0	0
6k. O&M Expenditures Total	965	995	921	926	940	997	1,041	1,073	1,106
7a. Depreciation	338	387	422	393	439	454	468	499	543
7b. Regulatory Asset - Solar SB-1	0	0	3	3	6	10	11	12	12
7c. Regulatory Asset - EE	0	0	4	5	17	29	42	56	72
8. Property Tax	12	12	13	12	14	15	17	18	20
9a. Interest Expense	220	288	281	280	285	328	381	434	476
9b. AFUDC	(8)	(12)	(36)	(31)	(52)	(35)	(48)	(28)	(5)
9c. CIAC	(13)	(28)	(13)	(23)	(15)	(16)	(16)	(17)	(18)
10. Total Expense	2,825	2,932	2,934	2,919	2,939	3,159	3,318	3,588	3,743
11a. Net Income Before City Transfer	542	316	325	301	299	301	319	536	359
11b. City Transfer	220	259	250	250	249	251	269	283	306
11c. Increase In Fund Net Assets	322	58	75	51	50	50	50	253	53
12. Capital Expenditures									
12a. DSM	2	2	55	55	127	138	143	152	180
12b. Gas Drilling	15	60	51	51	20	0	0	0	0
12c. Other Infrastructure	87	88	87	106	195	134	117	123	103
12d. IRP	13	201	407	396	428	402	109	489	22
12e. Operating Support	94	117	114	89	96	77	63	48	50
12f. PRP	446	419	361	360	427	512	539	567	590
12g. Public Benefits	0	0	0	0	0	0	0	0	0
12h. RPS	90	23	186	181	150	388	293	175	522
12i. PRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0
12j. Non-PRP Adds/(Cuts)	0	0	0	0	0	0	0	0	0
12k. Pension Adj	0	0	0	0	0	0	0	0	0
12l. COLA Adj	0	0	0	0	0	0	0	0	0
12l. Net Capital Expenditures Total	747	911	1,261	1,238	1,444	1,650	1,265	1,555	1,467
13a. Borrowing for CapEx	616	900	0	0	1,131	1,238	866	774	964
13b. Cash on Hand	424	561	264	322	309	300	300	300	300
13c. Total Debt Service	318	400	348	344	422	467	530	591	644
13d. Total Non-Debt Service Expenditures	3,022	3,180	3,522	3,507	3,888	4,023	3,714	4,154	4,096
14. Financial Ratios:									
Debt Service Coverage, net of BABs Subsidy	2.49	2.13	2.78	2.57	2.59	2.40	2.42	2.32	2.42
Adj. Debt Service Coverage, net of IPA Debt	2.12	1.90	1.90	2.13	2.02	1.91	1.89	1.83	1.83
Full Obligation Coverage, net of IPA Debt	1.63	1.44	1.77	1.65	1.64	1.57	1.58	1.54	1.54
Capitalization Factor	53.6%	56.5%	55.6%	55.7%	59.1%	62.2%	63.8%	64.2%	65.8%
15. Average Rate (cts/kWh)									
System Average	12.0	12.6	12.7	12.7	13.3	14.1	15.2	16.4	17.3
Avg. Rate Increase (%)	7.2%	4.9%	0.8%	0.5%	4.8%	6.0%	8.0%	7.5%	5.8%
16a. ECA (Under) Over Collection	(208)	(203)	(205)	(221)	(179)	(166)	(133)	(141)	(107)
16b. RCA (Under) Over Collection	(42)	(91)	(95)	(94)	(95)	(89)	(80)	(73)	(74)
16c. Barakat Settlement Balance	160	160	160	160	160	160	144	128	112

Appendix B: Salary Benchmarking

Table B.1: Variance from Market Salaries in Distribution Positions

Variance from Market Salaries in Distribution Positions													
Database Job Categories	Database Average of Maximum Annual Salaries	LADWP Weighted Average of Maximum Salaries	LADWP Weighted Average Salaries (by number of employees)	LADWP Average Annual Salaries	LADWP Median Annual Salaries	LADWP Annual Salary Range		LADWP Matched Job Categories	Number of Positions	Variance between LADWP Weighted Avg Salaries and Database Avg Max Salaries	Variance between LADWP and Database Max Salaries Averages	Variance between LADWP Weighted Max Salaries and Database Max Salaries' Avg	Variance between LADWP Median and Database Avg Maximum Salaries
						Low	High						
Engineer	109,310	147,819	137,433	138,861	142,193	129,469	145,337		116	26%	33%	35%	30%
Engineer - Select Group	105,654			138,861	142,193					30%	38%	40%	35%
				138,435	138,435	134,676	142,193	CIVIL ENGINEER	8				
				137,044	142,193	108,242	151,505	ELECTRICAL ENGINEER	57				
				141,824	142,193	134,676	148,603	MECHANICAL ENGINEER	19				
				142,193	142,193	142,193	142,193	STRUCTURAL ENGINEER	2				
				134,808	134,676	127,556	142,193	WATERWORKS ENGINEER	30				
Designer	80,605	92,654	91,538	90,324	91,027	86,412	93,532		23	14%	16%	15%	13%
Designer - Select Group	84,581			90,324	91,027					8%	11%	10%	8%
				92,185	92,185	92,185	92,185	ENGINEERING DESIGNER	19				
				88,462	89,868	80,639	94,879	GRAPHICS DESIGNER	4				
Engineering/Design Technician or Analyst	82,145	86,696	78,346	77,976	78,483	71,893	83,005		130	-5%	1%	6%	-4%
Engineering/Design Technician or Analyst - Select Group	79,967			77,976	78,483					-2%	4%	8%	-2%
				84,543	84,543	84,543	84,543	ARCHITECTURAL DRAFTING TECHNICIAN	5				
				76,275	77,434	60,489	86,401	CIVIL ENGINEERING	79				

Variance from Market Salaries in Distribution Positions													
Database Job Categories	Database Average of Maximum Annual Salaries	LADWP Weighted Average of Maximum Salaries	LADWP Weighted Average Salaries (by number of employees)	LADWP Average Annual Salaries	LADWP Median Annual Salaries	LADWP Annual Salary Range		LADWP Matched Job Categories	Number of Positions	Variance between LADWP Weighted Avg Salaries and Database Avg Max Salaries	Variance between LADWP and Database Max Salaries Averages	Variance between LADWP Weighted Max Salaries and Database Max Salaries' Avg	Variance between LADWP Median and Database Avg Maximum Salaries
						Low	High						
								DRAFTING TECHNICIAN					
				62,369	62,369	62,369	62,369	DRAFTING AIDE	3				
				78,166	79,532	71,347	84,543	ELECTRICAL ENGINEERING DRAFTING TECHNICIAN	18				
				77,689	77,434	71,347	84,543	MECHANICAL ENGINEERING DRAFTING TECHNICIAN	7				
				88,813	89,179	81,265	95,630	OFFICE ENGINEERING TECHNICIAN	18				
Journeyman lineman	78,023	109,266	93,505	92,196	94,602	64,540	107,960		668	20%	38%	40%	21%
Journeyman lineman - Select Group	80,095			92,196	94,602					17%	35%	36%	18%
				102,609	104,766	78,008	118,348	ELECTRIC DISTRIBUTION MECHANIC	376				
				81,783	84,439	51,072	97,572	ELECTRICAL MECHANIC	292				
Apprentice lineman	62,878	93,177	80,226	77,064	78,154	52,994	89,805		139	28%	43%	48%	24%
Apprentice lineman - Select Group	59,904			77,064	78,154					34%	50%	56%	30%
				83,624	81,996	71,744	96,800	ELECTRIC DISTRIBUTION MECHANIC TRAINEE	103				
				70,503	74,312	34,243	82,810	LINE MAINTENANCE ASSISTANT	36				
Groundman/utility worker	54,092	76,937	62,421	61,788	62,014	40,447	76,465		795	15%	41%	42%	15%
Groundman/utility worker - Select Group	68,944			61,788	62,014					-9%	11%	12%	-10%
				56,566	59,759	23,615	73,414	ELECTRICAL CRAFT	291				

Variance from Market Salaries in Distribution Positions													
Database Job Categories	Database Average of Maximum Annual Salaries	LADWP Weighted Average of Maximum Salaries	LADWP Weighted Average Salaries (by number of employees)	LADWP Average Annual Salaries	LADWP Median Annual Salaries	LADWP Annual Salary Range		LADWP Matched Job Categories	Number of Positions	Variance between LADWP Weighted Avg Salaries and Database Avg Max Salaries	Variance between LADWP and Database Max Salaries Averages	Variance between LADWP Weighted Max Salaries and Database Max Salaries' Avg	Variance between LADWP Median and Database Avg Maximum Salaries
						Low	High						
								HELPER					
				87,613	87,613	84,961	90,264	EQUIPMENT OPERATOR	81				
				73,138	77,987	48,066	88,510	HEAVY DUTY EQUIPMENT MECHANIC	96				
				63,426	69,959	44,119	77,068	HEAVY DUTY TRUCK OPERATOR	90				
				58,781	60,395	36,206	73,414	MAINTENANCE CONSTRUCTION HELPER	192				
				32,879	29,483	9,745	59,174	MAINTENANCE LABORER	24				
				60,114	62,014	36,415	73,414	MECHANICAL HELPER	21				
Cable splicer	76,694	109,599	104,156	104,156	104,191	98,679	109,599		28	36%	43%	43%	36%
Cable Splicer - Select Group	78,027			104,156	104,191					33%	40%	40%	34%
				104,156	104,191	98,679	109,599	UG DISTRIBUTION CONSTRUCTION SUPERVISOR	28				
Technician/Shop	67,807	92,352	84,519	83,127	84,795	74,813	92,018		112	25%	36%	36%	24%
Technician/Shop - Select Group	90,545			83,127	84,795					-7%	2%	2%	-8%
				87,999	87,926	82,956	93,187	ELECTRICAL TESTER	72				
				78,256	79,574	66,670	90,849	LABORATORY TECHNICIAN	40				
Tree trimmer	69,682	82,601	78,314	78,314	78,237	74,103	82,601		31	12%	19%	19%	12%
Tree Trimer - Select Group	71,599			78,314	78,237					9%	15%	15%	9%
				78,314	78,237	74,103	82,601	TREE SURGEON	31				

Variance from Market Salaries in Distribution Positions													
Database Job Categories	Database Average of Maximum Annual Salaries	LADWP Weighted Average of Maximum Salaries	LADWP Weighted Average Salaries (by number of employees)	LADWP Average Annual Salaries	LADWP Median Annual Salaries	LADWP Annual Salary Range		LADWP Matched Job Categories	Number of Positions	Variance between LADWP Weighted Avg Salaries and Database Avg Max Salaries	Variance between LADWP and Database Max Salaries Averages	Variance between LADWP Weighted Max Salaries and Database Max Salaries' Avg	Variance between LADWP Median and Database Avg Maximum Salaries
						Low	High						
Admin	70,562	70,509	63,090	61,106	53,557	56,451	67,144		185	-11%	-5%	0%	-24%
Admin - Select Group	72,202			61,106	53,557					-13%	-7%	-2%	-2[illegible]
				45,075	44,955	36,206	54,184	CLERK	24				
				53,656	53,557	50,843	56,668	CLERK TYPIST	83				
				51,205	49,423	47,523	56,668	DELIVERY DRIVER	8				
				43,013	43,013	43,013	43,013	MESSENGER CLERK	2				
				69,008	69,008	69,008	69,008	MANAGEMENT AIDE	1				
				83,558	81,839	73,226	97,134	UTILITY ACCOUNTANT	47				
				82,226	78,008	75,335	93,334	SECRETARY LEGAL	20				

Table B.2: Variance from Market Salaries in Customer Service Positions

Variance from Market Salaries in Customer Service Positions											
Database Job Categories	**Database Average Annual Salaries**	**LADWP Weighted Average Annual Salaries (by number of employees)**	**LADWP Average Annual Salaries**	**LADWP Median Annual Salaries**	**LADWP Annual Salary Range**		**LADWP Matched Job Categories**	**Number of Employees in Position**	**Variance between LADWP Average and Database Average Salaries**	**Variance between LADWP Median and Database Average Salaries**	**Variance between LADWP Weighted Average and Database Average Salaries**
					Low	**High**					
Field Service Representative	63,523	74,353	80,758	83,077				164	27%	31%	17%
Field Service Representative - Select Group	62,291		80,758	83,077					30%	33%	19%
			67,948	72,642	46,771	77,527	COMMERCIAL FIELD REPRESENTATIVE	123			
			93,569	93,511	86,172	101,080	ELECTRIC SERVICE REPRESENTATIVE	41			
Contact Center Representative	45,904	55,519	55,519	59,529				626	21%	30%	21%
Contact Center Representative - Select Group	46,294		55,519	59,529					20%	29%	20%
			55,519	59,529	32,364	75,335	CUSTOMER SERVICE REPRESENTATIVE	626			
Meter Readers	41,373	61,005	61,005	65,156	38,252	77,736		176	47%	57%	47%
Meter Readers - Select Group	**41,716**		**61,005**	**65,156**					**46%**	**56%**	46%
			61,005	65,156	38,252	77,736	METER READER	176			

Appendix C: Financial Planning Scenarios

PA requested that the Department generate 12 different scenarios to determine the savings from various cost cutting activities and the possible impact related to external factors. These 12 scenarios are listed in Table C.1 below. The analyses provided below are based on five years of financial results provided by the Department at PA's request. Observations for the three fiscal years beyond Fiscal Years 2013 and 2014 should only be considered preliminary and the scenarios should not be considered endorsed or supported by the Department.

Table C.1: List of Scenarios

Scenarios	System Average Rate Increase		
	Increase in FY 2013	Increase in FY 2014	Avg Increase (2013-2017)
Reference Case	4.8%	6.0%	6.4%
Cost Reduction Considerations			
1. Cuts to health plan	4.8%	5.9%	6.3%
2. 10% cut to labor costs	4.8%	6.0%	5.9%
3. Cuts to pension plan	4.7%	6.0%	6.4%
4. Cuts to health and pension plan and 10% labor costs	4.7%	5.9%	5.7%
5. Reduce the incremental rate increase by 20%	3.8%	4.8%	5.1%
6. Freeze Non-Mandated Spending	3.5%	4.3%	4.0%
7. Stop RPS spending	4.4%	4.8%	5.3%
8. Reduce DSM goal to 8.6%	4.5%	5.6%	6.1%
9. No Rate Increase	0.3%	0.0%	0.1%
External Factor Sensitivities			
10. High natural gas price	4.8%	6.6%	6.9%
11. High interest rates	5.0%	6.5%	6.9%
12. Extended Palo Verde outage	6.3%	6.3%	6.4%

Rate impacts for each scenario associated with cost reduction considerations are graphed in Figure C.1. Impacts to ratepayers due to external factors are provided in Figure C.2. The detailed discussion for each scenario is provided in the subsequent sections.

Figure C.1: System Average Rates - Cost Reduction Considerations Scenarios

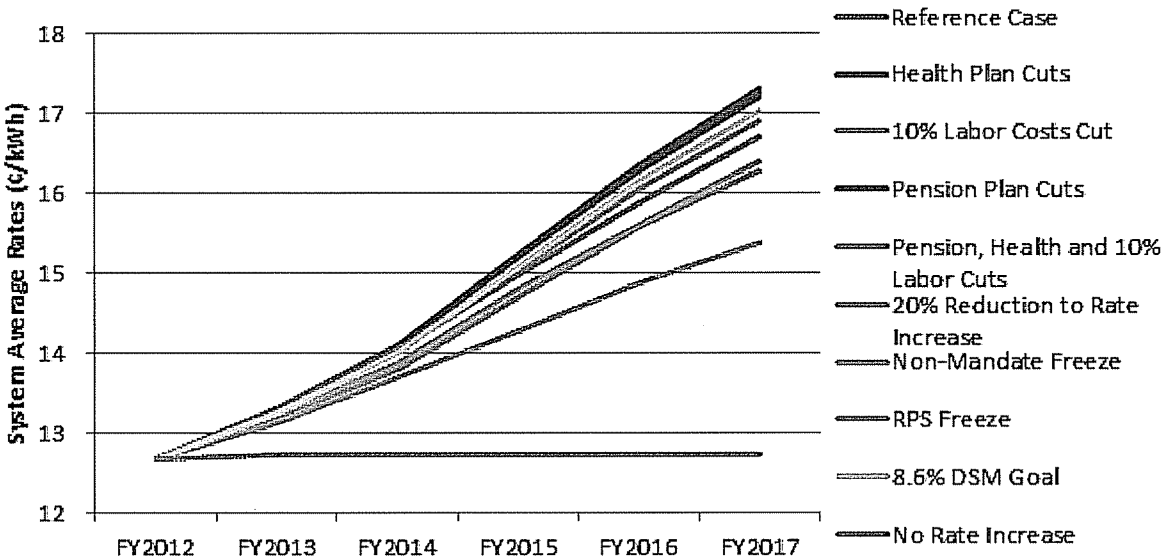
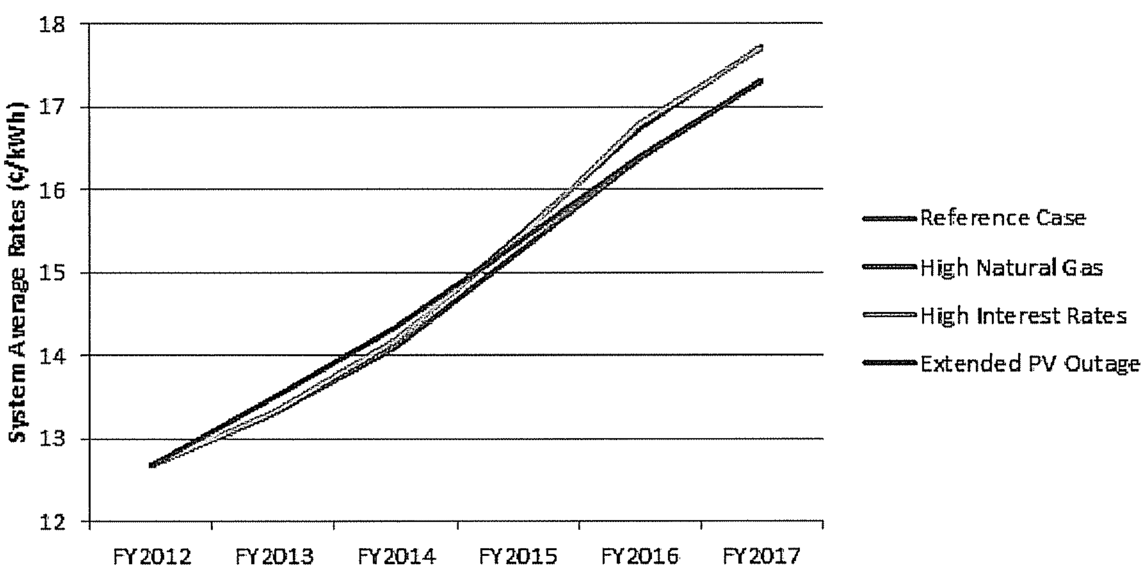


Figure C.2: System Average Rates - External Factor Sensitivities



C.1 Cuts to Health Plan

Cuts to Health Plan Scenario

Description

Existing:

0% employee contribution

Kaiser and IBEW sponsored plans: no co-pay

Other LADWP sponsored plans: $3-$25 co-pay

Scenario Assumptions:

20% employee contribution, co-pays of $25 for office visits and $15 for prescription starting in FY 2014 (to be consistent with the expected timing of a renegotiated labor contract).

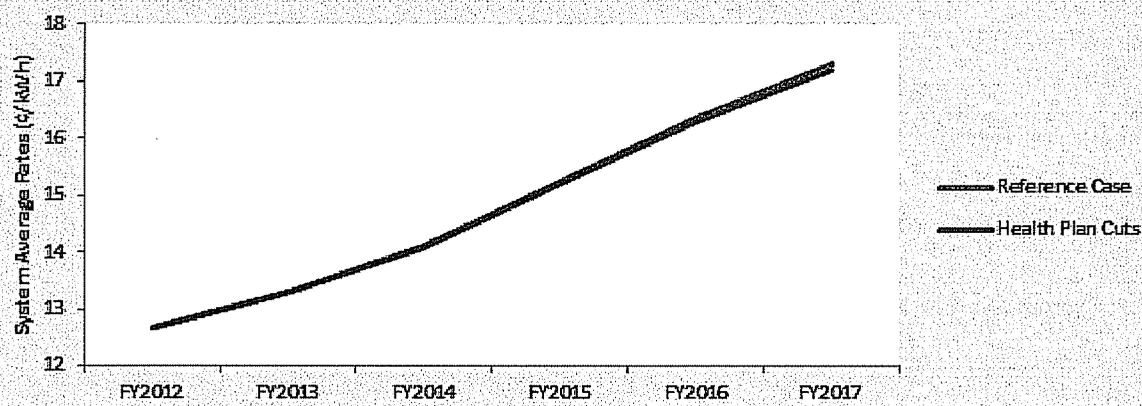
Key Findings:

- The majority of the savings will be in effect starting in FY 2016 since the IBEW Local 18 contract does not expire until September 2014.
- More than 88% of the savings are driven by the 20% employee contribution.

Revenue Requirement Savings:

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Retail Revenue Increase/(Savings) ($M)	(0)	(3)	(4)	(22)	(26)

Rate Impact:



The Department incurs all 100% of the contribution costs for its sponsored health plans. This scenario assumes the Department will cut its employees' health benefit plan by implementing the following new policy of 20% employee contribution, co-pays of $25 for office visits and $15 for prescriptions. However, since health benefit-related items are governed under labor contracts, it is assumed that contract negotiations are required before these changes can occur. The following implementation schedule for this scenario has been provided by the Department, based on the labor contract negotiation cycle:

- 20% of all employees and retirees starting on July 1, 2013.
- 100% of all employees and retirees starting on July 1, 2015.

Key considerations with respect to this scenario include:

- The cuts to health benefit costs will not result in a dollar-for-dollar rate reduction. LADWP's cost structure consists of both O&M and capital expenses -- savings from cuts to the latter accrue over a period of many years, not in the year they're made.
- The impacts to the Department's healthcare costs are documented in the following Table C.2.

Table C.2: Health Plan Cost Savings Breakdown[46]

	FY2013	FY2014	FY2015	FY2016	FY2017
20% Employee Contribution Savings	0	6.4	6.9	36.4	39.4
$25 Office Visit Co-pay Savings	0	0.5	0.5	3.0	3.1
$15 Prescription Co-pay Savings	0	0.3	0.3	1.9	1.9

[46] Table provided by LADWP as part of the Scenario-Impact on rates of Health Care Plan Revisions write-ups.

Total Savings (O&M + Capital)	0	7.3	7.8	41.3	44.3

The cuts to the health benefits plan will reduce O&M and capital expenses by more than $70M[47] and $30M, respectively, over the next five years. The overall impact to the ratepayer is a total of $54M decrease in retail revenue requirement over the five year period.

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
O&M Expenses ($M)	0.0	(5.1)	(5.5)	(28.9)	(31.0)
Capital Expenditures ($M)	0.0	(2.2)	(2.4)	(12.4)	(13.3)
System Average Rate (¢/kWh)	(0.00)	(0.01)	(0.02)	(0.09)	(0.11)

C.2 10% Cut to Labor Costs

10% Cut to Labor Costs Scenario

Description

Existing:
Currently regular labor and overtime expenses account for 25% of Power System O&M and capital expenditures.

Scenario Assumptions:
A10% cut to labor costs will be implemented starting in FY 2014, consistent with the labor contract negotiation cycle.

Key Findings:

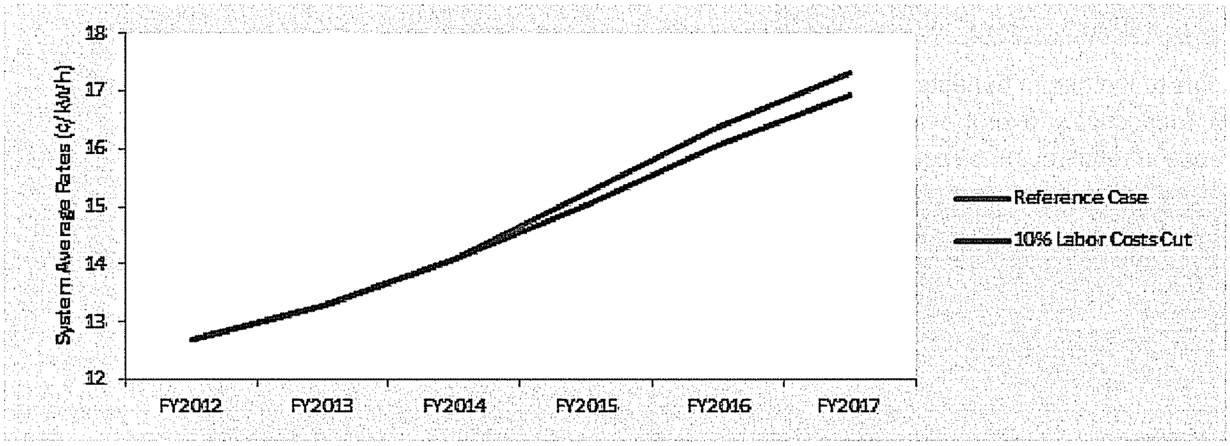
- A 10% cut to labor costs will reduce the retail revenue requirement by 1 to 2%. Since 55% of regular and overtime labor expenses fall under capital expenditures, cuts to labor costs will not result in a dollar-for-dollar rate reduction.

Revenue Requirement Savings:

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Retail Revenue Increase/(Savings) ($M)	(0)	0	(44)	(68)	(90)

Rate Impact:

[47] Cuts to O&M will also not result in dollar-to-dollar savings for the ratepayers on the current year basis. Part of the savings will be used to reduce RCA and/or ECA under collection accumulated over the past years.



Currently, regular labor and overtime costs account for a quarter of the Department's O&M and capital expenses. A 10% cut to labor costs will be implemented, with the nature of the cuts left to the Department's discretion. Potential cost reduction actions include, but are not limited to, salary reduction, work force reduction, and increased outsourcing.

Key considerations with respect to this scenario include:

- Since the majority of the fuel and purchased power expenses are non-labor related, the rate reductions only consists of decreases in i-Base and i-RCA.
- Since labor costs are governed under labor contracts, it is assumed that contract negotiations are required before these changes can occur. Based on the labor contract negotiation cycle, cuts to labor costs will not be in effect until July 2014.
- Cuts to labor costs will not result in a dollar-for-dollar rate reduction since LADWP's cost structure consists of O&M and capital expenses.

The cuts to labor costs scenario will reduce O&M and capital expenses by more than $223M and $125M respectively over the next five years. The overall impact to the ratepayer is $203M decrease in retail revenue requirement over the five year period.

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
O&M Expenses ($M)	0.0	0.0	(74.2)	(74.2)	(74.2)
Capital Expenditures ($M)	0.0	0.0	(41.6)	(41.6)	(41.6)
System Average Rate (¢/kWh)	(0.00)	0.00	(0.19)	(0.30)	(0.39)

C.3 Cuts to Pension Plan

Cuts to Pension Scenario

Description

Existing:

LADWP employees contribute 6% of gross salary

Scenario Assumptions:

All new employees contribute 7% of gross salary towards pension plan to be consistent with other City's towards their pension plan. employees.

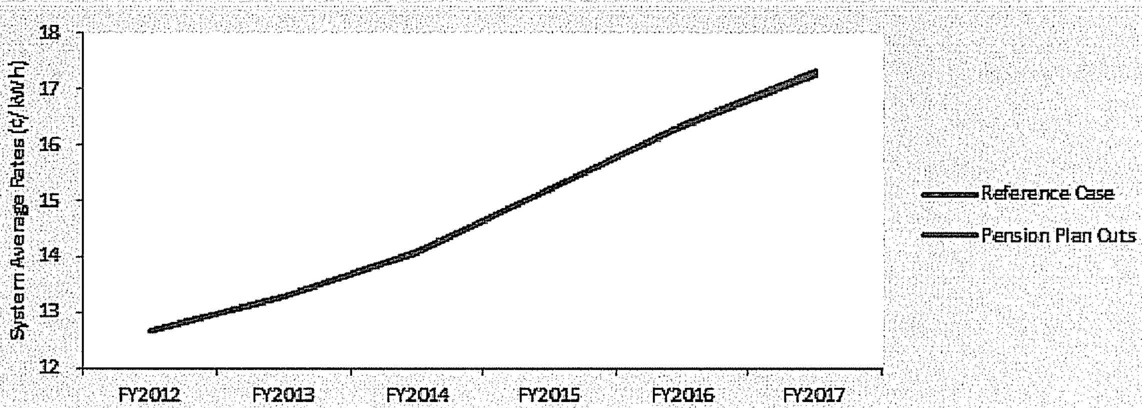
Key Findings:

- Adjusting the current pension plan will allow the Department to reduce its retail revenue requirements by approximately 0.3%.

Revenue Requirement Savings:

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Retail Revenue Increase/(Savings) ($M)	(5)	(5)	(5)	(9)	(12)

Rate Impact:



PA reviewed LADWP's pension plan and compared it with the pension plans for City's employees. One major difference is that LADWP's plan includes increased benefits for those who retire after reaching age 55 and 30 years of service. The Department's pension plan also suffered a significant cost when a large number of City employees were transferred to LADWP in 2010. This scenario gauges the financial impact to the ratepayer if all new Department employees received pension benefits similar to new employees at the City of LA or the Fire Department.

Cuts to pension plan will reduce O&M and capital expenses by $38M and $16M respectively from 2013-2017. The overall impact to the ratepayer is a $36M reduction in retail revenue requirement over the five-year period.

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
O&M Expenses ($M)	(6.5)	(6.7)	(7.0)	(7.3)	(10.9)
Capital Expenditures ($M)	(2.8)	(2.9)	(3.0)	(3.1)	(4.7)
System Average Rate (¢/kWh)	(0.02)	(0.02)	(0.02)	(0.04)	(0.05)

C.4 Cuts to Health and Pension Plan and 10% Labor Cuts

Cuts to Health and Pension Plan and 10% Labor Cuts Scenario

Description

Existing:

No additional labor-related cost cutting measures are proposed other than those in the 2011 cost reduction plan detailed in Section 3.

Scenario Assumptions:

LADWP implements all the labor-related cost cutting measures in the three scenarios detailed in Appendix C.1-C.3 (health plan cuts, 10% labor cost reduction, and pension cuts).

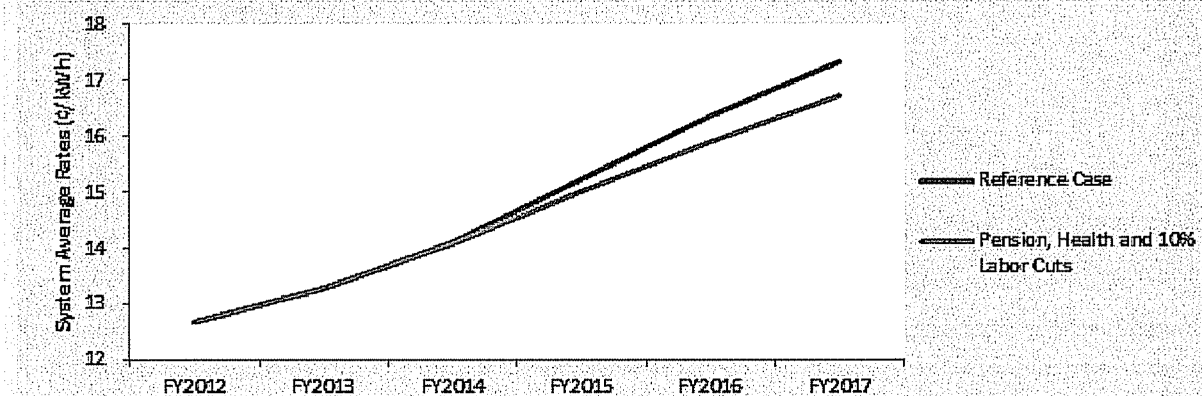
Key Findings:

- By implementing these three cost cutting measures at the same time, the Department will be able reduce its retail revenue requirements by more approximately 3% in FY 2016 and FY 2017.

Revenue Requirement Savings:

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Retail Revenue Increase/(Savings) ($M)	(5)	(8)	(54)	(111)	(136)

Rate Impact:



The three scenarios detailed in Appendix C.1-C.3 (health plan cuts, 10% labor cost reduction, and pension cuts) show that different labor-related cost cutting measures will have significantly different impact to ratepayers from magnitude and timing perspectives. This scenario examines the impacts to ratepayers of LADWP employing all three cost reduction efforts: 10% labor cut, lower health benefits, and pension cuts.

Cuts to health and pension plan and labor costs will reduce O&M and capital expenses by $332M and $171M respectively for the next five year. Reducing labor costs by 10% contributes more than two-thirds of the savings. The overall impact to the ratepayer is a $313M reduction in retail revenue requirement over the five year period.

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
O&M Expenses ($M)	(6.5)	(11.8)	(86.7)	(110.4)	(116.1)
Capital Expenditures ($M)	(2.8)	(5.1)	(46.9)	(57.1)	(59.5)
System Average Rate (¢/kWh)	(0.02)	(0.04)	(0.23)	(0.48)	(0.59)

C.5 Reduce the Incremental Rate Increase by 20%

Reduce the Incremental Rate Increase by 20% Scenario

Description

Existing:

The Department's Reference Case will cause an average increase of 6.4% per year over the next five years, according to preliminary projections.

Scenario Assumptions:

The Department will reduce its incremental rate increase by 20% without new borrowing and still meet all legally mandated compliance obligations.

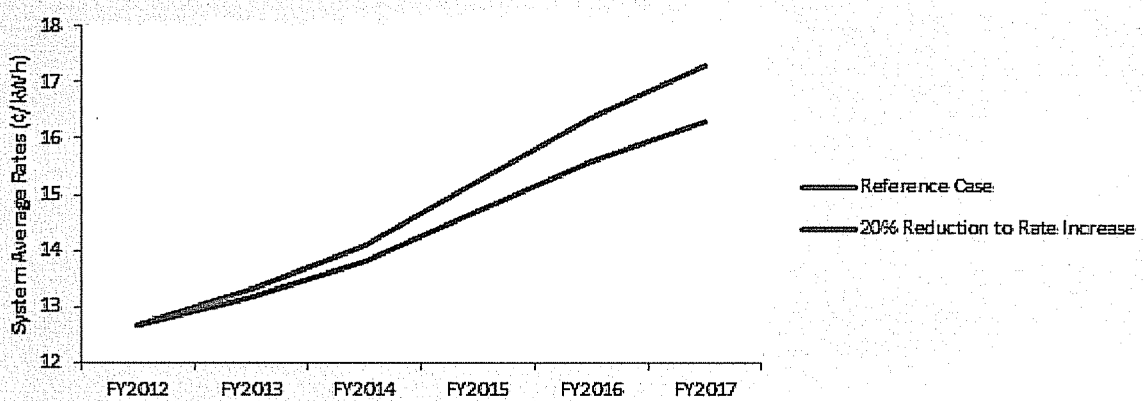
Key Findings:

- The Department will reduce its non-PRP related O&M spending by $588M over five-years.
- Capital expenses will not be impacted.

Revenue Requirement Savings:

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Retail Revenue Increase/(Savings) ($M)	(28)	(67)	(122)	(182)	(233)

Rate Impact:



The Department proposes an average of 6.4% rate increase per year from FY 2013 to FY 2017. Under this scenario, the proposed yearly rate increase in the Reference Case will be reduced by 20% without new borrowing, and the Department still needs to meet all legally mandated compliance obligations. The outcome of this scenario gauges not only the impact of the cost reduction but also the priority of all the non-mandated spending.

In order for the Department to meet the 20% reduction to the incremental rate increase, O&M expenses will be reduced by $588M in the form of reduction in non-PRP expenses. LADWP will not adjust its capital expenses because capital reductions would not provide a dollar-to-dollar reduction to the annual revenue requirement. In addition, new capital borrowing is not allowed, so the Department cannot capitalize other O&M expenses. The overall impact to the ratepayer is a total of $632M decrease in retail revenue requirement over the five year period. The Department has not provided a detailed list of impacted activities and the potential effect of the 20% reduction to the incremental rate increase. The Department has expressed its concern that reductions of this scale would severely impact customer service, reliability and the attainment of other utility objectives.

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
O&M Expenses ($M)	(28.0)	(64.0)	(116.0)	(167.0)	(213.0)
System Average Rate (¢/kWh)	(0.12)	(0.29)	(0.53)	(0.79)	(1.02)

C.6 Freeze Non-Mandated Spending

Freeze Non-Mandated Spending Scenario

Description

Existing:

The Department's Reference Case includes an average increase of 4% per year in non-mandated O&M spending -- which includes PRP, operating support, infrastructure reliability, and DSM -- over the next five years. Non-mandated CapEx will increase by an average of 9% per year over the same five year period.

Scenario Assumptions:

Starting in FY 2013, all non-mandated spending will be frozen at the lower of the approved FY 2012 level or the projected level in a given year according to Case 89.

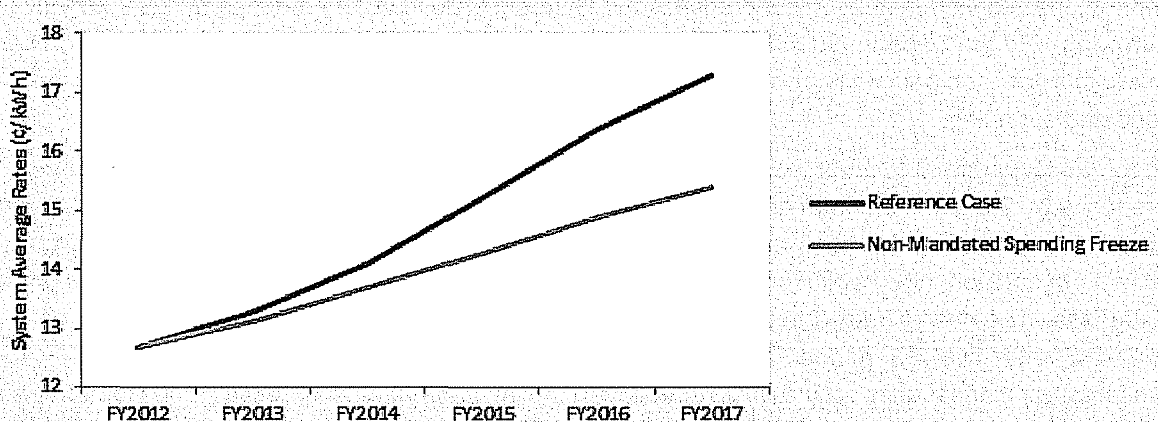
Key Findings:

- By freezing non-mandated spending at the FY 2012 level, ratepayers will experience an $802M reduction in the revenue requirement over the five-year period.
- If this scenario were feasible, the yearly system average rate increase would be within the 3.4 to 4.3% range over the next five years, well below the 4.8 to 8.0% annual increases projected under the Reference Case.
- Despite freezing 97% of its O&M spending, the Department will still see 3+% increase per year which indicates a significant portion of the rate increase is driven by debt service and depreciation resulting from past capital spending.

Revenue Requirement Savings:

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Retail Revenue Increase/(Savings) ($M)	(28)	(60)	(155)	(248)	(310)

Rate Impact:



Non-mandated spending includes PRP, operating support, infrastructure reliability and DSM expenses. Under the Reference Case, non-mandated expenses account for 97% of O&M expenses and 60% of total capital expenditures over the next five years. This scenario examines the results assuming the Department limited its future spending to only mandated items. The savings for each category are documented in Table C.3 below.

Table C.3: Freeze Non-Mandated Spending Savings by Category

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
PRP O&M ($M)	(9)	(25)	(44)	(63)	(89)
PRP CapEx ($M)	(67)	(152)	(179)	(207)	(230)
Operating Support O&M ($M)	(8)	(38)	(46)	(56)	(66)
Operating Support CapEx ($M)	(7)	0	0	0	0
Infrastructure Reliability O&M ($M)	(14)	(22)	(38)	(39)	(37)
Infrastructure Reliability CapEx ($M)	(89)	(28)	(11)	(17)	0
DSM CapEx ($M)	(72)	(83)	(88)	(97)	(125)

While the reduction in PRP, operating support, and infrastructure reliability spending may increase the maintenance backlog and slow down equipment replacement, detailed impacts to the system have not been provided by the Department. The lower level of DSM spending will likely prevent from meeting the Board's objective of 10% energy efficiency by 2020, but no penalty has been set for non-compliance. All DSM expenses will be capitalized, and therefore any spending freeze will not result in a dollar-for-dollar reduction from the annual revenue requirement perspective.

Freezing non-mandated spending will reduce O&M and capital expenses by $594M and $1,454M respectively for the next five year. The overall impact to the ratepayer is an $802M reduction in retail revenue requirement over the five year period.

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
O&M Expenses ($M)	(31.3)	(85.9)	(127.2)	(158.4)	(190.9)
Capital Expenditures ($M)	(235.6)	(262.4)	(278.9)	(321.7)	(354.9)
System Average Rate (¢/kWh)	(0.16)	(0.40)	(0.93)	(1.48)	(1.92)

C.7 Stop New RPS Spending

Stop New RPS Spending Scenario

Description

Existing:

The Department's Reference Case includes an average increase of 46% per year over the next two

Scenario Assumptions:

The Department will stop its new RPS spending immediately, and all expiring RPS related contracts will years due to RPS capital expenditure associated with new RPS projects increase from $181M in 2012 to $388M in 2014.

not to be replaced or renewed.

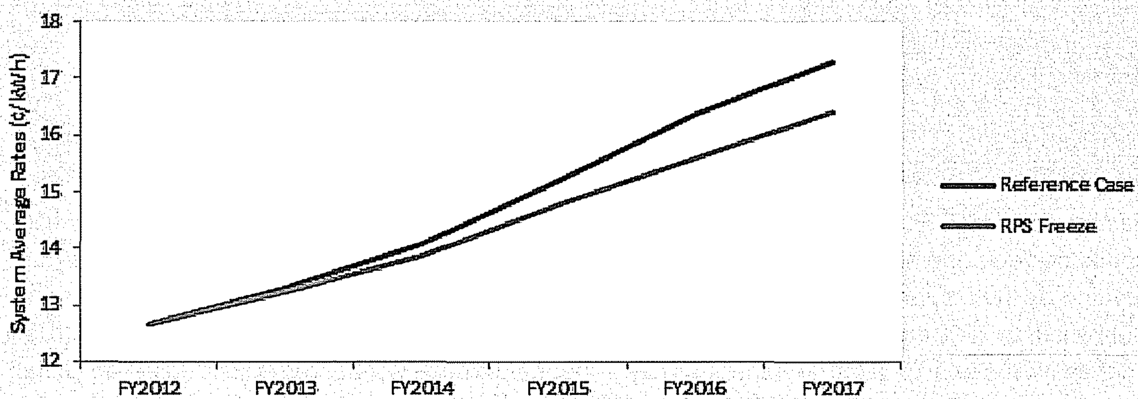
Key Findings:

- Reduction in RPS spending will have a long lasting effect since capital expenditures will be recouped through depreciation and interests over many years. Ratepayers can expect a $540M total reduction in retail revenue requirement over the five year period.
- Electricity generated by RPS projects, which cost approximately $90 to $120/MWh, will be replaced by combined cycle units which cost about $30/MWh.

Revenue Requirement Savings:

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Retail Revenue Increase/(Savings) ($M)	(12)	(49)	(99)	(174)	(206)

Rate Impact:



Based on the Reference Case, RPS spending will contribute more than 20% of the total capital spending over the next five years. This scenario looks into the financial impact of stopping investments in renewable energy going forward. With this level of RPS spending, the Department claims it will face a shortfall of 1.3% of its 2011 to 2013 Compliance Period 1 RPS goal requiring that 20% of all energy consumed by its customers be generated from renewable resources. The Department will also fail to meet its 2016 RPS target of 25% by more than 7% and says it would have to pursue aggressive RPS projects in 2017 and 2018 to meet its 2020 RPS goal of 33%. Under the current RPS rules, penalties and fines associated with RPS non-compliance are still unspecified.

Electricity generated by RPS projects which cost approximately $90 to $120/MWh will be replaced by electricity from combined cycle units at a cost of about $30/MWh. This results in significant savings in fuel and purchased power expenses, a total of $458M over the next five years. Since most of the RPS related activities are capitalized, capital expenses will decrease by $1,180M from FY 2013 to FY 2017. The overall impact to rate payer is a total of $540M reduction in retail revenue requirement over the five year period.

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Fuel and Purchased Power ($M)	(3)	(17)	(43)	(82)	(135)
Capital Expenditures ($M)	(66.5)	(295.7)	(232.6)	(111.5)	(473.7)

System Average Rate (¢/kWh)	(0.05)	(0.21)	(0.43)	(0.76)	(0.90)

C.8 Reduce DSM Goal to 8.6%

Reduce DSM Goal to 8.6% Scenario

Description

Existing:

The Department's Reference Case will achieve a 10% DSM by 2020.

Scenario Assumptions:

The Department will reduce its DSM spending to achieve an 8.6% DSM goal, as recommended in the Global Energy Partners 2010 Potential Study.

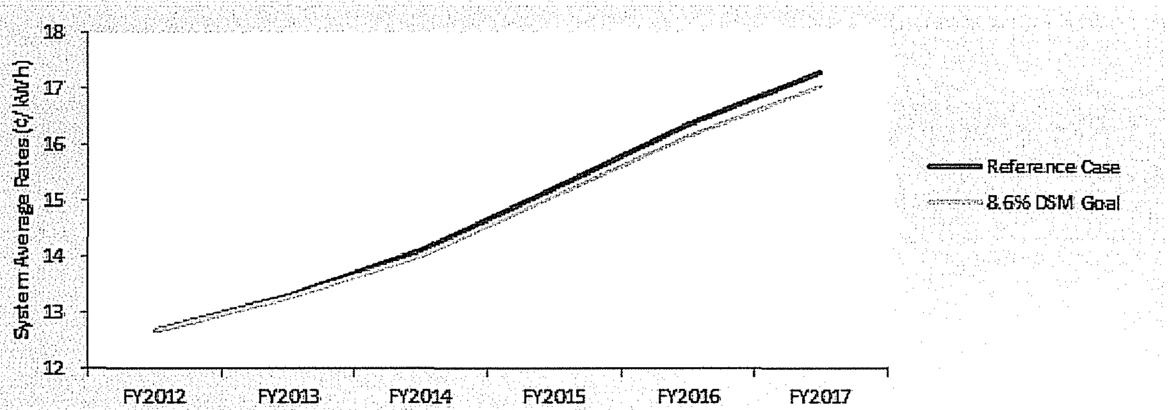
Key Findings:

- Majority of the savings from reduction in DSM capital spending will not be experienced by the ratepayers in the near term.
- Due to lower DSM capacity, additional energy will be required. Higher fuel and purchased power expenses, which will increase by an average of $8M per year over the five year period, will offset some of the savings from the DSM reduction.

Revenue Requirement Savings:

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Retail Revenue Increase/(Savings) ($M)	(3)	(6)	(6)	(11)	(12)

Rate Impact:



Based on the Reference Case, DSM spending will contribute approximately 10% of the total capital spending over the next five years which will allow the Department to achieve a 10% energy efficiency goal by 2020. However, the Energy Efficiency and Demand Response Potential Study done by Global Energy Partners published in 2011 indicated that cost effective DSM investment will most likely contribute only 8.6% of the retail electricity by 2020. This scenario looks into the financial impact of reducing DSM related expenditures to allow the Department to achieve the 8.6% DSM goal by 2020.

All of the DSM related activities are capitalized, and therefore, capital expenses will decrease by $184M from FY 2013 to FY 2017. Lower DSM capacity will increase the Department's net retail sales by an average of 165GWh per year over the five year period. The higher sales volume will have a positive impact on the electricity rates. On the other hand, the increase in fuel and purchased power to compensate for the reduced DSM capacity will offset the savings derived from less DSM investments. The overall impact to rate payer is a total of $39M reduction in retail revenue requirement over the five year period.

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Fuel and Purchased Power ($M)	1	4	6	8	11
Capital Expenditures ($M)	(39.7)	(38.5)	(28.7)	(27.9)	(49.6)
System Average Rate (¢/kWh)	(0.03)	(0.09)	(0.14)	(0.21)	(0.27)

C.9 No Rate Increase

No Rate Increase Scenario

Description

Existing:

Under the Reference Case, system average rate will increase at an average rate of 6.4% per year over the next five years, according to preliminary projections.

Scenario Assumptions:

The system average rate will remain stable at the FY 2012 rate of 12.7 ¢/kWh over the five year period.

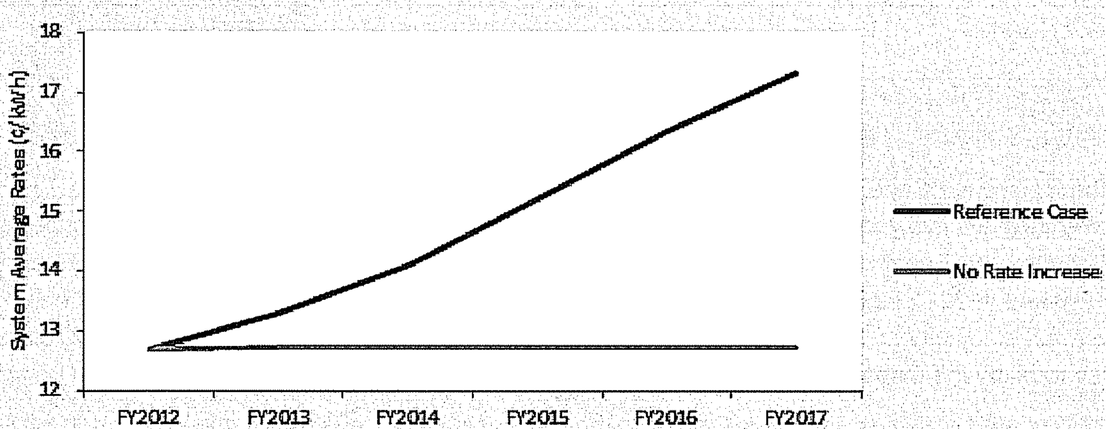
Key Findings:

- The Department has limited ability to reduce debt service associated with borrowings from previous years. In addition, there is no reduction in O&M spending.
- All the financial ratios will fall below the preferred thresholds quickly, and the Department will not be able to fulfill its obligation associated with city transfer.

Revenue Requirement Savings:

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Retail Revenue Increase/(Savings) ($M)	(117)	(264)	(484)	(704)	(874)

Rate Impact:



PA requested two scenarios which assume a no rate increase for the five year period. Under the first scenario, O&M and capital will remain the same as in the Reference Case. Without the rate increase and additional borrowings, all the financial metrics and city transfer will quickly deteriorate. Therefore, this scenario is not realistic and is excluded from further discussion in this report. The second scenario also assumes O&M spending will be the same as in the Reference Case. However, the Department will eliminate capital expenditure for non-mandated projects such as PRP and infrastructure improvement, but investments for IRP and RPS will remain unchanged. The reduction in capital spending will provide limited relief for current year rates. Therefore, without the rate increase to support O&M spending and debt services accumulated in the past years, all the financial metrics and city transfer will fall below the thresholds. The results for this scenario show that the Department do not appears to have a viable plan to achieve zero rate increase for the next five years.

C.10 High Natural Gas Price

High Natural Gas Price Scenario

Description

Existing:
The natural gas price in LADWP's forecast model is less than $3.40MMBtu for FY 2015-2017.

Scenario Assumptions:
The Department's natural gas price will increase to $6.50 per MMBtu from FY 2015-2017.

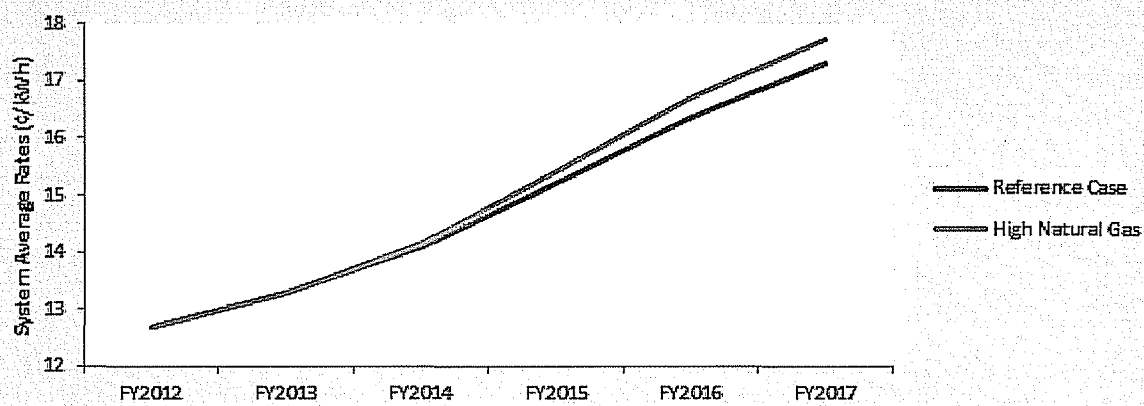
Key Findings:

- In FY 2014, retail revenue requirement will increase by $20M because LADWP uses a 12-month forecast based on the high gas prices.
- Natural gas price at $6.50 per MMBtu is not uncommon based on historical standard, but the rate payers will experience a total of $240M increase in rates between FY 2014 and FY 2017. It appears that the Department may be able to lower this fuel risk through hedging.

Revenue Requirement Savings:

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Retail Revenue Increase/(Savings) ($M)	0	20	46	82	93

Rate Impact:



Currently, LADWP assumes the natural gas prices will be within the $3.00 to $3.50 per MMBtu range from FY 2015 to FY 2017. This scenario assumes the Department's natural gas price will go up to $6.50 per MMBtu starting in FY 2015 and looks at the effect to the revenue requirements. The higher gas price will potentially change the dispatch sequence as natural gas units become less economical.

Under the Reference Case, natural gas already accounts for more than 40% ($136M) of the Department's fuel costs in FY 2015 and will continue to increase to 62% ($196M) in FY 2017. The higher gas price will significantly increase the ratepayer's burden if proper fuel prices hedges are not in place. The high natural gas price will have no impact on O&M and capital expenses over the next five years, but costs associated with fuel and purchased power will increase by almost $227M. The overall impact to rate payer is a total of $241M increase in retail revenue requirement over the five year period. The majority of this increase is driven by the i-ECA.

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Fuel and Purchased Power ($M)	0.0	0.1	48.3	78.0	100.2
System Average Rate (¢/kWh)	0.00	0.08	0.20	0.36	0.41

C.11 High Interest Rates

High Interest Rates Scenario

Description

Existing:

The Reference Case assumes the Department will maintain its long-term fixed debt rate at 4.5%.

Scenario Assumptions:

The Department's long-term fixed debt rate will increase to 6% starting in FY 2015.

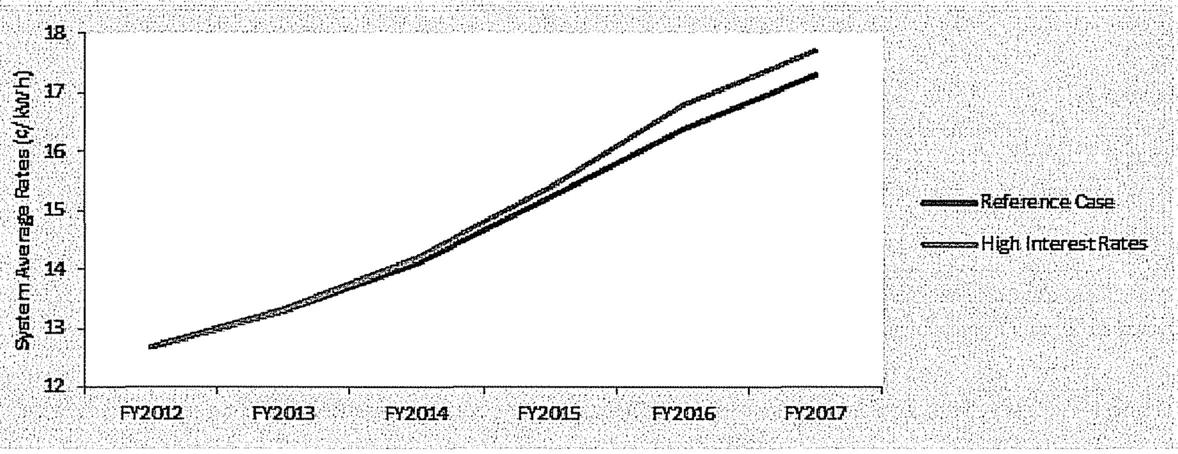
Key Findings:

- Both the incremental Base and ECA revenue requirement categories will increase in FY 2013 and FY 2014 prior to the interest rate increase in FY 2015.
- In order to maintain the Department's current credit rating under a high interest environment, the fund net assets will increase by $70M.

Revenue Requirement Savings:

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Retail Revenue Increase/(Savings) ($M)	7	22	38	99	89

Rate Impact:



Under the Reference Case, the Department develops its capital structure with a 4.5% long-term interest rate for its fixed debt. This scenario, which seeks to gauge the impact of higher interest rates given the Department's significant borrowing projections, assumes that starting in FY 2015, the Department's interest rate will be the "Worst Case" rates developed by Public Resources Advisory Group (PRAG), LADWP's financial advisor. These "Worst Case" rates are documented in Table C.4 below.

Table C.4: Projected Worst Case Rates for Debt and Investments Provided by PRAG

	2013	2014	2015	2016	2017
Investments	5.0%	5.0%	2.75%	4.5%	6.0%
Variable Debt	5.0%	5.0%	2.0%	3.5%	5.0%
Fixed Debt-Power	6.0%	6.0%	6.0%	6.0%	6.0%

The high interest rate will have no impact on O&M and capital expenses over the next five years. However, costs associated with interest expense will increase by $215M. In addition, fuel and purchased power costs will increase by almost $58M. The overall impact to the ratepayer is a total of $255M increase in retail revenue requirement over the five year period.

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Interest Expenses ($M)	5.5	16.9	42.6	66.0	83.5
Fuel and Purchased Power ($M)	1.8	5.1	12.5	17.4	21.0
Increase in Fund Net Assets ($M)	(0.0)	(0.0)	0.4	46.1	23.6
System Average Rate (¢/kWh)	0.03	0.10	0.16	0.43	0.39

C.12 Extended Palo Verde Outage

Extended Palo Verde Outage Scenario

Description

Existing:

Currently, the Department assumes Palo Verde will have a capacity factor of 92% for FY 2013 and 2014.

Scenario Assumptions:

The entire Palo Verde facility is offline for all of FY 2013 and FY 2014. The Department has to shift its generation mix.

Key Findings:

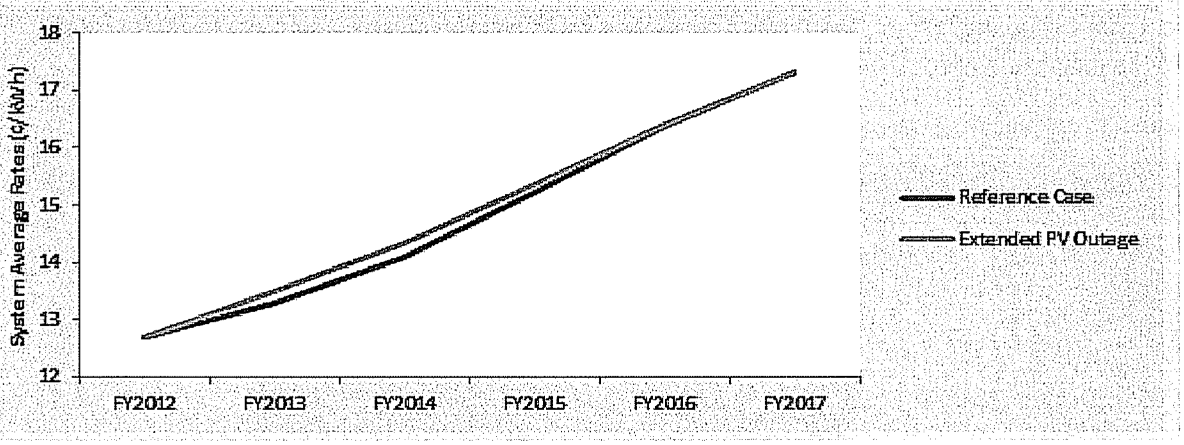
- Higher fuel and purchased power costs contribute to the majority of the revenue requirement increase. Ratepayers will experience a $138M increase in rates compared to the reference case.
- O&M and capital expenditures will not be impacted.

Revenue Requirement Savings:

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017

Retail Revenue Increase/(Savings) ($M)	45	58	28	6	1

Rate Impact:



Both units at San Onofre Nuclear Power Plant, a Southern California Edison's facility, have been off-line due to equipment problems. Several special interest groups have protested the use of nuclear power, and San Onofre has significant uncertainty regarding its restart schedule. Currently, LADWP owns almost 10% of the power output at the 3,875MW Palo Verde Nuclear Power Plant, and the Reference Case assumes Palo Verde will have a capacity factor of 92% for FY 2013 and 2014. There is a chance that Palo Verde will experience extended outage due to problems experienced at San Onofre. Under this scenario, the entire Palo Verde facility is offline for all of FY 2013 and 2014 and the associated effects are examined.

The extended outage at Palo Verde will have no impact on O&M and capital expenses over the next five years. However, in order for the Department to replace the capacity at Palo Verde, fuel and purchased power expense will increase by almost $100M. In addition, CO2 allowance expenses will increase by $35M. The overall impact to rate payer is a total of $138M increase in retail revenue requirement over the five year period.

Compared to Reference Case	FY2013	FY2014	FY2015	FY2016	FY2017
Fuel and Purchased Power ($M)	46.0	50.1	1.1	1.2	1.2
System Average Rate (¢/kWh)	0.19	0.25	0.12	0.03	0.00

Appendix D: Shared Services Cost Allocation Methodology

Shared Service Cost Allocation

For all the non-directly charged expenses, the Department developed a cost allocation methodology to distribute the costs to its Water and Power Funds. Currently, the Department determines cost allocation using a number of considerations:

- Number of Customers on System
- Number of Employees
- Number of Users
- Analysis of Duties
- Accounts Payable Basis
- Aggregate of Finance
- Average Voucher Process

LADWP utilizes the following process to update its shared services cost allocation factors yearly:

- The head of each department determines expenses that can be directly charged to the Water and Power Funds.
- For non-directly charged expenses, the head of each department has to determine the appropriate cost allocation factor.
- The cost allocation factors are calculated.

As part of a robust cost reduction effort, a hard look at this cost allocation methodology is warranted to ensure that both Systems are bearing their appropriate share of the costs.

Appendix E: Table of Recommendations

Rate Restructuring Recommendations

1. The proposed rate ordinances should be adopted on an interim basis.

2. The surcharge-based restructuring approach should be revisited in two years' time and replaced with fully restructured permanent rates once legal considerations allow.

3. Conduct a new formal cost of service study in order to prepare for subsequent rate restructuring.

4. The City should explicitly consider some of the program costs that would be collected in the new surcharges.

Costs Saving Studies

5. Examine the costs associated with repowering construction through a benchmarking study or through a bottom up review of costs and consideration of equipment procurement practices. Review the cost per plant and technology for the program to ensure that costs are reasonable on a per MW basis.

6. Conduct a benchmarking assessment of the PRP's targets, spending level, and effectiveness to make sure the appropriate resources are being brought to bear in this area.

7. Begin to work with the union to find common ground that allows greater flexibility to contract out effectively and bring salaries and benefits closer to market rates, as indicated by LADWP's utility peers.

8. Benchmark staffing and outsourcing levels against that of utility peers. Identify opportunities to contract out and explore the potential savings to begin making a case where promising opportunities exist. Investigate the outsourcing potential across all Systems, with the best additional opportunities expected to found in Joint Services.

9. Complete a rigorous review of the hedging plan in the interest of locking in today's low fuel prices and protecting ratepayers from downside risk.

10. Review overtime expenses allocation, as well as a review of LADWP's contractual requirements that have an impact on overtime.

11. Evaluate the net impact of increasing the number of odd-hour shifts (at a 4-7% salary premium) as a means of limiting overtime.

12. Set a firm three-year plan for energy efficiency, similar to that of the other large California utilities,

that plans expenditure levels at a realistically achievable tempo according to cost effectiveness measurements and includes savings verification.

13. Consider the costs and benefits of a ratings downgrade.

Processes Reviews

14. Find greater efficiency by pursuing process improvement efforts across a range of areas and practices. Appropriate studies should be completed to identify the cost reduction potential associated with a range of process improvements.

15. Adopt a more methodical approach to assessing and communicating the viability of new investments, an important effort that has been practiced more effectively in the Water System. All evaluations should include the consequences of inaction, alternatives considered, and cost-benefit analysis. Any non-mandated projects that cannot be shown to reduce costs or increase revenue collection should not be undertaken without further review.

16. Review the Joint System cost allocation methodology to ensure that both systems are bearing their appropriate share of the costs.

APPENDIX 9: DETAILED EXPLANATION OF RATE DRIVERS

MANDATES:

Rebuilding Local Power Plants to Eliminate Once Through Cooling (OTC)

Once Through Cooling (OTC) is the process by which water is drawn from the ocean for cooling equipment at a power plant and then is discharged back to the ocean. OTC is a major regulatory issue, stemming from the Federal Clean Water Act Section 316(b), administered nationally by the Environmental Protection Agency (EPA) and locally by the State Water Resources Control Board (SWRCB). The new state-wide OTC policy and 316(b) federal rule require LADWP to reduce or eliminate mortality due to impingement and entrainment of marine life and organisms.

Over the next five years, this legal mandate will require $914.6 million in capital investment. During the next two years, as outlined in the IRP, $752.8 million of capital investments will be made for two of the six separate projects to replace the OTC process:

- Haynes Generating Station Units 5 and 6 (also referred to as Haynes Phase I)
- Scattergood Generating Station Unit 3 (also referred to as Scattergood Phase I)

Figure 1 provides the current compliance schedule for complete elimination of OTC.

Figure 1: OTC Compliance Time Line

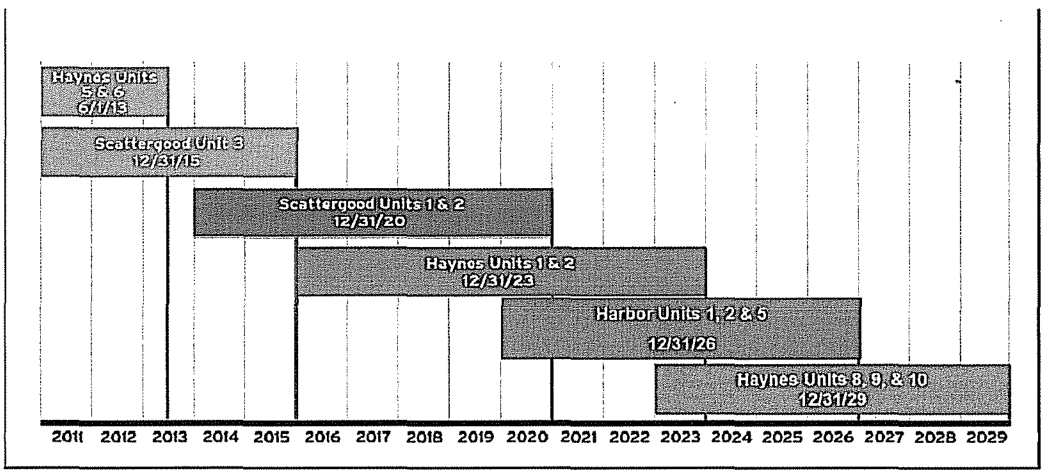


Figure 2 summarizes the budgeted capital and O&M expenditures and annual percentage rate impact for FYs 2012-13 and 2013-14.

Figure 2: Rebuilding Local Power Plants - Capital and O&M Expenditures and Annual Rate Increase

Cost Driver ($M)	Cost Type	Current Year	Upcoming Two-Year Period	
		FY 2012	FY 2013	FY 2014
Rebuilding Local Power Plants	Capital	$375.0	$380.0	$372.8
	O&M	0.00	0.00	0.00
Total Expenditures		$375.0	$380.0	$372.8
Annual Incremental Percentage Rate Increase		-	**1.0%**	**1.2%**

Renewable Energy to Meet State-Mandated Renewable Portfolio Standard (RPS) Compliance Dates

Shifting a greater amount of energy production to renewable energy sources is a major mandate and environmental initiative in California memorialized by the California Renewable Energy Resources Act, signed into law in April 2011. The rates proposed herein will allow LADWP to meet the current renewable compliance targets and maintain a pace of investment to reach the mandated targets in 2016 and 2020. During the next five fiscal years, as outlined in the IRP, $3.7 billion capital and O&M expenses will be required to ensure LADWP is able to meet the RPS compliance targets of:

Compliance with state-mandated interim milestones requires:

- 20.0% average for the period of January 1, 2011, through December 31, 2013
- 25.0% average by December 31, 2016 (based on the average percentage of retail sales for the period of January 1, 2016, to December 31, 2016)
- 33.0% average by December 31, 2020 (based on the average percentage of retail sales calculations for the period of January 1, 2020, to December 31, 2020)

Figure 3 provides the estimated renewable energy resource forecasts for the next two fiscal years (FY 2012-13 and 2013-14) for each year and energy type.

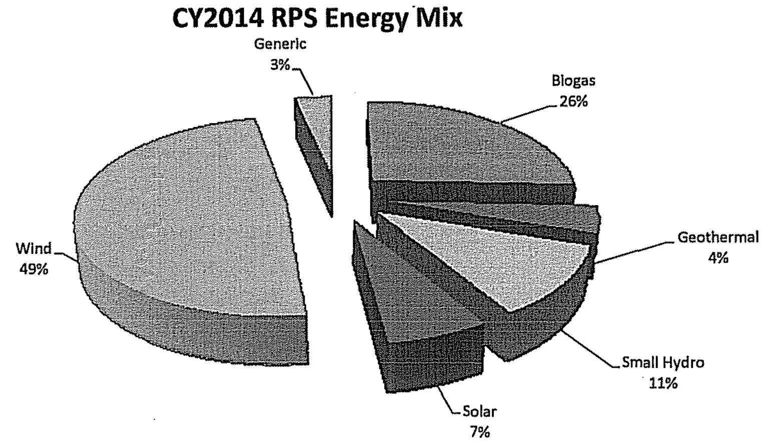
Figure 3: Renewable Energy Resource RPS Contribution Forecast

Renewable Energy Type	Current Year	Proposed Rate Period	
	FY 2012	**FY 2013**	**FY 2014**
Biogas	5.4%	5.6%	4.4%
Geothermal	0.0%	0.0%	0.0%
Small Hydro	1.8%	2.5%	2.7%
Solar	0.5%	0.8%	4.2%
Wind	10.1%	10.2%	10.5%
Generic[1]	1.7%	1.6%	0.1%
Total	**19.5%**	**20.8%**	**21.9%**
Required	20%[2]		

At the end of FY 2013-14, LADWP's mix of renewable energy resources is projected to include a diverse portfolio as shown in Figure 4.

[1] "Generic" category of renewables consists of renewable energy of unspecified type which could come from market purchase or increased size of planned renewable projects. Pricing used is $140 per MWh with no escalation.
[2] 20% average for the period January 1, 2011, through December 31, 2013

Figure 4: Calendar Year (CY) 2014 RPS Energy Mix



To ensure a reliable transport system to bring the Department's future reliable energy resources to its customer distribution system, LADWP is following a renewable energy transmission strategy that encompasses three prioritized options:

1. Utilize existing transmission lines;
2. Upgrade existing transmission lines to transport renewable power; or
3. Construct new transmission facilities.

The proposed rates and forecasted costs include funding for the following projects and line upgrade:

- *Barren Ridge Renewable Transmission Project:* Increase the capacity of the existing 230kV Barren Ridge - Rinaldi transmission segment by the end of 2016. During the next two fiscal years, however, costs will be incurred related to design and engineering as well as construction of the line.
- *Long-Term Transmission Development:* This program consists of several projects which will increase the transfer capacity of the Department's transmission network, principally the upgrade of the Pacific DC Intertie from 3,100 MW to 3,220 MW, Path 42 Imperial Irrigation District line upgrade to transport renewable power from the Coachella Valley, Victorville-Century line conversion to DC to increase capacity from 600 MW to 1,000 MW, and reactive power management of the Department's transmission network.
- *STS Transmission Upgrade:* Intermountain Power Agency (IPA) and Asea Brown-Boveri (ABB) entered into a contract to upgrade the Southern Transmission System (STS) from 1,920 MW to 2,400 MW. LADWP will perform all design and construction at the Adelanto AC Switching Station. LADWP, in its capacity as Operating Agent for IPA, is acting as the Project Manager and the contract administrator on behalf of IPA. The additional 480 MW will allow STS to transmit energy from authorized and planned wind turbines and other renewable electric generating resources to LADWP's service territories.

Over the next two years, the proposed revenue increase of $69.8 million will support $1.3 billion of expenditures ($537.7 million of capital expenditures; $746.5 million of O&M expenses) for renewable energy and renewable transmission facilities. The capital expenditures will be financed through debt borrowings, including $1.3 billion of off-balance sheet debt. Figure 5 summarizes the budgeted capital and O&M expenditures and annual percentage rate impact for FYs 2012-13 and 2013-14.

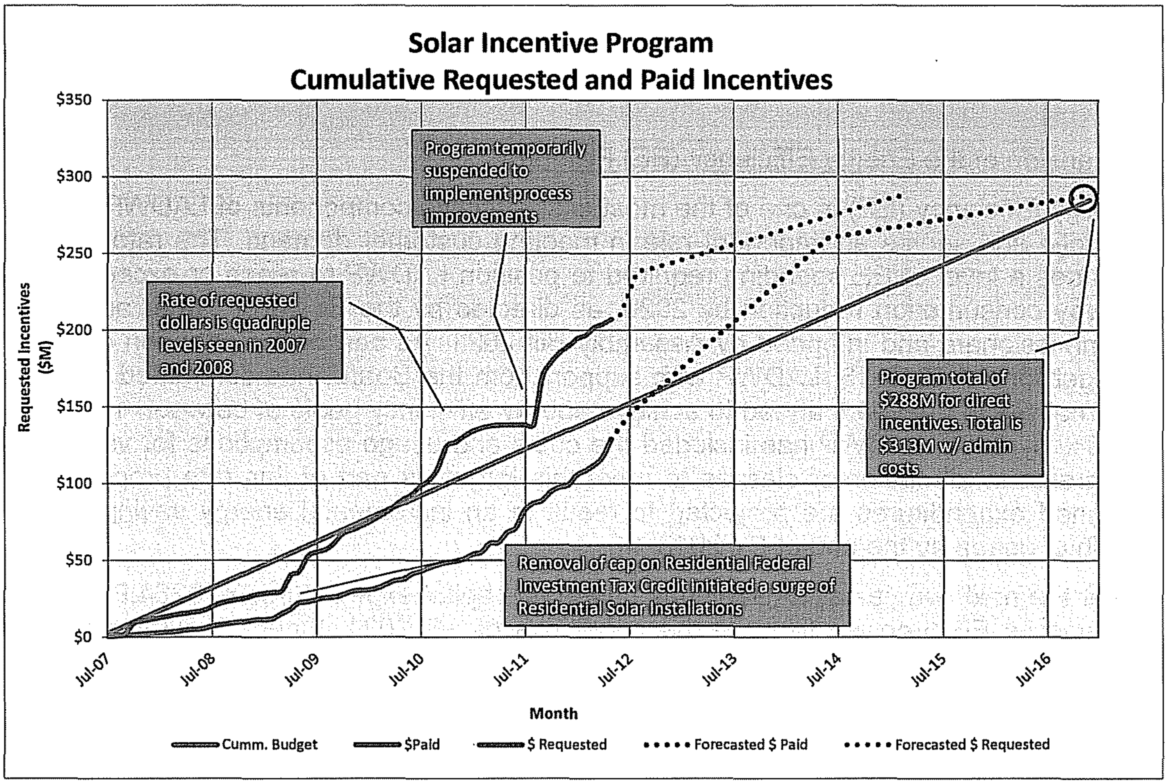
Figure 5: Renewable Energy and Transmission - Capital and O&M Expenditures and Annual Rate Increase

Renewable Energy Type ($M)	Current Year	Proposed Rate Period	
	FY 2012	FY 2013	FY 2014
Solar	$160.5	$95.4	$124.2
Wind	216.7	228.1	234.0
Geothermal	0.9	0.8	0.8
Small Hydro	56.0	31.6	41.8
Biogas / Biomass	62.9	84.4	84.1
Transmission	16.2	46.9	285.5
Generic	9.1	17.9	8.5
Total	$522.3	$505.2	$779.0
Annual Incremental Percentage Rate Increase		**1.2%**	**1.1%**

Solar Customer Rebate Program:

A part of the renewable energy shift is focused on solar energy production. State Senate Bill SB1, passed on August 21, 2006, mandates that all California electric utilities implement a solar incentive program by January 1, 2008 with a cap on expenditures of $3.4 billion. LADWP's program to meet this mandate is the Solar Photovoltaic Incentive Program. LADWP's share of the program, based on its percentage of load served in the state, is $313.0 million. Figure 6 provides the historical results for the program and expected activity for the next several years.

Figure 6: Projected Solar Customer Rebate Program Requests and Expenditures



LADWP's program is designed to provide incentives to customers to install solar facilities at their premises. Under SB 1, customers can receive financial incentives from LADWP for about one-third of the costs to install solar panels. For those facilities subsidized by LADWP, the total GWh generated by the customer-installed solar facilities are considered renewable energy resources for the purpose of meeting LADWP's mandated targets.

Over the next two years, LADWP has budgeted capital expenditures of $129.1 million for the solar rebate program. Figure 7 summarizes the budgeted capital expenditures and annual percentage rate impact for FYs 2012-13 and 2013-14.

Figure 7: Solar Customer Rebate Program – Capital Expenditures and Annual Rate Increase

Solar Customer Rebate Program ($M)	Current Year	Proposed Rate Period	
Fiscal Year	**FY 2012**	**FY 2013**	**FY 2014**
Capital Expenditures ($M)	$62.9	$64.5	$64.6
Annual Incremental Percentage Rate Increase	**-**	**0.3%**	**0.3%**

Expansion of the Energy Efficiency (EE) Program

Energy Efficiency (EE) is one of the most cost effective components of LADWP's supply portfolio and serves an important role in meeting customer demand. The rate proposal includes a level of EE spending required to position LADWP to reach or exceed a 10% energy consumption reduction by 2020, as directed by the Board of Water and Power Commissioners and intended by Assembly Bill 2021. As part of the adoption of the EE budget for FY 2012-13, LADWP with support from the Board, has committed to review alternatives in the years ahead to achieve energy efficiency goals of between 10.0% and 15.0% by 2020. LADWP has included the costs and usage assumptions for various EE programs in all customer classes to meet this target as part of this rate proposal. The planned expenditures are projected to result in an incremental energy savings of 561 GWh of usage by the end of FY 2013-14.

Over the next two years, LADWP has budgeted capital expenditures of $264.9 million to expand its EE program to meet the conditions of AB 2021. Figure 8 summarizes the budgeted capital and O&M expenditures, estimated incremental energy efficiency savings (GWh) and annual percentage rate impact for FYs 2012-13 and 2013-14.

Figure 8: Energy Efficiency – Capital and O&M Expenditures, Incremental Energy Efficiency Savings (GWh) and Annual Rate Increase

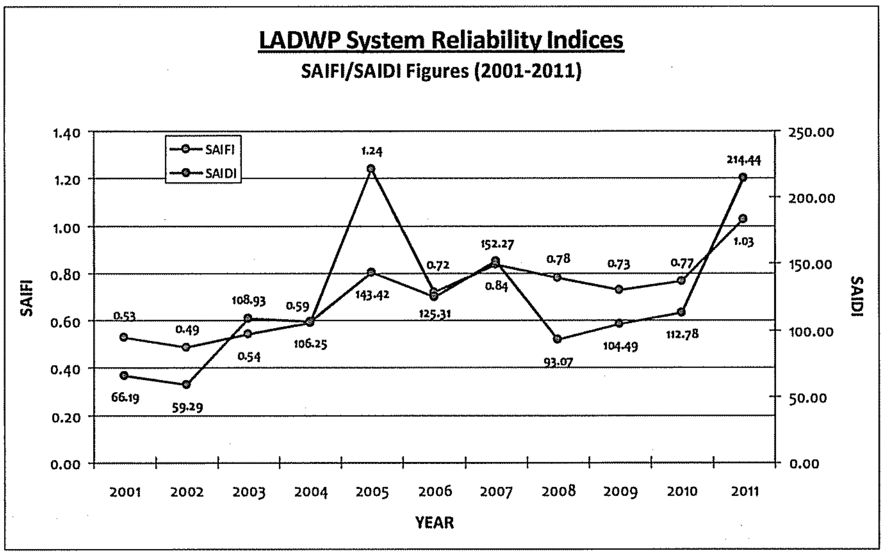
Energy Efficiency Plan ($M)	Current Year	Proposed Rate Period	
Fiscal Year	**FY 2012**	**FY 2013**	**FY 2014**
Capital	$55.1	$127.2	$137.7
O&M	18.0	0.0	0.0
Total Expenditures	$73.1 budgeted $55 forecast	$127.2	$137.7
Incremental Energy Efficiency Savings (GWh)	146	266	295
Annual Incremental Percentage Rate Increase	**-**	**0.9%**	**1.5%**

POWER RELIABILITY PROGRAM

The purpose of the Power Reliability Program (PRP) is to replace and/or upgrade aging infrastructure necessary for the reliable delivery of power to customers. During the next two years, LADWP's rate proposal includes increased funding for the PRP. This increase, while on the surface appearing substantial, brings expenditures to a level close to that of two years ago and falls short of that which would be necessary to truly get ahead of the rate of decline that LADWP faces with the aging system to deliver reliable power to customers.

As shown in Figure 9, LADWP's latest SAIFI is 1.03 vs. the 1.1 national average, and its SAIDI is 215.8 minutes vs. the national average of 90 minutes. As the chart below shows, both of these indices for LADWP are trending in the wrong direction.

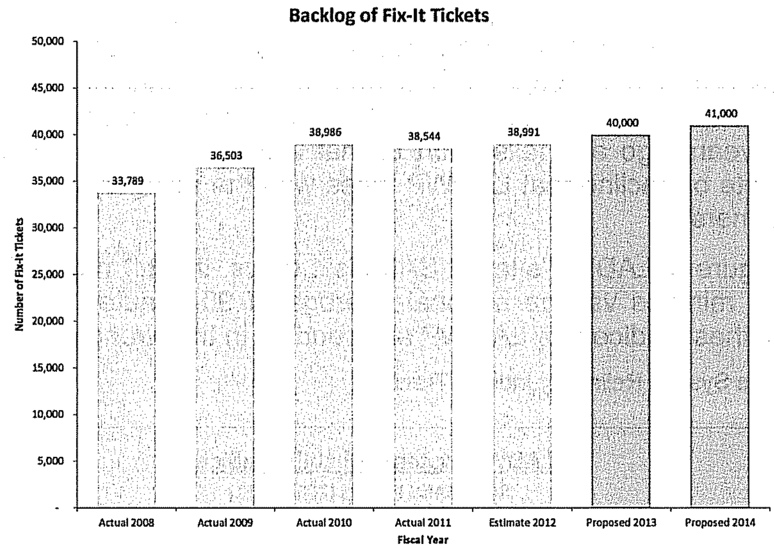
Figure 9: LADWP's System Reliability Indices Trends



In recent years, while investments have increased, LADWP has still been reacting to aging assets, often replacing facilities after they fail. To reduce the number of outages, especially those due to pole and cross-arm deterioration, a more proactive approach with continued investments over the next two years is proposed. This increased investment will have a positive impact on reliability, but it will not preclude the need for further reliability program increases in later years. The specific aspects of the PRP are discussed below.

Backlog of Fix-It Tickets: Fix-it tickets represent maintenance work required to provide permanent repairs to temporary fixes. To reduce the approximately 41,000 fix-it tickets in the queue to a desired more reasonable base, or ongoing level, of 2,000 to 5,000, it would take 3 million work hours to catch up. The proposed level of funding for the PRP in the FY 2012-13 and FY 2013-14 does not provide sufficient funding for this catch-up. Based on the forecasted PRP funding levels, the fix-it ticket backlog will increase by approximately 1,000 tickets per year, as shown in Figure 10.

Figure 10: Historical and Forecasted Backlog of Fix It Tickets (FYs 2007-08 – 2013-14)

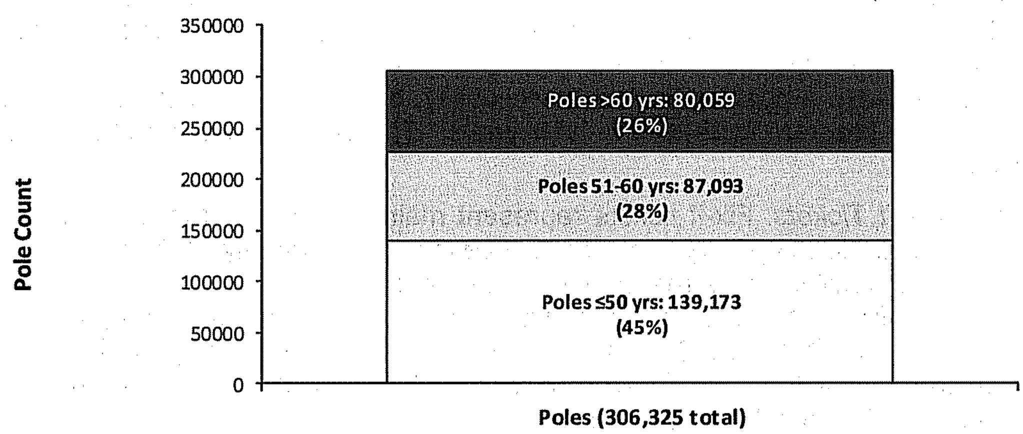


Replacement/Upgrade of Aging Infrastructure

The condition of several key components of the distribution infrastructure poses a growing threat to overall reliability. The increased PRP investment is designed to target these areas by replacing or repairing the specific facilities that are expected to have the greatest impact on reliability.

Pole Replacement Program: Since approximately 70.0% of LADWP's system is overhead, pole and cross arm replacements are a major driver of reliability. The proposed rates are designed to accelerate pole and cross-arm replacement. As shown in Figure 11, 26.0% of LADWP's poles currently exceed their 60-year useful life, and an additional 28.0% of LADWP's poles will reach 60 years of age during the next 1 to 10 years.

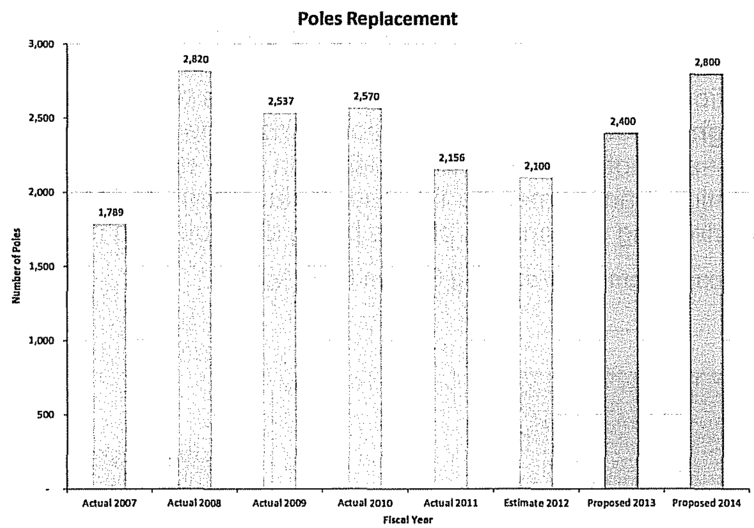
Figure 11: Pole Aging



The recommended replacement rate is 60 years; however, LADWP is currently on a 152-year replacement cycle, which is more than double the recommended cycle. Therefore, additional investment in pole replacement is warranted.

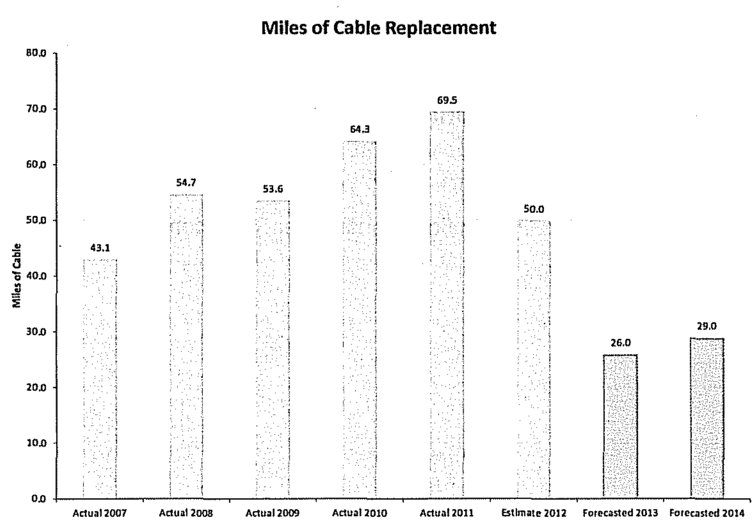
As shown in Figure 12, LADWP is requesting funding to begin modestly accelerating the pole replacement program from the current level of 2,100 poles per year to approximately 2,400 poles in FY 2012-13 and 2,800 poles in FY 2013-14, which would reduce the replacement cycle to 133 years. To achieve the recommended 60-year cycle, 5,000 poles per year would need to be replaced each year.

Figure 12: Historical and Forecasted Pole Replacement (FYs 2006-07 – 2013-14)



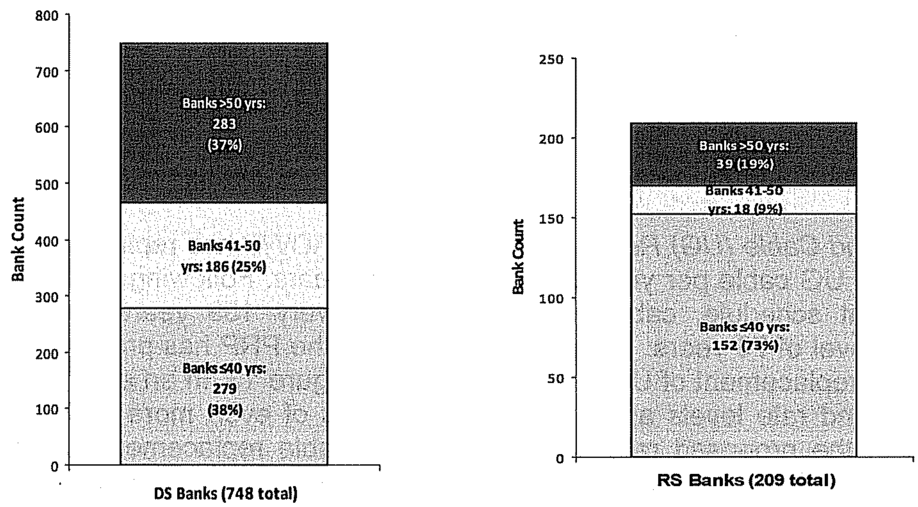
Underground Cable (UG) Replacement Program: LADWP has replaced, on average, 53 miles of UG cable per year over the past five years. Following LADWP's current replacement schedule, cable will be replaced every 159 years compared to a preferred level of 75 years. In the past five years, the PRP has provided funding for the rate of replacement of UG cable as shown in Figure 13. In an attempt to balance spending and rate levels and address other areas of even more critical need, the funding in the proposed rate plan reduces the cable replacement program to an average annual replacement of 27 miles of UG cable per year for the next two years. To achieve the preferred level of cable replacements, the rate of replacement would need to be 60 miles of cable per year, which would require additional revenue increases.

Figure 13: Historical and Forecasted Cable Replacement (FYs 2006-07 – 2013-14)



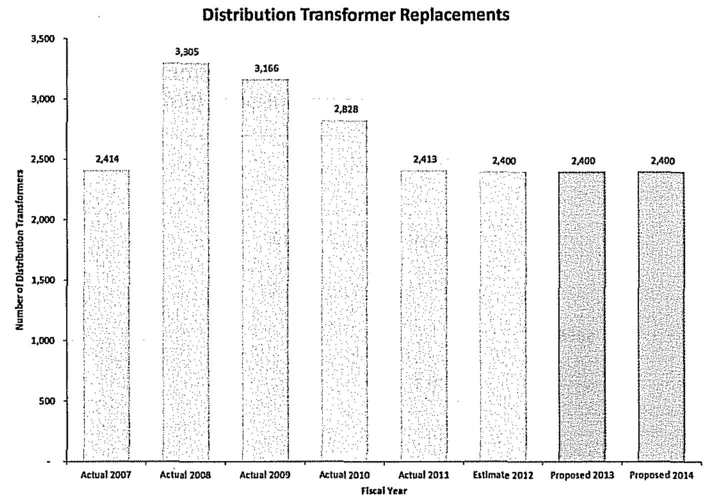
Substation Transformer Replacement Program: As Figure 14 shows, over 60.0% of LADWP's 957 substation transformer banks are over 40 years old, with 37.0% over 50 years old. These transformer banks are nearing the end of their service life and are critical to the continued reliability of the Power Distribution System. Replacement of these banks is needed due to the large number of customers that lose power when these transformers fail. From the aging graph below, significant progress has been made over the past five years to address the very old, large bulk power receiving station banks. Work continues for these as well as increased replacements for aging neighborhood distributing station transformer banks. Two areas that need to be addressed, not shown in the illustration, are needed replacements for large switching station transformer banks and replacement of the large transformers in LADWP's generating stations. A plan is being developed to address those assets.

Figure 14: Distribution System and Receiving System Bank Aging



Distribution Transformer Replacements: In recent years, the PRP has provided funding to replace significant numbers of transformers as shown in the figure below. Prior to the heat wave in July 2006, LADWP installed about 2,000 transformers per year. Following that heat wave, which caused a significant number of transformer failures, LADWP increased transformer installations by 20.0%, implemented an asset modeling tool, and does substantial replacements every year in preparation for summer. Transformer replacements are expected to average 2,400 for the next two years, as depicted in Figure 15. At this rate of replacement, the average age of LADWP's transformers will remain at 27 years.

Figure 15: Historical and Forecasted Distribution Transformer Replacements (FYs 2006-07 – 2013-14)



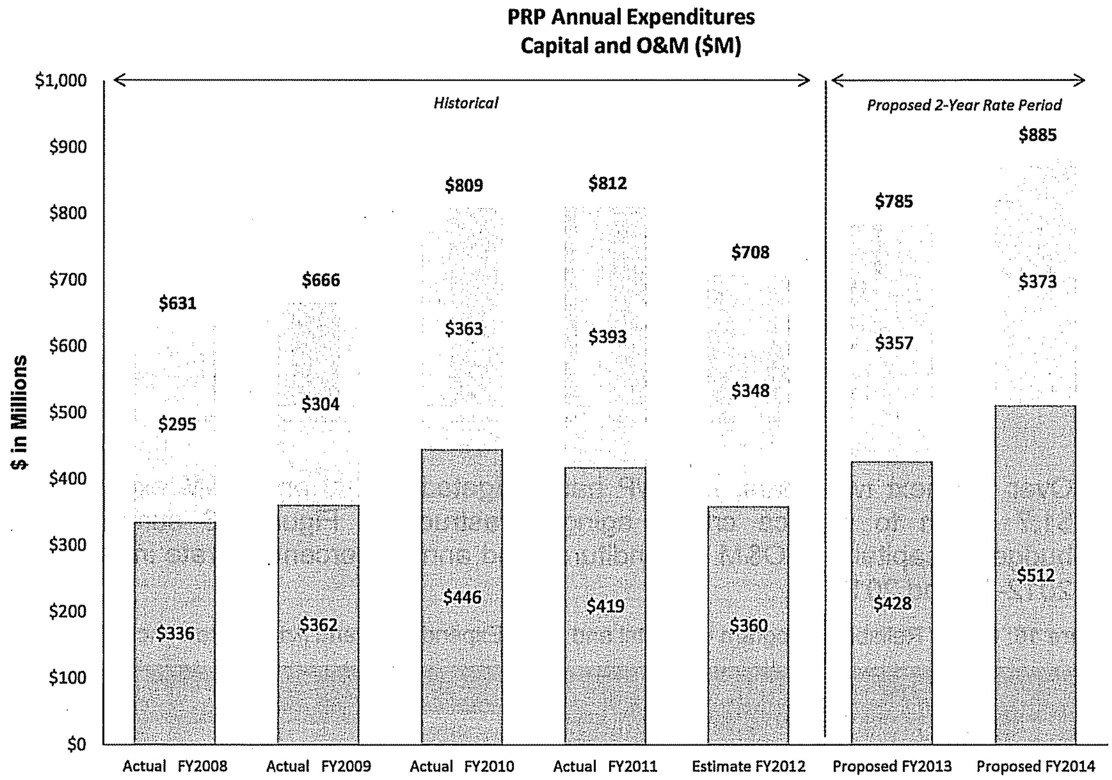
Over the next two years, LADWP has budgeted capital and O&M expenditures of $1.7 billion to replace critical aging infrastructure. Figure 16 summarizes the budgeted capital and O&M expenditures and annual percentage rate impact for FYs 2012-13 and 2013-14.

Figure 16: Power Reliability Program – Capital and O&M Expenditures and Annual Rate Increase

Cost Driver ($M)	Cost Type	Current Year	Proposed Rate Period	
		FY 2012	**FY 2013**	**FY 2014**
PRP Expenditures	Capital	$360.2	$427.5	$511.9
	O&M	348.1	357.1	373.3
Total Expenditures		$708.3	$784.6	$885.2
Annual Incremental Percentage Rate Increase		-	**0.9%**	**0.8%**

The actual annual expenditures from FY 2008 through FY 2012 (FY 2012 estimated) are shown in Figure 17 below, along with the proposed PRP spending levels for the next two fiscal years.

Figure 17: PRP Historical and Upcoming Two-Year Period - Capital and O&M Expenditures



** Actual expenditures exclude AFUDC, CIAC, REV*

Balancing investment levels for infrastructure reliability with the need to comply with external mandates while mitigating rate increases to the extent possible will continue to be a major challenge for LADWP. As a result, the Department will focus available resources on maintaining critical assets and enhancing processes to offset the impact of lower than desired PRP funding in the short term with the goal of maintaining existing reliability levels. LADWP is implementing programs to balance asset management, efficient cost management, and service levels in the near term, recognizing that, in the longer term, focused and increased PRP spending will be required to replace aging infrastructure (i.e., move to critical assets prioritization based on exposure and risk).

MARKET DRIVEN

Fuel and Purchased Power

LADWP must account for purchasing significant volumes of fuel and for purchased power and related fuel costs (as well as exposure to fuel price volatility) in its budget, operating, and rate plans. Fuel in this context includes all costs associated with natural gas, coal, and nuclear fuel procurement. Fuel also includes emissions, greenhouse gas reduction, and retirement costs. Similarly, purchased power from coal, nuclear, renewable, and other sources includes all costs associated with payments made for contracted energy purchases.

Fuel costs are driven primarily by free market forces and can fluctuate significantly year to year, and within a year. LADWP mitigates the risk of price volatility through financial hedging programs, owned gas fields, and long-term fixed price contracts. The Department's gas hedging program, which began in 2002, was implemented against the backdrop of extreme volatility in natural gas prices to maintain stable net income levels and supply reliability. The purpose of the Department's hedging program is to reduce the volatility of the Department's costs and resulting rates paid by its customers. Hedge programs limit the exposure to natural gas price swings by using physical and financial contracts and gas storage.

Over the next two years, LADWP expects fuel and purchased power costs to total $2.7 billion. Figure 18 summarizes the budgeted fuel and purchased power costs and annual percentage rate impact for FYs 2012-13 and 2013-14.

Figure 18: Annual Fuel and Purchased Power Costs and Annual Rate Increase

Fuel / Purchased Power Costs ($M)	Current Year	Proposed Rate Period	
Fiscal Year	**FY 2012**	**FY 2013**	**FY 2014**
Fuel			
Biomethane	$60.0	$81.5	$81.5
Natural Gas	252.8	199.2	189.8
Coal	69.9	74.2	76.6
Nuclear	20.8	16.6	21.0
Fuel Subtotal	**403.6**	**371.5**	**368.9**
Purchased Power			
Renewables	255.0	246.8	281.0
Coal	427.5	476.7	515.3
Nuclear	58.2	61.4	63.0
Others[3]	155.3	143.1	140.9
Purchased Power Subtotal	**896.0**	**928.1**	**1,000.2**
Total	$1,299.5	$1,299.6	$1,369.1
Annual Incremental Percentage Rate Increase	-	**0.5%**	**1.2%**

Feed-in Tariff Program: The FiT is a program to encourage customers to invest in customer-owned renewable technologies, including solar facilities. Power supplied by the FiT is considered a power purchase agreement (PPA) and is budgeted as O&M expense in the fuel and purchased power budget. LADWP and the City benefit from the procurement of this power in several ways — the power counts toward the RPS requirement, and there are reliability and economic benefits to having the power produced in the City. The rates presented in this letter include a 75 MW FiT program phased in by year-end of 2016, under which LADWP will purchase power generated by

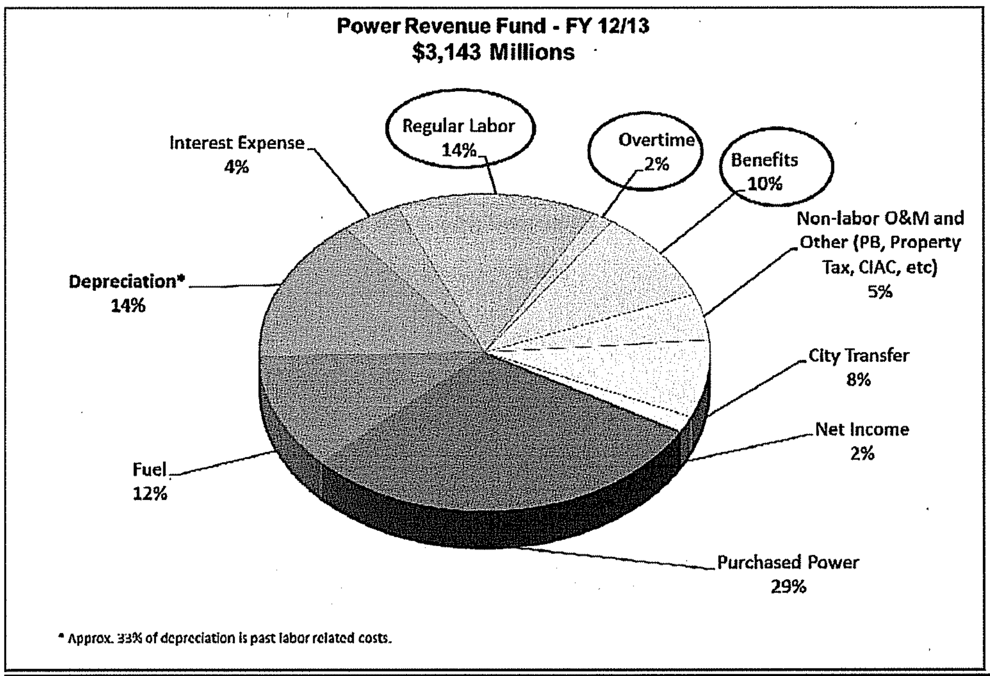
[3] "Others" category includes economy purchases, cogeneration, non-RPS transmission, and Hoover hydro power

local solar power producers. Over the next two years, LADWP has budgeted O&M expenditures of $6.73 million for the FiT program.

Other Considerations

The rate covenant contained within LADWP's bond indentures requires that LADWP pay all basic operating expenses required to operate and maintain the Power System. These expenses typically escalate over time due to inflation and provide pressure on rates other than the cost pressures LADWP faces from the need to rebuild aging infrastructure and address regulatory mandates and goals. LADWP has separately estimated the impact of inflation and pension costs (benefits include both pension costs and healthcare costs) on basic operations. Figure 19 shows that portion of the Power System's revenue requirement and proposed rates represented by wages and benefits in operating and maintenance expenses; inflation (in the form of cost of living adjustments, or COLA) and pension costs cause increases in wage and benefit costs over time. Collectively, wages and benefits represent approximately 26.0% of the Power System's $3.15 million revenue requirement for FY 2012-13. The proposed rates for the next two years are designed to provide the revenue to cover these expenses.

Figure 19: Power Revenue Fund (FY 2012-13)



APPENDIX 10: Public Outreach Summary (April – August 2012)

Group	Date	Attendance
Neighborhood Councils		
Greater Wilshire NC	04/11/12	31
Rates Briefing with DWP MOU Committee	04/16/12	
Rampart Village NC	04/17/12	22
NC Valley Village	04/25/12	25
Sunland Tujunga NC	05/09/12	40
Valley Alliance of NCs (VANC)	05/10/12	35
NC/DWP MOU OSC & LANNC	06/02/12	45
Tarzana NC	06/12	
Sylmar NC	06/12/12	6
Pacoima NC	06/20/12	36
Hollywood United NC	07/16/12	35
NC Valley Village	07/18/12	15
Central Hllywd NC	07/23/12	14
Winnetka NC	07/12	
Greater Valley Glen NC	08/06/12	15
South Robertson NC	08/12	
Glassell Park NC	6/19/12 & 8/21/12	
Harbor Gateway North	5/10/12	
Harbor Gateway South	5/10/12	
Highland Park	4/15/12	
Arroyo Seco	4/15/12	
Toluca Lake	08/21/12	35

Group	Date	Attendance
Sub-Total	**22**	
General Workshops		
Harbor Area (CD 15) Rates Briefing	04/25/12	
West Valley Area (CD 3) Rates Briefing	04/26/12	
DWP Metro regional rates workshop	04/28/12	
South LA Area (CD 8) Rates Briefing	04/30/12	
East LA Area (CD 14) Rates Briefing	05/02/12	
Central Valley Area (CD 6) Rates Briefing	05/03/12	
West LA Area (CD 5) Rates Briefing	05/10/12	
Sub-Total	**7**	
Council Office Hosted Workshops		
CD 4 local area community meeting	05/15/12	1
CD 2 local area community meeting	05/16/12	32
CD 7 local area community meeting	05/17/12	0
CD 6 local area community meeting	05/21/12	8
CD 8 local area community meeting	5/12	
CD 11 local area community meeting	5/12	
CD 10 local area community meeting	5/12	
CD 12 local area community meeting	5/12	
CD 15 local area community meeting	5/12	
CD 9 local area community meeting	06/13/12	
CD 15 local area community meeting	06/14/12	10
Sub-Total	**11**	
Business Workshops		
Rates Briefing with Los Angeles Area Chamber of Commerce Energy, Water & Environmental	04/20/12	

Group	Date	Attendance
Sustainability Council (committee)		
Rates Briefing with Central City Association	05/03/12	
Premier Accounts Rates Briefing	05/03/12	
Rates Briefing with VICA (Valley Industry & Commerce Association)	05/31/12	
Rates Briefing with VICA Energy, Environment, & Utilities Committee	06/07/12	
Rates Briefing with BOMA (Building Owners & Managers Association)	06/08/12	
Rates Briefing with LABC Executive Committee (LA Business Council)	06/12/12	
Follow Up Rates Briefing with VICA Energy, Environment, & Utilities Committee	08/02/12	
Sub-Total	**8**	
Other Workshops		
Council Staff Rates Briefing	04/26/12	
LADWP Employee Rates Meeting	05/30/12	
Community Rates Briefing with Repower LA Coalition/Scope/Agenda	07/21/12	
Sub-Total	**3**	
Total	**51**	